Oregon
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June 22, 2022

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UE 399 – In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.

Attached for filing are the following:
UE 399 Staff Opening Testimony Exhibits 100-1705 Redacted Versions and Non- Confidential Exhibits, Cover Letter, Certificate of Service and Service List.

Please retrieve both versions from agency drive under Temporary Confidential Filings.

Confidential testimony, exhibits and work paper will be available in the Huddle workspace after filing has been accepted.

/s/ Kay Barnes
Kay Barnes
Oregon Public Utility Commission
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CERTIFICATE OF SERVICE

UE 399

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 22nd day of June, 2022 at Salem, Oregon

Kay BARNES

Kay Barnes
Public Utility Commission
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CASE: UE 399
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony:
Overview, Public Comments, Overall Rate of Return, and Return on Equity

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Matt Muldoon. I am a Manager employed in the Rates, Finance and Audit (RFA) Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I introduce Staff-sponsored adjustments and issues regarding the PacifiCorp (PAC, or Company) request for a general rate revision, docketed as Docket No. UE 399. Please refer to Exhibit No. Staff/200, the testimony of John Fox for additional detail about component revenue, expense, and rate base components of Staff proposed adjustments.

In addition, I summarize public comments received by the Commission regarding this rate case, point to Staff testimony where these issues are examined and provide a count of the public comments that shared each concern.

I also address Cost of Capital components and overall Rate of Return (ROR), going into greater detail regarding Return on Common Equity (ROE), and Capital Structure.

Q. Will other Staff witnesses submit testimony regarding the issues they reviewed?

A. Yes. Each Staff assigned to Docket No. UE 399 is submitting separate testimony. In my testimony, I first introduce the Staff witnesses and their respective assignments and estimate the revenue requirement impact of Staff recommended adjustments to the Company's initial filing. These are the issues identified to date. Staff's recommendations and issues may change after reviewing testimony and analysis by other parties.

Q. How is your testimony organized?

A. My testimony is organized around the following issues as follows:

Q. Please outline other supporting exhibits for this testimony?

A. My testimony is supported by the following exhibits:

102	Framework for ROE Modeling	Page:
	Moody's vs. S&P Credit Ratings	1
	Peer Utility Screening	2
	Value Line (VL) Dividends for Modeling Peers	3
	Hamada Equation	4
	Earnings per Share (EPS) for Modeling Peers	4
103	Three Stage Discounted Cash Flow (DCF) ROE Models	
	Model X with Perpetual Dividend Cash Flow	1
	Model Y with Terminal Sale of Stock	2
104	Three-Stage DCF Modeling Results	
105	Capital Asset Pricing Model (CAPM)	
106	Single Stage (Gordon Growth) DCF Model	
107	U.S. Bureau of Economic Analysis (BEA) GDP Growth	
108	U.S Treasury (UST) Treasury Inflation-Protected Security (TIPS) Implied Inflation Rates	1
109	Financial News	
110	Edison Electric Instutute (EEI) 2020 Annual Financial Review Report	
111	U.S. White House Budget Fiscal Year (FY) 2023	
112	Blue Chip Financial Forecasts	
113	VL Covered Electric Utilities	
114	Utility Capital Structure Discussion	
	Sanyal & Bulan 2011	1
	Spiegel and Spulber 1997	22
115	Company Responses to Data Request (DR) 422.	

1. REVENUE REQUIREMENT IMPACT BY STAFF TOPIC

Q. Please provide a list of the rate case topics that Staff reviewed and introduce the responsible Staff.

A. See Table 1 below:

TABLE 1 – STAFF RATE CASE TOPICS

Price Change - 12 Months Ending December. 31, 2023 [Non-Net Power Cost (NPC) Related - (excludes TAM)]				**$ 84,399.29**
Testimony	**Issue**	**Staff**	**Staff Adjustments ($000)**	**Revenue Requirement Effect**
100	1	Muldoon	Revenue Requirement by Staff Topic	$0
	2		Intro to Staff Opening Testimony	$0
	3		Public Comments Received	$0
	4		Overall Rate of Return (ROR)	$0
			Capital Structure	($7,023)
			Return on Equity	($17,270)
200	.	Fox	TAM-Related Rev. Sensitive Expense	($120)
	.		Overall Revenue Requirement	
	1		Interest Synch	($4,129)
	.		Electric Plant Acquisition Adjustments	
	.		Consolidated Deferrals	
	2		Deferral Amortization	$4,706
	3		Escalation Adjustments	$2,899
	.		Income Taxes	
	.		Taxes Other Than Income	
	4		OPUC Fee Rate	$761
	5		Wyoming Wind Tax	($45)
	.		Emissions Control Investment Adjustment	
	.		Utility Plant	
	6		Carbon Cholla Land	($118)
	7		Blanket Projects	$0
	8		Project Attestation	$0
	.		Unbundling and Functionalization	
300	1	Anderson	TB Flats Cost Increase	$0
	2		Coal Depreciation Changes and Exit Orders	$0
	3		Removing Coal From Rates	$0
400	1	Bain	Load and Revenue Forecast	$0
	2		Energy Efficiency	$0
	3		Sales for Resale, Wheeling & REC Revenues	$0
500	1	Bolton	Voluntary Renewable Energy Tariff (VRET)	$0

Continued on Next Page

(Continued)

600	1	Cohen	Wages,Salaries and Full Time Equivalents (FTE)	($2,380)
	2		Customer Service	$0
			Sales & Administrative and General (A&G) Expenses	$0
	3		Promotional Activity and Expenses	$0
	4		Directors Fees and Expenses	$0
700	1	Dlouhy	Marginal Cost Study	$0
	2		Rate Spread	$0
	3		Residential Rate Design	$0
800	1	Drennen	Merwin In-Lieu Funding	($320)
900	1	Enright	Fuel Stock	$0
	2		Generation Expenses, Non-Labor (NL)	$0
	3		Proposed Changes to PacifiCorp's TAM	$0
1000	1	Farrell	Lighting	$0
	2		Low-income Issues	$0
1100	1	Fjeldheim	Transmission and Distribution (T&D) - Operations and Maintenance (O&M) Expenses	$0
	2		Customer Accounts Expenses NL	($3,393)
	3		Uncollectable Accounts Expense	($2,221)
	4		Gains on Sales of Utility Property	$0
	5		Non-fuel Materials and Supplies	$0
	6		Miscellaneous Deferred Debits	$0
	7		Working Capital	$0
	8		Miscellaneous Rate Base	$0
	9		Customer Advances for Construction	$0
	10		Cyber Security	$0
	11		Information Technology (IT) Costs	$0
	12		Legal Fees & Expenses	($251)
1200	1	Jent	Advertising Expenses	($115)
	2		Promotional Activity and Expenses	$0
	3		Current Medical / Health Insurance	($111)
	4		Insurance & Risk (Non-Medical)	($2,317)
	5		Directors and Officers (D&O) Insurance	$0
1300	1	Moore	Wildfire Mitigation Capital Investment	$0
	2		Wildfire Mitigation and Vegetation Management Expense	($6,785)
1400	1	Peng	Depreciation Expense	($1,106)
	2	Peng	Cost of LT Debt	$5,987
1500	1	Rossow	Memberships & Subscriptions	($41)
	2	Rossow	Meals, Entertainment, and Awards	($7)
1600	1	Shierman	Clean Fuels Program (CFP) Revenue Credit	($1,423)
1700	1	Storm	Multi-State Process (MSP)	$0
	2		Klamath Hydroelectric Settlement Agreement, and KRRC	$0
	3		Pension Expense	($7,965)
	4		UM 2185 Non-Contributory Pension Plans	$0
	5		Amortization of COVID-19 Deferrals and Rate Spread	$0
	6		Wildfire Mitigation Mechanism	$0
	7		Energy Vision 2020 Projects	$0
			Total Staff Adjustments	**($42,790)**

Staff-Calculated Revenue Requirements Change (Base Rates):	**$41,610**

2. INTRODUCTION TO OTHER STAFF OPENING TESTIMONY

Q. What is the exhibit number, respective Staff witness, and topic of the various Staff rebuttal testimonies?

A. The Staff exhibit number, respective Staff witness, and topic are presented below:

In Exhibit 200, John Fox, Senior Financial Analyst discusses revenue requirement; electric plant acquisitions, consolidated deferrals, escalations, income taxes, taxes other than income, the OPUC fee rate, Wyoming wind tax, emission control investments and utility plant.

In addition, Mr. Fox reviews, Carbon and Cholla land in rate base, blanket projects, attestations, unbundling and functionalization.

In Exhibit 300, Rose Anderson, Senior Economist, discusses three issues: TB Flats cost increases, coal depreciation and exit order changes, and removing coal from rates.

In Exhibit 400, Dr. Ryan Bain, Ph.D., Senior Economist, analyzes load and revenue forecasts, energy efficiency, and sales for resale – wheeling and renewable energy credit (REC) revenues.

In Exhibit 500, Madison Bolton, Utility and Energy Analyst, considers PacifiCorp's proposed Voluntary Renewable Energy Tariff (VRET).

In Exhibit 600, Heather Cohen, Senior Utility Analyst, reviews wages, salaries and full-time equivalents (FTE), as well as customer service, sales and administrative and general expenses. In addition, Ms. Cohen examines

PacifiCorp's promotional activity and expenses, and directors' fees and related expenses.

In Exhibit 700, Dr. Curtis Dlouhy, Ph.D., Senior Economist, analyzes the Company's marginal cost study, rate spread and rate design.

In Exhibit 800, Ted Drennan Energy Policy Economist, analyzes PacifiCorp's proposed Merwin Reservoir downstream aquatic restoration in lieu of constructing fish passages.

In Exhibit 900, Moya Enright, Utility Economist, examines fuel stock, generation expenses, non-labor (NL) and Company proposed changes to PacifiCorp's Transition Adjustment Mechanism (TAM).

In Exhibit 1000, Bret Farrell, Senior Economist, reviews lighting and low-income issues inclusive of compliance with HB 2475 and other recent legislation.

In Exhibit 1100, Brian Fjeldheim, Senior Financial Analyst, addresses transmission and distribution (T&D) – operations and maintenance (O&M) expenses, customer accounts expenses NL, uncollectibleble accounts, gains on sales of utility property, and non-fuel (NF) materials and supplies.

In addition, Mr. Fjeldheim analyzes: miscellaneous deferred debits, working capital, miscellaneous rate base, customer advances for construction, cyber security, information technology (IT), and legal expenses and fees.

In Exhibit 1200, Julie Jent, Utility Analyst, examines PacifiCorp's advertising expenses, promotional activities and expenses, current medical expenses, (non-medical) insurance and risk management, and Directors' and Officers' (D&O) insurance.

In Exhibit 1300, Ming Peng, Senior Economist, analyzes: depreciation expense, amortization expense, depreciation reserve, amortization reserve, Allowance for Funds Used During Construction (AFUDC), Cost of Long-Term (LT) Debt, Cost of Preferred Stock, mine closures, and TB Flats wind deferral amortization.

In Exhibit 1400, Mitch Moore, Senior Economist, analyzes PacifiCorp's proposed test-year expenditures for wildfire and vegetation management.

In Exhibit 1500, Paul Rossow, Utility Economist, reviews the Company's memberships and subscriptions, as well as meals, entertainment and awards.

In Exhibit 1600, Eric Shierman, Senior Utility Analyst, analyzes PacifiCorp's Oregon Department of Environmental Quality's (DEQ) Clean Fuels Program (CFP) credit revenue.

In Exhibit 1700, Steve Storm, Senior Economist, examines nine issues: PacifiCorp's proposed changes to the UE 374-Commission approved Wildfire and Vegetation management cost recovery mechanism, Multi-State Process (MSP), Klamath Hydroelectric Settlement Agreement (KHSA); as well as pensions and post-retirement medical expenses. Mr. Storm also analyzes Docket No. UM 2185 non-contributory pension plans, amortization of Covid deferrals and associated rate spread, and wildfire mitigation mechanism. Finally, he considers PacifiCorp's proposed new tariff for incremental coal plant decommissioning costs, and the Company's Energy Vision 2020 projects.

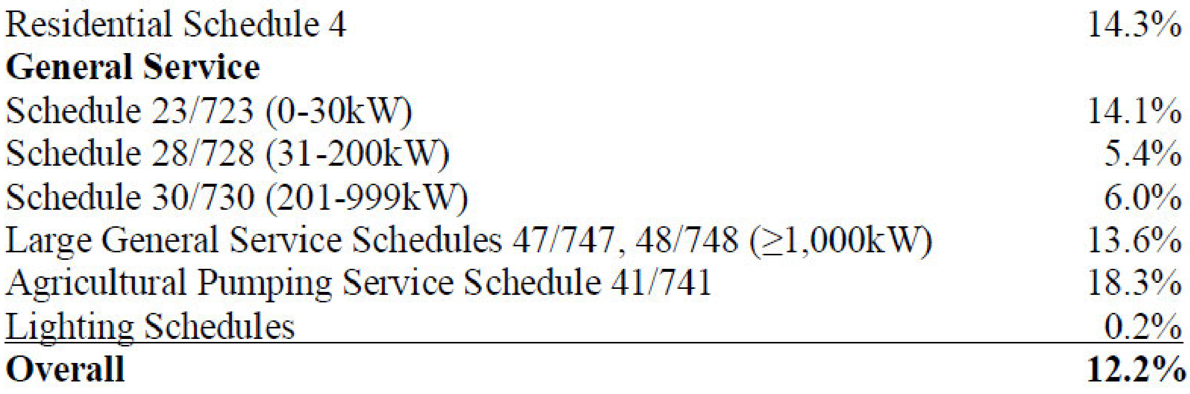
KEY CONCERN – RATE SHOCK

Q. Are there any issues that appear in the case that you would like to highlight?

A. Yes. Staff is concerned that the aggregate rate increase impacts of this general rate case, deferrals, and power costs may constitute rate shock for PacifiCorp's Oregon utility customers, particularly as inflation is outpacing Oregon wages.[1] Further, the U.S. Federal Reserve (Fed) is tightening monetary policy to control this high inflation.[2]

Q. Do responses to Staff DR's provide a complete picture of aggregate impacts on customers yet?

A. In PacifiCorp's response to DR 422, the Company indicated that proposed prices change from the Company's general rate case (GRC), Docket UE-399 and the Company's 2023 transition adjustment mechanism (TAM), Docket UE-400 would have the following impacts:



Residential Schedule 4	14.3%
General Service	
Schedule 23/723 (0-30kW)	14.1%
Schedule 28/728 (31-200kW)	5.4%
Schedule 30/730 (201-999kW)	6.0%
Large General Service Schedules 47/747, 48/748 (≥1,000kW)	13.6%
Agricultural Pumping Service Schedule 41/741	18.3%
Lighting Schedules	0.2%
Overall	**12.2%**

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[1] See Exhibit Staff/109 Muldoon/5, /14, /17, /26, /40, /50, /55, /59, and /70 for the inflation customers are experiencing.

[2] See Exhibit Staff/109 Muldoon/7, /10, /32, and /72 for Fed activity on interest rates

But this table does not yet capture costs associated with PacifiCorp's Power Cost Adjustment Mechanism (PCAM) power cost true-up and outstanding deferrals.

Q. On May 13, 2022, Administrative Law Judge Lackey issued Bench Requests 4-6 to PacifiCorp, indicating parties may file replies to PacifiCorp's response by June 10, 2022. Assume that the bench requests were issued for the purpose of facilitating a comprehensive understanding of changes to the company's rates occurring through the year, and to obtain information concerning the effects of amortizations and adjustment mechanisms outside of base rates. Do the responses to these bench requests capture the big picture rate impact on customers?

A. It is unclear. Staff also seeks to understand this general rate case filing in the context of currently effective, potential and proposed rate adjustments. On review of PacifiCorp's response to Bench Request Nos. 4 and 5, Staff has one concern in particular. Where a percentage rate change was requested, the response does not identify how the percentage change was calculated or provide the percentage with and without including power costs. Staff believes, as noted in its reply to the bench request responses, that it would be helpful in understanding the values to have both percentages identified and the calculation explained.

In addition to reviewing PacifiCorp's response to Bench Requests 4-6, and discussion with the Company, Staff has issued its own discovery requests to this end. Staff plans to incorporate responsive information, as appropriate, in Staff's subsequent testimony in this proceeding.

FINANCIAL RISK OF PACIFICORP

Q. What is the second key issue you wish to highlight?

A. PacifiCorp paints a picture of itself as a Company facing much more difficult financing challenges than the other Commission jurisdictional energy utilities such as PGE. The Company suggests that its, "heightened level of investment increases the risk of under recovery of the invested capital; and … an inadequate return would put downward pressure on key credit metrics".[3] Further PacifiCorp states that, "… while Portland General Electric Company is similarly rated to PacifiCorp, they have a lower credit metric requirement making it easier for them to maintain an A rating."[4] In fact, the Company states that it would, "likely result in a ratings downgrade,"[5] if the Commission were not to authorize an extraordinarily high ROE, significantly in excess of prevailing average ROE determinations in general rate case decisions by state public utility commissions in 2022 to date; and, in addition if the Company were not permitted a high equity capital structure.

Q. Fundamentally, what information is encapsulated in credit ratings?

A. Business credit is basically the ability to buy something now and pay for it later. Credit ratings are indicators of how likely it is that a company would fail to meet its financial obligations. Low ratings cause lenders, business partners and

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[3] See PAC/300 Bulkley/48 @11-13.
[4] See PAC/200 Kobliha/8 @5-7.
[5] See PAC/200 Kobliha/5 @16.

transaction counterparties to charge higher fees and seek guarantees. In contrast, companies with Standard & Poor’s (S&P) long-term issuer stable credit ratings of “A” and Moody’s Investor Service (Moody’s) like ratings of “A3” [6]are generally seen as highly reliable enterprises, likely to meet all bond service and revolving credit obligations, and overall excellent entities with which to do business.[7]

Q. The Company states that, “… interest rates and utility share prices are inversely correlated … an increase in interest rates will result in a decline in the share price of utilities.”[8] Does Staff agree that interest rates are a key driver for utility stock prices?

A. No. On February 24, 2022, Russia invaded Ukraine. The invasion caused Europe's fastest-growing refugee crisis since World War II, with more than 7.4 million Ukrainians fleeing the country and a third of the population displaced. Sanctions on Russia in response exacerbated already challenged global supply chains. In a flight to safety, investors have sought stocks and bonds of utilities with stable growing dividends and stable domestic U.S. cash flows, insulated from international turmoil.

Q. How have shares of U.S. IOUs in the S&P 500 index fared compared to the returns for the index as a whole since Russia invaded Ukraine?

A. U.S. IOU Stocks in the S&P 500 Index outperformed the S&P 500 as a whole.[9]

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[6] See PAC/300 Bulkley/26 216.
[7] See https://about.moodys.io/overview.
[8] See PAC/300 Bulkley/21 @3-5.
[9] See Staff/109 Muldoon/22, /29, and /46.

Q. Are PacifiCorp and its parent company Berkshire Hathaway, Inc. (BRK) actually facing dire economic conditions in which they are unlikely to meet financial obligations and would face credit ratings downgrades based on usual and customary Commission decisions in this rate case?

A. No. Warren Buffet, CEO of BRK, at BRK's last annual shareholder meeting – published by CNBC on YouTube on May 1, 2022, explained, "One thing at Berkshire, we will always have a lot of cash on hand. When I say cash, I do not mean commercial paper. … We have Treasury bills."[10]

Q. Just how much money is Mr. Buffet talking about keeping available is cash and cash equivalents at BRK?

A. The amount fluctuates around $100,000,000,000 dollars.[11]

Q. Is the Company's testimony plausible given the above context?

A. No.

Q. In the past two years after the Commission issued Order No. 20-473 in PacifiCorp's last general rate case, in Docket No. UE 374, did S&P or Moody's put PacifiCorp on credit watch, or lower the Company's credit ratings?

A. No.

Q. Does this conclude your Introduction?

A. Yes.

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[10] Please start viewing this video at 23.55 into BRK's presentation as captured by CNBC on www.youtube.com.

[11] See Exhibit Staff/109 Muldoon/3 and 67 for a sense of the magnitude of BRK cash reserves.

4. SUMMARY OF PUBLIC COMMENTS RECEIVED

Q. Please summarize the public comments received to date in this rate case.

A. In this docket, the OPUC has received a significant number of public comments. This may in part be due to PacifiCorp requesting a 6.8% overall general rate increase, and an even higher increase for residential customers. Below is a table reflecting the characteristics of comments received.

TABLE 1

For Increase	Against Increase	Form Comments	Total Comments
3	132	77	135

Almost all the comments are from residential customers and all but three of the comments reflect similar feelings. In fact, there are 77 identical emails from residential customers which indicate that a rate increase is inappropriate given that so many families are struggling financially. These comments also express concerns over a seasonal rate system and the disproportionate impacts that the seasonal rate proposal would have on Eastern and Southern Oregon communities.

One commenter at the Commission's Informational Hearing on May 24 questioned whether PacifiCorp needed to increase profits when its parent company had such extensive cash reserves.

Small businesses including employee-owned grocers in Central Oregon indicated that they were currently operating on razor thin margins. The grocers explain that they are large power users because their stores keep food safe at varying temperatures. Moreover they indicate that PacifiCorp's proposed increase would challenge their ability to operate safely, reliably and profitably.

Q. What is the range of perspectives shared by commenters?

A. Separate from the 77 identical emails, there are 55 other negative comments. These comments generally reflect the same sentiments as the form comments. However, some commenters put forth suggestions for improvement to the current system. For example, one individual proposes that PacifiCorp raise rates "on high usage businesses who draw far more power than individual residential users" and to, "install solar panels on business roofs to minimize environmental impacts of solar farm installation."

Other sentiments found throughout the public comments include a general distrust of the Public Utility Commission (PUC) and a belief that the PUC "rubber stamps" rate increases. For example, one commenter states, "Even asking for comments and opinions is a slap in the face to many of us that know all-too-well that the PUC rubber stamps requests for rate increases."

Finally, one commenter expresses that a rate increase is inappropriate because of the, "non-existent threat of fake climate change." This commenter indicates that the Boardman facility should be re-commissioned, and that natural gas is needed in order to reduce the costs of electricity.

Q. Is there a common theme to the majority of comments received?

A. Yes. Docket No. UE 399's public comments generally reflect opposition to a rate increase except for three comments that support an increase. The overall sentiment from the public comments is that now is not an appropriate time for a rate increase of this size, especially in light of current events including inflation.

Q. Please explain the reasoning behind the inclusion of public comments in Staff's testimony.

A. Consistent with the Commission's Internal Operating Guidelines as addressed in Order 20-065 in Docket No. UM 2055, to provide more transparency about the public comments in contested cases, public comments received are now made part of the Staff's Opening Testimony.

The Commission will post a link or instructions on how the public can see all public comments received, and the public comments from the edited transcript for the Public Informational Hearing, of Tuesday, May 24, 2022, at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23186.

Written comments received after preparation of Staff's Opening Testimony will be included in subsequent Staff testimony. However, Staff will not be able to testify regarding comments received after Staff prepares its final round of UE 399 testimony.

Presenting comments at a Commission Informational Hearing or through the Commission's website does not subject the commenting person to cross examination. Any party, though, may respond to Staff's summary of the public comments or the comments themselves in evidentiary testimony.

Q. Does Staff Opening Testimony address comments received?

A. Yes.

5. OVERALL RATE OF RETURN (ROR)

Q. Did you prepare tables showing PacifiCorp's current Commission authorized, Company proposed and Staff calculated RORs?

A. Yes. The following three tables provide that information.

TABLE 2

PAC Current OPUC Authorized (UE 374 Order Nos. 20-473)			**PAC**
Component	**Percent of Total**	**Stipulated or Implied Cost**	**Weighted Average**
Long Term Debt	49.99%	4.774%	2.387%
Preferred Stock	0.01%	6.75%	0.001%
Common Stock	50.00%	9.50%	4.750%
	100.00%		**7.137%**

TABLE 3

PAC Requested – UE 399		**PAC Direct Testimony**		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**47.74%**	**4.380%**	2.091%	**0.075%**
Preferred Stock	0.01%	**6.75%**	0.001%	
Common Stock	**52.25%**	**9.80%**	5.121%	
	100.00%		**7.212%**	

TABLE 4

Staff Proposed – UE 399		**Staff Opening Testimony**		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**49.99%**	**4.588%**	2.294%	**-0.243%**
Preferred Stock	0.01%	**6.75%**	0.001%	
Common Stock	**50.00%**	**9.20%**	4.600%	
	100.00%		**6.894%**	

Note: Based on a change in forward market conditions due to high inflation exacerbated by a war in Eastern Europe, and projected Federal Reserves (Fed) interest rate actions to control inflation, Staff recommends a higher cost of Long-Term Debt than did PacifiCorp in its initial testimony.

Capital Structure

Q. Has the Commission recently considered the matter of PacifiCorp's capital structure?

A. Yes. In Order No. 20-473 at 24: Commission adopted a notional 50 percent equity capital structure – "We consider all components to the company's cost of capital that will result in a fair and reasonable rate of return, 'to strike a balance between the interests of ratepayers and the interests of investors.'"

Q. In the introduction to this testimony you indicated PacifiCorp thinks Portland General Electric has an easier time in maintaining credit ratings than PacifiCorp, do you agree with the Company?

A. No. Staff disagrees with PacifiCorp for many reasons including the following:

1. PacifiCorp is a wholly owned subsidiary of BRK. It does not need to maintain a regular and growing quarterly dividend to satisfy investors when the Company has opportunities for capital spending for utility purposes.
2. Actual capital structure for PacifiCorp is at the Company and its parent BRK's discretion. It is not simply driven by financial market conditions.
3. BRK seeks investment opportunities that exceed the meager return it receives for holding short-term U.S. Treasuries (UST). PacifiCorp's authorized rate of return is about double that earned on BRK's UST. PacifiCorp's authorized return on equity is an even greater magnitude larger than BRK's UST.

Q. Staff points to cash reserves (UST) owned by PacifiCorp's parent company, BRK as proof PacifiCorp is at least somewhat insulated from concerns about inflation, credit worthiness and certain requirements of other investor owned utilities. How does that cash balance ensure that insulation considering how many businesses are owned by BRK?

A. BRK cash reserved are over twice the entire $50 Billion market capitalization of PacifiCorp. Those holdings exceed 15% of the market cap of all of BRK combined. With these reserves BRK can operate for an extended period of time, even if capital markets were entirely frozen or non-functional such in a depression.

PAC also does not need to float stock in these times as a wholly owned subsidiary. Further PAC can go for some time paying no dividends as needed or reflective of capital spending opportunities, sharply contrasting with most IOU's which must have a steady and growing dividend to avoid being dropped by investors.

Q. Is not the Company's testimony provided in Exhibit PAC/200 Kobliha not sufficient justification for PacifiCorp's proposed capital structure?

A. No. PacifiCorp's substantial control over its capital structure and its capital spending opportunities – in part because it had built so many coal fired generation resources – does not justify preferred treatment for the Company.

Q. Is there an academic or market justification for PacifiCorp's desire for a higher equity capital structure.

A. No. Other than BRK's objective to maximize its return for shareholders. Staff and the Company have access to the same financial publications.[12] In general, capital structure is thought to be parabola or “U” shaped. Too little debt puts pressure on common equity and dilutes the earnings per share (EPS) for investors holding stock, making it harder to float new equity. Conversely too much debt increases the risk of default and stresses bond covenants and credit ratings. The precise optimal capital structure is not precisely defined, but a balanced 50 percent equity and 50 percent long-term debt appears within the optimal range of capital structures. For that reason a notional capital structure with 50 percent equity is reasonable. The Commission has adopted a 50-50 capital structure in nearly all of its recent orders for energy utilities.

Q. What are the currently authorized capital structures of the other five Commission jurisdictional energy IOUs?

A. All five are within 10 basis points (bps) of a 50 percent Equity and 50 percent Long-Term Debt Capital Structure. See below for their equity layers:[13]

AVA	CNG	IPC	NWN	PGE
50.0 %	50.0 %	49.9 %	50.0 %	50.0 %

Q. Are interest rates at all-time highs?

A. No. Despite Federal Reserve intent to raise interest rates, currently interest

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[12] Examples include: Dr. Roger A. Morin, PhD, ”New Regulatory Finance”; Paroma Sanyal and Laarni T. Bulan, “Regulatory Risk, Market Uncertainties, and Firm Financing Choices”, The Quarterly Review of Economics and Finance 51 (2011); and Yossef Spiegel and Daniel F. Spulber, “Capital Structure with Countervailing Incentives”, The RAND Journal of Economics , Spring, 1997.

[13] Avista Corp. (AVA); Cascade Natural Gas (CNG); Idaho Power Company (IPC); Northwest Natural Gas (NWN) and Portland General Electric (PGE).

rates are closer to all-time lows. Debt is relatively cheap compared to equity at this time.

Return on Equity (ROE)

Q. What range of reasonable ROEs does Staff recommend, and within that range what point ROE?

A. Staff recommends a **point ROE** of **9.2 percent** within a range of reasonable ROE's of 8.95 percent to 9.38 percent derived from Staff's two separate Three-Stage Discounted-Cash-Flow (DCF) models. The Commission has traditionally relied on the Three-Stage DCF models for its authorized ROE decisions.

Q. Did you perform a check on the results of Staff's Three-Stage DCF models?

A. Yes. Staff employed two simpler models to check the reasonableness of its findings:

1. A Single-Stage DCF or Gordon Growth Model; and,
2. A Capital Asset Pricing Model (CAPM).

Q. What results did these models generate?

A. The Gordon Growth Model generated a mean ROE of 8.6 percent using Staff's peer electric utilities and 8.8 percent with the Company's peer electric utilities.

The CAPM generated a mean ROE of 9.6 percent using Staff's peer electric utilities and 9.8 percent as well with the Company's peer electric utilities.

Based on these conflicting checks, one pointing to top of range and one pointing to bottom of range, Staff finds that the point estimate for ROE in Staff's range of reasonable ROEs generated by its two separate Three-Stage DCF models should be at the midpoint of modeling results reflective of the above checks on reasonableness.

Q. Does your recommended ROE meet appropriate standards?

A. Yes. The 9.2 percent ROE Staff recommends is appropriate for overall rates that are reflective of forward looking conditions in conjunction with Staff's adjustments and meets the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statute (ORS) 756.040.[14] Staff recommendations are consistent with establishing "fair and reasonable rates", that are both, "commensurate with the return on investments in other enterprises having corresponding risks" and, "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[15]

PEER SCREEN

Q. How did you select comparable companies (peers) to estimate PacifiCorp's ROE?

A. Staff used companies that met the following criteria as peer utilities to the regulated electric utility activities of PacifiCorp:

1. Covered by Value Line (VL) as an electric utility;
2. Forecasted by VL to have positive dividend growth;
3. LT Issuer Credit Rating from A1 to Baa2 inclusive from Moody's and from AA- to BBB+ inclusive from S&P;
4. No decline in annual dividend in last five years based on VL;

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[14] *See Federal Power Commission v. Hope Natural Electric Co*., 320 U.S. 591 (1944) and *Bluefield* Water *Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

[15] *See* ORS 756.040(1)(a) and (b).

5. Has heavily regulated electric utility revenue;
6. Has LT Debt from 45 percent to 55 percent inclusive in VL Capital Structure; and,
7. Has no recent merger and acquisition activity.

Q. What peer groups of electric utilities did Staff and Company ROE modeling primarily depend on, and were there similarities?

A. The Company and Staff recommended regulated electric utility peer groups both drew from pertinent electric utilities covered by VL. In Staff Exhibit 102, Page 2, Staff flags electric utilities not selected due to merger activity as it shows how each element of its screening was applied. Table 5 shows a fair amount of overlap between PacifiCorp's and Staff's peer groups.

Q. Did the Company apply some different criteria?

A. Yes, PacifiCorp emphasized thermal generation fuel mix, which Staff saw as largely a distraction. However, there was much overlap between PacifiCorp's and Staff's screening criteria.

TABLE 5[16]

Screen #	Abbreviated Utility	UE 399 PAC	UE 399 Staff
1	Allete	Yes	No
2	Alliant	Yes	**Yes**
3	Ameren	Yes	**Yes**
4	AEP	Yes	No
6	Avista	Yes	No
9	CMS	Yes	No
10	Consol Ed	No	**Yes**
13	Duke	Yes	**Yes**
16	Entergy	Yes	No
17	Evergy	Yes	**Yes**
18	Eversource	No	**Yes**
24	IDACORP	Yes	No
26	NextEra	Yes	No
27	NorthWestern	Yes	No
29	Otter Tail	Yes	No
31	PGE	Yes	**Yes**
32	Pinnacle	No	**Yes**
38	Southern	Yes	No
40	WEC	No	**Yes**
42	Xcel	Yes	No

A comparison of the peer groups used by Staff and PacifiCorp are set forth in Table 5. Staff excluded eleven of the companies used by PacifiCorp based on its screening criteria described above. PacifiCorp excludes three of the companies used by Staff. Five companies were relied upon by both Staff and PacifiCorp.

Q. What are the results of your multistage DCF models?

A. See Table 6 below for the results from Staff's three stage DCF modeling.

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[16] See Exhibit Staff 102, Muldoon/2 for the full peer screening table.

TABLE 6 – RESULTS OF STAFF'S 3-STAGE DCF MODELING[17]

Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :				**12.5**	bps
	8.95%	**to**	9.38%	**ROE**	
Staff Point ROE Recommendation:	**Midpoint**	**9.2%**	**ROE**	**Testimony**	

CAPM and Single Stage DCF point to top and bottom respectively of Staff's Three Stage DCF Modeling Results

Supporting Exhibit Staff/104 Muldoon/1 shows step-by-step how Staff's Hamada adjusted three-stage DCF modeling results, using Staff peers and growth rates, generates a higher recommended ROE than using PacifiCorp's peer electric utility group.

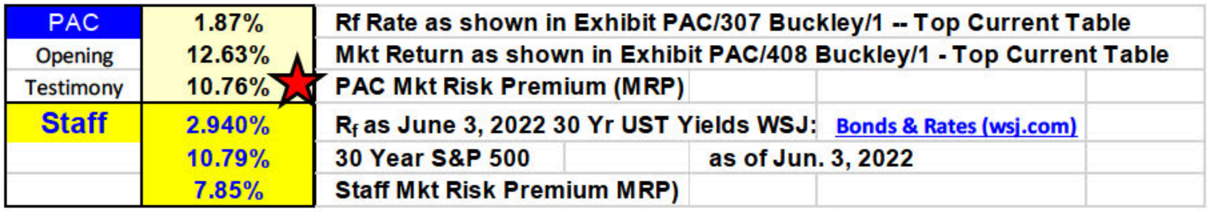
Q. Are there other key drivers that cause the Company's modeling to generate different results than utilizing Staff's modeling?

A. Yes. In its Three-Stage DCF, PacifiCorp relies on a 5.49 percent long-term third-stage growth rate. This caused the Company to have to reach back to the 1920's to pull in periods of higher growth than have been experienced by most investors in their lifetimes.

Q. Please provide another example of an extreme input that PacifiCorp has not labeled as such.

A. In its CAPM modeling PacifiCorp overstates its market risk premium estimate.

Example 1 – NOT a Staff Recommendation:



PAC	**1.87%**	**Rf Rate as shown in Exhibit PAC/307 Buckley/1 -- Top Current Table**	
Opening	**12.63%**	**Mkt Return as shown in Exhibit PAC/408 Buckley/1 - Top Current Table**	
Testimony	**10.76%**	**PAC Mkt Risk Premium (MRP)**	
Staff	**2.940%**	**R_f as June 3, 2022 30 Yr UST Yields WSJ:**	**Bonds & Rates (wsj.com)**
	10.79%	**30 Year S&P 500**	**as of Jun. 3, 2022**
	7.85%	**Staff Mkt Risk Premium MRP)**	

Note that PacifiCorp does not identify its "extreme" market risk premiums as such.

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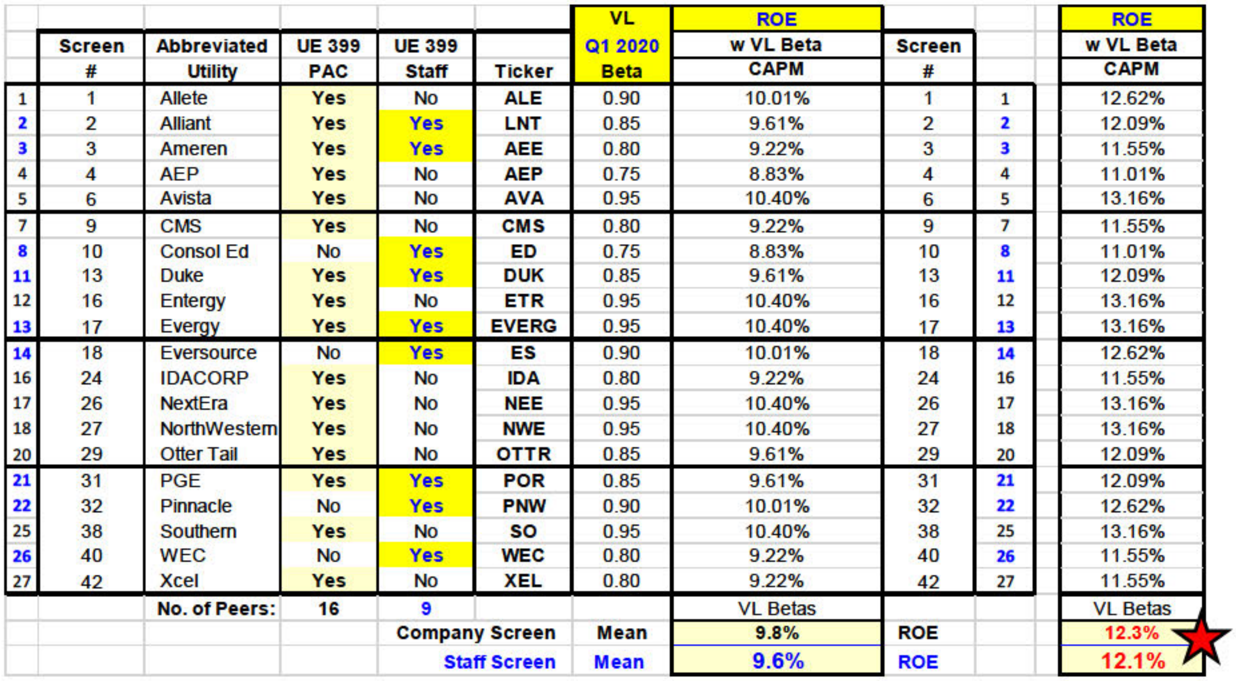
[17] See Exhibit Staff/104, Muldoon/1 for the results of Staff three-stage DCF modeling.



	Screen #	Abbreviated Utility	UE 399 PAC	UE 399 Staff	Ticker	VL Q1 2020 Beta	ROE w VL Beta CAPM	Screen #		ROE w VL Beta CAPM
1	1	Allete	Yes	No	ALE	0.90	10.01%	1	1	12.62%
2	2	Alliant	Yes	Yes	LNT	0.85	9.61%	2	2	12.09%
3	3	Ameren	Yes	Yes	AEE	0.80	9.22%	3	3	11.55%
4	4	AEP	Yes	No	AEP	0.75	8.83%	4	4	11.01%
5	6	Avista	Yes	No	AVA	0.95	10.40%	6	5	13.16%
7	9	CMS	Yes	No	CMS	0.80	9.22%	9	7	11.55%
8	10	Consol Ed	No	Yes	ED	0.75	8.83%	10	8	11.01%
11	13	Duke	Yes	Yes	DUK	0.85	9.61%	13	11	12.09%
12	16	Entergy	Yes	No	ETR	0.95	10.40%	16	12	13.16%
13	17	Evergy	Yes	Yes	EVERG	0.95	10.40%	17	13	13.16%
14	18	Eversource	No	Yes	ES	0.90	10.01%	18	14	12.62%
16	24	IDACORP	Yes	No	IDA	0.80	9.22%	24	16	11.55%
17	26	NextEra	Yes	No	NEE	0.95	10.40%	26	17	13.16%
18	27	NorthWestern	Yes	No	NWE	0.95	10.40%	27	18	13.16%
20	29	Otter Tail	Yes	No	OTTR	0.85	9.61%	29	20	12.09%
21	31	PGE	Yes	Yes	POR	0.85	9.61%	31	21	12.09%
22	32	Pinnacle	No	Yes	PNW	0.90	10.01%	32	22	12.62%
25	38	Southern	Yes	No	SO	0.95	10.40%	38	25	13.16%
26	40	WEC	No	Yes	WEC	0.80	9.22%	40	26	11.55%
27	42	Xcel	Yes	No	XEL	0.80	9.22%	42	27	11.55%
		No. of Peers:	16	9			VL Betas			VL Betas
				Company Screen		Mean	9.8%	ROE		12.3%
				Staff Screen		Mean	9.6%	ROE		12.1%

Above is an example of how PacifiCorp generates
ROE modeling results above 12 percent.

Normally, Staff does not call out odd methods like that used by PacifiCorp in the Company's testimony. Staff does so in this case however, because inputs are not labeled as outlier values and because results using extreme inputs are given equal weighting with more reasoned inputs.

Q. PacifiCorp/300 Bulkley/3 at lines 20-21 indicates the Company finds a reasonable range of ROEs from 9.9 to 10.75 percent, with a point request by the Company of 9.8 ROE below the low end of this range. Why is that not a reasonable recommendation?

A. If you eliminate unreasonable modeling inputs, select only peer electric utilities most like PacifiCorp using Staff's standard screening methods, and eliminate the Company's Risk Premium Modeling, you arrive at result equal to Staff's ROE recommendations.[18]

According to Regulatory Research Associates (RRA), "US Electric and Electric ROE Determinations in Q1'22 Remains near All-Time Low Mark", the average return on equity authorized electric utilities was 9.35% in rate cases decided in the first quarter of 2022, slightly below the 9.38% average for full-year 2021.[19] PacifiCorp's recommendations do not seem to have any correlation whatsoever to prevailing state commission decisions regarding authorized ROE in rate case decisions this year.

GROWTH RATES USED IN THIRD STAGE OF DCF MODELS[20][21]

Q. What long-term growth rates did you use in Staff's two three-stage DCF models?[22,23]

A. Staff used three different long-term growth rates, with different methods employed in developing each.

The first method uses the U.S. Congressional Budget Office's (CBO) 4.0 percent nominal 20-year GDP growth rate estimate.

Staff's second Composite Growth Rate applies a 50 percent weight to the

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[18] Exhibits Staff/102 – /106 show how Staff's recommendations are generated.

[19] See Exhibit Staff/109 Muldoon/62.

[20] See Exhibit Staff/106, Muldoon1 for BEA historical GDP growth rates.

[21] See Exhibit Staff/107, Muldoon1 for TIPS implied long-run inflation rates.

[22] Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. *See*, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, Exhibit Staff/800, Storm/46 – 52. Growth rates relied upon by Staff are also shown in Exhibit Staff/104, Muldoon/1

[23] See three-stage DCF models X and Y in Exhibit Staff/103.

average annual growth rate resulting from estimates of long-term GDP by the U.S. Energy Information Administration (EIA), the U.S. Social Security Administration, PricewaterhouseCoopers estimate for long-run (10- to 30-years from now), and the CBO, with each receiving one-quarter of that 50 percent weight.[24] The remaining 50 percent is the average annual historical real GDP growth rate, established using regression analysis, for the period 1980 through 2021 to which we apply a TIPS implied inflation forecast.

Staff's third "Near Historical" Stage 3 annual growth rate, is the earlier described U.S. Bureau of Economic Analysis (BEA) derived projection which presumes the future will look much like the past. Table 7 below captures LT GDP growth rates Staff used.

TABLE 7
GROWTH RATES STAFF RELIED UPON

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates

Component	Real Rate	TIPS Inflation Forecast	20-Yr Nominal Rate	Weight	Weighted Rate	
Energy Information Administration (EIA)	**2.10%**	**2.23%**	4.38%	12.50%	0.55%	
PricewaterhouseCooper	**2.40%**	**2.23%**	4.68%	12.50%	0.59%	
Social Security Administration	**2.00%**	**2.23%**	4.27%	12.50%	0.53%	
Congressional Budget Office	**1.60%**	**2.23%**	3.87%	12.50%	0.48%	
BEA Nominal Historical,1980 Q1 – 2021 Q4	**2.66%**	**2.23%**	4.95%	50.0%	2.47%	
Composite				100%	**4.62%**	**Composite**
Congressional Budget Office Long-Term 20-Year Budget Outlook			**4.00%**	100.0%	**4.00%**	**CBO**
BEA Nominal Historical,1980 Q1 – 2021 Q4	**2.66%**	**2.23%**	4.95%	100.0%	**4.95%**	**Near Historical**
Though shown below for comparison purposes - Staff disagrees with the Company's third Stage Growth Rate						**5.49%**

Q. Did your analysis reflect a synthetic forward curve?

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[24] The EIA is the Energy Information Administration within the U.S. Department of Energy (DOE), OMB is the Office of Management and Budget, and CBO is the Congressional Budget Office. EIA and OMB's estimates are of nominal GDP. We applied to CBO's estimate of real GDP as an inflation rate for the relevant timeframe developed using the Treasury Inflation-Protected Securities method described by Staff in testimony in multiple recent general rate case proceedings.

A. Yes. Staff utilized synthetic forward curve using UST Treasury Inflation Protected Securities (TIPS) break-even points. This reflects implied market-based inflationary expectations. Staff's recommendations are consistent with market activity indicating investor expectations of future inflation.

Staff assumes for purposes of its three-stage DCF modeling that LDC utility growth is bounded by the growth of the U.S. economy, and more specifically impacted by challenges regarding U.S. population, workforce participation, and productivity in the long-run (20-year) modeling period.

Q. Assume that future U.S. GDP growth would look like the growth experienced in the past 30 years. Would a ROE based on that assumption still fall within Staff's recommended range?

A. Yes. Staff extracted and ran regression on data from the U.S. Bureau of Economic Analysis (BEA) to generate the annual real historical GDP growth rate. Staff recommended range of ROEs includes values that presume GDP growth over the next 30 years would look like that of the past 30 years informed by other federal projections.

Q. How do your growth rates compare to the Company's?

A. Staff's 20-year GDP growth rate estimates of 4.0 percent from the U.S. Congressional Budget Office (CBO); 4.62 percent aggregated from the U.S. Energy Information Administration (EIA), Pricewaterhousecooper, the U.S. Social Security Administration, the CBO, and the U.S. Bureau of Economic Analysis (BEA) (Composite); and Staff's regression analysis of BEA historical data of 4.95 percent are lower than the Company's proposed 5.49 percent, and are more consistent with referent data sources.

Q. How do your methods employed in this case differ from those utilized by Staff in recent general rate cases?

A. Staff's methods and modeling parallel those employed by Staff in recent electric utility general rate cases. Staff continues to look primarily to referent federal sources for long-term GDP growth rates which weight long-run population, workforce participation, and productivity higher than current financial market events and global events with shorter if not transitory effects. Nevertheless, Staff monitors current financial news and this testimony is informed by such.[25]

Q. Describe the two three-stage DCF models on which you primarily rely.

A. Staff's first model is a conventional three-stage discounted dividend model, which Staff denotes as a "30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity" (referred to as "Model X"). This model captures the thinking of a money manager at a pension fund or insurance company, or other institutional investor, who expects to keep the Company's stock indefinitely and use the dividend cash flow to meet future obligations.

Staff's second model is the "30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio" (referred to as "Model Y").

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[25] See Exhibit Staff/108, Muldoon/23, /30, /43, /45, and /50 for news that investors in electric utilities are seeing.

This model best fits the investor who has a goal they are working toward. In addition to the income stream from dividends, this investor intends to sell the stock as the goal is reached.

Both models require, for each proxy company analyzed by Staff, a "current" market price per share of common stock, estimates of dividends per share to be received over the next five years calculated from information provided by Value Line, and a long-term growth rate applicable to dividends 10- to 30-years out. On this last point, Staff always recommends the Commission be particularly vigilant for any substitution of a short-term growth rate for a long-term 20- to 30-year growth rate. Some growth rates labeled "long" may be supported by information looking at the next ten years or less into the future.

For a smooth transition, Staff steps the rate of dividend growth between the near-term (the next five years) and that of long-run expectations.

Q. How does Model X calculate the terminal value of dividends as a perpetual cash flow into the future?

A. Model X includes a terminal value calculation, in which Staff assumes dividends per share grow indefinitely at the rate of growth in Stage 3 ("growing perpetuity"). In contrast, Model Y terminates in a sale of stock where the price is determined by our escalated price/earnings (P/E) ratio.

Q. Why is thirty years the primary horizon for financial decision-making?

A. Investors focus on the 30-year U.S. Treasury (UST) Bond against alternate investment opportunities. Thirty years is a generally accepted period for economists to ascribe to one generation. It is a common length of time for mortgages of plants, equipment, and homes. Many institutional holders of utility securities match the cash flows from utility dividends to future obligations, such as the payout of life insurance, preparing to meet future pension and post-retirement obligations, and interest service for borrowing. Individuals plan for the education of their children, ownership of their home, and provision for their retirement on this same multi-decade timeframe.

Staff uses five years for Stage One, as that is the timeframe for which Value Line estimates of future dividends are available. This is as far as Value Line projects near-future trends. Staff also uses five years for Stage Two as a reasonable length of time for individual company's dividend growth rates that are materially different from the growth rate used in Stage Three (and common to all companies) to converge to a LT dividend growth rate more representative of all electric utilities.

Q. How do you address dividend timing?[26]

A. Each model uses two sets of calculations that differ in the assumed timing of dividend receipt. One set of calculations is based on the standard assumption that the investor receives dividends at the end of each period.

The second set of calculations assumes the investor receives dividends at the beginning of each period. Each model averages the unadjusted ROE values to generate an Internal Rate of Return (IRR) produced with each set of

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[26] See Exhibit Staff/109 for Value Line (VL) information relied on in this testimony regarding publicly-traded electric utilities

calculations for each peer utility. This approach accounts for the time value of money, closely replicating actual quarterly receipt of dividends by investors.

Q. What price do you use for each peer utility's stock?

A. Staff used the average of closing prices for each utility from the first trading day in April, May, and June 2022, to represent a reasonable snapshot of utility stock prices.

Q. To recap, do you capture both the perspective of a buy and hold investor and an investor who plans to sell in the future?

A. Yes. Staff's recommended 9.2 percent point ROE is consistent with findings modeling the perspectives of both types of investors through Staff's two different three-stage DCF models.

Q. Does this approach capture a reasonable set of investor expectations similar to Staff's analysis in other recent general rate cases?

A. Yes. Staff modeling captures the expectations of investors who think that: A) the non-partisan CBO is reliable; B) blended federal agency expert analysis also informs the historical track record; and, C) one should be optimistic about the economy's long-run growth, provided there are still enough non-retired adult Americans to make it happen 20 years from now.

Q. Is it appropriate to use estimates of long-term GDP growth rates to estimate future dividends for electric utilities?

A. Yes. In many of the Company's prior rate cases, Staff has shared plots of U.S. electric demand growth since 1950 on a three-year moving average. This downward trending consumption curve allows GDP growth to be a conservative proxy for both electric utility sales and dividend growth rates.

Q. Can relying on a long-term GDP growth rate overstate required ROE?

A. Yes. It is possible that Staff modeling anticipates greater growth than may be realized and so overstates required ROE to attract investors. Our highest growth rate presumes return to near historical U.S. GDP growth rates.

Q. Is it important to distinguish between long-run 20- to 30-year rates and rates over the next five years?

A. Yes. Over-extrapolating a snapshot of short-term data undermines confidence in modeling results. For example, Value Line, Blue Chip, and a variety of other financial resources focus primarily on the next five years. The next five years may be affected by recent events. Over the long run, <u>population and productivity</u> are the key drivers of economic growth. This is of concern with declines in the rate of growth of America's population.[27]

Q. In Staff's two different three-stage DCF models, Staff is looking for growth rates for a period between 10 and 30 years in the future, or an average of 20-years out. Why not just use a five- or ten-year projection?

A. Staff could use a five- or ten-year projection, but there is better information available. If a primary concern is whether enough Americans are both working and highly productive to support a robustly growing economy 30 years from now, 10-year data will not be the most useful. This is because 10-year data is

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[27] See Exhibit Staff/108, Muldoon/1 and /43 for long-run concerns about birth rate declines.

not yet impacted by retirement of persons born in 1960 or persons not immigrating and not being born to U.S. families now. A better solution is to use data that is projected with those difficulties in mind, i.e., 30-year data.

HAMADA EQUATION

Q. Your application of the Hamada Equation to un-lever peer utility capital structures and to re-lever at PacifiCorp's target capital structure increases required ROE. Why is this adjustment reasonable?

A. Staff employs the Hamada Equation to better compare companies with different capital structures driven by differing amounts of outstanding debt. As earlier discussed, Staff applied screening criteria already identify peers that have a very close capital structure to the Company. Use of the Hamada-adjusted results helps ensure that Staff has captured all material risk in our analysis because it captures additional risk associated with varying capital structure.

Within the confines of Staff's testimony, one can see the steps to un-lever and re-lever a peer company's capital structure as the equivalent of removing debt of peer companies with varying capital structures, and then adding enough debt back to equal the Company's balanced target capital structure in this general rate case.

Q. What accounts for differences in peer capital structures?

A. Each of the two models employs the Hamada equation[28] to calculate an adjustment for differences in capital structure between each peer utility and the Staff-proposed capital structure for the Company. When few peer utilities are available, the Hamada equation ensures Staff's analysis addresses differences in peer utility capital structures.

Q. Why is it important to consider capital structure when modeling ROE?

A. Different amounts of debt financing along with different tax rates result in disparate risk profiles among peer utilities used in ROE modeling to approximate the unknown appropriate ROE for the utility examined. All else equal, with more debt in a capital structure, investors require higher expected equity returns to compensate for the increased risk. Debt has a higher call on the company's available cash, and so less cash is available for equity holders. Staff uses the Hamada's equation, named after Robert Hamada, to separate the financial risk of a levered firm from its business risk, and adjust the results of peer utilities to have results as though they had the same capital structure as the utility for whom an appropriate ROE is sought.

Q. Did you use robust and proven analytical methodologies?

A. Yes. Staff's methods are robust, proven, and parallel Staff's work over the last decade. The Commission for example expressly relies on the multi-stage DCF

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[28] Dr. Robert Hamada's Equation as used in Staff/104 separates the financial risk of a levered firm, represented by its mix of common stock, preferred stock, and debt, from its fundamental business risk. Staff corrects its ROE modeling for divergent amounts of debt, also referred to as leverage, between the Company and its peers.

to determine the range of ROEs, and relies on CAPM and risk premium models to check the reasonableness of results. This can be seen in Order No. 22-129 in Docket No. PGE UE 394 as well as in Order 20-473 in Docket No. PAC UE 374.

Q. Describe how you performed your analysis.

A. Using the cohort of proxy companies that met our screens, Staff ran each of Staff's two three-stage DCF models three times, each time using a different long-term growth rate.

Q. Was your analysis consistent with a top supportable finding of 9.2 percent point ROE?

A. Yes.

BALANCED APPROACH TO ROE

Q. Are your results robust given uncertainty around COVID-19, high inflation, U.S. Federal Reserve (Fed) intent to raise interest rates, and a major war in Eastern Europe further disrupting global supply chains?

A. Yes. The downward glide path for ROE in Figure 1 below, is not linear and may fluctuate through these uncertainties, but long-run GDP growth rates are mostly determined by the long future U.S. working age population and its productivity.[29]

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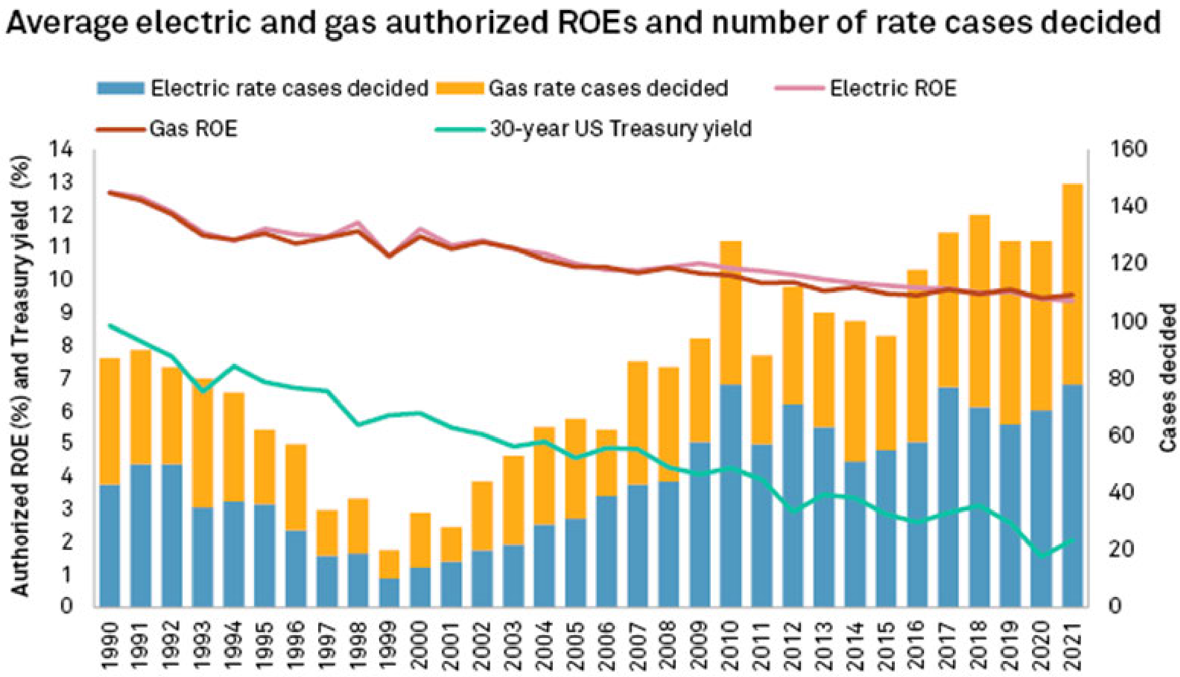
[29] See Exhibit Staff/108, Muldoon/1, 20 for pertinent population growth rates.

FIGURE 1 – Downward Glide Path of Utility ROES[30]



Data compiled Jan. 26, 2022.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Q. What trend is Staff seeing?

A. Since 1990, according to Regulatory Research Associates (RRA), Electric and Electric Utility authorized ROEs have declined as the 30-year US Treasury (UST) has also declined. While the Fed now proposes to raise interest rates, to date it has increased short term rates by less than 100 basis points to date, leaving Treasury yields still close to all-time lows.

Q. When will updated growth forecasts be available from referent federal agencies?

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[30] Published by Regulatory Research Associates (RRA), an affiliate of S&P Global Market Intelligence on Feb. 10, 2022.

A. Staff expects federal agencies to update long-run (20-year out and longer) forecasts this summer. Staff will update its modeling in its next round of testimony to incorporate updated information available then.

GORDON GROWTH MODEL – As Check on ROE Findings

Q. What is the Gordon Growth model?

A. The Gordon Growth model (or Single Stage DCF model), similarly to the Three-Stage DCF model, is based on the principle that a company's value is equal to the net present value (NPV) of all its future cash flows and the company's current stock price. The Single-Stage DCF uses simpler assumptions than other models however, with dividend payments representing the only cash flow, and an assumption that growth will remain constant in perpetuity.[31]

Q. What are the positive aspects, and potential shortfalls of the DCF model?

A. The most positive aspect of the Single-Stage model is its simplicity. An analyst can use this model to calculate a rudimentary cost of equity valuations without needing complex inputs or analysis, beyond selecting a trusted source for the next quarter's expected dividends. In fact, after some algebraic simplification, the return can be expressed by:

$$R = \frac{D_1}{P_0} + g$$

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[31] See Docket No. UG 347, Staff/1300, Muldoon Watson/31 – 39, for further discussion of the Single-Stage DCF model, and the Commission's historical treatment of its results.

Where $\boldsymbol{R}$ is estimated ROE, $\boldsymbol{D_1}$ is the first dividend paid after stock purchase, $\boldsymbol{P_0}$ is the stock price, and $\boldsymbol{g}$ is the growth rate.

Caution and discretion must be used when sourcing inputs to the model, for example, growth rates should be based on well vetted and reliable sources, as opposed to sell-side marketing information used by investment advisors to entice new investors. This is important to bear in mind when considering the results of any Single-Stage model, as reliance on overly optimistic inputs or use of outboard after-the-fact adjustments can have a large impact on the model output.

The Single-Stage model is based on simple principles and serves as a rough estimation of investor required ROE. It cannot incorporate known, measurable, and material information about the future usually built into Three-Stage DCF analysis. For this reason, Staff consistent with Commission precedent, has traditionally only relied on it as a sensitivity check when rate making.

Q. How does Staff determine the dividend flow and growth rate for the single-stage DCF?

A. Much like Staff's Multi-Stage DCF, Staff sources its expected dividends from Value Line. We calculate the average dividend growth rate by comparing the expected dividend by Value Line and actual dividend for each for each company in the peer screen.

Q. What inputs are used to build Staff's single-stage DCF model?

A. Staff uses the same representative draw of stock prices to build its single-stage DCF model as it uses in the three-stage DCF model. Current dividends and anticipated dividend growth are sourced from Value Line.

Q. What are the results of Staff's Gordon Growth model?

A. Using Staff's peer utility screen, the average required ROE under Staff's Gordon Growth model is 8.6 percent. The average required ROE increased to 8.8 percent if the Company's larger peer screen is used instead. This supports Staff's recommended ROE of 9.2 percent. Table 8 summarizes the results of Staff's modelling.

TABLE 8[32]

Staff's Representative Single Stage (Gordon Growth) Discounted Cash Flow (DCF) Model

Presumes the Peer Utility will pay its divident as a fixed multiple of growth into the future as it is now.

The results would be true only if the utility stock's dividends were to grow at a constant rate forever.

Value of Stock (P_0) = D_1 / (k- g) Stock Price Now = Next Year's Dividend / (Required Stock Return - Growth in Dividends)

k = (D_1 / $P_{0)}$ + g Required Rate of Return on Utility Equity = (Next Year's VL Dividend / Recent Stock Price) - Perpetual Growth

This Model Implies: **Points toward Upper End of Staff's 3-Stage DCF Modeling Results**

		1	2	3	4	5	6	7	8	9	11	13	14
											= 8 + 9		
	Screen #	**Abbreviated Utility**	**UE 399 PAC**	**UE 399 Staff**	**Ticker**	**Recent Stock $ Price**	**Current Dividend Yield**	**Next VL Annual Dividend**	**Anticipated Dividend Yield**	**VL Dividend Growth**	**Investor Required ROE**	**Screen #**	
1	1	Allete	Yes	No	**ALE**	61.23	4.2%	2.70	4.4%	3.5%	7.9%	1	1
2	2	Alliant	Yes	**Yes**	**LNT**	61.94	2.8%	1.81	2.9%	6.0%	8.9%	2	**2**
3	3	Ameren	Yes	**Yes**	**AEE**	94.07	2.5%	2.52	2.7%	7.2%	9.9%	3	**3**
4	4	AEP	Yes	No	**AEP**	101.06	3.1%	3.35	3.3%	5.8%	9.1%	4	4
5	6	Avista	Yes	No	**AVA**	42.41	4.2%	1.83	4.3%	4.0%	8.3%	6	5
7	9	CMS	Yes	No	**CMS**	70.19	2.6%	1.94	2.8%	5.9%	8.6%	9	7
8	10	Consol Ed	No	**Yes**	**ED**	96.88	3.3%	3.24	3.3%	2.4%	5.7%	10	**8**
11	13	Duke	Yes	**Yes**	**DUK**	111.45	3.6%	4.06	3.6%	2.2%	5.8%	13	**11**
12	16	Entergy	Yes	No	**ETR**	119.78	3.4%	4.30	3.6%	5.2%	8.8%	16	12
13	17	Evergy	Yes	**Yes**	**EVERG**	69.27	3.4%	2.48	3.6%	6.8%	10.4%	17	**13**
14	18	Eversource	No	**Yes**	**ES**	90.61	2.8%	2.72	3.0%	5.9%	8.9%	18	**14**
16	24	IDACORP	Yes	No	**IDA**	107.60	2.8%	3.25	3.0%	6.6%	9.7%	24	16
17	26	NextEra	Yes	No	**NEE**	74.29	2.3%	1.87	2.5%	9.8%	12.3%	26	17
18	27	NorthWestern	Yes	No	**NWE**	59.67	4.2%	2.56	4.3%	2.0%	6.3%	27	18
20	29	Otter Tail	Yes	No	**OTTR**	63.27	2.6%	1.75	2.8%	6.0%	8.8%	29	20
21	31	PGE	Yes	**Yes**	**POR**	48.63	3.7%	1.90	3.9%	6.5%	10.4%	31	**21**
22	32	Pinnacle	No	**Yes**	**PNW**	75.43	4.6%	3.52	4.7%	3.1%	7.7%	32	**22**
25	38	Southern	Yes	No	**SO**	74.87	3.6%	2.78	3.7%	2.9%	6.6%	38	25
26	40	WEC	No	**Yes**	**WEC**	103.26	2.8%	3.11	3.0%	7.0%	10.0%	40	**26**
27	42	Xcel	Yes	No	**XEL**	74.57	2.6%	2.08	2.8%	6.7%	9.5%	42	27
		No. of Peers:	**16**	**9**							**Mean**		
										Company Screen	8.8%	**ROE**	
										Staff Screen	**8.6%**	**ROE**	

Points toward lower end of Staff's 3 Stage DCF Modeling results.

CAPM – As Check on ROE Findings

Q. What is the Capital Asset Pricing Model (CAPM)?

A. The CAPM assumes that a stock's return on equity is a function of a risk-free return and a risk premium and that the risk premium should be augmented by a company's level of risk relative to the market, which is captured by Beta or β. All told, CAPM takes the form:

$$\boldsymbol{Required\ Return} = \boldsymbol{r_f} + \boldsymbol{\beta}(\boldsymbol{r_m} - \boldsymbol{r_f})$$

Where $\boldsymbol{r_f}$ is the risk-free rate and $\boldsymbol{r_m}$ is the market return. Generally, the risk-free rate is assumed to be the rate of return on bonds. Taking cues from long-

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[32] See Exhibit Staff/105, Muldoon/4 for Staff's full Gordon Growth Model.

standing financial modelling, Staff calculates its CAPM using the yield on 30-year and 10-year US Treasury bonds as stand-ins the risk-free rate.

Q. Should the Commission scrutinize CAPM carefully?

A. Yes. CAPM only relies on a few inputs. In this case, there are three inputs: the risk-free rate, the market return, and the choice of Beta. Although it is generally agreed that the rate of return on US Treasury bond is the proper choice for the risk-free rate, there is much discussion about what maturity should be used for Beta and the market return.

There are a variety of sources to find or calculate both Beta and the market return. Because there are so many sources for two inputs into this simple model, an uninformed or malicious investigator could use unrepresentative values to motivate abnormal required returns. It is therefore of the utmost importance to be thoughtful and consistent in choosing CAPM parameters. In Commission activities, we have standardized on Value Line (VL) Betas that are broadly used to give apples-to-apples modeling output comparisons. Staff has used CAPM for validation rather than rate setting in past cases.

Q. Where do you find information on companies' Beta estimates?

A. Estimates of Beta can be found from many sources including Bloomberg, Yahoo Finance, and VL. Traditionally, the Commission has relied on Value Line's Beta estimates to conduct analysis to maintain consistency in regulation between rate cases. The perils of switching between Beta estimates, known as "Beta shopping," will be addressed later in this testimony.

Q. Where do you find information on market returns?

A. Market returns can also be found or calculated from a variety of places. Two common sources for market returns are historical returns on stock market indices and projections for future growth. Care should be taken in selecting a market return due to the volatile nature of the stock market.

Q. What issues can arise from an improper market return selection?

A. For any company with a positive Beta, a higher market return translates directly into a higher required return according to the CAPM formula. Overstating market returns, a required return estimate can vary by over 300 basis points for a typical regulated utility.

Q. How does Staff recommend that market returns be calculated?

A. Staff recommends that market returns be calculated based off the historic long-run growth rates of stocks and an up-to-date measure of the risk-free rate. By using historical averages, a modeler does not run the risk of a large shock in one period unnecessarily augmenting estimated returns, much like the large negative shock caused by the COVID-19 pandemic, the roaring economic recovery post-pandemic, or the ongoing conflict in Ukraine.

As has been done in past rate cases, Staff uses the market risk premium calculated by Ibbotson and the implied market risk premium from Morningstar's Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook, which measures average returns since 1926. These two sources imply that the risk premium would be 4.5 percent and 6.0 percent, respectively. At the time of measurement on June 3, 2022, the 30-year yield on US Treasuries was 2.94 percent.

Q. What recommendations do you have for the maximum authorized ROE according to CAPM?

A. As stated previously, Staff only uses CAPM for validation rather than rate setting due to its historic unreliability. Within Staff's peer utility screen, the estimated ROEs from Staff's CAPM under Staff assumptions average 9.6 percent. Using the Company's peer screen, the average estimated ROE observed is 9. 8 percent.

Q. Has the Commission determined that CAPM should not be relied upon as a stand-alone modeling method, but may still be used as a check on other modeling methods employed?

A. Yes. The Commission made this determination in two general rate cases in 2001 with the issuance of Order No. 01-777 and Order No. 01-787.[33]

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[33] *In the Matter of Portland General Electric*, Docket UE 115, Order No. 01-777 at 32 (August 31, 2001). *In the Matter of PacifiCorp*, Docket UE 116, Order No. 01-787 at 21 (September 7, 2001).

TABLE 9[34]

Staff's CAPM Modeling Results

PAC	1.87%	**Rf Rate as shown in Exhibit PAC/307 Buckley/1 -- Top Current Table**
Opening	12.63%	**Mkt Return as shown in Exhibit PAC/408 Buckley/1 - Top Current Table**
Testimony	10.76%	**PAC Mkt Risk Premium (MRP)**
Staff	2.940%	**R_f as June 3, 2022 30 Yr UST Yields WSJ:** Bonds & Rates (wsj.com)
	10.79%	**30 Year S&P 500 as of Jun. 3, 2022**
	7.85%	**Staff Mkt Risk Premium MRP)**

$R_{PAC} = R_f + \text{Beta} * \text{MRP}$

	Screen #	Abbreviated Utility	UE 399 PAC	UE 399 Staff	Ticker	VL Q1 2020 Beta	ROE w VL Beta CAPM	Screen #	
1	1	Allete	Yes	No	ALE	0.90	10.01%	1	1
2	2	Alliant	Yes	Yes	LNT	0.85	9.61%	2	2
3	3	Ameren	Yes	Yes	AEE	0.80	9.22%	3	3
4	4	AEP	Yes	No	AEP	0.75	8.83%	4	4
5	6	Avista	Yes	No	AVA	0.95	10.40%	6	5
7	9	CMS	Yes	No	CMS	0.80	9.22%	9	7
8	10	Consol Ed	No	Yes	ED	0.75	8.83%	10	8
11	13	Duke	Yes	Yes	DUK	0.85	9.61%	13	11
12	16	Entergy	Yes	No	ETR	0.95	10.40%	16	12
13	17	Evergy	Yes	Yes	EVERG	0.95	10.40%	17	13
14	18	Eversource	No	Yes	ES	0.90	10.01%	18	14
16	24	IDACORP	Yes	No	IDA	0.80	9.22%	24	16
17	26	NextEra	Yes	No	NEE	0.95	10.40%	26	17
18	27	NorthWestern	Yes	No	NWE	0.95	10.40%	27	18
20	29	Otter Tail	Yes	No	OTTR	0.85	9.61%	29	20
21	31	PGE	Yes	Yes	POR	0.85	9.61%	31	21
22	32	Pinnacle	No	Yes	PNW	0.90	10.01%	32	22
25	38	Southern	Yes	No	SO	0.95	10.40%	38	25
26	40	WEC	No	Yes	WEC	0.80	9.22%	40	26
27	42	Xcel	Yes	No	XEL	0.80	9.22%	42	27
		No. of Peers:	**16**	**9**			VL Betas		
					Company Screen	**Mean**	**9.8%**	**ROE**	
					Staff Screen	**Mean**	**9.6%**	**ROE**	

Points to Upper Half of Staff's 3-Stage DCF Results

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[34] See Exhibit Staff/105, Muldoon/3 for Staff's full CAPM model.

CONCLUSION REGARDING CAPITAL STRUCTURE AND ROE

Q. What is Staff's recommendation regarding Capital Structure?

A. Staff recommends that the Commission adopt a notional Capital Structure of 50 percent Long-Term Debt and 50 percent Common Equity.

Q. What is Staff's recommendation regarding ROE?

A. Staff recommends that the Commission adopt a point ROE of 9.20 percent consistent with the findings herein within a range of reasonable ROEs between 8.95 percent and 9.38 percent.

Q. What Rate of Return (ROR) is generated by the Staff's aggregated Cost of Capital recommendations on Capital Structure, ROE and Cost of LT Debt?

A. Staff's calculations generate a 6.894 percent Overall Rate of Return (ROR). Though 24 bps lower than the Company last authorized ROR, this is a fair and reasonable recommendation to the Commission.

Q. Does that conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

June 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME:	Matthew (Matt) J. Muldoon
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	Manager, Rates Finance and Audit (RFA) Division
ADDRESS:	201 High Street SE, Suite 100, Salem, OR 97301
EDUCATION:	In 1981, I received a Bachelor of Arts Degree in Political Science from the University of Chicago. In 2007, I received a Masters of Business Administration from Portland State University with a certificate in Finance.
EXPERIENCE:	From April of 2008 to the present, I have been employed by the OPUC. My current responsibilities include financial analysis with an emphasis on Cost of Capital (CoC). I have worked on CoC in the following general rate case dockets: AVA UG 186; UG 201, UG 246, UG 284, UG 288, UG 325, UG 366, UG 389, and current UG 433; CNG UG 287, UG 305, UG 347, and UG 390; NWN UG 221, UG 344, UG 388, and current UG 435; PAC UE 246, UE 263, UG 374, and current UE 399; and PGE UE 262, UE 283, UE 294, UE 319, UE 335, and UE 394. From 2002 to 2008, I was Executive Director of the Acceleration Transportation Rate Bureau, Inc. where I developed new rate structures for surface transportation and created metrics to insure program success within regulated processes. I was the Vice President of Operations for Willamette Traffic Bureau, Inc. from 1993 to 2002. There I managed tariff rate compilation and analysis. I also developed new information systems and did sensitivity analysis for rate modeling.
OTHER:	I have prepared, and defended formal testimony in contested hearings before the OPUC, ICC, STB, WUTC and ODOT. I have also prepared OPUC Staff testimony in BPA rate cases.

Abbreviations: AVA – Avista Corp., CNG – Cascade Natural Gas Company, IPC – Idaho Power Company, NWN – Northwest Natural Gas Company, PAC – PacifiCorp, PGE – Portland General Electric Company

CASE: UE 399
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PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 102

ROE – Three-Stage DCF: Peer Screen, Dividends, Earnings per Share (EPS), and Hamada Equation

June 22, 2022

CASE: UE 399
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 103

ROE – Three-Stage DCF: Models X and Y

June 22, 2022

CASE: UE 399
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 104

ROE – Three-Stage DCF:
Summary and Recommendation

June 22, 2022

CASE: UE 399
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 105

ROE:
Capital Asset Pricing Model (CAPM)

June 22, 2022

CASE: UE 399
WITNESS: MATT MULDOON

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STAFF EXHIBIT 106

ROE: CAPM, and Gordon Growth – Single Stage DCF

June 22, 2022

CASE: UE 399
WITNESS: MATT MULDOON

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STAFF EXHIBIT 107

ROE: BEA Historical
GDP Growth

June 22, 2022

CASE: UE 399
WITNESS: MATT MULDOON

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STAFF EXHIBIT 108

ROE: TIPS Implied Inflation

June 22, 2022

CASE: UE 399
WITNESS: MATT MULDOON

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STAFF EXHIBIT 109

ROE: Financial News that Investors in Electric Utilities Are Seeing

June 22, 2022

News Articles Cited

Deaths Outpace Births in Most Counties as U.S. Growth Slowed in 2020

by Frederick Kunkle – Washington Post – Mar. 24, 2022
https://www.washingtonpost.com/dc-md-va/2022/03/24/census-population-counties-cities-covid/

Almost **three-fourths** of **all U.S. counties reported more deaths than births last year**, a development largely caused by the **pandemic**, which contributed to a dramatic slowing in the overall population growth of the nation, according to data released Thursday by the **Census Bureau**.

Low fertility rates, which have **persisted since** the **end** of the **Great Recession**, and the continuing demographic shift toward an older population also combined to create the **smallest population increase in 100 years**, said Kenneth Johnson, a sociology professor and demographer at the University of New Hampshire.

Johnson said he expected the data to show a natural decrease but was surprised at its scale. Natural decrease occurs when a population records more deaths than births. “I think one of the most important findings is the fact that almost **2,300 counties had more deaths than births** in them. That’s **unheard of in American history**,” he said.

He said the impact of the coronavirus, along with other trends that limited population growth, had created a “**perfect storm**,” and that one would **have to go back** at least **to** the **1918 flu pandemic** to **find anything like it**.

The data also offered statistical backing to widespread anecdotal evidence suggesting that **millions of Americans moved out** of the **largest cities** in the nation, including the District, during the pandemic.

Whether for safety from infectious disease or convenience during shutdowns, millions of residents traded cities for suburbs or larger suburbs for smaller ones. Many migrated farther into rural counties or resettled to second homes in vacation areas, such as the Catskill Mountains or the Delmarva Peninsula.

The **two largest cities** in the nation, **Los Angeles** and **New York**, suffered the **sharpest losses** as a result of internal migration. Los Angeles County lost over 179,750 people in net domestic migration, while New York County lost over 113,640.

California, **Oregon** and Mississippi had the most counties negatively affected by international migration losses, while Alaska, Louisiana and Illinois had the most counties affected by losses caused by domestic migration within the United States.

Of course, the outflows from some states meant gains in others. Maricopa County in Arizona, which includes Phoenix, received the most people, with more than 46,860 flowing in, from other areas of the United States.

"I'm very surprised by this because I didn't think it was going to be as dramatic, the domestic migration piece of it," said William Frey, a senior fellow at the Brookings Institution, who analyzed the data and its impact on the Washington region. "It may be a blip, and I think it is, but it's certainly noteworthy. I think that's the bigger demographic pattern here."

Census finds Black population grows in suburbs and shrinks in cities

Frey said that although outward domestic migration from these and other major cities had been underway for many years, its effect had been masked by increases in foreign immigrants, but those numbers also slowed during the pandemic.

The data released Thursday covered roughly 3,140 counties, more than 380 metropolitan statistical areas and over 540 smaller locales known as micropolitan statistical areas. The period covered by the data, July 2020 to July 2021, also coincided with some of the peak rates of the spread of the coronavirus, as reflected in reported cases.

In that time, nearly 75 percent of all U.S. counties experienced a natural population decrease, compared with 55 percent of all counties in 2020 and 45 percent in 2019, the Census Bureau found. In Maine, Delaware, Rhode Island and New Hampshire, the natural population decrease occurred in every county.

The District recorded a loss of 20,040 people, driven mostly by domestic migration, while the Washington metropolitan area lost more than 29,000 people, Frey said. Montgomery County experienced a loss of more than 6,410 people, Prince George's County reported a decline of nearly 10,300, and Fairfax County's population declined by over 8,750. Prince William County added more than 1,730 people, Frey found.

He also noted the huge turnaround in immigration, tracing a peak influx of more than 47,000 reported in July 2015 to only 12,600 last year.

More on the census:

- In the latest release, data showed that the **number** of **White people** in the **United States fell** for the **first time since 1790**. The White population also decreased in D.C.
- Population growth across the United States was also at the second-slowest pace in history, and the "places to be" have also shifted. Meanwhile, America's developed areas are growing.
- Historically, the census has never been delayed. But there have been past fears of an inaccurate count, and results have been used to target minorities.

Berkshire Hathaway Net Earnings Rose 11% in Fourth Quarter

by Justin Baer – WSJ – Feb. 26, 2022

Warren Buffett's conglomerate **records $90 billion net earnings for 2021**.

Left: Warren Buffett, CEO of **Berkshire Hathaway**, attending the annual Berkshire shareholders meeting in Omaha in 2019

Warren Buffett's Berkshire Hathaway Inc. said net earnings **jumped 11% on investment gains**.

Berkshire's fourth-quarter net earnings rose to $39.65 billion, or $26,690 per Class A share equivalent, from $35.84 billion, or $23,015 a share, in the same period a year before.

Operating earnings, which exclude some investment results, rose to $7.29 billion from $5 billion a year before.

The conglomerate runs a large insurance operation as well as a railroad, utilities, industrial manufacturers, retailers and auto dealerships. It also manages a large portfolio of investments.

Many of Berkshire's businesses posted higher revenue last year, reflecting the economy's broad recovery from the disruptions caused by the coronavirus pandemic as it swept through the globe in early 2020. And as growth accelerated, some parts of Berkshire were confronted with the same supply-chain issues and spiraling prices that beset other companies last year, analysts said.

An accounting-rule change in recent years has meant that Berkshire's earnings often reflect the larger performance of the stock market, while Mr. Buffett has said operating earnings more accurately reflect the firm's vast business operations.

The **S&P 500 rose 27% in 2021**, the index's third consecutive year of double-digit growth; on a total-return basis, which includes dividends, the benchmark notched a 28.7% gain. **Berkshire's stock** edged it out, with an **annualized total return of 29%**.

In the fourth quarter, Berkshire reported $32.36 billion in gains on investments and derivatives. That was up from $30.83 billion a year earlier.

Berkshire's Class A shares closed Friday at $479,345, up 5.5% for the year. Class B shares, which have risen 6.1% in 2022, closed at $319.24 on Friday.

The company produced annualized gains of 20% from 1965 to 2020, outperforming the S&P 500's 10.2% gains, including dividends. In recent years, Berkshire's performance has slipped. The company's annualized total returns over the past five years were about 13%, compared with 18% for the S&P 500.

Mr. Buffett's long record of savvy deal making and investments earned him the nickname "the Oracle of Omaha." Last year, though, was a quiet one for Berkshire in its quest for big acquisition targets. The company remains an **active buyer** of its **own stock**; **Berkshire spent $51.7 billion** on **repurchases** in the **past two years**, Mr. Buffett wrote in his annual letter to shareholders.

"Periodically, as alternative paths become unattractive, repurchases make good sense for Berkshire's owners," Mr. Buffett wrote. "That expenditure left our continuing shareholders owning about 10% more of all Berkshire businesses."

As of Feb. 23, he wrote, **Berkshire** had **spent another $1.2 billion** on **buybacks** in **2022**.

"Our **appetite** remains **large but** will always remain **price**-**dependent**," Mr. Buffett wrote.

Consumers Retreat as Rising Prices Bite

by Harriet Torry and Rina Torchinsky – WSJ – Jun. 16, 2022

Americans' retail spending declined in May as consumers felt the pinch from **inflation**, **higher gasoline prices** and **rising interest rates**.

Retail sales – a measure of spending at stores, online and in restaurants – fell a seasonally adjusted 0.3% in May from the previous month, the Commerce Department said Wednesday. That was the first decline in month-over-month retail spending this year.

The pullback in spending is another indicator that the economy is losing momentum as the Federal Reserve raises interest rates to combat historically high inflation.

Consumer spending, buoyed by strong job growth and stimulus measures, was the backbone of the country's economic recovery since a brief recession occurred in early 2020. That strength is fading in the face of the **strongest pace of inflation in four decades**. "Now consumers are planning to take a back seat," said Beth Ann Bovino, U.S. chief economist at S& P Global Ratings. "How far they're planning to sit back – it's still an open question."

A sharp drop in vehicle sales – due to high prices, low inventory and rising interest rates on car loans – played an outsize role in the decline in month-over-month retail spending. Consumers also reined in their spending on goods such as furniture, electronics and online purchases.

Higher borrowing costs are hitting the housing market as well, with the National Association of Home Builders reporting Wednesday that confidence among home builders in the U.S. decreased in June for the sixth consecutive month.

More broadly, monthly job gains slowed in May, as did annual wage increases. Consumer spending eased in April and the saving rate fell to the lowest in 14 years, suggesting many Americans are tapping savings to offset cost increases from inflation.

The weaker-than-expected retail sales in May and a downward revision to April spending prompted some economists to downgrade their expectations for economic growth in the second quarter. The economy contracted in the first quarter.

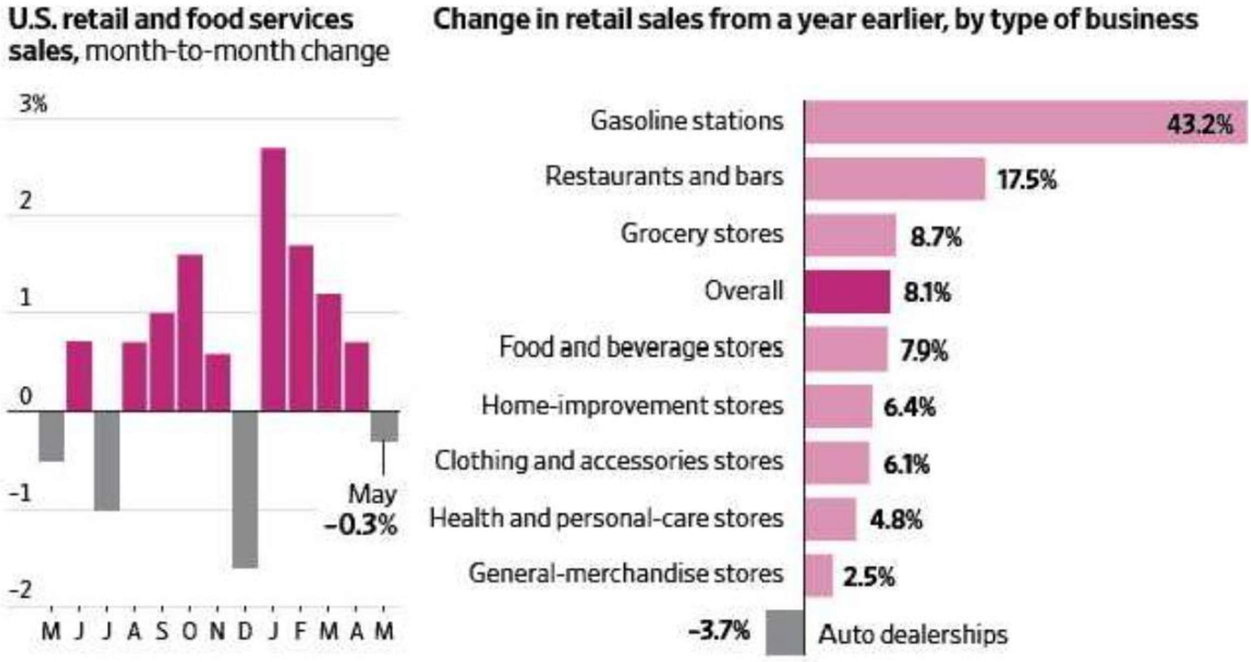
JPMorgan Chase & Co. analysts **lowered** their **forecast** for **U.S. gross domestic product growth to** an **annual rate of 2.5%** in the **second quarter from 3.25%** previously. Data firm **IHS Markit cut its growth estimate to 0.9%**.

Excluding autos and gasoline, retail sales rose just 0.1% in May, well behind the pace at which prices increased last month. Unlike other reports compiled by the government, retail sales aren't adjusted for inflation. **Soaring gasoline and grocery prices** meant households shelled out more on them in May – **Americans** are **spending** over **43% more on gasoline than** a **year ago** and nearly **9% more on groceries**.

Retail sales were up 8.1% last month from a year earlier, a robust gain but below the blistering pace of inflation, which was up to 8.6% in May from a year earlier, according to the Labor Department's consumer- price index.

The **Fed's decision** Wednesday to raise its benchmark **federal- funds rate** to a range between 1.5% and 1.75% **will make car loans** and **credit-card debt more expensive** in the months ahead. Still, Fed Chairman Jerome Powell said he thinks consumers are in good shape, and the economy is well positioned to deal with higher interest rates. "Overall spending is very strong," Mr. Powell told reporters, adding the central bank isn't seeing a broad slowdown.

Consumers are **getting less for their money due to rapidly rising prices**. The dynamic is also driving a **shift from discretionary purchases such as furniture** and electronics **to essentials like food** and **gasoline**.



U.S. retail and food services sales, month-to-month change

Change in retail sales from a year earlier, by type of business

Note: Seasonally adjusted
Source: Commerce Dept. via St. Louis Fed (month-to-month); U.S. Census Bureau (by type of business)

Fed Begins Shrinking $8.9 Trillion Portfolio

by Nick Timiraos – WSJ – Jun. 3, 2022

Central bank is **trimming** its asset holdings **by not reinvesting proceeds when securities mature**.

The Federal Reserve began the process Wednesday of shrinking its **$8.9 trillion asset portfolio**. Here are answers to five of the most commonly asked questions from readers about how it works.

When the Fed shrinks its asset portfolio, is it selling bonds?

No. The Fed dramatically expanded its portfolio in March 2020 to stabilize dysfunctional markets, and then it continued to purchase Treasury and mortgage-backed securities in large quantities after that to provide additional stimulus to the economy by holding down longer-term yields. It ended those purchases in March 2022 and has been keeping its holdings steady since then by reinvesting the proceeds of maturing securities into new ones.

As of **June 1**, the **Fed will let up to $30 billion** in **Treasurys** and **$17.5 billion** in **mortgage bonds mature every month without investing** the **proceeds**. The central bank is **shrinking** its **holdings passively**, or **by attrition**. (Because none of the Fed's Treasury holdings mature until June 15, this process for Treasurys doesn't actually take effect for two more weeks.) In September, the Fed will allow twice as many securities – $60 billion in Treasurys and $35 billion in mortgage bonds – to run off its portfolio.

What about mortgage securities? Some Fed officials have said those could be actively sold at some point. Why?

The **Fed** has said that **over** the **long run**, it **wants** to **own primarily Treasury securities**. Selling mortgage assets would more quickly shift the composition of its asset holdings toward Treasurys.

The Fed didn't actively sell mortgage bonds last decade, but it never ruled out such sales. And it hasn't ruled out sales of its $2.7 trillion in mortgage-backed securities at some point down the road this decade, because it will take a long time to shrink those holdings passively.

The 30-year mortgage rate has increased by more than 2 percentage points over the past six months, which will lead to much lower refinancing volumes and therefore fewer early pay-downs of such long-term securities in the coming years. The upshot is that even though the Fed will allow up to $35 billion in mortgages to run off its portfolio by September, in most months, the Fed might see less than $20 billion in securities decline through passive runoff.

Officials haven't decided whether or when to sell securities, and minutes from the Fed's recent policy meetings haven't provided many clues about the debate inside the central bank's rate-setting committee.

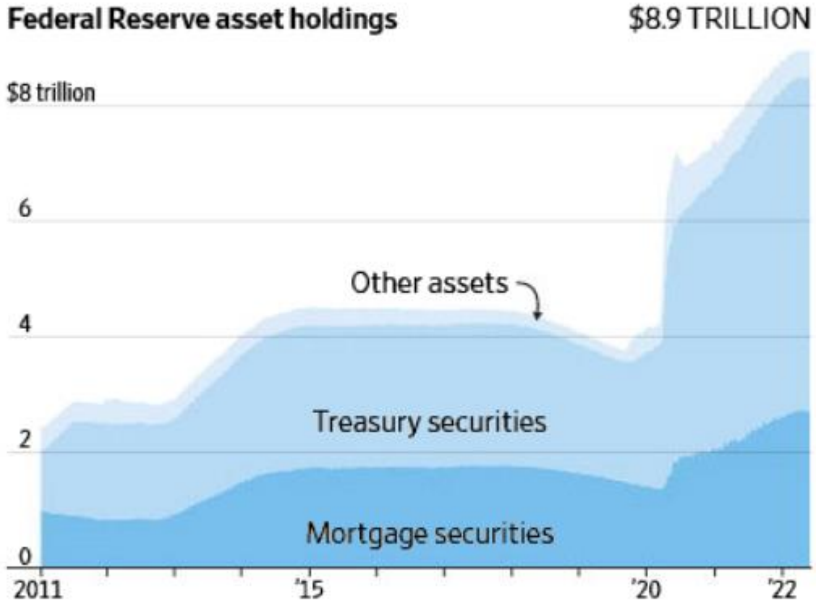
What does the Fed do with money it gets from payment of principal on holdings?

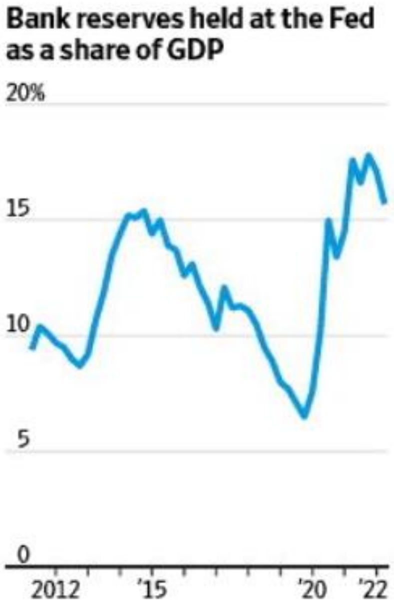
The **Fed essentially created money out of thin air to buy** the **bonds**. **Now**, it will **destroy** the **money** in the **same way**.

When private investors buy bonds, they use cash, borrow funds or sell assets to raise the money to make that purchase. The **Fed** is different. It doesn't have to do any of those things because it **can electronically credit money to** the **accounts** of **bond dealers who sell mortgage- backed securities or Treasurys**.

When the **Fed purchases** a **security**, it **creates** a **bank deposit** known as a **reserve** that **shows up in** the **account of** the **seller**. **When** the **process** is **reversed**, instead of reinvesting the proceeds of maturing bonds, the **Fed erases** them **electronically**. It **doesn't print currency to purchase** the **bonds**, and so it **won't be destroying any paper currency**. The **electronic money essentially vanishes from** the **financial system**.

The New York Fed provides a detailed breakdown of the accounting on its Liberty Street Economics blog.





What effect does this have on the economy?

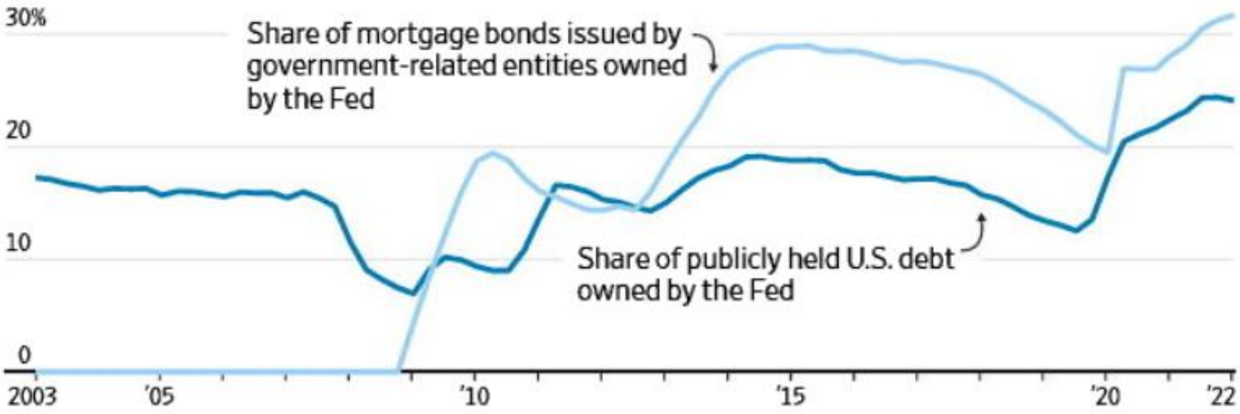
There is no consensus on the effects of the Fed's asset purchases, sometimes called **quantitative easing**, and the portfolio runoff, sometimes called **quantitative tightening**. Several analysts have suggested that the runoff could be equivalent to one or two quarter- percentage point increases in its benchmark short-term interest rate. In theory, the Fed's purchases should reduce long-term yields by pushing down the so-called term premium, or the extra yield that investors receive for holding longer-dated assets. Analysts **at JP-Morgan Chase** have **estimated** that **each $1 trillion** in **Fed bond purchases** during and after the 2008 financial crisis **reduced** the **term premium** on a **10-year Treasury note by 0.15 to 0.2 percentage point**. **Runoff should boost** the **term premium** by **increasing** the **supply** of **bonds** that private investors must now absorb, **pushing** their **prices down and raising yields**.

When will the Fed stop its portfolio runoff?

The end date **isn’t clear**. In 2019, the Fed slowed its runoff program much sooner than most officials had initially anticipated, and halted the runoff in July 2019, when the Fed cut interest rates amid concerns over an economic slowdown. In September 2019, turmoil in overnight lending markets led officials to conclude that they had drained too many reserves from the financial system, leading them to make a U-turn and increase the portfolio for several months. That fine-tuning was mooted by the aggressive response to the Covid-19 pandemic in March 2020.

In a February speech, Fed governor Christopher Waller said he thought reserves as a share of gross domestic product – around $3.8 trillion, or 16% of GDP at the end of March – could potentially decline to levels in early 2019, when they were around 8% of GDP. Projections released last month by the New York Fed suggested this might be consistent with allowing Treasury and mortgage holdings to decline to around $6 trillion in mid-2025.

Mortgage bonds and debt



Sources: Federal Reserve (assets, mortgage bonds, bank reserves, debt); Treasury Dept. (debt); Commerce Dept. (GDP)

Fed Sets Biggest Rate Rise since 1994

by Nick Timiraos – WSJ – Jun. 16, 2022

The **U.S. Central bank boosts** its **benchmark by 0.75 point, signals further rapid tightening in 2022**.

The Federal Reserve approved its **largest interest-rate increase since 1994** and signaled it would continue lifting rates this year at the most rapid pace in decades to **combat inflation** that is **running at** a **40-year high**.

Officials agreed to a 0.75 percentage-point rate rise at their two-day policy meeting that concluded Wednesday, which will **increase** the Fed's benchmark **federal-funds rate to a range between 1.5% and 1.75%.**

New projections showed all 18 officials who participated in the meeting expect the Fed to raise rates to at least 3% this year, with at least **half** of all **officials indicating** the **fed-funds rate might need to rise to around 3.375% this year**.

Left: "We're **not trying** to **induce** a **recession now**. Let's be clear about that," **said Fed Chair**man **Jerome Powell** at a news conference.

But he said it was becoming more difficult to achieve a so-called "soft landing," in which the economy slows enough to bring inflation down while avoiding a recession. That represented an implicit concession that the risks of a downturn could rise as the economy digests tighter monetary policy.

"It is not going to be easy," Mr. Powell said. "There's a much bigger chance now that it'll depend on factors that we don't control. Fluctuations and spikes in commodity prices could wind up taking that option out of our hands."

Stock prices ended the day higher after toggling between positive and negative territory before and after the decision, with the S&P 500 closing 1.5% higher, snapping a five-day losing streak. U.S. government bonds rallied after sliding in recent weeks in a selloff that had pushed yields to their highest levels in more than a decade.

Wednesday's rate increase marked an **abrupt change from** unusually precise **guidance** delivered by many members of the rate-setting Federal Open Market Committee in recent weeks, who had indicated they would raise rates by a **smaller half percentage point**, as officials did at their meeting last month.

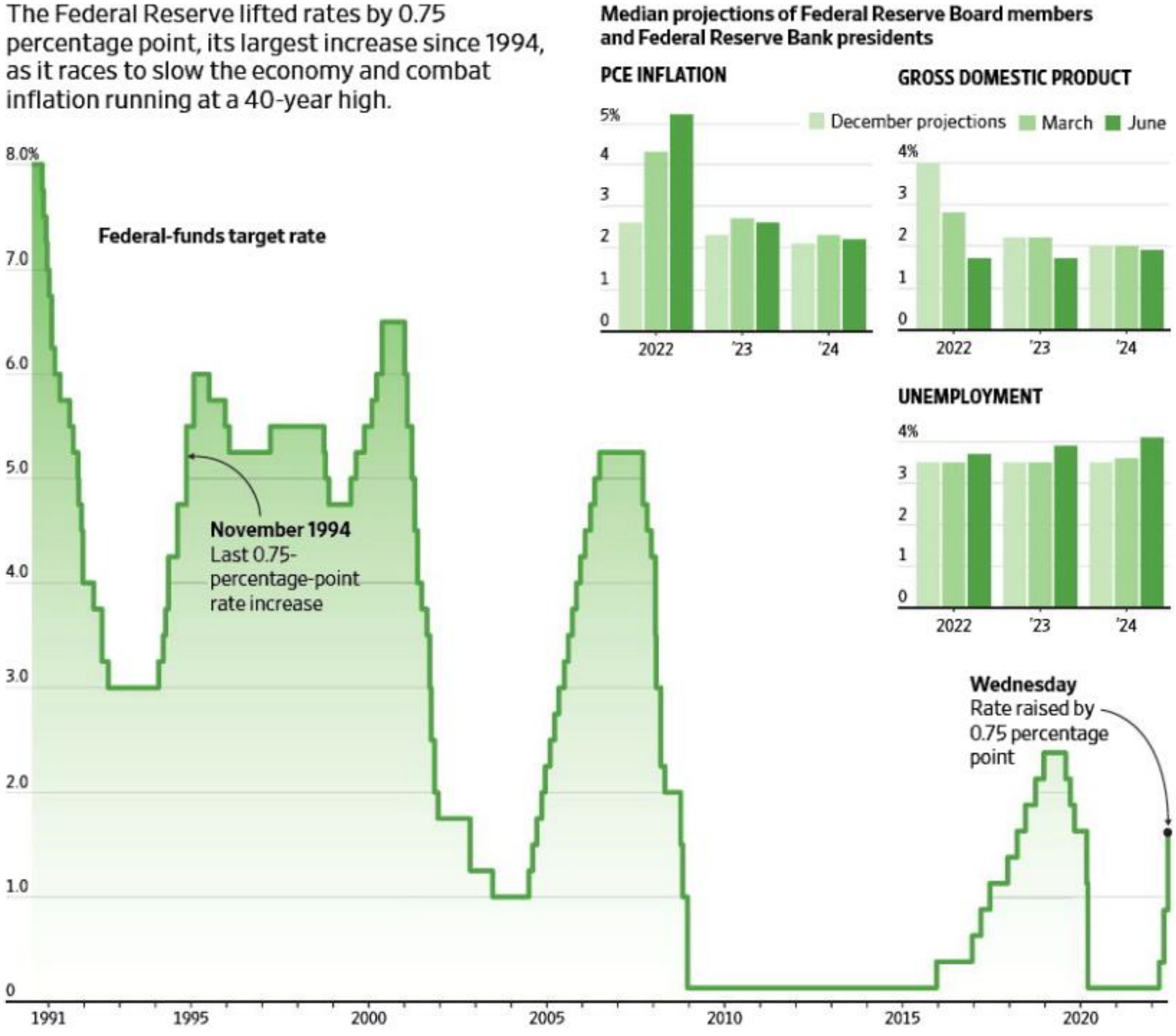
Mr. Powell said the committee had decided to approve the larger rate rise due to concerns over recent data on inflation and expectations of future inflation, which economists believe play a key role influencing actual price rises. He said officials decided it didn't make sense to wait until July to move to a larger rate increase.

Last week, the Labor Department reported the consumer-price index rose 8.6% in May, driven by higher energy prices. Rising fuel prices and supply-chain disruptions from **Russia's war against Ukraine** have sent prices up in recent months.

Mr. Powell's comments indicated that the Fed "will have to keep jamming on the brakes even if growth struggles, and the market didn't get it," said Priya Misra, head of interest-rate strategy at TD Securities.

Ms. Misra warned that markets would face higher volatility until inflation is clearly diminishing. "Today, everyone is cheering, but if inflation has not peaked, we will have to go through the stress of the last few days all over again," she said.

The Federal Reserve lifted rates by 0.75 percentage point, its largest increase since 1994, as it races to slow the economy and combat inflation running at a 40-year high.



Note: Federal-funds target rate shows midpoint of range since 2008. GDP is adjusted for inflation and seasonality for 4Q of each year.

The Fed has faced growing criticism in recent weeks for not acting sooner to withdraw aggressive stimulus it deployed through most of last year. "Powell took a bold decision today, and it sends the kind of message the economy needs to hear," Rep. French Hill (R., Ark.) said.

Expectations of a larger rate rise and a steeper path of rate increase had convulsed bond markets in recent days. Over the five days through Tuesday, the two-year Treasury yield had climbed by 0.7 percentage point, the largest such increase since 1982, according to JPMorgan Chase.

The committee vote was 10-1, with Kansas City Fed President Esther George dissenting in favor of a half-percentage-point, or 50-basis-point, increase.

“Clearly, today’s 75-basis-point increase is an unusually large one, and I do not expect moves of this size to be common,” Mr. Powell said. “From the perspective of today, either a 50-basis-point or a 75-basis-point increase seems most likely at our next meeting” on July 26-27.

Wednesday’s rate increase returns the Fed’s benchmark rate to its level in early March 2020, before the Fed slashed it to near zero as the Covid-19 pandemic hit the U.S. economy. But **interest rates in** the **U.S. and many other wealthy nations remain** at **very low levels historically**.

Mr. Powell said he expected the central bank would raise rates to levels designed to slow the economy. “We think that policy is going to need to be restrictive, and we don’t know how restrictive,” he said.

At the same time, Mr. Powell said he saw no signs of a broader slowdown in the economy. “You’re seeing continuing shifts in consumption…but overall spending is very strong,” he said.

Wednesday’s projections showed officials see the fed-funds rate peaking at around 3.75% by the end of 2023, up from the 2.75% rate that officials projected in March but slightly below what interest-rate futures markets had anticipated earlier this week.

Such a pace of increases would nevertheless represent the most aggressive rate-rise cycle since the 1980s. The central bank has also initiated a program to withdraw stimulus by shrinking its $8.9 trillion asset portfolio through attrition; the Fed is passively reducing its holdings as those securities mature.

The Fed’s monetary-policy statement removed a line that, in May, had indicated officials expected inflation to return to 2% and for the labor market to remain strong as it raised rates. Mr. Powell said the removal of that sentence reflected the sense that the Fed couldn’t reduce inflation to 2% by itself while maintaining a strong labor market.

“The worst mistake we could make would be to fail” to bring down inflation, Mr. Powell said. “It’s not an option. We have to restore price stability.”

The projections revealed that all but one official expect unemployment to rise over the next two years, an implicit acknowledgment of rising recession risks. The median projection showed the unemployment rate, which stood at 3.6% in May, ending at 3.7% this year before rising to 4.1% in 2024.

“Powell told us policy is going to create a recession, but soft peddled it enough to leave markets to figure that out for themselves,” said Steven Blitz, chief U.S. economist at TS Lombard.

The fed-funds rate, an overnight rate on lending between banks, influences other consumer and business borrowing costs throughout the economy, including rates on mortgages, credit cards, saving accounts, car loans and corporate debt. Raising rates typically restrains spending, while cutting rates encourages such borrowing.

The U.S. mortgage market has been slammed by the prospect of tighter money, and many lenders were quoting a 30-year fixed rate above 6% on Monday and Tuesday, levels not reached since 2008.

Mortgage rates stood near 3% at the beginning of the year. “You can’t double mortgage rates in a six month span and live to tell about it,” said Lou Barnes, a mortgage banker in Boulder, Colo., who expected housing to go through a sharp slowdown. “At 6%-plus, mortgages will be very painful.”

Markets began to anticipate the larger 0.75-percentage-point increase after a disappointing inflation report on Friday.

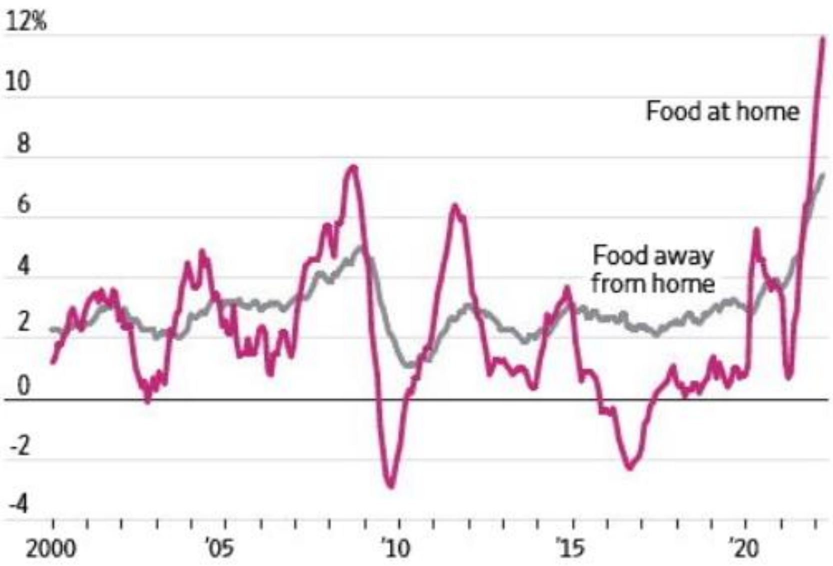
Some former Fed economists said the central bank risked sparking greater market volatility after the surprising shift to a larger rate rise. “It raises questions of whether they’re in control of the situation. It is panicky,” said Vincent Reinhart, chief economist at Dreyfus and Mellon.

Others said they viewed Mr. Powell’s decision as a sign that he was more committed to bring down inflation even if it risked a downturn. “If he’s willing to blow up carefully laid plans to deliver a hawkish surprise, we should take him at his word that he will stay the course,” said Ellen Meade, who retired from the Fed last August as a senior policy adviser.

Food Prices Keep Going Up as Costs Surge

by Jaewon Kang and Annie Gasparro
Heather Haddon and Patrick Thomas contributed to this article.

Consumer price index, change from a year earlier



Note: U.S. city average, all urban consumers, seasonally adjusted
Source: Labor Department

Some of the **nation's biggest food suppliers and restaurants**, **including Kraft** Heinz Co. and some **McDonald's** Corp. franchisees, **said** they **would continue to raise prices as they face higher costs**.

Kraft Heinz notified retailer customers this past Monday that it would raise prices in August on items ranging from Miracle Whip and Classico pasta sauce to Maxwell House coffee products and some deli meat.

Cory Onell, chief sales officer at Kraft Heinz, wrote in the memo to retailers that inflation continues to affect the economy and shape consumption patterns. Costs continue to rally and the persistence of increases makes it necessary to announce price changes, he wrote.

From farmers and factories to grocery stores and restaurants, many executives say they are experiencing jaw-dropping **cost increases for labor, packaging, ingredients and transportation**. The rise of **fuel prices** is **making it more expensive** to **produce and sell food**. Food retailers and restaurants have said they are **passing along** some wholesale **price increases** and additional **costs to consumers**.

The Labor Department on Friday said **grocery prices rose 11.9% in May over the past year**, and prices increased 7.4% at restaurants and other food venues outside the home in the period. For both, it marks the biggest jump in over four decades.

Russia's invasion of Ukraine, **one** of the **world's top grain-producing regions**, is **lifting** the **price** of pantry **staples**, **cooking oils** and **livestock feed** for meat. **Bad weather** affecting other big crop-producing countries, including in parts of South America, Australia and India, is **fueling** the **global crunch**, **too**.

Kraft, commenting on the coming price increases, said they reflect the costs of production the industry is facing.

Many food makers, **including Kraft**, have **already raised prices this year**. Kraft has raised prices 13.9% since 2019, Chief Executive Officer Miguel Patricio said at an investor conference this month. He said other brands have followed, and because price increases are widespread across stores, consumers aren't reacting as much as they have historically.

Still, in recent months, more people have switched to buying less expensive brands or cuts of meat at grocery stores and eating out at restaurants less often, industry executives said, as inflation and gas prices weigh on household budgets.

Companies are finding other ways to offset inflation, too. They **sell smaller packages for** a **higher price per ounce**. And they make operations more efficient to save money. Kraft, for example, said it is improving its productivity at factories. "If we only rely on price increases, we're going to have problems," Mr. Patricio said.

To soften the blow of price increases, food makers also provide deals. Kraft said it is offering some larger package sizes for a better value.

McDonald's is studying the impact of its restaurants' price increases to make sure they aren't too much for consumers, Ian Borden, head of McDonald's international business, said during an investor conference Thursday. The chain also wants to ensure McDonald's remains a good value for customers.

"We have the approach that we want to do more frequent increases but at smaller levels," Mr. Borden said.

The chain's franchisees ultimately determine prices at their locations, and some McDonald's restaurant owners said they are increasing prices now given rapidly escalating costs, particularly for fuel.

At grocery stores, discussions with vendors about price increases are increasingly tense, industry executives said, as retailers worry they will lose shoppers from sticker shock.

Left: More people have switched to less expensive cuts of meat.

In April, **Campbell** Soup Co. told retailers that it would soon **implement** its **third round** of **price increases in** the **past year**, affecting products that are increasingly expensive to make. CEO Mark Clouse said higher prices on some of its condensed soups have hurt sales to baby boomers. **But sales volume** of **Campbell's Chunky soup still rose 8%** in the **latest quarter despite significantly higher prices**.

Mr. Clouse said on a recent conference call that the company was trying to keep prices as reasonable as possible. "We know the pressure that consumers are feeling," he said.

Mondelez International, Inc. CEO Dirk Van de Put said this month that the snack maker's price increases haven't curtailed purchases, which he said was surprising. But there will be a lot more price increases to come over the next year, he said.

Meat prices have surged over the **past year** as processors have said their factories remain short-staffed, so they can't slaughter as many cattle, hogs and chickens. Meanwhile, demand from grocery stores and restaurants hasn't let up, executives have said, contributing to higher meat prices. Boneless, skinless chicken breast prices, for example, are up 68% since the start of the year, according to the Agriculture Department.

Tyson Foods Inc., the **biggest U.S. meat processor by sales**, said it **increased beef prices** by an average **24% over** the **three months** ended April 2, while its costs increased 15% over the quarter because of higher expenses for animal feed, freight and labor.

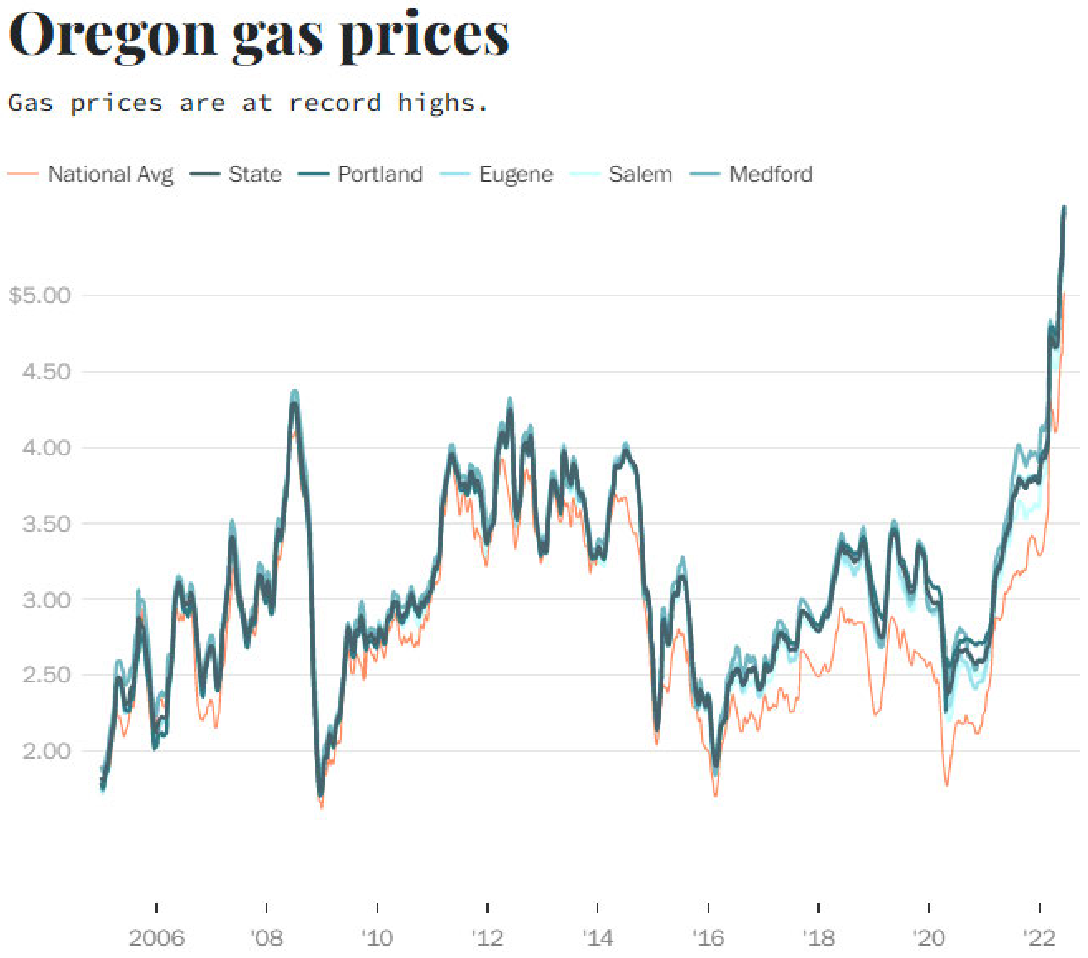
Sanderson Farms Inc., the third-largest chicken producer, said last month that it **raised prices** for its products by about **34% for** the **quarter** that ended April 30.

Hormel Foods Corp., the maker of Spam, **said prices** for **corn** and **soybean meal for livestock feed** were **up** more than **125% and 40%, respectively**, as of early May. High feed prices are expected to continue, company officials said, especially with farmers getting off to a late planting start this year because of cold and wet weather across the Midwest this spring.

The highly pathogenic **avian influenza outbreak** that has led to the **death** of nearly **40 million birds** has also **sent** the **price** of **eggs** and **turkey products higher** in recent months, analysts and Hormel officials have said.

Gas Prices Hit New Highs in Portland Metro, across Oregon;

$5 a Gallon Now the Norm Nationwide
by Jayati Ramakrishnan – Oregonian – Jun. 15, 2022
Gas prices hit new highs in Portland metro, across Oregon; $5 a gallon now the norm nationwide - oregonlive.com


Oregon gas prices

Gas prices are at record highs.

Dave Cansler/staff
Source: AAA

The price of a **gallon of gas** in the **Portland** area hit a **new high** of **$5.59** on **Tuesday**, up 8 cents from a week ago, as the **nationwide average topped $5 for** the **first time**.

Oregon's average price for a **gallon** of **regular** was **$5.54**, up 8 cents from last week and also a record, and motorists nationwide were paying an average of $5.02.

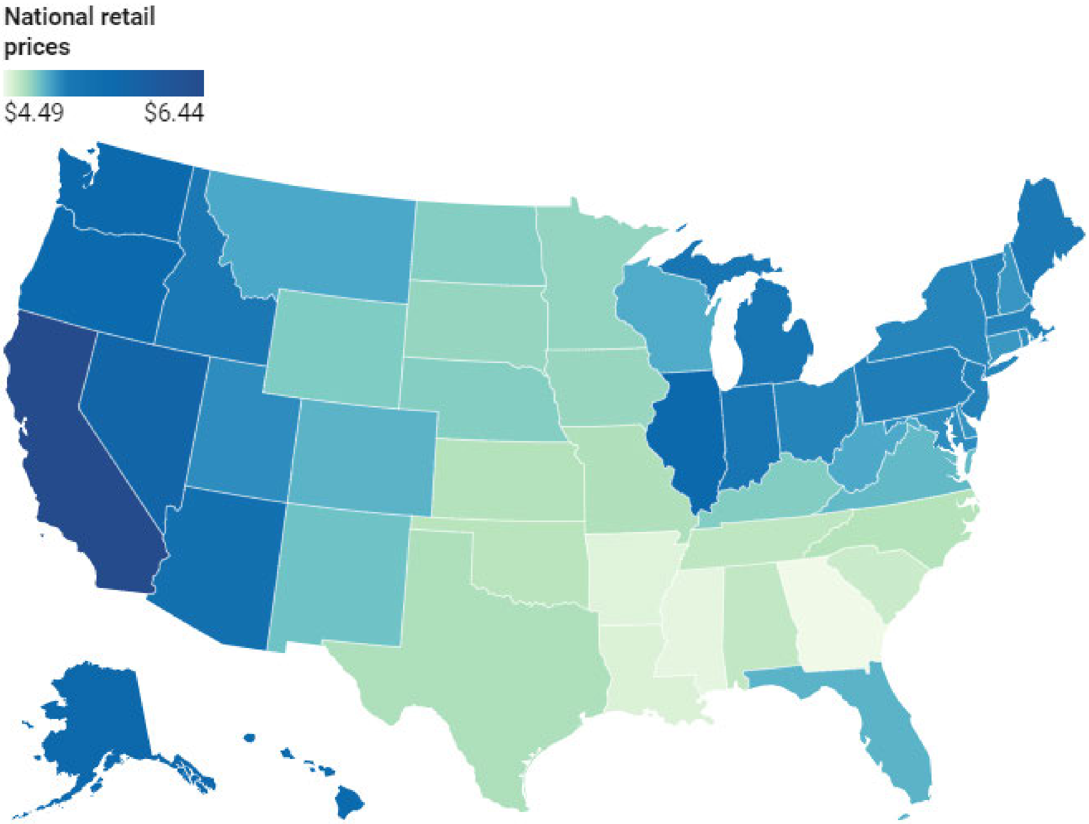
Gas prices are setting new records nearly every day.

Demand remains high, said AAA Oregon/Idaho spokesperson Marie Dodds, and the climbing prices haven't deterred people from getting out on the road.

“People seem eager to drive and take summer vacations after staying close to home for two years during the pandemic,” Dodds said.

U.S. gas prices

Oregon has the nation’s sixth-highest gasoline rates per gallon as of June 14.



Dave Cansler/staff
Source: AAA

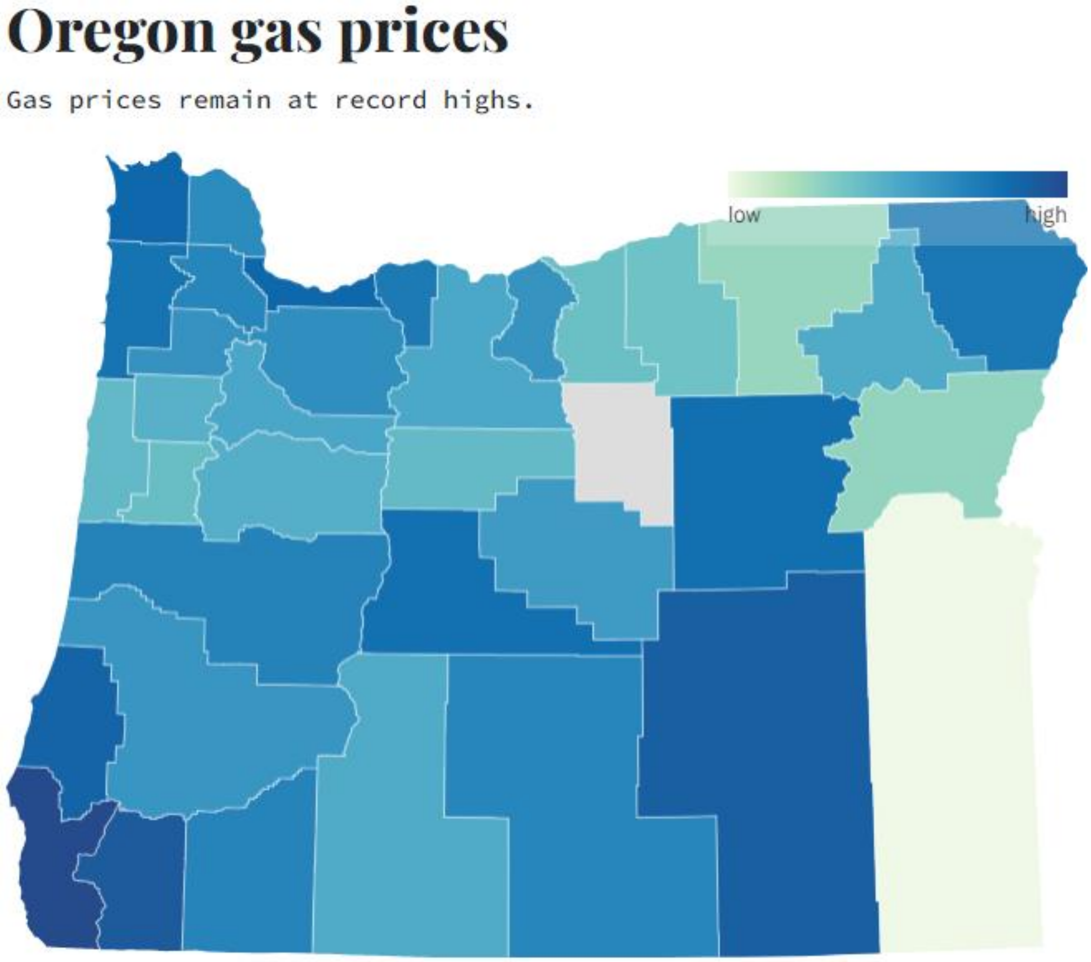
High gas prices are mainly driven by **crude oil** costs, **now above $120 a barrel**. The U.S. and several other countries placed strict **sanctions on Russia**, one of the world’s largest oil producers, **after** its **invasion of Ukraine** earlier this year. Those constraints have driven global oil prices higher.

Oil companies, **including those in the U.S.**, also **have not ramped up production** to meet a rebound in demand since the start of the pandemic.

Prior to this year, Oregon and national gas prices had peaked in the summer of 2008. Oregon’s $4.29 per gallon record from that year would be about $5.76 today, accounting for inflation.

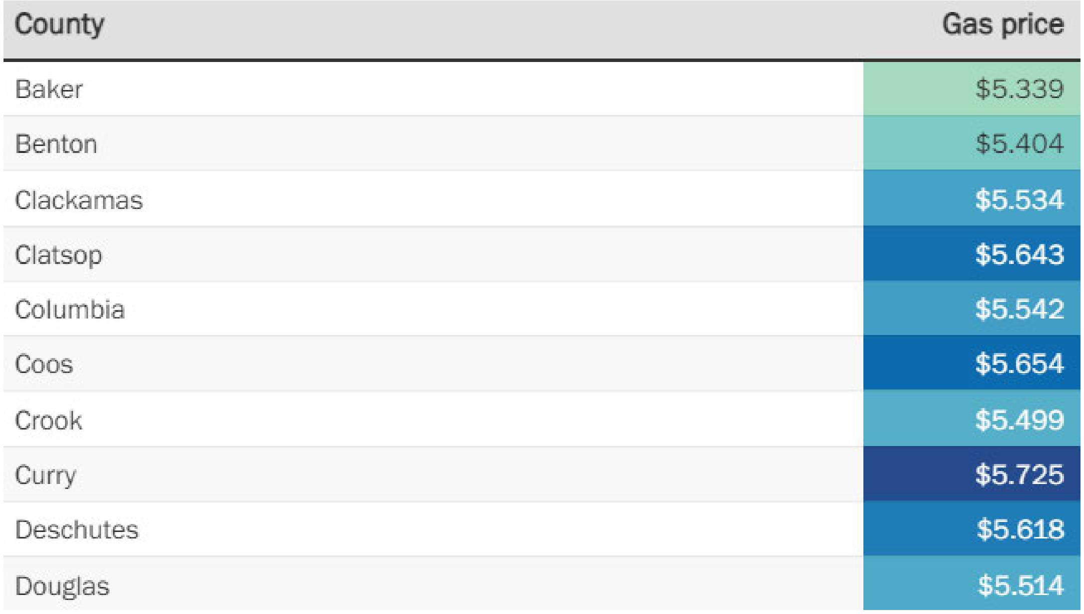
Gas prices are now above $4 a gallon in all 50 states, and nearly half the country is averaging more than $5 a gallon. **California** is the only state with **gas averaging above $6**.

Oregon’s gas prices are **sixth-highest in** the **nation**, behind California, Alaska, Nevada, Washington and Illinois.



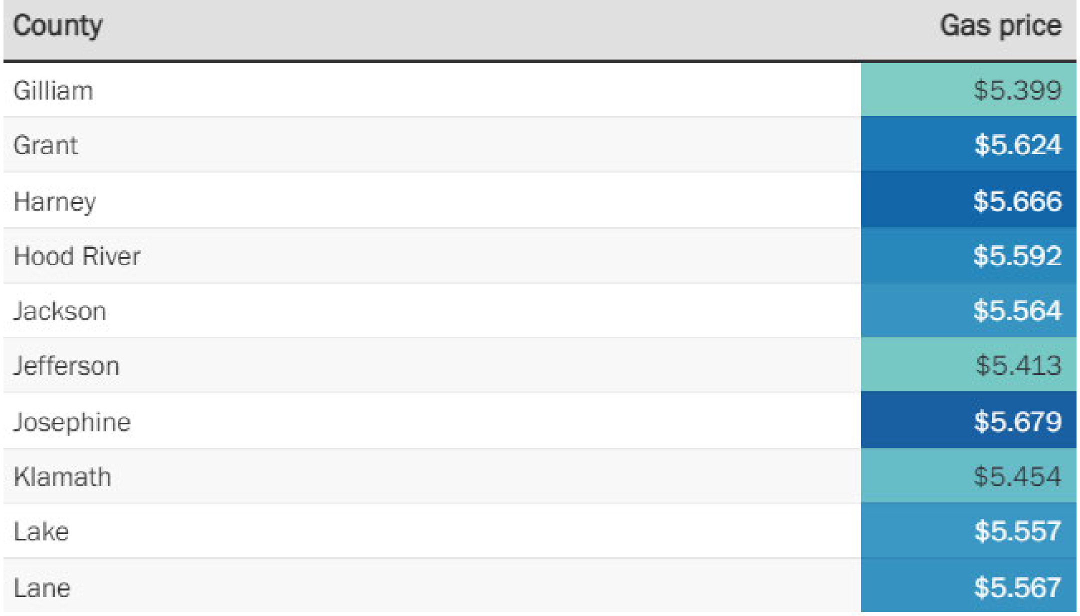
Oregon gas prices

Gas prices remain at record highs.



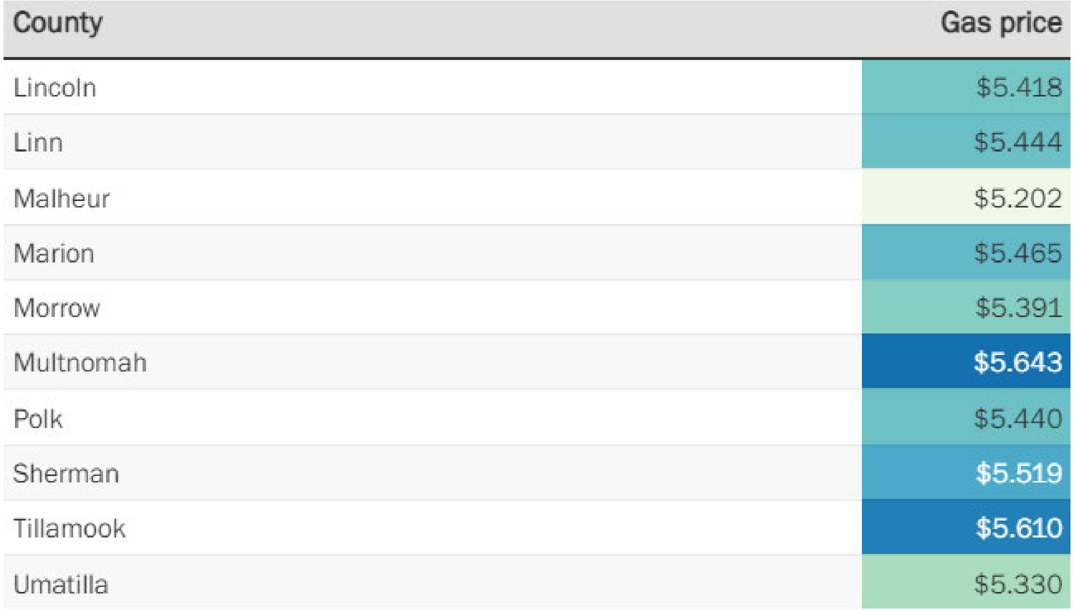
County	Gas price
Baker	$5.339
Benton	$5.404
Clackamas	$5.534
Clatsop	$5.643
Columbia	$5.542
Coos	$5.654
Crook	$5.499
Curry	$5.725
Deschutes	$5.618
Douglas	$5.514

Dave Cansler/staff
Source: AAA



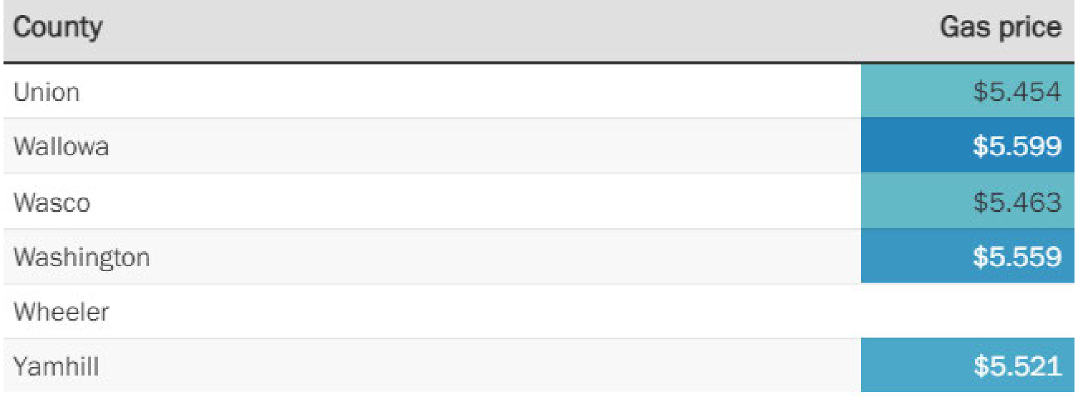
County	Gas price
Gilliam	$5.399
Grant	$5.624
Harney	$5.666
Hood River	$5.592
Jackson	$5.564
Jefferson	$5.413
Josephine	$5.679
Klamath	$5.454
Lake	$5.557
Lane	$5.567

Dave Cansler/staff
Source: AAA



County	Gas price
Lincoln	$5.418
Linn	$5.444
Malheur	$5.202
Marion	$5.465
Morrow	$5.391
Multnomah	$5.643
Polk	$5.440
Sherman	$5.519
Tillamook	$5.610
Umatilla	$5.330

Dave Cansler/staff
Source: AAA



County	Gas price
Union	$5.454
Wallowa	$5.599
Wasco	$5.463
Washington	$5.559
Wheeler	
Yamhill	$5.521

Dave Cansler/staff
Source: AAA

In Oregon, Curry County's gas prices remain the highest, this week reaching $5.73 a gallon. Coos, Josephine and Harney counties all follow close behind. Multnomah County is averaging $5.64 a gallon.

How Utility Stocks Have Kept Their Spark

by Jinjoo Lee – WSJ – May 14, 2022

Sector isn't cheapest place to park money, **but right now** a compelling enough argument seems to be that there are **few alternatives**

The utility sector's rally is something of an anomaly given the macroeconomic environment.

Rising interest rates and inflation are **typically** a **circuit breaker** **for richly valued utility stocks, but these are unusual times**.

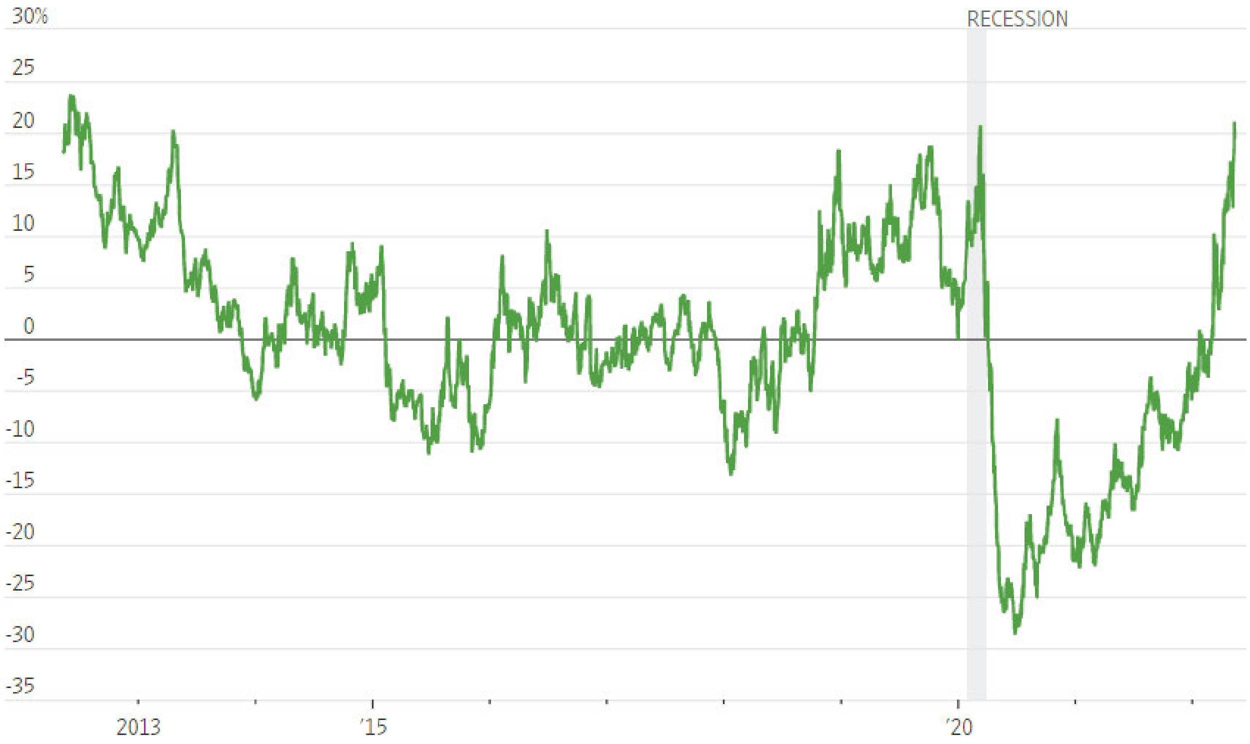
The **sector** is the **second-best performing** one **in** the **U.S. behind energy year to date**, **trouncing** the **S&P 500 by 15 percentage points** through Friday. That leaves **utility stocks trading** at almost **20 times forward 12-month earnings on average** – **close to an all-time high** and nearly a **fifth richer than** the **S&P 500**. The last time utilities fetched such a large premium was during the Covid-19 market panic in March 2020. The staid sector has typically traded at a slight discount to the broader index over the past decade.

As markets fear a recession, being in the business of collecting monthly checks is understandably appealing to investors. Cash-strapped consumers are more likely to pull back on eating out or shopping before risking that the power or gas will be shut off.

And, by some measures, utilities look more defensive today than they have in past years, according to Jay Rhame, chief executive officer of Reaves Asset Management, which manages utility exchange-traded funds. In recent years, utilities have become much simpler, having sold or spun off units that are riskier than or less related to their regulated, monopoly business. Exelon, for example, spun off earlier this year a business unit that has exposure to competitive electricity markets. CMS Energy last year sold off a bank subsidiary.

High Voltage

Utility industry's valuation premium/discount compared with the S&P 500



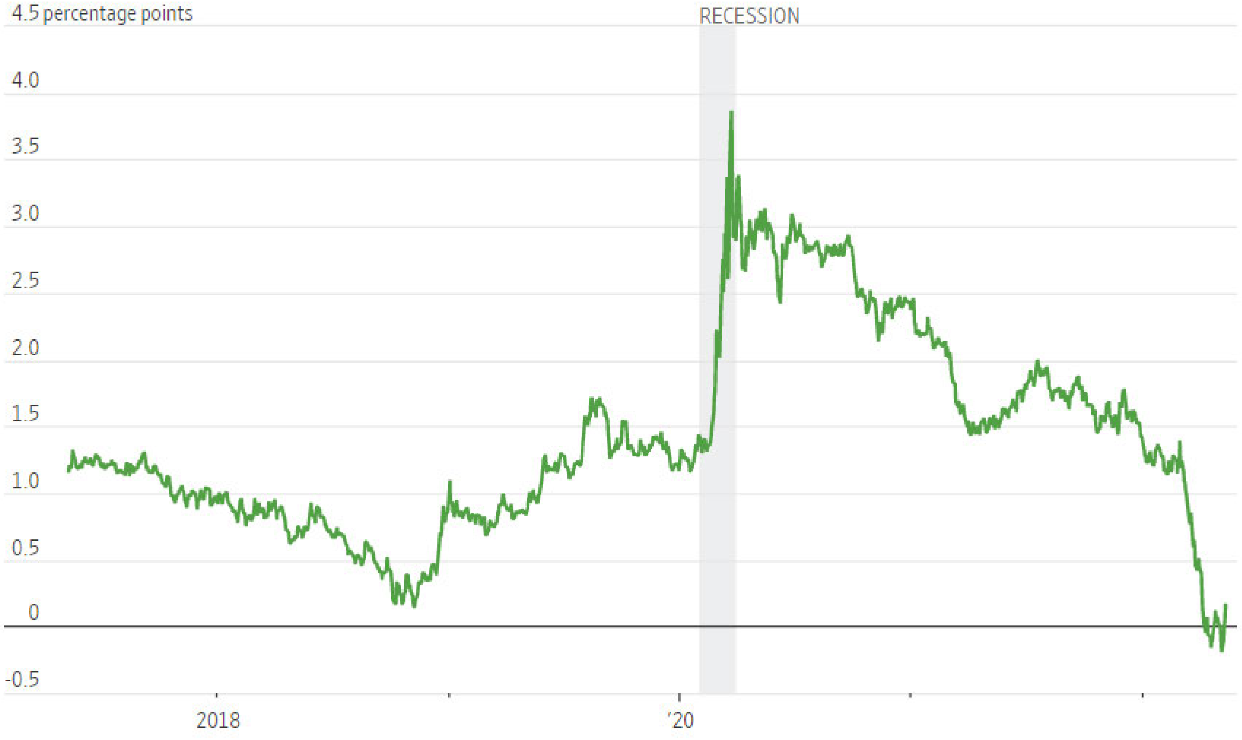
Source: S&P Global Market Intelligence

Still, the sector's rally is something of an **anomaly** given the macroeconomic environment. **Utility stocks tend not** to **take well** to **rising interest rates** for **two reasons**: **First**, utilities have **large debt burdens**, with those in the S&P 500 **on average** carrying net debt that is more than **five times earnings before interest**, taxes, depreciation and amortization, according to S&P Global Market Intelligence. **Second**, they are a **bond substitute**. **When interest rates rise**, **utilities' dividend yields start looking less attractive compared with Treasurys**. At one point during the early-**2020** recession, the **dividend yield on utility stocks** was nearly **4 percentage points higher than** the **yield** on **10-year Treasury notes**. That **edge** is **now just 0.17 percentage point**.

In addition, **high inflation** tends to be bad news for utilities. When inflation starts pushing up overall costs for households, it becomes **harder** to **persuade utility regulators** to **grant higher rates**. **Regulators** are typically either appointed by governors or elected, so they **aren't immune to** the **sentiments** now **prompting politicians** to blame **companies**—ranging from oil producers to supermarket chains—**for causing consumer pain**.

Diminishing Yield Power

S&P 500 utility group's dividend yield minus 10-year U.S. Treasury yield



Source: S&P Global Market Intelligence

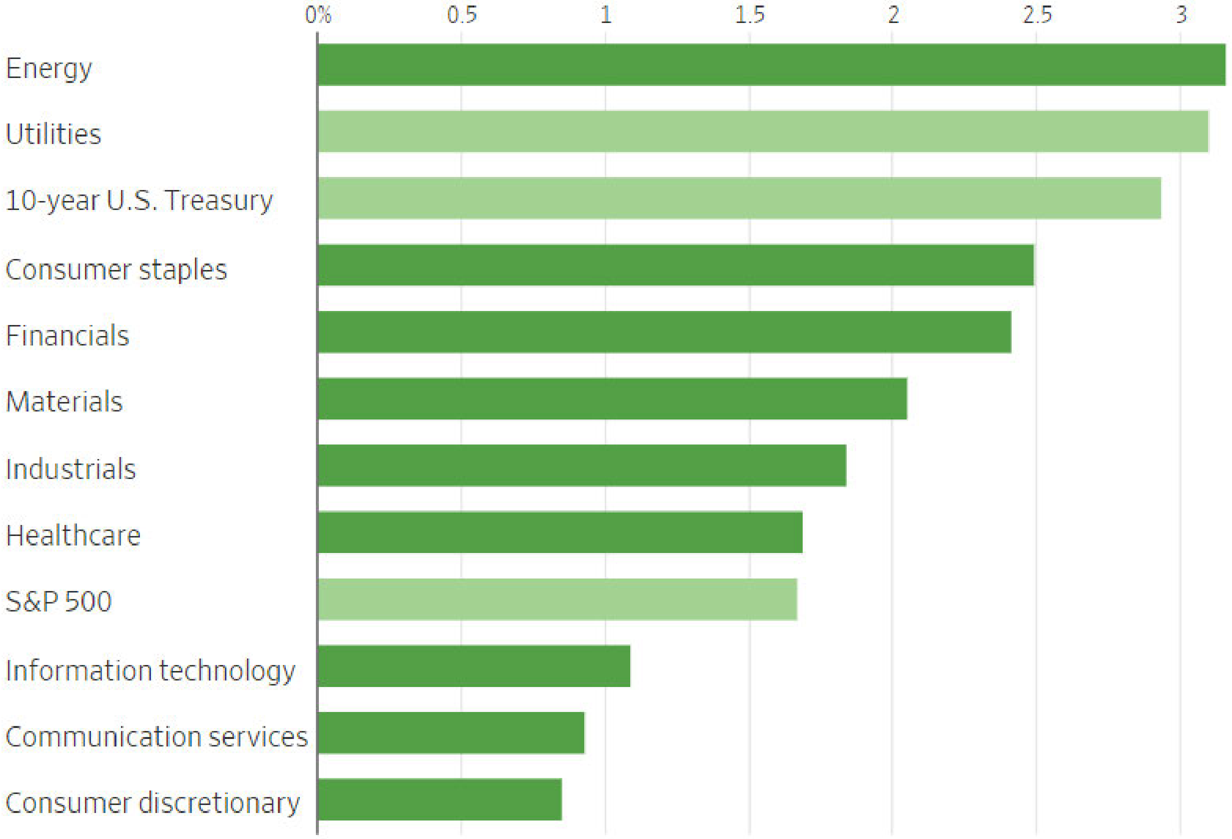
"Price caps, as seen abroad in the U.K. and elsewhere, have strained companies' ability to successfully invest and earn at full ROE," wrote Nicholas Campanella, equity analyst at Credit Suisse, in a report, referring to return on equity. He added that such moves don't seem likely in the U.S. just yet, but that they are worth monitoring. At the moment, though, the fear regarding inflation's destructive effect on fixed-income investments might be overriding the other inflation problem.

"At least **with utilities**, **you get** a **growing income stream**. And you'd think that the utility income stream could be better in an inflationary environment than a fixed-income stream," said Mr. Rhame.

The question is just how much those streams will be pinched by high interest rates and inflation. Moreover, industry-specific clouds also loom over the sector, including the lost momentum in Congress for what was widely known as the Build Back Better package, which included clean-energy incentives. The most recent roadblock is the U.S. Commerce Department's investigation into whether Chinese solar producers are circumventing solar tariffs – a development that could substantially delay new solar build-out plans. Because **utilities' returns** in **large part** are **based on how much** they **spend** on the grid, delays to spending plans can damp earnings growth.

With investors seemingly finding new worries around every corner lately, the forces holding the rest of the market back can make utilities look like a hidden jewel one moment and a lump of expensive coal in the next. In a softening stock market, though, these power lines are starting to look stretched.

Dividend yield of sectors in the S&P 500 and the 10-year U.S. Treasury yield



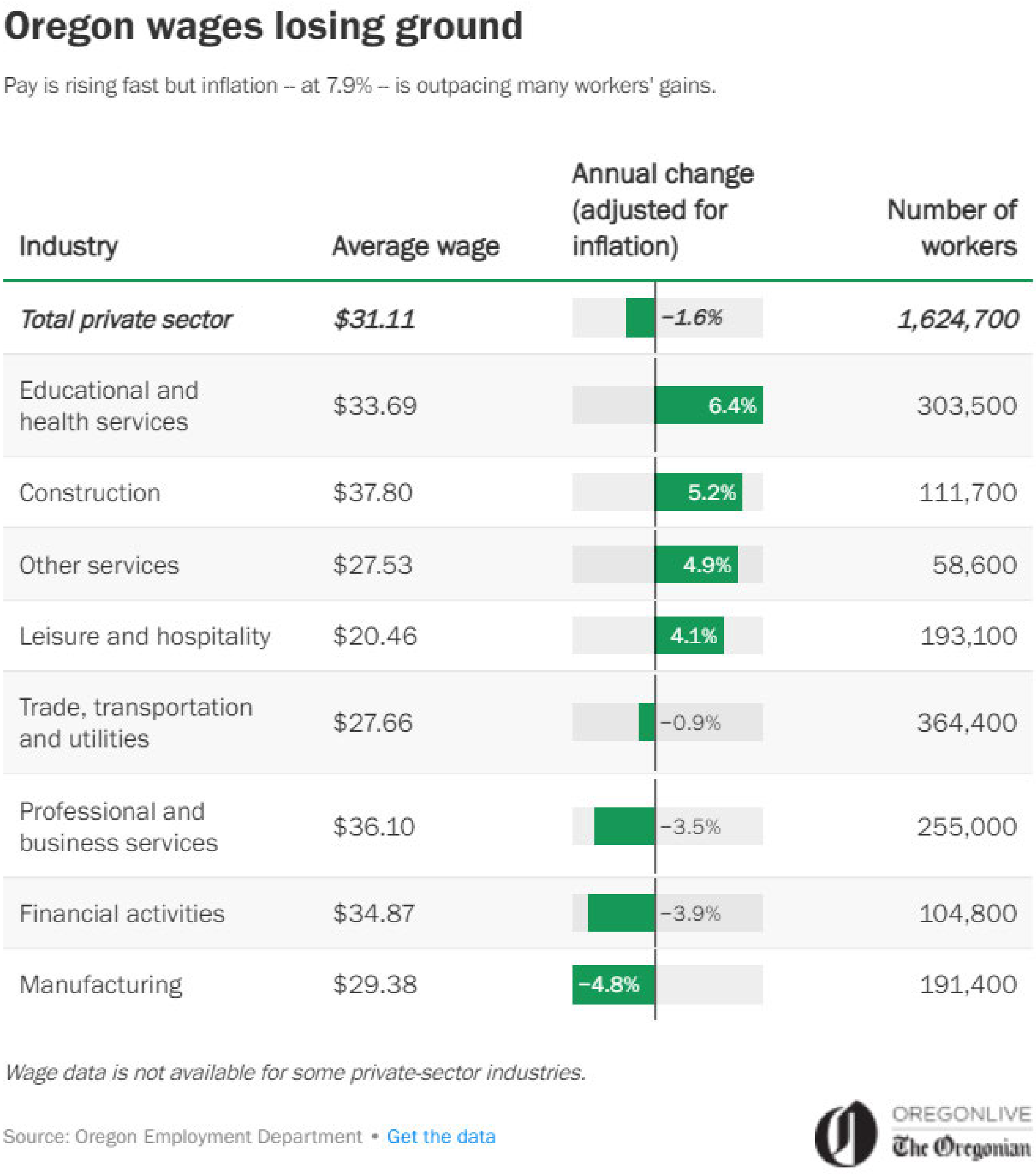
Source: FactSet

Inflation is Outpacing Oregon Wages

by Mike Rogoway – Oregonian – April 3, 2022

https://www.oregonlive.com/business/2022/04/inflation-is-outpacing-oregon-wages-heres-how-major-industries-measure-up.html

Here's how major industries measure up.



Oregon wages losing ground

Pay is rising fast but inflation -- at 7.9% -- is outpacing many workers' gains.

Industry	Average wage	Annual change (adjusted for inflation)	Number of workers
Total private sector	***$31.11***	***-1.6%***	***1,624,700***
Educational and health services	$33.69	6.4%	303,500
Construction	$37.80	5.2%	111,700
Other services	$27.53	4.9%	58,600
Leisure and hospitality	$20.46	4.1%	193,100
Trade, transportation and utilities	$27.66	-0.9%	364,400
Professional and business services	$36.10	-3.5%	255,000
Financial activities	$34.87	-3.9%	104,800
Manufacturing	$29.38	-4.8%	191,400

Wage data is not available for some private-sector industries.

Source: Oregon Employment Department • Get the data

OREGONLIVE The Oregonian

On paper, Oregon wages are rising rapidly. But anyone who's been to the grocery store, gas station or brewpub recently can tell you that's not the whole story.

The state's average, private-sector hourly wage was $31.11 in February, according to new survey data out from the Oregon Employment Department. That's up $1.82 from a year earlier.

But factoring in annual inflation, which was 7.9% in February, Oregon workers actually lost ground. They were effectively making less than they were a year earlier.

In Oregon, "**real wages**" **fell by 1.6%** in **February**. Inflation-adjusted paychecks dropped by even more rapidly **nationwide**, **down 2.6%**.

Economists have many explanations for why inflation is running at its hottest pace in four decades.

The global supply chain crunch has demand for goods outpacing supply, which pushes up prices.

People came out of the pandemic recession with more to spend, thanks to stimulus payments and rising wages. That gave retailers the flexibility to pass along some of their higher costs to shoppers.

And it's not just supplies that cost more – workers do, too. Oregon has more open jobs than unemployed people, forcing companies to bid up wages to bring in staff.

Those raises vary considerably across industries. Many lower-paid professions and in-demand jobs are still outpacing inflation.

Take Oregon's hospitality sector, which was paying an average hourly wage of $20.46 in February. That's up 4.1% from a year earlier, even after accounting for inflation.

David Cooke, statistics coordinator for the **employment department**, said the rising wages probably reflect the pandemic's unique effect on hospitality jobs.

Restaurants, bars and many other attractions closed altogether early in 2020 when the state ordered mandatory lockdowns to prevent the spread of COVID-19.

"Then when the demand and conditions returned more toward normal, many of the workers had found jobs in other industries," Cooke said. "So it is tough to attract them back to the restaurant industry."

Additionally, Cooke noted, hospitality work and other relatively low-paying industries have reaped a boost from rapid increases in Oregon's minimum wage. The hourly minimum has climbed from $9.75 in 2016 to $14 an hour today.

Skilled jobs, like construction and nursing, are in high demand and have pushed up Oregon wages in their categories (up 5.2% and 4.1%, respectively, both handily outpacing national wage gains).

But Cooke said other factors may be at work. He notes that the number of people working in nursing and residential care facilities, a relatively low-paying job, has fallen in the past year. With fewer jobs at the bottom of the wage scale, that means the average across the sector will be greater. Meanwhile, hospitals are hiring higher-paid nursing staff as fast as they can.

The majority of Oregon industries are paying less, after accounting for inflation. Manufacturing suffered the biggest decline in adjusted wages, 4.8%, according to the survey numbers. That could reflect a peculiarity of the data, according to Cooke. By another measure, manufacturers' own reports of wages paid, he said pay appears to have modestly outpaced inflation over the past year.

On the flip side, the category of "other services" (which includes repair and maintenance jobs, religious organizations and other small categories) appears to have shown strong wage gains in the last year. But Cooke cautioned that the relatively small number of Oregon jobs in that segment might make the data unreliable, given that the category showed a 2.9% decline – after adjusting for inflation – nationally.

Broadly speaking, **80% of workers are losing ground to inflation**, according to federal data. And **Cooke said** the Oregon wage data underscores the toll inflation is having on what workers take home.

"Wage increases have risen substantially across most industries," Cooke said. "But overall, wage gains have been less than consumer price increases."

Inflation-Proof Stocks in Demand

by Karen Langley – WSJ – Apr. 18, 2022

Investors seek out travel companies in addition to energy and utilities shares

Investors are on the hunt for companies with the magic words during any spell of inflation: pricing power.

With consumer prices rising at their fastest pace in 40 years and stocks wobbly over the Federal Reserve's plans to raise interest rates, investors are putting a premium on firms whose customers will accept price increases, happily or otherwise. They are trawling through an unsettled market, with the **S&P 500 down 7.8% to start 2022** and the tech-heavy **Nasdaq Composite off 15%**.

Last week, in a reprise of the reopening trade that has emerged at points throughout the Covid-19 pandemic, many traders decided that travel stocks were the play. They snapped up shares of airlines, hotel companies and cruise operators, betting that consumers stuck at home during multiple surges of the virus would be willing to pay steep fares and high rates to get back on the road.

The frenzy kicked off Wednesday with an earnings report from Delta Air Lines Inc. which said that strong demand had helped it return to profitability in March. Delta executives said demand is so robust that the company has been able to recoup elevated fuel costs through higher fares.

Delta shares rose 6.2% on Wednesday, returning them to positive territory for the year. But investors looked further: They sent American Airlines Group Inc. shares soaring 11% and shares of Southwest Airlines Co. and Marriott Inter-national Inc. up 7.5% apiece in the best day for all three stocks since 2020.

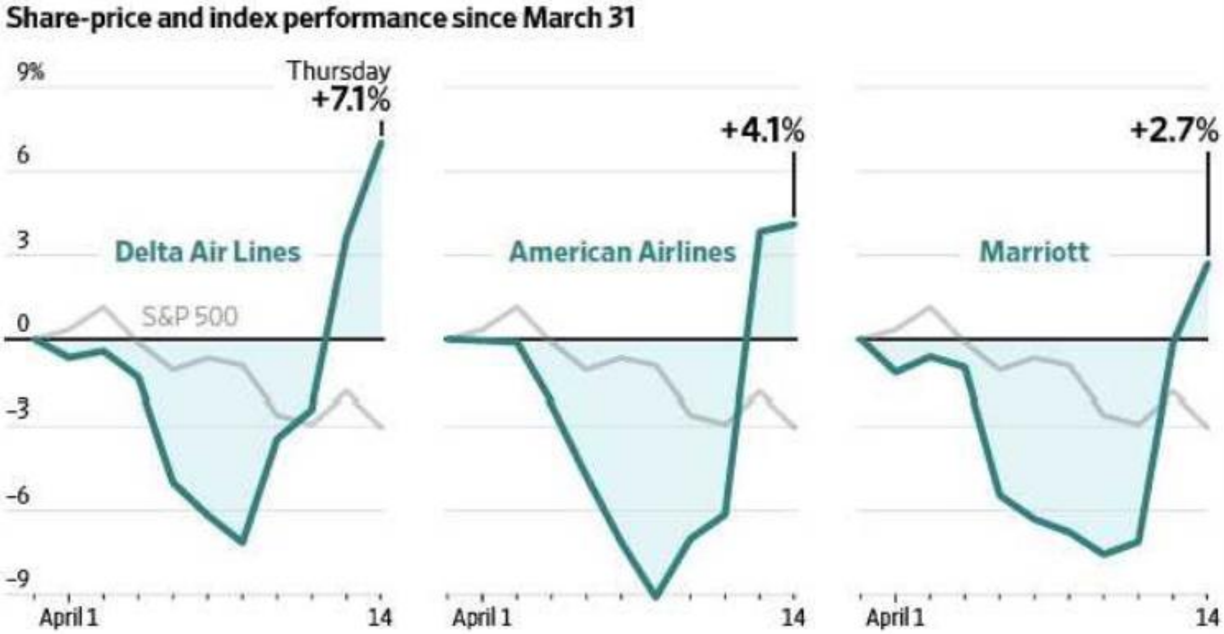
Other likely winners in the fight for profitability include companies in the energy sector, home to many of the top-performing stocks in the S& P 500 this year. Oil prices soared with the Russian invasion of Ukraine, and the sector is expected to report rising profit margins for the first quarter. The **utilities segment**, the **second- strongest-performing sector in 2022**, is **also projected to report higher profit margins**.

"Right now pricing power is the name of the game," said Yung-Yu Ma, chief investment strategist at BMO Wealth Management. "Given the pent-up demand over the past two years, travel is a big place where consumers will pay a couple hundred bucks extra for a ticket."

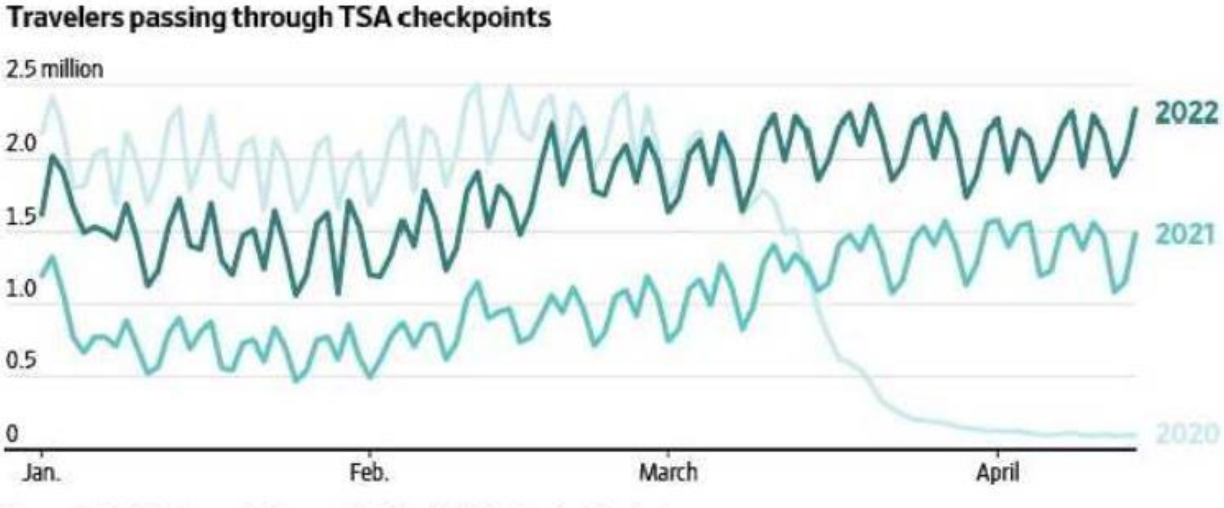
Investors this week will get another look at airline performance when United Airlines Holdings Inc., Alaska Air Group Inc. and American Airlines report earnings. They are just a few of the dozens of big U.S. companies, from Bank of America Corp. to Johnson & Johnson to Tesla Inc., expected to post results.

The race higher between a company's sales and its costs is a primary concern as investors survey an economy marked by steep inflation. The **consumer-price index rose 8.5% in March from** a **year earlier**, the **fastest annual pace since December**

1981. Private-sector average hourly earnings were 5.6% higher in March than a year before, and prices of energy and other commodities are up sharply this year.



Share-price and index performance since March 31



Travelers passing through TSA checkpoints

Sources: FactSet (performance); Transportation Security Administration (travelers)

Many traders snapped up shares of airlines, betting that consumers are ready to get back on the road.

Investors have been searching for clues that the surge in inflation is nearing a peak. And they are parsing companies' quarterly results for indications as to whether higher costs are weighing on profits. Analysts expect the S& P 500 net profit margin to come in at 12.1% for the first quarter, continuing a decline from a high of 13.1% in the second quarter of last year but still above the five-year average of 11.2%, according to FactSet.

For airlines, the consumer-price index data held signs that rising ticket prices are helping companies cope with higher costs.

Airline fares jumped 10.7% in March from February, leaving air-travel prices 23.6% higher than a year earlier.

Jay Hatfield, chief executive and portfolio manager at Infrastructure Capital Advisors, said that on Wednesday he bought shares of Delta as well as hotel-focused, real-estate investment trusts. He was impressed by Delta's high level of bookings.

"There's still some Omicron headlines, and you still do have to wear a mask," Mr. Hatfield said. "So in light of that, to have that kind of boom, that's pretty surprising."

The first full week of earnings season wasn't all good news. Shares of CarMax Inc. dropped 9.5% Tuesday after the used-auto retailer missed earnings expectations. The company's chief executive said he believed consumer confidence and vehicle affordability weighed on used-car sales.

Some investors said the market's recent embrace of airline stocks stemmed in part from the relative lack of options for consumers looking to fly.

It could be more difficult for a consumer-staples company to significantly raise the price of paper products, for example, without customers fleeing to a competing brand.

"A Delta flight isn't toilet paper," said Kimberly Woody, senior portfolio manager at Globalt Investments. "You can trade down there, but I can't fly another airline out of Atlanta. You don't have nearly the amount of trade-off options."

As investors try to discern where the market will head next, they will factor in the success of companies across industries at holding down costs – and getting customers to pay more.

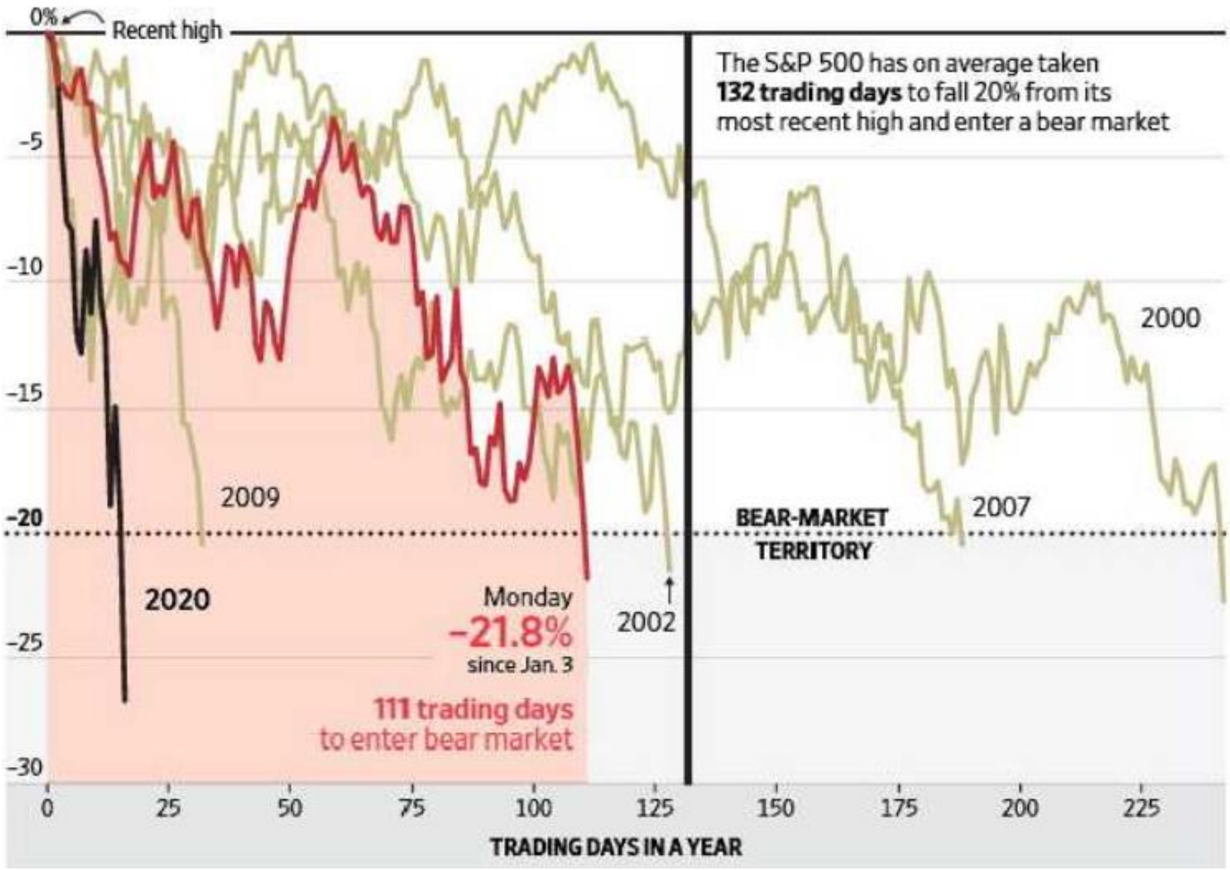
Markets Dive, Fed Eyes Bigger Rise

by Nick Timiraos – WSJ – Jun. 14, 2022
Quentin Webb, Dave Sebastian and Megumi Fujikawa contributed to this article.

Central bank weighs 0.75 percentage point boost this week as inflation data worsen. Worries about prices send S&P 500 into bear territory, spur bets on aggressive Fed rate moves.

A string of troubling inflation reports in recent days is **likely** to lead Federal Reserve officials to consider surprising markets with a larger-than-expected 0.75-percentage-point interest-rate increase at their meeting **this week**.

Before officials began their pre-meeting quiet period on June 4, they had **signaled** they were **prepared** to **raise interest rates** by a **half percentage point this week and again** at their meeting **in July**. But they also had said their outlook depended on the economy evolving as they expected. Last week's inflation report from the Labor Department showed a bigger jump in prices in May than officials had anticipated.


S&P 500 bear-market entrances since 2000

Two consumer surveys have also shown households' expectations of future inflation have increased in recent days. That data could alarm Fed officials because they believe such expectations can be self-fulfilling.

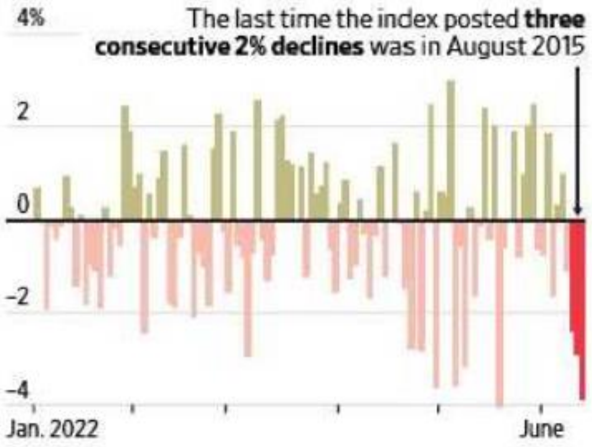
The Fed raised rates by a half percentage point at its meeting last month, the first such increase since 2000, to a range between 0.75% and 1%. The Fed last raised rates by 0.75 percentage point at a meeting in 1994, when the central bank was rapidly raising rates to pre-empt a potential rise in inflation.

Fed Chairman Jerome Powell has avoided surprising markets on the day of policy meetings, instead arguing that the central bank can achieve its goals of tightening policy by shaping market expectations.

But he also said in an interview last month that the Fed would be guided by the economic data to come. "What we need to see is clear and convincing evidence that inflation pressures are abating and inflation is coming down. And if we don't see that, then we'll have to consider moving more aggressively," Mr. Powell said.

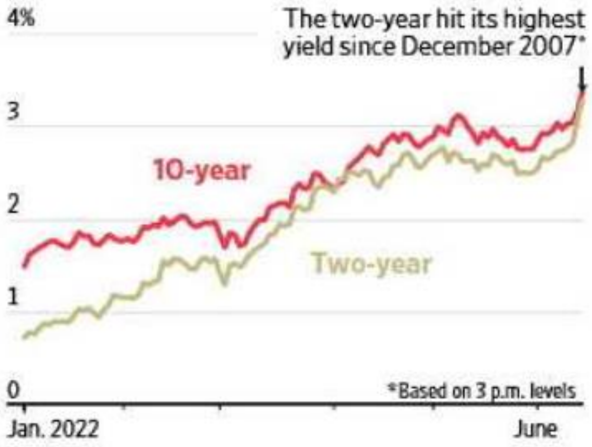
At a news conference last month, Mr. Powell said the central bank would "strive to avoid adding uncertainty" but also acknowledged the possibility of "further surprises" in the inflation data. "We therefore will need to be nimble in responding to incoming data and the evolving outlook," he said.

S&P 500 daily performance



The last time the index posted **three consecutive 2% declines** was in August 2015

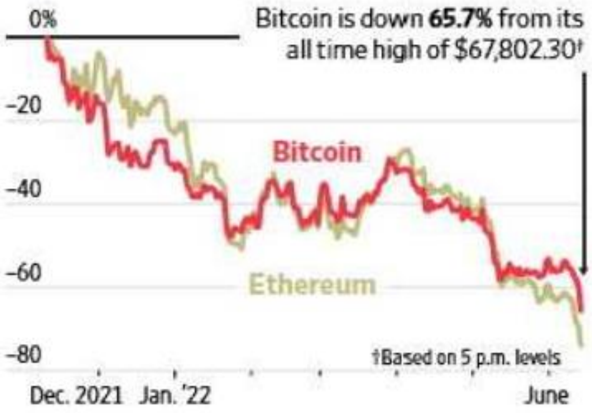
U.S. Treasury yields



The two-year hit its highest yield since December 2007*

*Based on 3 p.m. levels

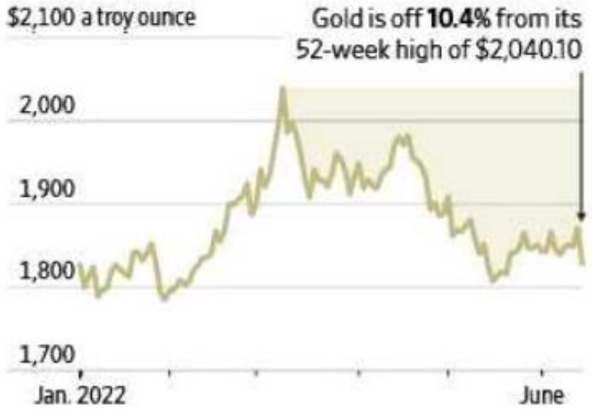
Cryptocurrency performance since Nov. 9, 2021 peaks



Bitcoin is down **65.7%** from its all time high of $67,802.30†

†Based on 5 p.m. levels

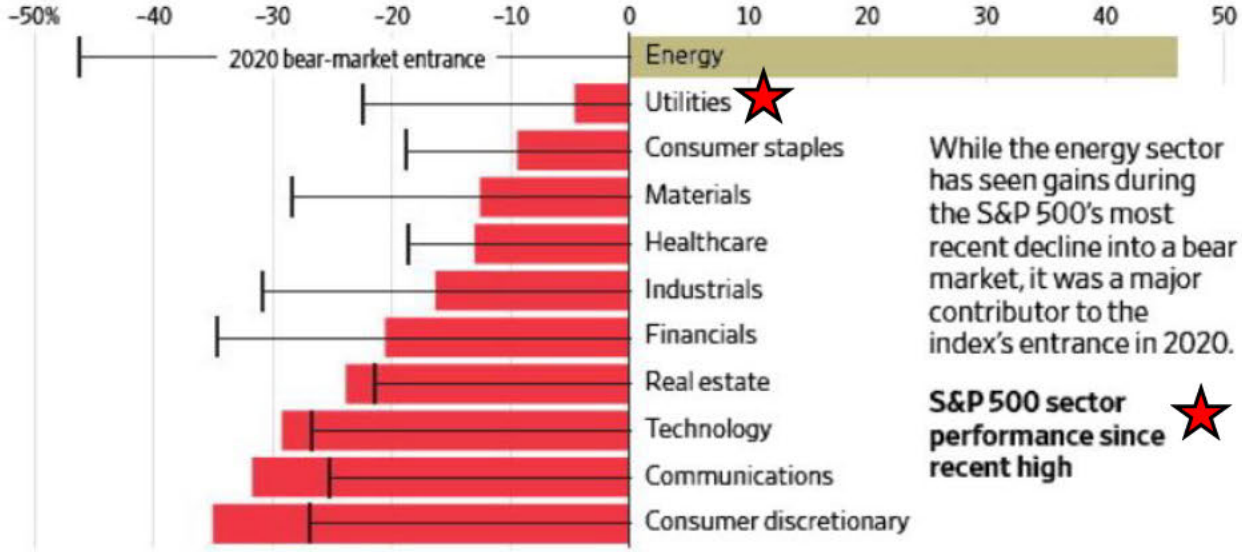
Gold futures price, front-month contract



Gold is off **10.4%** from its 52-week high of $2,040.10

Sources: FactSet (S&P 500, gold); Ryan ALM (yields); CoinDesk (bitcoin); Kraken (ethereum)

Tristan Wyatt/THE WALL STREET JOURNAL



While the energy sector has seen gains during the S&P 500's most recent decline into a bear market, it was a major contributor to the index's entrance in 2020.

S&P 500 sector performance since recent high

The **Labor Department reported Friday** that its **Consumer-Price Index rose 8.6% in May from** the **same month** a **year ago**, **pushing inflation** to a **new 40-year high**. That was a setback for forecasters who were looking for signs that inflation had peaked in March. **Rising fuel prices** and **supply-chain disruptions** from **Russia's war against Ukraine** have **sent prices up in recent months**.

A handful of Wall Street forecasters, including at investment banks Barclays and Jefferies, said Friday after the inflation data that they expected the Fed to raise rates by 0.75 percentage point this week.

"We believe that risk-management considerations call for aggressive action to reinforce the Fed's inflation-fighting credibility," Barclays economists wrote in a subsequent report Monday. While such a move "would go against communications leading into the blackout period," the report said "risks of prolonged inflation have intensified."

After the publication of this article on Monday afternoon, other forecasters, including at JPMorgan Chase & Co. and Goldman Sachs Group Inc., said they anticipated a 0.75-percentage- point rate rise this week.

On Friday, a **University of Michigan survey** of **consumers' long-term inflation expectations rose** to its **highest level since 2008**. On Monday, the **New York Fed** reported that its **survey showed consumers' short-term inflation expectations had jumped** and that the distribution of households' **longer-term expectations** was **more varied than in** the **past**, suggesting more households may be expecting higher inflation to stay, even though the median didn't rise.

Fed officials have said they would want to respond aggressively to signs that inflation expectations were rising, or becoming "de-anchored," because they believe the process of wringing inflation from the economy will become far more difficult if that has happened.

"It's a one-two punch," said Diane Swonk, chief economist at Grant Thornton. "They've got to go now with 75. The Fed is behind the curve, and they know it."

Bond yields, which **surged Friday amid** a **broad market selloff**, continued to climb as that rout deepened Monday. Investors in interest-rate futures markets placed a nearly 30% probability on the larger 0.75-percentage-point increase on Monday afternoon, up from around 4% before last Friday's inflation reports, according to CME Group. After publication of this article, those market-implied probabilities rose above 90%.

Officials will have to weigh several considerations at their two-day meeting that begins on Tuesday. They could stick with their strategy of raising rates in half-percentage-point increments indefinitely until they see signs that inflation is conclusively downshifting.

Such a path of rate rises would lift the Fed's overnight benchmark rate to a range between 2.25% and 2.5% by September, and to a range between 3.25% and 3.5% by December. This would represent the most aggressive interval of policy tightening since the 1980s.

Alternatively, Mr. Powell and his colleagues could signal a rising likelihood of shifting to larger rate rises at the Fed's meeting in late July. But if officials anticipate a significant likelihood of such an increase at the July meeting, they could move more aggressively now. Ms. Swonk said she expected officials to make such an argument at this week's meeting. "The data now is not good. The data is saying they have to do more," Ms. Swonk said. "We're moving into a more inflation-prone world, and they know that, and if they don't derail it now, this could be incredibly corrosive."

Already, borrowing costs set by markets have climbed faster than the Fed's benchmark rate. Mortgage lenders on Monday said they were beginning to quote a 30-year fixed loan with rates above 6%, levels that haven't been reached since 2008.

Other analysts said a larger rate jump would cause more problems for the central bank than it would solve.

"It just opens up additional communication challenges thereafter," said Neil Dutta, an economist at research firm Renaissance Macro. "It suggests the Fed is losing confidence in its forecast. We all know they were trying to catch up, but now it looks like they are panicking."

Mr. Dutta said he also worried that a supersized rate rise would make it harder for the central bank to avoid a recession. "It suggests the Fed is willing to push the economy into a ' hard-landing'-like scenario to get inflation under control," he said.

The **stock-market selloff deepened** on **Monday**, with the **S&P 500 entering** a **bear market**, as investors took another look at Friday's inflation data and liked it even less.

Faced with rising chances of aggressive monetary tightening by the Federal Reserve, **investors unloaded risk**. The S&P 500 slumped 3.9% as 495 of its 500 components ended the day lower. The declines left the U.S. stock benchmark down more than 20% from its January record, sending it into a bear market for the first time since 2020.

Even rare bets that have worked in 2022 stumbled on Monday. The energy segment, the only one of the S& P 500's 11 sectors in positive territory this year, fell 5.1%, a steeper decline than that of the index. The **utilities group**, the second-best performer in 2022, lagged behind the market with a **drop of 4.6%**.

"We're definitely seeing a risk-off atmosphere, a flight to quality," said Charlie Ripley, senior investment strategist at Allianz Investment Management. "In that environment, people need to raise cash."

The **S&P 500 fell** 151.23 points, or **3.9%**, to 3749.63. The Dow Jones Industrial Average dropped 876.05 points, or 2.8%, to 30516.74. The tech-heavy Nasdaq Composite declined 530.80 points, or 4.7%, to 10809.23, off 33% from its November record.

Markets were poised for a slight recovery. Futures for the S& P 500 advanced 0.6% Tuesday morning in Asia. Those for the Dow and the Nasdaq increased 0.5% and 0.8%, respectively.

Shares in Asia remained under pressure. Hong Kong's Hang Seng Index fell 1.1%, Japan's Nikkei 225 retreated 2% and South Korea's Kospi Composite shed 1.2%. In mainland China, the blue-chip CSI 300 declined 1.9%.

Meanwhile, a **rout in cryptocurrencies** highlighted investors' increasing unwillingness to hang on to their most speculative holdings. The price of bitcoin plunged Monday below $23,000, before paring that loss to trade at 5 p.m. Eastern down 66% from its November high.

Shares of Coinbase Global fell 11%, while Celsius Network said it was pausing all withdrawals and swaps between cryptocurrencies.

Markets have swung wildly this year as investors tried to decipher how rapidly the central bank will raise interest rates in an attempt to tame inflation. Rock-bottom rates and other **stimulative policies** helped keep the economy – as well as markets – afloat as the pandemic idled businesses and threw people out of work.

Now, the Fed is trying to tame surging prices by unwinding that easy-money policy. The Wall Street Journal reported Monday afternoon that the Fed, which is set to begin its latest two-day policy meeting on Tuesday, will likely consider a bigger increase of 0.75 point after a string of troubling inflation reports.

Friday's data showed U.S. consumer prices rose 8.6% year over year in May, the fastest such increase since 1981. The report jolted markets and intensified fears that the campaign of monetary tightening could tip the economy into a recession.

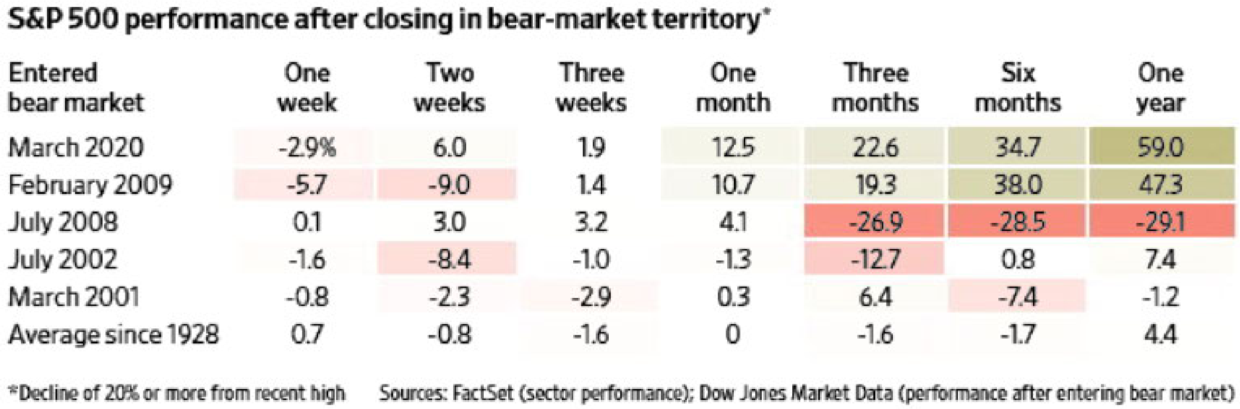
“If inflation is going higher, the Federal Reserve has no choice but to raise interest rates,” said Chris Zaccarelli, chief investment officer at Independent Advisor Alliance. “The higher the Federal Reserve needs to raise interest rates, and the longer they need to keep raising interest rates, the more likely it is that we go into a recession.”

On Monday, futures bets showed traders assigned a roughly 85% probability that the Fed will raise its benchmark short-term interest rate by at least 2.5 percentage points by the end of the year from its current range between 0.75% and 1%, according to CME Group. That would equate to at least a half-percentage- point rate increase at every Fed meeting this year. On Friday, traders placed the chances of that at 50%, according to CME Group.

“It seems as though inflation is staying for longer than expected,” said Kiran Ganesh, a multiasset strategist at UBS. “People are now beginning to fear that the Fed will have to go further or faster in terms of interest rates.”

Government-bond yields surged on Monday as investors worried that persistent inflation could prompt the Fed to raise rates higher and faster than expected. The **yield** on the benchmark **10-year U.S. Treasury note rose to 3.371% on Monday**, its **highest closing level since 2011**, from 3.156% Friday. It was its largest one-day yield gain since March 2020.

U.S. tech stocks, which soared throughout the pandemic, notched big declines. Apple shares fell 3.8%, while Amazon.com shares lost 5.5%. Chip maker Nvidia slid 7.8% and Tesla dropped 7.1%. Meta Platforms, the parent company of Facebook, lost 6.4%.



S&P 500 performance after closing in bear-market territory*

Entered bear market	One week	Two weeks	Three weeks	One month	Three months	Six months	One year
March 2020	-2.9%	6.0	1.9	12.5	22.6	34.7	59.0
February 2009	-5.7	-9.0	1.4	10.7	19.3	38.0	47.3
July 2008	0.1	3.0	3.2	4.1	-26.9	-28.5	-29.1
July 2002	-1.6	-8.4	-1.0	-1.3	-12.7	0.8	7.4
March 2001	-0.8	-2.3	-2.9	0.3	6.4	-7.4	-1.2
Average since 1928	0.7	-0.8	-1.6	0	-1.6	-1.7	4.4

*Decline of 20% or more from recent high Sources: FactSet (sector performance); Dow Jones Market Data (performance after entering bear market)

“This is what you call a bear market, where fear is taking place and pushing people out of the market and having people empty up portfolios and capitulate,” said Todd Morgan, the chairman of Los Angeles-based Bel Air Investment Advisors.

Still, Mr. Morgan said developments in the next month or two could help damp inflationary pressures, such as lower gasoline demand after the summer and slowing demand for houses due to rising mortgage rates.

He added: “China opening up is a big deal, too,” as that would help ease supply-chain constraints. Figures last week showed Chinese exports to the rest of the world surged in May as Covid-19 restrictions eased, adding to signs of economic recovery there. At a conference Monday, Morgan Stanley CEO James Gorman said, “We’re in a brave new world right now. I don’t think anyone can accurately predict inflation one year from now.”

In currency markets, the dollar gained against a range of its peers, with the WSJ Dollar Index climbing 0.9% to 97.66. Higher U.S. interest rates typically boost the dollar’s value.

Stock markets abroad on Monday were jolted by fears of tighter U.S. policy and a potential slowdown in the world’s biggest economy. The pan-continental Stoxx Europe 600 dropped 2.4% to its lowest closing value since March 2021, while the U.K.’s FTSE 100 index fell 1.5%.

Early Tuesday, the S& P/ASX 200 index in Sydney erased 4.8%, putting the benchmark on course for its biggest one-day drop in percentage terms in more than two years.

Gasoline Tops $5 a Gallon, Deepening Price Pain

by Omar Abdel-Baqui and Hardika Singh – WSJ – Jun. 13, 2022
Ginger Adams Otis contributed to this article.

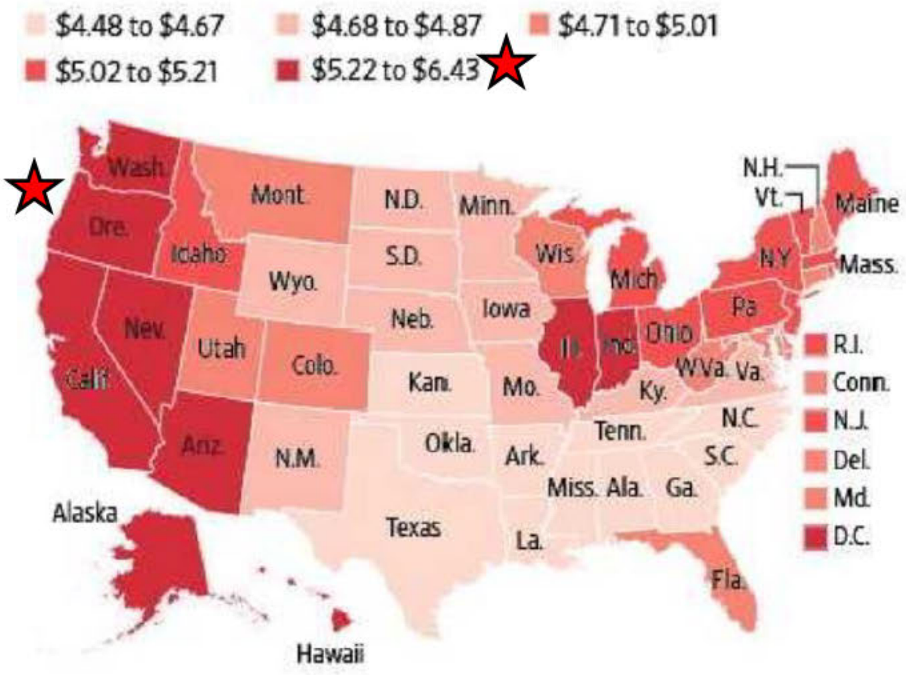
The **average price** of a gallon of **regular gasoline** in the **U.S. hit** a **record $5.01** Sunday after reaching the $5 mark for the first time Friday, with the rise in fuel costs expected to persist throughout the busy summer driving season.

The record price, according to OPIS, an energy-data and analytics provider, comes as **U.S. consumer inflation hit** its **highest level in 40 years** and crude oil prices remain elevated.

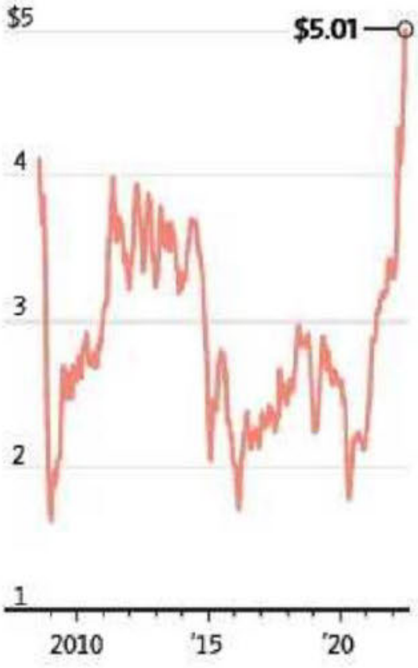
Gasoline prices skyrocketed after Russia's invasion of Ukraine earlier this year, with traders, shippers and financiers shunning Russian oil supplies. Oil inventories, which were already tight because of higher demand from economic reopening, have depleted even more, with no sign of relief ahead.

That has translated to pain at the pump, further **squeezing Americans' household budgets already hit by higher prices** on everything from items at the grocery store to restaurant meals and air travel. Prices for **energy jumped 34.6% from** a **year earlier**, while the cost of **groceries rose 11.9%**.

State Gas Price Average



Gasoline price per gallon



Note: Numbers as of June 12
Source: AAA's Gas Prices

Shenetha James, a mother of four in Jackson, Miss., hasn't seen her eldest daughter, who lives about 700 miles away in North Carolina, since Christ-mas, because of high gasoline prices. “It’s been kind of hard,” Ms. James said, “not being able to really be there.”

The average cost of a gallon of regular gasoline in Mississippi was still below the national average Sunday, at about $4.52, according to OPIS, which is part of Dow Jones & Co., publisher of The Wall Street Journal.

Ms. James, who works for the Mississippi Department of Child Protection Services, drives one child to basketball practice and another to work at Chick-fil-A a few times a week. After dropping them off, to save money on gasoline, Ms. James waits in a parking lot instead of driving back home.

“We’ve got to manage this gas to get from one pay period to another,” she said.

A report from **JPMorgan last month said prices could jump to an average $6.20 a gallon by August**. The cost of gasoline has **already** exceeded that price in **California**, where it was about **$6.43 on average** Sunday, according to OPIS.

“People are still fueling up, despite these high prices,” said Andrew Gross, a spokesman at AAA. “At some point, drivers may change their daily driving habits or lifestyle due to these high prices, but we are not there yet.” AAA, an automobile organization, obtains data from OPIS.

Some drivers are purchasing fewer gallons on each visit to gas stations but making more frequent trips to fuel up. Patrick De Haan, head of petroleum analysis at price tracker Gas-Buddy, said consumer resilience has remained relatively strong, even as demand has started to waver. He projects people will more significantly adjust their driving habits when it hits between $5.40 and $5.50. That is around the price that, adjusted for inflation, would surpass the 2008 peak, Mr. De Haan said.

Left: The average U.S. price of gasoline hit a record $5.01 for a gallon of regular. The rise in fuel costs is expected to persist all summer.

Chris Stevenson, a 24-year-old from New Jersey, said he’s just going to ignore the prices for as long as possible. “I don’t care about the gas. I’m doing a lot of trips,” he said while filling up at a Manhattan gas station Friday afternoon. The average price in New York City was about $5.20 a gallon on Sunday, according to OPIS.

Pandemic-related **strains** have **added pressure on price**s. **Refineries** around the world **closed** some plants **after Covid-19-related lockdowns** and **travel restrictions** dragged down fuel demand.

Now, as demand hovers closer to prepandemic levels, the **shortage** of **online refineries** is exasperating the market and **contributing** to **high gasoline prices**.

Scott Solis, a 51-year-old resident of Goodyear, Ariz., who lives on a fixed income, said he has limited his trips to grocery and retail stores because of high gasoline prices.

He added that he used to go on sightseeing driving trips to Sedona and Flagstaff with his wife and friends. The average cost of a gallon of gasoline in Arizona was $5.31 Sunday. “There’s no way in heck we can do that now,” Mr. Solis said.

Portland Metro Slammed the Brakes on Population Growth in 2021, Census Estimates Show

by Kristine de Leon – Oregonian – Mar. 27, 2022

https://www.oregonlive.com/business/2022/03/portland-metro-slammed-the-brakes-on-population-growth-in-2021-census-estimates-show.html

Portland skyline as seen from the Japanese Gardens early December, 2021

Population growth in the **Portland area** has **ground to** a **halt in 2021 after** a **period of slowing down since** its **mid-2010s boom**, new **U.S. Census Bureau** data show.

The **Portland metro** — **defined** as **Multnomah**, **Washington**, **Clackamas**, **Columbia and Yamhill counties and Washington's Clark and Skamania counties** — saw its **population drop 0.2% from July 2020 to July 2021**, to an estimated 2,511,612 residents. That translates a loss of about 4,618 people, according to new estimates released Thursday.

The relatively small decline conflicts with other estimates. Charles Rynerson, a faculty member of the Population Research Center at Portland State University, said the center's own estimates for 2021 showed a slight increase in population.

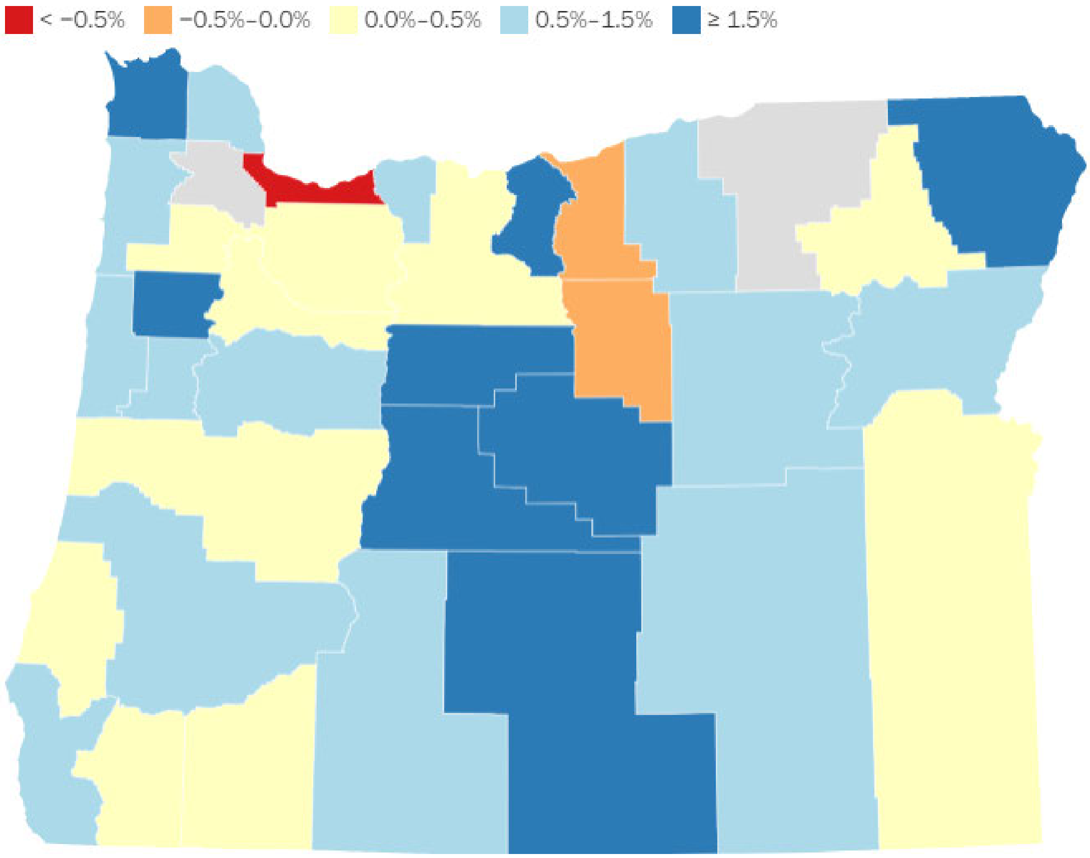
But both are a **far cry from** the **rapid population growth** of **recent decades**. From 2000 to about 2018, the region gained an average of 30,000 residents per year.

"The story is basically, there's definitely been less growth this past year because of more deaths and fewer births," he said. "And there's been very little international migration, nationally or locally, which is attributable in part to COVID, since people couldn't even enter the country."

Migration, both between states and internationally, has been the state’s primary source of new residents, Rynerson said. The same goes for the Portland area.

“Generally we gain more people than we lose due to domestic net migration in Oregon and in Multnomah County, but these estimates are saying that we lost more than we gained,” he said.

Population change (%) in Oregon by county, 2020-2021



Map: Kristine de Leon • Source: U.S. Census Bureau

OREGONLIVE
The Oregonian

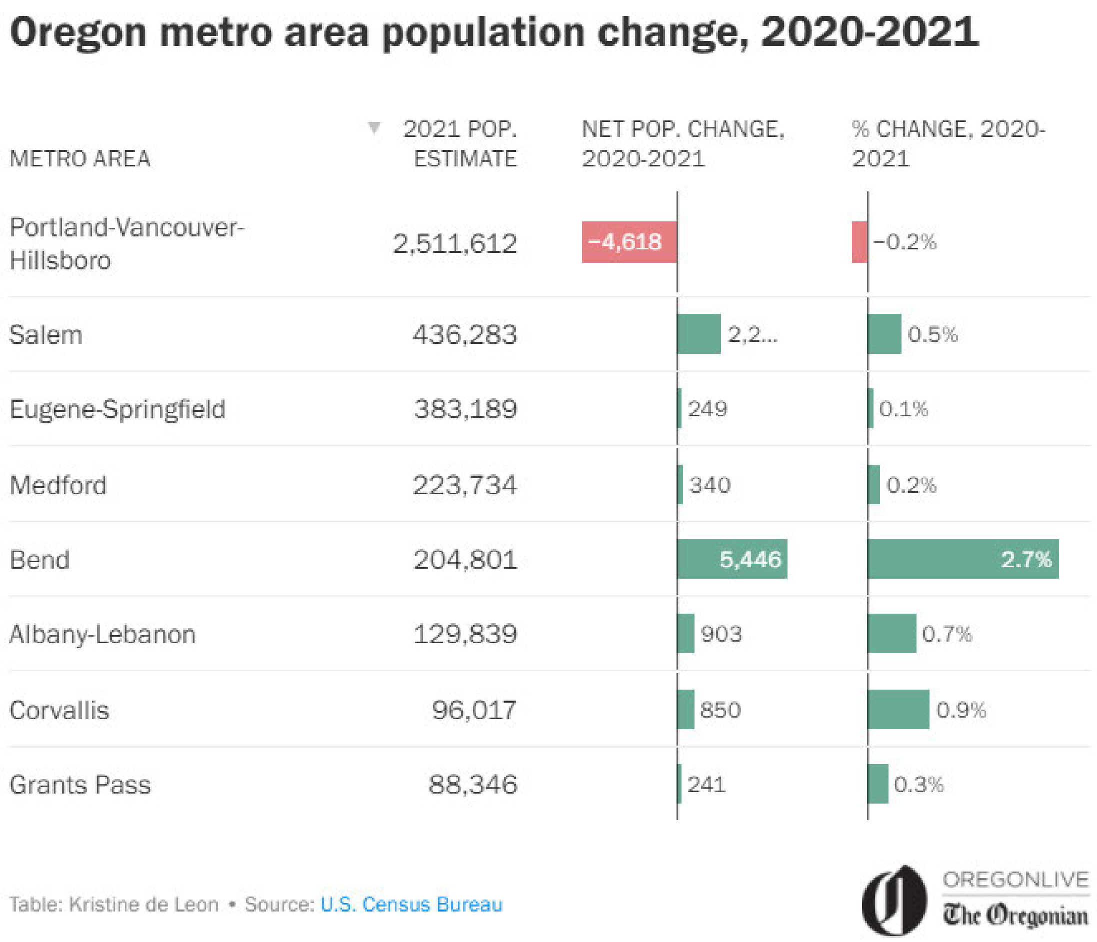
Metro population numbers have turned negative as recently as 2010, according to census numbers, when the Great Recession temporarily put a damper on growth. It soon bounced back.

While there are anecdotal reports of people leaving large metro areas for more spacious suburbs and rural communities during the pandemic, Rynerson said this one year of census data doesn’t provide that kind of insight.

“There’s always lots of churn in the population,” he said. 2021 “was an unusual year, and things may have stabilized after July, or some people may have even relocated temporarily. So it's difficult to say what these estimates really mean for the long term."

Meanwhile, **Central Oregon continued** to **see rapid population growth** — **among** the **fastest in** the **nation**.

The **Bend metro area** in central Oregon, which includes all of **Deschutes County**, saw its **population grow 2.7%** — the **13th fastest growth** among the **nation's 355 metro areas** — to an estimated 204,801 residents. That's a boost of about 5,446 people in the year ending July 2021, census numbers show.



Oregon metro area population change, 2020-2021

METRO AREA	▼ 2021 POP. ESTIMATE	NET POP. CHANGE, 2020-2021	% CHANGE, 2020-2021
Portland-Vancouver-Hillsboro	2,511,612	−4,618	−0.2%
Salem	436,283	2,2...	0.5%
Eugene-Springfield	383,189	249	0.1%
Medford	223,734	340	0.2%
Bend	204,801	5,446	2.7%
Albany-Lebanon	129,839	903	0.7%
Corvallis	96,017	850	0.9%
Grants Pass	88,346	241	0.3%

Table: Kristine de Leon • Source: U.S. Census Bureau

OREGONLIVE
The Oregonian

Nearby **Crook County**, home to fast-growing **Prineville**, saw the **fastest growth** of all 36 Oregon counties. From 2020 to 2021, the county saw the population rise 3.3% to 25,739, a boost of 816 residents.

The **Census Bureau updates population estimates every year using** the **most recent decennial census** — **in this case**, the **2020 figures** — **as** a **baseline**. Annual population estimates are **projected using vital records** such as **birth and death**

certificates, **tax returns from** the **IRS**, **housing counts**, **building permits** and **school enrollment**.

–

It’s Been a Terrible Year for Stocks; that’s Doubly True for Oregon Companies

by Mike Rogoway – Oregonian – Jun. 5, 2022

As Wall Street stumbled this spring, **Oregon stocks took a dive**.

From starry-eyed startups to venerable Northwest brands, **publicly traded companies** in **Oregon** and **Southwest Washington** are **losing value**. In **some** cases, they’ve been **nearly wiped out**.

Of 26 publicly traded companies in the region, 21 have fallen faster than the S&P 500 (down 15%.) Eleven of those stocks have lost more than half their value from their peak in the past year; five are down more than 80%.

“Asset values in certain industries got ahead of where they should be, or are likely to end up, over the past two years. This is an old story,” said **Tim Duy**, **econ**omics **professor** at the **U**niversity **of O**regon.

Companies that thrived when people were staying home during the pandemic, or promised to capitalize on new technologies, are now facing a reckoning as Wall Street takes a more sober look at their prospects.

“**Eventually**,” Duy said, “**reality sets in**.”

That matters both to shareholders, who have lost a great deal of money, and to the companies themselves. It’s more difficult to raise additional backing with a depressed stock price and rising interest rates make it more expensive to borrow.

The stock declines in Oregon and Southwest Washington reflect **two** separate **phenomena**:

Established companies whose **values soared to unrealistic levels during** the **boom** that **followed** the **pandemic**; **and newly public companies** that are **suddenly out of favor on Wall Street amid** an **uncertain economic outlook**.

Together, the two trends paint an ugly picture.

Take Vancouver exercise equipment company Nautilus. Although it has a well-known brand, Nautilus' performance has long been erratic and its sales were down sharply in the year before COVID-19.

The pandemic reversed Nautilus' fortunes, boosting sales as Americans stayed away from the gym and stocked up on home exercise equipment. But like Peloton and other pandemic darlings, Nautilus' fortunes plunged as life began returning to normal.

Sales staled and the company fell into the red, posting big losses and bleeding cash. Nautilus shares tanked, plunging by nearly 90%, to a little over $2 a share.

For a less extreme example, consider Hillsboro-based Lattice Semiconductor. The programmable chip company began a turnaround in 2019, posting its first profit in eight years and then soared as demand for computer chips boomed in the wake of the pandemic recession.

Lattice's business remains strong – its sales rose 30% last quarter. But investors bid the stock up to outrageous levels last fall, evidently anticipating years of explosive growth. Shares topped $85 in November, nearly triple where they were a year earlier.

The market for Lattice's chips is still robust but the broader economy is not. Inflation has spooked consumers and rising interest rates have companies talking about a recession. So investors have severely tempered their expectations.

The result has been a sharp pullback in Lattice shares, which have fallen nearly 40%.

Other brands like **Nike** (**down 33% from** its **52-week peak**) and **Columbia Sportswear** (**down 26%**) are in the same boat, as investors recalibrate their prospects in light of the diminished economic outlook.

More serious is the predicament facing some of **Oregon's newly public companies**. These are businesses that sought to sell investors on the idea that their big growth was still ahead of them. Some had very little revenue, or none at all.

And with interest rates rising and uncertainty clouding the horizon, those risky bets look a lot less appealing.

Plant-based foods company Laird Superfood, based in Sisters, made the unusual decision to hold an IPO in 2020 even though it was a small business, just five years old, with little track record for investors to judge.

The public bought in, at first, as sometimes happen at companies whose ideas sound appealing. Laird approached $60 share in the months after going public.

And while Laird's business has grown steadily – it recorded sales of $9.3 million last quarter – the company has given no indication it can operate profitably. Its most recent quarterly losses totaled $14.1 million, compared to $5.3 million a year earlier.

Wall Street wants nothing to do with a story like that in these volatile times. Shares closed Friday at $2.74, down 92% from their highest point in the last year.

It's the same story with **Eugene electric vehicle manufacturer Arcimoto**, which held an IPO in 2017. The stock soared above $36 last year amid a wave of investor enthusiasm for new transportation technologies.

But Arcimoto is still in the very early stages of ramping up its production and has struggled against a wave of supply chain troubles. Its **shares** are **down** more than **80% from** their **52-week high**, closing Friday around $3.32.

Investors have soured on six other newly public companies in Oregon and Southwest Washington, among them Vancouver biotech startup **Absci and** Wilsonville battery manufacturer **ESS** Tech. **Neither** company **has meaningful revenue**; they went public last year asking investors to back the promise of new technologies that could revolutionize their industries.

Startups are always a gamble but they look more appealing to investors when markets are soaring, and more established stocks are trading at high valuations. With the markets in flux, investors prefer safer bets.

Absci shares are **down 89% from** their **post-IPO peak**. **ESS** is **down 87**%.

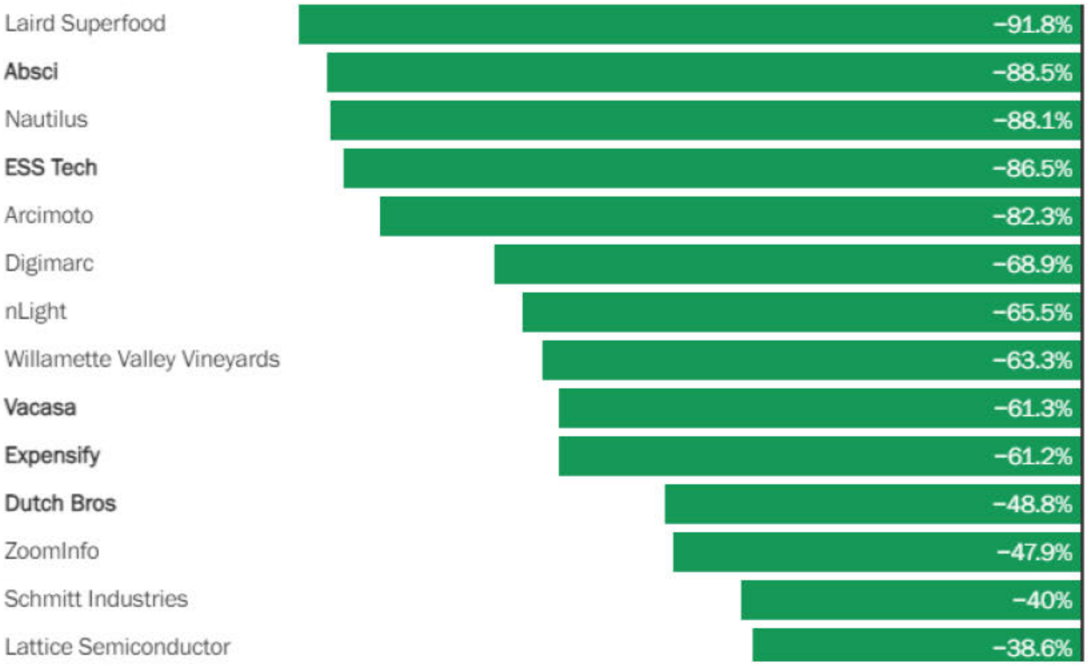
"What we're seeing is a **retreat from** these **risky assets**," Duy said.

Volatility isn't uncommon with newly public companies as Wall Street learns about the business and the businesses build trust with investors. So it's not terribly surprising that some of these stocks are wobbling after their debut.

Those rocky starts, though, could have other Oregon companies thinking twice before taking the same path.

Regional stocks, compared to their peaks

The S&P 500 is down 15% from its most recent peak. Most companies in Oregon and Southwest Washington have fallen much further from their 52-week highs. (Stocks that went public in the last year are in bold.)



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Share price compared to each stock's highest points in the last year.

Russian Sanctions Signal End of Free Trade in Energy

by Christopher M. Matthews, Summer Said, and Benoit Faucon
WSJ – Jun. 4, 2022

Geopolitical calculations are starting to rule market, raising costs. ‘Russia’s days as an energy superpower are over,’ according to Daniel Yergin.

Russia’s attack on Ukraine is **redrawing** the **world’s energy map**, ushering in a new era in which the flow of fossil fuels is influenced by geopolitical rivalries as much as supply and demand.

Over the **past half-century**, **oil** and **natural gas** have **moved with relative freedom to** the **markets where** they **commanded** the **highest prices around** the **world**. That **ended abruptly** when **Russian tanks rumbled across** the **Ukraine border** on Feb. 24, triggering a **barrage** of **trade sanctions by** the **U.S. and Europe** targeting Russia that have **plunged global commerce into disarray**.

This week, the European Union agreed to its toughest sanctions yet on Russia, banning imports of its oil and blocking insurers from covering its cargoes of crude.

Whatever new order emerges won’t be fully clear for years. But traders, diplomats and other experts in energy geopolitics generally agree that it will be more Balkanized, and less free-flowing, than what the world has seen since the end of the Cold War.

Three likely axes of energy influence are emerging: the U.S. and other Western nations, which have used their massive economic and purchasing power as a political weapon; **China** and large emerging nations such as **India**, **Turkey** and **Vietnam**, which have rebuffed Western pressure and **continued doing business with Russia**; and **Saudi Arabia and other Middle Eastern oil-producing nations**, which have sought to maintain neutrality, and may **stand** to **gain market share** in the years to come.

“We are in a real hinge of history,” said Chas Freeman, a former U.S. ambassador to Saudi Arabia. Mr. Freeman, who is now a senior fellow at Brown University, said **Europe can never again trust Russia to be its primary energy provider**, and that even if sanctions are lifted, countries are proposing costly new infrastructure and endorsing long-term alternative supply contracts that will lock in the new energy map.

The new order promises to make the energy trade less efficient and more expensive, potentially putting commodities at the center of the next global economic crisis, said Zoltan Pozsar, a former official at the Treasury Department who now heads short-term interestrate strategy at Credit Suisse Group AG.

‘Friend-shoring’

A German embargo of Russian crude would likely mean that instead of Russian oil reaching Hamburg in a week or two, it would take several months to travel to China, he noted. Conversely for Middle Eastern oil, the embargo would trigger a longer voyage to Europe for crude that would have ordinarily gone to Asia. Such **inefficiencies will drive up** the **costs** that underpin the energy trade, he said.

Many predict Russia's energy industry, the backbone of its economy, will contract because the loss of its largest market cannot be completely replaced. Western financial and technological sanctions will undermine Russia's ability to maintain current revenues and production levels, these people say.

"Russia's days as an energy superpower are over," said Daniel Yergin, the vice chairman of S& P Global and a noted oil-industry historian.

But the new map isn't without **risks to American power and** the country's **standing** as the guarantor of global trade. Since the end of World War II, the **dollar** has been the **default currency for oil transactions**, which has helped maintain its centrality to the global economy.

Leveraging the might of the U.S. financial system to muster sanctions against Russia has called into question its reliability as a place to store wealth, Mr. Freeman said.

Now **Saudi Arabia**, **India** and **other developing countries** are **exploring conducting energy transactions in non-U.S. dollar currencies**. **Russia** has similarly begun **seeking recompense in rubles for** its **fossil fuels**.

"We may have had good reasons, but the **U.S.** has **politicized** the **trade of energy**," Mr. Freeman said.

Geopolitics and energy have always been linked, and U.S. sanctions against Iran and Venezuela have disrupted global oil flows in recent years. But since the end of the Arab oil embargo of the early 1970s, the relatively free trade of commodities, backed by U.S. military and financial might, has been a hallmark of the international system.

That is now changing. During a speech in April, U.S. Treasury Secretary Janet Yellen said that in the wake of Russia's invasion, it was time to redesign Bretton Woods, the system of trade rules adopted in 1944 that prioritized economic efficiency and international cooperation. **Ms. Yellen advocated for** "**friend-shoring**" **supply chains** of **critical raw materials** by deepening trade ties with "a group of countries that have strong adherence to a set of norms and values."

Trade flows are already being redirected as Western energy companies pull out of Russia and shippers, lenders and insurers refuse to touch Russian exports.

The EU, in beginning to implement its embargo on Russian oil exports today, joins the U.S., U.K. Canada and Australia. Following concerns Hungary raised about the economic impact, the embargo will exempt oil delivered from Russia via pipelines. Still, by the end of the year, the embargo would cover 90% of previous Russian oil imports, EU officials said. Russian oil exports to the EU, the U.S., the U.K., Japan and South Korea have already fallen by 563,000 barrels per day, or 32% from February to April. A full EU ban would mean some 2.8 million barrels per day of crude and 1.1 million barrels per day of products that normally flow into Europe will have to find a new market, according to investment bank Piper Sandler.

Saudi Aramco, with massive facilities such as this, has supplanted Apple Inc. as the world's most valuable company.

European leaders will find it more difficult to wean themselves off **Russian natural gas**, which **typically accounts** for more than **30%** of the **EU's supply** and **mostly** comes **via pipeline**. **JPMorgan Chase estimates** that by the **end** of the **year Europe will still receive between 81% and 94%** of the **amount** of **Russian gas** it **took in 2021**. The EU has said it would stop using Russian oil and gas by 2027, but **ending** its **reliance on Russian energy** could come at a **heavy cost**.

Amos Hochstein, President Biden's coordinator for energy security, has worked with foreign officials and energy executives to bolster alternative supplies of oil and gas to Europe to blunt the pain.

But Europe and the U.S. are operating under an additional constraint: Mr. Hochstein said the U.S. won't provide incentives for long-term fossil-fuel investments that run counter to its plan to encourage a transition to greener energy sources.

"We're trying to help Europe, stabilize the market and protect U.S. consumers while making Putin pay the price and do that without cheating our overall goal of reduced fossil-fuel usage," Mr. Hochstein said.

EU leaders have said they would now accelerate ambitious plans to build out renewable energy projects as a result of the war, but concede Europe will need more fossil fuels in the interim.

Increased demand coupled with Western energy sanctions against Russia that will cut its output may lead to physical shortages of global oil, according to Joseph McMonigle, secretary- general of the Saudi Arabia-based International Energy Forum.

“If Russia is removed from the export market, there will be a global recession that kills demand,” Mr. McMonigle said.

Middle Eastern producers look poised to be winners in the emerging energy map.

Saudi Arabia and other Gulf states had been under pressure to diversify away from fossil fuels in recent years due to growing global concerns about climate change. But President Biden called on the kingdom to drill more in the lead-up to war, a stark turnaround from his presidential campaign, when he called the nation a pariah.

Retired Adm. Dennis Blair, who served as President Barack Obama’s first director of national intelligence, said despite efforts to pivot U.S. foreign policy away from the region, the importance of the Middle East to U.S. interests has been elevated again by the war.

“We need to have a very eyes-open, transactional relationship with Saudi, where we do have to go back to being their ultimate provider of defense until we can electrify our transportation and transition to more diverse energy sources,” Mr. Blair said.

State-owned energy giant Saudi Arabian Oil Co., known as **Saudi Aramco**, which recently overtook Apple Inc. as the world’s most valuable company, is already receiving more requests for its crude from buyers in Europe. More broadly, Saudi officials say the war has shown that aggressive targets to reduce carbon emissions by rapidly cutting fossil fuel usage were unrealistic.

“The kingdom finds it laughable that **last year**, several countries, including the **United States**, have been **pressuring them** to stick to [plans to **zero out carbon emissions by 2050**] but **now** are **asking** them **for more oil**,” **said** a **Saudi official**.

After rejecting U.S. requests for more production for months, OPEC and its allies agreed Thursday to a bigger-than expected output increase, allowing Saudi Arabia to potentially pump more crude and paving the way for a potential oil-for-security deal with the U.S. and a visit from President Biden later this month.

“The Russian invasion has taught the world one thing loud and clear: We need more Saudi oil,” another Saudi official said.

Challenge for Russia

Russia’s new imperative is **deepening ties** with Asia, and especially **China**, to offset the looming loss of its European market.

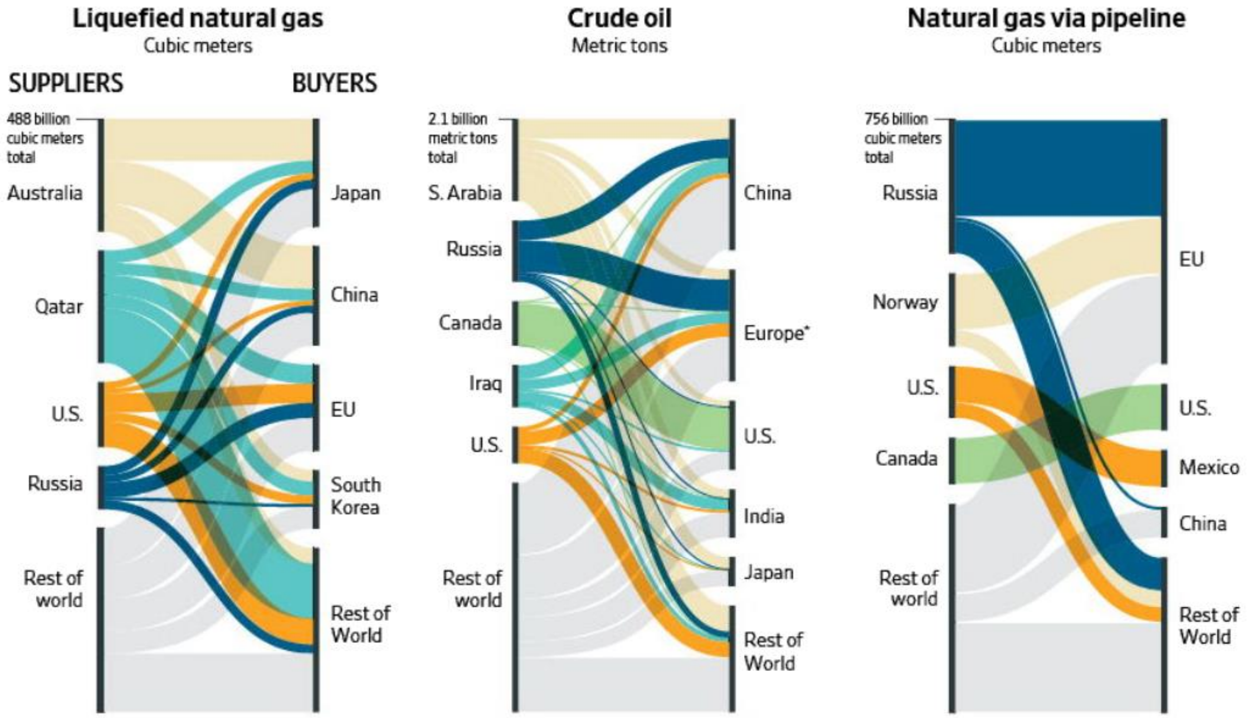
Such a pivot is particularly necessary for Russia’s natural-gas exports, which are less fungible than its oil, and will require a massive infrastructure build-out to find a new home. Russia previously exported as much as 200 billion cubic meters of gas a year to Europe, by far its biggest market. It sold about 33 bcm to Asia last year.

Russia has a handful of proposed pipelines and liquefied natural gas projects, which convert the gas to a liquid enabling seaborne trade, that would boost its ability to send gas to Asia, but many of the projects are technically challenging and expensive, and Western sanctions will hamper their progress, say analysts.

The most important planned project is a roughly 1,600-mile pipeline connecting Russia’s Yamal peninsula to China, called Power of Siberia 2. The first Power of Siberia project cost more than $50 billion and took more than five years to build. It will send nearly 40 bcm a year to China at full capacity and the second could send as much as 50 bcm.

When the two countries agreed to terms on the first pipeline in 2014, **China extracted relatively cheap gas prices**. “Our Chinese friends drive a hard bargain as negotiators,” Russian President Vladimir Putin remarked at the time.

Top global suppliers and buyers, in 2020, of:



*European members of the OECD plus Albania, Bosnia-Herzegovina, Bulgaria, Croatia, Cyprus, Georgia, Gibraltar, Latvia, Lithuania, Malta, Montenegro, North Macedonia, Romania, Serbia, Turkey and Ukraine.
Source: BP Statistical Review of World Energy

Josh Ulick/THE WALL STREET JOURNAL

U.S. Inflation Hit 8.6% in May

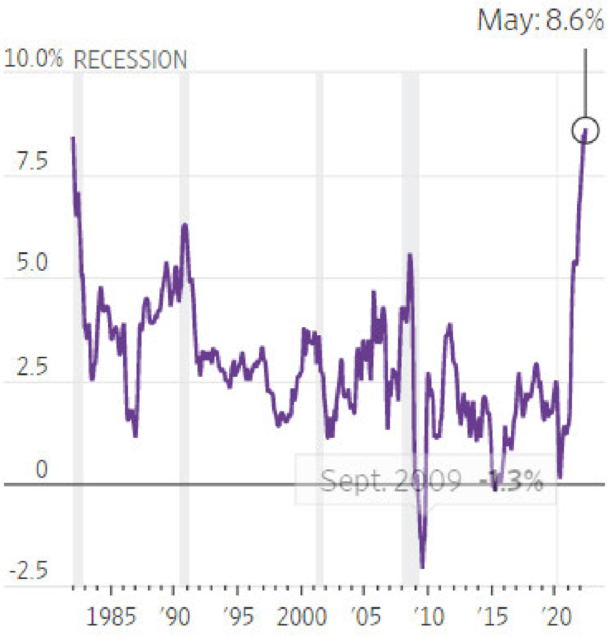
by Gwynn Guilford – WSJ – Jun. 10 2022

Energy, groceries, shelter costs drive fastest rise in consumer-price index since December 1981.

U.S. consumer inflation reached an **8.6% annual rate** in **May**, its highest level in more than four decades as surging energy and food prices pushed prices higher.

The **Labor Department** on Friday said that the consumer-price index increased 8.6% in May from the same month a year ago, marking its **fastest pace since December 1981**. That was also up from April's CPI reading, which was slightly below the previous 40-year high reached in March. The CPI measures what consumers pay for goods and services.

Consumer-price index, change from a year earlier



Source: Labor Department

May's increase was driven in part by sharp rises in the prices for **energy**, which **rose 34.6% from** a **year earlier**, and **groceries**, which **jumped 11.9% on** the **year**, the biggest increase since 1979. But **inflation pressures** were distinctly **broad**-**based** in May, said Sarah House, senior economist at Wells Fargo Securities.

"Inflationary pressures were seen nearly everywhere," she said.

Prices for used cars and trucks – a key engine of the past year's inflation surge – rose 1.8% in May from April, reversing three months of declines. Shelter costs, an indicator of broad inflation pressures, accelerated on a monthly basis in May and were up 5.5% compared with a year ago.

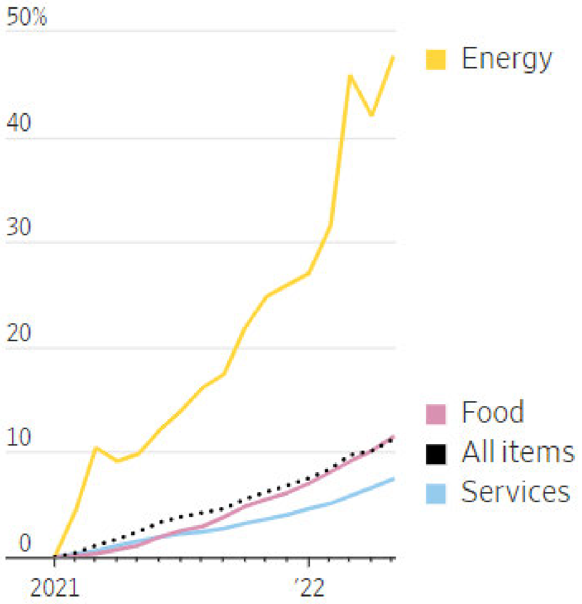
Airline fares rose 12.6% on the month, the third straight double-digit rise.

"We suspect that the formidable momentum in inflation could push the headline rate for CPI close to 9% as early as next month," said Ms. House, adding that it is likely to stay near those levels through the autumn.

High inflation is a downside of strong U.S. growth, fueled in part by low interest rates and government stimulus to counter the Covid-19 pandemic's impact. The annual rate of inflation has risen sharply since early 2021, when the U.S. economy's rebound from the pandemic accelerated, leading to supply disruptions and other imbalances that put upward pressure on prices for longer than policy makers anticipated.

The Federal Reserve faces the difficult task of tightening monetary policy enough to cool the economy and calm inflation, while avoiding a recession. Fed officials on May 4 lifted rates by a half-percentage point and will meet again next week to consider a similar increase.

Consumer-price index, change since January 2021



Note: Seasonally adjusted
Source: Labor Department

Economists and policy makers had been watching closely for signs that inflationary pressures are ebbing. But May's resurgence in price increases ratchets up pressure on the Fed to raise rates aggressively to tame inflation, said James Knightley, chief international economist at ING.

"The breadth of inflation pressures in the economy should alarm the Fed," he said.

On a monthly basis, the CPI jumped a seasonally adjusted 1% in May after rising 0.3% in the prior month. The so-called core-price index, which excludes the often volatile categories of food and energy, increased 0.6% on the month, the same as in April. That compares with an average monthly gain of 0.2% for both measures in the two years before the pandemic.

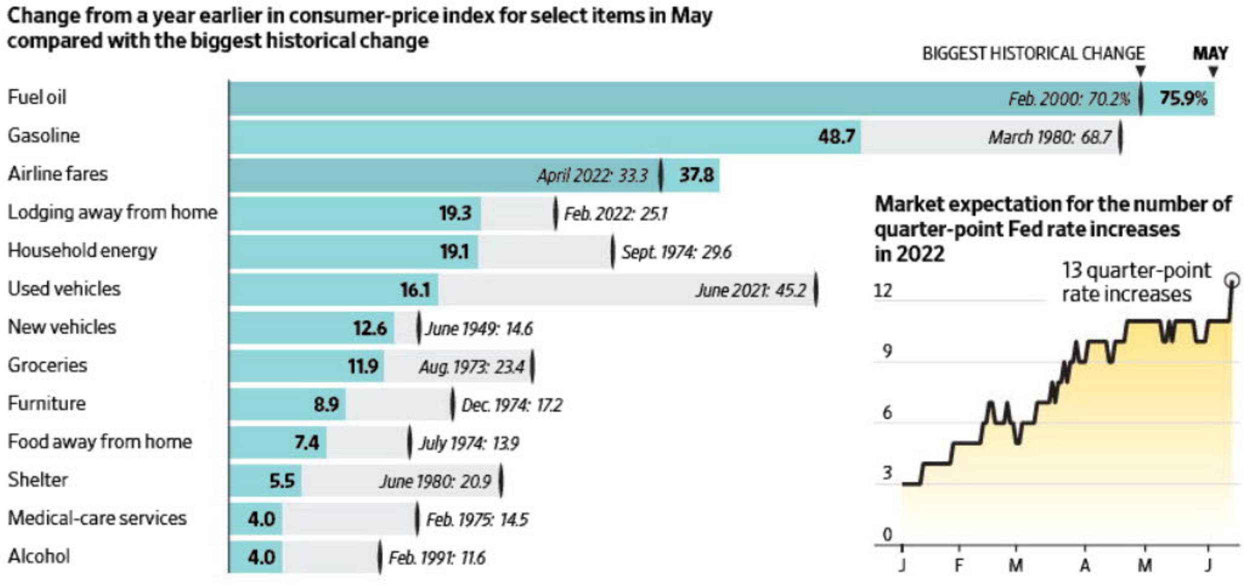
On a 12-month basis, the core-price index increased 6% in May, down from 6.2% in April. March's 6.5% rise was the highest rate since August 1982.

Consumers' grocery bills have risen by an annual rate of more than 10% since earlier this year.

Energy prices rose in May as **Russia's invasion of Ukraine** continued to push up prices for crude-oil and natural gas. **Gasoline prices** have breached record levels in recent weeks, with the average gallon of regular unleaded currently going for $4.97, according to AAA. The strength in energy price rises will keep putting upward pressure on inflation, said Ms. House, the Wells Fargo economist.

"Given everything from the implications of the Russian invasion of Ukraine, the Chinese lockdowns and just the sheer appetite for travel … what we've seen is the perfect storm of those factors hitting, along with some major refinery closures," she said.

Consumers' grocery bills have risen by an annual rate of more than 10% since earlier this year, a pace last seen in the early 1980s. Food prices are unusually broad, and every single grocery category measured in the report rose in May from a year ago – most of them by double-digits. There are numerous causes, unlike early in the pandemic when meat prices drove much of the increase, said Paul Ashworth, chief North America economist at Capital Economics.



Sources: U.S. Labor Department (CPI); CME Group FedWatch Tool (Fed increases)

Erik Brynildsen and Angela Calderon/THE WALL STREET JOURNAL

"It's not just the weather – it's diseases affecting citrus trees and chickens. It's the Ukraine conflict," which has affected prices for baked goods and cereals, he said. Drought, too, is hitting prices for vegetables and other crops.

"**For people on lower incomes** this is **not discretionary spending**," Mr. Ashworth said. "Other than substituting out cheaper food types – cheaper meat cuts, whatever it might be – people need to continue buying food."

U.S. Supplier Price Gains Accelerated in May

by Gabriel T. Rubin – WSJ – Jun. 14, 2022

Producer-Price Index rose 0.8%, double the **April reading.**

May marked the sixth consecutive month of double-digit annual gains in the prices that suppliers charge businesses.

U.S. suppliers' prices rose in May amid higher food and energy costs, adding to pressure on inflation.

The producer-price index, which measures what suppliers are charging businesses and other customers, rose a seasonally adjusted 0.8% in May from the prior month, up from a 0.4% monthly gain in April, the Labor Department said Tuesday.

Producer prices had moderated somewhat in April, after the March gain had been the highest since records began in 2010, pushed up by **surging energy prices after Russia invaded Ukraine**.

The so-called core price index – which excludes the often-volatile categories of food, energy and supplier margins – rose 0.5% after a 0.4% gain the prior month.

On an **annualized basis**, the **PPI rose 10.8% in May from** a **year ago**, down slightly from a revised 10.9% in April. May marked the sixth consecutive month of double-digit annual gains for producer prices.

Economists are watching producer- and consumer-price indexes closely for signs that inflation could be peaking. With the annual increase in consumer prices ticking back up in May to 8.6%, Federal Reserve officials are contemplating a larger-than-expected 0.75-percentage-point interest-rate increase at their meeting this week. Continued pressure on producer prices often signals future rises in consumer inflation as costs pass through supply chains.


U.S. producer-price index, change from a year ago

Source: U.S. Labor Department

Elevated **producer prices** suggest that **consumer prices** "would continue to have upward pressure in the coming months," said PNC economist Kurt Rankin. While the **relationship** between the two measurements is **indirect**, that pattern has been consistent as the economy emerges from its pandemic-induced slowdown. May's jump in consumer inflation didn't come as a total surprise because "PPI was telling us that this number was coming, that inflation was going to stay high in response to higher oil prices," Mr. Rankin said.

Consumer demand for goods and services has outpaced supply. **Shortages** of **commodities** such as **wheat** and precious metals, along with **new restrictions** on **buying Russian oil**, have been exacerbated by the continuing **war in Ukraine**. **Rolling Covid-19 lockdowns** in **China** have **roiled supply chains** that had begun to resolve snarls from earlier in the pandemic.

Sustained high prices for inputs that have been in short supply because of the war and other global trade issues are unlikely to be resolved soon and have likely become baked into prices for other goods and services, economists say.

In recent weeks, executives at food suppliers and restaurant chains have complained of **rapidly rising prices** for **labor**, **packaging**, **ingredients** and **transportation**. The rising cost of fuel is making it more expensive to produce and sell food. Food retailers and restaurants have said they are passing along some wholesale price increases and additional costs to consumers.

In the early stages of the current period of inflation, many companies were able to pass higher costs along to consumers by raising prices. Analysts expect the S&P 500 net profit margin to come in at 12.3% for the first quarter, above the five-year average of 11.1%, according to FactSet. But there are signs that that trend may be reaching its end.

The stock market has been jolted by high-profile examples of costs squeezing corporate earnings. Last month, Walmart Inc. said higher product, supply-chain and employee costs eroded its profit. Target Corp. shares plummeted 25% the following day after the company said it would absorb elevated costs this year instead of raising prices.

“The benign explanation from an inflation standpoint is that consumers are beginning to resist price hikes, which would be bad news for retail profitability but might signal a forthcoming cooling of inflation,” said Stephen Stanley, chief economist at Amherst Pierpont. Another explanation, he said, is that “stores misread how much they needed to raise prices to recoup their higher costs” and will continue to raise prices going forward.

Along with higher prices from suppliers, businesses are dealing with an unusually **tight U.S. labor market**, with demand for workers outstripping supply by nearly two job openings for every available unemployed worker. **Although** there are some early signs the labor market is starting to cool, employers added 390,000 jobs last month and the unemployment rate hovered near a half-century low at 3.6%. **Fewer Americans** are **employed as** a **share of** the **population than before** the **pandemic**, even after a run of gains that has led to the creation of 6.5 million jobs in a year.

As a measure of price pressures, the PPI differs from the Labor Department’s more widely followed consumer-price index, which only measures the final prices paid directly by households for goods and services.

The **PPI also includes prices paid by companies**, **governments**, **third-party payers such as insurers and buyers** in other countries. The **CPI**, **unlike** the **PPI**, **includes taxes and user charges and** the **prices of imported goods and services**, because they are **part** of the**total costs paid by consumers**.

US Electric and Gas ROE Determinations in Q1'22 Remains near All-Time Low Mark

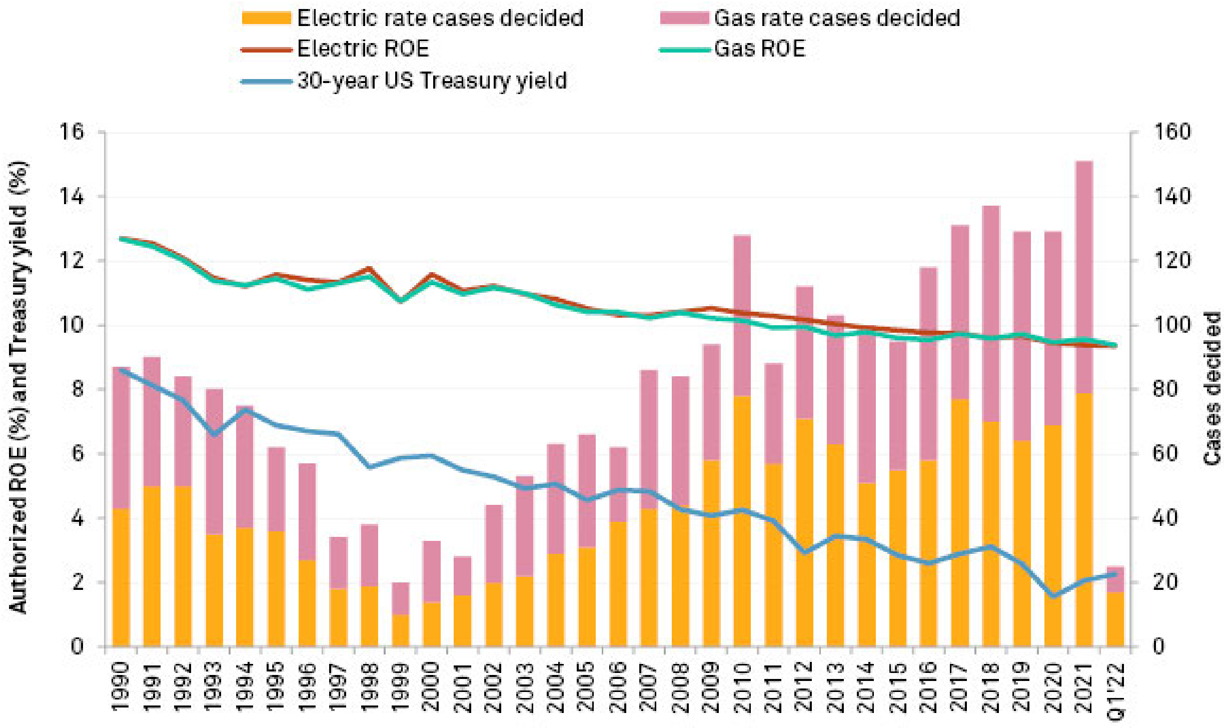
by Lisa Fontanella – Regulatory Research Associates (RRA)

The average electric and gas authorized returns on equity hit near all-time lows as per averages calculated for the first quarter of 2022.

The **average return on equity authorized electric utilities was 9.35% in rate cases decided in the first quarter of 2022, slightly below the 9.38% average for full-year 2021**. There were 12 electric ROE authorizations in the first quarter of 2022, versus 55 in full-year 2021.

The **average ROE authorized gas utilities was 9.38% in cases decided in the first quarter of 2022 versus 9.56% in full-year 2021**. There were six gas cases that included an ROE determination in the first quarter of 2022, versus 43 in full-year 2021.

Average electric and gas authorized ROEs and total number of rate cases decided



Data compiled April 25, 2022.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury

The **electric** data set includes several **limited-issue rider cases**, although there is scant difference between the ROE averages including rider cases and those excluding rider cases in the first quarter of 2022. Historically, the annual average authorized

ROEs in electric cases involving limited-issue riders were meaningfully higher than those approved in general rate cases, driven primarily by substantial ROE premiums authorized in generation-related limited-issue rider proceedings in **Virginia**. These premiums, however, were approved for limited durations and have since begun to expire. As a result, the gap between the average ROEs observed in rider cases and general rate cases has narrowed. Limited-issue rider cases in which a separate ROE is determined have had little use in the gas industry, as most of the gas riders rely on ROEs approved in a previous base rate case. **Excluding these** cases, the average authorized ROE for electric utilities was **9.34%** in the **first quarter of 2022**, versus 9.39% in full-year 2021.

In the first three months of 2022, the median ROE authorized in all electric utility rate cases was 9.25%, versus 9.38% in full-year 2021; for gas utilities, the metric was 9.40% in the first quarter of 2022, versus 9.60% in full-year 2021.

Looking at the last 12 months ended March 31, 2022, the average ROE authorized in all electric utility rate cases was 9.36%, and the median was 9.35%. For gas utilities in the last 12 months ended March 31, 2022, the average was 9.50%, and the median was 9.50%.

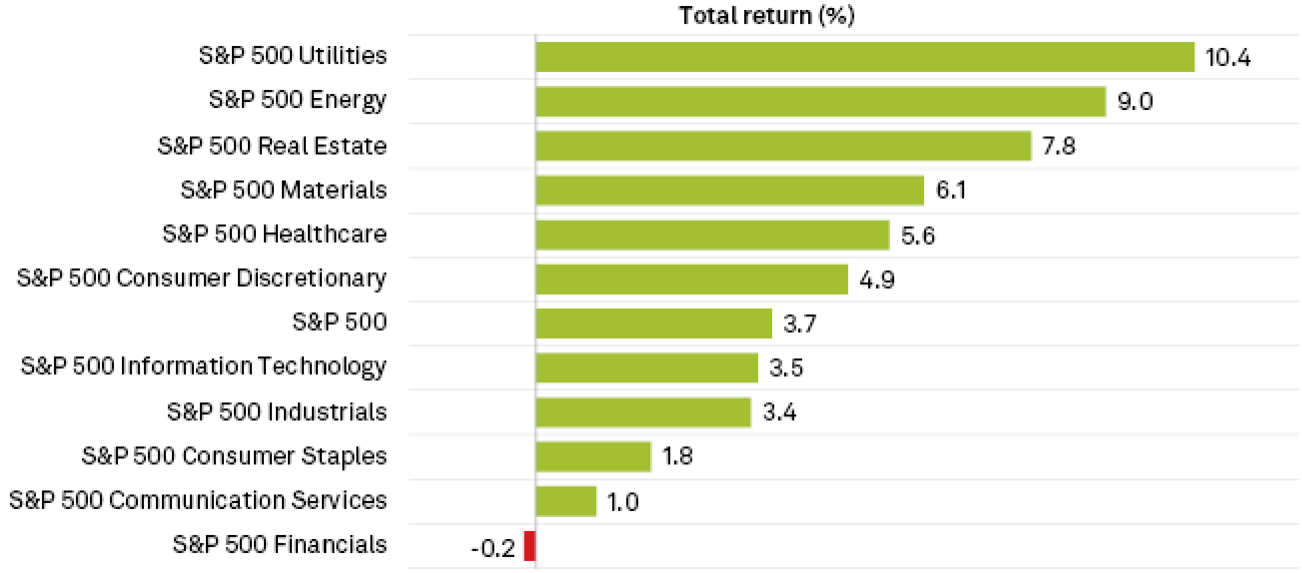
Utilities, Energy Outperform Other S&P 500 Sectors in March

by Selene Balasta and Annie Sabater
S&P Global Market Intelligence – April, 5, 2022

Utilities bested other sectors and the **broader S&P 500 index** in **March**, with the **S&P 500 Utilities index logging** a **total return** of **10.4%.**

Still reaping the benefits of rising crude and natural gas prices, the S&P 500 Energy index saw a total return of 9.0%. Meanwhile, the S&P 500 index saw a total return of 3.7%.

Market performance of the S&P 500 index, sectors in March



Data compiled April 1, 2022.
Total return calculated between Feb. 28, 2022, and March 31, 2022.
Source: S&P Global Market Intelligence

Fresh from its spinoff from Exelon Corp., Constellation Energy Corp. saw its share price climb 22.3% in March, leading the components of the S&P 500 Utilities sector.

Constellation Energy, which has a sizable nuclear generation fleet, is focused on meeting ambitious climate goals in the next two decades, including by investing in hydrogen production and blending, President and CEO Joseph Dominguez said in February.

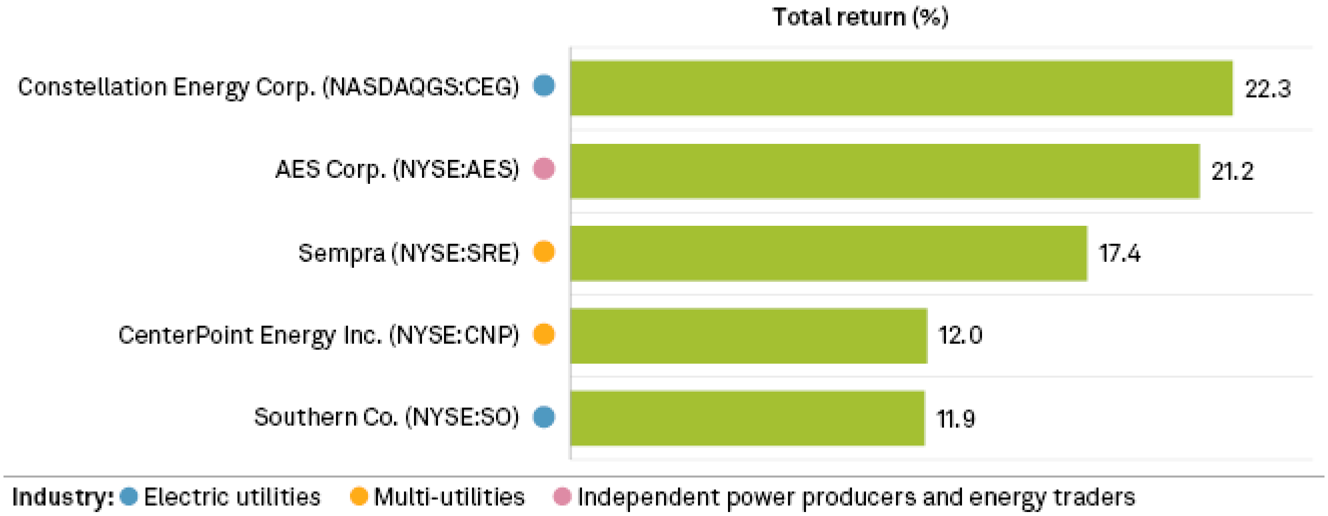
CenterPoint Energy Inc., which logged a total return of 12.0%, completed its exit from the midstream sector by selling its remaining interest in pipeline giant Energy Transfer LP.

Southern Co. recorded a share price increase of 11.9% in March. Southern shareholders reached a settlement connected to the utility's abandoned 745-MW Plant

Ratcliffe (Kemper County IGCC) project that will require certain corporate governance reforms.

AES Corp. and Sempra also logged double-digit share price increases in March.

Top, bottom performers of S&P 500 Utilities index in March



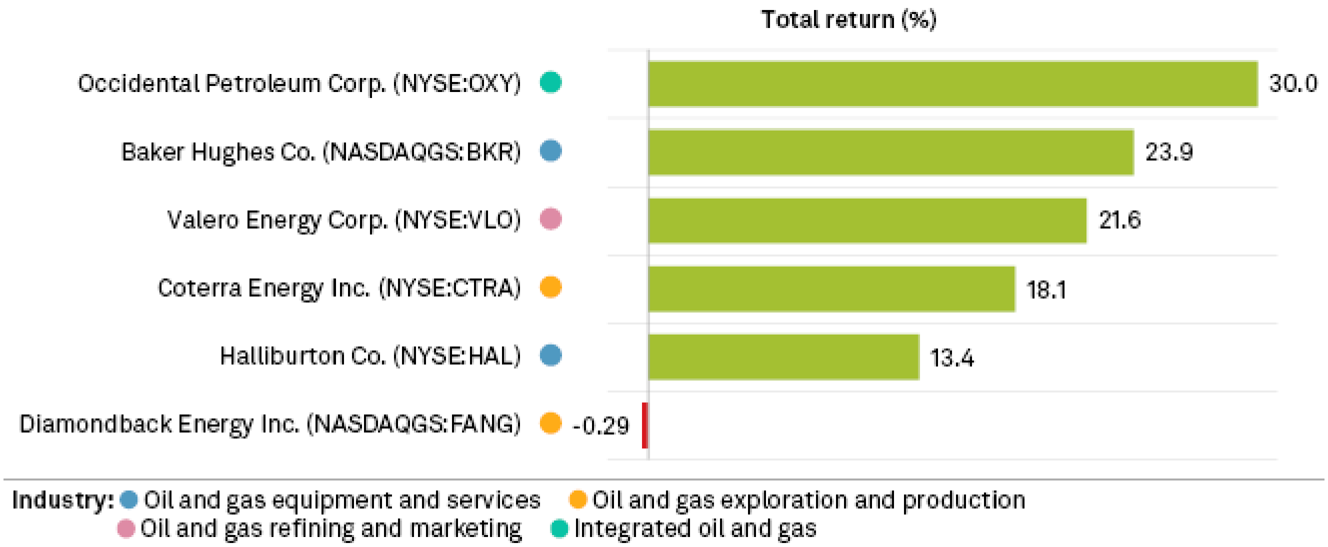
Data compiled April 1, 2022.
None of the S&P 500 Utilities index companies had a negative return during the month of March.
Analysis limited to S&P 500 Utilities constituents at March 31, 2022.
Total return calculated between Feb. 28, 2022, and March 31, 2022.
Industries are classified according to the Global Industry Classification Standard of S&P Global Market Intelligence.
Source: S&P Global Market Intelligence

Occidental Petroleum Corp. outperformed other energy companies, recording a total return of 30.0% in March.

The U.S. oil and gas producer will spend roughly 5% of its 2022 capital budget to start construction on an industrial-scale direct air carbon capture plant in the Permian Basin of Texas and New Mexico.

Halliburton Co. saw its share price increase 13.4% in March. The company suspended future business in Russia, citing sanctions imposed following Russia's invasion of Ukraine.

Other top performers in the sector during the month included Baker Hughes Co., Valero Energy Corp. and Coterra Energy Inc.


Top, bottom performers of S&P 500 Energy index in March

Data compiled April 1, 2022.
Only one of the S&P 500 Energy index companies had a negative return during the month of March.
Analysis limited to S&P 500 Energy index constituents at March 31, 2022.
Total return calculated between Feb. 28, 2022, and March 31, 2022.
Industries are classified according to the Global Industry Classification Standard of S&P Global Market Intelligence.
Source: S&P Global Market Intelligence

S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro.

Warren Buffett Spends Big as Stock Market Sells Off

by Akane Otani – WSJ – May 16, 2022

Berkshire Hathaway loads up on energy stocks as inflation soars

Berkshire Hathaway CEO Warren Buffett has long advised that investors ‘be greedy when others are fearful.’

The stock market’s selloff has been bad news for most investors.

Not for Warren Buffett and his team.

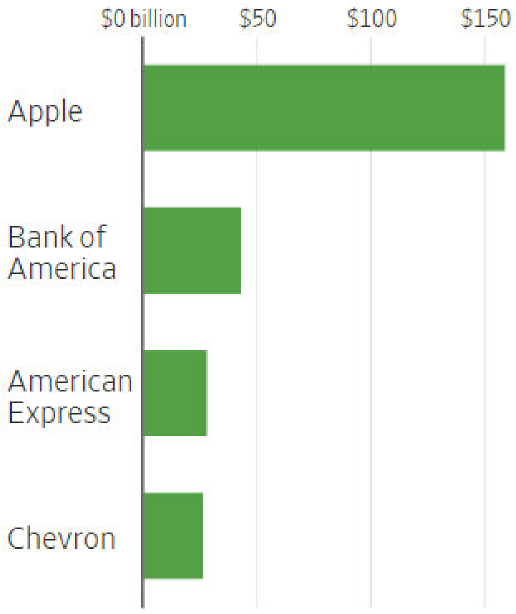
Mr. Buffett’s Berkshire Hathaway Inc. has used the slump as an opportunity to increase spending on stocks, deploying tens of billions of dollars the past couple of months after ending 2021 with a near-record cash pile.

The Omaha-based company bought 901,768 shares of Occidental Petroleum Corp. last week, according to a regulatory filing. The move likely makes Occidental, in which Berkshire began buying shares in late February, one of its 10 biggest holdings.

In the past few months, Berkshire has also boosted its stake in Chevron Corp., placed a merger-arbitrage bet on Activision Blizzard Inc., bought an 11% stake in HP Inc., and continued adding to its position in Apple Inc., its biggest stockholding.

Investors will **get** a **look** at **what** else **Berkshire has been buying** – as well as what it has been selling – **when** it **files** what is known as **Form 13F with** the **S**ecurities and **E**xchange **C**ommission on **Monday**. The SEC requires all institutional investors that manage more than $100 million to file the form within 45 days of the end of each quarter. Because institutions must disclose their equity holdings on the form, as well as the size and market value of each position, investors often use 13Fs to gauge how large money managers are playing the stock market.

Berkshire Hathaway's biggest holdings, ranked by market value*



*Data are as of March 31

Source: Berkshire Hathaway's Form 10-Q

One takeaway from Berkshire's filing is likely to be this: The market's tumult has allowed the company to go on a spending spree.

Mr. Buffett, a longtime practitioner of value investing, has long advised that investors "be greedy when others are fearful." That philosophy was likely difficult to practice for much of the past two years, during which investors' mood largely seemed anything but fearful. Now that the market is slumping, Berkshire is in a prime position to add to its mammoth stock portfolio, investors say.

"Cash is dry powder, and he has a lot of it," said Rupal Bhansali, chief investment officer for global equities at Ariel Investments, of Mr. Buffett. Ms. Bhansali manages Ariel's global mutual fund, which owns Berkshire shares.

Ms. Bhansali, among others, also believes that Berkshire's investments in Chevron and Occidental might reflect a bet that commodities prices will stay elevated for some time.

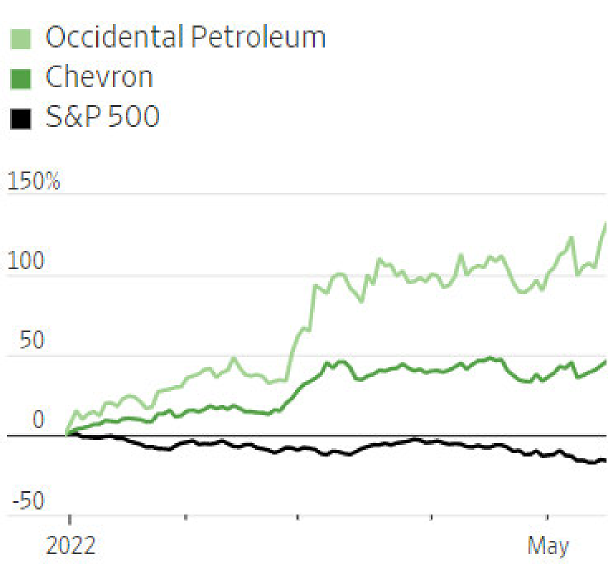
Energy stocks have been by far the **best-performing group** in the **S&P 500 this year**, **benefiting from** a **surge** in **commodities prices** that began **after Russia's invasion** of **Ukraine** raised concerns about disruptions to oil and gas supply lines. **Chevron shares** are **up 43% this year**, while **Occidental** shares have gone **up 121%**. **In comparison**, the S**&P 500** has **fallen 16%**.

"They're clearly owning companies that are likely to be an inflation hedge," Ms. Bhansali said.

Energy stocks also offer two characteristics that Mr. Buffett has traditionally gravitated toward: **low valuations**, as well as shareholder returns in the form of **buybacks and dividends**, said Jim Shanahan, senior equity research analyst at Edward Jones.

Dividend-paying stocks have outperformed the **S&P 500 this year**, in part as investors whipsawed by market volatility have sought out stocks that can offer steady cash returns.

Performance, year to date



As of May 16, 10:09 a.m. ET

Source: FactSet

“It fits the profile,” Mr. Shanahan said of Berkshire’s Chevron and Occidental share purchases.

With stock volatility remaining elevated, many investors and analysts expect Mr. Buffett, as well as Berkshire portfolio managers Ted Weschler and Todd Combs, to keep putting cash to work in the market over the coming months.

Berkshire ended last year with a mountain of cash on its hands – not necessarily out of a desire to build up its war chest, but because it had been impossible to find companies that seemed worth investing in for the long term, Mr. Buffett said to shareholders in his annual letter sent out in February. It **had $106.3 billion in cash** as of **March 31, down from $146.7 billion** at the **end of 2021**.

This year has changed that. With tightening monetary policy, slowing economic growth and sustained supply-chain disruptions putting markets on edge, Mr. Buffett is in his element, said David Kass, a finance professor at the University of Maryland’s Robert H. Smith School of Business.

“This is what I’d consider to be Warren Buffett’s sweet spot,” Mr. Kass said. “The almost **wholesale selling** in the market has **provided Berkshire** an **opportunity to buy securities at bargain prices**.”

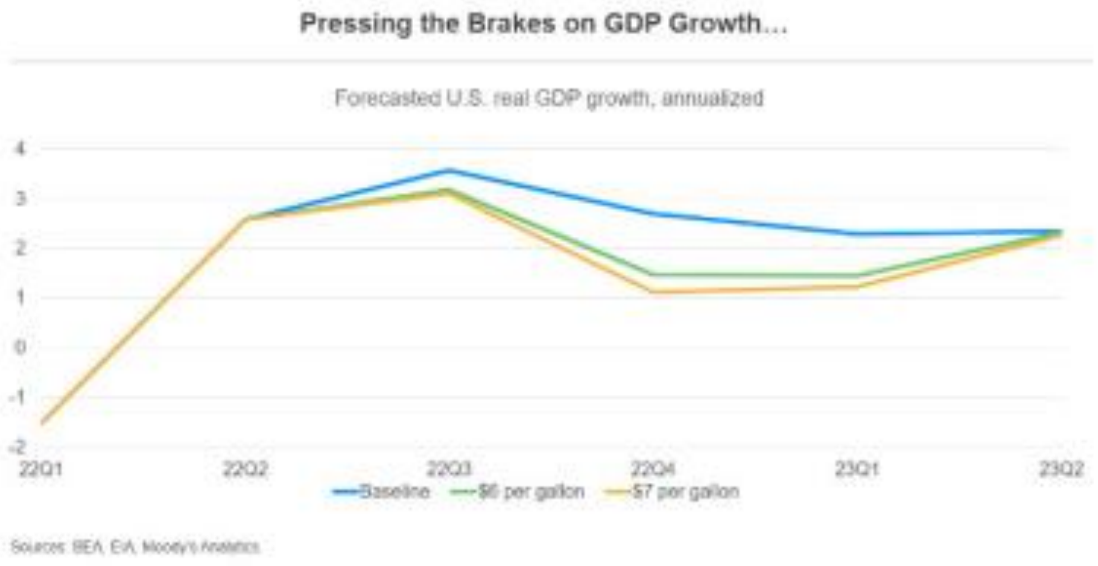
What if Gasoline in the U.S. Goes to $6? $7?

by Moody's Analytics – Jun. 9, 2022

The **pain U.S. consumers** are **feeling at** the **pump will get worse before** it **gets better**. Wholesale gasoline prices lead retail gasoline prices by two weeks and there isn't any good news. Wholesale gasoline prices point toward an increase in average U.S. gasoline prices from $5 to $5.50 over the next couple of weeks. Critical to the forecast for growth and inflation is that energy prices, including gasoline, are near their peaks and will steadily decline through the rest of this year and into next

What if we're wrong? **If global energy prices haven't peaked**, and additional oil supply doesn't hit the market, then U.S. retail gasoline prices could climb even further. To assess the potential costs of significantly higher retail gasoline prices, we ran two scenarios through our global macroeconomic model

In the first scenario, U.S. prices at the pump average $6 per gallon in the latter half of 2022. In the second scenario, prices surge to $7 per gallon. In both scenarios, gasoline prices quickly return to our baseline forecast by mid-2023. A general rule of thumb is that a **$10 increase** in the **price** of a **barrel** of **oil** **results** in a **$0.25 increase** in the **price** of a **gallon of gasoline**. Further, **every penny change** in **retail gas prices adds or subtracts $1.28 billion in consumer spending** over the course of a year. Therefore, the economic costs of higher gasoline prices increase quickly and are likely nonlinear. **Gasoline prices** at **$6 or $7** would be **psychological thresholds** and would likely **weigh heavily on consumer sentiment** and potentially increase the economic costs of higher prices at the pump


Pressing the Brakes on GDP Growth…

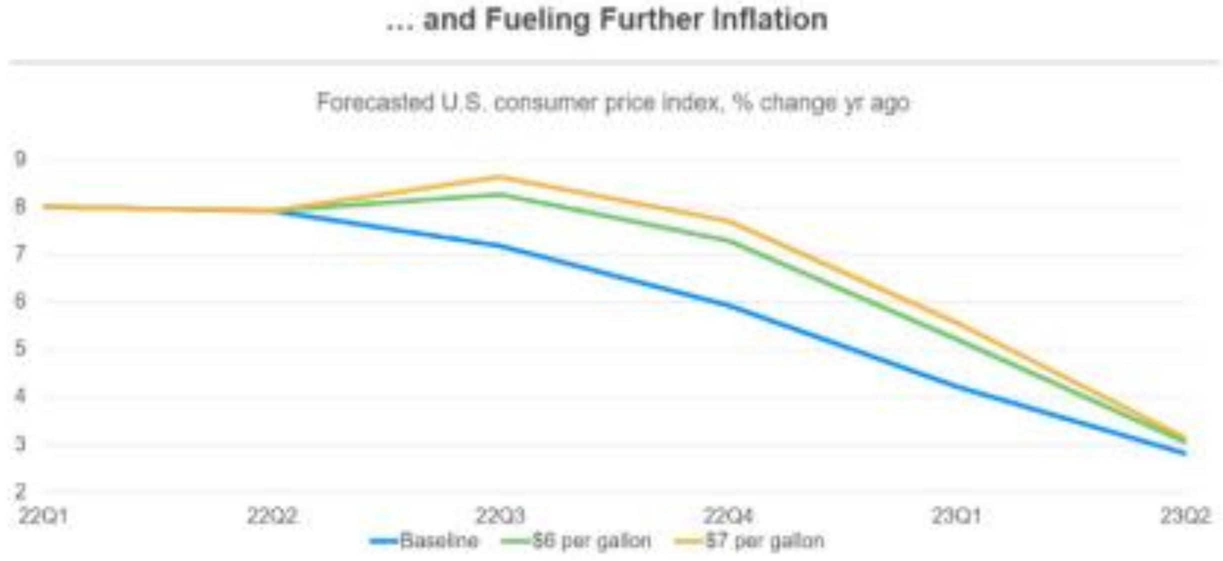
Forecasted U.S. real GDP growth, annualized

Sources: BEA, EIA, Moody's Analytics

Gasoline prices at $6 per gallon shave 0.4 percentage point off U.S. GDP growth in the **third quarter**, dragging output from the annualized growth rate of 3.6% in our baseline to 3.2%. In the final quarter, the hit to GDP growth is 1.2 percentage points. The decline is a function of a reduction in real consumer spending.

U.S. consumer prices, which we forecast to moderate steadily after peaking in the first half of 2022, instead accelerate to an average of 8.3% in the third, more than a percentage point higher than our baseline. In the fourth quarter, prices rise 7.3%, 1.4 percentage points hotter than our forecast of a 5.9% increase. In total, prices rise 7.8% in 2022, 0.6-percentage point higher than our forecast of 7.2%

In our second and more severe scenario, we push gasoline prices up another dollar, averaging $7 per gallon in the second half of this year. This scenario requires the price of a barrel of oil to be more than $200 per barrel in the final two quarters. As would be expected, the economic situation worsens.



Sources: BLS, EIA, Moody's Analytics

At $7 per gallon, GDP growth in the **U.S. slumps to 3.1% in** the **third quarter and 1.1% in** the **fourth**. This marks a half percentage point and 1.6-percentage point reduction from our baseline, respectively. The **inflationary impacts of $7 gas** are **similarly pronounced**. The **CPI jumps 8.6%** in the **third quarter** and **7.7%** in the **fourth**.

With Stubbornly High Inflation, Central Banks Will Ratchet Up Monetary Policy Tightening

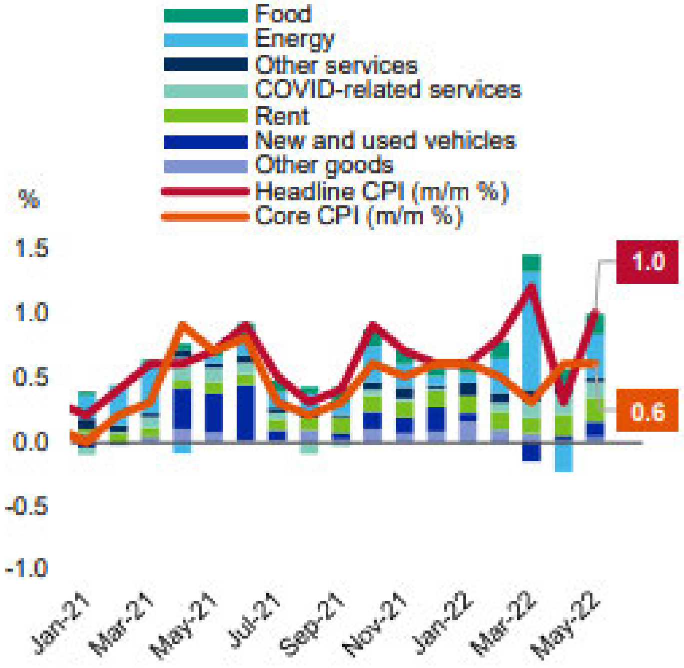
by Madhavi Bokil, Senior Vice President/CSR,
Radhika Ramalingam, Associate, Elena H Duggar,
Managing Director-Credit Strategy, and
Atsi Sheth, Managing Director - Credit Strategy
Moody's Investor Service – Jun. 13, 2022

On **10 June, US May CPI data showed inflation rose to 8.6% on an annual basis**, with **shelter**, **gasoline** and **food together contributing** about **5 percentage points** to the gain. Core inflation rose 6.0% from May 2021. Additionally, a **drop** in the **U**niversity of **Michigan's consumer confidence index to** a **record-low 50.2** in early June from 58.4 in May **indicates** that **inflation** is **weighing significantly on consumers' sense of economic well-being**. The **inflation data adds urgency** to the **Fed's efforts to tame inflation** and will **keep it on** an **aggressive tightening path**

Exhibit 1

Food, energy and rent were the biggest contributors to US inflation in May

Percentage point contributions to month-over-month US headline CPI inflation



Rent represents the sum of rent of primary residence and owners' equivalent rent.

Sources: Haver Analytics and Moody's Investors Service

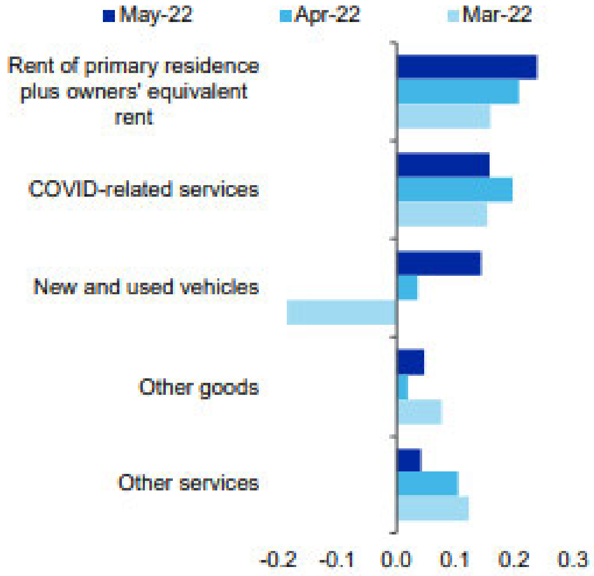
US headline CPI inflation accelerated to 1.0% in May from 0.3% in April, while core CPI inflation rose by 0.6%, the same as in April. The biggest contributors to monthly inflation were a 4.1% rise in gasoline prices, 8% rise in utility gas prices and 1.2% rise in food prices in May from April. Other major contributors were higher prices for new and used vehicles and the rise in airfares (Exhibit 1). The silver lining in the May CPI data was a diminished contribution to inflation from non-pandemic-affected core goods and services (Exhibit 2). However, a 0.6% increase in shelter costs in May, up from 0.5% in April, suggests that inflation remains sticky

Similarly in the euro area, headline Harmonised Index of Consumer Prices (HICP) inflation increased in May to 8.1% from 7.4% in April, exacerbated by rising energy and food prices. However, while month-over-month momentum in core prices was high, it has slowed since March. Core inflation, excluding food, energy, alcohol and tobacco, rose 0.5% after a 1% gain in April and 1.2% in March. Among the components of core inflation, the pace of rising non-energy industrial goods prices has slowed since March (Exhibit 3).

Exhibit 2

Contribution from non-pandemic affected core goods and services fell in May

Percentage point contributions to month-over-month US core CPI inflation

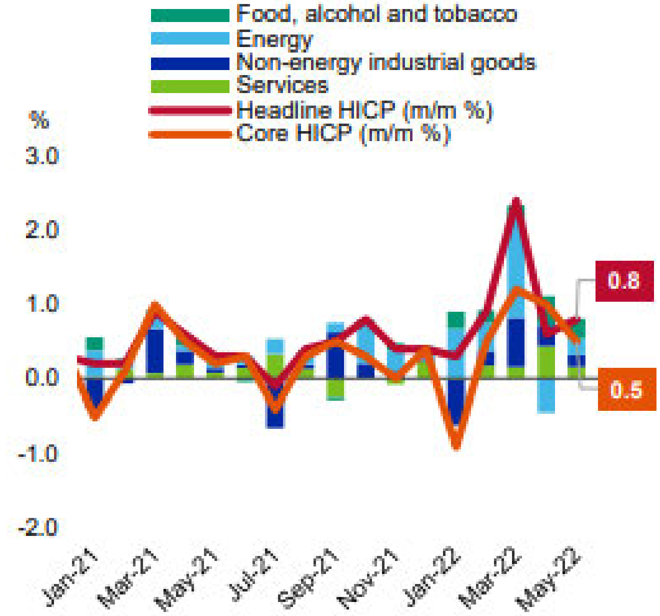


Sources: Haver Analytics and Moody's Investors Service

Exhibit 3

Euro area core HICP inflation slowed in May

Percentage point contributions to month-over-month euro area headline HICP inflation



Core HICP represents HICP excluding food, energy, alcohol and tobacco.

Sources: Haver Analytics and Moody's Investors Service

A majority of central banks around the world have begun or are poised to tighten monetary policy to dampen aggregate demand and restore long-term price stability. Those at an early stages of the tightening cycle have indicated that a series of rate hikes are likely. For example, the European Central Bank governing council indicated on 9 June that it would raise key interest rates 25 basis points (bp) at its July meeting and follow with a series of rate increases in subsequent meetings, including a potential 50 bp hike in September if inflation does not abate. Central banks raising rates in June so far include the Bank of Canada, which raised its target policy rate 50 bp; the Reserve Bank of Australia, which hiked its official cash rate 50 bp; and the Reserve Bank of India, which raised its repo rate 50 bp, as well as central banks of Poland and Chile, each of which raised the policy rates by 75 basis points.

Looking ahead, we expect economic activity to slow because of the maturing business cycle and because tightening financial and monetary conditions should temper aggregate demand, particularly in advanced and emerging market countries that have inflationtargeting central banks. However, central banks have little control over price pressures that stem from supply challenges, including commodity and food prices

Exhibit 4

Semiconductor prices eased in May

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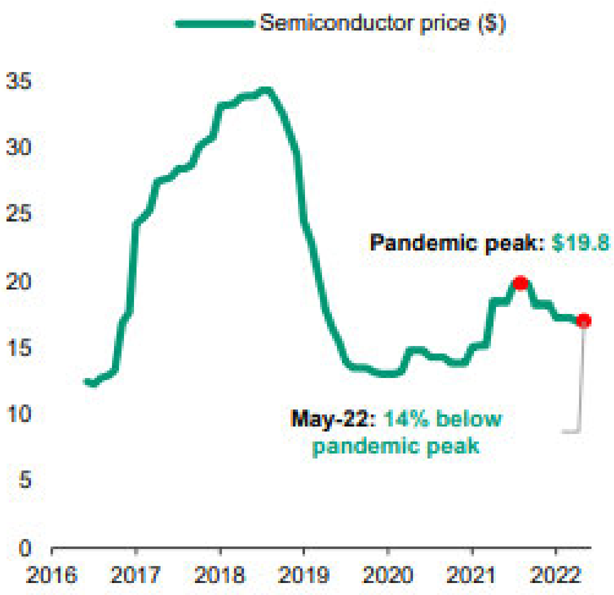


Pandemic peak: $19.8

May-22: 14% below pandemic peak

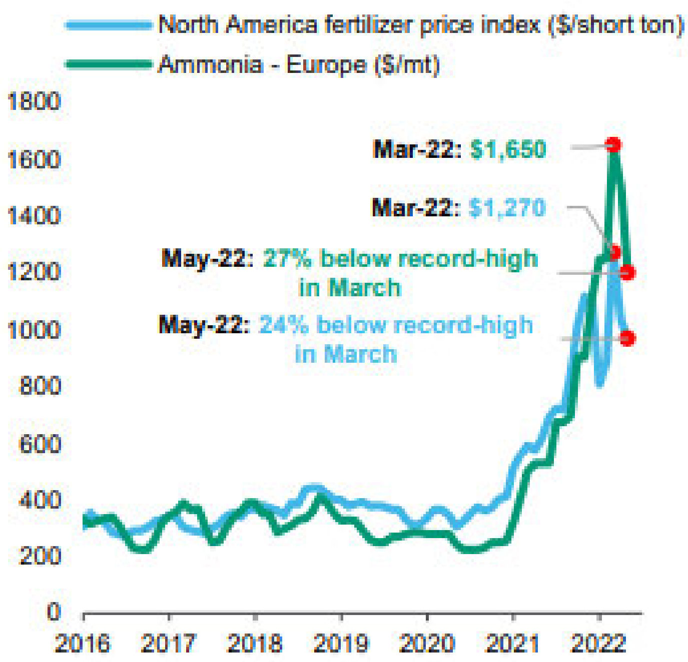
The inSpectrum Tech PC DRAM contract price is a proxy for the price of semiconductors.

Sources: Bloomberg and Moody's Investors Service

Exhibit 5

American and European fertilizer prices have dipped

$/short ton , $/metric ton



Mar-22: $1,650

Mar-22: $1,270

May-22: 27% below record-high in March

May-22: 24% below record-high in March

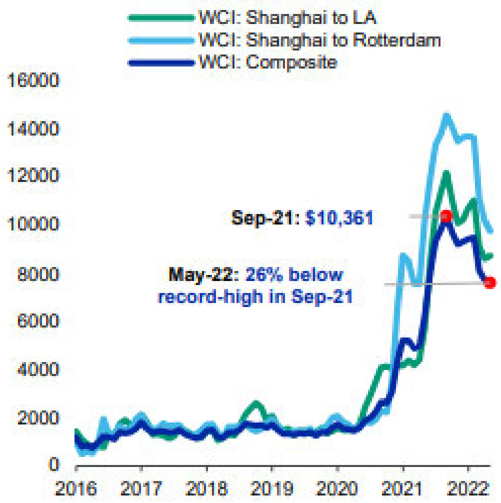
Sources: Bloomberg and Moody's Investors Service

ply chain impediments remain significant obstacles

Exhibit 6

The spot rate for shipping containers has declined

World container index (WCI), $/40-foot container



Sep-21: $10,361

May-22: 26% below record-high in Sep-21

Sources: Bloomberg and Moody's Investors Service to lower prices. However, the latest data for the month of May indicate that global supply-side inflation pressure is peaking in some areas. If the improvements persist, it will ease cost side inflationary pressure. The high price of semiconductors used in the production of cars, computers and other electronic products eased in May, as did fertilizer prices, which hit record-highs in March after Russia’s invasion of Ukraine (Exhibits 4 and 5). Additionally, container freight rates declined significantly from their peak in the second half of last year, indicating that price pressure may ease in the coming months (Exhibit 6).

CASE: UE 399
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 110

Edison Electric Institute (EEI) 2020 Annual Financial Review Report

June 22, 2022

EEI
Edison Electric
INSTITUTE

2020 Financial Review

Annual Report of the U.S. Investor-Owned Electric Utility Industry

Thank you to the following EEI Power Member
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Edison Electric
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2020
FINANCIAL REVIEW

ANNUAL REPORT OF THE U.S. INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY

About EEI and the Financial Review

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our U.S. members provide electricity for 220 million Americans and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than 7 million jobs in communities across the U.S. and contributes 5 percent to the nation's GDP. The 2020 Financial Review is a comprehensive source for critical financial data covering 39 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges. The report also includes data on five additional companies that provide regulated electric service in the United States but are not listed on U.S. stock exchanges because they are owned by holding companies not primarily engaged in the business of providing retail electric distribution services in the United States. These 44 companies are referred to throughout the publication as the U.S. Investor-Owned Electric Utilities. Please refer to page 80 for a list of these companies.

Contents

Highlights of 2020

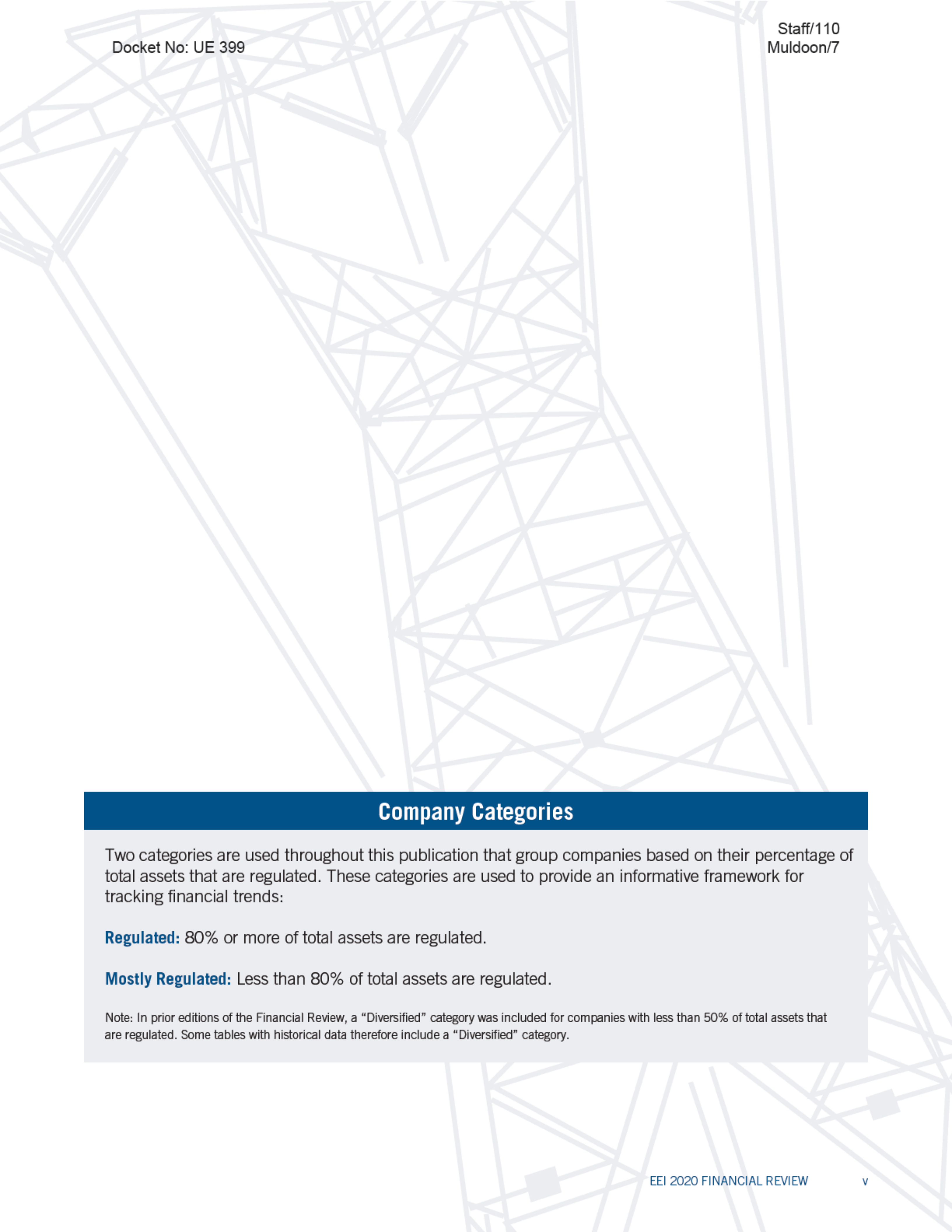
U.S. INVESTOR-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	**2020**	**2019r**	**% Change**
Total Operating Revenues	351,085	357,127	(1.7%)
Utility Plant (Net)	1,316,416	1,239,029	6.2%
Total Capitalization	1,128,491	1,022,415	10.4%
Earnings Excluding Non-Recurring and Extraordinary Items	54,359	49,148	10.6%
Dividends Paid, Common Stock	29,503	27,876	5.8%

r = revised   Note: Percent changes may reflect rounding.

Abbreviations and Acronyms

AFUDC	Allowance for Funds Used During Construction
BTU	British Thermal Unit
CFTC	Commodity Futures Trading Commission
CPI	Consumer Price Index
DOE	Department of Energy
DOJ	Department of Justice
DPS	Dividends per share
EEI	Edison Electric Institute
EIA	Energy Information Administration
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPS	Earnings per share
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GW	Gigawatt
GWh	Gigawatt-hour
IPP	Independent Power Producer
IRS	Internal Revenue Service
ISO	Independent System Operator
ITC	Independent Transmission Company
kWh	Kilowatt-hour
M&A	Mergers & Acquisitions
MW	Megawatt
MWh	Megawatt-hour
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxide
NOAA	National Oceanic & Atmospheric Administration
NRC	Nuclear Regulatory Commission
O&M	Operations and Maintenance
PSC	Public Service Commission
PUC	Public Utility Commission
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
ROE	Return on Equity
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide
T&D	Transmission & Distribution



Company Categories

Two categories are used throughout this publication that group companies based on their percentage of total assets that are regulated. These categories are used to provide an informative framework for tracking financial trends:

Regulated: 80% or more of total assets are regulated.

Mostly Regulated: Less than 80% of total assets are regulated.

Note: In prior editions of the Financial Review, a “Diversified” category was included for companies with less than 50% of total assets that are regulated. Some tables with historical data therefore include a “Diversified” category.

President's Letter

2020 Financial Review

2020 was unprecedented, and the past year has been tough for our world, for our nation, for our cities and communities, and for so many families across our country. Throughout the challenges of the pandemic, we have had constant reminders of how valuable electricity is to our society and to our everyday lives.

Like they do when faced with any crisis, EEI's member companies—America's investor-owned electric companies—met these challenges head on, with courage and commitment. They quickly adapted to very adverse circumstances, and they have worked tirelessly to deliver the safe, reliable, affordable, and clean energy their customers and communities need, while also protecting the health and safety of their employees.

As always, our North Star is serving our customers. As we look to all that we hope to accomplish this year, we will continue to center our efforts on maintaining the steady and strong transition to clean energy; modernizing the energy grid to make it more dynamic, more resilient, and more secure; and developing the innovative solutions our customers expect and deserve. We are proud that we stand on a strong foundation, and we look forward to our continued work together to deliver value to our customers, to our investors, and to all industry stakeholders.

Clean energy remains central to our industry vision, and EEI and our member companies are committed to getting the energy we provide as clean as we can as fast as we can, without compromising on the reliability or affordability that our customers expect and value. We are leaders on clean energy, and we already are making progress. Today, 40 percent of the nation's electricity comes from carbon-free sources, including nuclear energy, hydropower, wind, and solar energy. Equally important, carbon emissions from the U.S. power sector are at their lowest level in more than 40 years—and continue to fall.

> “EEI, working with our member companies and the investment community, created the first-of-its-kind, industry-wide environmental, social, governance, and sustainability reporting template.

As impressive as our progress has been, and continues to be, now is the time to accelerate our efforts. With the right policies and the right technologies, a 100-percent clean energy future can be more than a goal. It can be a reality.

Existing technologies can get us much of the way to a 100-percent clean energy future. Completing the work will require advanced renewables and new, carbon-free, 24/7 technologies that are affordable for customers. Ultimately, technology will drive the timeline to a 100-percent clean energy future, and federal policies are a necessary catalyst to accelerate the pace of innovation and to ensure these technologies are demonstrated and commercialized in the time that electric companies need them.

Our position is—and has always been—that we should take an economy-wide approach to addressing climate change. The transportation sector is the largest domestic source of carbon emissions—and has been since 2016. By accelerating transportation electrification and increasing the number of electric vehicles (EVs) in the federal fleet and on U.S. roads, we can leverage the already ongoing emissions reductions in our sector to meet economy-wide carbon reduction goals. EEI's member companies already are investing more than $3 billion to deploy charging infrastructure and to accelerate electric transportation.

A robust transmission system is essential to helping our industry continue its clean energy transformation. The transmission system integrates renewables, enhances grid resilience, powers electric transportation, and facilitates the adoption of a broad array of smart technologies to better serve our customers. Given the time needed to build new transmission infrastructure, it is imperative to move quickly to take stock of where we are, what is working, what is not, and what the needs are in each region of the country. We look forward to working with the Department of Energy, the Federal Energy Regulatory Commission, and the Administration to get this critical energy infrastructure built more quickly.

EEI and our member companies also are working constantly to improve energy grid security, reliability, and resiliency, and we will continue to strengthen cyber and physical defenses and to elevate preparedness. Our strong industry-government partnership, coordinated through the CEO-led Electricity Subsector Coordinating Council, will continue to be critical to accomplishing our shared goal of protecting the energy grid against all threats.

We know that our stakeholders need a clear and consistent way to measure our progress on delivering a sustainable energy future. That is why EEI, working with our member companies and the investment community, created the first-of-its-kind, industry-wide environmental, social, governance, and sustainability (ESG/sustainability) reporting template. Launched in 2018, the template helps member companies provide investors, Wall Street analysts, and other key stakeholders with more consistent and uniform ESG/sustainability data and information. In 2020, we worked with our member companies and the financial community to enhance the diversity, equity, and inclusion metrics and information that can be reported in the template, among other important updates, such as providing an emissions reduction goals table to provide more uniformity in how our member companies report long term climate goals. Following this collaborative process, Version 3 of the template was launched this year for our member companies to report 2020 ESG/sustainability data and information.

Building on the work of the ESG/sustainability template and recognizing the important role that natural gas has—and will continue to have—in our clean energy future, EEI and the American Gas Association now are focused on the Natural Gas Sustainability Initiative (NGSI). The NGSI is an overarching framework that enables the natural gas industry to measure, disclose, and recognize individual company and industry-wide progress and innovation on key sustainability metrics. This year, we are expanding our effort by engaging natural gas producers and midstream natural gas companies on a reporting platform that encompasses the entire value chain and calls for using consistent protocols to report their methane intensity.

> *“The Natural Gas Sustainability Initiative is an overarching framework that enables the natural gas industry to measure, disclose, and recognize individual company and industry-wide progress and innovation on key sustainability metrics.*

The pandemic has highlighted a deep inequity around broadband access across the country. The digital divide is acute, and EEI's member companies are stepping up to help tackle this problem. Electric companies long have incorporated telecommunications equipment and fiber technology into their operations—particularly in rural areas—to support communications and to provide real-time monitoring and controls for generation and transmission operations. Allowing electric companies to leverage these fiber investments to provide middle-mile broadband infrastructure, in partnership with telecommunications companies and last-mile internet providers, is a win for all stakeholders, particularly those customers in underserved and unserved areas.

As you will see in this year's Financial Review, EEI's member companies continue to build upon a strong financial foundation. The industry's average credit rating was BBB+ for the seventh straight year in 2020, after increasing from the BBB average that previously had held since 2004. This improved credit quality greatly supports the continued level of elevated capital expenditures, which set a ninth consecutive record high of $132.7 billion in 2020. We continue to be America's most capital-intensive industry.

The EEI Index fell by 1.2 percent in 2020; it has produced a positive total return in 15 of the last 18 years. Our industry produced returns greater than 10 percent in 12 of the 15 positive years and greater than 20 percent in 5 of the past 15 years.

Our industry extended its long-term trend of widespread and consistent dividend increases in 2020. A total of 34 companies increased or reinstated their dividend in 2020, compared to 37 in 2019, 39 in 2018, 38 in 2017, 40 in 2016, and 39 in 2015. Our industry's dividend payout ratio—65.3 percent for the 12 months ended December 31, 2020—was leading among the major U.S. business sectors, surpassed only by the industrial sector. As of December 31, 2020, 38 of the 39 companies in the EEI Index were paying a common stock dividend.

Importantly, the Tax Cuts and Jobs Act, which was signed into law in December 2017, maintains preexisting tax rates for dividends and capital gains. Sustaining this balance, along with keeping overall tax rates down, is important to sustain our investments in reliable, affordable, and clean energy and to avoid a capital-raising disadvantage for the high-dividend companies in our industry. There is a real prospect for major new tax legislation to be offered in the 117th Congress, and EEI will be educating lawmakers on the impact that significant tax increases on corporations and dividends would have on our customers.

In 2021 and beyond, EEI and our member companies will remain focused on building a cleaner, smarter, and stronger energy future—and on delivering the safe, reliable, affordable, and clean energy our customers need and deserve. Ultimately, every success we have as an industry leads back to our commitment to do what is right for our customers.

We truly value the partnership that we share with the financial community.

Thomas R. Kuhn

Thomas R. Kuhn

President
Edison Electric Institute

Capital Markets

Stock Performance

Future stock market historians will likely view 2020 as one of the strangest years ever. Who could have predicted in March — when major indices were rocked by COVID-19 and down 35% from January 1 — that full-year returns would reach nearly 10% for the Dow Jones Industrials, almost 20% for the S&P 500 and more than 40% for the Nasdaq? Utilities, despite their defensive characteristics, were also off 35% at the March lows but recovered only tepidly compared to broad market ebullience. The EEI Index finished 2020 with a -1.2% return including dividends.

The market's gyrations seemed to anticipate the trajectory of economic data, which showed spectacular volatility. The Bureau of Economic Analysis (BEA) reported U.S. gross domestic product (GDP) fell 5.1% in Q1 2020 from the preceding quarter before crashing to a -31.4% decline in Q2. Aggressive support from the Federal Reserve and the late March CARES act — which injected $2.3 trillion of stimulus (11% of GDP) through direct payments to individuals, unemployment support and $483 billion of forgivable loans to small businesses — powered

2020 Index Comparison

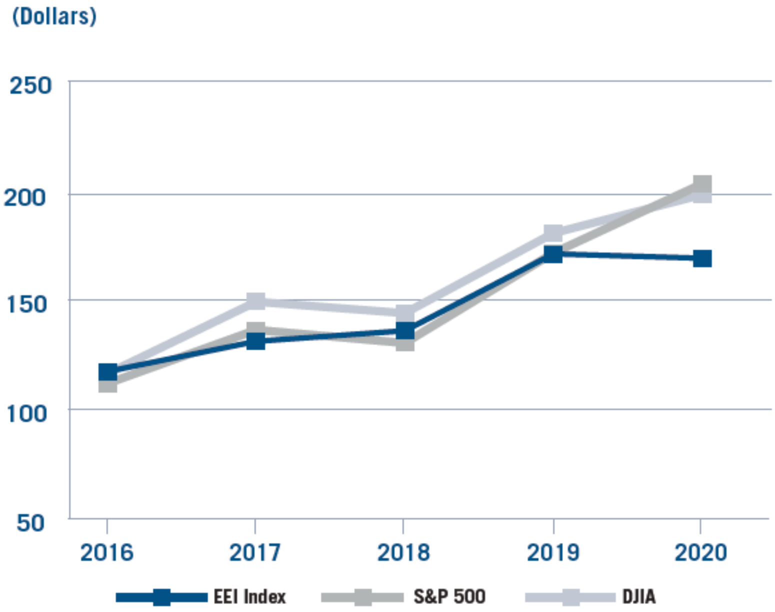
EEI Index	**(1.2)**
Dow Jones Industrials	9.7
S&P 500	18.4
Nasdaq Composite Index*	43.6

* Price gain/(loss) only. Other indices show total return.

Source: EEI Finance Department and S&P Global Market Intelligence.

Comparison of the EEI Index, S&P 500, and DJIA Total Return 1/1/16–12/31/20

REFLECTS REINVESTED DIVIDENDS



All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2015.

Source: EEI Finance Department and S&P Global Market Intelligence.

EEI Index Top 10 Performers

Twelve-month period ending 12/31/2020

Company	Total Return %	Category
NextEra Energy, Inc.	30.2	MR
PG&E Corporation	14.6	R
Xcel Energy Inc.	7.8	R
Duke Energy Corporation	5.0	R
Eversource Energy	4.5	R
Ameren Corporation	4.4	R
WEC Energy Group, Inc.	2.6	R
PSEG, Inc.	2.6	MR
Southern Company	1.0	R
CMS Energy Corporation	-0.2	R

Note: Return figures include capital gains and dividends.
Source: EEI Finance Department.

Sector Comparison 2020 Total Shareholder Return

Sector	Total Return %
Technology	47.3%
Consumer Goods	33.2%
Consumer Services	29.8%
Basic Materials	18.3%
Industrials	17.9%
Healthcare	16.0%
Financials	-0.5%
Utilities	-0.6%
EEI Index	**-1.2%**
Telecommunications	-5.9%
Oil & Gas	-33.2%

Source: EEI Finance Dept., Dow Jones & Company, Yahoo! Finance.

a 33.4% GDP recovery in Q3 from Q2. Stocks were also lifted late in the year's second half by optimism over COVID-19 vaccine progress, which seemed to offer welcome hope that life in 2021 may slowly return to normal.

Investor sentiment always colors macroeconomic news with confirmation bias. Measured on a year-over-year basis (rather than quarter-to-quarter), U.S. GDP fell 9.0% in Q2 and 2.8% in Q3, hardly a picture of strength. But investors had their minds set on "recovery" and sequential data gave them the numbers they were looking for.

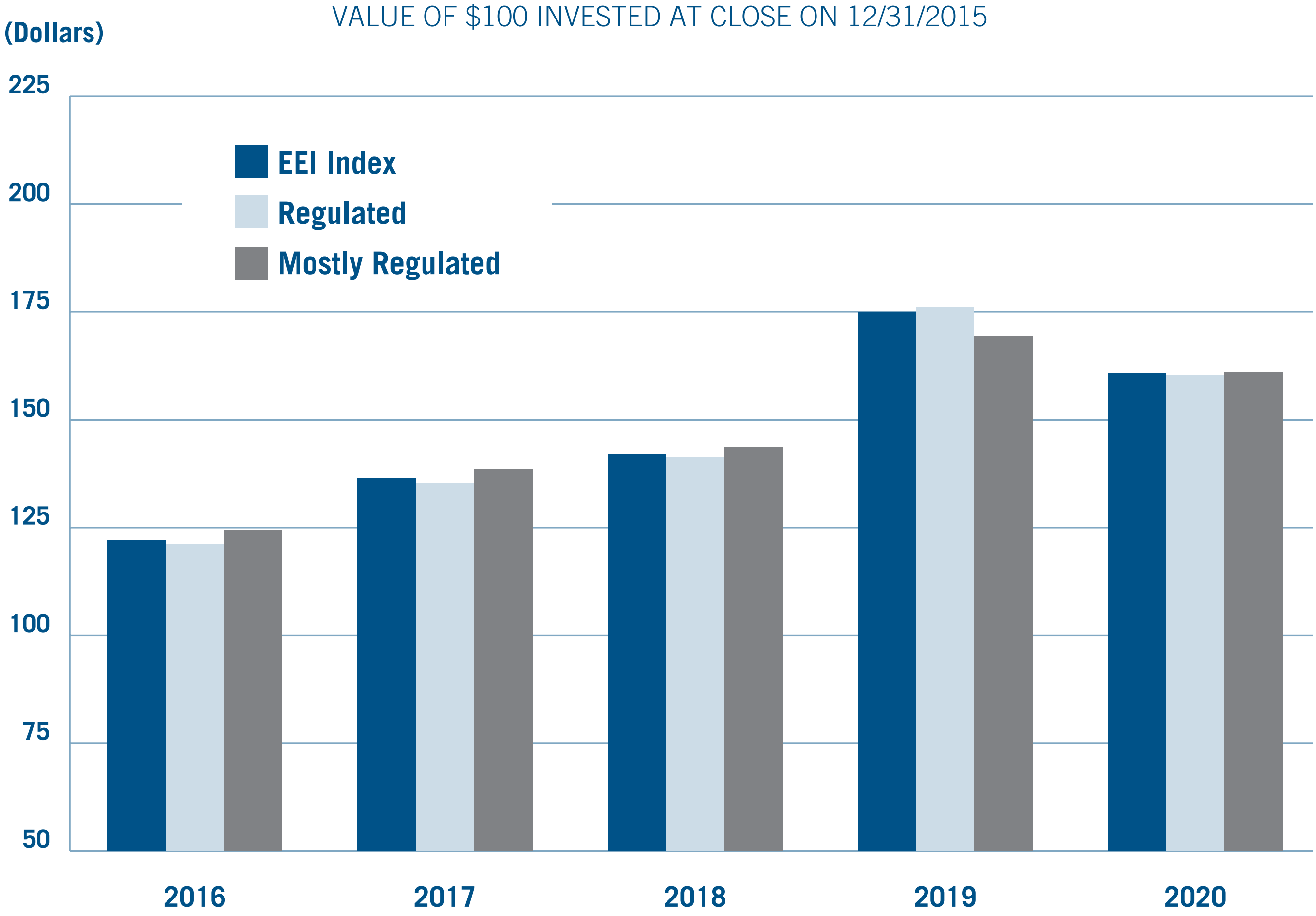
Interest Rates Fall to Record Lows

Wall Street analysts scratched their heads a bit over utility shares' 2020 performance since utilities are classically seen as safe-havens in times of market stress. Some cited as potential causes utilities' rich valuations as the year began, concerns over load strength, and dysfunctional credit markets when pandemic news worsened by the day (given the industry's capital raising needs). But 2020 was so atypical that historical patterns may simply be poor guides. Analysts viewed utilities' sluggish second half as a function of market technicals and the strength of money flows into technology and consumer goods and services companies that benefit from both stay-at-home lifestyles and a cyclical economic rebound.

Interest rate moves certainly favored utilities, whose steady dividends make them a bond substitute for income-oriented investors. The Federal Reserve cut its overnight Fed Funds rate from 1.5% in February to near 0% by late March, where it remained through year-end. The 10-year Treasury yield fell from 1.8% in January to under 0.6% in August before drifting back to just over 1% at year-end. The 30-year Treasury yield likewise fell from 2.3% to a range of 1.3% to 1.6% through August before rising to 1.6% at year-end. These rate moves somewhat contradict the stock market's expectation for a fast rebound to pre-COVID-19 economic strength.

Comparative Category Total Annual Returns 2016–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES,
VALUE OF $100 INVESTED AT CLOSE ON 12/31/2015



	2016	2017	2018	2019	2020
EEI Index Annual Return (%)	22.21	11.56	4.28	23.06	(8.07)
EEI Index Cumulative Return ($)	122.21	136.34	142.17	174.95	160.83
Regulated EEI Index Annual Return	21.16	11.66	4.55	24.56	(9.01)
Regulated EEI Index Cumulative Return	121.16	135.29	141.44	176.18	160.30
Mostly Regulated EEI Index Annual Return	24.57	11.32	3.62	17.87	(4.95)
Mostly Regulated EEI Index Cumulative Return	124.57	138.67	143.69	169.37	160.99

- For the Category Comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).
- Cumulative Return assumes $100 invested at closing prices on December 31, 2015.

Source: EEI Finance Dept., S&P Global Market Intelligence.

10-Year Treasury Yield
1/1/11 through 12/31/20

Source: U.S. Federal Reserve.

2020 Returns By Quarter

Index	**Q1**	**Q2**	**Q3**	**Q4**
EEI Index	(13.6)	1.8	5.6	6.5
Dow Jones Industrial Average	(22.7)	18.5	8.2	10.7
S&P 500	(19.6)	20.5	8.9	12.2
Nasdaq Composite*	(14.2)	30.6	11.0	15.4
Category	**Q1**	**Q2**	**Q3**	**Q4**
All Companies	(15.8)	(1.0)	1.3	8.8
Regulated	(15.0)	(1.3)	(0.1)	8.6
Mostly Regulated	(18.3)	0.2	6.2	9.3

* Price gain/loss only. Other indices show total return.
For the Category comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).

Source: EEI Finance Department, S&P Global Market Intelligence.

Pandemic Hits Electricity Demand

Widespread energy efficiency programs and economic deindustrialization have put a stop to secular electricity demand growth, which has been flat for a decade. COVID-19 shutdowns depressed demand further in 2020. U.S. electric output fell 4.7% year-to-year in Q2 and 1.6% in Q3 with a full-year decline of 2.9%. However, analysts noted that weakness was focused on commercial and industrial load, which fell more than 10% year-to-year from Q2 on. After falling 6% in Q1 on mild winter temps, residential demand actually jumped 7.5% in Q2 and roughly 3% to 4% in 2020's second half as people were stuck at home. The rise in higher-margin residential demand helped soften the pandemic's impact on utility earnings.

Industry Outlook Remains Upbeat

Wall Street research published late in the year showed remarkable thematic stability relative to pre-pandemic thinking. Industry growth stories remained intact. Capex projections ratcheted slightly higher. Earnings visibility extended out to the decade's back half as companies embraced growth largely through regulated investments.

Investors and analysts sharpened their focus on environmental, social and governance (ESG) metrics in 2020 leading to a perceived lift in share price performance for companies that rank well. As leaders of the nation's transition to clean energy, EEI members have a very positive ESG story to tell. Working with member companies, analysts and investors, EEI created the first industry-wide ESG/sustainability reporting template, which is now utilized by virtually all EEI member companies. An enhanced template with additional focus on social topics will be released this year for 2020 reporting.

Earnings growth outlooks for many utilities under analyst coverage rose slightly, in synch with the size and scope of growing capex programs. Industry long-term earnings growth targets cluster around 5% to 6% (as a rough generality), with individual utilities higher or lower depending on specific circumstances. Utilities also contributed to improved outlooks through aggressive operations and maintenance cost management as smart-grid investments pay off. And analysts generally observed that most utilities under their research coverage saw little earnings impact from the COVID-19 shock.

Ongoing capex programs run the gamut and include new renewable generation, new gas-fired generation, gas pipeline upgrades, electric transmission and distribution modernization and expansion, smart-grid deployment, and reliability-related network hardening. Analysts continued to view state regulatory relations as generally fair, balancing the interests of ratepayers, utilities and other stakeholders. Some utilities have successfully advocated for changes to rate design — such as forward test years, rate mechanisms and adjustment clauses — that allow timely recovery of costs associated with big-ticket capital investment programs and offer some protection from lethargic demand.

2020 Category Comparison

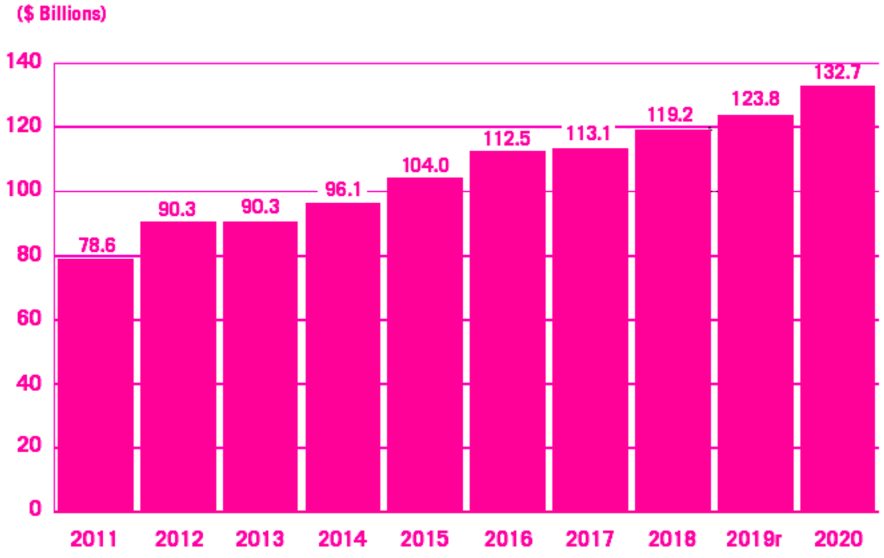
Category	Return (%)
EEI Index	**(8.1)**
Regulated	(9.0)
Mostly Regulated	(4.9)

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2020 Index Comparison table is cap-weighted.

Source: EEI Finance Department, S&P Global Market Intelligence, and company annual reports.

Capital Expenditures 2011–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



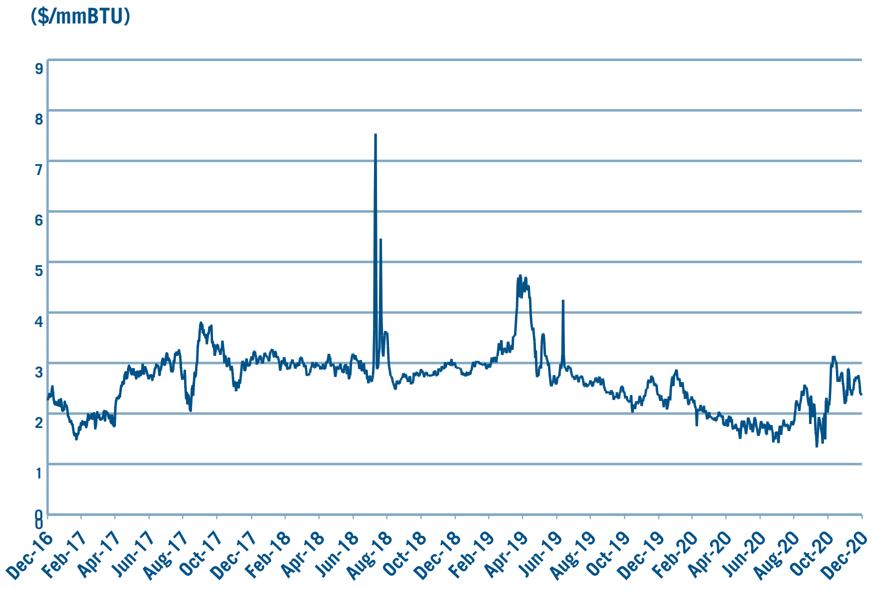
r = revised

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department.

Biden Win Boosts Green Themes

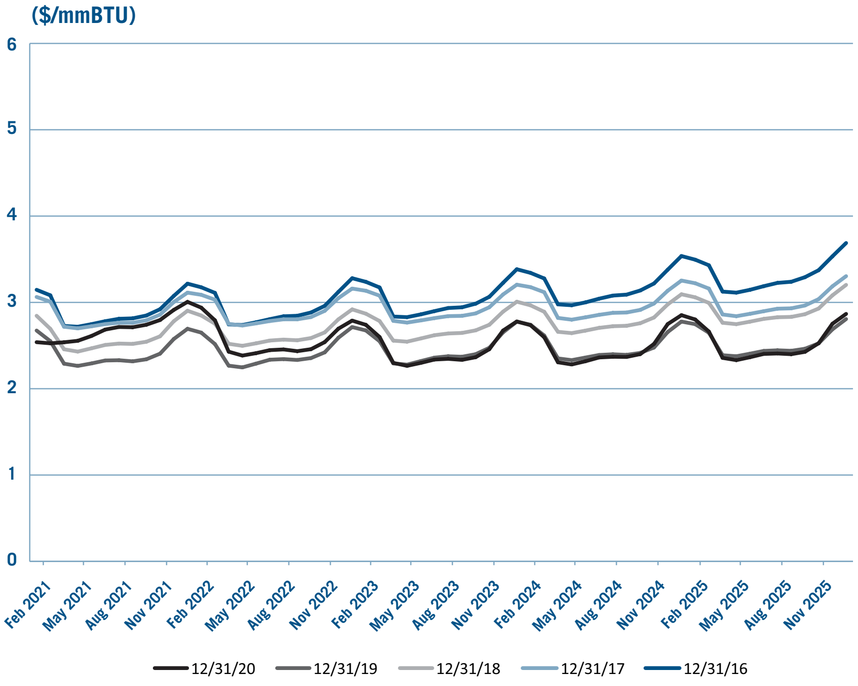
Biden campaign messaging included $2 trillion in clean energy investments, a 100% clean power economy and net-zero U.S. carbon emissions by 2050. Given political uncertainty over that long a horizon and the challenge of predicting technical innovation, revising long-term industry outlooks to reflect what "might" happen if these plans become policy is impossible with any

Natural Gas Spot Prices - Henry Hub
12/31/16 through 12/31/20



Source: S&P Global Market Intelligence.

NYMEX Natural Gas Futures
February 2021 through December 2025



Source: S&P Global Market Intelligence.

precision. But the broad contours seem positive for renewable generation of all kinds, for electrification of transportation and potentially for utility capex and demand growth.

The prospect of electric vehicle (EV) adoption gained some analytical traction in 2020 as the first potential secular spur to power demand since air conditioning. Some estimates suggested widespread EV adoption could boost load by 1% annually over the next few decades. Industry chatter late in the year included hydrogen power and renewable natural gas as long-term substitutes for the conventional and more carbon-intensive natural gas used today. Natural gas-focused utility shares were relatively weak in 2020 over concern that terminal values of pipeline investments may be challenged in a post-carbon world. But analysts noted these hypotheticals are beyond the visible horizon and won't effect predictable earnings outlooks. And gas remains the most economical heating fuel in many colder regions, with broad public and regulatory support.

Attractive Valuations

At year-end 2019, Wall Street viewed utility stock valuations as high. Price weakness in 2020 turned that on its head. With most utility shares in the red for the year, interest rates lower and long-term growth prospects unchanged (if not improved), analysts became broadly bullish. As 2021 began, most saw the group as extraordinarily undervalued with headroom for gains even if interest rates were to rise from today's unusually low levels. Investment programs underpin prospects for ag-

Market Capitalization at December 31, 2020 (in $MM)

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Ticker	Market Cap.	% of Total	Company Name	Ticker	Market Cap.	% of Total
NextEra Energy, Inc.	NEE	151,183	16.90%	AVANGRID, Inc.	AGR	14,066	1.57%
Duke Energy Corporation	DUK	67,297	7.52%	Alliant Energy Corporation	LNT	12,867	1.44%
Southern Company	SO	64,993	7.27%	Evergy, Inc.	EVRG	12,617	1.41%
Dominion Energy, Inc.	D	62,702	7.01%	CenterPoint Energy, Inc.	CNP	11,790	1.32%
American Electric Power Company, Inc.	AEP	41,317	4.62%	Pinnacle West Capital Corporation	PNW	9,009	1.01%
Exelon Corporation	EXC	41,207	4.61%	NiSource Inc.	NI	8,804	0.98%
Sempra Energy	SRE	36,884	4.12%	OGE Energy Corp.	OGE	6,375	0.71%
Xcel Energy Inc.	XEL	35,068	3.92%	MDU Resources Group, Inc.	MDU	5,282	0.59%
Eversource Energy	ES	29,680	3.32%	IDACORP, Inc.	IDA	4,853	0.54%
Public Service Enterprise Group Inc.	PEG	29,383	3.28%	PNM Resources, Inc.	PNM	3,876	0.43%
WEC Energy Group, Inc.	WEC	29,026	3.25%	Hawaiian Electric Industries, Inc.	HE	3,864	0.43%
PG&E Corporation	PCG	24,509	2.74%	Black Hills Corporation	BKH	3,845	0.43%
Consolidated Edison, Inc.	ED	24,174	2.70%	Portland General Electric Company	POR	3,828	0.43%
Edison International	EIX	23,746	2.65%	ALLETE, Inc.	ALE	3,215	0.36%
DTE Energy Company	DTE	23,432	2.62%	NorthWestern Corporation	NWE	2,949	0.33%
PPL Corporation	PPL	21,680	2.42%	Avista Corporation	AVA	2,737	0.31%
Entergy Corporation	ETR	19,990	2.23%	MGE Energy, Inc.	MGEE	2,532	0.28%
Ameren Corporation	AEE	19,289	2.16%	Otter Tail Corporation	OTTR	1,743	0.19%
CMS Energy Corporation	CMS	17,424	1.95%	Unitil Corporation	UTL	662	0.07%
FirstEnergy Corp.	FE	16,591	1.85%				
					Total Industry	**894,490**	**100%**

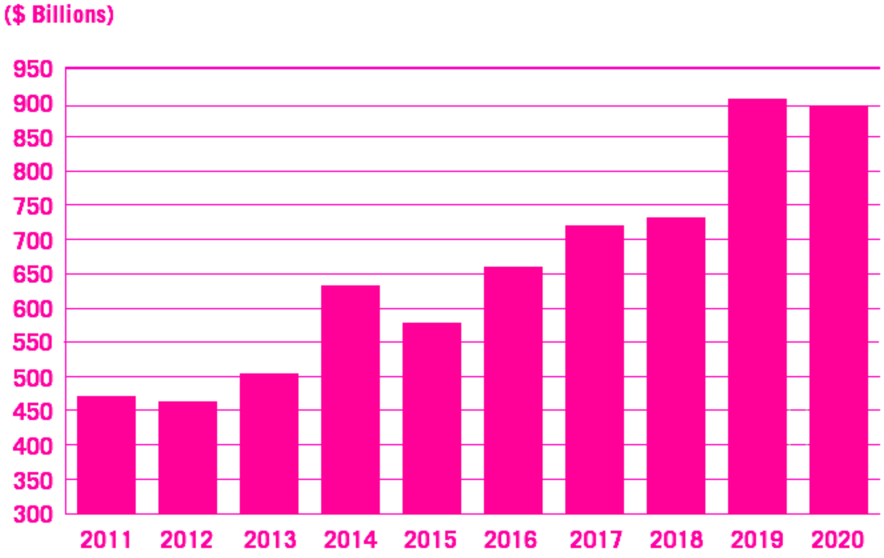
Source: EEI Finance Department and S&P Global Market Intelligence.

gregate total returns in excess of 8% (5% or more from earnings growth and 3%+ from the dividend). And whether measured by relative PE ratios or dividend yields versus Treasuries or investment-grade bonds, several analysts said utility stocks as 2021 began offered the best value in years.

Other Risks

Wall Street's ebullient recovery from March lows rests on a premise yet to be fully tested — that pre-crisis economic strength will return and persist, and along with it corporate earnings gains. Utilities face a related risk: that sluggish wage growth in a Covid-impaired economy provokes regulatory pushback on rate relief needed to fund aggressive capex programs, which in turn cools outlooks for dividend and earnings growth. The public's demand for cleaner

EEI Index Market Capitalization 2011–2020

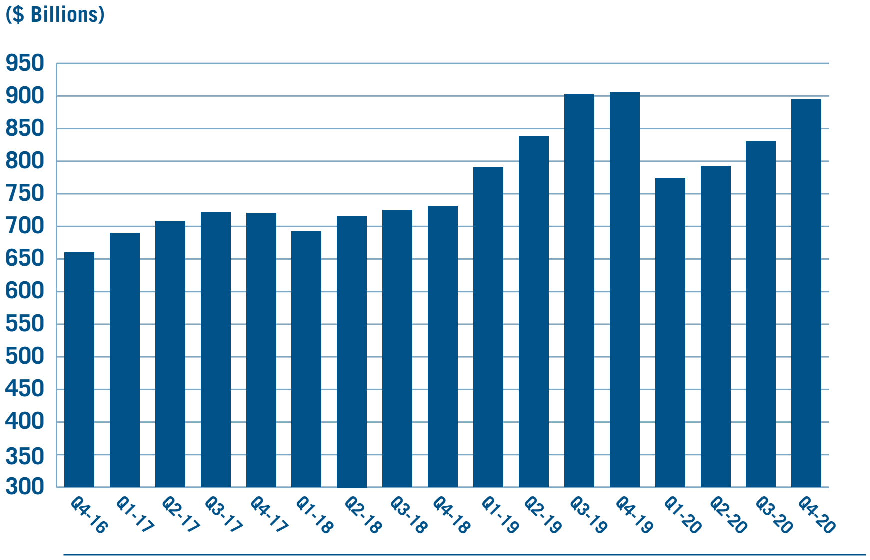


Note: Results are as of December 31 of each year.

Source: EEI Finance Department and S&P Global Market Intelligence.

EEI Index Market Capitalization

December 31, 2016–December 31, 2020



Source: EEI Finance Department and S&P Global Market Intelligence.

energy along with good local jobs created throughout the utility capex supply chain offer some protection against punitive treatment by regulators, but no guarantee. Stable fuel costs and low interest rates have kept bill pressures muted in recent years, but neither trend can continue indefinitely. Even interest rates, which have confounded rate-rise prophets for 40 years, can't go down forever. And if the V-shaped recovery thesis fails, managing regulatory risk and financing needed capex through customer rates may become more challenging than it has been in recent years.

Dividends

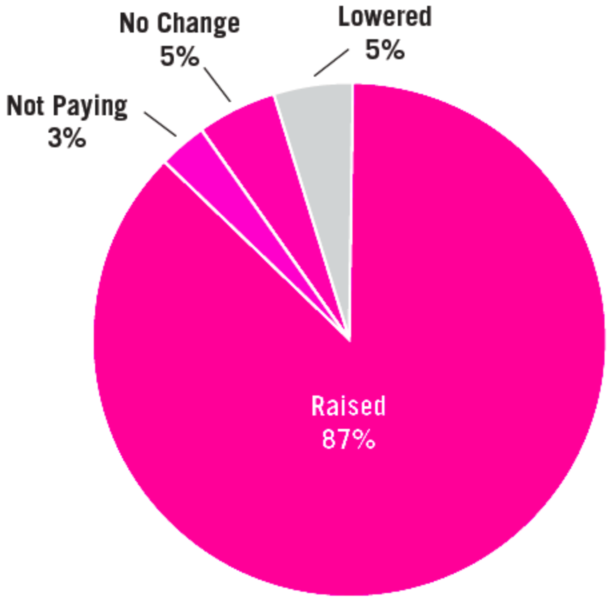
The investor-owned electric utility industry continued its long-term trend of widespread dividend increases in 2020. A total of 34 companies increased or reinstated their dividend compared to 37 in 2019, 39 in 2018, 38 in 2017, 40 in 2016 and 36 to 40 companies annually from 2012 through 2015.

The percentage of companies that raised or reinstated their dividend in 2020 was 87%, only slightly below the record high 93% in both 2019 and 2018 and consistent with the historically high 88% in 2017, 91% in 2016 and 85% in 2015. Only 27 of the 65 utilities tracked by EEI increased their dividend in 2003, just prior to the passage of legislation that reduced dividend tax rates. M&A activity reduced the number of publicly traded utilities included in the EEI Index from 65 in 2003 to 39 at year-end 2020. The record high 93% noted above is based on data beginning in 1988.

As shown in the Dividend Patterns table, 38 of the 39 publicly traded utilities in the EEI Index were paying a common stock dividend as of December 31, 2020. Each company is limited to one action per year in the table. For example, if a company raised its dividend twice during a year, that counts as one in the Raised column. Companies generally use the same quarter each year for dividend changes, with Q1 the most common for electric utilities.

2020 Dividend Patterns

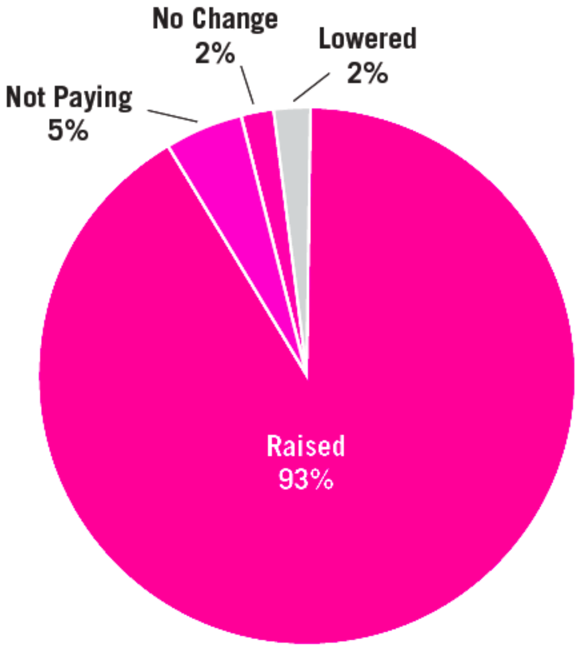
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

2019 Dividend Patterns

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

2020 Increases Average 5.1%

The average dividend increase in 2020 was 5.1%, with a range of 0.6% to 12.0% and a median increase of 5.3%. NextEra Energy (+12.0% in Q1), Sempra Energy (+8.0% in Q1), WEC Energy (+7.2% in Q1) and DTE Energy (+7.2% in Q4) posted the largest percentage increases.

NextEra Energy, headquartered in Juno Beach, Florida, increased its quarterly dividend from $1.25 to $1.40 per share during the first quarter. The increase is consistent with its plan, announced in 2018, to target 12% to 14% annual growth in its dividend per share through at least 2020, measured off a 2017 base. NextEra also recorded the industry's highest percentage increase in 2019 (+12.6%), the second-highest in 2018 (+13.0%) and the highest in both 2017 (+12.9%) and 2016 (+13.0%, along with Edison International and DTE Energy).

Sempra Energy, based in San Diego, California, raised its quarter-

Dividend Patterns 1996–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Raised	No Change	Lowered	Omitted*	Reinstated	Not Paying	Total	Dividend Payout Ratio
1996	48	44	2	1	1	2	98	70.7%
1997	40	45	6	2	–	3	96	84.2%
1998	40	37	7	–	–	5	89	82.1%
1999	29	45	4	–	3	2	83	74.9%
2000	26	39	3	1	–	2	71	63.9%
2001	21	40	3	2	–	3	69	64.1%**
2002	26	27	6	3	–	3	65	67.5%
2003	26	24	7	2	1	5	65	63.7%
2004	35	22	1	–	–	7	65	67.9%
2005	34	22	1	1	2	5	65	66.5%
2006	41	17	–	–	–	6	64	63.5%
2007	40	15	–	–	3	3	61	62.1%
2008	36	20	1	–	1	1	59	66.8%
2009	31	23	3	–	–	1	58	69.6%
2010	34	22	–	–	–	1	57	62.0%
2011	31	22	–	1	1	–	55	62.8%
2012	36	14	–	–	1	–	51	64.2%
2013	36	12	1	–	–	–	49	61.5%
2014	38	9	1	–	–	–	48	60.4%
2015	39	7	–	–	–	–	46	67.0%
2016	40	4	–	–	–	–	44	62.9%
2017	38	4	–	1	–	–	43	64.0%
2018	39	1	1	–	–	1	42	63.9%
2019	37	2	–	–	–	1	40	62.6%
2020	34	2	2	–	–	1	39	65.3%

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Average of the Increased Dividend Actions ***	6.8%	7.2%	5.3%	5.7%	5.8%	5.6%	5.6%	5.7%	5.1%	5.1%
Average of the Declining Dividend Actions ***	(100.0%)	NA	(41.0%)	(34.5%)	NA	NA	NA	(79.8%)	NA	(40.6%)

* Omitted in current year. This number is not included in the Not Paying column.

** * Prior to 2000: Total industry dividends/total industry earnings. Starting in 2000: Average of all companies paying dividend.

*** Excludes companies that omitted or reinstated dividends.

2020 current year figures reflect dividend changes (raised, lowered, etc.) through 12/31/2020 and earnings and dividends through 12/31/2020 (payout ratio).

Source: S&P Global Market Intelligence and EEI Finance Department ly dividend from $0.9675 to $1.045 per share in Q1, marking its tenth consecutive annual increase. Sempra increased its dividend by more than 10% annually, on average, over the past ten years.

WEC Energy Group, headquartered in Milwaukee, Wisconsin, raised its quarterly dividend from $0.59 to $0.6325 in the first quarter. This marked its 310th consecutive quarterly dividend, dating back to 1942, and its 17th straight annual increase. WEC Energy continues to target a dividend payout ratio of 65% to 70% of earnings.

DTE Energy, based in Detroit, Michigan, increased its quarterly dividend from $1.0125 to $1.085 per share in Q4. DTE has issued a cash dividend for more than 100 years.

The industry's average and median increases have been relatively consistent in recent years. The average was 5.1% in 2019, 5.7% in 2018 and 5.6% in 2017 and 2016. The median was 4.9% in 2019, 5.5% in 2018 and 2017 and 5.1% in 2016.

CenterPoint Energy (CNP), based in Houston, Texas, lowered its quarterly dividend from $0.29 to $0.15 per share in Q2. The decrease was driven by the announcement that Enable Midstream Partners, of which CNP owns 53.7%, planned to cut its distributions by 50% thus impacting CNP's cash flow. CenterPoint subsequently increased its quarterly dividend to $0.16 per share in Q4.

Dominion Energy, headquartered in Richmond, Virginia, reduced its quarterly dividend from $0.94 to $0.63 per share in Q4. The decrease relates to the near-term cash flow impact of Dominion's sale of its natural gas transmission and storage assets to Berkshire Hathaway Energy, announced in July. Beginning in 2022, Dominion expects annual dividend-per-share growth of 6%.

Sector Comparison Dividend Payout Ratio

For 12-month period ending 12/31/20

Sector	Payout Ratio (%)
EEI Index Companies*	**65.8%**
Industrial	66.5%
Utilities	64.3%
Consumer Staples	56.7%
Materials	49.4%
Consumer Discretionary	39.2%
Financial	38.1%
Technology	30.2%
Health Care	28.9%
Energy	NM

* For this table, EEI (1) sums dividends and (2) sums earnings of all index companies and then (3) divides to determine the comparable DPR.

Assumptions:

1. EEI Index Companies payout ratio based on LTM common dividends paid and income before nonrecurring and extraordinary items.

2. S&P sector payout ratios based on 2020E dividends and earnings per share (estimates as of 12/31/2020).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, S&P Global Market Intelligence, and EEI Finance Department.

Payout Ratio and Dividend Yield

The industry's dividend payout ratio was 65.8% for the twelve months ended December 31, 2020, exceeding all other U.S. business sectors. The industry's payout ratio was 65.3% when measured as an un-weighted average of individual company ratios. From 2000 through 2019, the industry's annual payout ratio ranged from 60.4% to 69.6%.

While the industry's net income has fluctuated from year to year, its payout ratio has remained relatively consistent after eliminating nonrecurring and extraordinary items from earnings. We use the following

Sector Comparison, Dividend Yield

As of December 31, 2020

Sector	Dividend Yield (%)
EEI Index Companies	**3.6%**
Energy	5.9%
Utilities	3.3%
Consumer Staples	2.6%
Financial	2.1%
Materials	1.8%
Health Care	1.6%
Industrial	1.5%
Technology	0.9%
Consumer Discretionary	0.7%

Assumptions:
1. EEI Index Companies' yield based on last announced, annualized dividend rates (as of 12/31/2020); S&P sector yields based on 2020E cash dividends (estimates as of 12/31/2020).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, S&P Global Market Intelligence and EEI Finance Department.

Category Comparison, Dividend Yield

As of December 31, 2020

Category	Dividend Yield
EEI Index	**3.6%**
Regulated	3.6%
Mostly Regulated	3.4%

Regulated: 80% or more of total assets are regulated

Mostly Regulated: Less than 80% of total assets are regulated

Source: S&P Global Market Intelligence, company reports and EEI Finance Department

Category Comparison, Dividend Payout Ratio

Category	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
EEI Index	**62.8**	**64.2**	**61.5**	**60.4**	**67.0**	**62.9**	**64.0**	**63.9**	**62.6**	**65.3**
Regulated	63.4	62.1	60.5	59.4	68.7	61.1	68.7	60.1	62.1	65.3
Mostly Regulated	63.1	69.7	64.7	63.8	62.6	68.0	53.3	72.8	64.1	65.2
Diversified	54.7	53.4	44.7	56.4	64.9	64.6	–	–	–	–

Regulated: 80% or more of total assets are regulated
Mostly Regulated: Less than 80% of total assets are regulated
Diversified: Prior to 2017, less than 50% of total assets are regulated

*2020 figures reflect earnings and dividends through 12/31/2020.

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department approach when calculating the industry's dividend payout ratio:

1. Non-recurring and extraordinary items are eliminated from earnings.
2. Companies with negative adjusted earnings are eliminated.
3. Companies with a payout ratio in excess of 200% are eliminated.

The industry's average dividend yield was 3.6% on December 31, 2020, trailing only the Energy sector's 5.9%. The year-end yield was 3.0% in 2019 and 3.4% in each of the three previous years. In 2020, the industry's strong dividend activity and lower overall stock prices resulted in the higher average yield. The market cap-weighted EEI Index had a total return of negative 1.2% in 2020.

We calculate the industry's aggregate dividend yield using an unweighted average of the yields of EEI Index companies paying a dividend. The strong yields prevalent among most electric utilities have helped support their share prices over the past decade, particularly given the period's historically low interest rates.

Business Category Comparison

The Regulated category's dividend payout ratio was 65.3% for the 12 months ended December 31, 2020 compared to 65.2% for the Mostly Regulated category. Among these two categories, the Regulated group produced the highest annual payout ratio in 2020, 2017, 2015, 2011, 2010 and in each year from 2003 through 2008.

The Regulated and Mostly Regulated average dividend yields were 3.6% and 3.4% on December 31, 2020, following yields of 3.0% and 3.1% at year-end 2019. The dividend yield for both at year-ends 2018 and 2017 was 3.4%.

Biden Proposal on Dividend Tax Rates

Although the new Administration hasn't put forward tax proposals, the Biden campaign proposed corporate and personal tax code changes including an increase in capital gains and dividend tax rates for the highest individual tax bracket, applying ordinary income tax rates for those with incomes over $1 million. The highest individual income tax rate will likely increase from 37.0% to the pre-Tax Cuts & Jobs Act (TCJA) highest rate of 39.6%. No other income tax bracket would incur a dividend tax rate increase.

The top tax rate for dividends and capital gains is currently 20%, with 2021 income thresholds of $501,600 for couples and $445,850 for individuals. For taxpayers below these thresholds, dividends and capital gains are currently taxed at rates of 15% or 0%, depending on a filer's income. A 3.8% Medicare tax that was included in 2010 health care legislation is also applied to all investment income for couples earning more than $250,000 ($200,000 for singles).

Low dividend tax rates support the industry's ability to attract capital for investment. Maintaining parity between dividend and capital gains tax rates is crucial to avoid a disadvantage for companies that rely on a strong dividend to attract investors. The TCJA, which was signed into law in December of 2017, maintained pre-existing tax rates for dividends and capital gains.

Dividend Summary

As of December 31, 2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
ALLETE, Inc.	ALE	MR	$2.47	79.3%	4.0%	Raised	$2.47	$2.35	2020 Q1
Alliant Energy Corporation	LNT	R	$1.52	60.4%	2.9%	Raised	$1.52	$1.42	2020 Q1
Ameren Corporation	AEE	R	$2.06	56.3%	2.6%	Raised	$2.06	$1.98	2020 Q4
American Electric Power Company, Inc.	AEP	R	$2.96	64.9%	3.6%	Raised	$2.96	$2.80	2020 Q4
AVANGRID, Inc.	AGR	MR	$1.76	96.5%	3.9%	Raised	$1.76	$1.73	2018 Q3
Avista Corporation	AVA	R	$1.62	85.1%	4.0%	Raised	$1.62	$1.55	2020 Q1
Black Hills Corporation	BKH	R	$2.26	54.3%	3.7%	Raised	$2.26	$2.14	2020 Q4
CenterPoint Energy, Inc.	CNP	R	$0.64	28.8%	3.0%	Raised	$0.64	$0.60	2020 Q4
CMS Energy Corporation	CMS	R	$1.63	60.8%	2.7%	Raised	$1.63	$1.53	2020 Q1
Consolidated Edison, Inc.	ED	R	$3.06	66.6%	4.2%	Raised	$3.06	$2.96	2020 Q1
Dominion Resources, Inc.	D	R	$2.52	129.7%	3.4%	Lowered	$2.52	$3.76	2020 Q4
DTE Energy Company	DTE	MR	$4.34	54.1%	3.6%	Raised	$4.34	$4.05	2020 Q4
Duke Energy Corporation	DUK	R	$3.86	67.3%	4.2%	Raised	$3.86	$3.78	2020 Q3
Edison International	EIX	R	$2.65	40.7%	4.2%	Raised	$2.65	$2.55	2020 Q4
Entergy Corporation	ETR	R	$3.80	52.2%	3.8%	Raised	$3.80	$3.72	2020 Q4
Evergy, Inc.	EVRG	R	$2.14	66.4%	3.9%	Raised	$2.14	$2.02	2020 Q4
Eversource Energy	ES	R	$2.27	59.9%	2.6%	Raised	$2.27	$2.14	2020 Q1
Exelon Corporation	EXC	MR	$1.53	59.2%	3.6%	Raised	$1.53	$1.45	2020 Q1
FirstEnergy Corp.	FE	R	$1.56	84.2%	5.1%	Raised	$1.56	$1.52	2019 Q4
Hawaiian Electric Industries, Inc.	HE	MR	$1.32	75.7%	3.7%	Raised	$1.32	$1.28	2020 Q1
IDACORP, Inc.	IDA	R	$2.84	57.9%	3.0%	Raised	$2.84	$2.68	2020 Q4
MDU Resources Group, Inc.	MDU	MR	$0.85	42.6%	3.2%	Raised	$0.85	$0.83	2020 Q4
MGE Energy, Inc.	MGEE	R	$1.48	56.0%	2.1%	Raised	$1.48	$1.41	2020 Q3
NextEra Energy, Inc.	NEE	MR	$1.40	78.1%	1.8%	Raised	$1.40	$1.25	2020 Q1
NiSource Inc.	NI	R	$0.84	50.3%	3.7%	Raised	$0.84	$0.80	2020 Q1
NorthWestern Corporation	NWE	R	$2.40	77.5%	4.1%	Raised	$2.40	$2.30	2020 Q1
OGE Energy Corp.	OGE	R	$1.61	51.9%	5.1%	Raised	$1.61	$1.55	2020 Q4
Otter Tail Corporation	OTTR	R	$1.48	62.9%	3.5%	Raised	$1.48	$1.40	2020 Q1
PG&E Corporation	PCG	R	–	0.0%	0.0%	Lowered	–	$2.12	2017 Q4
Pinnacle West Capital Corporation	PNW	R	$3.32	61.5%	4.2%	Raised	$3.32	$3.13	2020 Q4
PNM Resources, Inc.	PNM	R	$1.31	52.0%	2.7%	Raised	$1.31	$1.23	2020 Q4
Portland General Electric Company	POR	R	$1.63	90.3%	3.8%	Raised	$1.63	$1.54	2020 Q3
PPL Corporation	PPL	R	$1.66	86.8%	5.9%	Raised	$1.66	$1.65	2020 Q1
Public Service Enterprise Group Incorporated	PEG	MR	$1.96	55.7%	3.4%	Raised	$1.96	$1.88	2020 Q1
Sempra Energy	SRE	MR	$4.18	45.8%	3.3%	Raised	$4.18	$3.87	2020 Q1
Southern Company	SO	R	$2.56	75.3%	4.2%	Raised	$2.56	$2.48	2020 Q2
Unitil Corporation	UTL	R	$1.50	70.2%	3.4%	Raised	$1.50	$1.48	2020 Q1
WEC Energy Group, Inc.	WEC	R	$2.53	64.4%	2.7%	Raised	$2.53	$2.36	2020 Q1
Xcel Energy Inc.	XEL	R	$1.72	58.9%	2.6%	Raised	$1.72	$1.62	2020 Q1
Industry Average				**65.3%**	**3.6%**				

NOTES

Business Segmentation: Assets as of 12/31/2019

R = Regulated: 80% or more of total assets are regulated. **MR = Mostly Regulated:** Less than 80% of total assets are regulated.

Dividend Per Share: Per share amounts are annualized declared figures as of 12/31/2020.

Dividend Payout Ratio: Dividends paid for 12 months ended 12/31/2020 divided by net income before nonrecurring and extraordinary items for 12 months ended 12/31/2020. While net income is after-tax, nonrecurring and extraordinary items are pre-tax, as there is no consistent method of gathering these items on a tax adjusted basis under current reporting guidelines. On an individual company basis, the Payout Ratio in the table could differ slightly from what is reported directly by the company.

"NM" applies to companies with negative earnings or payout ratios greater than 200%.

Dividend Yield: Annualized Dividends Per Share at 12/31/2020 divided by stock price at market close on 12/31/2020.

By Business Segment: Average of Dividend Payout Ratios and Dividend Yields for companies within these business segments.

Source: EEI Finance Department and S&P Global Market Intelligence.

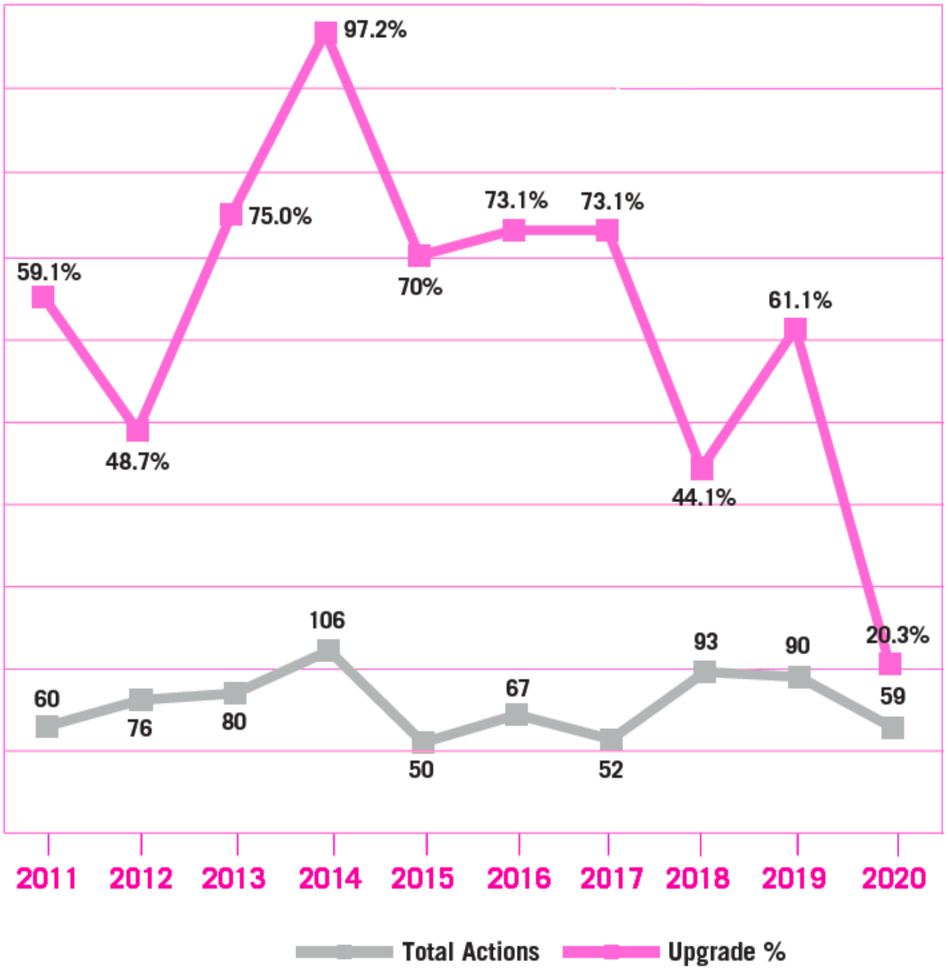
Credit Ratings

The industry's average parent company credit rating in 2020 remained at BBB+ for a seventh straight year, although three parent-level downgrades outnumbered one upgrade and caused a slight underlying weakening in general holding company credit quality. There were only 59 total actions — 12 upgrades and 47 downgrades — affecting both parents and subsidiaries. This pace was below the 73-action annual average of the previous ten calendar years and the fourth-lowest annual total in our historical dataset (back to 2000).

On December 31, 2020, 59.1% of parent company ratings outlooks were "stable", 6.8% were "positive" or "watch-positive", and 2.3% were "developing". A relatively high 31.8% were "negative" or "watch-negative", up from 18.2% at year-end 2019 and 23.4% at year-end 2018. While the economic impact of COVID-19 initially caused Standard and Poor's (S&P) to revise its North American regulated utility industry outlook (including electric, gas and water) to negative from stable, Moody's and Fitch each maintained a stable outlook for their broad U.S. regulated utility sectors. At year end, all three agencies noted that regulated utilities managed the pandemic well.

Direction of Rating Actions

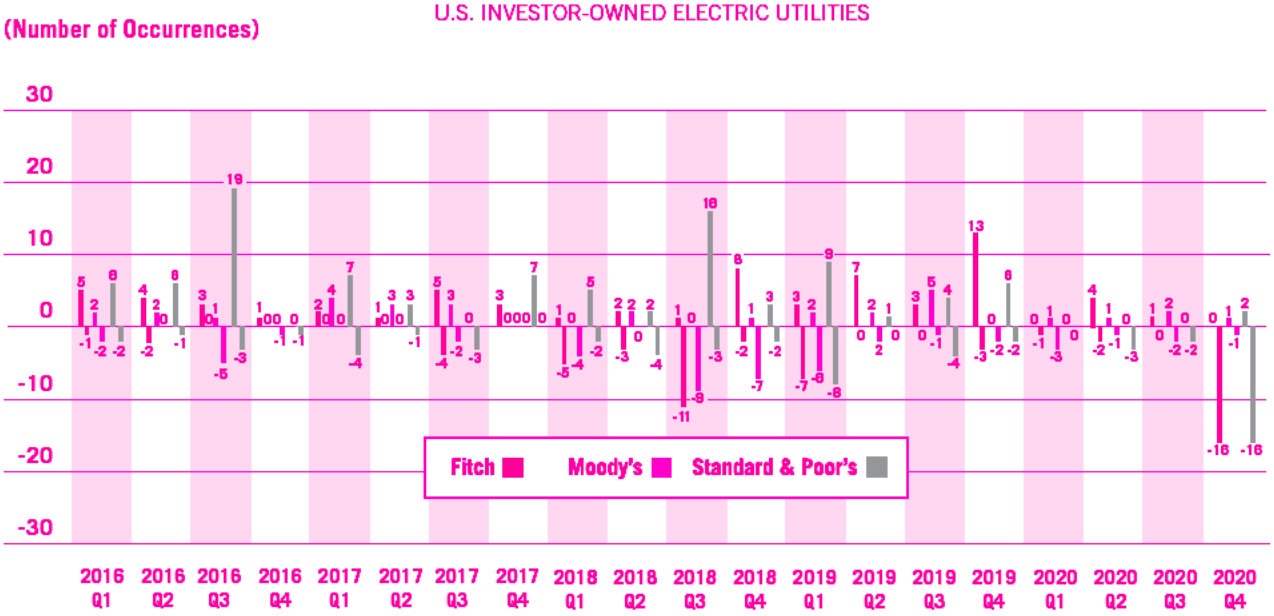
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: Fitch Ratings, Moody's, and Standard & Poor's.

Credit Rating Agency Upgrades and Downgrades 2016 Q1–2020 Q4

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Note: Data presents the number of occurrences and includes each event, even if multiple actions occurred for a single company.

Source: Fitch Ratings, Moody's, and Standard & Poor's.

Credit Rating Agency Upgrades and Downgrades 2016 Q1–2020 Q4

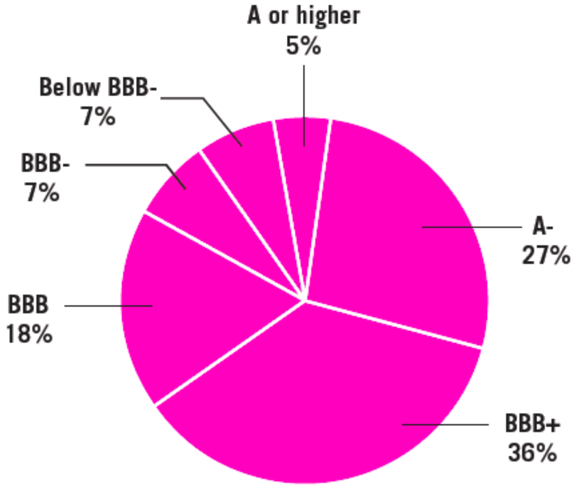
	2016		2017		2018		2019		2020	
	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades
Fitch										
Q1	5	(1)	2	0	1	(5)	3	(7)	0	(1)
Q2	4	(2)	1	0	2	(3)	7	0	4	(2)
Q3	3	0	5	(4)	1	(11)	3	0	1	0
Q4	1	0	3	0	8	(2)	13	(3)	0	(16)
Total	**13**	**(3)**	**11**	**(4)**	**12**	**(21)**	**26**	**(10)**	**5**	**(19)**
Moody's										
Q1	2	(2)	4	0	0	(4)	2	(6)	1	(3)
Q2	2	0	3	0	2	0	2	(2)	1	(1)
Q3	1	(5)	3	(2)	0	(9)	5	(1)	2	(2)
Q4	0	(1)	0	0	1	(7)	0	(2)	1	(1)
Total	**5**	**(8)**	**10**	**(2)**	**3**	**(20)**	**9**	**(11)**	**5**	**(7)**
S&P										
Q1	6	(2)	7	(4)	5	(2)	9	(8)	0	0
Q2	6	(1)	3	(1)	2	(4)	1	0	0	(3)
Q3	19	(3)	0	(3)	16	(3)	4	(4)	0	(2)
Q4	0	(1)	7	0	3	(2)	6	(2)	2	(16)
Total	**31**	**(7)**	**17**	**(8)**	**26**	**(11)**	**20**	**(14)**	**2**	**(21)**

Note: Chart depicts the number of occurrences and includes each event, even if multiple downgrades occurred for a single company.

Source: Fitch Ratings, Moody's, and Standard & Poor's.

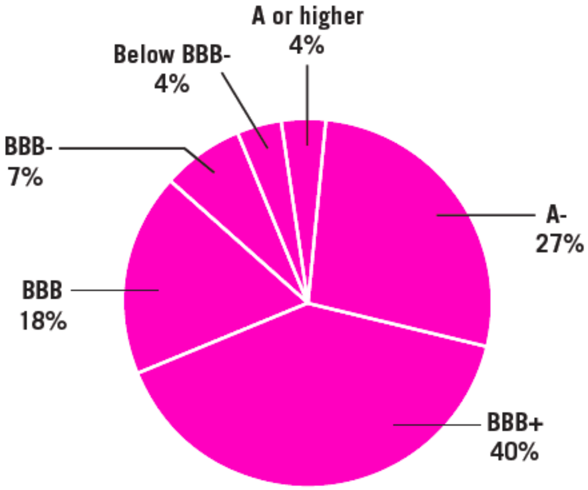
Bond Ratings December 31, 2020
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Bond Ratings December 31, 2019
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Electric utility industry credit quality generally improved over the past decade. Aggregate parent-level credit strengthened in each year other than 2020, 2019 and 2012. And across EEI's larger universe of parents and subsidiaries, the five-year period 2013 through 2017 produced the five highest upgrade percentages in our historical data. Moreover, upgrades outnumbered downgrades in seven of the past ten calendar years with an annual average upgrade percentage of 62.8%.

EEI captures upgrades and downgrades at both the parent and subsidiary levels. The industry's average credit rating and outlook are the unweighted averages of all S&P parent holding company ratings and outlooks. However, our upgrade/downgrade totals reflect all actions by the three major ratings agencies within a parent holding company, including those at subsidiaries. Our universe of 44 U.S. electric utilities at December 31, 2020 included 39 electric utility holding companies that are publicly traded and five companies that are not listed on U.S. stock exchanges because they are owned by holding companies not primarily engaged in the business of providing retail electric distribution services in the United States.

Credit Actions at Parent Level

Parent-level ratings actions in 2020 included three downgrades, one upgrade and one reinstatement. By comparison, there were five downgrades and one upgrade in 2019 and six upgrades and two downgrades in 2018.

PNM Resources

On April 6, S&P lowered PNM Resources' parent-level rating to BBB from BBB+ due to weakened financial metrics. The agency noted PNM's funds from operations to debt ratio was 15.8% in 2018 and 15.5% in 2019 and said the pandemic's revenue impact may further pressure the company's financials. S&P's stable outlook is based in part on a belief that PNM can securitize costs related to closing its San Juan coal-fired power plant.

ALLETE

On April 22, S&P downgraded ALLETE to BBB from BBB+ on deteriorating credit metrics that have pushed funds from operations to debt below 20%. The company's credit metrics were expected to continue to be pressured by weakened economic conditions related to COVID-19 and an elevated capital spending plan. S&P's stable outlook reflects ALLETE's focus on regulated utility operations and a belief it can maintain funds from operations to debt at 18% to 20% for the next one to two years.

PG&E

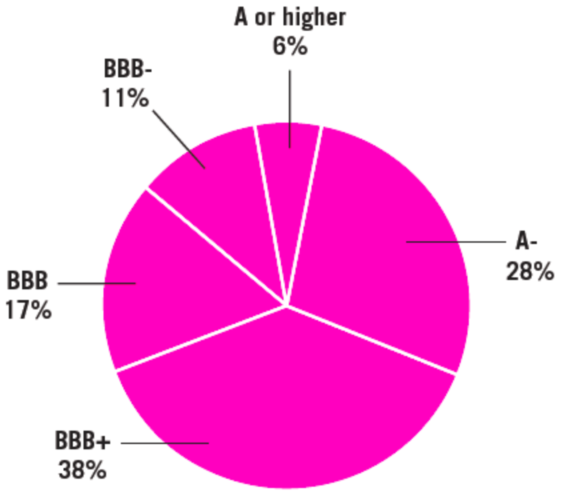
S&P assigned a BB- rating to PG&E on June 15 as the company prepared to emerge from Chapter 11 bankruptcy. S&P's previous rating was D, which last appeared in our quarter-ending tracking on December 31, 2019. S&P did not have a rating assigned to PG&E at quarter-end March 31, 2020. On July 1, PG&E Corporation and subsidiary Pacific Gas & Electric Company emerged from Chapter 11, successfully completing a restructuring process.

FirstEnergy

During the fourth quarter, S&P downgraded FirstEnergy's issuer credit rating to BB from BBB following the termination of three executives, including the CEO. The terminations related to legal and other regulatory challenges the company is facing, with S&P citing concerns over internal controls. S&P also lowered the rating for thirteen of FirstEnergy's subsidiaries.

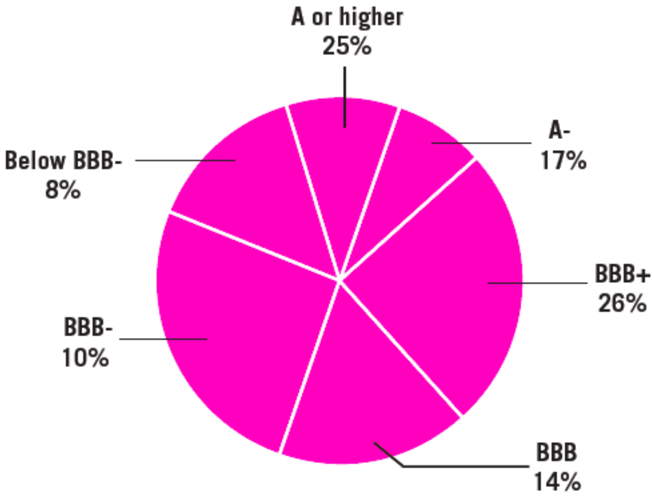
Bond Ratings December 31, 2018
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Bond Ratings December 31, 2001
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



DPL

On November 3, S&P upgraded the issuer credit rating for DPL, Inc. to BB+ from BB based on an upgrade for its parent company, AES Corp., which reflected an improved financial risk profile. S&P noted that AES has de-risked its business portfolio by focusing on rate-based utilities and long-term contracted businesses while also narrowing its geographical scope to 13 countries from 29. S&P also upgraded DPL's principal subsidiary, Dayton Power and Light Co. (DP&L). The outlooks for both DPL and DP&L remain developing, reflecting potential for another upgrade in the coming months.

Ratings Activity Slows in 2020

The 59 rating changes during 2020 (upgrades plus downgrades) was the fourth-lowest total for any year back to our dataset's inception on January 1, 2000. By comparison, there were 90 actions in 2019 and an annual average of 73 over the last ten calendar years. The previous two calendar years were very active, ranking with 2014 as the most active of the last decade. As a result, the slowdown in 2020 is not surprising. Although COVID-19 was referenced in some of 2020's downgrades, it was cited only as a factor that could exacerbate existing trends. Its impact began only after much of the first quarter's actions had occurred and became secondary to other considerations as the year wore on.

The industry's 12 upgrades in 2020 were outnumbered by 47 downgrades, for an upgrade percentage of 20.3%, which made 2020 only the second year since 2013 with more downgrades than upgrades. In 2019, the industry's 55 upgrades outnumbered 35 downgrades for a 61.1% upgrade percentage, up from 44.1% in 2018. The five-year period 2013 through 2017 produced the five-highest upgrade percentages in our historical data. Upgrades outnumbered downgrades in seven of the past ten calendar years, with an annual average upgrade percentage of 62.8%.

Rating Agency Activity table presents quarterly activity by all three ratings agencies. Following are full-year totals for 2020:

- Fitch (5 upgrades, 19 downgrades)
- Moody's (5 upgrades, 7 downgrades)
- Standard & Poor's (2 upgrades, 21 downgrades)

Merger Benefits Support Upgrades

Several of the year's upgrades were based on favorable impacts on subsidiaries from recently completed mergers. Four went to Dominion Energy subsidiaries acquired in January 2019 through Dominion's purchase of SCANA. On January 30, 2020, Moody's upgraded Dominion Energy South Carolina (DESC) to Baa2 from Baa3, citing an $875 million equity infusion received from its parent company, the retirement of approximately $1.0 billion of debt and a pending rate case proceeding. On May 29, Fitch upgraded DESC to BBB+ from BBB, Public Service Company of North Carolina (PSNC) to BBB+ from BBB, and SCANA to BBB from BBB-. Cited reasons for DESC's upgrade included resolution of legal and regulatory issues, an approved regulatory plan, an upcoming base rate case, the merger with Dominion Energy, improved credit metrics and a favorable service territory. Reasons cited for PSNC's upgrade included Dominion's ownership upon merger approval, a supportive regulatory environment, improving credit metrics, demand and capex growth, and limited commodity risk.

On April 13, Fitch upgraded NextEra Energy subsidiary Gulf Power to A from A-, reflecting better than expected financial performance driven by a reduction in operating expenses. In addition, NextEra injected $400 million of equity into Gulf Power in the first two months of 2020, which strengthened Gulf Power's capital structure. Specific key drivers that Fitch cited for the upgrade included Gulf Power's transformation (which includes the modernization of its generation

Rating Agency Activity

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Total Ratings Changes	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Fitch	25	26	23	14	11	16	15	33	36	24
Moody's	11	20	17	85	12	13	12	23	20	12
Standard & Poor's	30	30	40	7	27	38	25	37	34	23
Total	**66**	**76**	**80**	**106**	**50**	**67**	**52**	**93**	**90**	**59**

Source: Fitch Ratings, Moody's, Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

fleet, lower operating costs and the creation of a transmission interconnection with FPL), benefits from integration with FPL, a limited impact from the coronavirus, a material jump in capex, constructive regulation and a general expectation that credit metrics will strengthen.

On May 27, Moody's upgraded Jersey Central Power & Light (JCP&L) to A3 from Baa1, projecting that JCP&L's improved financial profile will remain stable for the next two to three years as New Jersey's state regulatory environment remains supportive. Moody's expects JCP&L, a FirstEnergy subsidiary, to maintain its ratio of cash flow to debt in the low 20% range for a sustained period of time.

Mississippi Power, a Southern Company subsidiary, received upgrades from both Moody's and Fitch during Q3. On August 27, Moody's upgraded Mississippi Power to Baa1 from Baa2, reflecting an improved relationship with state regulators and a stronger financial profile. On September 25, S&P raised Mississippi Power's rating to BBB+ from BBB, citing a significant improvement in its regulatory construct.

Deteriorating Metrics, Regulatory Risk Drive Downgrades

Many of the year's downgrades point to actual or projected negative impacts on key credit metrics. Increased regulatory risk was cited as a primary underlying driver for several and one downgrade resulted from increased business risk from an acquisition. Although the impact of COVID-19 was frequently referenced in individual company downgrades, it was mentioned only as an additional factor that could exacerbate an existing trend.

On February 19, Fitch downgraded CenterPoint Energy Houston Electric (CEHE) to BBB+ from A- following CEHE's rate case settlement with the Public Utilities Commission of Texas. Fitch believes the settlement signals a more challenging regulatory environment in Texas for CEHE. On March 4, Moody's downgraded CEHE to Baa1 from A3 noting that financial measures will weaken more than originally projected following 2017's tax reform (as unprotected deferred taxes are refunded to customers) along with an anticipated lower return in its pending final rate order. Although Moody's views the Texas regulatory environment as supportive of credit quality, the agency noted that CEHE's ratio of cash flow pre-working capital to debt is falling into the 15% to 16% range, down from around 19% historically.

On March 17, Moody's downgraded Consolidated Edison (ConEd) to Baa2 from Baa1 and subsidiary Consolidated Edison Company of New York (CECONY) to Baa1 from A3. Moody's noted that despite $1.7 billion of planned equity through 2022, ConEd's key credit ratios will decline as a result of up to $3.8 billion of new debt planned through 2022 and weaker cash flow at CECONY. Following the approval of a recent rate order, CECONY is expected to generate a ratio of cash flow to debt between 14% and 16% over the next three years, in-line with Moody's Baa1 peer ratios. ConEd's roughly $2.0 billion of debt is structurally subordinate to that of its operating companies, with approximately 85% of consolidated revenue represented by CECONY. As a result, Moody's downgraded ConEd's rating in-step with CECONY's, despite ConEd's relatively strong and stable financial profile for a utility holding company focused mostly on transmission and distribution.

On April 6, Fitch downgraded DPL to BB from BB+ citing a potential weakening of credit metrics due to regulatory challenges in Ohio. On April 15, Fitch downgraded DTE Energy to BBB from BBB+ referencing the increased leverage and business risk associated with a recent midstream acquisition.

On June 9, Moody's downgraded Sempra Energy to Baa2 from Baa1 citing consolidated financial metrics that have remained below Moody's Baa1 downgrade threshold for the past few years and that are expected to remain below the threshold through 2022. The agency said it expects Sempra's cash flow to debt ratio will remain in the 16% range, which is more appropriate for a Baa2 rating given Sempra's consolidated risk profile.

On August 20, Moody's downgraded Ohio Power to A3 from A2 and Public Service of Oklahoma to Baa1 from A3. The downgrades for both of these American Electric Power subsidiaries reflected weakened financial metrics from large capital programs with increased use of leverage.

On October 8, S&P downgraded Entergy New Orleans to BBB from

S&P Utility Credit Ratings Distribution by Company Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	2016		2017		2018		2019		2020	
	#	%	#	%	#	%	#	%	#	%
Regulated										
A or higher	2	6%	2	6%	1	3%	1	3%	1	3%
A-	10	28%	12	34%	11	32%	11	31%	11	32%
BBB+	13	36%	10	29%	11	32%	11	31%	10	29%
BBB	8	22%	7	20%	7	21%	8	23%	7	21%
BBB-	3	8%	4	11%	4	12%	2	6%	2	6%
Below BBB-	0	0%	0	0%	0	0%	2	6%	3	9%
Total	36	100%	35	100%	34	100%	35	100%	34	100%
Mostly Regulated										
A or higher	1	8%	1	7%	2	15%	1	10%	1	10%
A-	2	17%	2	14%	2	15%	1	10%	1	10%
BBB+	7	58%	7	50%	7	54%	7	70%	6	60%
BBB	0	0%	2	14%	1	8%	0	0%	1	10%
BBB-	1	8%	1	7%	1	8%	1	10%	1	10%
Below BBB-0	1	8%	1	7%	0	0%	0	0%	0	0%
Total	12	100%	14	100%	13	100%	10	100%	10	100%

Note: Totals may not equal 100.0% due to rounding.
Refer to page v for category descriptions.
Source: Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

BBB+ over severe storm and hurricane risk in the utility's service territory. S&P said its negative outlook for this Entergy subsidiary reflects its small service territory, ongoing exposure to severe storms and hurricanes, and the agency's expectation of weaker financial measures partly from higher capital spending and elevated leverage.

S&P downgraded two generation subsidiaries based on potential asset divestitures. On August 6, PSEG Power was downgraded to BBB from BBB+ after its parent, Public Service Enterprise Group, announced plans to explore a sale of its merchant, non-nuclear power assets. In its announcement of that decision, PSEG cited decreasing profit margins at PSEG's fossil fuel and solar assets. On November 4, Exelon Generation Company was also downgraded to BBB from BBB+ after its parent Exelon Corp. confirmed it is conducting a strategic review of its corporate structure to create value and position the business for success. This may include the possibility of separating Exelon Generation from utility operations.

Ratings by Company Category

S&P Utility Credit Rating Distribution by Company Category table presents the distribution of credit ratings over time by company category (Regulated and Mostly Regulated) for the investor-owned electric utilities. Ratings are based on S&P's long-term issuer ratings at the holding company level, with only one rating assigned per company. At December 31, 2020, the average rating for both the Regulated and Mostly Regulated categories was BBB+.

Credit Impact of COVID-19

In April 2020, S&P revised its ratings outlook for the North America regulated utility industry to negative from stable with the possibility of a one-notch decline in the industry's median credit rating, but also said it expects the industry to remain a high credit quality, investment-grade industry. Prior to the coronavirus outbreak in North America, about 25% of utilities had either a negative outlook or were on CreditWatch with negative implications. S&P viewed the economic impact of COVID-19 as a source of incremental pressure that could lead to additional downgrades and negative outlooks.

In its February 2021 update, S&P maintained its negative outlook for the industry, reflecting the weakening of credit quality in 2020 as downgrades outpaced upgrades. But S&P said that COVID-19 was not the direct culprit, as the industry has generally handled the pandemic well. S&P instead cited regulatory issues caused by COVID-19's broader impact on the U.S. economy, companies' practice of strategically managing financial measures close to their downgrade threshold with little or no cushion, as well as some specific governance matters. S&P's universe of North American utilities consists of about 250 water, gas and electric utilities.

Moody's and Fitch each maintained their stable outlook for electric utilities. In March, Moody's reported that the U.S. regulated utility sector (electric, gas and water) is better positioned than many industries to withstand the economic fallout from COVID-19. In addition to benefiting from relatively stable residential customer demand, utilities can rely on a variety of cost recovery tools provided by state regulators. Moody's stated that market volatility is the biggest risk for utilities because the sector requires external capital to meet sizeable liquidity needs. While Moody's expects utilities to generally retain unfettered access to the capital markets, it noted that the continued spread of the coro-

Long-Term Credit Rating Scales

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Moody's	Standard & Poor's	Fitch
Investment Grade	Aaa	AAA	AAA
	Aa1	AA+	AA+
	Aa2	AA	AA
	Aa3	AA-	AA-
	A1	A+	A+
	A2	A	A
	A3	A-	A-
	Baa1	BBB+	BBB+
	Baa2	BBB	BBB
	Baa3	BBB-	BBB-

	Moody's	Standard & Poor's	Fitch
Speculative Grade	Ba1	BB+	BB+
	Ba2	BB	BB
	Ba3	BB-	BB-
	B1	B+	B+
	B2	B	B
	B3	B-	B-
	Caa1	CCC+	CCC+
	Caa2	CCC	CCC
	Caa3	CCC-	CCC-
	Ca	CC	CC
	C	C	C

	Moody's	Standard & Poor's	Fitch
Default	C	D	D

Source: Fitch Ratings, Moody's, and Standard & Poor's.

navirus and mounting pressures on commercial and industrial customers could ultimately weigh on utility credit quality. In a November sector update, Moody's observed that many businesses closed or curtailed operations after the initial coronavirus outbreak, causing a sharp decline in commercial and industrial electricity sales beginning in late March. By contrast, residential electricity sales increased because of the large number of people remaining at home as well as higher-than-normal summer temperatures. Going forward, Moody's expects that higher residential demand will mitigate the loss of revenues and cash flow from commercial and industrial customers as residential sales generate a higher gross margin per kilowatt-hour.

Fitch's 2021 Outlook for North American Utilities, Power & Gas report (released December 2020) noted its stable outlook is based on the pandemic's benign direct impact on the industry and a generally favorable regulatory environment. Utilities have aggressively managed O&M costs in 2020; in combination with higher residential sales, this more than offset the impact of commercial and industrial sales declines. Fitch's stable outlook is further supported by low interest rates (given the industry's capital-intensive nature), low commodity costs, and a likely return to modest secular sales growth as the economic recovery gains strength.

Business Strategies

Business Segmentation

The industry's regulated business segments — regulated electric and natural gas distribution — grew their combined assets by $83.4 billion, or 5.6%, in 2020, extending a multi-year trend and driving a $110.4 billion, or 6.3%, increase in total industry assets. Regulated assets comprised 80.8% of the industry total, slightly below the 81.0% at year-end 2019. The Regulated Electric segment's share of total industry assets increased to 68.7% at year-end 2020 from 68.2% at year-end 2019, rising $82.5 billion, or 6.6%. The industry's three other primary business segments also grew assets in 2020. Competitive Energy assets rose by $9.7 billion, or 4.9%, driven largely by growth in merchant renewable generation. Natural Gas Distribution assets rose by $896 million, or 0.4%, while Natural Gas Pipeline assets rose $2.6 billion, or 8.0%. A record-high $132.7 billion of capital expenditures and generally constructive regulatory relations supported the significant growth in Regulated Electric assets.

Each primary business segment had lower revenue in 2020 as energy demand was broadly suppressed by the COVID-19 pandemic. The Regulated Electric business segment's revenue fell by $2.1 billion, or 0.8%, as power demand was 2.9% lower in 2020 than in 2019. Competitive Energy revenue declined by $9.7 billion, or 18.6%, Natural Gas Distribution revenue fell by $1.5 billion, or 3.3%, and Natural Gas Pipeline revenue was down by $825 million, or 15.5%. As a result, total industry revenue declined by $13.8 billion, or 3.8%, from the prior year.

2020 Revenue by Segment

Regulated Electric revenue decreased slightly in 2020, falling by $2.1 billion, or 0.8%, to $251.4 billion from $253.5 billion in 2019. Despite the drop, the segment's share of total industry revenue rose to 69.4% from 67.5% in 2019, re-

Business Segmentation—Revenues

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2020	2019r	Difference	% Change
Regulated Electric	**251,443**	**253,505**	**(2,061)**	**-0.8%**
Competitive Energy	42,463	52,150	(9,688)	-18.6%
Natural Gas Distribution	45,054	46,592	(1,539)	-3.3%
Natural Gas Pipeline	4,499	5,324	(825)	-15.5%
Other	18,592	18,218	375	2.1%
Discontinued Operations	—	—	—	0.0%
Eliminations/Reconciling Items	(10,966)	(10,894)	(72)	0.7%
Total Revenues	**351,085**	**364,895**	**(13,810)**	**-3.8%**

r = revised

Note: Difference and percent change columns may reflect rounding. Totals may reflect rounding.

Business Segmentation—Assets

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2020	12/31/2019r	Difference	% Change
Regulated Electric	1,326,815	1,244,310	82,505	6.6%
Competitive Energy	206,563	196,867	9,695	4.9%
Natural Gas Distribution	233,005	232,109	896	0.4%
Natural Gas Pipeline	35,283	32,677	2,607	8.0%
Other	129,298	117,514	11,785	10.0%
Discontinued Operations	1	3,960	(3,959)	-100.0%
Eliminations/Reconciling Items	(63,662)	(70,500)	6,839	-9.7%
Total Assets	**1,867,303**	**1,756,936**	**110,367**	**6.3%**

r = revised

Note: Difference and percent change columns may reflect rounding. Totals may reflect rounding.

maining well above its level near the beginning of the industry's migration back to a regulated focus (its share was 51.9% in 2005).

Natural Gas Distribution revenue fell by $1.5 billion, or 3.3%, to $45.1 billion from $46.6 billion in 2019. This followed annual increases of 4.4% in 2019, 3.0% in 2018, 17.6% in 2017 and 8.9% in 2016; these gains were due in part to the completion in 2016 of four large acquisitions of natural gas distribution businesses.

Total regulated revenue — the sum of the Regulated Electric and Natural Gas Distribution segments — deceased by $3.6 billion, or 1.2%, to $296.5 billion in 2020. The industry's focus on regulated operations has driven a steady growth in these two business segments' share of industry revenue. Regulated revenue in total accounted for 81.9% of industry revenue in 2020, up from 79.9% in 2019 and well above 2005's 65.3% share.

Eliminations and reconciling items were added back to total revenue to arrive at the denominator for the segment percentage calculations shown in the graphs *Revenue Breakdown 2020 and 2019*.

2020 Assets by Segment

Regulated Electric assets increased by $82.5 billion, or 6.6%, during 2020. The segment's share of total industry assets increased to 68.7% at year-end 2020 from 68.2% at year-end 2019. Competitive Energy assets increased by $9.7 billion, or 4.9%, while Natural Gas Distribution assets edged higher by $896 million, or 0.4%. Although a relatively small piece of the entire industry, Natural Gas Pipeline assets experienced an increase of $2.6 billion, or 8.0%.

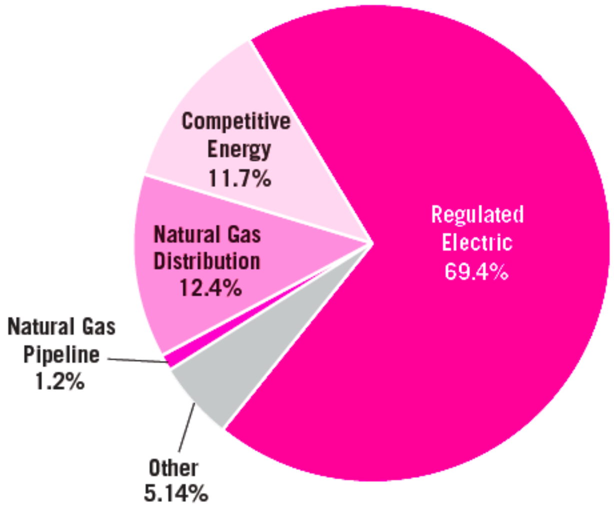
Total regulated assets (Regulated Electric and Natural Gas Distribution) grew by $83.4 billion, or 5.6% in 2020, maintaining a slightly lower share of total industry assets at year-end, at 80.8%, relative to the 81.0% share at year-end 2019. This aggregate measure has risen steadily from 61.6% at year-end 2002, underscoring the significant regulated rate base growth and widespread divestitures of non-core businesses over the 18-year period. Twenty-seven of 44 companies (61.4%) either increased regulated assets as a percent of total assets or maintained a 100% regulated structure in 2020.

Regulated Electric

Regulated Electric segment operations include the generation, transmission and distribution of electricity under state regulation for residential, commercial and indus-

Revenue Breakdown 2020

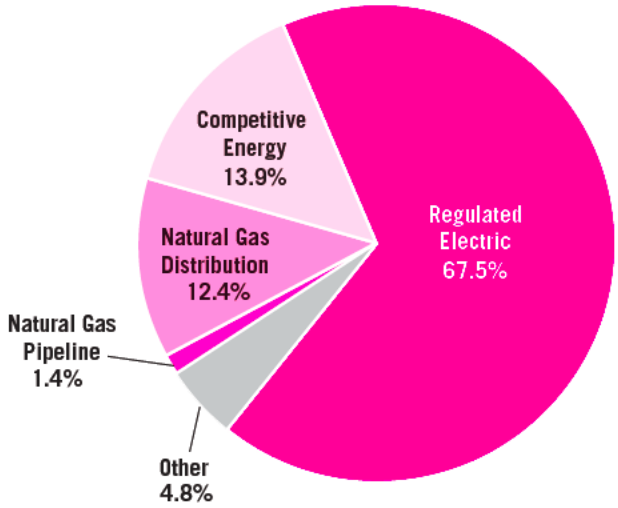
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Revenue Breakdown 2019r

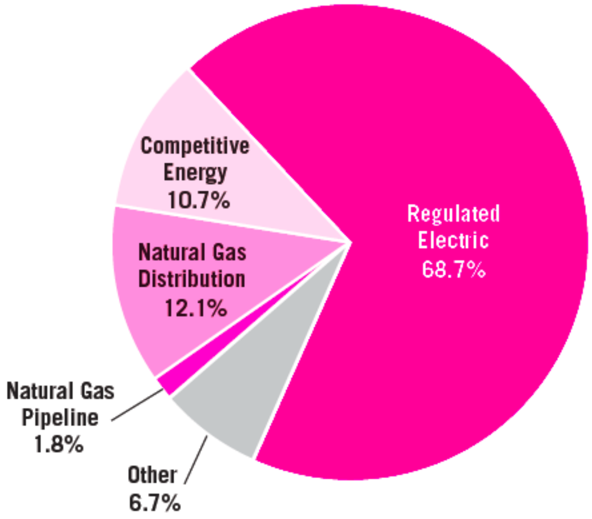
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Asset Breakdown
As of December 31, 2020

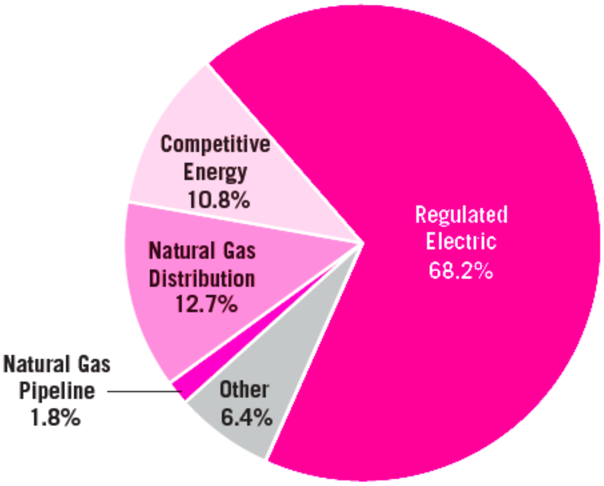
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Asset Breakdown
As of December 31, 2019r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

trial customers. Regulated Electric revenue was slightly lower in 2020, falling by $2.1 billion, or 0.8%. Twenty-nine companies, or 66% of the industry, had lower Regulated Electric revenue versus the prior year. Regulated Electric revenue fell by 0.5% in 2019, was unchanged in 2018, grew 0.8% in 2017 and declined slightly in 2016 (-0.1%) and in 2015 (-2.6%).

Annual electric output decreased by 2.9% in 2020 in a unique year that was impacted by the COVID-19 pandemic. On a weather-adjusted basis, electric output was down 2.0% in 2020 versus 2019. Electric output declined by 1.7% in 2019 and has risen in only six of the last 13 years. Prior to this extended period, a year-to-year output decline was a rare event in an industry that typically experienced low-single-digit percent demand growth. Energy efficiency initiatives, demand-side management programs and the off-shoring of formerly U.S.-based manufacturing and heavy industry are all forces that have suppressed the growth of electricity demand since the late 20th century.

Regulated Electric assets increased by $82.5 billion, or 6.6%, in 2020, achieving the largest asset growth in dollar terms of all business segments. The industry's record-high $132.7 billion of capital expenditures in 2020 and generally constructive regulatory relations supported the increase in regulated assets. The 2020 capital expenditure total represents the ninth consecutive annual record high, with this expansion well represented across the industry's four primary business segments. Asset growth is also evident in the industry's property, plant and equipment in service, which rose 6.5% from year-end 2019 and 34.0% over the level at year-end 2015. Such strong growth in assets reflects the magnitude of the industry's build-out of new renewable and clean generation, new transmission, reliability-related infrastructure and other capital projects in recent years.

Competitive Energy

Competitive Energy assets increased by $9.7 billion, or 4.9%, to $206.6 billion in 2020 from $196.9 billion in 2019 driven largely by new renewable generation. Although the segment's assets are on the rise, its revenue experienced a sharp decline of $9.7 billion, or 18.6%, from $52.2 billion in 2019 to $42.5 billion in 2020, its lowest annual total in data going back to 2000. With the segment's 2020 asset growth, its total assets have returned to about their level a decade ago; the segment's year-end 2010 assets were $208.1 billion and its annual revenue peaked at $110.9 billion in 2008. Competitive Energy covers the generation and/or sale of electricity in competitive markets, including both wholesale and retail transactions. Wholesale buyers are typically regional power pools, large industrial customers and electric utilities seeking to supplement generation capacity. Competitive Energy also includes the trading and marketing of natural gas. Of the 21 companies that maintain Competitive Energy operations, 13 (62%) grew these assets during 2020 and 24% had revenue gains from this segment.

NextEra Energy (NEE), a world leader in renewable generation, produced the largest Competitive Energy segment asset growth among all companies, increasing its NextEra Energy Resources assets (which includes its wholesale power generation and energy-related services business) by $4.1 billion, or 8.0%. NEE's two regulated electric segments, FPL and Gulf Power, collectively grew assets by $5.3 billion, or 7.7%, providing balanced growth across NEE's regulated and unregulated businesses. CMS Energy had the highest percentage increase for this segment, growing assets by $749 million, or 58.7%.

Natural Gas

Natural Gas Distribution assets rose by $896 million, or 4.9%, to $233.0 billion at year-end 2020 from $232.1 billion at year-end 2019. The segment's revenue declined by $1.5 billion, or 3.3%, to $45.1 billion in 2020 from $46.6 in 2019 after revenue growth of 4.4% in 2019, 3.0% in 2018, 17.6% in 2017 and 8.9% in 2016 that was produced in part by four large gas acquisitions completed in 2016. Overall, only seven of the 27 companies (26%) that report gas distribution revenue showed a year-to-year increase in 2020. This followed increases at 70%, 86% and 93%, respectively, of reporting companies in 2019, 2018 and 2017. Natural Gas Distribution includes the delivery of natural gas to homes, businesses and industrial customers throughout the United States.

Natural Gas Pipeline assets increased by $2.6 billion, or 8.0%, to $35.3% at year-end 2020 from $32.7 billion at year-end 2019. The gains were driven by Berkshire Hathaway Energy's $13.4 billion, or

List of Companies by Category at December 31, 2020

Regulated (35)

Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Avista Corporation
Black Hills Corporation
CenterPoint Energy, Inc.
*Cleco Corporate Holdings LLC**
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Energy, Inc.
*DPL Inc.**
Duke Energy Corporation
Edison International
Entergy Corporation
Evergy, Inc.
Eversource Energy
FirstEnergy Corp.
IDACORP, Inc.
*IPALCO Enterprises, Inc.**
NiSource Inc.
NorthWestern Corporation
MGE Energy, Inc.
OGE Energy Corp.
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
*Puget Energy, Inc.**
Sempra Energy
Southern Company
Unitil Corporation
WEC Energy Group, Inc.
Xcel Energy Inc.

Mostly Regulated (9)

ALLETE, Inc.
AVANGRID, Inc.
*Berkshire Hathaway Energy**
DTE Energy Company
Exelon Corporation
Hawaiian Electric Industries, Inc.
MDU Resources Group, Inc.
NextEra Energy, Inc.
Public Service Enterprise Group Incorporated

Note:* Non-publicly traded companies.

220.1%, increase due to its acquisition of Dominion Energy's natural gas transmission and storage business for approximately $9.7 billion (part of which was settled in early 2021). Despite the segment's overall increase at the industry level, six of the nine companies that report this segment had asset declines. The Natural Gas Pipeline business concentrates on the transmission and storage of natural gas for local distribution companies, marketers and traders, electric power generators and natural gas producers. Added together, the Natural Gas Distribution and Natural Gas Pipeline segments increased assets by $3.5 billion, or 1.3%, in 2020 and produced revenue of $49.6 billion, down from $51.9 billion in 2019. In percentage terms, the contribution to total industry revenue from these two natural gas activities barely changed, falling to 13.6% in 2020 from 13.8% in 2019.

2020 Year-End List of Companies by Category

Early each calendar year, EEI updates our list of investor-owned electric utility holding companies organized by business category. The list is based on previous year-end business segmentation data presented in 10-Ks. Our categories are as follows: Regulated (80% or more of holding company assets are regulated) and Mostly Regulated (less than 80% of holding company assets are regulated).

We use assets rather than revenue for determining category membership because we believe assets provide a clearer picture of strategic trends; fluctuating commodity prices for natural gas and power can impact revenue so greatly that a company's strategic approach to business segmentation may be distorted by reliance on revenue data alone. Comparing the list of companies from year to year reveals company migrations between categories and indicates the general trend in industry business models. We also base our quarterly category financial data during the year on this list.

There was minimal movement between categories in 2020. The Regulated category remained at 35 companies as a result of one addition and one deletion. Sempra Energy was added as its regulated asset percentage rose above 80% while El Paso Electric was removed due to its acquisition by Infrastructure Investments Fund (IIF), an infrastructure fund advised by J.P. Morgan Investment Management.

The Mostly Regulated category was reduced from ten to nine companies due to Sempra's migration to the Regulated category. The increase in Sempra's regulated percentage resulted from asset growth at its regulated utility segments SDG&E, SoCalGas, and Sempra Texas Utilities.

The total number of parent companies in the EEI universe fell from 45 at year-end 2019 to 44 at year-end 2020, a result of the acquisition of El Paso Electric. At year-end 2020, the EEI universe included 35 Regulated and nine Mostly Regulated utility holding companies. (*see List of Companies by Category at December 31, 2020*).

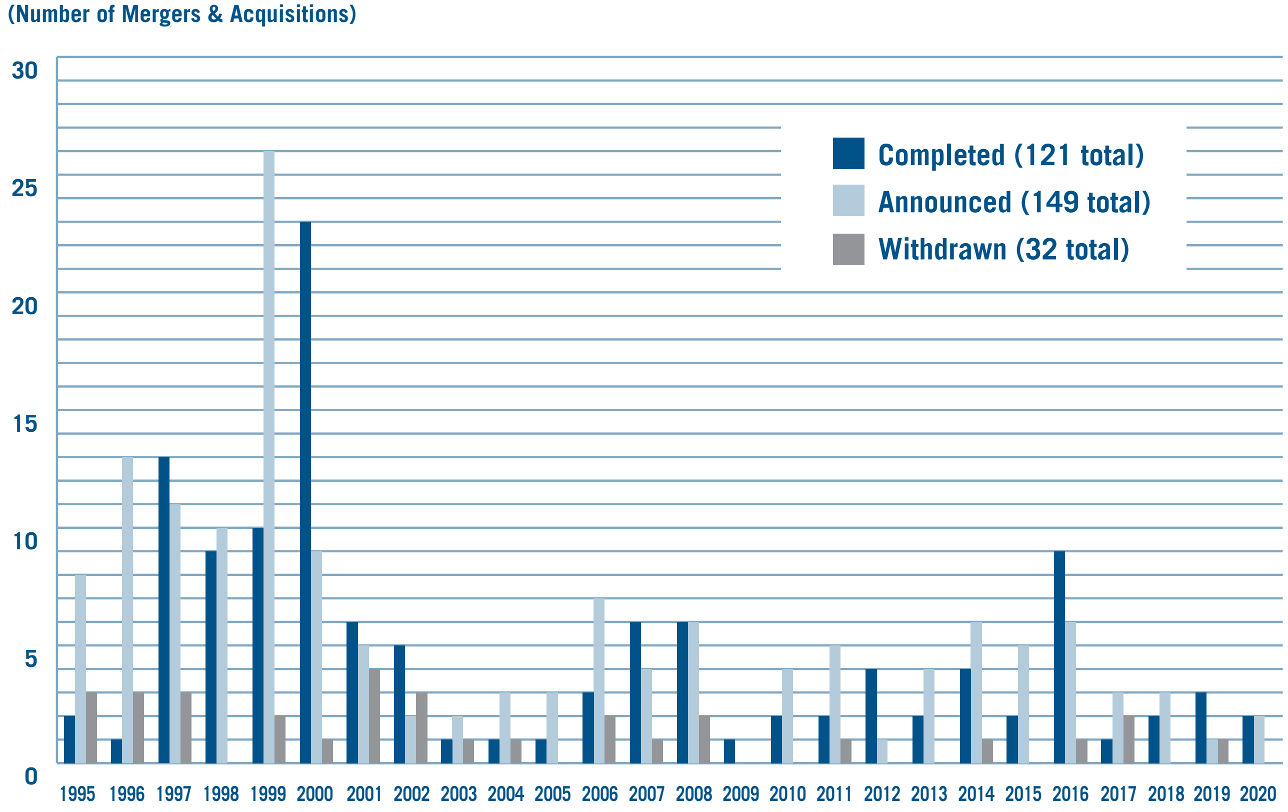
Mergers and Acquisitions

M&A activity involving whole U.S. utility operating companies with regulated service territories fell during a pandemic-impaired 2020 to its slowest pace in two decades. Only one deal was announced, AVANGRID's October 20 bid for PNM Resources. One was completed, El Paso Electric's acquisition in July by institutional investors. Attention turned from M&A to the pandemic, as companies focused on mitigating impacts on customers while state commissions concentrated on oversight of utilities' pandemic-related needs. Other constraints to active M&A were utilities rich valuations entering 2020, which raised prices for both strategic and financial buyers, and a perception that the bar for regulatory approval has climbed higher; six mergers have been withdrawn since 2011 after encountering resistance from state regulators and other stakeholders. Two decades of M&A activity reduced the number of investor-owned utilities to 39 as 2020 began from 58 ten years earlier and more than 70 at the turn of the century; this shrinking pool of potential buyers and sellers is another reason for the slowed pace of M&A.

Yet 2020 was eventful in related areas of corporate strategy. Renewable generation costs continued to fall. Public sentiment and political mandates for clean energy continued to rise. These trends were mirrored by a big jump in investors' attention to ESG metrics, with carbon reduction targets viewed as especially important. Companies with strong ESG profiles and strategies emphasizing growth through clean energy investments appeared to gain a share price boost. Utilities broadly sought to improve and promote their ESG characteristics. Numerous companies — including NiSource, Dominion, PPL, PSE&G, Exelon, DTE and CenterPoint — made moves to re-

Status of Mergers & Acquisitions 1995–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

structure and focus on developing state-regulated, clean energy infrastructure as their primary path to shareholder value creation.

Several multi-year tailwinds for M&A were also strengthened by these same forces, which analysts viewed as potential energy for renewed activity once the pandemic passes. While wind and solar fuel are cost free, building clean energy infrastructure is not. The size of the nation's clean energy investment needs means smaller companies who lack renewables development experience and big balance sheets may benefit from larger parents with the deep expertise and lower capital costs. Economies of scale can help reduce development and operating costs and constrain upward pressure on customer bills. And mergers can be pitched as supportive of ESG goals. Filling in geographical footprints or increasing regulatory diversity also remained cited as potential deal drivers.

Shareholders have a legal right to be contentious, but utility M&A cannot be. The need for buy-in from key stakeholders and regulators means utility M&A cannot be hostile or confrontational, only transformational. These hurdles prohibit the forced deals seen in other industries, but most utility industry observers see potential for more combinations that will show tangible benefits for ratepayers, communities and shareholders. After a strange 2020, the consensus view sees M&A resuming its recent measured, moderate pace.

Status of Announced Mergers & Acquisitions
1995–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Year	Completed	Announced	Withdrawn
1995	2	8	3
1996	1	13	3
1997	13	11	3
1998	9	10	–
1999	10	26	2
2000	23	9	1
2001	6	5	4
2002	5	2	3
2003	1	2	1
2004	1	3	1
2005	1	3	–
2006	3	7	2
2007	6	4	1
2008	6	6	2
2009	1	–	–
2010	2	4	–
2011	2	5	1
2012	4	1	–
2013	2	4	–
2014	4	6	1
2015	2	5	–
2016	9	6	1
2017	1	3	2
2018	2	3	–
2019	3	1	1
2020	2	2	0
Totals	**121**	**149**	**32**

Source: EEI Finance Department.

Announced Transactions

NiSource Sells Columbia Gas of Massachusetts to Eversource

On February 26, Eversource Energy and NiSource announced an agreement to sell NiSource's Columbia Gas of Massachusetts subsidiary to Eversource for $1.1 billion in cash. The transaction was completed in mid-October. Sale proceeds enabled NiSource to eliminate a previously planned 2020 block equity issuance and focus on long-term growth opportunities across its remaining operating companies. Following the sale, NiSource established a five to seven percent long-term growth rate goal for per-share operating earnings and dividends, driven by renewable investments that replace fossil generation. Eversource noted its strong track record of investing in infrastructure and opportunities for pipeline replacements and upgrades in the Columbia Gas of Massachusetts system. Eversource said the transaction should be accretive to earnings per share in the first 12 months after closing. Eversource Energy is New England's largest energy delivery company, with approximately 4 million electric and natural gas customers in Connecticut, Massachusetts and New Hampshire.

Dominion Sells Gas Assets to Berkshire Hathaway

On July 5, 2020 Dominion Energy said it agreed to sell its natural gas transmission and storage assets to an affiliate of Berkshire Hathaway in a transaction valued at $9.7 billion, including the assumption of $5.7 billion of existing debt. Dominion cited an improved ESG profile as a key motivation for the sale, noting it plans to invest up to $55 billion in emissions reduction technologies over the next 15 years, including zero-carbon generation and energy storage, gas distribution line replacement and renewable natural gas. It also said it expects to retire more than four gigawatts of coal- and oil-fired electric generation by 2025. The sale advances Dominion's strategic repositioning into a pure-play state-regulated utility; after the sale it expects that up to 90 percent of its operating earnings will come from its portfolio of electric and natural gas state-regulated utility companies in Virginia, the Carolinas, Ohio and Utah with gas transmission and storage eliminated from its reporting and operating structure. Dominion expects the repositioning to be credit positive given the reduction of nearly $6 billion of debt and the increased percentage of cash flow from state-regulated utilities. It also said it would use $3 billion of the sale pro-

Merger Impacts 1995–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Date	No. of Utilities	Change
12/31/95	98	–
12/31/96	98	–
12/31/97	91	(7.14%)
12/31/98	86	(5.49%)
12/31/99	83	(8.79%)
12/31/00	71	(14.46%)
12/31/01	69	(2.82%)
12/31/02	65	(5.80%)
12/31/03	65	–
12/31/04	65	–
12/31/05	65	–
12/31/06	64	(1.54%)
12/31/07	61	(4.69%)
12/31/08	59	(3.28%)
12/31/09	58	(1.69%)
12/31/10	56	(3.45%)
12/31/11	55	(1.79%)
12/31/12	51	(7.27%)
12/31/13	49	(3.92%)
12/31/14	48	(2.04%)
12/31/15	47	(2.08%)
12/31/16	44	(6.38%)
12/31/17	43	(2.27%)
12/31/18	42	(2.33%)
12/31/19	40	(4.76%)
12/31/20	39	(2.50%)

Number of Companies Declined by 60% since Dec.'95

Note: Based on completed mergers in the EEI Index group of electric utilities.

Source: EEI Finance Department.

ceeds in a stock repurchase program. The announcement came the same day Dominion and Duke jointly cancelled the Atlantic Coast Pipeline (ACP) after legal challenges to the project's federal and state permits resulted in cost increases and timing delays that threatened the project's economic viability.

NRG Offers to Buy Direct Energy

While neither company is an investor-owned regulated utility, NRG's July 24 $3.6 billion all-cash bid to acquire U.S. retail energy provider Direct Energy from U.K.-based energy conglomerate Centrica showcases themes in the competitive power market. With operations in 50 states and six Canadian provinces, Direct Energy is one of North America's largest retail providers of electricity, natural gas, and energy-related products and services. NRG said the acquisition builds on and complements its integrated generation and retail supply model, better matching its power generation with customer demand. It also broadens NRG's Texas presence into states where it does not currently operate, supporting its objective to geographically diversify by adding three million customers outside of Texas. And it provides NRG the ability to expand its renewable power purchase agreement strategy outside of Texas. NRG said the transaction will allow the combined company to reduce costs and leverage best practices.

U.K.-based Centrica cited themes similar to those shaping U.S. utility strategies. The sale creates a simpler, leaner company with predictable and stable cash flows focused on enabling a lower-carbon future in its core home markets of the U.K. and Ireland. The sale also boosts balance sheet strength with proceeds to be used to reduce debt and support its defined benefit pension plan.

PPL to Exit U.K. Business

In another strategic repositioning, Pennsylvania-based PPL Corporation announced on August 10 that it would like to sell its U.K. utility distribution business, Western Power Distribution (WPD), and become a purely U.S. utility holding company focused on advancing the nation's clean energy goals with rate-regulated assets. PPL observed that, while WPD is the premier distribution network operator (DNO) group in the U.K., it continues to be undervalued by the market as part of PPL. Shareholders would benefit from a simplified corporate structure with sale proceeds used to strengthen PPL's balance sheet and enhance long-term earnings growth, potentially through strategic M&A in the U.S. and through returning capital to shareowners.

WPD, which serves about eight million customers in central and southwest England and south Wales, is expected to play a critical role in supporting the U.K.'s transition to net-zero carbon emissions by 2050, providing a new owner with significant investment opportunities and regulated asset growth potential.

AVANGRID Seeks to Buy PNM Resources

The only 2020 announcement that made EEI's list of whole company deals was the October 20 news that AVANGRID offered to acquire PNM Resources for $50.30 in cash, creating an equity value of approximately $4.3 billion and enterprise value of $8.3 billion. The proposed transaction implies a 19% premium to PNM's pre-announcement price.

AVANGRID said the transaction is consistent with its parent IBERDROLA Group's disciplined growth strategy, calling the proposed buyout a friendly transaction focused on regulated businesses and renewables in states with legal and regulatory stability and predictability. PNM called the move a strategic fit that will help it invest in clean energy distribution and transmission and expand its position in renewables. Both companies emphasized their cultural fit and mutual commitment to environmental, social and governance issues that impact all stakeholders.

The companies said the combination will create a larger and more diversified regulated utility and renewable energy company with electric and gas utilities in complementary geographies, offering enhanced operational and regulatory diversification. If approved, the combined company will serve more than four million electric and natural gas customers through ten regulated utilities in New York, Connecticut, Maine, Massachusetts, New Mexico, and Texas. And it would become the nation's third-largest renewables company with operations in 24 states.

The companies said PNM provides a platform for AVANGRID to expand its renewables business in the Southwest U.S. beyond its existing 1.9-gigawatt capacity wind projects in New Mexico and Texas and 200 megawatts of wind and solar capacity in Arizona.

The companies said the combined company's robust financial profile will provide flexibility to pursue enhanced growth opportunities, particularly in electric transmission, renewable energy, energy efficiency and new grid technologies. Through AVANGRID's parent company, Iberdrola, S.A., the combined company will have access to extensive financial resources to support this growth profile.

The merger needs approval from state regulators in Texas and New Mexico in addition to FERC and several other federal agencies.

Other Simplifications through Business Spin-Offs

Other companies that disclosed moves to simplify their businesses included PSE&G, Exelon, DTE and CenterPoint.

- On July 31, Public Service Enterprise Group (PSE&G) said it's exploring strategic alternatives for PSEG Power's non-nuclear generating fleet, which includes more than 6,750 megawatts of fossil generation and a 467-megawatt solar portfolio. It said the move would accelerate its transformation into a primarily regulated electric and gas utility, reduce business risk and earnings volatility, improve its credit profile and enhance its ESG position through clean energy investments, methane reduction, and zero-carbon generation.

- Exelon confirmed in October that it is exploring ways to separate its nuclear, solar and wind generation business from its regulated electric segment and focus on regulated utility operations

- Also in October, DTE Energy said it would spin-off DTE Midstream, its non-utility natural gas pipeline, storage and gathering business. DTE said the transaction would transform it into a predominantly pure-play regulated electric and natural gas utility. Under the plan, DTE Energy shareholders will retain their current shares of DTE Energy stock and receive a pro-rata dividend of shares of the new Midstream company in a transaction that is expected to be tax-free. DTE Energy is targeting to complete the spin-off by mid-year 2021.

- In December, CenterPoint said it would seek to sell its Arkansas and Oklahoma natural gas distribution utilities to finance a $3 billion increase in regulated electric system capex, including new solar and wind generation, without issuing new equity.

Completed Transactions

Three deals announced in 2019 were completed in 2020. Only El Paso's acquisition by financial investors is included in EEI's list of transactions involving U.S. utilities with regulated service territories.

Canadian Pension Fund Acquires Pattern Energy

Canadian investment funds have been active buyers of renewable assets in recent years, attracted to the steady returns which are generally far above the yields available in public bond markets. On March 16, 2020, the Canada Pension Plan Investment Board (CPPIB) completed its acquisition of renewable energy generator Pattern Energy. Announced in November 2019, the all-cash transaction at $26.75 per share created an enterprise value of approximately $6.1 billion including net debt. The deal price represented a 15% premium to Pattern's price before reports of buyer interest emerged in August 2019. Pattern Energy is an independent power company running a portfolio of 28 renewable energy projects with 4.4 GW of operating capacity in the United States, Canada and Japan. Pattern went public in 2013 with a focus on wind generation assets in the first wave of so-called "yieldcos". Yet these somewhat opaque investment vehicles fell out of investor favor beginning in 2015 through a self-reinforcing cycle in which investors questioned their ability to fund growth as their stock prices sagged. Pattern was one of several who produced steady earnings and dividends in the years that followed but never returned to investor favor. Pattern's dividend yield reached 10% in 2018, roughly triple the yields available in the bond market.

Canadian utility ENMAX Acquires Emera Maine

On March 24, Calgary, Canada-based ENMAX and Nova Scotia's Emera completed their plan for ENMAX to buy Emera Maine, Emera's regulated electric transmission and distribution subsidiary in Maine, for $959 million USD or $1,286 million Canadian (CAD). The deal closed almost one year to the day after its March 25, 2019 announcement date. Including assumed debt, the transaction had an

Mergers & Acquisitions Announcements Updated through December 31, 2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Ann'cd	Buyer	Seller/Acquired/Merged	Status	New Company	Completed Date	Months to complete	Bus.	Terms	Est. Trans Value ($MM)
10/21/20	AVANGRID	PNM Resources	PN				EE	AGR to pay $50.30/share in cash (roughly 10% premium) for PNM common stock	4,300.0
7/5/20	Berkshire Hathaway Energy	Dominion Energy Natural Gas Transportation and Storage	C		11/1/2020	4	EG	$5.7 billion debt + $4.0 billion cash	9,700.0
6/3/19	JP Morgan Investment Management	El Paso Electric	C		7/29/20	13	EE	JPMorgan pays $68.25/share in cash for each share of El Paso Electric Co. common stock	4,285.7
5/21/2018	NextEra Energy, Inc.	Gulf Power Company	C		1/1/2019	7	EE	NEE to pay $4.35 billion in cash to acquire Gulf Power Company from Southern Company	4,350.0
4/23/2018	CenterPoint Energy	Vectren Corporation	C		2/1/2019	10	EG	CNP pays $72.00/share in cash for each share of Vectren common stock	6,000.0
1/3/2018	Dominion Energy, Inc.	SCANA Corporation	C		1/1/2019	12	EE	$6.7B debt + $7.9 stock (per share value of $55.35, roughly 31% premium)	14,600.0
8/21/2017	Sempra Energy	Oncor Electric Delivery Company	C		3/8/2018	6	EE	$9.5B cash	9,450.0
7/19/2017	Hydro One Limited	Avista Corporation	W		1/23/2019			$5.3B cash (per share value of $53.00, roughly 24% premium)	5,300.0
7/7/2017	Berkshire Hathaway Energy	Oncor Electric Delivery Company	W		8/21/2017			$9.0B cash	9,000.0
9/28/2016	DTE Energy	Appalachia Gathering System / Stonewall Gas Gathering	C		10/20/2016	1	EG	Undisclosed	1,300.0
7/29/2016	NextEra Energy	Oncor Electric Delivery Company	W		10/31/2017			$9.5B debt + additional cash and common stock	11,178.0
5/31/2016	Great Plains Energy	Westar Resources	C	Evergy, Inc.	6/5/2018	24	EE	$3.6B debt + $8.6 stock and cash (per share value of $60.00)	12,200.0
2/9/2016	Fortis Inc.	ITC Holdings Corp.	C		10/14/2016	8	EE	$4.4B debt + $6.9B common shares and cash (per share value of $44.90, roughly 33% premium)	11,300.0
2/9/2016	Algonquin Power & Utilities	Empire District Electric Company	C		1/1/2017	11	EE	$1.6B debt + additional debt and equity (per share value of $34.00, roughly 21% premium)	2,400.0
2/1/2016	Dominion Resources	Questar Corporation	C		9/16/2016	8	EG	$1.5B debt + $2.4B cash + $500M equity (per share value of $25.00, roughly 30% premium)	4,400.0
10/26/2015	Duke Energy	Piedmont Natural Gas	C		10/3/2016	12	EG	$3.3B debt + $1.0B cash + $625M equity (per share value of $60.00, roughly 40% premium)	4,900.0
9/4/2015	Emera	TECO Energy, Inc.	C		7/1/2016	10	EE	$6.5B debt + $3.9B equity (per share value of $27.55, roughly 48% premium)	10,400.0
8/24/2015	Southern Company	AGL Resources	C		7/1/2016	10	EG	$4.1B debt + $8.0B equity (per share value of $66.00, roughly 36% premium)	12,060.4
7/12/2015	Black Hills Corporation	SourceGas Holdings	C		2/12/2016	10	GG	$760M debt + $1.13B cash	1,890.0
2/25/2015	Iberdrola USA	UIL	C	AVANGRID, Inc.	12/16/2015	10	EE	$1.8B debt + $0.6B cash + $2.4B equity (per share value of $52.75, roughly 25% premium, of which $10.50 will be cash)	4,756.0
12/3/2014	NextEra Energy	Hawaiian Electric	W		7/18/2016			NEE to acquire HE for $2.6B equity + $1.4B debt (fixed exchange ratio of 0.2413 NEE shares)	3,963.0
10/20/2014	Macquarie-led Consortium	Cleco	C		4/13/2016	18	EE	$3.4B equity (all Cleco shares at $55.37 / share in cash (~15% premium)) + $1.3 debt	4,700.0
6/23/2014	Winsconsin Energy	Integrys	C	WEC Energy Group, Inc.	6/30/2015	12	EE	WEC to acquire TEG for $5.758B equity + $3.374B debt (fixed exchange ratio of 1.128 WEC shares + $18.58)	9,100.0
5/1/2014	Berkshire Hathaway Energy	AltaLink (Canadian)	C		12/1/2014	7	ET	BHE to acquire AL for $3.2B cash + $2.7B debt	5,927.0
4/30/2014	Exelon	Pepco	C		3/23/2016	24	EE	EXC to acquire POM for $6.8B in cash ($27.25 per POM share)	12,337.0
3/3/2014	UIL Holdings	Philadelphia Gas Works	W		12/4/2014			UIL to acquire assets & liabilities of PGW from city of Philadelphia for $1.86 billion in cash	1,860.0
12/12/2013	Fortis Inc.	UNS Energy	C		8/15/2014	8	EE	Fortis pays $60.25 / share (31% premium to announcement day's close) + $1.8B in debt	4,578.1
11/4/2013	Avista	Alaska Energy & Resources Company	C		7/1/2014	8	EE	AVA to acquire Alaska Energy & Resources Company for $145MM equity + $24.5MM debt	169.5
5/29/2013	MidAmerican Energy Holdings Co.	NV Energy	C	Berkshire Hathaway Energy	12/19/2013	7	EE	MidAmerican pays $23.75 / share + assume $4.8 billion debt	10,494.3
5/25/2013	TECO Energy, Inc.	New Mexico Gas Intermediate, Inc.	C		9/2/2014		EE	TECO will pay $950 million, including assume $200 million debt to Continental Energy Systems LLC	950.0
2/20/2012	Fortis Inc.	CH Energy Group	C		6/27/2013	16	EE	Fortis pays $65.00/share cash & assumes approx. $687.37 MM debt.	1,699.7
5/27/2011	Fortis Inc.	Central Vermont Public Service Corp	W		7/11/2011		EE	Fortis pays approx. $35.10/share cash & assumes approx. $226.4 mill in debt.	701.6
1/8/2011	Duke Energy	Progress Energy	C		7/3/2012	18	EE	0.87083 Duke shares (after 1-3 reverse split) for each Progress share + assume $12.1 billion net debt.	32,000.0
7/11/2011	Gaz Metro LP	Central Vermont Public Service Corp	C		6/27/2012	12	GE	Gaz Métro pays $35.25/share for each CVPS share & assumes $226 million debt.	704.2
10/16/2010	Northeast Utilities	NSTAR	C		4/10/2012	18	EE	1.312 NU shares for each NSTAR shr, plus $3.36 bill assume debt	7,566.7
4/28/2011	Exelon Corp.	Constellation Energy Group Inc.	C		3/12/2012	11	EE	CEG receive 0.93 shares of EXC for each CEG share. EXC assumes approx. $2.9 bill net debt	10,623.2

4/19/2011	AES Corporation	DPL Inc.	C		11/28/2011	7	EE	AES pays 30.00/share cash & assumes approx $1.1 billion of net debt	4,613.2
4/28/2010	PPL Corp.	E.ON U.S.	C		11/1/2010	6	EE	$6.83 billion cash + $764.0 million in assumed debt	7,625.0
3/12/2010	Emera Inc	Maine & Maritimes	C		12/21/2010	9	EE	$76 mm cash + $28.6 mm debt + $13.8mm postretirement benefits	117.4
2/10/2010	FirstEnergy	Allegheny Energy	C		2/25/2011	12	EE	$4.3 billion in equity + $4.7 billion in assumed debt	9,273.2
9/17/2008	Berkshire Hathaway	Constellation Energy Group Inc.	W		12/17/2008		PE	$4.7 bill cash + $4.4 bill net debt and adjustments	9,152.5
7/25/2008	Sempra Energy	EnergySouth Inc.	C		10/1/2008	3	EG	$499 million cash + 283 million debt	771.9
7/1/2008	MDU Resources Group, Inc.	Intermountain Gas Co.	C		10/1/2008	3	EG	$245 million cash + $82 million debt	327.0
6/25/2008	Duke Energy	Catamount Energy Corp.	C		9/15/2008	3	EP	$240 million cash + $80 million assumed debt	320.0
2/15/2008	Unitil Corp.	Northen Utilities / Granite State Gas Transmission	C		12/1/2008	10	EG	$160 million cash	160.0
1/12/2008	PNM Resources, Inc.	Cap Rock Holding Corp.	W		7/22/2008		EE	$202.5 million	202.5
10/26/2007	Macquarie Consortium	Puget Energy	C		2/6/2009	16	EE	$3.5 billion cash + $3.02 billion net debt	6,520.2
6/25/2007	Iberdrola S.A.	Energy East Corp.	C		9/16/2008	15	EE	$4.5 billion cash + $4.1 billion net debt	8,600.0
2/26/2007	KKR & Texas Pacific Group	TXU Corp.[1]	C	Energy Future Holdings Corp.	10/10/2007	8	PE	$31.8 billion cash + $12.1 billion net debt	43,882.0
2/7/2007	Black Hills Corp. / Great Plains Energy Inc.[2]	Aquila Inc. (CO elec. util. + CO, KS, NE, IA gas utils.)	C		7/14/2008	17	EG	$940 million cash +working capital and other adjustments	940.0
7/8/2006	MDU Resources Group, Inc.	Cascade Natural Gas Corporation	C		7/2/2007	12	EG	$305.2mm in cash + ($173.6 in debt - $13.0 in cash equivalents)	465.8
7/8/2006	WPS Resources Corporation	Peoples Energy Corporation	C	Integrys Energy Group	2/21/2007	7	EG	$2.47 billion	2,472.4
7/5/2006	Macquarie Consortium	Duquesne Light Holdings	C		5/31/2007	10	EE	$1.59 billion cash + $1.09 billion total debt	2,674.4
6/22/2006	Gaz Metro LP	Green Mountain Power Corp.	C		4/12/2007	10	EE	$187 million in cash + ($100.8 debt - $9.1mm in cash equivalents)	279.5
5/11/2006	ITC Holdings Corp	Michigan Electric Transmission Co.	C		10/10/2006	5	EE	$485.6mm cash + $70mm common stock + $311mm assumed debt	866.6
4/25/2006	Babcock and Brown Infrastructure	NorthWestern Corp.	W		7/24/2007		EE	$2.2 billion cash	2,200.0
2/27/2006	National Grid	KeySpan Corp.	C		8/24/2007	18	EE	$7.4 billion cash + $4.5 billion long-term debt	11,877.5
12/19/2005	FPL Group Inc.	Constellation Energy Inc.	W		10/25/2006		EE	$11.3 billion equity + $4.1 billion net debt and pension liabilities	15,311.5
5/24/2005	MidAmerican Energy Holdings Co.	Pacificorp	C		3/21/2006	10	EE	$5.1 billion cash + $4.3 billion in net debt and preferred stock	9,300.0
5/9/2005	Duke Energy Corp.	Cinergy Corp.	C		4/3/2006	11	EE	$9.1 billion equity + $5.5 billion net debt and pension liabilities	14,600.0
12/20/2004	Exelon Corp.	Public Service Enterprise Group	W		9/14/2006		EE	$12.3 billion in equity + $13.4 billion in net debt and pension liabilities	25,700.0
7/25/2004	PNM Resources	TNP Enterprises	C		6/6/2005	12	EE	$189 million in stock and cash and $835 million in debt	1,024.0
2/3/2004	Ameren Corp	Illinois Power[3]	C		10/1/2004	8	EE	$1.9 billion in debt, pref stock, & other liab + $400 million in cash	2,300.0
11/24/2003	Saguaro Utility Group L.P.	UniSource Energy	W		12/30/2004		PE	$850 million cash + $2 billion in debt	2,850.0
11/3/2003	Exelon Corp.	Illinois Power	W		11/22/2003		EE	$275 million cash + $1.8 billion in debt + $150 million promissory note	2,225.0
4/30/2002	Aquila Inc	Cogentrix Energy Inc	W		8/2/2002		EIPP	$415 million cash + $1.125 billion in assumed debt	1,540.0
4/29/2002	Ameren Corp	CILCORP[4]	C		1/31/2003	9	EE	$541 million cash + $781 in assumed debt + $41 million in pref stock	1,400.0
10/8/2001	Northwest Natural Gas	Portland General	W		5/16/2002		GE	$1.55 billion cash + $250mm in stock	1,800.0
9/20/2001	Duke Energy	Westcoast Energy	C		3/14/2002	6	EG	Equity + cash valued at $27.90 per Westcoast share	8,500.0
9/10/2001	Dominion Resources	Louis Dreyfus Natural Gas	C		11/1/2001	2	EG	$890mm cash + $900mm stock +$505mm debt	2,295.0
2/20/2001	Energy East	RGS Energy	C		6/28/2002	16	EE	$1.4 bill. cash & equity + $1.0 bill. net debt	2,400.0
2/12/2001	PEPCO	Conectiv	C		8/1/2002	18	EE	$2.2 bill cash & equity + $2.8 bill. net debt	5,000.0
11/9/2000	PNM	Western Resources[5]	W		1/8/2002		EE	Stock transfer	4,442.0
10/2/2000	NorthWestern	Montana Power[6]	C		2/15/2002	16	EE	$1.1 billion in cash	1,100.0
9/5/2000	National Grid Group	Niagara Mohawk	C		1/31/2002	16	EE	$19 per share	8,900.0
8/8/2000	FirstEnergy	GPU Inc.	C		11/7/2001	15	EE	$35.60 per share	12,000.0
7/31/2000	FPL Group	Entergy	W		4/2/2001		EE	1/1 - FPL, 0.585/1 - ETR	27,000.0
7/17/2000	AES Corporation	IPALCO	C		3/27/2001	8	IPPE	$25 per share	3,040.0
6/30/2000	NS Power	Bangor Hydro	C	Emera	10/10/2001	16	EE	$26.50 per share	206.0

C = Completed
W = Withdrawn
PN = Pending

E = Electric
G = Gas
O = Oil
IPP = Independent Power Producer
P = Privatized

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[1] TXU (now Energy Future Holdings Corp.) was acquired by the Texas Energy Future Holdings Limited Partnership (TEF) on 10/10/2007.
TEF was formed by a group of investors led by Kohlberg Kravis Roberts and Texas Pacific Group to facilitate the merger.

[2] Aquila was divided with Black Hills Corp. acquiring the electric utility in Colorado and NG utilities in CO, IA, KS, and NE. Great Plains Energy Inc. acquired the MI electric utility, stock, and other corporate assets.

[3] Ameren purchased Illinois Power from Dynegy Corporation. Dynegy Corp acquired Illinois Power in February 2000.

[4] Ameren purchased CILCORP from AES Corporation. AES Corp acquired CILCORP in October 1999.

[5] PNM purchased Western Resources' electric operations including generation, transmission, and distribution.

[6] NorthWestern Corporation purchased Montana Power's electric and natural gas transmission and distribution assets.

Source: EEI Finance Department, S&P Global Market Intelligence.

aggregate enterprise value of $1.3 billion USD ($1.8 billion CAD) on closing. ENMAX, with $5.6 billion CAD in assets and revenue of $2.4 billion CAD, provides electricity, natural gas, renewable energy and other services to approximately 670,000 residential and commercial customers across Alberta, Canada. The company is wholly owned by the City of Calgary, Alberta. Nova Scotia-based Emera serves 2.5 million customers in Canada, the U.S. and the Caribbean with more than $32 billion CAD in assets and approximately $6.5 billion in revenue. Its U.S. subsidiaries include Tampa Electric, TECO People's Gas and New Mexico Gas in addition to Emera Maine, which provides transmission and distribution services to approximately 150,000 residential, commercial and industrial customers in Maine.

While the deal was relatively small by industry standards, it showcased political and regulatory challenges often attendant with utility M&A. Local politicians and stakeholders in Calgary criticized the planned $1.8 billion expenditure and assumption of new debt by a city-owned entity when city budgets were being cut and local commercial property prices were in steep decline. Maine politicians and stakeholders worried about potential rate hikes, job cuts and the influence Calgary's city government could have over Emera Maine's management. Maine regulators rejected the deal in early March 2020, but gave it their blessing a few weeks later when ENMAX agreed to a negotiated settlement that offered a range of benefits to Maine ratepayers.

Infrastructure Fund Buys El Paso Electric

On July 29, Infrastructure Investments Fund (IIF), an infrastructure fund advised by J.P. Morgan Investment Management, completed its purchase of west Texas and southern New Mexico regulated utility El Paso Electric. On June 3, 2019 the utility announced it had agreed to be purchased by IIF for $68.25 per share, a cash deal valued at $4.3 billion including debt. The purchase price was a 17% premium to El Paso's closing price before the announcement, representing a PE multiple of nearly 29 times 12-month earnings through March 31, 2019. El Paso said IIF's renewable energy expertise will help the utility navigate a rapidly changing industry that requires significant long-term investments in renewable energy and sustainability. The agreement left El Paso independently operated with headquarters in El Paso and its workforce remaining in place. Other benefits included $21 million in rate credits over 36 months and a $100 million commitment to fund economic development in El Paso's service area over the next 20 years. IIF, which calls itself a long-term owner of utilities, said El Paso would be its flagship investment in the U.S. Analysts cited the strong customer growth and need for investment in El Paso's service territory as points of attraction for IIF.

El Paso Electric is a regional electric utility providing generation, transmission and distribution service to more than 400,000 retail and wholesale customers in a 10,000-square mile area of the Rio Grande valley in west Texas and southern New Mexico. When the deal was announced, IIF owned 19 portfolio companies located primarily in the United States, Western Europe and Australia, including 11 energy, utility and electric generation companies. IIF has significant experience developing renewable energy sources, with $3 billion in renewable power generation assets that collectively provide 3.4 GW of renewable capacity.

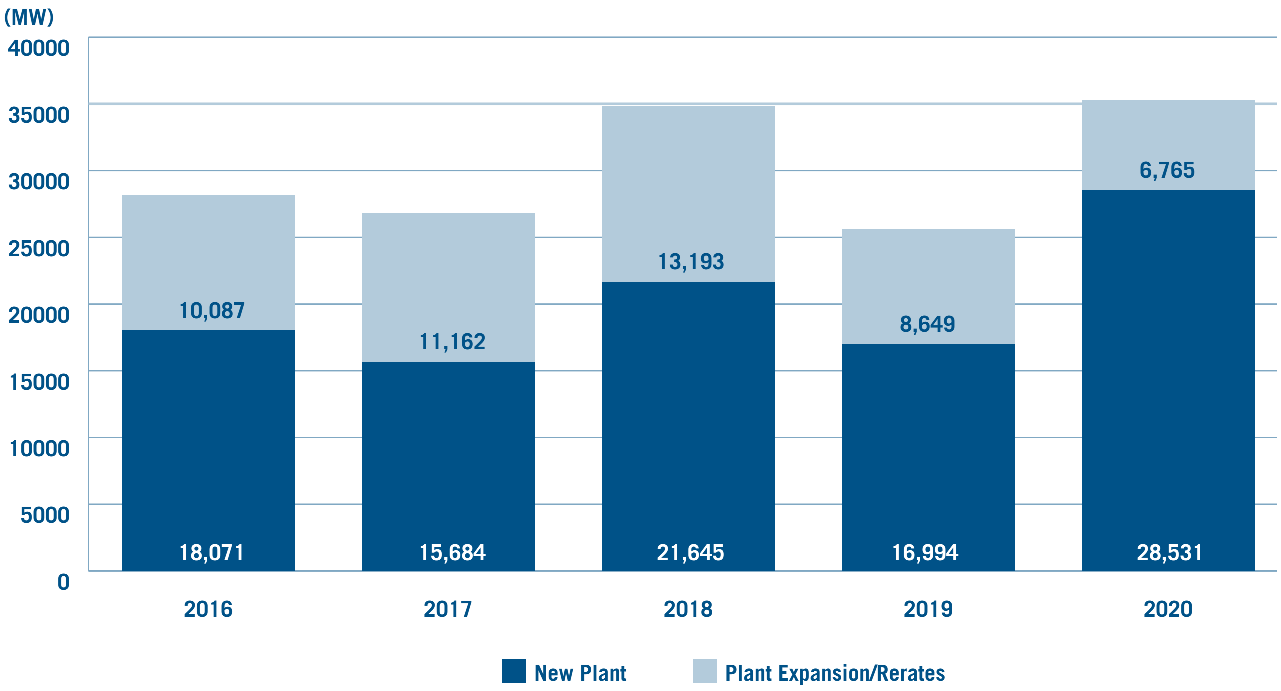
Construction

The electric utility industry brought 35,296 MW of new capacity online in 2020; this was a 38% increase over 2019's 25,643 MW, which was the lowest annual total since 2016. New plants comprised 81% of 2020's total; expansions and rerates contributed the remaining 19%. Capacity added by new plants increased 68% versus last year while capacity from plant expansions and rerates declined 22%. Wind power led new capacity additions and accounted for 15,621 MW or 44% of the 2020 total. Solar was second at 10,978 MW, or 31%. Natural gas contributed 8,302 MW, or 24%.

The nation's aggressive build-out of renewable energy is evident in wind and solar's 75% share of 2020's added capacity and the 65% and 77% growth in each fuel's added capacity versus their respective 2019 totals. Investor-owned utilities that brought the most renewable capacity online, either as new plants or expansions at existing facilities, were NextEra Energy (2,179 MW of solar and 2,563 MW of wind), Berkshire Hathaway Energy (857 MW of wind), Duke Energy (637 MW, all solar), Alliant Energy (549 MW of wind and 3 MW of solar), CMS Energy (525 MW, all wind capacity), Xcel Energy (401 MW of wind), Southern Company (392 MW of wind and 50 MW of solar), ALLETE (380 MW of wind capacity), and Dominion Energy (343 MW of solar and 12 MW of wind).

Approximately 76% of 2020's added natural gas capacity is combined-cycle while 21% is combustion turbine. New plants accounted for 4,061 MW, or 49%, of the gas capacity brought online in 2020, while 4,241 MW, or 50%, resulted from expansions at existing facilities and 5% came from rerates. Entergy led natural gas additions with 1,993 MW of new combined-cycle capacity and 299 MW powered by gas turbines; nearly all was new build, only 49 MW of the total came from expansions. AES was next, at 1,333 MW, a mix of expansions (693 MW) and new build (640 MW). Duke Energy added 830 MW of combus-

New Capacity Online 2016–2020



Note: Includes all new capacity placed on the grid by investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations. Totals may reflect rounding.

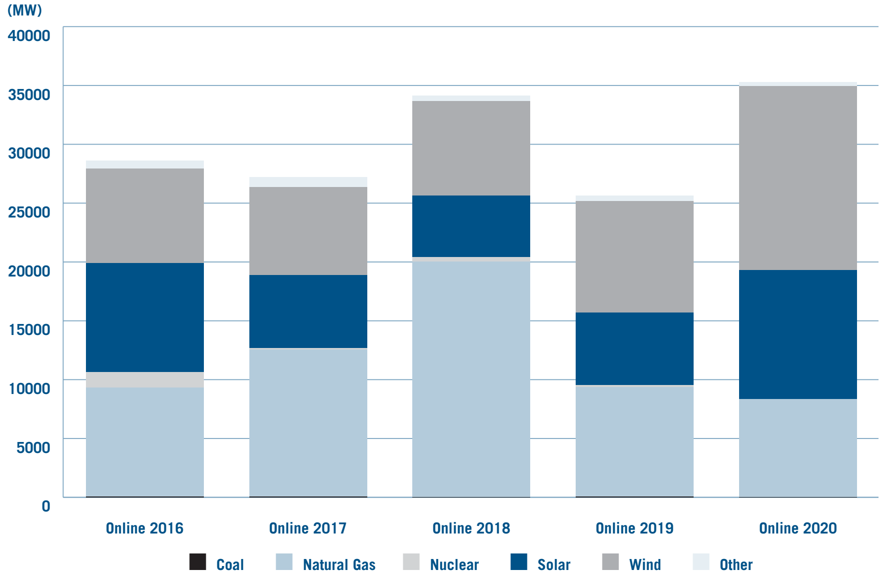
Source: Hitachi ABB Power Grids; EEI Finance Department, March 2021

tion turbine and combined-cycle capacity though expansions. Alliant added 700 MW of combined-cycle power through an expansion project.

New Capacity Online by Region

The Southwest Power Pool (SPP) saw the largest year-to-year increase in new capacity added in percentage terms, at 214%; 3,296 MW of wind capacity and 59 MW of solar came online in 2020 in contrast to 954 MW of wind and 42 MW of solar in 2019. The Western Electricity Coordinating Council (WECC) experienced the second-largest year-to-year growth in percentage terms, at 102%, boosted by 3,253 MW of new wind capacity, 2,610 MW of solar, and 1,572 MW of natural gas. Hawaii (HCC) saw 59% growth from 2019's level, driven by 270 MW of new solar capacity and 28 MW of wind. Capacity added in the Midwest Reliability Organization (MRO) region rose 42% above the total added in 2019, supported by 700 MW of additional gas generation, 3,631 MW of new wind, and 294 MW of solar. Capacity added in the Reliability First Corporation (RFC) region was down 19% versus 2019, largely because new gas additions declined 59%, to 1,218 MW from 2,945 MW in 2019. The Northeast Power Coordinating Council (NPCC) also saw a drop in new capacity additions, at 11% against 2019 levels, mostly because natural gas capacity additions fell 55%, from 1,494 MW in 2019 to 675 MW in 2020.

New Capacity Online by Fuel Type 2016–2020



Fuel Type	2016	2017	2018	2019	2020
Coal	45	45	10	62	30
Natural Gas	9,282	12,530	20,033	9,301	8,302
Nuclear	1,291	102	350	155	0
Solar	9,287	6,222	5,246	6,188	10,978
Wind	8,045	7,456	8,031	9,441	15,621
Other	672	861	456	496	365
Total	**28,622**	**27,216**	**34,126**	**25,643**	**35,296**

Note: Includes all new capacity placed on the grid by investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding.

Source: Hitachi ABB Power Grids; EEI Finance Department, March 2021

Announcements by Region and Fuel Type

New capacity announced in 2020 totaled 66,386 MW, up 26% from 52,648 MW in 2019. Renewable generation accounted for 94% of 2020's total, with solar contributing 73%, wind 20%, hydro 1% and natural gas the remaining 6%. No new coal capacity was announced.

The Western Electricity Coordinating Council (WECC) produced the highest regional total for announced new capacity in 2020, at 23,608 MW; nearly all is renewable generation, with approximately 83% solar, 11% wind and 6% natural gas. In 2019, the Northwest Power Coordinating Council led with 12,091 MW of new capacity, including 7,342 MW of solar and 4,641 MW of wind. In 2020, solar power again accounted for nearly all of Hawaii's announced new capacity.

Announced natural gas capacity was 13% lower in 2020 versus 2019, confirming the industry's consensus expectation for a leveling off in new natural gas generation build-out.

Projected Capacity Additions

In early 2021, projected new capacity over the five-year period 2021 through 2025 totaled 330,556 MW; this represents an 8.6% increase over the total for the 2020 through 2024 five-year period projected one

New Capacity Online by Region (MW) 2020

Region	Online 2017	Online 2018	Online 2019	Online 2020
ASCC	111	1	25	6
FRCC	2,408	2,532	See SERC	See SERC
HCC	48	136	187	297
MRO	1,998	3,116	3,257	4,634
NPCC	529	2,948	1,704	1,520
RFC	5,358	10,606	3,475	2,828
SERC	3,720	6,428	6,966	9,209
SPP	3,411	1,947	1,072	3,364
TRE	6,522	2,882	5,189	5,811
WECC	3,111	3,530	3,768	7,627
Total	**27,216**	**34,126**	**25,643**	**35,296**

Note: Data includes new plants and expansions of existing plants, including nuclear uprates. Totals may reflect rounding.

Source: Hitachi ABB Power Grids; EEI Finance Department, March 2021

Stage of Announced Capacity Additions (MW) 2021–2025

Fuel	Proposed	Feasibility	Application Pending	Permitted	Site Prep	Under Construction	Testing	Total
Coal	106	0	0	454	0	0	0	560
Natural Gas	20,090	876	10,099	13,183	—	13,392	722	58,362
Nuclear	4,773	1,900	—	197	—	2,200	—	9,070
Wind	57,970	3,200	15,464	8,130	412	12,062	1,821	99,059
Solar	95,482	200	24,173	20,086	565	17,480	1,026	159,012
Other	1546	1,897	194	568	5	278	5	4,493
Total	**179,967**	**8,073**	**49,930**	**42,618**	**982**	**45,412**	**3,574**	**330,556**

Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding. Data includes new plants and expansions of existing plants, including nuclear uprates. Data includes projects with an expected online date up to 2025.

Source: Hitachi ABB Power Grids; EEI Finance Department, March 2021

Announced New Capacity by Region and Fuel Type in 2020 (MW)

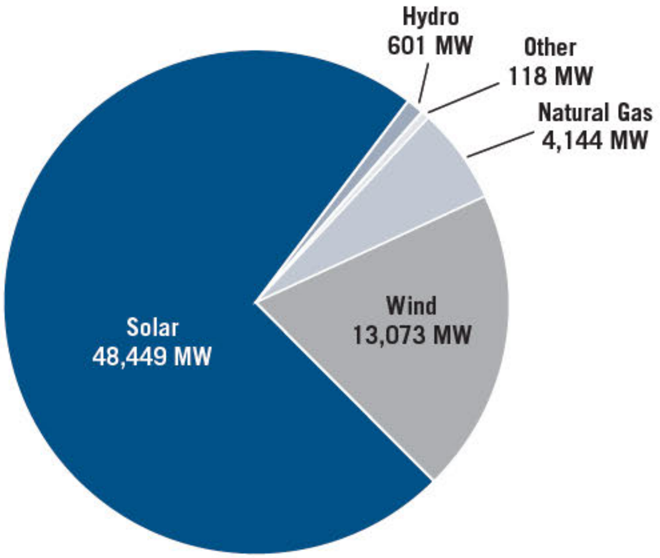
Fuel Type	Electric Reliability Council of Texas	Hawaiian Coordinating Council	Midwest Reliability Organization	Northeast Power Coordinating Council	Reliability First	SERC Reliability Corp	Southeast Power Pool Inc.	Western Electricity Coordinating Council	Total
Coal	—	—	—	—	—	—	—	—	—
Natural Gas	264	—	45	143	129	2,219	33	1,311	4,144
Nuclear	—	—	—	—	—	—	—	—	—
Wind	649	—	1,995	3,291	1,354	2,574	486	2,524	13,073
Solar	3,941	216	991	3,189	10,994	8,294	1,112	19,707	48,449
Hydro	—	—	—	600	—	—	—	1	601
Other	—	46	2	3	3	—	—	65	118
Total	**4,854**	**262**	**3,033**	**7,226**	**12,480**	**13,087**	**1,631**	**23,608**	**66,385**

Notes: Data includes new plants and expansions of existing plants announced, including nuclear uprates in 2019 for years 2020–2025. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding.

Source: Hitachi ABB Power Grids; EEI Finance Department, March 2021

2020 New Capacity Announcements by Fuel Type

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Notes: Data includes new plants and expansions of existing plants announced, including nuclear uprates in 2019 for years 2020-2025. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding.

Source: Hitachi ABB Power Grids; EEI Finance Department, March 2021

year ago. Projected capacity is overwhelmingly renewable generation; solar represents 48% of the total and wind 30%. Natural gas generation accounts for 18% and nuclear 3%. More than half, at 54%, of the 331 GW total was in the proposal stage in early 2021; that included 59% of projected wind capacity and 60% of projected solar capacity. Only 14% of the 331 GW total was under construction, 13% was in the permitted stage and 15% was in the application pending stage.

Retirements

As of March 2021, 98 GW of capacity was scheduled to retire between 2021 through 2025. While annual coal retirements are expected to taper off from a 14 GW peak in 2019, they still dominate at 38% of total planned retirements through 2025, followed by gas at 35% and fuel oil at 18%. Gas retirements are expected to peak in 2022 at 12,170 MW, the fuel's highest annual retirement total during the 2016-2025 ten-year period.

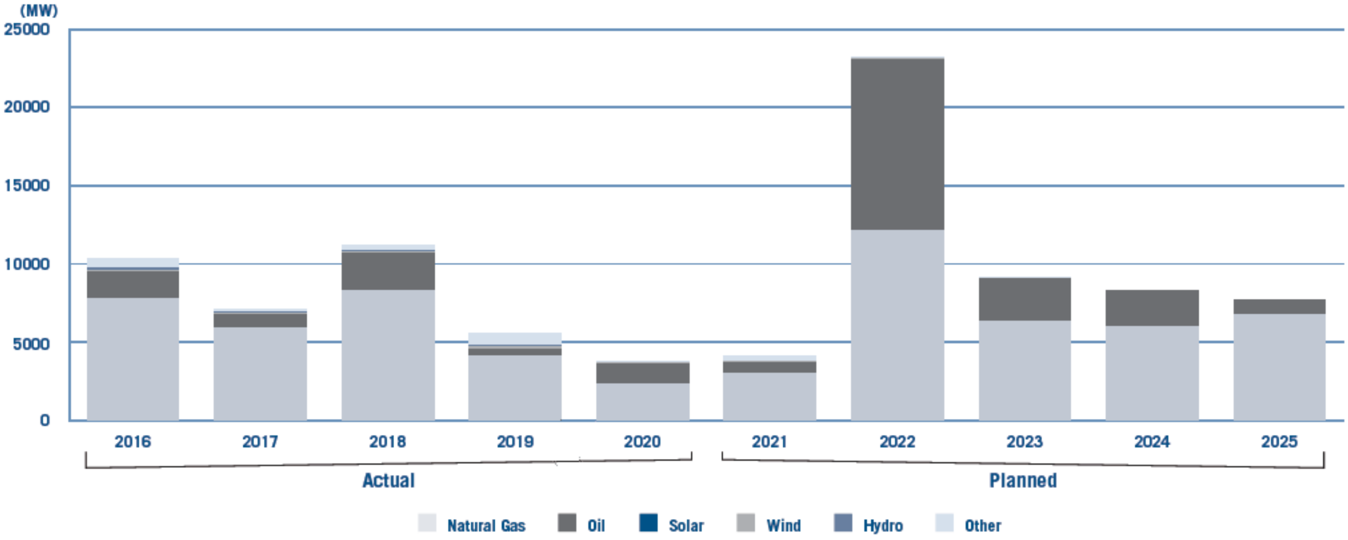
Wind and solar retirements remain minimal given their recent buildout; no solar is slated for retirement while wind retirements, at a mere 0.2% of the total, result from four plants that started operation in 1999, 2003 and 2004 in Minnesota. Hydro retirements are also minimal, at only 0.1% of the total, and are largely associated with small turbines in California, Utah, Maine and New Hampshire (including some that were operational as far back as 1907), as well as the Cornell plant in Wisconsin.

Energy Storage

Energy storage continues to be a fast-growing area for the industry. Electric companies own, operate, or utilize approximately 25 GW of storage capacity, or about 96 percent of all energy storage in the United States. Since 2015, total installed energy storage capacity in the U.S. has increased about 13 percent, from nearly 23 GW to about 26 GW. Pumped hydro accounts for the majority, at about 22 GW, or roughly 84 percent of the total. Yet battery storage is, by far, the fastest-growing storage technology, increasing sixfold from 540 MW in 2015 to about 3,373 MW in 2020. Between 2015 and 2020, battery energy storage grew from two percent of total energy storage capacity to about 13 percent.

Energy storage is expected to continue its rapid growth from 2021 through 2025. Approximately 31 GW of new battery and pumped hydro energy storage is projected to come online, increasing total capacity 120 percent by 2025. Electric companies will remain the main drivers of this growth, accounting for 24.5 GW, or nearly 79 percent, of anticipated new installations over

Actual and Planned Retirements 2016–2025



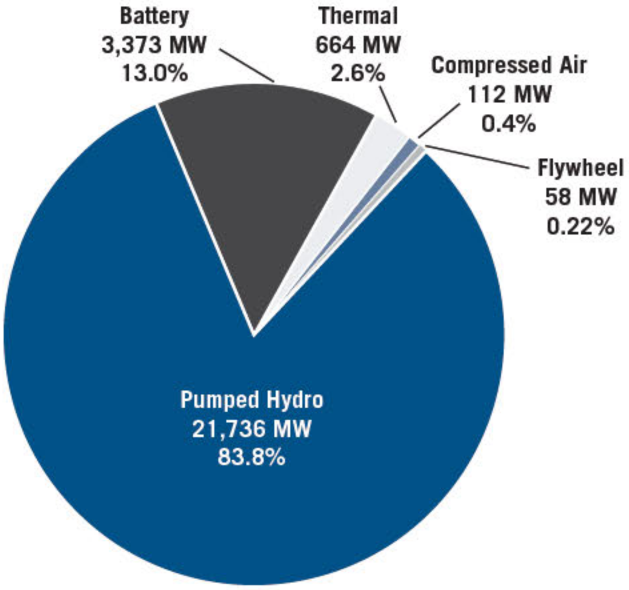
	Actual					Planned					
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Natural Gas	7,811	5,887	8,270	4,075	2,307	2,996	12,170	6,287	6,022	6,738	34,213
Oil	1,652	854	2,424	492	1,332	721	10,882	2,748	2,293	930	17,574
Solar	35	—	1	—	—	—	—	—	—	—	—
Wind	89	60	80	106	75	53	98	—	—	1	152
Hydro	127	125	54	156	2	9	—	38	6	2	55
Other	619	204	352	693	96	329	84	70	6	1.3	491
Total	**10,333**	**7,130**	**11,181**	**5,522**	**3,812**	**4,108**	**23,234**	**9,143**	**8,327**	**7672.3**	**52,485**

Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding. 2015-2019 is actual plants retired. 2020-2024 data is from announced retirements as of March 2020.

Source: Hitachi ABB Power Grids; EEI Finance Department, March 2020

Total Installed Energy Storage Capacity by Technology - 25,943 MW

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI 2021 Data, GTM Research/ESA U.S. Energy Storage MonitorReport; Dept. of Energy's Energy Storage Database; Hitachi ABB Power Grids 2021.

the next five years. Battery storage is expected to maintain its leading pace; total battery capacity is projected to increase ten-fold from about 3.4 GW in 2020 to over 34 GW by 2026. Based on ABB data, 422 MW of pumped storage hydropower is expected to come online by 2025 through both a new project and an uprate at an existing facility.

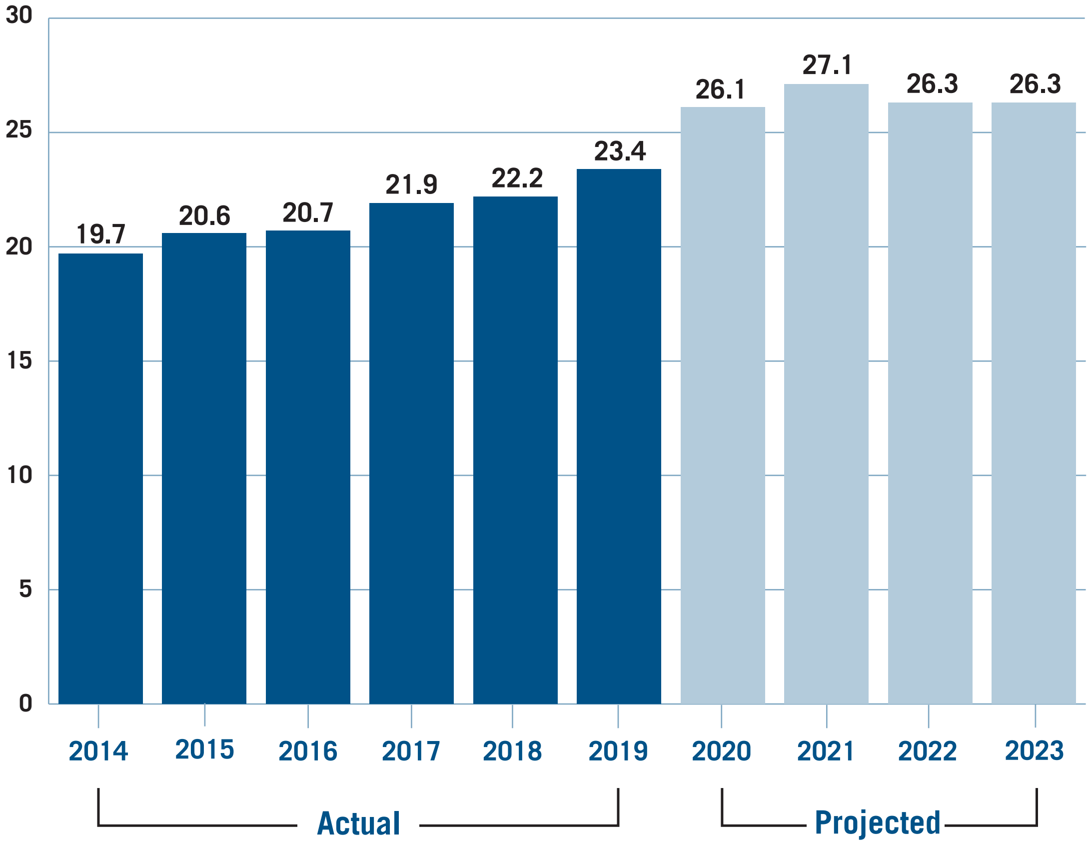
Transmission and Distribution

According to EEI's Property & Plant Capital Investment Survey, investor-owned electric utilities and stand-alone transmission companies invested $23.4 billion in transmission assets in 2019, a 5.4% increase over the $22.2 billion invested in 2018. The increase reflects the industry's efforts to meet changing customer expectations while providing low-cost, reliable, and increasingly clean service. EEI members continue to invest in the transmission system in order to provide access to clean energy; to increase the reliability, security and resiliency of the energy grid; and to reduce congestion so that lower priced resources can meet customer needs now and in the future.

EEI member companies are spending a significant and growing amount of resources on adaptation, hardening, and resilience (AHR) initiatives. In recent years, it is estimated that EEI's member companies have invested around $20 billion per year in AHR for transmission and distribution infrastructure. Specific examples of AHR investments in the electric grid include undergrounding power lines, installing cement poles, and elevating or relocating transformers. AHR is increasingly becoming an important way that electric companies fulfill their mission of supplying customers with reliable, affordable and increasingly sustainable energy. Electric companies also are developing weather predictive services, risk modeling, fire spread modeling, deployment of sensors and high-definition cameras, communication networks, satellite data damage assessment, and other real or near real time situational awareness instruments that can help them better predict and prepare for extreme weather event and wildfires.

Actual & Projected Transmission Investment* 2014–2023

($ Billions)



r = revised

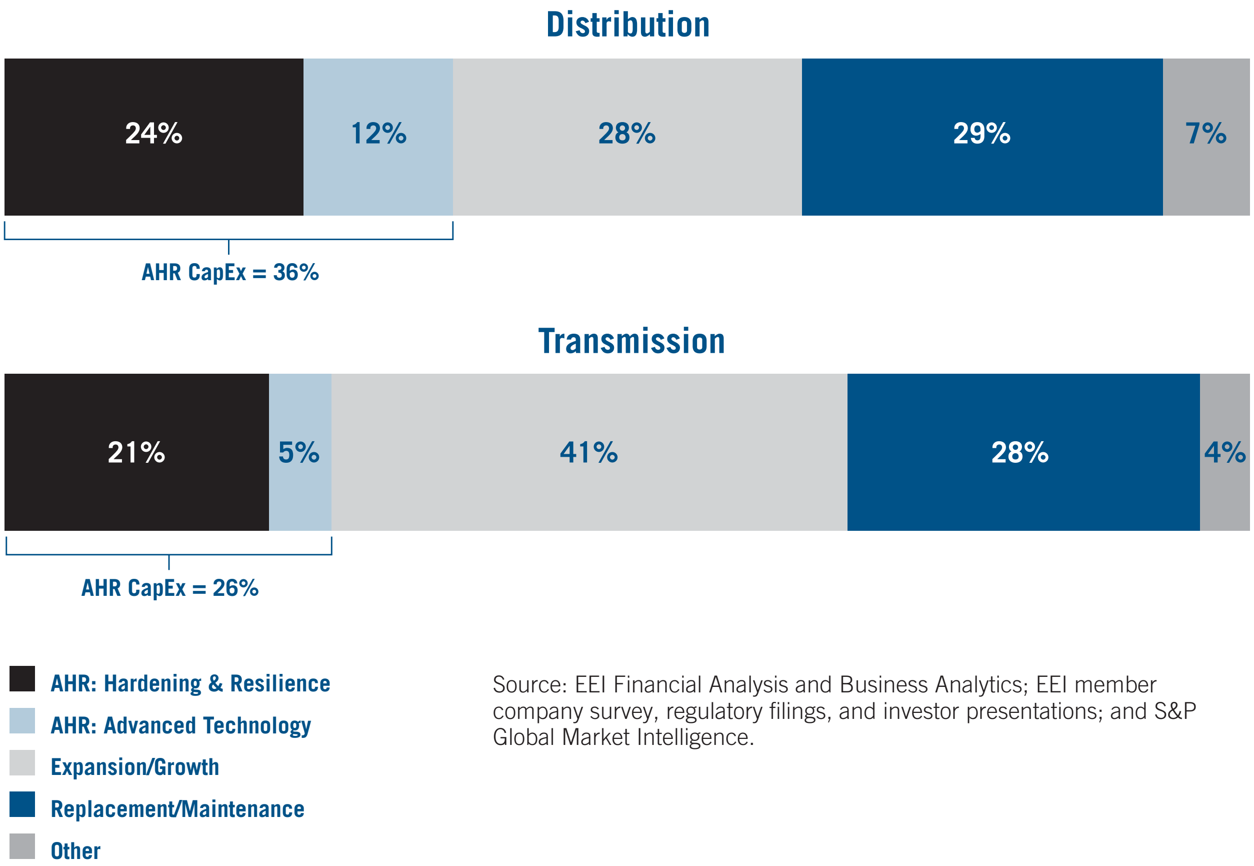
*Investment of investor-owned electric companies and stand-alone transmission companies. Actual Investment figures were obtained from the EEI Property & Plant Capital Investment Survey supplemented with FERC Form 1 data. Projected investment figures were obtained from the EEI Transmission Capital Budget & Forecast Survey supplemented with data obtained from company 10-k reports and investor presentations.

Source: EEI Business Analytics.

Updated November 2020.

Adaptation, Hardening, and Resilience (AHR) as Drivers of T&D Investment

Based on 2020 Survey Results



Source: EEI Financial Analysis and Business Analytics; EEI member company survey, regulatory filings, and investor presentations; and S&P Global Market Intelligence.

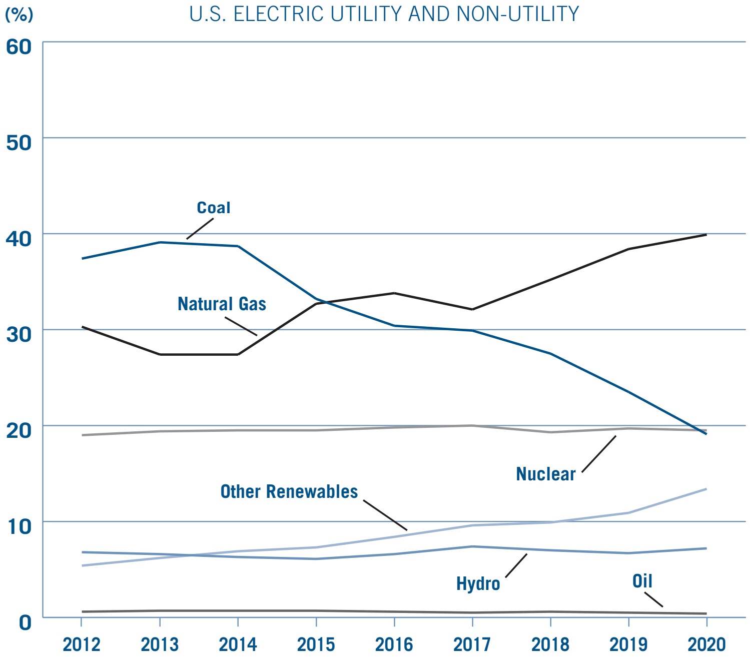
Fuels Analysis

Net Generation and Electricity Sales

Total electric power industry net generation in 2020 amounted to 4,050,825 gigawatt hours (GWh), a decrease of 2.7% from 2019's net generation. Total nationwide retail electricity sales decreased 3.9% in 2020 as the COVID-19 pandemic impacted commercial and industrial electricity demand across most of the country. Total retail sales declined in 45 states when compared to 2019 levels. Indiana and Wyoming experienced the largest percentage declines at 8.6% and 8.5%, respectively. Arizona produced the largest year-to-year percentage increase of any state, at 4.6%.

Total sales to commercial customers decreased 6.3% as the pandemic caused office buildings to temporarily close and commercial businesses to severely curtail services; this is the

Fuel Sources for Net Electric Generation (in Percent of total electric generation) 2012–2020



U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

Non-Utility Power Producer: Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: U.S. Department of Energy, Energy Information Administration (EIA), March 2021.

Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

	2019	2020
Coal	23.5%	19.1%
Gas	38.4%	39.9%
Nuclear	9.7%	19.5%
Oil	0.5%	0.4%
Hydro	6.7%	7.2%
Renewables	10.9%	13.4%
Biomass	1.4%	1.4%
Geothermal	0.4%	0.4%
Solar	1.8%	3.3%
Wind	7.3%	8.3%
Other fuels	0.5%	0.5%
Total	100%	100%

Note: Totals may not equal 100% due to rounding.

U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

Non-Utility Power Producer: Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: U.S. Department of Energy, Energy Information Administration (EIA). March 2021.

largest year-to-year percentage drop in annual commercial sales since the Energy Information Administration's (EIA) predecessor organizations began compiling electricity sales data in 1949. Commercial sales fell more than 10% in Mississippi, Pennsylvania and Hawaii; Hawaii experienced the largest percentage decrease of any state, at 14.2%. Sales increased 2.4% in Nevada, the only state in which commercial electricity sales did not decline.

Total electricity sales to retail industrial customers fell 8.3% in 2020 in response to the year's shutdowns. Industrial sales declined in 41 states, with Oregon, Michigan and Washington experiencing declines of more than 15%. North Dakota saw the largest increase in industrial sales, at 6%.

U.S. electricity sales to residential customers increased 1.5% as government mandates forced people to stay at home and most employers supported working from home when possible. Arizona (+11.5%) and Nevada (+10.8%) had the largest percentage increases in residential demand among all states. Arkansas (-3.3%) and North Dakota (-3.1%) were the two states that experienced a decrease in residential demand of more than 3%.

Coal

Net generation from coal-fired plants decreased 19.8% in 2020 and accounted for 19.1% of the total electricity generated nationwide. The year's 773,805 GWh of coal-fired generation was the lowest annual total for coal since 1973; 2020 also marked the first year coal generation was neither the leading nor the second-largest contributor to total electric generation. The coal fleet's capacity factor for the year was only 40% compared with 72% in 2008, according to EIA data.

Even though electric utilities paid an average $1.97 per million British Thermal Units (MMBtu) for coal in 2020, 11 cents less than in 2019, coal remains the most expensive fuel for electricity production when all costs are considered. According to ABB/Hitachi Power Grids, the modeled 2020 total production cost from coal was $32.10/MWh, 39% higher than the cost of producing electricity from natural gas. Fuel-related costs for coal were the highest of all fuel types in 2020, at $21.33/MWh, a decrease of 5% versus 2019.

The retirement of approximately 58 GW of coal generating capacity from 2016 through 2020 is another factor contributing to declining coal generation. While the rate of coal plant retirements is expected to slow, another 37 GW of coal capacity throughout the U.S. is expected to shut down by the end of 2025.

Natural Gas

Natural gas accounted for the most generation of all the fuel types in 2020 – a 39.9% share of total generation at utility scale facilities and a 2% increase over 2019 generation total, driven largely by capacity additions and the lower cost of natural gas.

In 2020, natural gas prices were the lowest in decades, at an average of $2.64/MMBtu. This led to a 15% drop in the average cost to produce electricity from natural gas to $23.13/MWh. The fuel cost of coal was 15% higher than that of natural gas in 2020, contributing to natural gas being the leading generation fuel that year.

Nuclear

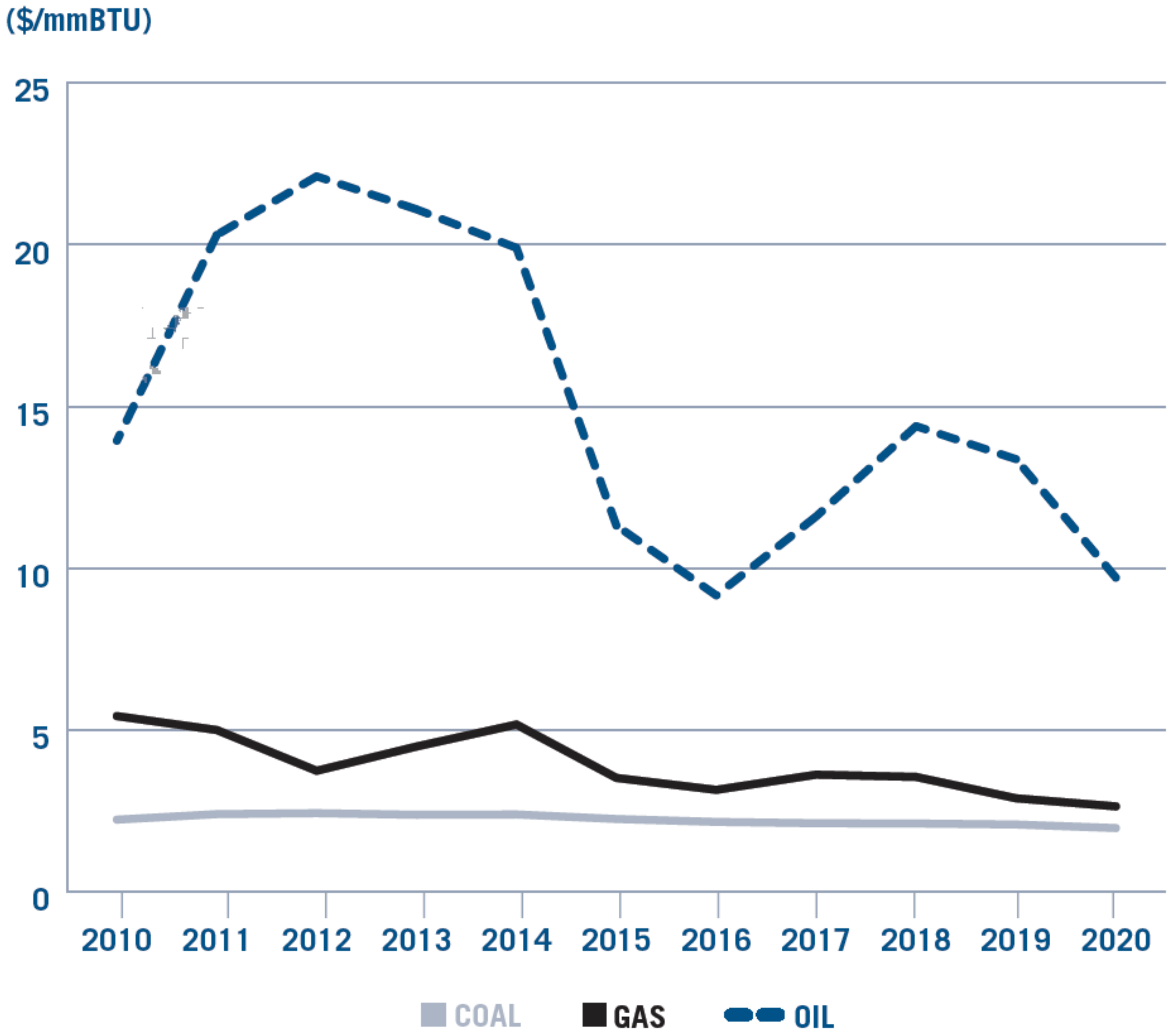
Nuclear power output decreased 2.4% in 2020 and accounted for 19.5% of total electric power generation, slightly exceeding its 19.4% share in 2019 and nearly matching its 19.6% annual average since 2001. New nuclear plants have been made uneconomical by high construction costs and lengthy permitting and building processes. However, nuclear generation has the highest capacity factor of all generation, at 92.5%. In other words, nuclear power plants ran at their maximum power output more than 92.5% of the time in 2020; this is about 1.5 to 2 times more than natural gas and coal plants, according to EIA data.

While approximately 4.8 GW of nuclear capacity was retired from 2016 through 2020, an additional 8.8 GW will be retired from 2021 through 2025. Enhancements to existing nuclear generation, however, are ongoing. Uprates scheduled online in 2022 at two reactors at Southern Company's Vogtle nuclear generation station in Georgia, which will augment nameplate capacity by 2,320 MW, are the only new nuclear capacity built over the last three decades.

In 2020, the Nuclear Regulatory Commission (NRC) approved uprates at two nuclear facilities: a 17 MW uprate at Tennessee Valley Authority's Watts Bar plant unit 2 in Tennessee, operational in 2020, and

Average Cost of Fossil Fuels 2010–2020 in $/MMBtu

U.S. ELECTRIC UTILITIES

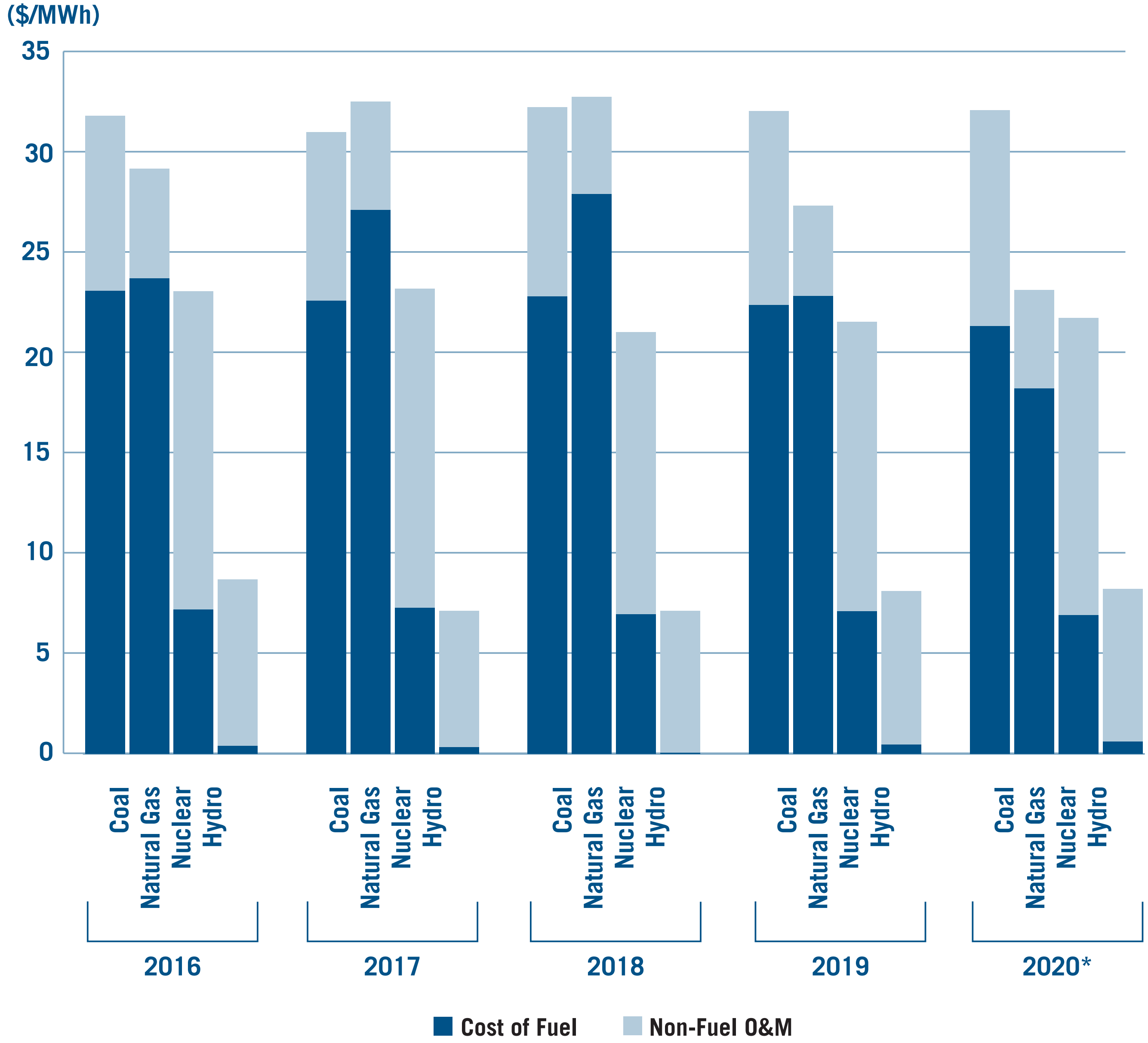


U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

Source: U.S. Department of Energy, Energy Information Administration (EIA), March 2021.

Average Cost to Produce Electricity 2016–2020

U.S. ELECTRIC UTILITY AND NON-UTILITY



U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

Non-Utility Power Producer: Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

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*2020 results are preliminary. All years based on modeled data from Hitachi ABB Power Grids March 2021.

a 77 MW uprate at Southern's Farley plant units 1 and 2 in Alabama set to go into operation in 2021. In February 2021, the NRC approved uprates for Duke Energy's South Carolina Oconee Nuclear Station units 1, 2, and 3; these are expected to add 14 MW of generating capacity at each unit for a 42 MW total.

Renewables

The nation's fuel mix has changed markedly over the past decade. EEI member companies have been leaders in implementing this change by shifting from coal to natural gas generation and by growing renewable generation capacity, primarily solar and wind. Many states are evolving the Renewable Portfolio Standards established as far back as the 1990s to a higher percentage, or to goals that require electricity generation from clean sources or more specifically, net zero emissions.

America's investor-owned electric companies are leading the clean energy transformation. They are united in their commitment to get the energy they provide as clean as they can as fast as they can, without compromising on the reliability or affordability that their customers value. Today, carbon emissions from the U.S. power sector are at their lowest level in more than 40 years—and continue to fall. At the same time, 40 percent of the nation's electricity now comes from carbon-free sources, including nuclear energy, hydropower, wind, and solar energy.

Electricity generated from carbon-free sources accounted for 1,624,155 MWh, or 40.1%, of total electric power industry generation in 2020. Generation from all renewable energy sources made up 834,236 MWh or 20.6% of the total, compared to 763,629 MWh, or 18.3% of the total, in 2019. Conventional hydroelectric generation increased 1.1% as a result of more precipitation during the year and accounted for 291,111 MWh, or 7.2%, of total electric power generation. Generation from wind power increased 14.1% to 337,510 MWh, or 8.3% of the year's total, producing a 257% increase in wind generation over the past 10 years; in 2010, wind generation was only 94,652 MWh. Generation from all photovoltaic and solar thermal sources increased about 45% in 2020 and produced 132,632 MWh, or 3.3%, of total electricity generated. Universal solar accounted for about 90,891 MWh, or 68%, of all solar generation in 2020, up 26% from 2019 when it accounted for 67% of total solar generation.

The 47 EEI members that account for approximately 87% of EEI-member generation have set near- and long-term greenhouse gas (GHG) reduction goals, with many targeting reductions of 80% or more by 2050 or sooner. More than half aspire to net-zero emissions by 2050 or an earlier target date.

States with Renewable Energy, Clean Energy and Greenhouse Gas Reduction Goals and Targets

State	Greenhouse Gas Reduction Targets	100% Clean Energy Target	RPS Target
Arizona	The Arizona Corporation Commission (ACC) is considering a greenhouse gas reduction mandate or goal of 100% by 2050.		15% by 2025, 4.5% distributed generation. The ACC is considering replacing the RPS with a greenhouse gas reduction target. Timeline for approval not specified.
California		✓ 2045	50% by 2026 60% by 2030 100% by 2045
Colorado		✓ 2050	30% by 2020 3% distributed generation 1.5% customer sited 100% by 2050
Connecticut			28% by 2022, increasing 2% annually to 44% by 2030, plus 4% energy efficiency
Delaware			40% by 2035, 10% solar
Hawaii		✓ 2045	30% by 2020 70% by 2040 100% by 2045
Illinois			25% by 2026, 18.75% wind, 1.5% solar, 0.25% distributed generation
Indiana			10% by 2025 (goal)
Iowa			105 MW; 1 GW wind goal by 2010
Kansas			20% by 2020 (goal)
Maine		✓ 2050	50% by 2030, goals of 80% by 2030 and 100% by 2050
Maryland			30.8% by 2021 (7.5% solar) 50% by 2030 (14.5% solar, 1,200 MW offshore wind)
Massachusetts	100% by 2050		35% by 2030, +1% annually
Michigan			15% by 2021
Minnesota			31.5% by 2020 (Xcel Energy), 26.5% by 2025 (all other IOUs), 1.5% solar
Missouri			15% by 2021, 2% solar
Montana			15% by 2015
Nebraska			No state goal but Nebraska's two largest public power districts have renewable goals
Nevada		✓ 2050	24% by 2021 50% by 2030, 2.4 multiplier for solar. 100% by 2050 (goal)
New Hampshire			21.6% by 2021 (.7% solar) 25.2% by 2025
New Jersey		✓ 2050	35% by 2025 50% by 2030, 5.1% from solar by 2021 then declines to 1.1% by 2033. 100% clean energy by 2050 (goal)
New Mexico		✓ 2045	50% by 2030 80% by 2040 100% by 2045 (IOUs)
New York		✓ 2040	70% by 2030 100% by 2040
North Carolina	70% by 2030, 100% by 2050 (goal)	✓ 2050	12.5% by 2021 for investor owned utilities, 0.2% solar by 2018.
Ohio			8.5% by 2026
Oklahoma			15% by 2015 (goal)
Oregon			25% by 2025 50% by 2040 (large utilities)
Pennsylvania			18% by 2021, 0.5% solar by 2021
Rhode Island			38.5% by 2035
South Carolina			2% by 2021, 0.25% from distributed generation (goal)
South Dakota			10% by 2015 (goal)
Tennessee			Tennessee Valley Authority's goal is 60% clean energy by 2030
Texas			5,880 MW by 2015 10,000 MW by 2025. 500 MW non-wind (goal)
Vermont			55% by 2017 75% by 2032. Additional 12% energy efficiency by 2032.
Virginia		✓ 2050	Dominion Energy Inc.: 14% by 2021, 100% by 2045. Appalachian Power Co. and all retail providers: 6% by 2021, 100% by 2050.
Washington	100% by 2030	✓ 2045	15% by 2020 100% by 2045
Wisconsin		✓ 2050	Varies by electric company. Total of 10% by 2015.

Notes: the table depicts finalized and proposed state actions. Goal indicates there is no explicit compliance requirement.

Updated March 2021.

Industry Financial Performance

Income Statement

- Energy Operating Revenues declined 1.7% versus last year. Nationwide electricity demand fell 2.9% as COVID-19 restrictions depressed commercial and industrial load. Mild winter weather also constrained energy demand for heating. With people homebound from March through year-end, residential electricity demand gained about 1%. The average retail price of electricity nationwide also rose about 1%, according to EIA data. Only 10 of the 44 utilities included in EEI's industry consolidated data experienced revenue growth in 2020.
- Falling coal and natural gas prices drove Total Energy Operating Expenses down 11.2%. Total Electric Generation Cost was almost 10% lower; it's two components, electric fuel expense and cost of purchased power, each showed declines across nearly all companies who report these metrics. Growth in zero-fuel-cost renewable generation may also have contributed to lower fuel expense. Gas Cost fell almost 21%; it was sharply lower for nearly all companies.
- Operations and Maintenance (O&M) costs rose 1.2%, roughly the same as 2019's 1.0% increase. Utilities are benefitting from smart-grid investment productivity and have worked hard to constrain O&M-related expenses in recent years; that focus continued during the pandemic as a means of addressing revenue declines. But these costs are also driven by essential reliability needs. Of the 42 utilities who report O&M as a line item, 25 reported a decline and year-to-year comparisons varied widely.
- Depreciation & Amortization (D&A) expenses rose 7.5%. This metric increased for 41 of the 44 constituent companies, reflecting the industry's ongoing widespread and diverse investments in new clean generation, transmission, distribution and grid modernization.
- Operating Income rose less than 1%. Lower fuel costs and the industry's cost management efforts partly offset lower revenue and higher Depreciation and Amortization expenses. Operating Income rose for 20 companies and declined for the other 24.
- Total Other Recurring and Non-Recurring Revenue show the influence of a few company-specific situations. Together, these metrics added $3.5 billion to consolidated pre-tax income compared to last year.

- Interest Expense rose only 2.2%, less than last year's 8.2%. This was the result of declines at a few large utilities and falling interest rates during the year. Most companies had slightly higher interest costs due to rising levels of long-term debt required to finance capital spending.

- The large jump in Asset Write-downs and offsetting decline in Other Non-Recurring Expenses were driven by actions at just a few companies. These two items together had little impact on the year-to-year change in consolidated industry figures.

- Net income Before Taxes increased 9.4%. Net Income rose 4.2% as Provision for Taxes jumped 25.7%. These figures are driven by the industry's largest companies and mask a wide variation in company-specific results. Pre-Tax Income rose at 19 companies and declined at 25. Net Income likewise rose at 20 and fell at 24. The year-to-year change in both metrics showed considerable variation across companies.

- The industry's Common Dividend payments rose 5.8% versus 2019. Utilities' reliable stock dividends offer a welcome source of income for savings-oriented investors, especially given the near-zero short-term rates and meager bond yields available during 2020.

Consolidated Income Statement

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

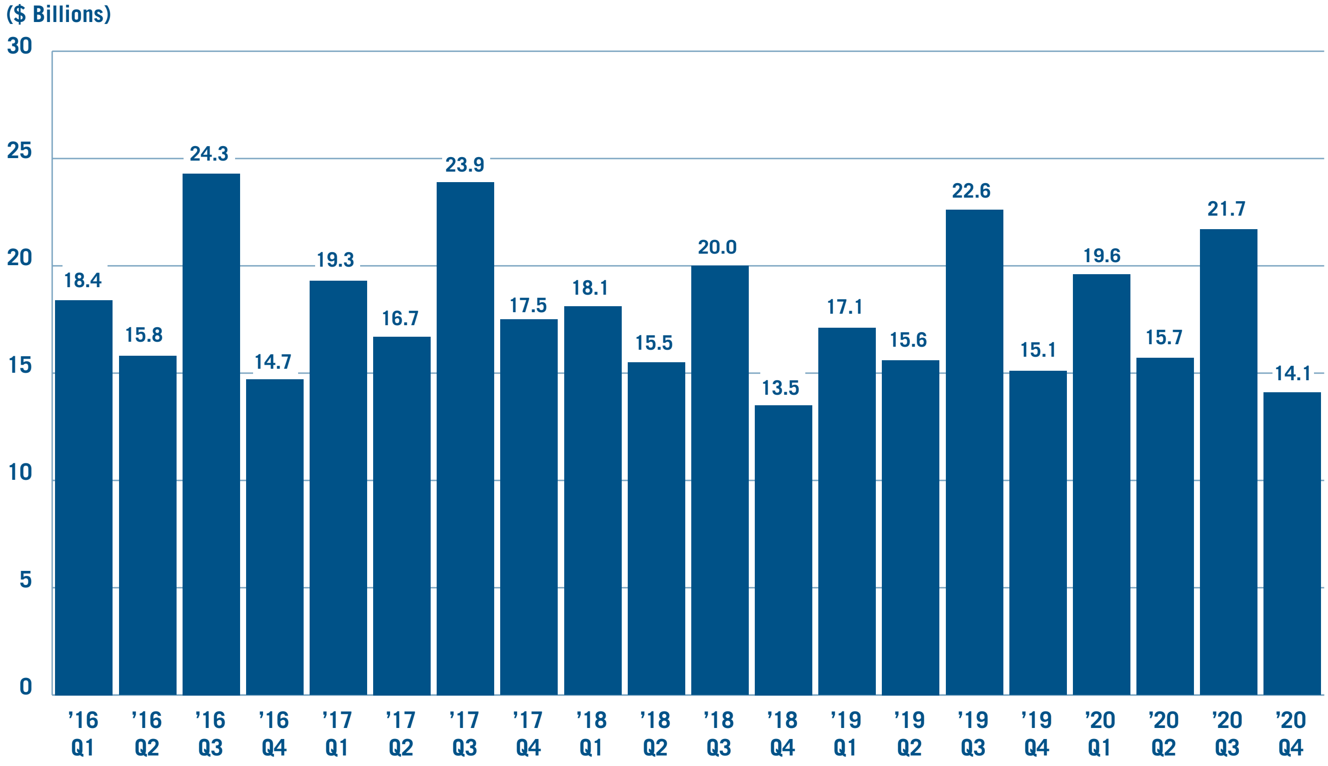
	12 Months Ended		
($ Millions)	**12/31/2020**	**12/31/2019r**	**% Change**
Energy Operating Revenues	$351,085	$357,127	(1.7%)
Energy Operating Expenses			
Total Electrical Generation Cost	80,661	89,208	(9.6%)
Gas Cost	11,986	15,112	(20.7%)
Total Energy Operating Expenses	**92,647**	**104,320**	**(11.2%)**
Revenues less energy operating expenses	**258,438**	**252,807**	**2.2%**
Other Operating Expenses			
Operations & Maintenance	93,907	92,824	1.2%
Depreciation & Amortization	56,966	52,979	7.5%
Taxes (not income) - Total	21,075	20,428	3.2%
Other Operating Expenses	15,390	16,091	(4.4%)
Total Operating Expenses	**279,986**	**286,641**	**(2.3%)**
Operating Income	**71,099**	**70,486**	**0.9%**
Other Recurring Revenue			
Partnership Income	2,329	1,621	43.7%
Allowance for Equity Funds Used for Construction	2,027	1,801	12.5%
Other Revenue	9,869	4,625	113.4%
Total Other Recurring Revenue	**14,226**	**8,047**	**76.8%**
Non-Recurring Revenue			
Gain on Sale of Assets	566	3,049	(81.4%)
Other Non-Recurring Revenue	-	117	(100.0%)
Total Non-Recurring Revenue	**566**	**3,167**	**(82.1%)**
Interest Expense	27,178	26,583	2.2%
Other Expenses	453	149	203.3%
Asset Writedowns	8,657	3,470	149.5%
Other Non-Recurring Expenses	7,518	13,034	(42.3%)
Total Non-Recurring Expenses	16,175	16,504	(2.0%)
Net Income Before Taxes	**42,085**	**38,463**	**9.4%**
Provision for Taxes	3,336	2,653	25.7%
Dividends on Preferred Stock of Subsidiary	-	-	NM
Other Minority Interest Expense	-	-	NM
Minority Interest Expense	-	-	NM
Trust Preferred Security Payments	-	-	NM
Other After-tax Items	-	-	NM
Total Minority Interest and Other After-tax Items	-	-	NM
Net Income Before Extraordinary Items	**38,749**	**35,810**	**8.2%**
Discontinued Operations	(122)	1,243	(109.8%)
Change in Accounting Principles	-	-	NM
Early Retirement of Debt	-	-	NM
Other Extraordinary Items	-	-	NM
Total Extraordinary Items	(122)	1,243	(109.8%)
Net Income	**38,627**	**37,053**	**4.2%**
Preferred Dividends Declared	597	376	58.8%
Other Preferred Dividends after Net Income	2	2	0.0%
Other Changes to Net Income	(3)	(3)	0.0%
Net Income Attributable to Noncontrolling Interests	(533)	60	NA
Net Income Available to Common	**38,558**	**36,612**	**5.3%**
Common Dividends	**29,503**	**27,876**	**5.8%**

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

Quarterly Net Operating Income

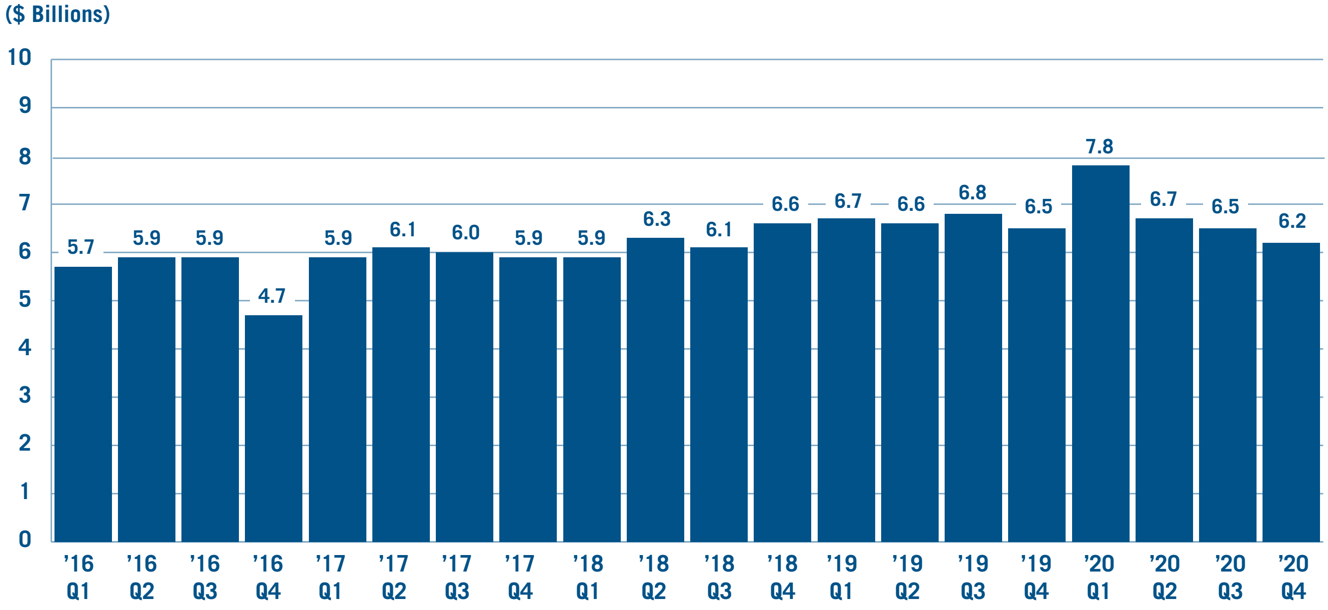
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Quarterly Interest Expense

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Individual Non-Recurring and Extraordinary Items 2011–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2011	2012	2013	2014	2015	2016	2017	2018	2019r	2020
Net Gain (Loss) on Sale of Assets	891	311	414	996	789	767	1,012	5,272	3,049	566
Other Non-Recurring Revenue	946	264	78	296	(4)	888	493	131	117	–
Total Non-Recurring Revenue	**1,837**	**576**	**492**	**1,292**	**785**	**1,655**	**1,505**	**5,403**	**3,167**	**566**
Asset Writedowns	(2,743)	(5,646)	(4,276)	(8,762)	(5,189)	(17,487)	(4,166)	(4,121)	(3,470)	(8,657)
Other Non-Recurring Charges	(851)	(3,136)	(3,510)	(2,675)	(1,764)	(3,109)	(5,630)	(17,841)	(13,034)	(7,518)
Total Non-Recurring Charges	**(3,594)**	**(8,783)**	**(7,786)**	**(11,437)**	**(6,953)**	**(20,596)**	**(9,796)**	**(21,962)**	**(16,504)**	**(16,175)**
Discontinued Operations	(1,011)	(4,317)	(88)	295	(1,148)	(732)	(1,554)	602	1,243	(122)
Change in Accounting Principles	–	–	–	–	–	–	–	–	–	–
Early Retirement of Debt	–	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	960	–	–	–	–	–	–	–	–	–
Total Extraordinary Items	**(51)**	**(4,317)**	**(88)**	**295**	**(1,148)**	**(732)**	**(1,554)**	**602**	**1,243**	**(122)**
Total Non-Recurring and Extraordinary Items	**(1,808)**	**(12,524)**	**(7,381)**	**(9,850)**	**(7,316)**	**(19,674)**	**(9,844)**	**(15,957)**	**(12,094)**	**(15,731)**

r = revised Note: Figures represent net industry totals. Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Top Net Non-Recurring and Extraordinary Gains (Losses) 2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

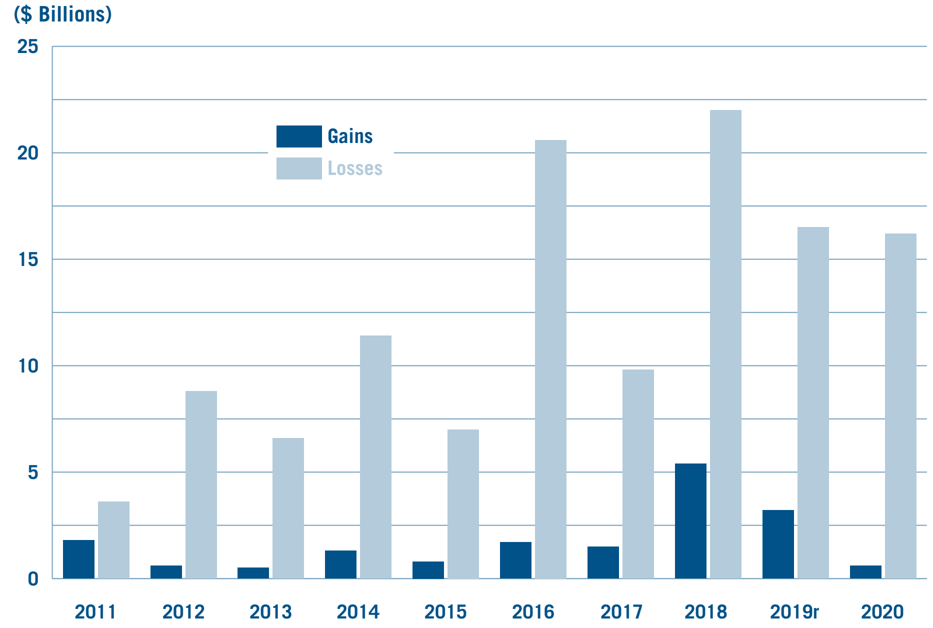
($ Millions)

Company	Gains	Losses	Net Total
Duke Energy	10	3,111	3,101
PG&E Corp	-	2,623	2,623
Dominion Energy	61	2,233	2,172
CenterPoint Energy	-	1,951	1,951
Edison International	282	1,698	1,416
NextEra Energy	403	1,520	1,117
OGE Energy	-	780	780
NiSource	(411)	244	654
Exelon Corp	24	591	567
Southern Company	65	531	466

Source: S&P Global Market Intelligence and EEI Finance Department.

Aggregate Non-Recurring and Extraordinary Items 2011–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



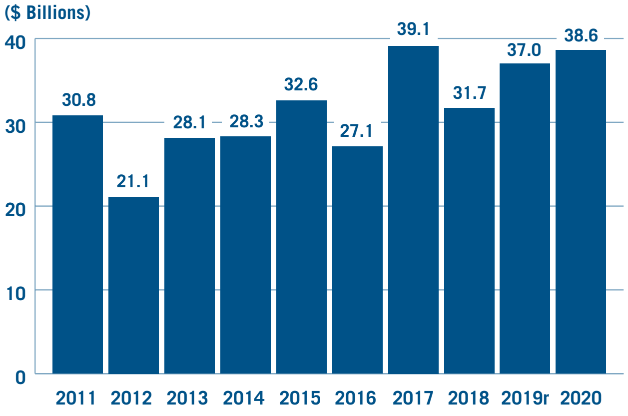
	2011	2012	2013	2014	2015	2016	2017	2018	2019r	2020	Total
Gains	1.8	0.6	0.5	1.3	0.8	1.7	1.5	5.4	3.2	0.6	22.9
Losses	3.6	8.8	6.6	11.4	7.0	20.6	9.8	22.0	16.5	16.2	132.4
Total	**(1.8)**	**(8.2)**	**(6.2)**	**(10.1)**	**(6.2)**	**(18.9)**	**(8.3)**	**(16.6)**	**(13.3)**	**(15.6)**	**(109.5)**

r = revised Note: Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income 2011–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

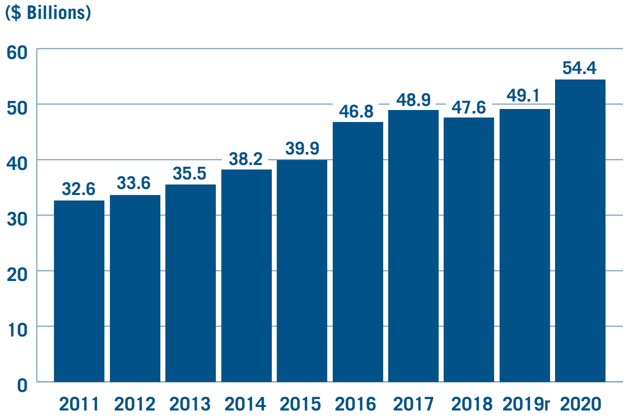


r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income Before Non-Recurring and Extraordinary Items 2011-2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

U.S. Electric Output (GWh)

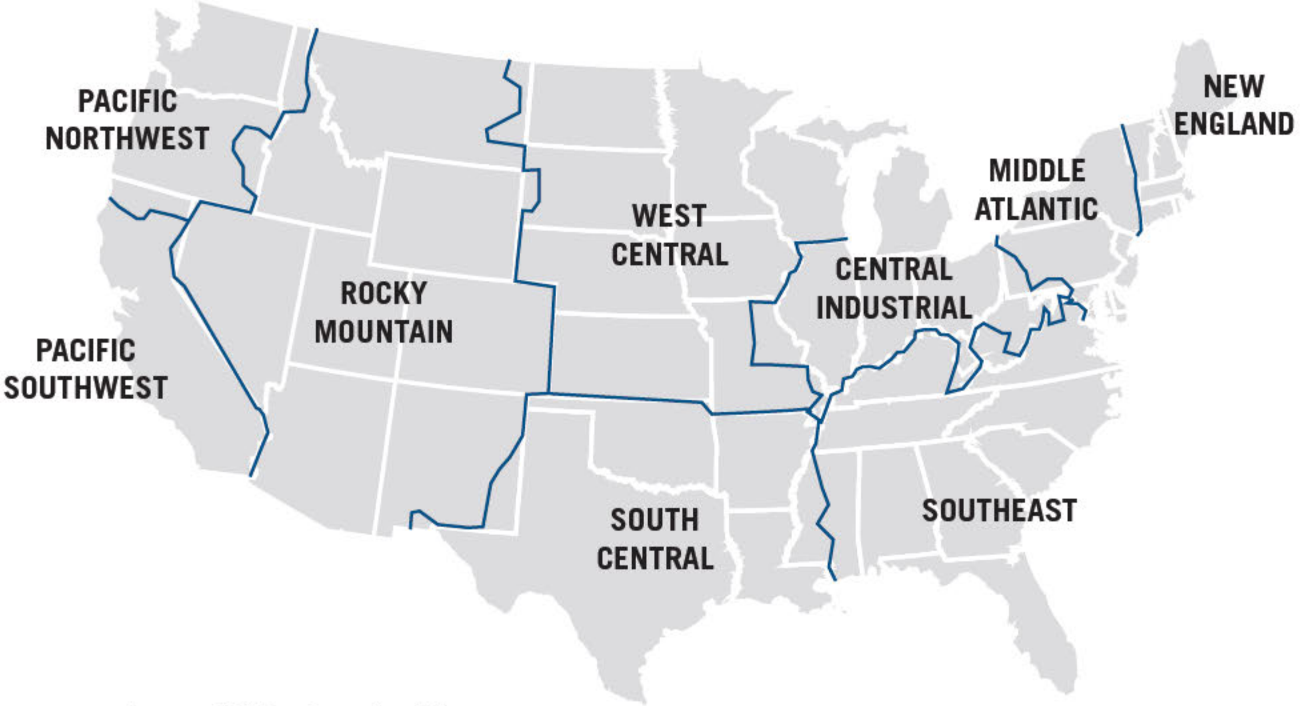
Periods Ending December 31

Region	2020	2019	% Change
New England	114,308	117,133	(2.4%)
Mid-Atlantic	408,677	428,514	(4.6%)
Central Industrial	630,703	660,478	(4.5%)
West Central	321,004	329,870	(2.7%)
Southeast	984,921	1,027,445	(4.1%)
South Central	756,856	769,886	(1.7%)
Rocky Mountain	287,084	283,888	1.1%
Pacific Northwest	153,806	157,502	(2.3%)
Pacific Southwest	266,450	268,153	(0.6%)
Total United States	**3,923,809**	**4,042,869**	**(2.9%)**

Note: Represents all power placed on grid for distribution to end customers; does not include Alaska or Hawaii.

Source: EEI Business Analytics.

EEI U.S. Electric Output – Regions



Source: EEI Business Analytics.

U.S. Weather

January – December 2020

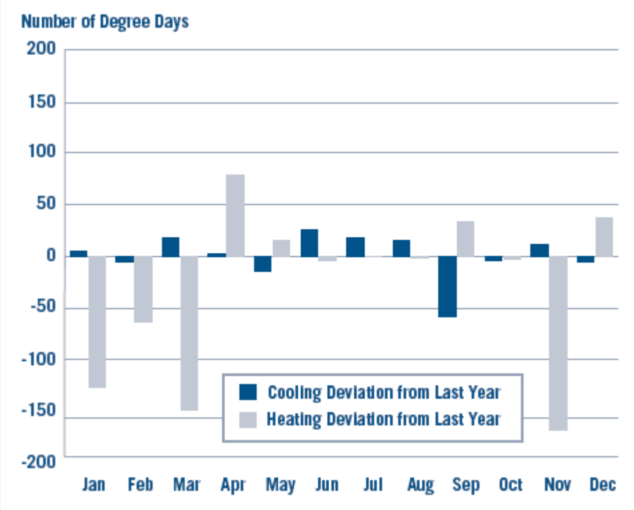
	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
New England	736	319	76%	173	31%
Mid-Atlantic	946	290	44%	119	14%
East North Central	865	157	22%	27	3%
West North Central	1,003	75	8%	(3)	(0%)
South Atlantic	2,348	383	19%	(159)	(6%)
East South Central	1,695	147	9%	(252)	(13%)
West South Central	2,726	275	11%	(108)	(4%)
Mountain	1,504	261	21%	134	10%
Pacific	982	278	39%	190	24%
United States	**1,474**	**257**	**21%**	**11**	**1%**
Heating Degree Days					
New England	5,852	(793)	(12%)	(683)	(10%)
Mid-Atlantic	5,107	(836)	(14%)	(528)	(9%)
East North Central	5,861	(670)	(10%)	(510)	(8%)
West North Central	6,315	(469)	(7%)	(706)	(10%)
South Atlantic	2,354	(514)	(18%)	(93)	(4%)
East South Central	3,051	(572)	(16%)	(110)	(3%)
West South Central	1,872	(427)	(19%)	(324)	(15%)
Mountain	4,837	(395)	(8%)	(265)	(5%)
Pacific	3,000	(243)	(7%)	(191)	(6%)
United States	**4,008**	**(539)**	**(12%)**	**(348)**	**(8%)**

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65 degrees Fahrenheit is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration, National Weather Service, Climate Prediction Center.

2020 Weather Compared to 2019

AS MEASURED BY DEVIATIONS BETWEEN THE TWO YEARS



Source: National Oceanic and Atmospheric Administration and National Weather Service.

	Cooling Deviation From Last Year	Heating Deviation From Last Year
Jan	5	(127)
Feb	(5)	(63)
Mar	18	(148)
Apr	3	79
May	(14)	16
Jun	26	(4)
Jul	18	0
Aug	15	(1)
Sep	(58)	34
Oct	(4)	(3)
Nov	12	(168)
Dec	(5)	37
Total	**11**	**(348)**

Heating and Cooling Degree Days and Percent Changes

January—December 2020

	COOLING DEGREE DAYS			HEATING DEGREE DAYS			PERCENTAGE CHANGE			
	Total	Deviation From Norm	Deviation From Last Yr	Total	Deviation From Norm	Deviation From Last Yr	Cooling Degree Change From Norm	Cooling Degree Change From Last Yr	Heating Degree Change From Norm	Heating Degree Change From Last Yr
Jan	9	0	5	741	(176)	(127)	0.0%	125.0%	(19.2%)	(14.6%)
Feb	10	1	(5)	689	(66)	(63)	11.1%	(33.3%)	(8.7%)	(8.4%)
Mar	33	15	18	495	(98)	(148)	83.3%	120.0%	(16.5%)	(23.0%)
First Quarter	**52**	**16**	**18**	**1,925**	**(340)**	**(338)**	**44.4%**	**52.9%**	**(15.0%)**	**(14.9%)**
Apr	41	11	3	372	27	79	36.7%	7.9%	7.8%	27.0%
May	108	11	(14)	170	11	16	11.3%	(11.5%)	6.9%	10.4%
Jun	246	33	26	26	(13)	(4)	15.5%	11.8%	(33.3%)	(13.3%)
Second Quarter	**395**	**55**	**15**	**568**	**25**	**91**	**16.2%**	**3.9%**	**4.6%**	**19.1%**
Jul	396	75	18	3	(6)	0	23.4%	4.8%	(66.7%)	0.0%
Aug	345	55	15	7	(8)	(1)	19.0%	4.5%	(53.3%)	(12.5%)
Sep	179	24	(58)	70	(7)	34	15.5%	(24.5%)	(9.1%)	94.4%
Third Quarter	**920**	**154**	**(25)**	**80**	**(21)**	**33**	**20.1%**	**(2.6%)**	**(20.8%)**	**70.2%**
Oct	75	22	(4)	259	(23)	(3)	41.5%	(5.1%)	(8.2%)	(1.1%)
Nov	27	12	12	423	(116)	(168)	80.0%	80.0%	(21.5%)	(28.4%)
Dec	5	(2)	(5)	753	(64)	37	(28.6%)	(50.0%)	(7.8%)	5.2%
Fourth Quarter	**107**	**32**	**3**	**1,435**	**(203)**	**(134)**	**42.7%**	**2.9%**	**(12.4%)**	**(8.5%)**
Full Year	**1,474**	**257**	**11**	**4,008**	**(539)**	**(348)**	**21.1%**	**0.8%**	**(11.9%)**	**(8.0%)**

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Heating Degree Days Percentage Change from Historical Norm	(4.5)	(16.6)	(0.6)	1.1	(9.1)	(14.8)	(14.2)	(4.2)	(4.4)	(11.9%)
Cooling Degree Days Percentage Change from Historical Norm	21.5	22.4	10.9	5.8	19.2	29.4	16.0	26.4	20.3)	21.1%

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65°F is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration and National Weather Service.

Balance Sheet

- In a year defined by COVID-19 lockdowns, U.S. real gross domestic product (GDP) fell 5.0% in Q1 and 31.4% in Q2 followed by nearly equivalent 33.4% and 4.3% gains in Q3 and Q4 (measured sequentially from the preceding quarter). Despite this historically unprecedented volatility, full-year real GDP was nearly unchanged, rising just 0.3% versus 2019.

- Interest rates fell sharply through March as pandemic news worsened by the day; the U.S. Federal Reserve cut short-term rates from 1.5% to zero, the 10-year Treasury yield declined from almost 2.0% in January to 0.5%, and corporate credit spreads jumped as markets grappled with the severity of the pandemic. While fiscal and monetary policy support steadied credit markets as the year progressed, Treasury yields and corporate yields remained broadly lower than their pre-pandemic levels. Utility debt continued to attract investors seeking yield with relatively low business risk exposure.

- The industry's financial condition remained strong in 2020. Aggregate balance sheet leverage increased slightly as the industry extended its multi-year trend toward a regulated focus with leverage appropriate for a lower risk profile. However, balance sheet structures show wide differentiation across the industry; aggregate figures are only suggestive of broad trends. The slight rise in Preferred Equity and Noncontrolling Interest (which has risen from 1% in 2015) results primarily from the use of preferred shares and accounting for subsidiaries at a few large utilities.

- Total debt rose as utilities took advantage of very low interest rates and strong demand from investors while managing balance sheet ratios and cash flows to maintain investment-grade credit ratings. Long-term debt increased at nearly all utilities in 2020, an expected outcome of the industry's widespread asset growth.

- PG&E's July 1 emergence from bankruptcy accounted for half the year's $17.9 billion new equity issuance. While thirty utilities issued new equity in 2020, the same total as in 2019, broad equity issuance was stronger in 2019 as companies addressed the impact of tax reform. Equity issuance was also strong In 2018 as utilities took advantage of high price-earnings ratios and welcoming capital markets to fund capex, offset debt issuance and strengthen balance sheets.

- Property, plant and equipment in service (PPE in Service) rose 6.5% from year-end 2019 and 13.7% over the level at year-end 2018; this metric grew at nearly all utilities which constitute EEI's consolidated data. Such strong, broad growth indicates the size and scope of the industry's build-out of new renewable and clean generation, new transmission, reliability-related infrastructure and other capital projects.

- Debt-to-cap ratios by category show the dominance of regulated operations in the industry and a tendency, at the aggregate industry level, toward slightly higher leverage versus 2019. The dispersion of moves across individual companies, with some companies showing higher, some lower and others no change in leverage, indicates why individual company strategies are as meaningful as aggregate totals when assessing industry trends.

- Regulated companies as a group continued to report higher balance sheet leverage then their mostly regulated peers. This is to be expected given their lower business risk profile.

Consolidated Balance Sheet

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	**12/31/2020**	**12/31/2019r**	**% Change**	**$ Change**
PP&E in service, gross	1,678,135	1,584,364	5.9%	93,771
Accumulated depreciation	479,514	454,484	5.5%	25,030
PP&E in service, net	1,198,621	1,129,880	6.1%	68,741
Construction work in progress	82,641	75,945	8.8%	6,696
Net nuclear fuel	15,252	15,447	(1.3%)	(195)
Other property	19,903	17,757	12.1%	2,146
PP&E, net	1,316,416	1,239,029	6.2%	77,388
Cash & cash equivalents	16,848	11,699	44.0%	5,149
Accounts receivable	42,262	41,133	2.7%	1,129
Inventories	24,367	23,514	3.6%	853
Other current assets	52,011	45,534	14.2%	6,477
Total current assets	135,488	121,880	11.2%	13,608
Total investments	130,323	119,576	9.0%	10,747
Other assets	285,076	273,265	4.3%	11,810
Total Assets	**1,867,303**	**1,753,750**	**6.5%**	**113,553**
Common equity	494,910	462,915	6.9%	31,995
Preferred equity	14,529	9,265	56.8%	5,264
Noncontrolling interests	27,502	20,547	33.8%	6,955
Total equity	536,940	492,727	9.0%	44,213
Short-term debt	36,445	36,099	1.0%	347
Current portion of long-term debt	40,651	41,099	(1.1%)	(448)
Short-term and current long-term debt	77,097	77,198	(0.1%)	(101)
Accounts payable	73,062	70,580	3.5%	2,481
Other current liabilities	51,881	43,412	19.5%	8,469
Current liabilities	202,040	191,190	5.7%	10,850
Deferred taxes	108,113	106,773	1.3%	1,340
Non-current portion of long-term debt	666,009	586,563	13.5%	79,445
Other liabilities	353,444	375,190	(5.8%)	(21,745)
Total liabilities	1,329,606	1,259,716	5.5%	69,890
Subsidiary preferred	712	712	0.0%	0
Other mezzanine	45	596	(92.4%)	(550)
Total mezzanine level	757	1,307	(42.1%)	(550)
Total Liabilities and Owner's Equity	**1,867,303**	**1,753,750**	**6.5%**	**113,553**

r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Capitalization Structure

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Capitalization Structure ($M)	12/31/2020	12/31/2019r	12/31/2018r
Common Equity	494,910	462,915	437,843
Noncontrolling Interests & Preferred Equity	42,030	29,811	23,163
Long-term Debt (current & non-current)*	706,660	627,662	561,409
Total	**1,243,600**	**1,120,389**	**1,022,415**
Common Equity %	39.8%	41.3%	42.8%
Noncontrolling Interests & Preferred Equity %	3.4%	2.7%	2.3%
Long-Term Debt (current & non-current)* %	56.8%	56.0%	54.9%
Total	**100.0%**	**100.0%**	**100.0%**

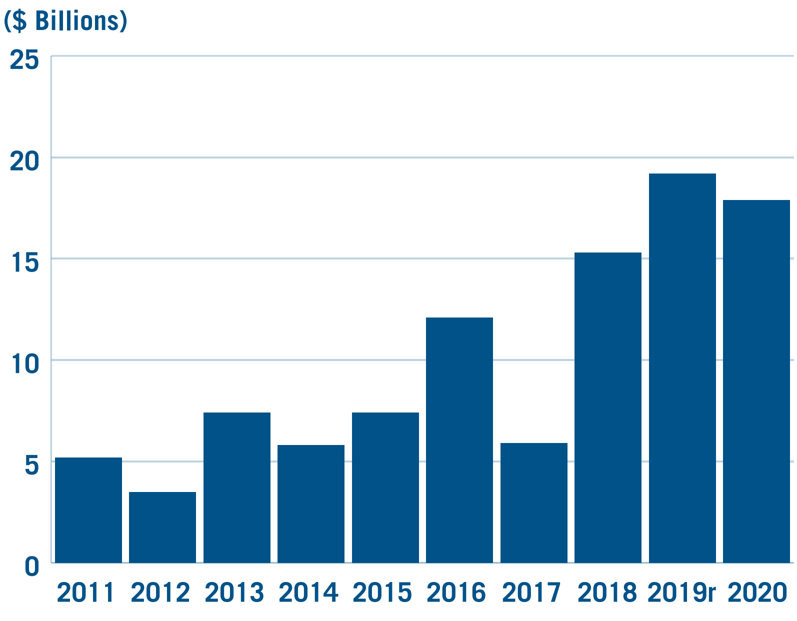
r = revised

Long-term debt not adjusted for (i.e., includes) securitization bonds.

Source: S&P Global Market Intelligence and EEI Finance Department.

Proceeds from Issuance of Common Equity 2011–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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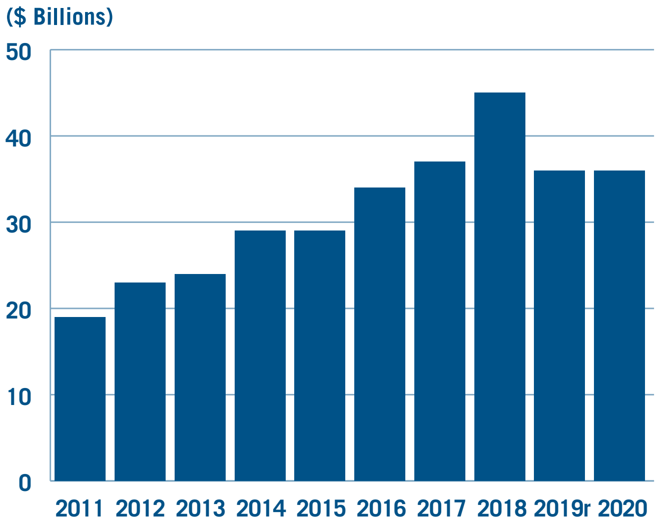
Source: S&P Global Market Intelligence and EEI Finance Department.

Short-term Debt 2011–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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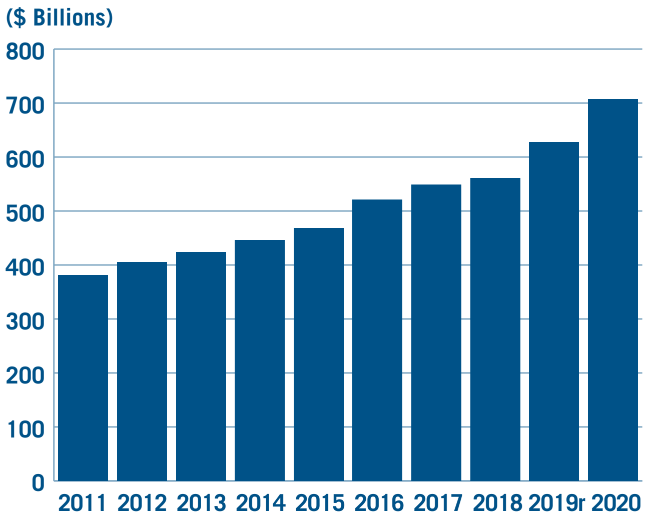
Source: S&P Global Market Intelligence and EEI Finance Department.

Long-term Debt 2011–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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Source: S&P Global Market Intelligence and EEI Finance Department.

Debt-to-Cap Ratio by Category 2020 vs. 2019r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Total Industry	
	Number	%	Number	%	Number	%
Lower	5	14.7%	4	40.0%	9	20.5%
No Change*	14	41.2%	3	30.0%	17	38.6%
Higher	15	44.1%	3	30.0%	18	40.9%
Total	**34**	**100.0%**	**10**	**100.0%**	**44**	**100.0%**

*No change defined as less than 1.0%

Note: December 31, 2020 vs. December 31, 2019. Refer to page v for category descriptions.

Source: S&P Global Market Intelligence and EEI Finance Department.

Capitalization Structure by Category 2020 vs. 2019r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated			Mostly Regulated		
	2020	**2019r**	**Change**	**2020**	**2019r**	**Change**
Common Equity ($M)	494,910	462,915	31,995	314,997	294,256	20,741
Noncontrolling Interests & Preferred Equity	42,030	29,811	12,219	17,620	18,228	(608)
Long-term Debt (current & non-current)*	706,660	627,662	78,998	492,737	440,076	52,660
Total Capitalization	1,243,600	1,120,389	123,211	825,353	752,560	72,793
Common Equity %	39.8%	41.3%	-1.5%	38.2%	39.1%	-0.9%
Noncontrolling Interests & Preferred Equity %	3.4%	2.7%	0.7%	2.1%	2.4%	-0.3%
Long-Term Debt (current & non-current)* %	56.8%	56.0%	0.8%	59.7%	58.5%	1.2%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

r = revised

Long-term debt not adjusted for (i.e., includes) securitization bonds.

Source: S&P Global Market Intelligence and EEI Finance Department.

Date	PP&E in Service, Net ($M)	% Change from 12/31/2016
12/31/2020	1,203,334	23.6%
12/31/2019r	1,129,880	16.5%
12/31/2018r	1,058,164	9.1%
12/31/2017	1,015,100	4.7%
12/31/2016	969,838	

Source: S&P Global Market Intelligence and EEI Finance Department.

Cash Flow Statement

- Net Cash Provided by Operating Activities decreased by $27.6 billion or 29.0%. The two main drivers of this metric both generated cash; cash supplied by Net Income grew 4.2% while cash supplied by Depreciation and Amortization (a non-cash expense) increased 6.7%. The decline in the overall total was largely the result of accounting statement activity at one large company reflecting its restructuring in 2020.

- Cash provided by Deferred Taxes & Investment Credits has leveled off over the last three years compared to much higher amounts previously. Deferred taxes had been at historically high levels due to elevated capex and use of bonus depreciation. The Tax Cuts & Jobs Act (TCJA), passed in late 2017, significantly reduced deferred taxes due to the reduction in the corporate income tax rate from 35% to 21% and the elimination of bonus depreciation.

- Net Cash Used in Investing Activities increased by $10.4 billion or 7.5%. The industry's capital spending — by far the largest component of this metric — totaled $132.7 billion in 2020, up $8.9 billion, or 7.2% from 2019. Industry capex has reached a new record high in each of the past nine years. About 70% of the 44 utilities represented in consolidated data grew capex in 2020.

- EEI member companies continue to invest in clean energy resources and the infrastructure necessary to make the power grid more modernized, more resilient, and more secure for all customers. Spending on transmission and distribution continues to increase relative to recent years, as EEI member companies expand their focus on adaptation, hardening, and resilience (AHR) initiatives. Investment in generation continues to be driven by the development of renewable energy and natural gas generation.

- Cash provided by Asset Sales increased from $16.9 billion to $25.7 billion while cash used for Asset Purchases decreased 10.6%, to $23.8 billion. As in 2019, activity was driven by a number of larger utilities, primarily AEP, Berkshire Hathaway Energy, CenterPoint, Dominion, Duke, Eversource Energy, NextEra, NiSource and Southern.

- Net Cash Provided by Financing Activities increased by $30.1 billion or 85.4%. This resulted primarily from the rising debt at most utilities required to fund the aggressive clean energy asset growth goals across the industry. Issuance of common equity remained elevated in 2020 at $17.9 billion, down slightly from 2019's $19.2 billion, which partially offset higher debt and helped utilities maintain targeted balance sheet leverage ratios.

- Dividends Paid to Common Shareholders rose 5.2%, to $29.7 billion.

Statement of Cash Flows

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

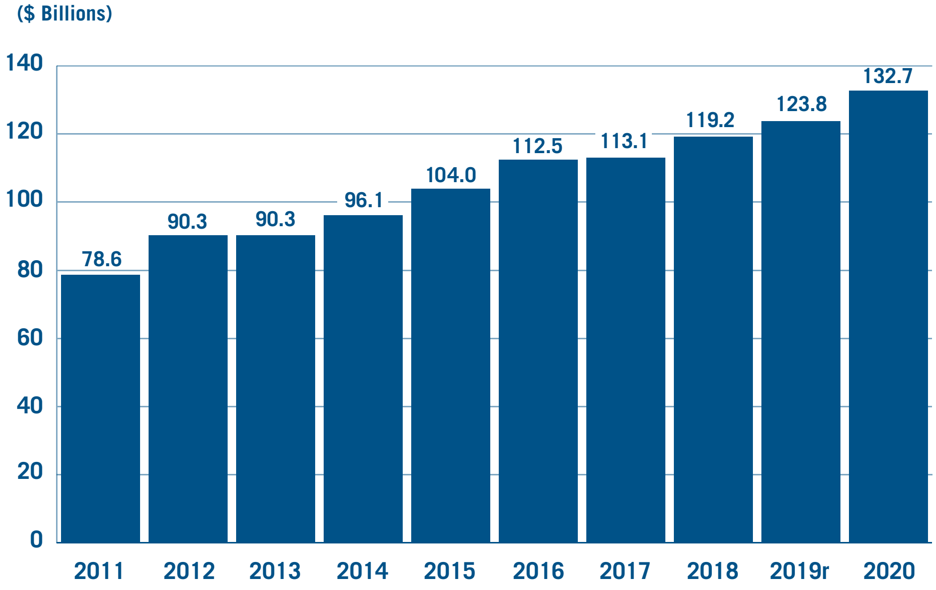
$ Millions	12 Months Ended 12/31/2020	12 Months Ended 12/31/2019r	% Change
Net Income	$38,627	$37,053	4.2%
Depreciation and Amortization	60,052	56,293	6.7%
Deferred Taxes and Investment Credits	4,429	3,003	47.5%
Operating Changes in AFUDC	(1,432)	(1,278)	12.0%
Change in Working Capital	(20,713)	(2,628)	688.1%
Other Operating Changes in Cash	(13,313)	2,820	NM
Net Cash Provided by Operating Activities	**67,651**	**95,263**	**(29.0%)**
Capital Expenditures	(132,732)	(123,812)	7.2%
Asset Sales	25,656	16,933	51.5%
Asset Purchases	(23,805)	(26,617)	(10.6%)
Net Non-Operating Asset Sales and Purchases	1,851	(9,684)	NM
Change in Nuclear Decommissioning Trust	(408)	(365)	11.9%
Investing Changes in AFUDC	102	142	(28.1%)
Other Investing Changes in Cash	3,083	(4,746)	NM
Net Cash Used in Investing Activities	**(128,104)**	**(138,465)**	**(7.5%)**
Net Change in Short-term Debt	3,352	(4,880)	NM
Net Change in Long-term Debt	68,291	45,972	48.5%
Proceeds from Issuance of Preferred Equity	5,364	2,786	92.5%
Preferred Share Repurchases	–	(50)	NM
Net Change in Prefered Issues	5,364	2,736	96.0%
Proceeds from Issuance of Common Equity	17,938	19,171	(6.4%)
Common Share Repurchases	(3,927)	(2,137)	83.8%
Net Change in Common Issues	14,011	17,035	(17.7%)
Dividends Paid to Common Shareholders	(29,321)	(27,876)	5.2%
Dividends Paid to Preferred Shareholders	(388)	(359)	8.0%
Other Dividends	–	–	NM
Dividends Paid to Shareholders	(29,709)	(28,235)	5.2%
Other Financing Changes in Cash	3,965	2,586	53.3%
Net Cash (Used in) Provided by Financing Activities	**65,274**	**35,214**	**85.4%**
Other Changes in Cash	9	33	(72.7%)
Net increase (decrease) in cash and cash equivalents	$4,830	$(7,955)	NM
Cash and cash equivalents at beginning of period	$12,018	$19,654	(38.9%)
Cash and cash equivalents at end of period	$16,848	$11,699	44.0%

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

Capital Expenditures 2011–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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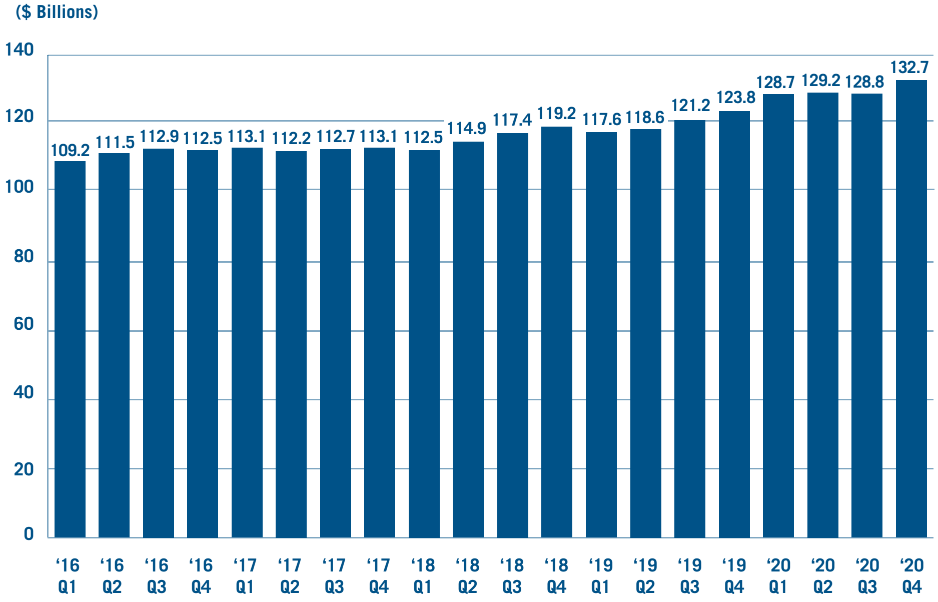
Source: S&P Global Market Intelligence, company reports, and EEI Finance Department.

Capital Spending—Trailing 12 Months

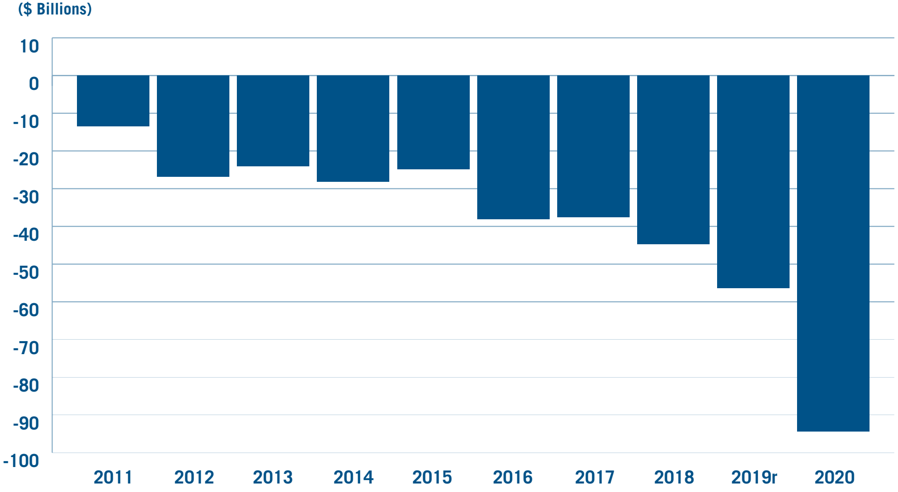
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Free Cash Flow (FCF) 2011–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



($ Billions)	2011	2012	2013	2014	2015	2016	2017	2018	2019r	2020
Net Cash Provided by Operating Activities	84.4	84.0	87.1	89.0	101.6	98.3	101.2	100.1	95.3	67.7
Capital Expenditures	(78.6)	(90.3)	(90.3)	(96.1)	(104.0)	(112.5)	(113.1)	(119.2)	(123.8)	(132.7)
Dividends Paid to Common Shareholders	(19.3)	(20.5)	(20.8)	(21.1)	(22.5)	(23.8)	(25.5)	(25.6)	(27.9)	(29.3)
Free Cash Flow	**(13.5)**	**(26.8)**	**(24.0)**	**(28.2)**	**(24.8)**	**(38.1)**	**(37.5)**	**(44.7)**	**(56.4)**	**(94.4)**

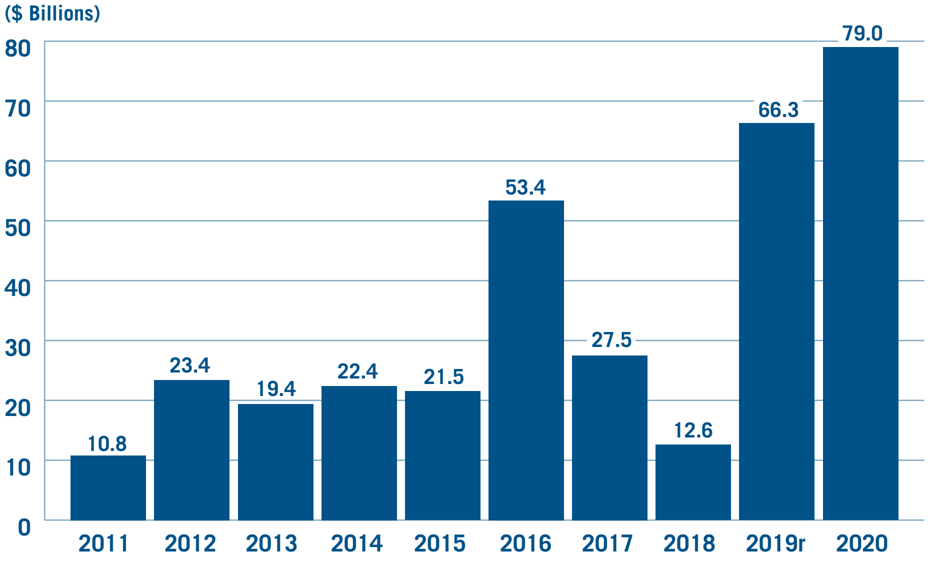
r = revised

Note: Totals may not equal sum of components due to rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Change in Long-term Debt 2011–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Note: Based on data from industry's consolidated balance sheet.

Source: S&P Global Market Intelligence and EEI Finance Department.

Rate Review Summary

- In 2020, there were approximately a quarter less rate reviews than those filed in the last three years. At the end of the year, there were 18 pending rate reviews and 53 rate reviews decided. This measured pace of filings is likely due to the economic impacts of the pandemic.

- For 2020, the average awarded ROE was 9.43%, continuing a negative trend. By way of comparison, for 2019, the average awarded ROE was 9.64%. On average, awarded ROE in 2020 was approximately 30 basis points lower than the average requested ROE. Consistent with declining interest rates, average awarded ROEs have been trending downward for the electric industry over the past four decades. In addition, the increased use of adjustment and cost recovery mechanisms, which arguably reduce risk of recovery for utilities, have often been cited by commissions as contributing to lower authorized ROEs. Going forward, it is reasonable to expect that ROEs will remain lower due to the sustained low interest rate environment combined with current economic conditions as a result of the pandemic.

- Regulatory lag was approximately 8.93 months, which is slightly higher than the last 2 years; but well within the historic average. Although there were fewer rate reviews filed in 2020 compared with previous years, commission agendas were filled with numerous other regulatory filings including those related to COVID. Many commissions also delayed or postponed hearings and working groups in the first few months of the year and ultimately shifted to virtual meetings.

For 2021, it is anticipated that there will be more rate reviews filed than in 2020. It is also expected that the following rate review trends seen in 2020 will continue or even accelerate in 2021.

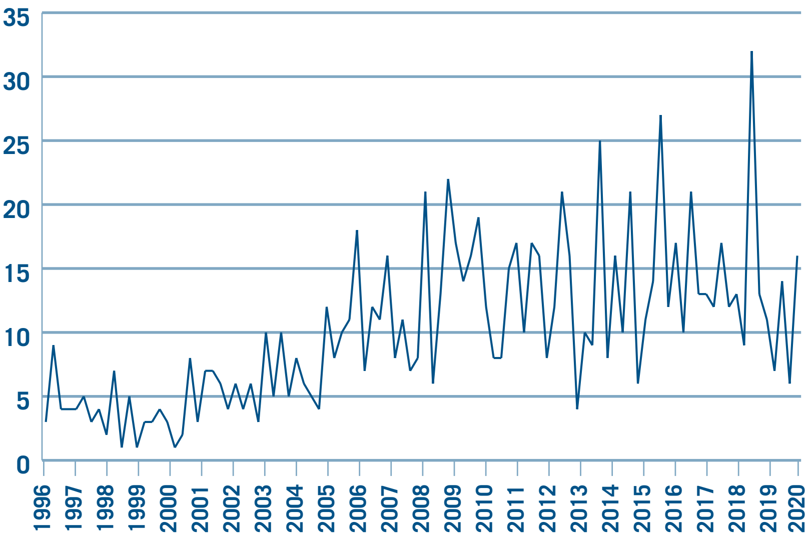
- **COVID-Related Matters** – Disconnection moratoria and recovery of COVID-related costs will still be a major focus for commissions in 2021. The impacts of the pandemic were already documented in a number of rate reviews decided in 2020. Accordingly, electric companies in Hawaii, Maryland, and New York have either agreed to no revenue increase, reduced the requested increase amount, or delayed approved revenue increases because of the current financial hardships of many of their customers.

- **Accelerated Clean Energy Transition and Cost Recovery** – Momentum for increased clean energy and carbon-free resources was strong in 2020. Industry dynamics are rapidly changing and in response to this shift, nearly all EEI members have made or updated commitments to reducing their carbon emissions. This shift will require the industry to address numerous issues, chief among them how to retire previously approved carbon intense resources while transitioning to cleaner generation and, at the same time, ensuring cost recovery at just and reasonable rates. The tools with which the electric industry will address this transition are changing and varied as well. Some states have preferred and approved securitization while others have allowed the use of accelerated depreciation or other adjustment mechanisms.

- **Alternative Regulation** – Due to the rapid transition described above, changing customer preferences, and recognition that charging rates on volumetric throughput does not adequately correlate to cost causation, regulators (and legislators) increasingly recognize that the traditional regulatory framework must continue evolving to enhance the ability of electric companies to meet customer expectations. Alternative regulation as a concept is not new; however, its application varies by state. For example, Maryland recently passed legislation allowing multi-year rate plans, as a pilot, and 2020 the Commission approved Baltimore Gas & Electric's pilot program. For the electric industry to get as clean as it can, as fast as it can, while maintaining reliability and affordability, alternative regulation mechanisms will likely need to be utilized more going forward.

Number of Rate Reviews Filed 1996–2020

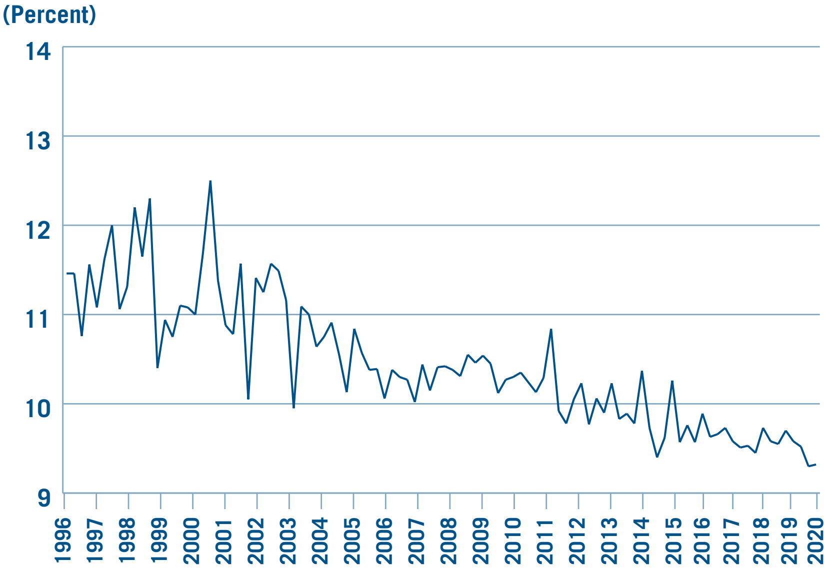
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

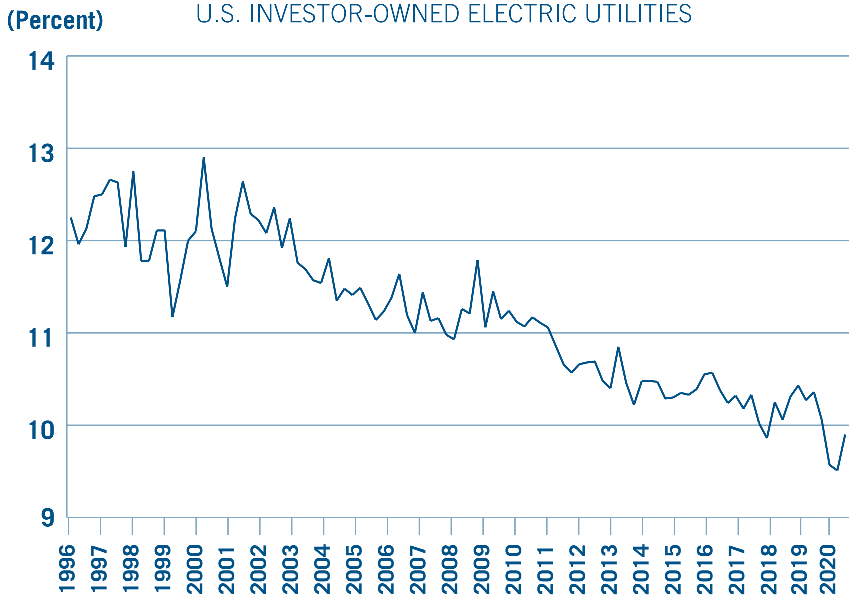
Average Awarded ROE 1996-2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



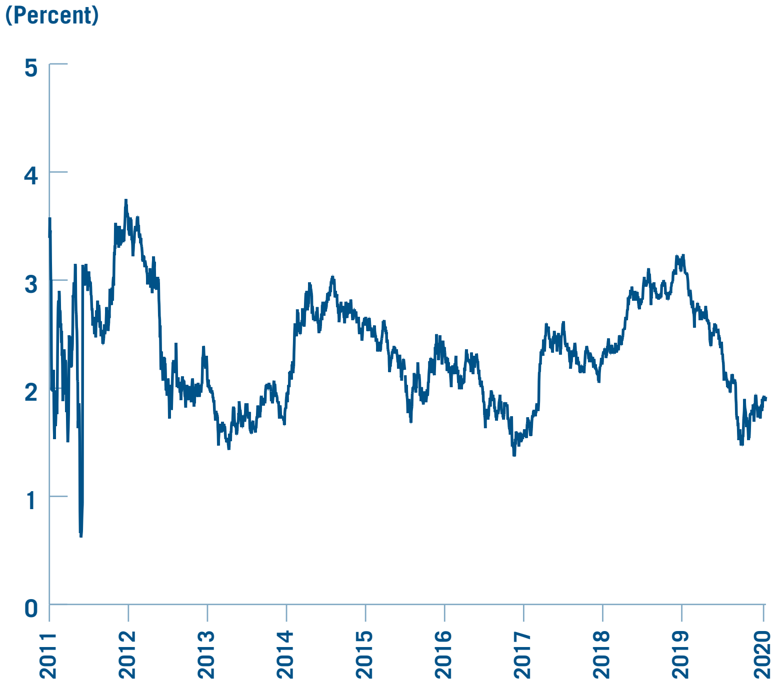
Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

Average Requested ROE 1996–2020



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

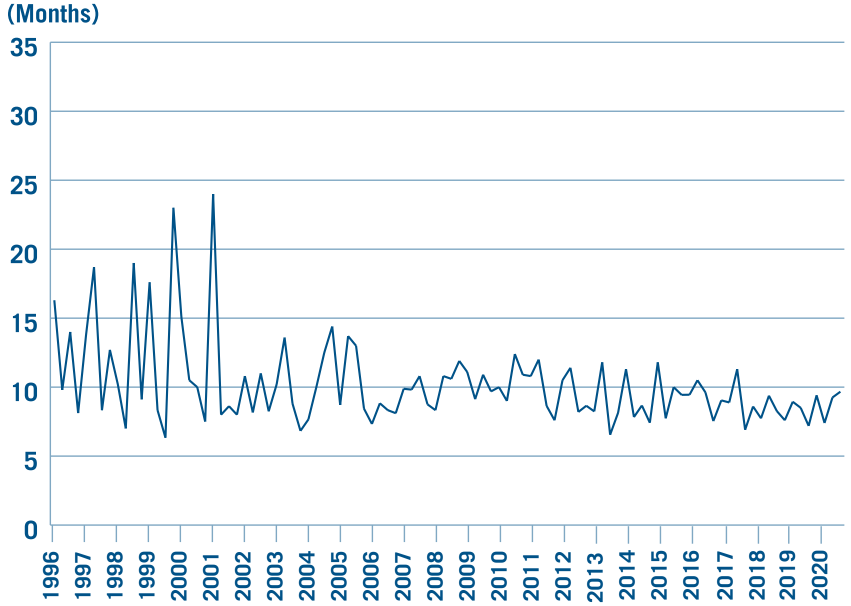
10-Year Treasury Yield
1/1/11 through 12/31/20



Source: U.S. Federal Reserve.

Average Regulatory Lag 1996–2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

Finance, Accounting, and Investor Relations

The Finance, Accounting, and Investor Relations teams are part of EEI's Business Operations Group. This division provides the leadership and management for advocating industry policies, technical research, and enhancing the capabilities of individual members through education and information sharing. The division's leadership is used in areas that affect the financial health of the investor-owned electric utility industry, such as finance, accounting, taxation, internal auditing, investor relations, risk management, and budgeting and financial forecasting. If you need research information about these issue areas, please contact an EEI Finance, Accounting, or Investor Relations staff member (listed in this section). Under the direction of both the Finance and the Accounting Executive Advisory Committees, the division provides staff representatives to work with issue area committees. These committees give member company personnel a forum for information exchange and training and an opportunity to comment on legislative and regulatory proposals.

Publications

Quarterly Financial Updates

A series of financial reports on the investor-owned segment of the electric utility industry. Quarterly Financial Update (QFU) reports include stock performance, dividends, credit ratings, and rate review summary.

Financial Review

An annual report that provides a review of the financial performance of the investor-owned electric utility industry including the QFU topics mentioned above as well as the industry's consolidated financial statements. The report also includes an analysis in the areas of business segmentation, mergers & acquisitions, construction and fuel use by electric utilities.

EEI Index

Quarterly stock performance of the U.S. investor-owned electric utilities. The EEI index, which measures total return and provides company rankings for year to date and trailing one-year periods, is widely used in company proxy statements and for overall industry benchmarking.

Executive Accounting News Flash

Published quarterly and distributed to members of accounting committees, this update provides current information about the impact on our companies of evolving accounting and financial reporting issues. The News Flash is prepared jointly with AGA by the Utility Industry Accounting Fellow in coordination with our accounting staff in order to keep members informed on proposed and newly effective requirements from key accounting standard-setters.

Introduction to Depreciation for Utilities and Other Industries

Updated in 2013, the latest edition of this book serves as a primer on the concepts of depreciation accounting including fundamental principles, life analysis techniques, salvage and cost of removal analysis methods and depreciation rate calculation formulas and examples. The 2013 edition features updated chapters on Tax Depreciation, Accounting for Asset Retirement Obligations (AROs) and includes a new chapter on Depreciation in an IFRS Environment.

Industry directories published by the Business Services and Finance Division:

- Electric Utility Investor Relations Executives Directory
- Accounting and Internal Audit Directory

For more information, please visit the EEI website at: www.eei.org.

Conference Highlights

Financial Conference

This three-day conference is the premier annual fall gathering of utilities and the financial community; it is attended by more than 1,000 senior executives, including utility CEOs, CFOs, treasurers, investor relations executives, and Wall Street investment analysts, portfolio managers, commercial and investment bankers and the rating agencies. The General Sessions cover topics of strategic interest to the industry and financial community. Contact Devin James or Aaron Cope for more information.

Chief Financial Officers' Forum

This forum is held once a year in the fall in conjunction with the EEI Financial Conference. The forum provides an opportunity for chief financial officers to identify and discuss critical issues and challenges impacting the financial health of the electric utility industry. The forum is open to member company chief financial officers only. Contact Devin James or Aaron Cope for more information.

Finance Committee Meeting

This day and a half meeting is held in the spring or summer. The meeting covers current and emerging industry issues critical to the electric power industry. It also provides an opportunity for utility financial officers to identify best practices and share management skills that contribute to financial performance. Contact Devin James or Aaron Cope for more information.

Investor Relations Meeting

This one-day meeting is held in the spring. Executives gain insight on current and evolving industry issues, analysts' perspectives on the industry and have an opportunity to identify and share IR best practice concepts within and outside the electric utility industry. Contact Devin James or Aaron Cope for more information.

Treasury Group Meeting

Half day meetings are held in the spring and the fall annually. Discussion is focused on pension funding, capital markets and economic and regulatory impacts on debt and equity issuances. Members are provided an opportunity to share and identify best practices beneficial to the well-being of the industry. Contact Devin James or Aaron Cope for more information.

Accounting Leadership Conference

This annual meeting, held jointly with the Chief Audit Executives and their counterparts from AGA, covers current accounting, finance, business, and management issues for the Chief Accounting Officers and key accounting leadership of EEI member companies. Contact Randall Hartman for more information.

Chief Audit Executives Conference

This annual conference provides a forum for EEI and AGA Chief Audit Executives to discuss issues and challenges and exchange ideas on utility-specific internal auditing topics. The conference is open to members of the Internal Auditing Committee and other employees of EEI/ AGA member companies designated by the CAE. Contact Dave Dougher for more information.

EEI Accounting Standards Committee

Provides a forum for technical accounting, accounting research, financial reporting, and other interested member-company accounting leaders and staff, to update their knowledge on emerging accounting standards, implementation issues associated with newly issued standards, and other technical and business issues. This Committee meets in conjunction with the Spring Accounting Conference. Contact Randall Hartman for more information.

Spring and Fall Accounting Conferences

Hosted by the EEI Corporate Accounting Committee, the Property Accounting & Valuation Committee, the Accounting Standards Committee, the Budgeting & Financial Forecast Committee and the AGA Accounting Services Committee, the conference provides a forum for members to discuss current issues and challenges and exchange ideas in the electric and natural gas utility industries. The spring meeting is intended for all aforementioned committees, while the fall meeting is designed for the Corporate Accounting Committee and the Property Accounting & Valuation Committee. The meetings are open to members of the Committees and other employees of EEI/AGA member companies. Contact Dave Dougher for more information.

Tax School

Provides utility tax professionals with a forum to discuss developing tax issues impacting our member companies. This two and half day training is held every other year in the spring and is targeted for intermediate-level personnel. Contact Mark Agnew for more information.

Accounting Courses

Introduction to Public Utility Accounting

This 4-day program, offered jointly with AGA, concentrates on the fundamentals of public utility accounting. It focuses on providing basic knowledge and a forum for understanding the elements of the utility business. It is intended primarily for recently hired electric and gas utility staff in the areas of accounting, auditing, and finance. Contact Randall Hartman or Dave Dougher for more information.

Advanced Public Utility Accounting

This intensive, 4-day course, jointly sponsored with AGA, focuses on complex and specific advanced accounting and industry topics. It addresses current accounting issues including those related to deregulation and competition, as they affect regulated companies in the changing and increasingly competitive environment of the electric and gas utility industries. Contact Randall Hartman or Dave Dougher for more information.

Property Accounting & Depreciation Training Seminar

This is a one and a half day seminar offered jointly with AGA that provides an introduction to property accounting and depreciation in the electric and natural gas utility industries. Contact Dave Dougher for more information.

Utility Internal Auditor’s Training

Provides utility staff auditors, managers, and directors with the fundamentals of public utility auditing and specific utility audit/accounting issues including advanced internal auditing topics and is presented jointly by EEI and AGA – convenes for two and one-half days. Contact Randall Hartman or Dave Dougher for more information.

Additional Training Opportunities

Provides additional training opportunities as appropriate, such as Accounting for Energy Derivatives and FERC Accounting. Contact Randall Hartman or Dave Dougher for more information.

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Edison Electric Institute Schedule of Upcoming Meetings

To assist in planning your schedule, here are upcoming meetings related to finance and accounting that may be of interest to you. For further details, please contact Devin James at (202) 508-5057, Aaron Cope at (202) 508-5127, Randall Hartman (202) 508-5494, or Dave Dougher (202) 508-5570.

August 23-25, 2021

EEI-AGA Utility Internal Auditor's Training Course
Loews Atlanta
Atlanta, Georgia

August 23-26, 2021

EEI-AGA Introduction to Public Utility Accounting and Advanced Public Utility Accounting Training Courses
Loews Atlanta
Atlanta, Georgia

November 7-9, 2021

EEI Financial Conference
Diplomat Beach Resort Hollywood
Hollywood, FL

November 7, 2021

EEI Treasury Group Meeting
(Closed meeting, admittance by invitation only)
JW Marriott Desert Ridge
Resort & Spa
Phoenix, Arizona

November 7, 2021

Chief Financial Officers Forum
(Closed meeting, admittance by invitation only)
JW Marriott Desert Ridge
Resort & Spa
Phoenix, Arizona

November 14-17, 2021

Fall Accounting Conference and Property Accounting & Depreciation Training
Disney's Grand Floridian
Lake Bueno Vista, Florida

November 17-18, 2021

Property Accounting & Depreciation Training Seminar
Disney's Grand Floridian
Lake Bueno Vista, Florida

Date To Be Announced

Investor Relations Planning Group Meeting
(Closed meeting, admittance by invitation only)
Hyatt Centric Times Square
New York
New York, New York

Date To Be Announced

Wall Street Advisory Group Meeting
(Closed meeting, admittance by invitation only)
Hyatt Centric Times Square
New York
New York, New York

May 22-25, 2022

Spring Accounting Conference
Hyatt Regency Tamaya Resort
Santa Ana Pueblo, New Mexico

June 12-15, 2022

EEI-AGA Accounting Leadership Conference
Hyatt Regency Tamaya Resort
Santa Ana Pueblo, New Mexico

Earnings Twelve Months Ending December 31

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2020	2019r
Earnings Excluding Non-Recurring and Extraordinary Items	**54,359**	**49,148**
Non-Recurring Items (pre-tax)		
Gain on Sale of Assets	566	3,049
Other Non-Recurring Revenues	—	117
Asset Write-downs	(8,657)	(3,470)
Other Non-Recurring Expenses	(7,518)	(13,034)
Total Non-Recurring Items	**(15,609)**	**(13,337)**
Extraordinary Items (net of taxes)		
Discontinued Operations	(122)	1,243
Change in Accounting Principles	—	—
Early Retirement of Debt	—	—
Other Extraordinary Items	—	—
Total Extraordinary Items	**(122)**	**1,243**
Net Income	**38,627**	**37,053**
Total Non-Recurring and Extraordinary Items	**(15,731)**	**(12,094)**

r = revised Note: Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

U.S. Investor-Owned Electric Utilities

(At 12/31/2020)

ALLETE, Inc.
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
AVANGRID, Inc.
Avista Corporation
Berkshire Hathaway Energy
Black Hills Corporation
CenterPoint Energy, Inc.
Cleco Corporate Holdings LLC
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Energy, Inc.
DTE Energy Company
Duke Energy Corporation
Edison International
Entergy Corporation
Evergy, Inc.
Eversource Energy
Exelon Corporation
FirstEnergy Corp.
Hawaiian Electric Industries, Inc.
IDACORP, Inc.
MDU Resources Group, Inc.
MGE Energy, Inc.
NextEra Energy, Inc.
NiSource Inc.
NorthWestern Corporation
OGE Energy Corp.
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Public Service Enterprise Group Inc.
Puget Energy, Inc.
Sempra Energy
Southern Company
The AES Corporation *
  DPL Inc.
  IPALCO Enterprises, Inc.
Unitil Corporation
WEC Energy Group, Inc.
Xcel Energy Inc.

Note: This list includes 39 publicly traded U.S. electric utility holding companies plus an additional five electric utilities (shown in italics) that are not listed on U.S. stock exchanges because they are owned by holding companies not primarily engaged in the business of providing retail electric distribution services in the United States.

* The AES Corporation is not included in the count of 39, but rather its two U.S. electric utility subsidiaries are included in the group of five italicized companies.

Other EEI Member Companies

Alaska Power & Telephone Company
American Transmission Company
Central Hudson Gas & Electric Corp.
Cross Texas Transmission
Duquesne Light Company
El Paso Electric
Florida Public Utilities
Green Mountain Power
ITC Holdings Corp.
Liberty Utilities
Mt. Carmel Public Utility Company
National Grid
Ohio Valley Electric Corporation
Sharyland Utilities
Tampa Electric an Emera Company
UGI Corporation
UNS Energy Corporation
Upper Peninsula Power Company
Vermont Electric Power Company

Note: These companies are not included in the EEI Financial Review data sets for one of the following reasons: they do not provide retail electric distribution service (i.e., transmission-only), they are subsidiaries of foreign-owned companies, they are not traded on a major U.S. stock exchange, or they are owned by a non-utility holding company and the granularity of publicly available financial data is insufficient.

The **Edison Electric Institute** (EEI) is the association that represents all U.S. investor-owned electric companies. Our U.S. members provide electricity for 220 million Americans and operate in all 50 states and the District of Columbia. EEI also has dozens of international electric companies as International Members, and hundreds of industry suppliers and related organizations as Associate Members.

Safe, reliable, affordable, and increasingly clean energy enhances the lives of all Americans and powers the economy. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States and contributes 5 percent to the nation's GDP.

Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

For more information, visit our Web site at **www.eei.org**.

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CASE: UE 399
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 111

US White House Budget
Fiscal Year (FY) 2023

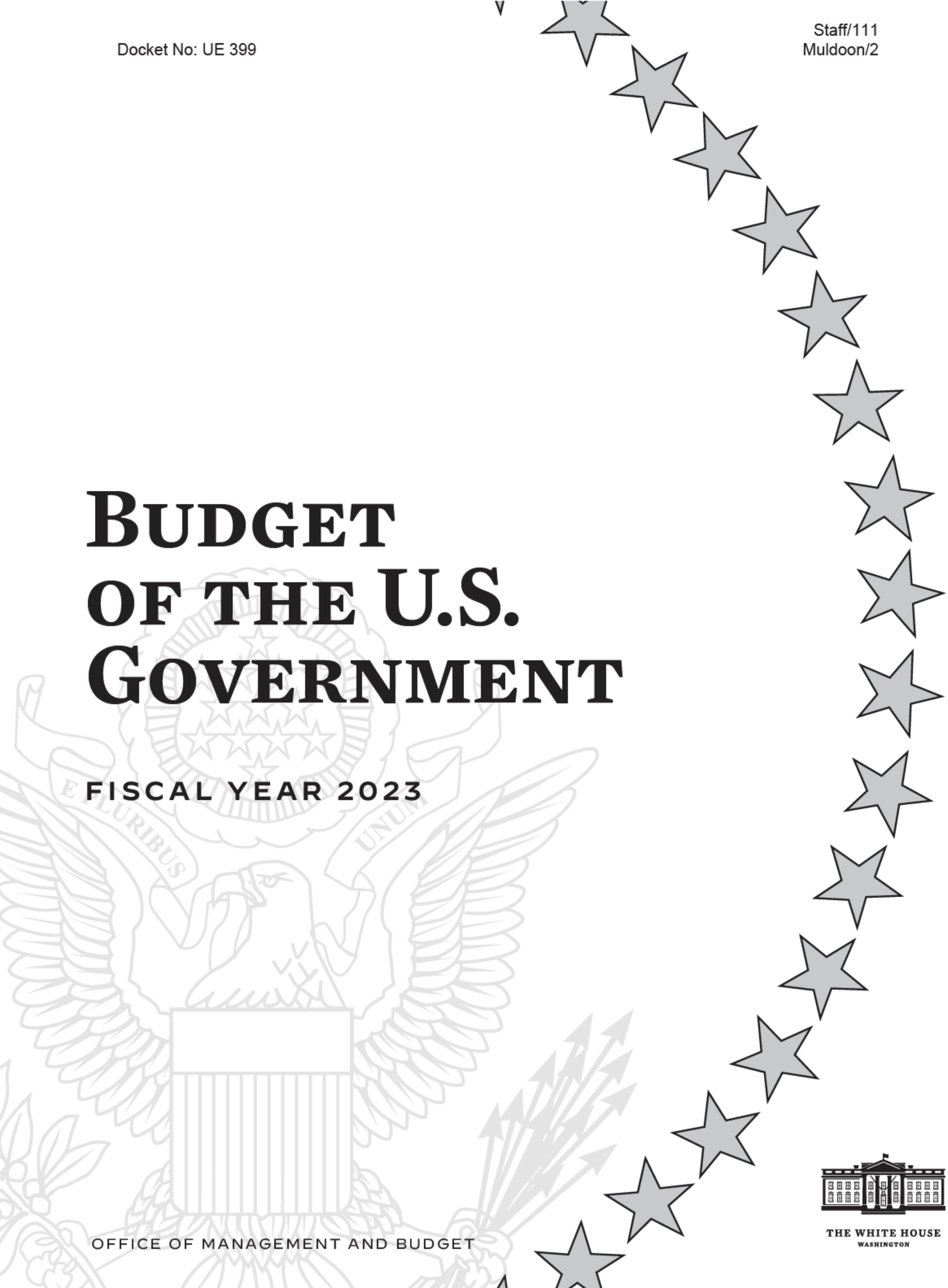
June 22, 2022

BUDGET OF THE U.S. GOVERNMENT

FISCAL YEAR 2023

OFFICE OF MANAGEMENT AND BUDGET

THE WHITE HOUSE
WASHINGTON



BUDGET
OF THE U.S.
GOVERNMENT

FISCAL YEAR 2023

OFFICE OF MANAGEMENT AND BUDGET

THE WHITE HOUSE
WASHINGTON

THE BUDGET DOCUMENTS

Budget of the United States Government, Fiscal Year 2023 contains the Budget Message of the President, information on the President's priorities, and summary tables.

Analytical Perspectives, Budget of the United States Government, Fiscal Year 2023 contains analyses that are designed to highlight specified subject areas or provide other significant presentations of budget data that place the budget in perspective. This volume includes economic and accounting analyses, information on Federal receipts and collections, analyses of Federal spending, information on Federal borrowing and debt, baseline or current services estimates, and other technical presentations.

Supplemental tables and other materials that are part of the Analytical Perspectives volume are available at https://whitehouse.gov/omb/analytical-perspectives/.

Appendix, Budget of the United States Government, Fiscal Year 2023 contains detailed information on the various appropriations and funds that constitute the budget and is designed primarily for the use of the Appropriations Committees. The Appendix contains more detailed financial information on individual programs and appropriation accounts than any of the other budget documents. It includes for each agency: the proposed text of appropriations language; budget schedules for each account; legislative proposals; narrative explanations of each budget account; and proposed general provisions applicable to the appropriations of entire agencies or group of agencies. Information is also provided on certain activities whose transactions are not part of the budget totals.

BUDGET INFORMATION AVAILABLE ONLINE

The President's Budget and supporting materials are available online at https://whitehouse.gov/omb/budget/. This link includes electronic versions of all the budget volumes, supplemental materials that are part of the Analytical Perspectives volume, spreadsheets of many of the budget tables, and a public use budget database. This link also includes Historical Tables that provide data on budget receipts, outlays, surpluses or deficits, Federal debt, and Federal employment over an extended time period, generally from 1940 or earlier to 2027. Also available are links to documents and materials from budgets of prior years.

For more information on access to electronic versions of the budget documents, call (202) 512-1530 in the D.C. area or toll-free (888) 293-6498. To purchase the printed documents call (202) 512-1800.

GENERAL NOTES

1. All years referenced for budget data are fiscal years unless otherwise noted. All years referenced for economic data are calendar years unless otherwise noted.
2. At the time the Budget was prepared, none of the full-year appropriations bills for 2022 have been enacted, therefore, the programs and activities normally provided for in the full-year appropriations bills were operating under a continuing resolution (Public Law 117-43, division A, as amended by Public Law 117-70, division A; Public Law 117-86, division A; and Public Law 117-95). References to 2022 spending in the text and tables reflect the levels provided by the continuing resolution and, if applicable, the following Public Laws which provided additional appropriations to certain accounts in 2022—
   - The Disaster Relief Supplemental Appropriations Act, 2022 (Public Law 117-43, division B);
   - The Afghanistan Supplemental Appropriations Act, 2022 (Public Law 117-43, division C);
   - The Infrastructure Investment and Jobs Appropriations Act (Public Law 117-58, division J); and
   - The Additional Afghanistan Supplemental Appropriations Act, 2022 (Public Law 117-70, division B).
3. The estimates in the 2023 Budget do not reflect the effects of the Ukraine Supplemental Appropriations Act, 2022 (included in Public Law 117-103) due to the late date of enactment.
4. Detail in this document may not add to the totals due to rounding.

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THE BUDGET MESSAGE OF THE PRESIDENT

To the Congress of the United States:

There is no greater testament to the grit and resilience of the American people than the extraordinary progress we have made together over the last year.

America entered 2021 in the midst of a devastating health crisis, on the heels of the worst economic crisis since the Great Depression. We ended 2021 having created over 6.5 million new jobs, the most our Nation has ever recorded in a single year. Our economy grew at a rate of 5.7 percent, the strongest growth in nearly 40 years. As of February, the unemployment rate has fallen from 6.4 percent when I took office to 3.8 percent—the fastest decline in recorded history. We are bringing everyone along, and leaving no one behind; child poverty is projected to reach the lowest level ever recorded, while long-term unemployment, youth unemployment, and Black and Hispanic unemployment have all dropped at record rates. Though family budgets are still tight, millions more Americans are earning paychecks today—and families have more money in their pockets than they did a year ago.

This progress was no accident. It was a direct result of the new economic vision for America I ran on—to build our economy from the bottom up and the middle out.

That vision was reflected in the American Rescue Plan Act of 2021, which lifted our Nation out of crisis; fueled our efforts to vaccinate America and combat the COVID-19 pandemic globally; enabled small businesses and State and local governments to hire, rehire, and retain workers; and delivered immediate economic relief to tens of millions of Americans—to put food on their tables, keep a roof over their heads, enable them to work by keeping schools and child care providers open, and maintain their dignity in the face of the pandemic.

That vision was also reflected in the Bipartisan Infrastructure Law—the most sweeping investment to rebuild America in history. After years of merely talking about fixing our infrastructure, we brought together Democrats and Republicans to finally get it done. Already, that law is paving the way for better jobs for millions of Americans—modernizing roads, bridges, ports, and airports; building a national network of charging stations, so America can own the electric car market; replacing lead pipes across the Nation, so every child can drink clean water at home and at school; providing affordable high-speed internet for every American; and strengthening our resilience to withstand both cyber and physical threats, including the devastating effects of the climate crisis.

There have been challenges as we have recovered from the COVID-19 pandemic. Due to the speed of our recovery, businesses have had a hard time hiring workers quickly enough to keep pace with resurgent demand. Disruptions to global supply chains have also contributed to higher prices. As a result, America was not immune to the worldwide inflation that has followed the pandemic—leaving too many families struggling to keep up with their bills. Since January, that pain has also been compounded by the anticipation and aftermath of Vladimir Putin's invasion of Ukraine—from the time he began amassing troops on Ukraine's borders, triggering a response in global oil markets, the price of a gallon of gas has risen by more than a dollar here at home as of mid-March.

Today, however, as a result of the new economic vision we are building our economy around, we are well-positioned to meet the challenges and seize the opportunities of this decisive decade. We are competing with China from a position of strength, while leading a global coalition united in condemnation of Russian aggression against Ukraine. We are tackling the climate crisis with urgency, strengthening the global health architecture to combat COVID-19 and future pandemics, and enhancing cybersecurity and addressing emerging cyber threats. We are joining with allies and partners to write the rules of 21st Century economics, trade, and technology.

My Budget details the next steps forward on our journey to execute a new economic vision, reduce costs for families, reduce the deficit, and build a better America. It is a Budget anchored in my bedrock belief that America is at its best when we invest in the backbone of our Nation: the hardworking people in every community who make our Nation run.

My Budget lays out detailed investments to build on a record-breaking year of broad-based, inclusive growth—and meet the challenges of the 21st Century. It is a call to reduce costs for families' biggest expenses; grow, educate, and invest in our workforce; bolster our public health infrastructure; save lives by investing in strategies such as community policing and community violence interventions, strategies proven to reduce gun crime; and advance equity, environmental justice, and opportunity for all Americans.

As I discussed in my 2022 State of the Union Address, my Budget also reflects a bipartisan unity agenda—areas where we can all come together to make progress. That includes investments to help beat the opioid epidemic; take on the invisible costs of the mental health crisis, especially among our children; support our veterans; and end cancer as we know it. My super-charged Cancer Moonshot plan has a goal of cutting cancer death rates by at least 50 percent over the next 25 years—while my vision for ARPA-H, the Advanced Research Projects Agency for Health, seeks breakthroughs in cancer, Alzheimer's, diabetes, and more.

Critically, my Budget would also keep our Nation on a sound fiscal course. It fights inflation and helps families deal with rising costs by growing our economy, making more goods in America, and lowering the costs families face. Its bold ideas are fully paid for, with tax reforms that more than offset the cost of new investments. It fulfills my ironclad promise that no one earning less than $400,000 per year would pay an additional penny in new taxes—while ensuring that the wealthiest Americans and the biggest corporations begin to pay their fair share. It keeps us on track to reduce the deficit this year to less than half of what it was before I took office.

After a year of historic progress, I am more optimistic about America today than I have ever been. We are on a path to win the competition for the 21st Century. We are prepared once again to turn a moment of crisis into a breathtaking opportunity. We are stronger today than we were a year ago—and we will be stronger a year from now than we are today.

All we have to do is keep coming together—to keep building, keep giving working families a fighting chance, and keep expanding the possibilities of our Nation. That is what my Budget is all about, and I look forward to working together to keep delivering for the American people.

JOSEPH R. BIDEN, JR.

THE WHITE HOUSE.

CONFRONTING URGENT CRISES AND DELIVERING HISTORIC PROGRESS

When the President took office, the United States was confronting overlapping crises of unprecedented scope and scale: a once-in-a-century pandemic; a sharp economic downturn; an accelerating climate crisis; and a legacy of persistent inequity. On day one of his Administration, the President immediately got to work leveraging every tool at his disposal to tackle these crises head-on—mobilizing the Nation around an ambitious agenda to deliver results for working families. Under the President's leadership—and thanks to the grit and resilience of the American people in the face of significant challenges—America has made historic progress.

POWERING A HISTORIC ECONOMIC RESURGENCE

When the President took office, he faced an economy that was struggling to recover from the most severe downturn since the Great Depression. The unemployment rate stood at 6.4 percent, with 10 million Americans unable to find a job. Factoring in workers who dropped out of the labor force or couldn't find full-time work, the unemployment rate was closer to 11 percent. Between February 2020 and January 2021, the labor force participation rate for women dropped by 3.7 percent overall, 6.4 percent for Black women, and 7.1 percent for Hispanic women, undoing more than 35 years of progress in labor force participation. More than 18 million Americans were receiving unemployment benefits, and more than half of the unemployed had been without a job for more than 15 weeks. Thousands of small businesses—the backbone of the American economy—were forced to close their doors, some permanently. Millions of Americans reported that they were struggling to pay their rent or mortgage, put food on the table, and cover basic expenses.

In the face of these challenges, the President took decisive action—not only to put a floor under the immediate economic fallout, but to begin rebuilding the economy from the bottom-up and the middle-out. The President's strategy helped rescue the economy, delivered urgently needed relief to families and small businesses, fueled record-breaking economic growth and job creation, and bolstered American competitiveness and manufacturing.

Fueling Record-Breaking Economic Growth and Job Creation

Thanks to the American Rescue Plan Act of 2021 (American Rescue Plan) and the President's vaccination program, the American economy is recovering faster than other advanced economies around the world, with record-breaking economic growth and job creation. In 2021, the Administration achieved the best record of job creation in American history, with the single largest calendar year decrease in the unemployment rate on record. As of February 2022, the unemployment rate had fallen to 3.8 percent. Prior to passage of the American Rescue Plan, the Congressional Budget Office did not project the unemployment rate dropping to 3.8 percent at any point over this entire decade. Since the

President took office, the economy has created 7.4 million jobs. The number of long-term unemployed Americans decreased by two million during the President's first year in office—a record decline. More than 1.6 million women have reentered the workforce.

As more Americans have gotten back to work, the economy has come roaring back to life. In 2021, the American economy grew at 5.7 percent, the fastest rate in nearly four decades. For the first time in 20 years, the economy grew faster than China's. Applications for new small businesses increased 30 percent since before the pandemic. Retail sales rose by $90 billion. Between the American Rescue Plan's tax cuts for families that are raising children and rising wages for middle class families, the average American had more money in their pocket each month in 2021 than they did in 2020—after accounting for inflation.

Strengthening Supply Chains, Promoting Competition, and Bolstering Manufacturing

To sustain and build on this economic momentum, the President has taken aggressive actions to address other global challenges triggered by the COVID-19 pandemic and expand the productive capacity of the economy—strengthening domestic supply chains, promoting competition and innovation to help lower prices, and bolstering American manufacturing.

In the face of global supply chain bottlenecks and global inflation, last year the President issued an Executive Order 14017, "America's Supply Chains," to strengthen the Nation's supply chains and launched the Supply Chain Disruptions Task Force to address disruptions linked to the COVID-19 pandemic. Thanks to those efforts, more cargo is moving through American ports than at any time in the Nation's history. The number of containers sitting on the docks at the Ports of Los Angeles and Long Beach—two of the largest ports in America—for more than eight days has been cut by more than 70 percent since the beginning of November 2021. Holiday sales surged 14 percent last year—a new record. Despite dire predictions about delivery delays at the end of last year, holiday season delivery times dropped below their pre-pandemic levels, while retail inventories hit an all-time record. In addition, the Administration's Action Plan for America's Ports and Waterways and Trucking Action Plan to Strengthen America's Trucking Workforce continue to help American port operators move a record amount of goods from ships to shelves as quickly as possible and connect more Americans to good jobs in the trucking industry.

The President has also taken key steps to promote greater competition, protect consumers, and lower prices. In July 2021, the President signed a historic Executive Order 14036, "Promoting Competition in the American Economy," to encourage competition across industries, including travel, healthcare, food, internet service, and more. Executive Order 14036 includes 72 initiatives by more than a dozen Federal agencies to promptly tackle some of the most pressing competition problems across the economy. In the months since, the Administration has worked to lower prices for hearing aids and has taken on meat processors that are raking in record profits while raising prices for consumers at the grocery store. Also, enforcement agencies like the Federal Trade Commission and the Department of Justice (DOJ) have taken strong actions to protect consumers from anti-competitive mergers that could have raised prices for consumers and businesses.

The President has also relentlessly focused on implementing an industrial strategy to revitalize America's manufacturing base. During his first week in office, the President signed Executive Order 14005, "Ensuring the Future is Made in All of America by All of America's Workers," that created the first-ever Made in America Office within the Office of Management and Budget and launched a Government-wide initiative to leverage the Federal Government's procurement power to support American manufacturing and American workers. To help translate that commitment into action, the President announced the most robust changes to the Buy American Act of

1933 in more than 70 years—raising the domestic content threshold, strengthening domestic supply chains for critical goods, and increasing transparency and accountability. Since the President took office, the economy has added more than 423,000 new manufacturing jobs. Manufacturing as a share of Gross Domestic Product has returned to pre-pandemic levels. In recent months, major companies have announced significant investments in new manufacturing lines and factories that will create thousands of good-paying jobs in the United States.

MOUNTING A FORCEFUL RESPONSE TO THE PANDEMIC

In January 2021, the United States lacked the tools to fully protect people against COVID-19. Less than one percent of Americans—some two million people—were fully vaccinated. Less than half of our Nation's schools were open for in-person instruction. Zero at-home tests were on the market. The Nation faced shortages of protective equipment for frontline workers and didn't have enough vaccines, vaccinators, or locations where people could get vaccinated. Meanwhile, the rapid spread of the virus had disrupted the education of millions of students, forced an estimated 1-in-4 child care providers to close their doors, taken a significant toll on Americans' mental health, produced a massive surge in domestic violence incidents and overdose deaths, worsened food and housing insecurity, and deepened long-standing health inequities in communities across the Nation.

From the day he took office, the President has been unrelenting in his focus on ensuring that the American people have the tools necessary to protect themselves against COVID-19: more vaccines, boosters, tests, masks, and treatments. Through the American Rescue Plan, the Administration secured $160 billion to support the President's vaccination program, therapeutics, testing and mitigation, personal protective equipment, and the broader COVID-19 response. These resources have played a key role in preventing hospitalizations and deaths from COVID-19 and combatting the Delta and Omicron variants.

As a result of these efforts, the United States is moving forward safely. As of March 2022, more than 216 million Americans—including more than 75 percent of adults—had been fully vaccinated. Vaccines are approved or authorized for all Americans five years of age and older. There are more than 90,000 vaccination locations in communities across the Nation, with 90 percent of Americans living within five miles of a site. The Administration is securing millions of doses of a highly effective pill to treat COVID-19. In addition, the President's focus on equity is delivering results: the latest CDC data show that gaps in vaccination rates among Latino, Black, and White adults have been effectively closed.

After a year of children falling behind on learning, the President took action to open schools and get kids and teachers back into their classrooms. The American Rescue Plan provided $130 billion to schools to allow for their safe operation and address the COVID-19 pandemic's impacts on learning, as well as an additional $10 billion to support COVID-19 testing. The Administration has also ensured schools have the flexibility and resources they need to ensure children are fed healthy meals. As a result, about 99 percent of schools are now open, full-time and in person—up from just 46 percent when the President took office. This progress has been crucial to ensuring that all students can safely be back where they belong—learning alongside their peers—and to helping them recover from any learning loss or mental health setbacks they experienced since the onset of the COVID-19 pandemic.

As the Administration combats the COVID-19 pandemic at home, the United States is also leading the international effort to respond to the Global COVID-19 pandemic and vaccinate the world. At the President's direction, the United States has committed to donating 1.2 billion vaccine doses for free with no strings attached—the largest commitment in the world—and has already shipped 500 million doses to 112 countries, four times more doses than any other country. The Administration is also working to expand access to tests, treatments, and personal protective equipment globally. These efforts are saving lives, improving our national and economic security, and helping prevent the emergence and spread of other dangerous variants and future biological catastrophes like pandemics.

Delivering Urgent Relief

With the passage of the American Rescue Plan, the Administration quickly mobilized vital resources to help families and small businesses weather the worst of the pandemic and create a bridge to an economic recovery.

In 2021, the Administration delivered more than 175 million economic impact payments of $1,400 to the vast majority of Americans—totaling over $400 billion in relief. The American Rescue Plan expanded the Child Tax Credit for families of more than 61 million children, with up to $3,600 available for families with children under six, and $3,000 for families with children 6 to 17 years old. For the first time—and beginning just four months after the American Rescue Plan's passage—these payments were made on a monthly basis, providing a reliable boost to working families to help cover essential expenses. The American Rescue Plan also helped make quality health insurance coverage through the Affordable Care Act more affordable than ever—with families saving an average of $2,400 on their annual premiums, and 4 out of 5 consumers finding quality coverage for under $10 a month.

At the same time, the American Rescue Plan provided funding to all 50 States and more than 34,000 cities, towns, and counties to help prevent layoffs and get workers back on the job. It provided $28 billion through the Restaurant Revitalization Fund (RRF) to help more than 100,000 restaurants and bars keep their doors open. The RRF was part of the more than $450 billion in emergency relief delivered to more than six million small businesses in 2021 through the Administration's implementation of the Paycheck Protection Program, COVID Economic Injury Disaster Loan (EIDL) program, the COVID EIDL Targeted and Supplemental Advance programs, and the Shuttered Venue Operators Grants program.

The Administration also implemented the Emergency Rental Assistance program, which delivered 3.8 million payments totaling over $33 billion to eligible households in 2021. Over 80 percent of the assistance was delivered to lowest-income households (those earning 50 percent of area median income and below). As a result of these efforts, the Administration has built a nationwide infrastructure for rental assistance and eviction prevention, helping keep eviction filings below 60 percent of historical levels and preventing households from experiencing further economic setbacks associated with housing insecurity.

DELIVERING PROGRESS AT HOME

Under the President's leadership, our Nation has not only risen to meet urgent crises, but we have begun building a better and more resilient America. Since taking office, the President has advanced an agenda to bring more dignity, opportunity, security, and prosperity to working families across the Nation—from rebuilding America's infrastructure and laying a new foundation for growth, to taking historic action to combat the climate crisis, to embedding equity as a priority across the Federal Government.

Rebuilding America's Crumbling Infrastructure

After decades of talk in Washington about rebuilding our crumbling infrastructure, last year the President worked with members of both parties in the Congress to pass and sign into law the Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Law)—a once-in-a-generation investment in our Nation's infrastructure and competitiveness that will help build a better America, create good-paying union jobs, ease inflationary pressures, and grow the economy sustainably and equitably so that everyone has the chance to get ahead for decades to come.

For the up to 10 million American households that lack safe drinking water, the Bipartisan Infrastructure Law invests $55 billion to deliver clean water to all American families and eliminate the Nation's lead service lines—including in tribal, rural, and disadvantaged communities. To ensure that every American has access to reliable, affordable, high-speed internet, it invests a historic $65 billion for broadband deployment to help lower the cost of internet service and to close the digital divide. To fix and rebuild our roads and bridges, it reauthorizes surface transportation programs for five years and makes the single largest investment in repairing and reconstructing our Nation's bridges since the construction of the interstate highway system.

The Bipartisan Infrastructure Law also: includes crucial resources to improve transportation options for millions of Americans and reduce greenhouse emissions through the largest investment in public transit in U.S. history; upgrades the Nation's airports and ports to strengthen domestic supply chains; makes the largest investment in passenger rail since the creation of Amtrak; builds a national network of electric vehicle chargers; makes our Nation's infrastructure resilient against the impacts of climate change, cyber-attacks, and extreme weather events; and includes more for our Nation.

In the months since the President signed the Bipartisan Infrastructure Law into law, the Administration has hit the ground running to deliver results. Already, the Administration has mobilized resources to: connect tribal Nations to reliable, affordable high-speed internet; replace, repair, and rehabilitate bridges across the Nation; upgrade critical infrastructure at 3,075 airports; update America's aging water infrastructure, sewerage systems, pipes and service lines; and stop toxic waste from harming communities.

Taking Aggressive Action to Tackle the Climate Crisis

When the President took office, he made tackling the climate crisis a central priority across the entire Federal Government. At his direction, the Administration has launched an unprecedented effort to reduce climate pollution while creating good-paying union jobs, advancing environmental justice, strengthening the Nation's resilience, and protecting public health.

On the first day of his Administration, the President rejoined the Paris Agreement. The President set an ambitious goal to reduce greenhouse gas pollution 50 to 52 percent from 2005 levels by 2030, while rallying countries around the world to make their own bold contributions. At the 2021 United Nations Climate Change Conference, the President launched the *U.S. Methane Emissions Reduction Action Plan* in support of the Global Methane Pledge of September 18, 2021 (Global Methane Pledge) to reduce the world's methane emissions 30 percent from 2020 levels by 2030. To advance the global phasedown of hydrofluorocarbons, the President secured domestic action to reduce emissions of these super pollutants by 85 percent within 15 years. Also, to reward clean manufacturing in the global marketplace, the President announced a groundbreaking commitment to negotiate the world's first carbon-based arrangement on steel and aluminum trade with the European Union.

The President also set a target to eliminate carbon pollution from the electricity sector by 2035 and is fast-tracking clean energy—including the launch of the American offshore wind industry, with the first approvals of large-scale projects on the path to 30 gigawatts by 2030. The President's support for innovation and deployment of wind, solar, storage, transmission, and more is creating good-paying union jobs and lowering energy bills for consumers. To jumpstart an electric transportation future that's Made in America, the President brought together automakers and autoworkers around a new ambitious goal for 50 percent electric vehicle sales share in 2030. The President also launched a Federal Sustainability Plan to lead by example through the Federal Government's vehicle fleet, buildings, and purchasing power. The President has pursued new climate-smart agriculture and forestry initiatives, protections for cherished monuments and habitats, and the America the Beautiful initiative to conserve 30 percent of U.S. lands and waters by 2030. Also, the President launched whole-of-Government efforts to build resilience to intensifying climate impacts, protect the economy and financial systems from climate-related financial risks, and secured emergency funding last year to help communities recover from disasters and related crop losses.

The President is also making good on his Justice40 commitment to deliver 40 percent of the benefits from Federal investments in climate and clean energy to disadvantaged communities to build their economies. To create good-paying union jobs in hard-hit energy communities, the President has driven Federal resources to coal, oil and gas, and power plant communities. The President made environmental justice and economic revitalization a centerpiece of the Bipartisan Infrastructure Law, which includes the largest investment in addressing legacy pollution in American history, including capping orphaned oil and gas wells that are major sources of methane emissions and local air pollution. The Environmental Protection Agency has committed to cleanup and clear the backlog of 49 previously unfunded Superfund sites and accelerate cleanup at dozens of other sites across the Nation.

Through the Bipartisan Infrastructure Law, the Administration also secured the largest investments ever in the Nation's water infrastructure, power grid, public transit, and resilience. The law will help replace lead service lines and reduce exposure to the dangerous per- and polyfluoroalkyl chemical substances. It will make communities safer and our infrastructure more resilient to the impacts of climate change and cyber-attacks, with an investment of over $50 billion to protect against droughts, heat, floods, and wildfires, in addition to a major investment in weatherization. It invests more than $65 billion through the Department of Energy to upgrade our power infrastructure, facilitate the expansion of renewables and clean energy, and fund new programs to support the development, demonstration, and deployment of cutting-edge clean energy technologies to accelerate our transition to a zero-emission economy. Also, it will deliver thousands of electric school buses nationwide, including in rural communities, helping school districts across the Nation buy clean, American-made, zero-emission buses, and replace the yellow school bus fleet for America's children.

Advancing Equity across the Economy and Nation

The promise of our Nation is that every American has an equal chance to live to their full potential. Yet persistent systemic inequities and barriers to opportunity have denied this promise for so many. That is why the President has taken historic steps to put equity at the center of his agenda—and why the President assembled the most diverse cabinet in American history to deliver on this Government-wide effort.

Beginning on his first day in office, the President took a series of landmark executive actions to advance equity. The President signed a day-one Executive Order 13985, "Advancing Racial Equity and Support for Underserved Communities Through the Federal Government," on advancing equity and racial justice across the Federal Government; a day-one Executive Order 13988, "Preventing and Combating Discrimination on the Basis of Gender Identity or Sexual Orientation," directing Federal agencies to extend protections against discrimination based on gender identity and sexual orientation, upon which agencies have already acted in the areas of housing, lending services, education, healthcare, and more; and Executive Order 14035, "Diversity, Equity, Inclusion, and Accessibility in the Federal Workforce," on advancing diversity, equity, inclusion, and accessibility (DEIA) across the Federal workforce. In the months since, Federal agencies have been hard at work implementing these orders—delivering more equitable external work, revised DEIA policies and trainings, and updated civil rights guidance and regulations.

The Administration set a Government-wide goal of increasing the share of Federal contracts to small disadvantaged businesses, including those owned by people of color, by 50 percent by 2025—which would translate to an increase of $100 billion to these firms over five years. The Bipartisan Infrastructure Law made permanent the Minority Business Development Agency, the only Federal entity focused exclusively on promoting growth and competitiveness of minority-owned businesses, and elevated the head of the Agency to the Under Secretary level. The Administration provided $32 billion specifically for tribal communities and Native Americans as part of the American Rescue Plan, as well as $13 billion in direct investments in tribal communities through the Bipartisan Infrastructure Law. Also, the American Rescue Plan's $122 billion Elementary and Secondary School Emergency Relief Fund, in addition to providing critically needed funds to safely reopen and operate schools and support students, included landmark maintenance of equity requirements that protected high-poverty districts and schools from disproportionate funding reductions and the highest poverty districts from any reductions.

On International Women's Day in March 2021, the President signed Executive Order 14020, "Establishment of the White House Gender Policy Council," establishing the first White House Gender Policy Council within the Executive Office of the President and charged the office with leading a Government-wide effort to advance gender equity and equality. To guide that work, last year the Administration issued the first ever *National Strategy on Gender Equity and Equality* in the United Sates to advance equal opportunity for people of all genders—now, agencies are developing action plans to achieve their top priorities for advancing gender equity and equality. The Administration has also: taken critical steps to eliminate racial disparities in maternal health; advanced historic military justice reform; deployed resources from the American Rescue Plan for domestic violence and sexual assault prevention and services; and announced bold commitments to advance women's economic security, gender-based violence prevention and response, and sexual and reproductive health and rights both at home and around the world.

The President has also moved decisively to condemn racism, xenophobia, and intolerance against Asian Americans (AA) and Native Hawaiian and Other Pacific Islanders (NHOPI). In his first week in office, the President signed a Presidential Memorandum establishing an official policy to ensure the Federal Government stands up against racism, xenophobia, nativism, and bias. The memorandum directed all Federal agencies to take steps to ensure their actions mitigate anti-Asian bias and xenophobia, especially in the response to the COVID-19 pandemic, and charged DOJ to partner with AA and NHOPI communities to respond to and prevent hate crimes and violence. In May 2021, the President signed into law the COVID-19 Hate Crimes Act, bipartisan legislation that makes significant improvements to the Nation's response to hate crimes.

The Administration is also creating opportunity and building wealth in rural communities. For example, the American Rescue Plan's Coronavirus State and Local Fiscal Recovery Fund has enabled States to invest in critical rural broadband and water infrastructure. In addition, the Administration's efforts to strengthen the food system through American Rescue Plan funding are opening up new markets for farmers and ranchers in rural America and supporting a fairer, more competitive, and more resilient meat and poultry supply chain. The Administration is also working to keep rural hospitals open, supporting rural providers, expanding rural healthcare coverage, and making it more affordable than ever, with nearly 700,000 rural Americans gaining coverage through the Patient Protection and Affordable Care Act in 2021 alone and families saving an average of $2,400 per year due to the American Rescue Plan.

RESTORING AMERICAN LEADERSHIP ON THE WORLD STAGE

As the President has restored the Nation's strength at home, he has revitalized our alliances and partnerships around the world, brought American leadership to bear on the defining issues of our time, and invested in our military advantage. The President has prioritized strategic competition with China and worked with allies and partners to resist coercion and deter aggression from Beijing and Moscow, and ended America's 20-year war in Afghanistan while removing all U.S. troops. The President has led a global response to the COVID-19 pandemic and made historic investments to confront the climate crisis. As the United States enters what will be a decisive decade, the President is positioning America to win the competition for the 21st Century.

The President strengthened our foundational partnership with Europe on the full range of global challenges, including climate, health security, trade and technology, and our collective and decisive response to Russian aggression against Ukraine. In the Indo-Pacific, America is strengthening its role and expanding its cooperation with longtime allies and partners, including new diplomatic, defense and security, critical and emerging technology and supply chain, and climate and global health initiatives, while supporting stronger ties between our European and Indo-Pacific allies. Closer to home, the United States has invested in relationships in the Western Hemisphere, including by reviving the North American Leaders' Summit to consult with neighboring countries, committing to work together on major regional migration efforts, and collaborating on health security, democratic renewal, and shared economic growth. In the Middle East and North Africa, the United States is working to deescalate tensions, curb Iran's destabilizing activities, and help regional partners lay the foundation for greater security, prosperity, and opportunity for their people. The United States is partnering with African nations and publics to solve problems of common interest—from health security to shared economic prosperity to countering terrorism—mindful of the continent's importance to critical global issues.

From his first days in office, the President has restored U.S. leadership to the most significant global challenges of our time. At the President's direction, the United States has served as the world's vaccine arsenal, pledging more than 1.2 billion COVID-19 vaccines to countries around the world, providing lifesaving supplies, and hosting a Global COVID-19 Summit to build better health security for the future. The President renewed U.S. leadership on climate, including by rejoining the Paris Agreement. Alongside the Group of Seven partners, the United States launched the Build Back Better World Initiative to meet the developing world's infrastructure needs transparently, sustainably, and with high standards. The President convened 110 governments in the first Summit for Democracy to catalyze action to strengthen democracy at home and abroad. The United States rejoined and reinforced international institutions such as the World Health Organization and the United Nations Human Rights Council. In addition, the Administration reprioritized cybersecurity by strengthening resilience at home and accelerating cooperation with allies and the private sector.

Under the President's leadership, the United States has resolved significant trade disputes, including on airplanes, steel, and aluminum, and protected American workers by centering them in our foreign policy. Last year, the United States rallied more than 100 countries to join the Global Methane Pledge to cut emissions by 30 percent by 2030. In addition to fueling the global economic recovery, America secured a historic win for workers and middle-class families through the agreement of 130 countries to support a global minimum tax for the world's largest corporations.

As America leads with diplomacy, we are also investing in our military—the strongest fighting force the world has ever known. We are investing in our warfighting advantages, understanding that a combat-credible military is the foundation of deterrence and America's ability to prevail in conflict. At the same time, the United States is making disciplined choices about the use of military force and focusing its attention on the military's primary responsibilities: to defend the homeland; deter conflict; and to fight and win the Nation's wars, while remaining committed to the wellbeing of its servicemembers and their families.

BUILDING A BETTER AMERICA

Under the President's leadership, America is on the move again. Together, in the face of unprecedented crises and ongoing challenges, we have begun to change the trajectory of our economy to finally make it work for working people—with historic job creation, faster economic growth, and more money in workers' pockets. We are moving forward safely, continuing to combat the pandemic and building better preparedness for the next health emergency. We have mobilized the Federal Government to tackle the climate crisis with the urgency that the science demands. We have launched a Government-wide effort to advance equity and expand opportunity across our Nation and economy. We have revitalized our global alliances and our leadership on the world stage. While much work remains, we are poised to meet the challenges and opportunities ahead.

The President's Budget details his vision for how to carry this momentum forward and build a better America. It is a Budget anchored in the President's bedrock belief that the economy grows from the bottom up and the middle out, and that America is at its best when all Americans—not just the wealthiest few—can get ahead and pursue their promise and potential.

In last year's Budget, the President put forward a set of proposals designed to ensure America emerged from the pandemic even stronger than before. Just months later, the President's proposals to rebuild America's crumbling infrastructure, expand access to clean drinking water, and invest in communities too often left behind were enacted in the Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Law). Earlier this month, the Congress reached a bipartisan agreement to fund the Government for 2022, ending a damaging series of short-term continuing resolutions and taking a first step to reinvest in research, education, public health, and other core functions of the Government.

In the State of the Union, the President reiterated his commitment to work with the Congress to pass legislation to lower costs for American families, reduce the deficit, and expand the productive capacity of the American economy. The President supports legislation that: cuts costs for prescription drugs, healthcare premiums, child care, long-term care, housing, and college, including tuition-free community college and expanded support for Historically Black Colleges and Universities (HBCUs), Tribally Controlled Colleges and Universities (TCCUs), and Minority-Serving Institutions (MSIs); reduces energy costs by combatting climate change and accelerating the transition to a clean energy economy while creating good-paying jobs for American workers; supports families with access to free, high-quality preschool and paid family and medical leave and by continuing the enhanced Child Tax Credit and Earned Income Tax Credit; and provides health coverage to millions of uninsured Americans. The President believes these proposals must be paired with reforms that ensure corporations and the wealthiest Americans pay their fair share, including by paying the taxes they already owe and closing loopholes that they exploit.

Because discussions with the Congress continue, the President's Budget includes a deficit neutral reserve fund to account for future legislation, preserving the revenue from proposed tax and prescription drug reforms for the investments needed to bring down costs for American families and expand our productive capacity. This approach reflects the President's continued commitments to: advancing the policies that strengthen our economy and reduce costs for American families; working collaboratively with the Congress to shape this legislation; and fully paying for the long-term costs of all new investments and reducing the deficit. As the President said in the State of the Union, he is committed to working with the Congress on legislation that both cuts costs for families and reduces the Federal deficit. To be conservative, however, the Budget reflects this reserve fund as deficit neutral.

In addition, the President's 2023 Budget proposes other targeted investments that would: help expand the productive capacity of our economy to create jobs, bring down prices, and continue our historic recovery; improve our public health infrastructure and spur transformational medical research; combat and prevent gun violence and other violent crime; drive action to lead the world in combating the climate crisis; and make higher education more affordable and accessible while advancing equity, opportunity, and security for all Americans. (Due to the timing of enactment, the 2023 Budget does not reflect the details of the 2022 appropriations bill, and investment levels in the Budget are compared to 2021 funding.)

The Budget also provides the resources necessary to deliver on our commitments to the American people's security and prosperity by revitalizing American leadership on the world stage. We are at the beginning of a decisive decade that will determine the future of strategic competition with China, the trajectory of the climate crisis, and whether the rules governing technology, trade, and international economics enshrine or violate our democratic values. The Budget enables us to meet these challenges by investing both in our domestic and international sources of strength—from our dynamic and diverse workforce, to our industrial and innovation base, to our military and development enterprise, to our unparalleled network of allies and partners. In doing so, the Budget enables us to marshal global coalitions to act from a position of strength, whether in the face of Russian aggression or transnational threats.

The Budget also delivers on the President's commitment to fiscal responsibility. The deficit is on track to drop by more than $1 trillion this year, the largest-ever one-year decline. Under the Budget policies, annual deficits would fall to less than half of last year's levels as a share of the economy, while the economic burden of debt would remain low. The Budget's investments are more than paid for through additional tax reforms that ensure corporations and the wealthiest Americans pay their fair share, allowing us to cut costs for American families, strengthen our economy, and cut deficits and debt by more than $1 trillion over the coming decade.

PROMOTING JOB CREATION, REDUCING COST PRESSURES, AND BOOSTING THE PRODUCTIVE CAPACITY OF THE ECONOMY

In 2021, America saw the strongest monthly job growth ever recorded, the largest decline in unemployment ever recorded, and the strongest economic growth in nearly four decades. Importantly, the benefits from this growth were broadly shared, and not only concentrated among those at the very top. At the same time, the United States—like virtually all advanced economies around the world—is facing pandemic-driven price increases that strain family budgets. That is why the President is laser focused on building a more productive economy that can deliver more goods and services to the American people while bringing down costs and driving growth and job creation. The Budget builds on the progress the Administration has already made—as well as additional steps the President is pursuing—through a package of investments that would bolster the supply-side of the economy, create jobs and address cost pressures, and expand the economy's capacity over the medium- and long-term.

Strengthening Supply Chains, Bolstering Manufacturing, and Improving Infrastructure

Strengthens the Nation's Supply Chains through Domestic Manufacturing. To help ignite a resurgence of American manufacturing and strengthen domestic supply chains, the Budget provides $372 million, an increase of $206 million over the 2021 enacted level, for the National Institutes of Standards and Technology's manufacturing programs to launch two additional manufacturing innovation institutes in 2023 and continue support for the two institutes funded in 2022. The Budget includes a $125 million increase for the Manufacturing Extension Partnership to make America's small and medium manufacturers more competitive, as well as $200 million for a new Solar Manufacturing Accelerator at the Department of Energy (DOE) to build domestic capacity in solar energy supply chains while moving away from imported products manufactured using unacceptable labor practices. The Budget provides $30 million to support programs that help ensure entrepreneurs have the tools and networks they need to bring cutting-edge innovation to the market.

Accelerates Efforts to Move More Goods Faster through American Ports and Waterways. The Budget continues support for the historic levels of Federal investment to modernize America's port and waterway infrastructure provided under the Bipartisan Infrastructure Law. The Budget includes $230 million for the Port Infrastructure Development Program to strengthen maritime freight capacity. In addition to keeping the Nation's supply chain moving by improving efficiency, the Department of Transportation will prioritize projects that also lower emissions—reducing environmental impact in and around America's ports. The Budget also includes $1.7 billion for the Harbor Maintenance Trust Fund to facilitate safe, reliable, and environmentally sustainable navigation at the Nation's coastal ports.

Reduces Bottlenecks and Commute Times through Investments in Competitive Programs. The Budget provides robust support for transportation projects that reduce commute times, improve safety, reduce freight bottlenecks, better connect communities, and reduce transportation-related greenhouse gas emissions. For example, investments include $4 billion for the new Bipartisan Infrastructure Law-authorized National Infrastructure Investments grant programs to support transportation projects with significant benefits across multiple modes.

Modernizes and Upgrades Roads and Bridges. To modernize, repair, and improve the safety and efficiency of the Nation's network of roads and bridges, the Budget provides $68.9 billion for the Federal-aid Highway program, including: $9.4 billion provided by the Bipartisan Infrastructure Law for 2023; $8 billion to rebuild the Nation's bridges; $1.4 billion to deploy a nationwide, publicly-accessible network of electric vehicle chargers and other alternative fueling infrastructure; $1.3 billion for a new carbon reduction grant program; and $1.7 billion for a new resiliency grant program to make surface transportation infrastructure more resilient to hazards such as climate change.

Invests in Reliable Passenger and Freight Rail. To ensure the safety and performance of the rail industry today and deliver the passenger rail network of the future, the Budget provides a historic $17.9 billion, a $15 billion increase over the 2021 enacted level. This includes $4.7 billion in additional funding on top of the $13.2 billion already provided by the Bipartisan Infrastructure Law for 2023. These resources would support $7.4 billion to significantly improve Amtrak's rolling stock and facilities, and $10.1 billion for existing and new competitive grant programs to support passenger rail modernization and expansion, address critical safety needs, and support the vitality of the freight rail network.

Connects All Americans to High-Speed, Affordable, and Reliable Internet. The President is committed to ensuring that every American has access to broadband, which would not only strengthen rural economies, but also create high-paying union jobs installing broadband. Building on key investments in the Bipartisan Infrastructure Law, the Budget provides $600 million for the ReConnect program, which provides grants and loans to deploy broadband to unserved areas—especially tribal areas—and $25 million to help rural telecommunications cooperatives refinance their Rural Utilities Service debt and upgrade their broadband facilities.

Addressing Cost Pressures and Expanding Economic Capacity

Increases Affordable Housing Supply. To address the critical shortage of affordable housing in communities throughout the Nation, the Budget proposes $50 billion in mandatory funding and additional Low-Income Housing Tax Credits (LIHTC) to address market gaps, increase housing supply, and help to stabilize housing prices over the long-term. Specifically, the Budget provides $35 billion in mandatory funding at the Department of Housing and Urban Development (HUD) for State and local housing finance agencies and their partners to provide grants, revolving loan funds and other streamlined financing tools, as well as grants to advance State and local jurisdictions' efforts to remove barriers to affordable housing development. In addition, the Budget proposes $5 billion in mandatory funding for the Department of the Treasury's Community Development Financial Institutions Fund to support financing of new construction and substantial rehabilitation that creates net new units of affordable rental and for sale housing. The Budget also proposes modifying LIHTC to better incentivize new unit production, with a 10-year cost of nearly $10 billion. The Budget also provides more than $1.9 billion in discretionary funding for the HOME Investment Partnerships Program to construct and rehabilitate affordable rental housing and provide homeownership opportunities—the highest funding level for HOME in nearly 15 years.

Fosters Competitive and Productive Markets and Targets Corporate Concentration. The Budget reflects the Administration's commitment to vigorous marketplace competition through robust enforcement of antitrust law by including historic increases of $88 million for the Antitrust Division of the Department of Justice (DOJ) and $139 million for the Federal Trade Commission. The President also supports legislation that would align executives' interests with the long-term interests of shareholders, workers, and the economy by requiring executives to hold on to company shares that they receive for several years after receiving them, and prohibiting them from selling shares in the years after a stock buyback. This would discourage corporations from using profits to repurchase stock and enrich executives, rather than investing in long-term growth and innovation.

Builds a Competitive and Resilient Food Supply Chain. The Budget strengthens market oversight through investments in the Agricultural Marketing Service and the Animal and Plant Health Inspection Service, resulting in competitive meat and poultry product prices for American families and increased protection against invasive pests and zoonotic diseases. These programs build on the pandemic and supply chain assistance funding in the American Rescue Plan Act of 2021 (American Rescue Plan) to address pandemic-related vulnerabilities in the food system and create new market opportunities and good-paying jobs.

Promotes Innovation and Science in Underrepresented Communities. The Budget supports programs, including community-led capacity building and training, that expand equitable inclusion in Federal science and technology programs and the use of scientific and technological innovation to advance equitable outcomes. The Budget provides $393 million for the National Science Foundation (NSF), an increase of $172 million or 78 percent above the 2021 enacted level, for programs dedicated to increasing the participation of historically underrepresented communities in science and engineering fields. The Budget also provides $260 million for DOE initiatives to build science and technology capacity in underserved institutions, including HBCUs, Hispanic Serving Institutions (HSIs), and TCCUs. In addition, the Budget provides $315 million through the U.S. Department of Agriculture (USDA) in agriculture research, education, and extension grants to build capacity in underserved institutions, including HBCUs, HSIs, and TCCUs.

Expanding Opportunities for Workers and Small Businesses

Expands Access to Capital for Small Businesses. The Budget addresses the need for greater access to affordable capital, particularly in underserved communities. The Budget increases the authorized lending levels in key Small Business Administration (SBA) programs by a total of $9.5 billion to significantly expand the availability of working capital, fixed capital, and venture capital funding for small businesses. The Administration looks forward to working with the Congress to ensure small manufacturers have sufficient working capital to help them meet human resource needs and purchase raw materials/inventory, while incentivizing them to finance renewable energy equipment projects.

Supports Minority-Owned Businesses to Narrow Racial Wealth Gaps. The Budget elevates the stature and increases the capacity of the Minority Business Development Agency by providing the full $110 million authorized in the Bipartisan Infrastructure Law. This funding would bolster services provided to minority-owned enterprises by expanding the Business Center program, funding Rural Business Centers, opening new regional offices, and supporting innovative initiatives to foster economic resiliency.

Creates New Global Markets for American Goods. The Budget provides an additional $26 million over 2021 enacted levels to bolster commercial diplomacy and enhance export promotion through a targeted expansion of the Foreign Commercial Service at the International Trade Administration, which would help American businesses seeking to increase exports abroad, navigate new foreign markets, or find market opportunities.

Equips Workers with Skills They Need to Obtain High-Quality Jobs. The Budget invests $100 million to help community colleges work with the public workforce development system and employers to design and deliver high-quality workforce programs. The Budget also provides $100 million for a new Sectoral Employment through Career Training for Occupational Readiness program, which would support training programs focused on growing industries, enabling disadvantaged workers to enter on-ramps to middle class jobs, and creating the skilled workforce the economy needs to thrive.

Expands Access to Registered Apprenticeships (RA). RA is a proven earn-and-learn model that raises participants' wages and puts them on a reliable path to the middle class. The Budget invests $303 million, a $118 million increase above the 2021 enacted level, to expand RA opportunities in high growth fields, such as information technology, advanced manufacturing, healthcare, and transportation, while increasing access for historically underrepresented groups, including people of color and women. To improve access to RA for women, the Budget doubles the Department of Labor's (DOL) investment in its Women in Apprenticeship and Nontraditional Occupations grants, which provide pre-apprenticeship opportunities to boost women's participation in RA.

Provides Youth Training and Employment Pathways. The Budget invests in programs that provide young people with equitable access to high-quality training and career opportunities, including $75 million for a new National Youth Employment Program to create high-quality summer and year-round job opportunities for underserved youth. The Budget also provides $145 million for YouthBuild, $48 million above the 2021 enacted level, to enable more at-risk youth to gain the education and occupational skills they need to obtain good jobs. To further advance equity and inclusion, the Budget also provides $15 million to test new ways to enable low-income youth with disabilities—including youth who are in foster care, involved in the justice system, or are experiencing homelessness—to successfully transition to employment.

RESTORING AMERICAN LEADERSHIP AND CONFRONTING GLOBAL THREATS

To ensure and strengthen American security, prosperity, and democracy, we must both deliver at home and lead on the world stage. The Budget invests in the key pillars of our international strength in order to position us to contend with determined competitors, address transnational threats, and manage crises as they arise. The Budget invests in deepening and modernizing our alliances and partnerships, as we are stronger in managing challenges—whether in the form of China's trade abuses, Russian aggression, or the worsening climate crisis—when we work in concert with those who share our values or interests. The Budget bolsters our cybersecurity and strengthens our military by ensuring we have the resources necessary to sustain deterrence and backstop our diplomacy, as well as fight and win the Nation's wars if necessary. Also, the Budget renews our commitment to sustainable and inclusive development, including through the President's Build Back Better World initiative, which supports building stronger infrastructure to confront the climate crisis, strengthening global health security, working toward gender equality, and shaping the rules of the road for digital connectivity. In addition, the Budget makes critical investments in addressing the root causes of migration while strengthening our immigration system, and in meeting the sacred commitments we have made to our Nation's veterans.

Confronting 21st Century Threats

Supports United States' European Allies and Partners. The Budget supports Ukraine, the United States' strong partnerships with North Atlantic Treaty Organization (NATO) allies, and other European partner states by bolstering funding to enhance the capabilities and readiness of U.S. forces, NATO allies, and regional partners in the face of Russian aggression.

Promotes Integrated Deterrence in the Indo-Pacific and Globally. The Budget proposes $773 billion for the Department of Defense (DOD). To sustain and strengthen deterrence, the Budget prioritizes China as the Department's pacing challenge. The 2023 Pacific Deterrence Initiative highlights some of the key investments that DOD is making that are focused on strengthening deterrence in the Indo-Pacific region. Also, DOD is building the concepts, capabilities, and posture necessary to meet these challenges, working in concert with the interagency and America's allies and partners to ensure that deterrence is integrated across domains, theaters, and the spectrum of conflict.

Defends Freedom Globally. To support American leadership in defending democracy, freedom, and security worldwide, the Budget includes nearly $1.8 billion to support a free and open, connected, secure, and resilient Indo-Pacific Region and the Indo-Pacific Strategy, and $400 million for the Countering the People's Republic of China Malign Influence Fund. In addition, the Budget provides $682 million for Ukraine, an increase of $219 million above the 2021 enacted level, to counter Russian malign influence and to meet emerging needs related to security, energy, cybersecurity issues, disinformation, macroeconomic stabilization, and civil society resilience.

Supports Democracy Globally. In response to political fragility and increasing authoritarianism around the world, the Budget provides more than $3.2 billion to support global democracy, human rights, anti-corruption, and governance programming, consistent with the commitments made during the President's Summit for Democracy. The Budget advances the Presidential Memorandum on Advancing the Human Rights of Lesbian, Gay, Bisexual, Transgender, Queer, and Intersex Persons around the World, the U.S. Strategy on Countering Corruption, and the Presidential Initiative on Democratic Renewal.

Counters Persistent Threats. While focused on maintaining robust deterrence against China and Russia, the Budget would also enable DOD to counter other persistent threats including those posed by North Korea, Iran, and violent extremist organizations.

Advances U.S. Cybersecurity. The Budget invests in cybersecurity programs to protect the Nation from malicious cyber actors and cyber campaigns. Last year, the President signed Executive Order 14028, "Improving the Nation's Cybersecurity," charting a new course to improve the Nation's cybersecurity. Executive Order 14028 prioritizes protecting and modernizing Federal Government systems and data, improving information-sharing between the U.S. Government and the private sector, enhancing standards for secure software development, improving detection of cyber threats and vulnerabilities on Federal systems, and strengthening the United States' ability to respond to incidents when they occur.

Modernizes the Nuclear Deterrent. The Budget maintains a strong, credible nuclear deterrent, as a foundational aspect of integrated deterrence, for the security of the Nation and U.S. allies. The Budget supports the U.S. nuclear triad and the necessary ongoing nuclear modernization programs, to include the nuclear command, control, and communication networks.

Marshalling American Leadership to Tackle Global Challenges

Renews America's Leadership in International Institutions. The Budget continues the Administration's efforts to lead through international organizations by meeting the Nation's commitments to fully fund U.S. contributions and to pay United Nations peacekeeping dues on time and in full. The Budget also provides $1.4 billion for the World Bank's International Development Association (IDA). This investment restores the United States' historical role as the largest World Bank donor to support the development of low- and middle-income countries, which benefits the American people by increasing global stability, mitigating climate and health risks, and developing new markets for U.S exports. The U.S. contribution would also support the United States' $3.5 billion pledge to the next IDA replenishment, a critical component of the global response to the devastating impacts of the COVID-19 pandemic on developing countries.

Advances American Leadership in Global Health, Including Global Health Security and Pandemic Preparedness. The Budget includes $10.6 billion to bolster U.S. leadership in addressing global health and health security challenges, a $1.4 billion increase above the 2021 enacted level. Within this total, the Budget demonstrates U.S. leadership by supporting a $2 billion contribution to the Global Fund's seventh replenishment, for an intended pledge of $6 billion over three years, to save lives and continue the fight against HIV/AIDS, tuberculosis, and malaria, and to support the Global Fund's expanding response to the COVID-19 pandemic and global health strengthening. This total also includes $1 billion to prevent, prepare for, and respond to future infectious disease outbreaks, including the continued expansion of Global Health Security Agenda capacity-building programs and a multilateral financial intermediary fund for health security and pandemic preparedness. The Budget also invests in the global health workforce and systems to enhance countries' abilities to provide core health services, improve health systems resiliency, and respond to crises while mitigating the impacts of crises on routine health services. In addition, the Budget includes $6.5 billion in mandatory funding for the Department of State and the U.S. Agency for International Development over five years to make transformative investments in pandemic and other biological threat preparedness globally in support of U.S. biodefense and pandemic preparedness strategies and plans. This pandemic preparedness funding would strengthen the global health workforce, support pandemic preparedness research and development (R&D), advance global R&D capacity, and support health security capacity and financing to prevent, detect, and respond to future COVID-19 variants and other infectious disease outbreaks.

Advances Equity and Equality Globally. The Budget provides $2.6 billion to advance gender equity and equality across a broad range of sectors. This includes $200 million for the Gender Equity and Equality Action Fund to advance the economic security of women and girls. This total also includes funding to strengthen the participation of women in conflict prevention, resolution, and recovery through the implementation of the Women, Peace, and Security Act of 2017.

Continues Collaborative U.S. Leadership in Central America and Haiti. As part of a comprehensive strategy to drive systemic reform while addressing the root causes of irregular migration from Central America to the United States, the Budget invests $987 million in the region to continue meeting the President's four-year commitment of $4 billion. Further, in response to deteriorating conditions and widespread violence in Haiti, the Budget invests $275 million to strengthen Haiti's recovery from political and economic shocks, such as strengthening the capacity of the Haitian National Police, combating corruption, strengthening the capacity of civil society, and support services for marginalized populations. These investments would ensure that the United States is able to revitalize partnerships that build economic resilience, democratic stability, and citizen security in the region.

Strengthens U.S. Leadership on Refugee and Humanitarian Issues. The Budget provides more than $10 billion to respond to the unprecedented need arising from conflict and natural disasters around the world to serve over 70 countries and approximately 240 million people. The Budget continues rebuilding the Nation's refugee admissions program and supports up to 125,000 admissions in 2023.

Strengthening America's Immigration System

Ensures a Fair and Efficient Immigration System. The Administration is committed to ensuring that United States Citizenship and Immigration Services (USCIS) meets its mission of administering the Nation's lawful immigration system and safeguarding its integrity and promise by efficiently and fairly adjudicating requests for immigration benefits. The Budget provides $765 million for USCIS to efficiently process increasing asylum caseloads, address the immigration application backlog, and improve refugee processing.

Supports America's Promise to Refugees. The Budget provides $6.3 billion to the Office of Refugee Resettlement (ORR) to help rebuild the Nation's refugee resettlement infrastructure and support the resettling of up to 125,000 refugees in 2023. The Budget would also help ensure that unaccompanied immigrant children are unified with relatives and sponsors as safely and quickly as possible and receive appropriate care and services while in ORR custody.

Improves Border Processing and Management. The Budget provides $15.3 billion for the U.S. Customs and Border Protection and $8.1 billion for the U.S. Immigration and Customs Enforcement to enforce the immigration laws, further secure the border, and effectively manage irregular migration along the Southwest border, including $309 million for border security technology and $494 million for noncitizen processing and care costs.

Improves Immigration Courts. The Budget invests $1.4 billion, an increase of $621 million above the 2021 enacted level, in the Executive Office for Immigration Review (EOIR) to continue addressing the backlog of over 1.5 million cases that are currently pending in the immigration courts. This funding supports 100 new immigration judges, including the support personnel required to create maximum efficiencies in the court systems, as well as an expansion of EOIR's virtual court initiative. The Budget would also invest new resources in legal access programming, including $150 million in discretionary resources to provide access to representation for adults and families in immigration proceedings. Complementing this new program is a proposal for $4.5 billion in mandatory resources to expand these efforts over a 10-year period. Providing resources to support legal representation in the immigration court system creates greater efficiencies in processing cases while making the system fairer and more equitable.

Delivering on Our Commitments to Veterans

Prioritizes Veteran Medical Care. The Budget provides $119 billion—a historic 32-percent increase above the 2021 enacted level for the Department of Veterans Affairs (VA). In addition to fully funding inpatient, outpatient, mental health, and long-term care services, the Budget supports programs that improve VA healthcare quality and delivery, including investments in training programs for clinicians, health professionals, and medical students. With more women choosing VA for their healthcare than ever before, the Budget also invests $9.8 billion for all of women veterans' healthcare, including $767 million toward women's gender specific care. The Budget also further supports VA's preparedness for regional and national public health emergencies.

Prioritizes Veteran Suicide Prevention. The Budget provides $497 million to support the Administration's veteran suicide prevention initiatives, including: implementation of the Veterans Crisis Line's 988 expansion initiative; the suicide prevention 2.0 program to grow public health efforts in communities; a lethal means safety campaign in partnership with other agencies; and the Staff Sergeant Parker Gordon Fox Suicide Prevention Grant Program to enhance community-based clinical strategies.

Bolsters Efforts to End Veteran Homelessness. The Budget increases resources for veterans' homelessness programs to $2.7 billion, with the goal of ensuring every veteran has permanent, sustainable housing with access to healthcare and other supportive services to prevent and end veteran homelessness.

Invests in Caregivers Support Program. The Budget recognizes the important role of family caregivers in supporting the health and wellness of veterans. The Budget provides funding for the Program of General Caregivers Support Services. The Budget also provides $1.8 billion for the Program of Comprehensive Assistance for Family Caregivers, which includes stipend payments and support services to help empower family caregivers of eligible veterans.

Supports Research Critical to Veterans' Health Needs. Extensive research at VA medical centers, outpatient clinics, and nursing homes each year has significantly contributed to advancements in healthcare for veterans and all Americans. The Budget provides $916 million to continue the development of VA's research enterprise, including research in support of the *American Pandemic Preparedness: Transforming Our Capabilities* plan's goals. The Budget also invests $81 million within VA research programs for precision oncology to provide access to the best possible cancer care for veterans.

Continues and Enhances Efficient Delivery of Veterans Benefits. The Budget would ensure that veterans receive the benefits they have earned and deserve, such as disability compensation, education and employment training, and home loan guarantees. The Budget invests $120 million for VA to support automating the disability compensation claims process from submission to authorization which would increase VA's ability to deliver faster and more accurate claim decisions for veterans.

Addresses Environmental Exposures. The Budget increases resources for new presumptive disability compensation claims related to environmental exposures from military service. The Budget also invests $51 million within VA research programs and $63 million within the VA medical care program for Health Outcomes Military Exposures to increase scientific understanding of and clinical support for veterans and healthcare providers regarding the potential adverse impacts from environmental exposures during military service.

Honors the Memory of All Veterans. The Budget includes $430 million to ensure veterans and their families have access to exceptional memorial benefits, including two new and replacement national cemeteries. These funds maintain national shrine standards at the 158 VA managed cemeteries and provide the initial operational investment required to open new cemeteries.

STRENGTHENING AMERICA'S PUBLIC HEALTH INFRASTRUCTURE

From the President's first days in office, the Administration has mounted a forceful response to the COVID-19 pandemic and taken action to advance the health and well-being of the American people. Through the American Rescue Plan, the Administration secured critical resources to support the President's historic vaccination program, testing and mitigation, therapeutics, and personal protective equipment—and to help make quality health insurance available through the Patient Protection and Affordable Care Act more affordable. To build on this progress and bolster America's public health infrastructure, the Budget includes key investments to ensure the United States is prepared to confront future pandemics and other biological threats domestically and globally, expand access to critical health services, address other diseases and epidemics, and advance and accelerate transformative medical research.

Ensuring World-Class Public Health Infrastructure

Prepares for Future Pandemics and Other Biological Threats. While combatting the ongoing COVID-19 pandemic, the United States must catalyze advances in science, technology, and core capabilities to prepare the Nation for the next biological threat and strengthen U.S. and global health security. The Budget makes transformative investments in pandemic preparedness across the Department of Health and Human Services (HHS) public health agencies—$81.7 billion available over five years—to enable an agile, coordinated, and comprehensive public health response to protect American lives, families, and the economy and to prevent, detect, and respond to emerging biological catastrophes. The Budget builds toward a goal of making effective vaccines and therapeutics available within 100 days of identifying a new pathogen by investing in basic and advanced R&D of medical countermeasures for high priority viral families and biological threats, including expansion and modernization of clinical trial infrastructure and regulatory capacity necessary to inform evaluation and subsequent authorizations or approvals, as well as expansion of domestic manufacturing capacity to ensure sufficient supply is available. The Budget also enhances public health infrastructure by making significant investments in public health laboratory capacity, domestic and global threat surveillance, and public health workforce development that would enable States, localities, tribal nations, and Territories to mount a rapid and robust response to future threats. Further, the Budget encourages development of innovative antimicrobial drugs through advance market commitments for critical-need antimicrobial drugs. The President also supports extending telehealth coverage under Medicare beyond the COVID-19 Public Health Emergency to study its impact on utilization of services and access to care. In addition, the Budget supports enhanced DOD and DOE investments in: medical countermeasures, including vaccines, diagnostics, and therapeutics research and manufacturing; disease detection and biosurveillance; advanced computing; lab biosafety and biosecurity; and threat reduction activities with America's global partners.

Builds Advanced Public Health Systems and Capacity. The Budget includes $9.9 billion in discretionary funding to build capacity at the Centers for Disease Control and Prevention (CDC) and at the State and local levels, an increase of $2.8 billion over the 2021 enacted level. These resources would improve the core immunization program, expand public health infrastructure in States and Territories, strengthen the public health workforce, support efforts to modernize public health data collection, increase capacity for forecasting and analyzing future outbreaks, including at Center for Forecasting and Outbreak Analytics, and conduct studies on long COVID conditions to inform diagnosis and treatment options. In addition, to advance health equity, the Budget invests in CDC programs related to viral hepatitis, youth mental health, and sickle cell disease. To address gun violence as a public health epidemic, the Budget invests in community violence intervention and firearm safety research.

Expands Access to Vaccines. The Budget establishes a new Vaccines for Adults (VFA) program, which would provide uninsured adults with access to all vaccines recommended by the Advisory Committee on Immunization Practices at no cost. As a complement to the successful Vaccines for Children (VFC) program, the VFA program would reduce disparities in vaccine coverage and promote infrastructure for broad, access to routine and outbreak vaccines. The Budget would also expand the VFC program to include all children under age 19 enrolled in the Children's Health Insurance Program and consolidate vaccine coverage under Medicare Part B, making more preventive vaccines available at no cost to Medicare beneficiaries.

Guarantees Adequate and Stable Funding for the Indian Health Service (IHS). The Budget significantly increases IHS's funding over time, and shifts it from discretionary to mandatory funding. For the first year of the proposal, the Budget includes $9.1 billion in mandatory funding, an increase of $2.9 billion above 2021. After that, IHS funding would automatically grow to keep pace with healthcare costs and population growth and gradually close longstanding service and facility shortfalls. Providing IHS stable and predictable funding would improve access to high quality healthcare, rectify historical underfunding of the Indian Health system, eliminate existing facilities backlogs, address health inequities, and modernize IHS' electronic health record system. This proposal has been informed by consultations with tribal nations on the issue of IHS funding and will be refined based on ongoing consultation.

Advances Maternal Health and Health Equity. The United States has the highest maternal mortality rate among developed nations, with an unacceptably high mortality rate for Black and American Indian and Alaska Native women. The Budget includes $470 million to: reduce maternal mortality and morbidity rates; expand maternal health initiatives in rural communities; implement implicit bias training for healthcare providers; create pregnancy medical home demonstration projects; and address the highest rates of perinatal health disparities, including by supporting the perinatal health workforce. The Budget also extends and increases funding for the Maternal, Infant, and Early Childhood Home Visiting Program, which serves approximately 71,000 families at risk for poor maternal and child health outcomes each year, and is proven to reduce disparities in infant mortality. To address the lack of data on health disparities and further improve access to care, the Budget strengthens collection and evaluation of health equity data. Recognizing that maternal mental health conditions are the most common complications of pregnancy and childbirth, the Budget continues to support the maternal mental health hotline and the screening and treatment for maternal depression and related behavioral health disorders. The Administration also looks forward to working with the Congress to advance the President's goal of doubling the Federal investment in community health centers, which would help reduce health disparities by expanding access to care.

Supports Survivors of Domestic Violence and Other Forms of Gender Based-Violence. The Budget proposes significant increases to support and protect survivors of gender-based violence, including $519 million for the Family Violence Prevention and Services (FVPSA) program to support domestic violence survivors—more than double the 2021 enacted level. This amount continues funding availability for FVPSA-funded resource centers, including those that support the Lesbian, Gay, Bisexual, Transgender, Queer, and Intersex community. The Budget would provide additional funding for domestic violence hotlines and cash assistance for survivors of domestic violence, as well as funding to support a demonstration project evaluating services for survivors at the intersection of housing instability, substance use coercion, and child welfare. In addition, the Budget would provide over $66 million for victims of human trafficking and survivors of torture, an increase of nearly $21 million over the 2021 enacted level. The Budget also proposes a historic investment of $1 billion to support Violence Against Women Act of 1994 (VAWA) programs, a $487 million or 95-percent increase over the 2021 enacted level. The Budget supports substantial increases for longstanding VAWA programs, including in legal assistance for victims, transitional housing, and sexual assault services. The Budget also provides resources for new programs to support transgender survivors, build community-based organizational capacity, combat online harassment and abuse, and address emerging issues in gender-based violence.

Expands Access to Healthcare Services for Low-Income Women. The Budget provides $400 million, an increase of nearly 40 percent over the 2021 enacted level, to the Title X Family Planning program, which provides family planning and other healthcare to low-income individuals. This increase in Title X funding would improve overall access to vital reproductive and preventive health services and advance gender and health equity.

Addressing Other Diseases and Epidemics

Transforms Mental Healthcare. Mental health is essential to overall health, and the United States faces a mental health crisis that has been exacerbated by the COVID-19 pandemic. To address this crisis, the Budget proposes reforms to health coverage and major investments in the mental health workforce. For people with private health insurance, the Budget requires all health plans to cover mental health and substance use disorder benefits and ensures that plans have an adequate network of behavioral health providers. For Medicare, TRICARE, the VA healthcare system, health insurance issuers, group health plans, and the Federal Employees Health Benefit Program, the Budget lowers costs for mental health services for patients. The Budget also requires parity in coverage between mental health and substance use disorder—or behavioral health—and other medical benefits, and expands the types of providers covered under Medicare to treat these conditions. The Budget invests in increasing the number of mental health providers serving Medicaid beneficiaries, as well as in behavioral health workforce development and service expansion, including in primary care clinics and at non-traditional sites. The Budget also provides sustained and increased funding for community-based centers and clinics, including a State option to receive enhanced Medicaid reimbursement on a permanent basis. In addition, the Budget makes historic investments in youth mental health and suicide prevention programs and in training, educational loan repayment, and scholarships that help address the shortage of behavioral health providers, especially in underserved communities. The Budget also strengthens access to crisis services by building out the National Suicide Prevention Lifeline, which will transition from a 10-digit number to 988 in July 2022.

Accelerates Innovation through the Advanced Research Projects Agency for Health (ARPA-H). The Budget proposes a major investment of $5 billion for ARPA-H, significantly increasing direct Federal R&D spending in health to improve the health of all Americans. With an initial focus on cancer and other diseases such as diabetes and dementia, this major investment would drive transformational innovation in health technologies and speed the application and implementation of health breakthroughs. Funding for ARPA-H, along with additional funding for the National Institutes of Health, total a $49 billion request to continue to support research that enhances health, lengthens life, reduces illness and disability, and spurs new biotechnology productions and innovation.

Advances the Cancer Moonshot Initiative. The Budget proposes investments in ARPA-H, the National Cancer Institute, CDC, and the Food and Drug Administration to accelerate the rate of progress against cancer by working toward reducing the cancer death rate by at least 50 percent over the next 25 years and improving the experience of people who are living with or who have survived cancer.

Commits to Ending the HIV/AIDS Epidemic. The *National HIV/AIDS Strategy for the United States 2022–2025* commits to a 75-percent reduction in HIV infection by 2025. To meet this ambitious target and ultimately end the HIV/AIDS epidemic in the United States, the Budget includes $850 million across HHS to aggressively reduce new HIV cases by increasing access to HIV prevention and care programs and ensuring equitable access to support services. This includes increasing access to pre-exposure prophylaxis (also known as PrEP) among Medicaid beneficiaries, which is expected to improve health and lower Medicaid costs for HIV treatment. The Budget also proposes a new mandatory program to guarantee PrEP at no cost for all uninsured and underinsured individuals, provide essential wrap-around services through States and localities, and establish a network of community providers to reach underserved areas and populations.

Addresses the Opioid and Drug Overdose Epidemic. The drug overdose epidemic claimed an estimated 104,000 lives in the 12-month period ending in September, 2021. To end this epidemic, a full range of service and supports are needed for individuals who use or are at risk of using substances that cause overdose, and their families. The Budget invests in services that prevent substance use disorder, expand quality evidence-based treatment, and help individuals sustain recovery. The Budget also includes $663 million specific to VA's Opioid Prevention and Treatment programs, including programs in support of the Jason Simcakoski Memorial and Promise Act.

TAKING HISTORIC STEPS TO COMBAT THE CLIMATE CRISIS AND ADVANCE ENVIRONMENTAL JUSTICE

The President has not only taken bold action to confront the climate crisis, but he has turned it into an opportunity to create good-paying union jobs, advance environmental justice, and position America to lead the industries of the future. At his direction, the Administration has moved swiftly and decisively to restore America's global climate leadership, accelerate clean energy to lower costs and create jobs, jumpstart an electric future that is Made in America, advance environmental justice in line with Justice40 and economic revitalization, and bolster our Nation's resilience in the face of accelerating extreme weather and natural disasters. To build on this progress, the President's Budget invests a total of $44.9 billion to tackle the climate crisis, a $16.7 billion increase over 2021 enacted. The Budget also makes historic investments in environmental justice, coal and powerplant communities facing energy transition, and innovation. These investments would enhance U.S. competitiveness and put America on a path to reduce greenhouse gas emissions 50 to 52 percent by 2030—all while supporting communities that have been left behind and ensuring that 40 percent of the benefits from tackling the climate crisis are targeted toward addressing the disproportionately high cumulative impacts on disadvantaged communities.

Advancing Clean Energy, Climate Data, and Resilience

Invests in Clean Energy Infrastructure and Innovation. The Budget invests $3 billion to support clean energy projects that would create good-paying jobs and drive progress toward the Administration's climate goals. Investments include $502 million to weatherize and retrofit low-income homes, including $100 million for a new Low Income Home Energy Assistance Program (LIHEAP) Advantage pilot to electrify and decarbonize low-income homes. In addition, the Budget funds $150 million to electrify tribal homes and transition tribal colleges and universities to renewable energy, and $90 million for a new Grid Deployment Office to build the grid of the future. In addition, the Budget provides $150 million in credit subsidy for the DOE Title XVII Innovative Technology Loan Guarantee Program to support up to $5 billion in loans to eligible projects that avoid, reduce, or sequester greenhouse gas emissions. DOE would also launch a new Net-Zero Laboratory Initiative with a $58 million competition to reduce emissions across the national laboratory complex.

Strengthens Domestic Clean Energy Manufacturing. Meeting the challenge of climate change will require a dramatic scale-up in domestic manufacturing of key climate and clean energy equipment, providing opportunities for U.S. workers. The Budget includes $200 million to launch a new Solar Manufacturing Accelerator that would help create a robust domestic manufacturing sector capable of meeting the Administration's solar deployment goals without relying on imported goods manufactured using unacceptable labor practices. At the same time, it is imperative that the United States partners with its allies to create resilient clean energy supply chains. In addition, the Budget proposes a new $1 billion mandatory investment to launch a Global Clean Energy Manufacturing effort that would build resilient supply chains for climate and clean energy equipment through engagement with allies, enabling an effective global response to the climate crisis while creating economic opportunities for the United States to increase its share of the global clean technology market.

Increases Demand for American Made, Zero-Emission Vehicles through Federal Procurement. The Budget invests $757 million for zero-emission fleet vehicles and supporting charging or fueling infrastructure in the individual budgets of 19 Federal agencies to provide an immediate, clear, and stable source of demand to help accelerate American industrial capacity to produce clean vehicles and components. This includes $300 million for dedicated funds at the General Services Administration for other agencies and for charging infrastructure at the United States Postal Service (USPS).

Provides Resources, Tools, and Coordination to Reduce Greenhouse Gas Emissions. To help reduce greenhouse gas emissions and make the Nation's infrastructure more resilient, the Budget invests $100 million in grants to States and Tribes that would support the implementation of on-the-ground efforts to reduce and prevent greenhouse gas emissions in communities across the Nation, such as ensuring safe and effective oil and gas well pollution management and prevention, and supporting State and local government development of zero emissions vehicle charging infrastructure. The Budget also provides an additional $35 million over the 2021 enacted level to continue phasing out potent greenhouse gases known as hydrofluorocarbons, as well as resources to spur the development of a Federal climate data portal with support from the Department of the Interior (DOI) that would provide the public with accessible information on historical and projected climate impacts. The Budget also supports multi-agency efforts to integrate science-based tools into conservation planning in order to measure, monitor, report, and verify carbon sequestration, greenhouse gas reduction, wildlife stewardship, and other environmental services at the farm level and on Federal lands. In addition, the Budget supports enhancement of greenhouse monitoring and measurement capabilities, as well as efforts to make greenhouse gas data more accessible to a broad range of users.

Strengthens Climate Resilience. The Budget provides more than $18 billion for climate resilience and adaptation programs across the Federal Government, including $3.5 billion for the Department of Homeland Security, $5.9 billion at DOI, $1 billion for HUD, and $376 million for the National Oceanic and Atmospheric Administration (NOAA). These critical investments would reduce the risk of damages from floods and storms, restore the Nation's aquatic ecosystems, and make HUD-assisted multifamily homes more energy and water efficient and climate resilient. Resources include $507 million, $93 million above the 2021 enacted level, for the Federal Emergency Management Agency's (FEMA) flood hazard mapping program to incorporate climate science and future risks and robust investments in FEMA programs that help disadvantaged communities build resilience against natural disasters. The Budget also sustains funding for key conservation and ecosystem management initiatives, including the Civilian Climate Corps, alongside a historic $1.4 billion investment in the Bipartisan Infrastructure Law for ecosystem restoration across America.

Invests in Conservation and Carbon Sequestration. The Budget invests in the Administration's America the Beautiful Initiative, a multi-agency, multi-jurisdictional ecosystem management effort that would strengthen conservation partnerships between communities and Federal partners such as DOI, USDA, and NOAA. The President's historic goal of conserving and restoring 30 percent of America's lands and waters by 2030 incentivizes America's farmers, ranchers, and forest landowners to sequester carbon in soils and vegetation, and support the efforts and visions of States and tribal nations.

Bolsters the Nation's Frontline Defenses against Catastrophic Wildfires. Protecting communities, ecosystems, and infrastructure from wildfire requires a resilient and reliable Federal workforce. The Budget provides nearly $3.9 billion for Forest Service Wildland Fire Management, an increase of $778 million, plus an additional $2.6 billion authorized in the suppression cap adjustment. The Budget upholds the President's commitment that no Federal firefighter will make less than $15 an hour, and increases the size of the Federal firefighting workforce by providing $1.8 billion for personnel and preparedness. Consistent with the President's commitment to use the latest technologies in the fight against wildfires, the Budget also permanently sustains a pilot program that leverages sensitive satellite imagery to rapidly detect wildfires. The Budget also invests $646 million in Hazardous Fuels Management and Burned Area Rehabilitation programs to help reduce the risk and severity of wildfires and restore lands that were devastated by catastrophic fire over the last several years. This funding complements the $2.5 billion for hazardous fuels management and $650 million for burned area rehabilitation projects provided through the Bipartisan Infrastructure Law.

Securing Environmental Justice and Delivering for Communities Left Behind

Advances Equity and Environmental Justice. The Budget provides historic support for underserved communities, and advances the President's Justice40 commitment to ensure 40 percent of the benefits of Federal investments in climate and clean energy reach disadvantaged communities. The Budget includes more than $12 million to coordinate implementation of the Justice40 initiative at impacted agencies. The Budget bolsters the Environmental Protection Agency's (EPA) environment justice efforts by investing over $1.5 billion across numerous programs that would help create good-paying jobs, clean up pollution, implement Justice40, advance racial equity, and secure environmental justice for communities that too often have been left behind, including rural and tribal communities. To better align with this vision, EPA's Budget structure includes the new Environmental Justice National Program Manager to help administer this work. The Budget also provides over $670 million for EPA's enforcement and compliance assurance efforts, including funding to implement an enforcement plan for climate and environmental justice inspections and community outreach. The Budget invests over $3 billion in DOI programs covered under the Justice40 initiative, such as tribal housing improvements, wildlife conservation grants, and energy infrastructure development in insular communities. In addition, the Budget provides DOE with $47 million to strengthen the Agency's environmental justice mission, $100 million to launch a new LIHEAP Advantage pilot to retrofit low-income homes with efficient electric appliances and systems, and $31 million for a new Equitable Clean Energy Transition initiative to help energy and environmental justice communities navigate and benefit from the transition to a clean energy economy. The Budget also provides $1.4 million for DOJ to establish an Office for Environmental Justice to further this important work.

Supports the Clean Energy Transition in Rural America. The Budget provides $300 million in new funding for grants, loans, and debt forgiveness for rural electric providers as they transition to clean energy, as well as $6.5 billion in loan authority for rural electric loans, an increase of $1 billion over the 2021 enacted level. The Budget also provides $20 million to support the new Rural Clean Energy Initiative, to provide technical assistance and promote coordination between USDA, DOE, and DOI that is necessary to achieve the President's de-carbonization goals and ensure clean energy funding is implemented effectively in rural areas. The Budget also supports multi-agency efforts to integrate science-based tools into conservation planning in order to measure, monitor, report, and verify carbon sequestration, greenhouse gas reduction, wildlife stewardship, and other environmental services at the farm level and on Federal lands.

Supports Legacy Energy Communities. The Budget includes over $9 billion in discretionary funding for priority programs and initiatives across the Federal Government that support economic revitalization and job creation in hard-hit coal, oil and gas, and power plant communities. This includes $100 million to support DOL's role in the multi-agency POWER+ Initiative, which aims to assist displaced workers and transform local economies and communities transitioning away from fossil fuel production to new, sustainable industries. The Budget also includes $35 million, administered by DOL in partnership with the Appalachian Regional Commission and the Delta Regional Authority, to help Appalachian and Delta communities develop local and regional workforce development strategies that promote long-term economic stability and opportunities for workers, especially those connected to the energy industry.

Upgrades Drinking Water and Wastewater Infrastructure Nationwide. The Budget provides roughly $4 billion for EPA water infrastructure programs, an increase of $1 billion over the 2021 enacted level. This includes full funding of grant programs authorized by the Drinking Water and Wastewater Infrastructure Act of 2021, an increase of $160 million over 2021 enacted for EPA's Reducing Lead in Drinking Water grant program. Outside of EPA, the Budget also includes $717 million in direct appropriation and $1.5 billion in loan level for USDA's Water and Wastewater Grant and Loan Program. These resources would help upgrade drinking water and wastewater infrastructure nationwide, with a focus on underserved communities that have historically been overlooked.

Protects Communities from Hazardous Waste and Environmental Damage. Preventing and cleaning up environmental damage that harms communities and poses a risk to public health and safety is a top Administration priority. The Budget includes $7.6 billion for DOE's Environmental Management program to support the cleanup of community sites used during the Manhattan Project and Cold War for nuclear weapons production, including $40 million for a new initiative to support historically underserved communities. The Budget also provides $1.2 billion for the Superfund program for EPA to continue cleaning up some of the Nation's most contaminated land, respond to environmental emergencies and natural disasters, and begin to adjust for revenue from the Superfund Tax. The Budget also provides $215 million for EPA's Brownfields program to enable EPA to provide technical assistance and grants to communities, including disadvantaged communities, so they can safely clean up and reuse contaminated properties. These funds complement Brownfields funding provided in the Bipartisan Infrastructure Law. These programs also support presidential priorities such as the Cancer Moonshot Initiative, by addressing contaminants that lead to greater cancer risk.

Tackles Per- and Polyfluoroalkyl Substances (PFAS) Pollution. PFAS are a set of man-made chemicals that threaten the health and safety of communities across the Nation, disproportionately impacting historically disadvantaged communities. As part of the President's commitment to tackling PFAS pollution, the Budget provides approximately $126 million, $57 million over the 2021 enacted level, for EPA to: increase the understanding of PFAS impacts to human health, as well as its ecological effects; restrict use to prevent PFAS from entering the air, land, and water; and remediate PFAS that have been released into the environment.

Investing in Innovation and Climate Science

Improves Climate Data and Forecasting. The Budget significantly improves the Nation's ability to predict extreme weather and climate events so that American businesses and communities can have accurate and accessible information to allow them to better prepare for such events. This includes a bold investment of $2.3 billion for the next generation of weather satellites at NOAA which would help support the development of next generation technologies, and $2.4 billion for the Earth Science program at the National Aeronautics and Space Administration, including more than $200 million to develop an Earth System Observatory that would provide a three-dimensional, holistic view of Earth to better understand natural hazards and climate change. The Budget also provides an additional $13 million over 2021 enacted levels to bolster EPA's abilities to forecast where smoke from wildfires could harm people and communicate where smoke events are occurring.

Makes Historic Investments in Innovation and Climate Research. To support the Administration's whole-of-Government approach to tackle the climate crisis, the Budget provides a historic investment of $17 billion for climate science and innovation, including more than $9 billion to DOE for clean energy research, development and demonstration, an increase of more than 33 percent over the 2021 enacted level. Within this total, the Budget provides $700 million for the Advanced Research and Projects Agency – Energy (ARPA-E) and proposes expanded authority for ARPA-E to more fully address innovation gaps around adaptation, mitigation, and resilience to the impacts of climate change. The Budget provides $913 million at NSF for research to better understand climate change and its adverse impacts and $500 million for R&D in clean energy and emission mitigation technologies. The Budget invests $6 million in USDA's climate hubs, a multi-agency undertaking to leverage climate science and increase landowner awareness of—and engagement in—efforts to combat climate change. In addition, the overall budget for DOE's Office of Science would grow 11 percent over 2021 enacted levels.

Restoring America's Global Climate Leadership

Advances the President's Historic Climate Pledge. The Budget request includes over $11 billion in international climate finance, meeting the President's pledge to quadruple international climate finance a year early. U.S. international climate assistance and financing would: accelerate the global energy transition to net-zero emissions by 2050; help developing countries build resilience to the growing impacts of climate change, including through the *President's Emergency Plan for Adaptation and Resilience (PREPARE)* and other programs; and support the implementation of the President's *Plan to Conserve Global Forests: Critical Carbon Sinks*. Among these critical investments are $1.6 billion for the Green Climate Fund, a critical multilateral tool for financing climate adaptation and mitigation projects in developing countries and support for a $3.2 billion loan to the Clean Technology Fund to finance clean energy projects in developing countries.

EXPANDING ECONOMIC OPPORTUNITY, ADVANCING EQUITY, AND STRENGTHENING AMERICAN DEMOCRACY

From his first days in office, the President has pursued an agenda to ensure all Americans can lead lives of dignity and extend the reach of America's promise. To further that agenda, the Budget includes a range of crucial investments to help ensure that all Americans can pursue their potential and fully participate in our economy and our democracy—improving education and supporting students; advancing equity, dignity, and security across our Nation and economy; expanding housing opportunities; and ensuring safety and justice and reinvigorating American democracy.

Improving Education

Makes Historic Investments in High-Poverty Schools. To advance the goal of providing a high-quality education to every student, the Budget provides $36.5 billion for Title I, more than doubling the program's funding compared to the 2021 enacted level, through a combination of discretionary and mandatory funding. Title I helps schools provide students in low-income communities the learning opportunities and supports they need to succeed. This substantial new support for the program, which serves 25 million students in nearly 90 percent of school districts across the Nation, would be a major step toward fulfilling the President's commitment to addressing long-standing funding disparities between under-resourced schools—which disproportionately serve students of color—and their wealthier counterparts.

Makes Historic Investments in College Affordability and Completion. To help low- and middle-income students overcome financial barriers to postsecondary education, the Budget proposes to double the maximum Pell Grant by 2029. This begins with a historic $2,175 increase for the 2023-2024 school year, compared to the 2021-2022 school year, thereby expanding access and reaching nearly 6.7 million students. The Budget would also support strategies to improve the retention, transfer, and completion of students by investing the Federal TRIO Programs, Gaining Early Awareness and Readiness for Undergraduate Programs, and new retention and completion grants. The Budget also invests in institutional capacity at HBCUs, TCCUs, MSIs, and low-resourced institutions such as community colleges, by providing an increase of $752 million over the 2021 enacted level. This funding includes $450 million in four-year HBCUs, TCCUs, and MSIs to expand research and development infrastructure at these institutions. The Administration also looks forward to working with the Congress on changes to the Higher Education Act that ease the burden of student debt, including through improvements to the Income Driven Repayment and Public Service Loan Forgiveness programs.

Expands Access to Affordable, High-Quality Early Child Care and Learning. The Budget provides $20.2 billion for HHS's early care and education programs, an increase of $3.3 billion over the 2021 enacted level. This includes $7.6 billion for the Child Care and Development

Block Grant, an increase of $1.7 billion over the 2021 enacted level, to expand access to quality, affordable child care for families. In addition, the Budget helps young children enter kindergarten ready to learn by providing $12.2 billion for Head Start, an increase of $1.5 billion over the 2021 enacted level. The Budget also helps States identify and fill gaps in early education programs by funding the Preschool Development Grants program at $450 million, an increase of $175 million over the 2021 enacted level.

Prioritizes the Health and Well-Being of Students. Disruptions caused by the COVID-19 pandemic continue to take a toll on the physical and mental health of students, teachers, and school staff. Recognizing the profound effect of physical and mental health on academic achievement, the Budget includes a $1 billion investment to increase the number of school counselors, psychologists, social workers, nurses, and other health professionals in schools.

Increases Support for Children with Disabilities. The President is committed to ensuring that children with disabilities receive the services and support they need to thrive in school and graduate ready for college or a career. The Budget provides an additional $3.3 billion over 2021 enacted levels—the largest two-year increase ever—for Individuals with Disabilities Education Act (IDEA) Grants to States, with a total of $16.3 billion to support special education and related services for students in grades Pre-K through 12. The Budget also doubles funding to $932 million for IDEA Part C grants, which support early intervention services for infants and families with disabilities that have a proven record of improving academic and developmental outcomes.

Advancing Equity, Dignity, and Security

Expands Opportunities for Minority- and Women-Owned Businesses. The Budget provides a $31 million increase over the 2021 enacted level to support women, people of color, veterans, and other underserved entrepreneurs through SBA's Entrepreneurial Development programs. This bold commitment ensures entrepreneurs have access to counseling, training, and mentoring services. The Budget also provides $331 million for the Department of the Treasury's Community Development Financial Institutions (CDFI) Fund, an increase of $61 million, or 23 percent, above the 2021 enacted level. CDFIs provide historically underserved and often low-income communities access to credit, capital, and financial support to grow businesses, increase affordable housing, and reinforce healthy neighborhood development.

Supports Economic Development and Invests in Underserved Communities. The Budget provides $3.8 billion for the Community Development Block Grant program to help communities modernize infrastructure, invest in economic development, create parks and other public amenities, and provide social services. The Budget includes a targeted increase of $195 million to spur equitable development and the removal of barriers to revitalization in 100 of the most underserved neighborhoods in the United States.

Empowers and Protects Workers. To ensure workers are treated with dignity and respect in the workplace, the Budget invests $2.2 billion, an increase of $397 million above the 2021 enacted level, in DOL's worker protection agencies. Between 2016 and 2020, these agencies lost approximately 14 percent of their staff, limiting their ability to perform inspections and conduct investigations. The Budget would enable DOL to conduct the enforcement and regulatory work needed to ensure workers' wages and benefits are protected, address the misclassification of workers as independent contractors, and improve workplace health and safety. The Budget also ensures fair treatment for millions of workers by restoring resources to oversee and enforce the equal employment obligations of Federal contractors, including protections against discrimination based on race, gender, disability, gender identity, and sexual orientation.

Reduces Lead and Other Home Health Hazards for Vulnerable Families. The Budget provides $400 million, an increase of $40 million above the 2021 enacted level, for States, local governments, and nonprofits to reduce lead-based paint and other health hazards in the homes of low-income families with young children. The Budget also includes $25 million to address lead-based paint and $60 million to prevent and mitigate other housing-related hazards, such as fire safety and mold, in Public Housing.

Provides Robust Support for Tribal Communities. The Budget requests $4.5 billion for DOI tribal programs, more than $1 billion above the 2021 enacted level. These investments would support public safety and justice, social services, climate resilience, and educational needs to uphold Federal trust responsibilities and promote equity for historically underserved communities. This includes a $156 million increase to support reconstruction work at seven Bureau of Indian Education schools. This funding complements Bipartisan Infrastructure Law investments to address climate resilience needs in tribal communities. The Budget proposes to reclassify Contract Support Costs and Indian Self-Determination and Education Assistance Act of 1975 Section 105(l) leases as mandatory spending, providing certainty in meeting these ongoing needs through dedicated funding sources. The Budget further proposes to provide mandatory funding to the Bureau of Reclamation for operation and maintenance of previously enacted Indian Water Rights Settlements, and the Administration is interested in working with the Congress on an approach to provide a mandatory funding source for future settlements. The Budget also complements Bipartisan Infrastructure Law investments to address climate resilience needs in tribal communities with $673 million in tribal climate funding at DOI.

Advances Child and Family Well-Being in the Child Welfare System. The Budget proposes to expand and incentivize the use of evidence-based foster care prevention services to keep families safely together and to reduce the number of children entering foster care. For children who do need to be placed into foster care, the Budget provides States with support and incentives to place more children with relatives or other adults who have an existing emotional bond with the child and fewer children in group homes and institutions, while also providing additional funding to support youth who age out of care without a permanent caregiver. The Budget proposes to nearly double flexible funding for States through the Promoting Safe and Stable Families program and proposes new provisions to expand access to legal representation for children and families in the child welfare system. The Budget also provides $100 million in competitive grants for States and localities to advance reforms that would reduce the overrepresentation of children and families of color in the child welfare system, address the disparate experiences and outcomes of these families, and provide more families with the support they need to remain safely together. In addition, the Budget provides $215 million for States and community-based organizations to respond to and prevent child abuse.

Supports Health and Economic Security of America's Seniors and People with Disabilities. The Budget provides $14.8 billion, an increase of $1.8 billion above the 2021 enacted level, to improve services at the Social Security Administration's field offices, State disability determination services, and teleservice centers for retirees, people with disabilities, and their families. At HUD, the Budget supports 2,000 units of new permanently affordable housing specifically for seniors and people with disabilities, supporting the Administration's priority to maximize independent living for people with disabilities. The Budget also includes nearly $500 million to Centers for Medicare and Medicaid Services Survey and Certification, a 24-percent increase, to support health and safety inspections at nursing homes and enhances Medicare for seniors by expanding behavioral health benefits, eliminating cost sharing for vaccines, and adding coverage of services from community health workers. The President also looks forward to working with the Congress on other policies to improve economic security and access to healthcare for seniors and people with disabilities.

Strengthens the Unemployment Insurance (UI) Program and Combats Fraud. The UI program has helped millions of Americans through periods of unemployment during the COVID-19 pandemic. The Budget invests $3.4 billion, an increase of $769 million above the 2021 enacted level, to modernize, protect, and strengthen this critical program. This includes several investments aimed at tackling fraud in the UI program, including funding to support more robust identity verification for UI applicants, help States develop and test fraud-prevention tools and strategies, and allow the Office of Inspector General to increase its investigations into fraud rings targeting the UI program.

Improves Healthcare, Nutrition Assistance, and Economic Support for Americans in Puerto Rico and Other Territories. The President supports: eliminating Medicaid funding caps for Puerto Rico and other Territories while aligning their matching rate with States; granting U.S. Territories the option to transition from current block grants to the Supplemental Nutrition Assistance Program; and providing parity to U.S. Territories in the Supplemental Security Income Program. The Administration will continue to work with the Congress to advance these policies.

Expanding Housing Opportunity

Expands the Housing Choice Voucher Program and Enhances Household Mobility. The Housing Choice Voucher program currently provides 2.3 million low-income families with rental assistance to obtain housing in the private market. The Budget provides $32.1 billion, an increase of $6.4 billion—including emergency funding—over the 2021 enacted level, to maintain services for all currently assisted families and to expand assistance to an additional 200,000 households compared to the 2021 level, particularly those who are experiencing homelessness or fleeing, or attempting to flee, domestic violence or other forms of gender-based violence. The Budget also funds mobility-related supportive services to provide low-income families with greater options to move to higher-opportunity neighborhoods.

Advances Efforts to End Homelessness. To prevent and reduce homelessness, the Budget provides $3.6 billion, an increase of $580 million over the 2021 enacted level, for Homeless Assistance Grants to meet renewal needs and expand assistance to nearly 25,000 additional households, including survivors of domestic violence and homeless youth.

Prevents and Redresses Housing Discrimination and Supports Access to Homeownership for First-Generation Homebuyers. The Budget provides $86 million in grants to support State and local fair housing enforcement organizations and bolster education, outreach, and training on rights and responsibilities under Federal fair housing laws. The Budget supports access to homeownership for underserved borrowers, including many first-time and minority homebuyers, through Federal Housing Administration and Ginnie Mae credit guarantees. The Budget also provides $115 million for complementary loan and down payment assistance pilot proposals to expand homeownership opportunities for first-generation and/or low-wealth first-time homebuyers.

Invests in Affordable Housing in Tribal Communities. Native Americans are seven times more likely to live in overcrowded conditions and five times more likely to have inadequate plumbing, kitchen, or heating systems than all U.S. households. The Budget helps address poor housing conditions in tribal areas by providing $1 billion to fund tribal efforts to expand affordable housing, improve housing conditions and infrastructure, and increase economic opportunities for low-income families.

Addresses Housing Needs in Rural America. The Budget includes $1.9 billion for USDA's rural housing loan and grant programs, including increases for the rural multifamily housing programs which would help address housing insecurity, rent burdens, and the impacts of climate change in rural America, including through a new policy requiring construction practices to improve energy or water efficiency, implement green features, or strengthen climate resilience. The multifamily housing programs would fund the preservation or development of 224 affordable multifamily housing properties, totaling 11,100 units and provide rental assistance to 270,000 units. USDA's single-family housing loans would provide new homeownership opportunities to 171,000 rural borrowers. The Budget also provides $39 million to continue the Rural Partners Network initiative from 2022, which connects America's rural communities to a broad range of programs and resources throughout the Federal Government.

Addressing Violent Crime, Ensuring Justice, and Strengthening American Democracy

Invests in Federal Law Enforcement to Combat Gun Crime and Other Violent Crime. The Budget once again makes robust investments to bolster Federal law enforcement capacity. The Budget includes $17.4 billion, an increase of $1.7 billion above the 2021 enacted level, for DOJ law enforcement, including a total of $1.7 billion for the Bureau of Alcohol, Tobacco, Firearms, and Explosives (ATF) to expand multijurisdictional gun trafficking strike forces with additional personnel, increase regulation of the firearms industry, enhance ATF's National Integrated Ballistic Information Network, and modernize the National Tracing Center. The Budget includes $1.8 billion for the U.S. Marshals Service to support personnel dedicated to fighting violent crime, including through fugitive apprehension and enforcement operations. The Budget also provides the Federal Bureau of Investigation with an additional $69 million to address violent crime, including violent crimes against children and crime in Indian Country. In addition, the U.S. Attorneys are provided with $72.1 million to prosecute violent crimes.

Supports State and Local Law Enforcement and Community Violence Prevention and Intervention Programs to Make Our Neighborhoods Safer. The Budget provides $3.2 billion in discretionary resources for State and local grants and $30 billion in mandatory resources to support law enforcement, crime prevention, and community violence intervention.

Reinvigorates Federal Civil Rights Enforcement. In order to address longstanding inequities and strengthen civil rights protections, the Budget invests $367 million, an increase of $101 million over the 2021 enacted level, in civil rights protection across DOJ. These resources support police reform, the prosecution of hate crimes, enforcement of voting rights, and efforts to provide equitable access to justice. Investments also provide mediation and conciliation services through the Community Relations Service.

Reforms the Federal Criminal Justice System. The Budget leverages the capacity of the Federal justice system to advance innovative criminal justice reform initiatives and serve as a model for reform that is not only comprehensive in scope, but evidence-informed and high-impact. The Budget supports key investments in First Step Act implementation, including $100 million for a historic collaboration with the Bureau of Prisons (BOP), DOJ, and DOL for a national initiative to provide comprehensive workforce development services to people in the Federal prison system, both during their time in the BOP facilities and after they are transferred to community placement. In support of Federal law enforcement reform and oversight, the Budget also proposes $106 million to support the deployment of body-worn cameras (BWC) to DOJ's law enforcement officers, as well as an impact evaluation to assess the role of BWC in advancing criminal justice reform.

Protects U.S. Elections and the Right to Vote. As America's democracy faces threats across the Nation, the State, county, and municipal governments that run Federal elections have struggled to obtain resources commensurate with the improved access and security that voters expect and deserve. Federal funding for the equipment, systems, and personnel that comprise the Nation's critical election infrastructure has been episodic or crisis-driven. To provide State and local election officials with a predictable funding stream for critical capital investments and increased staffing and services, the Budget proposes $10 billion in new elections assistance funding to be allocated over 10 years. The Budget also proposes to fund an expansion of USPS delivery capacity in underserved areas and support for vote-by-mail, including making ballots postage-free and reducing the cost of other election-related mail for jurisdictions and voters.

PUTTING THE NATION ON A SOUND FISCAL AND ECONOMIC COURSE

When the President took office, the COVID-19 pandemic and resulting economic crisis had driven deficits to high levels: $3.1 trillion, or 14.9 percent, of Gross Domestic Product (GDP) in 2020. Thanks in part to the success of the American Rescue Plan and the President's economic strategy, strong economic growth has driven deficits down dramatically. The Budget projects a deficit of $1.4 trillion, or 5.8 percent, of GDP for 2022—less than half the deficit the President inherited and more than $1 trillion less than the deficit for 2021.

The Budget builds on this progress by proposing smart, targeted, and fully-offset investments designed to expand economic capacity, spur durable economic growth, create jobs, reduce cost pressures, and foster shared prosperity. The Budget reflects the President's belief that growing the economy from the bottom up and the middle out creates more growth, higher wages, more jobs, lower prices, less poverty, and makes it easier to achieve fiscal sustainability.

The Budget also reflects the President's commitment to put the Nation on a sound fiscal course by more than fully offsetting the cost of its new investments. Overall, the Budget's policies would reduce deficits by more than $1 trillion over 10 years through additional tax reforms that ensure corporations and the wealthiest Americans pay their fair share. Under the Budget policies, annual deficits would fall further as a share of the economy, while the economic burden of debt would stay low.

Paying for Investments through a Fairer Tax System

The Budget's investments are more than paid for through reforms that would create a fairer tax system.

Proposes a New Minimum Tax on Billionaires. The tax code currently offers special treatment for the types of income that wealthy people enjoy. This special treatment, combined with sophisticated tax planning and giant loopholes, allows many of the very wealthiest people in the world to end up paying a lower tax rate on their full income than many middle-class households. To finally address this glaring problem, the Budget includes a 20 percent minimum tax on multi-millionaires and billionaires who so often pay indefensibly low tax rates. This minimum tax would apply only to the wealthiest 0.01 percent of households—those with more than $100 million—and over half the revenue would come from billionaires alone.

Ensures Corporations Pay Their Fair Share. The Budget also includes an increase to the rate that corporations pay in taxes on their profits. Corporations received an enormous tax break in 2017. While their profits have soared, their investment in the economy did not. Those tax breaks did not trickle down to workers or consumers. Instead of allowing some of the most profitable corporations in the world to avoid paying their fair share, the Budget would raise the corporate tax rate to 28 percent, still well below the 35 percent rate that prevailed for most of the last several decades. This increase is complemented by other changes to the corporate tax code that would incentivize job creation and investment in the United States and ensure that large corporations pay their fair share.

Prevents Multinational Corporations from Using Tax Havens to Game the System. For decades, American workers and taxpayers have paid the price for a tax system that has rewarded multinational corporations for shipping jobs and profits overseas. Last year, the Administration rallied more than 130 countries to agree to a global minimum tax that will ensure that profitable corporations pay their fair share and incentivizes U.S. multinationals to create jobs and invest in the United States. The Budget contains additional measures to ensure that multinationals operating in the United States cannot use tax havens to undercut the global minimum.

Improving the Nation's Fiscal Outlook

The Budget's investments boost economic growth, reduce cost pressures, and promote shared prosperity in a way that improves the fiscal outlook of the United States and reduces fiscal risks over the long term.

The Administration is on track to becoming the first in history to reduce the deficit by more than $1 trillion in a single year. Under the Budget's policies, deficits would continue to decline from recent levels. Deficits would fall from 14.9 percent of GDP in 2020 to 5.8 percent of GDP this year and then decline further and remain below 5 percent of GDP through the 10-year window.

Moreover, under the Budget's policies, the medium-term economic burden of Federal debt would remain low. Real interest—the Federal Government's annual interest payments after adjusting for inflation—directly measures the cost of servicing the debt: the real resources that are going toward paying off old debt, instead of investing in the future.

The widespread, persistent, and global phenomenon of interest rates falling even as debt has risen has meant that the burden associated with debt over the near and medium term has decreased. Even as the economy has recovered and growth has come roaring back, interest rates remain well below historical averages.

Real interest has averaged about one percent of the economy since 1980 and was about two percent in the 1990s. Since then, the effective real interest rate on Federal debt has fallen ten-fold, from over 4 percent to 0.4 percent in the 2010s. As a result, real interest has fallen—and real interest costs are expected to remain negative in 2022. The Budget's economic assumptions anticipate that real interest rates would rise over the coming decade, using projections in line with private forecasters. Nevertheless, under these assumptions, the President's policies would keep real interest at or below the historical average over the coming decade. This means that we have the capacity to make fully-offset, critical investments that expand the productive capacity of the economy while also keeping real interest cost burdens low by historical standards.

At the same time, the United States does face fiscal challenges over the long term—driven largely by demographic pressures on health and retirement programs, an inequitable tax system, and rising healthcare costs. There is also uncertainty about the interest rate outlook. The Budget's proposals prudently address these future challenges by reforming the tax system and more than paying for all new policies, reducing deficits over the long run. In total, the Budget policies reduce deficits by more than $1 trillion over the next 10 years

Overall, the Budget details an economically and fiscally responsible path forward—addressing the long-term fiscal challenges facing the Nation while making investments that produce stronger economic growth and broadly shared prosperity well into the future.

ENSURING AN EQUITABLE, EFFECTIVE, AND ACCOUNTABLE GOVERNMENT THAT DELIVERS RESULTS FOR ALL

Under the President's leadership, the Nation is rising to meet the full range of challenges and opportunities before us. As set forth in the President's Management Agenda (PMA), making the most of this historic moment and delivering on the President's agenda also requires strengthening the Government's capacity to meet the needs of all Americans—toward a Government that works for people by meeting them where they are. To help deliver that future, the President's Budget advances the goals of the PMA across three key priority areas: strengthening and empowering the Federal workforce; delivering excellent, equitable, and secure Federal services and customer experience; and managing the business of Government to build a better America. This work—including the investments the Budget puts forward in support of the PMA—is critical for bolstering the Federal Government's capacity and capabilities to deliver for the American people today and for years to come.

Values in Action

The Administration's work to further develop and implement the PMA, including through the Budget, is guided by values: equity, dignity, accountability, and results. These values guide the Administration's work to deliver results for the public and strengthen the capacity of Federal agencies. For example, the Budget advances these values by:

Advancing Equity as a Core Part of Government Management and Decision-Making Processes. To support the Administration's whole-of-Government approach to advancing equity, the Budget provides resources to hire Federal agency talent and expertise needed to help embed equity in agency decision-making and policy-making, such as civil rights legal expertise, human-centered design, public engagement and participatory design, evaluation and evidence design, planning and analysis, and data science. For example, the Budget includes resources to: expand the Department of Labor's Civil Rights Center in order to begin establishing regional offices across the Nation that can be more responsive to regional equity challenges; promote greater equity in service delivery at the Veterans Benefits Administration by placing evaluation analysts to assess potential disparities among veterans who have historically been disadvantaged based on their race, ethnicity, sex, sexual orientation, or gender identity; and help to bolster the Federal Emergency Management Agency's capacity to identify inequities and barriers to access in the application process for disaster assistance.

Treating Every Person with Dignity and Meeting the American People Where They Are. The Administration values and respects the inherent dignity of all people. The Government of the United States is working to recommit to being "of the people, by the people, [and] for the people" in order to solve the complex challenges the Nation faces. Through the PMA and the President's Executive Order 14058, "Transforming Federal Customer Experience and Service Delivery to Rebuild Trust in Government," the Administration has developed an accountability framework for designing and delivering services with a focus on the actual experience of the people whom Federal agencies are meant to serve. The Budget supports agencies conducting activities in support of this framework, including building increased mechanisms for providing feedback and input from the public into the work of the Government, hiring for the skills and expertise required to conduct human centered design, and forming interagency teams to tackle pain points from the lens of how *people* experience the Government's role in important events in their lives.

Managing Federal Funding with Accountability and Integrity. The Administration is committed to improving program integrity and ensuring effective stewardship of taxpayer dollars, including through implementation of the American Rescue Plan Act of 2021 (American Rescue Plan) and the Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Law). To deliver on those commitments, the Administration has provided comprehensive guidance to Federal agencies to ensure coordinated and consistent approaches to fostering program integrity and delivering on the intended outcomes for financial assistance programs. In addition, as the President has made clear, results and accountability go hand-in-hand. To that end, the Administration is committed to collaborating with the Congress and the oversight community, including Offices of Inspectors General and the U.S. Government Accountability Office, as appropriate, and across various sectors and levels of the Government. Also, the Administration will apply its commitment to accountability and transparency to implementation of the resources provided by the President's Budget as well, through sound financial management and a focus on delivering effective and equitable funding.

Managing the Government to Deliver Results that Improve Lives. As part of the Administration's commitment to deliver results for all, Federal agencies have worked with external stakeholders and their own workforces to create four-year strategic plans that define mission success, as well as two-year Agency Priority Goals (APGs), reflecting each agency's top implementation priorities. Concurrent with the President's Budget, Federal agencies have identified strategic goals, strategic objectives, and APGs that reflect the bottom line of the Government advancing outcomes across key Administration priorities, including improving customer experience, advancing equity, combatting climate change, improving the Nation's infrastructure, and meeting the health, welfare, and economic challenges of the COVID-19 pandemic. In addition, the Office of Management and Budget (OMB) has deployed Cross-Agency Priority (CAP) Goals to establish cross-cutting targets that cover a limited number of mission and management areas where Government-wide direction will be helpful to drive collective action on these cross-cutting issues. The public will be able to follow progress toward PMA priorities, agency strategic plans, and APGs, on *https://Performance.gov*, which will be updated quarterly.

Strengthening and Empowering the Federal Workforce

The strength of any organization rests on its people. As the Nation's largest employer, more than four million Americans work for the Federal Government, both at home in the United States and overseas. Those serving in Government today are dedicated and talented professional public servants. That is why the President has taken significant steps to protect, empower, and rebuild the career Federal workforce, and why the President charged the White House Task Force on Worker Organizing and Empowerment with developing steps to augment the voice of frontline Federal workers. The Budget makes further investments in the Federal workforce by providing agencies with new tools to help win the competition for highly-skilled talent. The Budget builds on this work and advances the first PMA priority—strengthening and empowering the Federal workforce—by:

Making Every Federal Job a Good Job, Where All Employees are Engaged, Supported, Heard, and Empowered. Federal agencies must cultivate the passion of their employees and empower them to advance agency missions—and the Federal Government must be a model employer with respect to worker organizing, collective bargaining, and labor-management partnership. The voices of Federal employees are critical to agency management, which is why the Administration is strengthening the annual Federal Employee Viewpoint Survey and piloting a Government-wide pulse survey of Federal employees. These efforts will help agencies retain qualified employees, empower workers to make their agencies better, create a pipeline of qualified leaders, and provide better services to the public. The Budget supports these objectives by ensuring that all those in Federal jobs earn at least $15 per hour and providing a pay increase of 4.6 percent for civilian and military personnel. The Budget also supports the Office of Personnel Management (OPM) and agencies' ability to answer the President's call for agencies to lead by example in supporting worker organizing and collective bargaining.

Helping Agencies Attract and Hire Talent that Reflect America's Diversity across the Federal Government. Federal agencies are focused on attracting more people to Federal service over the long term, while also addressing immediate agency hiring needs to rebuild capacity. The Federal Government is continuing to implement practices to hire based on skills rather than educational qualifications alone. Certain agency hiring practices are changing, including applicant assessment methods, to ensure that those most capable of performing the role do not get needlessly overlooked because they do not have a college degree. Agencies are also aligning with the *Government-wide Strategic Plan to Advance Diversity, Equity, Inclusion, and Accessibility in the Federal Workforce*, including through efforts to develop cultures within agencies that can foster a more diverse, equitable, inclusive, and accessible environment. To support hiring surges necessary to deliver on the Bipartisan Infrastructure Law and streamline hiring practices across the Federal Government, the Budget includes resources to help Federal agencies increase capacity for recruiting and talent management. This includes continued support for agency "talent teams" in each of the 24 Chief Financial Officers Act agencies. Given that internships can introduce students and those in the early stages of their careers to public service, the Budget prioritizes internships and equitable access to internships. Developing pipelines for internships would also be prioritized around the Nation through a reinvigorated vision and funding model for Federal Executive Boards, to ensure a pulse on the Federal impact in communities and support Federal employees and agencies across the Nation. The Budget also provides resources to support new requirements for personnel vetting and the Trusted Workforce 2.0 Initiative, which is designed to ensure all Americans can trust the Federal workforce to protect people, property, information, and mission.

Reimagining and Building a Roadmap to the Future of Federal Work. The Federal Government has an opportunity to reimagine the way Federal employees work. By utilizing expanded flexibilities in work arrangements such as: expanded telework and alternative work schedules; increased adoption of technology, such as cloud computing collaboration tools; and automation supported by information technology investments in the Budget the Government can enhance its ability to recruit and retain top talent, staying competitive with broader trends in how Americans work. A changing world has proven that innovation is possible in the way Federal employees work and operate, including changing needs and uses for Federal workplaces, which agencies will continue to evaluate and assess.

Building the Personnel System and Support Required to Sustain the Federal Government as a Model Employer. As the Government faces increasingly complex challenges, the need for Federal leaders, managers, and front-line staff with the right skills in the right jobs has never been greater. To meet this need, the Budget supports OPM in enhancing its ability to lead Federal human capital management, and serve as a central, strategic leader in Federal human resources, in alignment with OPM's Strategic Plan. In support of this work, the Budget requests $418 million, a $88 million increase over the 2021 enacted level, for OPM's Salaries and Expenses account, its primary discretionary appropriation. This funding would support staffing to enhance customer service provided by OPM to Federal agencies, allowing further collaboration in support of the Federal Government's strategic workforce planning and talent acquisition functions.

Delivering Excellent, Equitable, and Secure Federal Services and Customer Experience

Every interaction between the Government and the public is an opportunity to deliver the value and competence Americans expect and deserve. The American people rely on Federal services to support them through disasters, advance their businesses, provide opportunities for their families, safeguard their rights, and help rebuild their communities. That is why the President signed Executive Order 14058 that will help agencies center services around those who use them—toward delivering simple, secure, effective, equitable, and responsive solutions. The Budget advances these efforts and the second PMA priority—delivering excellent, equitable, and secure Federal services and customer experience—by:

Improving the Service Design, Digital Products, and Customer-Experience Management of Federal High-Impact Service Providers. The Budget supports Federal High Impact Service Providers—those services that serve the largest percentage of people, conduct the greatest volume of transactions annually, and have an outsized impact on the lives of the individuals they serve. Focusing on these high-impact services would yield capabilities, tools, and practices that cascade to other Federal programs and services Government-wide. For example, the Budget includes an additional $2 million to build the Office of Customer Experience at the U.S. Department of Agriculture, which would improve delivery of critical programs for farmers, producers, and ranchers, as well as support for the nutrition of more than six million participants in the Women, Infants, and Children program. The Budget supports the Small Business Administration's efforts to establish baseline customer experience measures for application processes across the Agency's loan, grant, and contracting programs, as well as streamlining the online disaster assistance application experience. The Budget also includes resources to advance customer experience efforts at the Department of Housing and Urban Development, to help deliver on the President's housing priorities, including eliminating barriers that restrict housing and neighborhood choice, furthering fair housing, and providing redress to those who have experienced housing discrimination. In addition, the Budget's investments in digital modernization would allow the U.S. Fish and Wildlife Service to enable Americans to access more permits online, and the Budget would help the Transportation Security Administration expand the use of innovative technologies to reduce passenger wait times at airport security checkpoints. The Budget also invests in the Social Security Administration's efforts to make it easier for individuals to file for Social Security retirement benefits, apply for replacement Social Security cards, and apply for need-based Supplemental Security Income disability payments. In addition, the Budget would also provide $2.7 billion to the Department of Education's Office of Federal Student Aid to provide better support to student loan borrowers by implementing customer experience improvements and ensuring the successful transition from the current short-term loan servicing contracts into a more stable long-term contract and servicing environment.

Designing, Building, and Managing Government Service Delivery for Key Life Experiences that Reach across Federal Agencies. When a person experiences a disaster, loses a job, or faces another key moment in their lives, Federal Government services should meet them where they are instead of forcing them to navigate Government siloes. By better coordinating service delivery based on the life experience of the customer, instead of around existing funding streams or organizational structures, Government can better serve the public. The Budget advances these efforts by providing funding for interagency teams to simplify the process of accessing Government services, such as, services for those surviving a natural disaster, approaching retirement, having a child, and navigating supports after a financial shock.

Enabling Simple, Seamless, and Secure Customer Experiences across High Impact Service Providers. The Budget supports efforts to develop shared products, services, and standards while designing safe and secure products that better meet customer needs. For example, these resources would support efforts at the Departments of Veterans Affairs and Defense to provide streamlined login credentials for servicemembers to access the benefits they have earned through their service as they transition to veterans status, as well as a $61 million increase over the 2021 enacted level for the Federal Citizen Services Fund at the General Services Administration (GSA) to power shared products and platforms that enable simple, seamless, and secure services across the Federal Government. As part of this request, GSA is investing an additional $35 million in the Public Experience Portfolio to continue to evolve *USA.gov* to deliver a seamless public experience when transacting with the Government and provide the public an optimal experience when seeking voting resources on *https://Vote.gov*.

Managing the Business of Government

The Federal Government influences and reshapes markets, supports key supply chains, drives technological advances, and supports domestic manufacturing. This scale creates an opportunity to leverage Federal systems for managing the business of Government—the goods and services the Government buys and the financial assistance and resources it provides and oversees—to create and sustain good quality union jobs, address persistent wealth and wage gaps, and tackle other challenges. The Administration has taken bold action to leverage Federal acquisition, financial assistance, and financial management systems to take on some of the Nation's most pressing challenges. That is why the Budget supports improvements that would make continued progress and improvements in these systems. The Budget supports this work and advances the third PMA priority—managing the business of Government—by:

Ensuring the Future is Made in America by America's Workers. The Administration is working to ensure that Federal resources and programs advance domestic jobs and industries. Two recent examples of that work include the creation of a new review process to ensure Made in America waivers are transparent and consistently applied and a change in the Buy American Act rule for procurement to increase domestic content. The Made in America Office within OMB will continue its work with Federal agencies to maximize the use of Federal procurement and assistance on domestic goods and services that provide good value while strengthening the U.S. industrial base in critical sectors and creating good-paying jobs and economic opportunities in communities across the Nation.

Leveraging Federal Contracting as a Catalyst to Drive Clean Energy Solutions, Support American Jobs, and Advance Equity. Federal agencies spent over $619 billion in 2021 through millions of contracts for goods and services, providing an opportunity to transform the marketplace in ways that mitigate the effects of climate change, bolster American manufacturing, and increase opportunities for small disadvantaged businesses (SDBs) and other small businesses in underserved communities. The Administration is leveraging Federal procurement power to move toward a clean energy future, including 100 percent carbon pollution-free Federal electricity on a net annual basis by 2030, 100 percent zero-emission vehicle acquisitions by 2035, and a net-zero emissions in the Federal building portfolio by 2045. The Administration is also using the Federal acquisition system to increase the procurement of Made in America products to support domestic manufacturing, including through greater transparency in agency acquisition plans so domestic providers can help meet agency requirements, and a new Government-wide acquisition regulation that establishes an aggressive schedule to raise domestic content to 75 percent by 2029. In addition, the Administration is taking steps through Federal acquisitions to better disclose and mitigate the risks that climate change poses in Federal contracting. Agencies are taking aggressive actions to increase contract awards to SDBs and other underserved entrepreneurs to advance the President's commitment to break down barriers and build generational wealth for underserved communities through procurement and contracting. This includes increasing contract awards for SDBs from just over 10 percent to 15 percent of total Federal contract spend by 2025. Agencies will continue to apply category management principles for common goods and services to ensure strong stewardship of taxpayer dollars, supported by increased use of business intelligence and data analytics. The President has directed the Administration to explore additional actions that strengthen the United States as a buyer, improving the efficiency and effectiveness of the Federal procurement system, including, for example, by utilizing approaches such as skills-based hiring, Registered Apprenticeship, and work-based learning.

Supporting Ongoing Improvements to Federal Government Capabilities and Systems in Support of the PMA

The Budget also supports ongoing improvements to Federal Government capabilities that support an equitable, effective, and accountable Government by:

Modernizing Federal Information Technology (IT) Systems and Strengthening Federal Data Capabilities. The Administration continues to prioritize the modernization of Federal IT systems to better deliver agency mission and services to the American public in an effective, efficient, and secure manner. This includes continued efforts by Federal agencies to leverage, utilize, and implement data as a resource and strategic asset, with focus on opening data, advancing equity through data collection, use, and management, and data sharing, accountability, and transparency in support of Administration priorities. The Budget supports the interagency driving data sharing practices project that promotes data sharing activities in support of the Administration's priorities on racial equity and climate. To support IT modernization efforts, the Budget also includes an additional $300 million for the Technology Modernization Fund (TMF). In the first tranche of TMF awards funded by the American Rescue Plan, the TMF Board invested $187 million in *Login.gov*, a secure sign-on service used by over 30 million citizens and businesses that: supports easy access to over 200 Government services spanning 27 agencies; reduces Government costs; prevents fraud; and protects individual privacy. This first tranche of TMF investments also is contributing to protecting the data and privacy of 100 million students and borrowers, two million civilian Federal employees, and millions of users of Government-wide shared services, as well as the security of hundreds of Federal facilities.

Bolstering Federal Cybersecurity. The Budget funds a strategic shift in the defense of Federal infrastructure and service delivery, better positioning agencies to guard against sophisticated adversaries. The Budget provides for investments across Federal agencies that align them to foundational cybersecurity practices and priorities as outlined in Executive Order 14028, "Improving the Nation's Cybersecurity." This includes funding to facilitate the ongoing transition to a "zero trust" approach, which would enable agencies to more rapidly detect, isolate, and respond to cyber threats. To support these efforts, the Budget provides $2.5 billion to the Cybersecurity and Infrastructure Security Agency, a $486 million increase above 2021 enacted, to: maintain critical cybersecurity capabilities implemented in the American Rescue Plan; expand network protection throughout the Federal Executive Branch; and bolster support capabilities, such as cloud business applications, enhanced analytics, and stakeholder engagement. The Budget also supports the Office of the National Cyber Director, which would improve national coordination in the face of escalating cyber attacks on Government and critical infrastructure.

Promoting Evidence-Based Policymaking and Decision Making in Federal Agencies.

The President has made clear that the Administration will make decisions guided by the best available science and data, which requires the Federal Government to foster and strengthen a culture of evidence where generation and use is routine and integrated across all agency functions. The Budget's investments have been informed by existing evidence of effectiveness. The Budget also includes investments to build evidence in critical areas where it is lacking and invests in agency capacity to execute priority studies, including those identified in publicly posted Learning Agendas and Annual Evaluation Plans required by the Foundations for Evidence-Based Policymaking Act of 2018. The Budget's investments in statistical infrastructure recognize the importance of Federal statistics in strengthening the evidence base. New investments also support cross-agency evaluation efforts aligned with Administration priorities, where policy and programmatic solutions span agencies and functions.

DEPARTMENT OF AGRICULTURE

The U.S. Department of Agriculture (USDA) is responsible for providing nutrition assistance to low-income Americans and income support for the farm sector, and for conserving and preserving the Nation's forests and private agricultural lands. The President's 2023 Budget for USDA: invests in tackling the climate crisis while mitigating its ongoing impacts on communities; strengthens the food supply chain and nutrition safety net; advances environmental justice; creates new jobs and opportunities in rural communities; supports underserved farmers and producers; and restores America's advantage in agriculture.

The Budget requests $28.5 billion in discretionary funding for USDA, a $4.2 billion or 17.1-percent increase from the 2021 enacted level, excluding Food for Peace Title II Grants, which is included in the State and International Programs total. Resources provided through the 2023 Budget complement investments in conservation, forest management, and broadband deployment provided in the Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Law).

The President's 2023 Budget:

- **Bolsters the Nation's Frontline Defenses against Catastrophic Wildfires.** Protecting communities, ecosystems, and infrastructure from wildfire requires a resilient and reliable Federal workforce. The Budget provides nearly $4.9 billion for Forest Service Wildland Fire Management, including $2.2 billion for the Wildfire Suppression Operations Reserve Fund. The Budget also upholds the President's commitment that no Federal firefighter would make less than $15 an hour, increases the size of the Federal firefighting workforce, and provides critical technological support for wildfire detection and response, including FireGuard satellite imagery. The Budget also complements investments provided in the Bipartisan Infrastructure Law to reduce the risk and severity of wildfires through smart investments in Forest Service hazardous fuels management and ecosystem restoration.

- **Builds a Fair and Resilient Food Supply Chain.** The Budget strengthens market oversight through investments in the Agricultural Marketing Service and the Animal and Plant Health Inspection Service, resulting in competitive meat and poultry product prices for American families and increased protection against invasive pests and zoonotic diseases. These programs build on the pandemic and supply chain assistance funding in the American Rescue Plan Act of 2021 to address pandemic-related vulnerabilities in the food system and create new market opportunities and good-paying jobs.

- **Spurs Climate Research.** To support the Administration's whole-of-Government approach to tackle the climate crisis, the Budget invests $24 million in USDA's climate hubs, a multi-agency undertaking to leverage climate science and increase landowner awareness of—and engagement in—efforts to combat climate change. The Budget also supports multi-agency efforts to integrate science-based tools into conservation planning in order to measure, monitor, report, and verify carbon sequestration, greenhouse gas reduction, wildlife stewardship, and other environmental services at the farm level and on Federal lands. In addition, the Budget increases funding for priority climate research and for innovative mechanisms to incentivize the adoption of innovative agricultural practices and open new markets for climate-smart commodities at scale, while complementing actions being undertaken by stakeholders and the private sector.

- **Advances Equity and Environmental Justice.** The Budget supports the Administration's ongoing work to advance racial justice and provide more equitable program delivery. Certain USDA programs and initiatives, such as High Cost Energy grants, Rural Energy for America grants and loan guarantees, Private Lands Conservation Operations, Urban Agriculture, and Water and Wastewater direct loans, would support the President's Justice40 Initiative, which directs that at least 40 percent of the overall benefits from climate and clean energy investments be directed to historically disadvantaged communities. In addition, the Budget includes $39 million for the Rural Partners Network, which would connect America's rural communities to a broad range of programs and resources throughout the Federal Government. The Budget also provides $31 million for USDA's Office of Civil Rights, an increase of $9 million over the 2021 enacted level.
- **Addresses Climate Change and Housing Insecurity in Rural Communities.** The Budget provides $1.8 billion for USDA multifamily housing programs, an increase of $259 million from the 2021 enacted level, including over twice the loan level as in 2021. This significant investment would help address housing insecurity, rent burdens, and the impacts of climate change in rural America, including through a new policy requiring construction practices to improve energy or water efficiency, implement green features, or facilitate climate resilience.
- **Helps Rural Communities Transition to Clean Energy.** Rural communities are critical to achieving the goal of transitioning to 100 percent zero carbon electricity by 2035. The Budget provides $300 million in new funding for grants, loans, and debt forgiveness for rural electric providers as they transition to clean energy. The Budget also provides $6.5 billion in loan authority for rural electric loans, an increase of $1 billion over the 2021 enacted level, to support additional clean energy, energy storage, and transmission projects that would create good-paying jobs and meet the ambitious climate progress that science demands. In addition, the Budget includes $15 million in new funding to support the creation of the Rural Clean Energy Initiative to help achieve the President's decarbonation goals and ensure clean energy funding is implemented effectively in rural areas.
- **Restores America's Advantage in Agriculture.** American farmers must be able to leverage new technologies to compete in world markets. The Budget provides $4 billion, $644 million above the 2021 enacted level, for USDA's research, education, and outreach programs, including $315 million targeted to under-served populations.
- **Connects All Americans to High-Speed, Affordable, and Reliable Internet.** The President is committed to ensuring that every American has access to broadband. High-speed internet strengthens rural economies, and the work of installing broadband creates high-paying union jobs. Building on the $2 billion for USDA broadband programs provided in the Bipartisan Infrastructure Law, the Budget provides $600 million for the ReConnect program, which provides grants and loans to deploy broadband to unserved areas, especially tribal areas. The Budget also provides $25 million to help rural telecommunications cooperatives refinance their Rural Utilities Service debt and upgrade their broadband facilities.

- **Protects America's Food Supply.** The Budget provides $1.2 billion for the Food Safety and Inspection Service (FSIS), an increase of $134 million from the 2021 enacted level. This funding would enable the hiring of more inspectors and Public Health Veterinarians, which would increase the strength and flexibility of FSIS to provide inspection services so that meat and poultry producers would be better able to respond to market demands and provide safe and healthy food products. The Budget is providing targeted funds to support smaller producers so that they may increase their production capacity, which in turn would create a more diverse food supply chain.

- **Invests in Tribal Communities.** The Budget invests $62 million for agriculture research, education, and extension grants to tribal institutions; $7 million to assist Native Americans with home ownership through the Single-Family Housing Native American Community Development Financial Institutions Re-lending Program, and $7 million to support Native American farmers and ranchers through the Intertribal Assistance Network. In addition, through the Tribal Forest Protection Act of 2004 and other authorities, the Forest Service would make initial investments of at least $11 million in 2023 to increase equity and expand tribal self-governance, allowing Tribes to participate in restoration activities under agreements and contracts.

- **Supports a Strong Nutrition Safety Net.** The Budget provides $6.8 billion for critical nutrition programs, including $6 billion for the Special Supplemental Nutrition Program for Women, Infants, and Children, to help vulnerable families put healthy food on the table and address racial disparities in maternal and child health outcomes.

- **Supports Economically Distressed Farmers.** USDA is committed to examining barriers faced by all underserved borrowers, especially those in economic distress, beginning farmers, and veterans. The Administration is interested in working with the Congress on legislative changes that would ease the debt burden for economically distressed farm loan borrowers to achieve a robust and competitive agriculture sector.

- **The 2023 Farm Bill.** The Administration looks forward to working this year with the Congress, partners, stakeholders, and the public to identify shared priorities for the 2023 Farm Bill that position USDA to live up to its moniker as "the People's Department" and deliver on its mission to serve all Americans by providing effective, innovative, science-based public policy leadership in agriculture, food and nutrition, natural resource protection and management, and rural development. The Administration also looks forward to working with the Congress to address climate change through climate-smart agriculture and forestry and investments in renewable energy that open new market opportunities and provide a competitive advantage for American producers of climate-smart commodities, including small and historically underserved producers and early adopters, and through voluntary incentives to reduce climate risk. The 2023 Farm Bill is also a critical opportunity to ensure that the wealth created in rural America stays there and to empower rural communities with the tools necessary to advance their locally-led vision. In addition, USDA's nutrition programs are among the most far-reaching tools available to improve health and well-being and to ensure that all Americans have access to healthy, affordable food. This is an important moment to reconsider barriers to food assistance for vulnerable groups that are likely undermining their chances of success, including low-income college students, individuals reentering society and seeking a second chance, youth who have aged out of foster care, kinship families, and low-income individuals in the U.S. Territories.

DEPARTMENT OF COMMERCE

The Department of Commerce (Commerce) is responsible for: promoting job creation; supporting and overseeing international trade; and providing economic, environmental, and scientific information needed by businesses, citizens, and governments. The President's 2023 Budget for Commerce makes historic investments to strengthen domestic supply chains, help American entrepreneurs bring their products to the market, support minority business development, tackle the climate crisis, and promote opportunity and safety in space.

The Budget requests $11.7 billion in discretionary funding for Commerce, a $2.8 billion or 31.2-percent increase from the 2021 enacted level. Resources provided through the 2023 Budget complement major investments in broadband Internet access and climate resilience through the Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Law).

The President's 2023 Budget:

- **Strengthens the Nation's Supply Chains through Domestic Manufacturing.** To help ignite a resurgence of American manufacturing, the Budget provides $372 million, an increase of $206 million from the 2021 enacted level, for the National Institutes of Standards and Technology's (NIST) manufacturing programs. These resources would help launch two additional Manufacturing Innovation Institutes in 2023 and continue support for two institutes funded in 2022 as part of the Administration's growing Manufacturing USA network, which brings together industry, academia, and Government to accelerate manufacturing innovation and commercialization. The Budget also expands the Manufacturing Extension Partnership, providing an increase of $125 million to make America's small and medium manufacturers more competitive and to ensure that the future is made in all of America by all of America's workers. The Budget also provides $11 million to the International Trade Administration (ITA) to build analytical capacity in meeting new requirements on supply chain resilience across the manufacturing and services industries, as well as $5 million for the Bureau of Economic Analysis (BEA) to develop new data tools to measure American competitiveness in global supply chains.
- **Revitalizes Coal Communities and Other Economically Distressed Communities.** To foster investment and economic revitalization in communities impacted by the transition from fossil fuel to a clean energy economy, the Budget provides more than $70 million in new funding to the Economic Development Administration (EDA) to create jobs and drive growth in economically distressed communities. This funding would allow EDA to more than double its Assistance to Coal Communities initiative. The Budget also provides $50 million for

an EDA pilot program to address structural prime-age employment gaps and boost competitiveness in persistently distressed communities through innovative, flexible, and locally-led grants.

- **Supports Minority-Owned Business to Narrow Racial Wealth Gaps.** The Budget elevates the stature and increases the capacity of the Minority Business Development Agency by providing the full $110 million authorized in the Bipartisan Infrastructure Law. This funding would bolster services provided to minority-owned enterprises by expanding the Business Center program, funding Rural Business Centers, opening new regional offices, and supporting innovative initiatives to foster economic resiliency.

- **Creates New Markets for American Goods by Expanding Economic Engagement Abroad.** The Budget provides an additional $26 million from the 2021 enacted level to bolster commercial diplomacy and enhance export promotion through a targeted expansion of the Foreign Commercial Service at the ITA. With this funding, Commerce would augment staff to assist American businesses seeking to increase exports abroad, navigate new foreign markets, or find market opportunities. These activities would focus on areas of high economic and geostrategic value, including the Indo-Pacific.

- **Responds to the Impacts of Climate Change and Extreme Weather.** The Budget invests $6.9 billion in the National Oceanic and Atmospheric Administration (NOAA), an increase of $1.4 billion from the 2021 enacted level, supporting programs that would catalyze wind energy, restore habitats, protect the oceans and coasts, and improve NOAA's ability to predict extreme weather associated with climate change. This includes $45 million to support NOAA's role in deploying 30 gigawatts of offshore wind energy by 2030, and a $30 million increase in funding for marine sanctuaries and other marine protected areas to assess and address climate change impacts. The Budget also supports the Administration's America the Beautiful initiative, and $92 million for expanded climate competitive research grants. Through a bold investment of $2.3 billion in the next generation of weather satellites, the Budget also provides a robust and predictable long-term funding strategy to develop new weather detection capabilities to help plan for extreme weather events.

- **Safeguards America's Burgeoning Space Industry.** The Budget expands opportunities for civil space situational awareness and supports the long-term sustainability of the space environment by committing $88 million, a $78 million increase from the 2021 enacted level, for the Office of Space Commerce in order to improve real-time tracking and reporting of space objects and debris, helping the space industry safely navigate a congested space environment. The Budget also provides $2 million for BEA to develop new data tools to measure the space economy.

- **Advances Key Emerging Technologies and U.S. Leadership in International Standards Development.** The Budget supports U.S. industry competing in the global communications market by providing $13 million for cutting-edge advanced communications research and engineering at the National Telecommunications and Information Administration. The Budget also includes a $187 million increase for research initiatives at NIST that would focus on developing standards to accelerate adoption of critical and emerging technologies with a focus on artificial intelligence, quantum science, and advanced biotechnologies. As part of this investment, the Budget includes an $8 million increase to strengthen U.S. leadership in international standards development for critical and emerging technologies.

- **Secures the American Economy and American's Sensitive Data against Foreign Threats.** The Budget strengthens the Nation's national and economic security by protecting the information and communications technology (ICT) supply chain and improving the security of the commercial cyber ecosystem. This includes a $36 million increase to review ICT transactions that pose an undue risk to the United States, and an enforcement program to deter and mitigate foreign malicious cyber-enabled activities. The Budget also provides the Bureau of Industry and Security (BIS) with a $30 million increase to advance national security and secure trade by bolstering BIS's ability to implement and enforce export controls. In addition, BIS monitors industrial base and supply chain trends with regard to critical and emerging technologies, such as microelectronics.

- **Supports Evidence-Based Policymaking.** The Budget supports evidence-based policy making and strengthens the ability of the Census Bureau to deliver reliable, high-quality data and innovative statistical products that improve understanding of the Nation's people and economy. The Budget includes $408 million to finalize and evaluate the Decennial Census and lay the groundwork for a successful 2030 Census and $141 million for BEA to support the production of vital economic indicators such as Gross Domestic Product. In 2023, BEA will transition the prototype Annual National and Annual State Distribution of Personal Income measures into regular production, providing policymakers and the public with crucial new information about how families across the income distribution spectrum are faring.

DEPARTMENT OF DEFENSE

The Department of Defense (DOD) is responsible for the military forces needed to safeguard U.S. vital national interests. The President's 2023 Budget for DOD provides the resources necessary to sustain and strengthen U.S. deterrence, advancing our vital national interests through integrated deterrence, campaigning, and investments that build enduring advantages. The Budget: supports America's servicemembers and their families; strengthens alliances and partnerships; preserves America's technological edge; bolsters economic competitiveness; and combats 21st Century security threats.

The Budget requests $773 billion in discretionary funding for DOD, a $69 billion or 9.8-percent increase from the 2021 enacted level. This two-year growth enables DOD to make the investments necessary to execute the Administration's *Interim National Security Strategic Guidance* and forthcoming National Security Strategy and National Defense Strategy.

The President's 2023 Budget:

- **Supports United States' European Allies and Partners.** The Budget supports Ukraine, the United States' strong partnerships with North Atlantic Treaty Organization (NATO) allies, and other European partner states by bolstering funding to enhance the capabilities and readiness of U.S. forces, NATO allies, and regional partners in the face of Russian aggression.
- **Promotes Integrated Deterrence in the Indo-Pacific and Globally.** The Budget proposes $773 billion for DOD. To sustain and strengthen deterrence, the Budget prioritizes China as the Department's pacing challenge. DOD's 2023 Pacific Deterrence Initiative highlights some of the key investments the Department is making that are focused on strengthening deterrence in the Indo-Pacific region. DOD is building the concepts, capabilities, and posture necessary to meet these challenges, working in concert with the interagency and U.S. allies and partners to ensure U.S. deterrence is integrated across domains, theaters, and the spectrum of conflict.
- **Counters Persistent Threats.** While focused on maintaining robust deterrence against China and Russia, the Budget also enables DOD to counter other persistent threats including those posed by North Korea, Iran, and violent extremist organizations.
- **Modernizes the Nuclear Deterrent.** The Budget maintains a strong, credible nuclear deterrent, as a foundational aspect of integrated deterrence, for the security of the Nation and U.S. allies. The Budget supports the U.S. nuclear triad and the necessary ongoing nuclear modernization programs, to include the nuclear command, control, and communication networks.

- **Advances U.S. Cybersecurity.** The Budget invests in cybersecurity programs to protect the Nation from malicious cyber actors and cyber campaigns. These priorities include strengthening cyber protection standards for the defense industrial base and investing in the cybersecurity of DOD networks.

- **Takes Care of Servicemembers and the DOD Civilian Workforce.** The Budget invests in America's servicemembers and civilian workforce with robust 4.6 percent pay raises—the largest in a generation—and addresses economic insecurity by funding a newly authorized basic needs allowance. The Budget also continues to combat the COVID-19 pandemic.

- **Fulfills America's Commitment to Military Families.** Military families are key to the readiness and well-being of the All-Volunteer Force, and therefore are critical to national security. The Budget supports military families by prioritizing programs that directly support military spouses, children, caregivers, survivors, and other dependents.

- **Strengthens Programs to Prevent and Respond to Sexual Assault.** The Budget fully funds DOD's implementation of the recommendations of the Independent Review Commission on Sexual Assault in the Military to improve the Department's ongoing work to enhance accountability, prevention, climate and culture, and victim care and support. Examples of these efforts include the establishment of a violence prevention workforce and enabling servicemembers who experience sexual harassment to access services from a sexual assault victim advocate. The Budget also supports the establishment of an independent Office of Special Trial Counsel in each military department, as required under the National Defense Authorization Act for Fiscal Year 2022, to carry out changes to the military justice process for handling sexual assault, domestic violence, and other serious crimes.

- **Promotes Climate Resilience and Energy Efficiency to Support Warfighting Operations.** It is vital to examine the security implications of climate-induced extreme weather and to adapt DOD platforms and military installations to protect mission critical capabilities. The Budget supports efforts to plan for and mitigate the impacts of climate change and improve the resilience of DOD facilities and operations. The Budget invests in power and energy performance, which makes U.S. forces more agile, efficient, and survivable in this complex and changing environment.

- **Enhances Biodefense and Pandemic Preparedness.** The Budget provides robust funding for programs that support the Administration's biodefense and pandemic preparedness priorities as outlined in U.S. biodefense and pandemic preparedness strategies and plans, including the Office of the Assistant Secretary for Health Affairs, Chemical and Biological Defense Program, and Biological Threat Reduction Program. The Budget supports enhanced investments in medical countermeasures, including vaccines, diagnostics, and therapeutics research and manufacturing; clinical research and testing; early warning and real-time monitoring; biosafety and biosecurity; and threat reduction activities with global partners.

- **Builds the Air Forces Needed for the 21st Century.** The Budget procures a mix of highly capable aircraft while continuing to make investments in the fighter, bomber, and training aircraft of the future. Investing in this mix of aircraft provides an opportunity to reduce the future fleet's operational costs while increasing its resiliency and flexibility to meet future threats.

- **Optimizes U.S. Naval Shipbuilding.** Maintaining U.S. naval power is critical to reassuring allies and deterring potential adversaries. The Budget proposes executable and responsible investments in the U.S. Navy fleet. In addition, the Budget continues the recapitalization of the Nation's strategic ballistic missile submarine fleet while also investing in the submarine industrial base.

- **Supports a Ready and Modern Army.** The Budget maintains a ready Army capable of responding globally as part of the Joint Force through investments in Army modernization initiatives, force posture improvements, and deterrence capabilities.
- **Invests in Long-Range Fire Capabilities.** The safety and security of the Nation requires a strong, sustainable, and responsive mix of long-range strike capabilities. The Budget invests in the development and testing of hypersonic strike capabilities while enhancing existing long-range strike capabilities to bolster deterrence and improve survivability.
- **Increases Space Resilience.** Space is vital to U.S. national security and integral to modern warfare. The Budget maintains America's advantage by improving the resilience of U.S. space architectures to bolster deterrence and increase survivability during hostilities.
- **Ensures Readiness.** The Budget continues to ensure that U.S. Soldiers, Sailors, Airmen, Marines, and Guardians remain the best trained and equipped fighting force in the world. At the same time, the Budget strengthens and empowers DOD's civilian workforce as a critical contributor to the Nation's security.
- **Optimizes Force Structure.** In line with the forthcoming National Defense Strategy, the Budget optimizes force structure to build a Joint Force that is lethal, resilient, sustainable, survivable, agile, and responsive. The Budget supports DOD's plan to responsibly upgrade capabilities by redirecting resources to cutting edge technologies in high-priority platforms. Some force structure is too costly to maintain and operate, and no longer provides the capabilities needed to address the current and future national security challenges. The Budget enables DOD to reinvest savings associated with optimized force structure to higher priority investments.
- **Supports Defense Research and Development and the Defense Technology Industrial Base.** DOD plays a critical role in overall Federal research and development that spurs innovation, yields high-value technology, ensures American dominance over strategic competitors, and creates good-paying jobs. The Budget prioritizes defense research, development, test, and evaluation funding to invest in breakthrough technologies that drive innovation, support capacity in the defense technology industrial base, ensure American technological leadership, and underpin the development of next-generation defense capabilities.
- **Strengthens the U.S. Supply Chain and Industrial Base.** The Budget invests in key technologies and sectors of the U.S. industrial base such as microelectronics, casting and forging, and critical materials.
- **Empowers Small Disadvantaged Businesses and Underserved Communities.** The Budget advances equity and supports small disadvantaged businesses and underserved communities. DOD will continue to explore opportunities to serve the American people, with a focus on these communities, through supplier and contracting operations.

DEPARTMENT OF EDUCATION

The Department of Education assists States, school districts, and institutions of higher education in providing a high-quality education to all students and addressing the inequitable barriers underserved students face in education. The President's 2023 Budget for the Department of Education makes historic investments in the Nation's future prosperity: increases aid for high-poverty schools; meets the needs of students with disabilities; and expands access to higher education.

The Budget requests $88.3 billion in discretionary funding for the Department of Education, a $15.3 billion or 20.9-percent increase from the 2021 enacted level.

The President's 2023 Budget:

K-12 Education

- **Makes Historic Investments in High-Poverty Schools.** To advance the goal of providing a high-quality education to every student, the Budget provides $36.5 billion for Title I, including $20.5 billion in discretionary funding and $16 billion in mandatory funding, which more than doubles the program's funding compared to the 2021 enacted level. Title I helps schools provide students in low-income communities the learning opportunities and support they need to succeed. This substantial new support for the program, which serves 25 million students in nearly 90 percent of school districts across the Nation, would be a major step toward fulfilling the President's commitment to address long-standing funding disparities between under-resourced schools—which disproportionately serve students of color—and their wealthier counterparts.

- **Prioritizes the Health and Well-Being of Students.** Disruptions caused by the COVID-19 pandemic continue to take a toll on the physical and mental health of students, teachers, and school staff. Recognizing the profound effect of physical and mental health on academic achievement, the Budget includes a $1 billion investment to increase the number of counselors, nurses, school psychologists, social workers, and other health professionals in schools.

- **Increases Support for Children with Disabilities.** The President is committed to ensuring that children and youth with disabilities receive the services and support they need to thrive in school and graduate ready for college or a career. The Budget provides an additional $3.3 billion from the 2021 enacted level—the largest two-year increase ever—for Individuals with Disabilities Education Act (IDEA) grants to States, with a total of $16.3 billion to support special education and related services for students in grades Pre-K through 12. The

Budget also doubles funding to $932 million for IDEA Part C grants, which support early intervention services for infants and families with disabilities that have a proven record of improving academic and developmental outcomes. The increased funding would support States in implementing critical reforms to expand their enrollment of underserved children, including children of color, children from low-income families, and children living in rural areas. The increase also includes $200 million to expand and streamline enrollment of children at risk of developing disabilities, such as children born with very low-birth weight or who have been exposed to environmental toxins, which would help mitigate the need for more extensive services later in childhood and further expand access to the program for underserved children. The Budget also more than doubles funding to $250 million for IDEA Part D Personnel Preparation grants to support a pipeline of special educators at a time when the majority of States are experiencing a shortage of special educators.

- **Supports Full Service Community Schools.** Community schools play a critical role in providing comprehensive wrap-around services to students and their families, from afterschool to adult education opportunities, and health and nutrition services. The Budget includes $468 million for this program, an increase of $438 million from the 2021 enacted level. The increase would also help school districts implement integrated student supports to meet student and family mental health needs through partnerships with community-based organizations and other entities.

- **Invests in Education Recruitment and Retention.** While the education sector has faced shortages in critical staffing areas for decades, the COVID-19 pandemic and tight labor market has made shortages worse, which has negatively impacted students and fallen hardest on students in underserved communities. The Budget includes $514 million for the Education Innovation and Research program, $350 million of which the Department would target toward identifying and scaling models that improve recruitment and retention of staff in education. Such models include those that would improve support for educators and provide teacher access to leadership opportunities that improve teacher retention and maximize the impact of great teachers beyond their classrooms.

- **Supports Multi-Language Learners.** Students learning English as a second language were disproportionately impacted by the multiple transitions to and from remote learning during the COVID-19 pandemic. The Budget would provide $1.1 billion for the English Language Acquisition (ELA) program, an increase of $278 million, or 35 percent, from the 2021 enacted level, including additional funding to provide technical assistance and build local capacity to better support multilanguage learners and their teachers. The ELA program helps students learning English attain English proficiency and achieve academic success.

- **Fosters Diverse Schools.** The segregation of students by race and income undermines the promise that public schools provide an equal opportunity for all students to learn and succeed. The Budget includes $100 million for a grant program to help communities develop and implement strategies to promote racial and socioeconomic diversity in their schools.

Education Beyond High School

- **Makes Historic Investments in College Affordability and Completion.** To help low- and middle-income students overcome financial barriers to postsecondary education, the Budget proposes to double the maximum Pell Grant by 2029. This begins with a historic $2,175 increase for the 2023-2024 school year compared to the 2021-2022 school year, thereby expanding access and reaching nearly 6.7 million students. The Budget would also support strategies to improve the retention, transfer, and completion rates of students by investing in the Federal TRIO Programs, Gaining Early Awareness and Readiness for Undergraduate Programs, and new retention and completion grants.

- **Increases Funding for Historically Black Colleges and Universities (HBCUs), Tribally Controlled Colleges and Universities (TCCUs), Minority-Serving Institutions (MSIs), and Community Colleges.** The Budget would increase institutional capacity at HBCUs, TCCUs, MSIs, and low-resourced institutions, including community colleges, by providing an increase of $752 million from the 2021 enacted level. This funding includes $450 million for four-year HBCUs, TCCUs, and MSIs to expand research and development infrastructure at these institutions.

- **Invests in Services for Student Borrowers.** The Budget provides $2.7 billion to the Department of Education's Office of Federal Student Aid (FSA), an $800 million, or 43-percent, increase compared to the 2021 enacted level. This additional funding is needed to provide better support to student loan borrowers. Specifically, the increase allows FSA to implement customer service improvements to student loan servicing and to ensure the successful transition from the current short-term loan servicing contracts into a more stable long-term contract and servicing environment.

Office for Civil Rights

- **Strengthens Civil Rights Enforcement.** The Budget provides $161 million to the Department of Education's Office for Civil Rights, an 18-percent increase compared to the 2021 enacted level. This additional funding would ensure that the Department has the capacity to protect equal access to education through the enforcement of civil rights laws, such as Title IX of the Education Amendments of 1972.

DEPARTMENT OF ENERGY

The Department of Energy (DOE) is responsible for supporting the Nation's prosperity by addressing its climate, energy, environmental, and nuclear security challenges through transformative science and technology solutions. The President's 2023 Budget for DOE: invests in domestic clean energy manufacturing; advances environmental justice; tackles the climate crisis; and modernizes and ensures the safety and security of the nuclear weapons stockpile.

The Budget requests $48.2 billion in discretionary funding for DOE, a $6.3 billion or 15.1-percent increase from the 2021 enacted level. Resources provided through the 2023 Budget complement major investments in clean energy demonstrations, advanced manufacturing, grid infrastructure, and low-income home weatherization funded in the Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Law).

The President's 2023 Budget:

- **Enables Progress toward Climate Goals.** The Budget supports investments in research, development, demonstration, and deployment, which are central to enabling achievement of the Administration's climate goals of a 50- to 52-percent reduction from 2005 levels in economy-wide net greenhouse gas pollution in 2030 and zero emissions economy-wide by no later than 2050.

- **Creates Jobs through Support for Clean Energy Infrastructure.** The Budget invests $2.1 billion to support clean energy workforce and infrastructure projects across the Nation, including: $502 million to weatherize and retrofit low-income homes; $150 million to electrify tribal homes and transition tribal colleges and universities to renewable energy; and $90 million for a new Grid Deployment Office to build a grid that is more reliable and resilient and that integrates accelerating levels of renewable energy. In addition, the Budget includes $58 million to launch the Net-Zero Labs Initiative, competitively selecting clean energy deployment projects across the national laboratories. These investments would create good-paying jobs while driving progress toward the Administration's climate goals, including the President's goal of carbon pollution-free electricity by 2035.

- **Tackles the Climate Crisis through Clean Energy Innovation.** To support U.S. preeminence in developing innovative technologies that accelerate the transition to a clean energy economy, the Budget invests $9.2 billion in DOE clean energy research, development, and demonstration, an increase of more than 33 percent from the 2021 enacted level. These investments strengthen clean energy-enabling transmission and distribution systems, decarbonize transportation, advance carbon management technologies, improve energy efficiency in industry and buildings, and secure the availability of high-assay low-enriched uranium. Funding would also leverage the tremendous innovation capacity of the national laboratories, universities, and entrepreneurs to transform America's power, transportation, buildings, and industrial sectors to achieve a net-zero emissions economy by 2050.

- **Strengthens Domestic Clean Energy Manufacturing.** Meeting the challenge of climate change will require a dramatic scale-up in domestic manufacturing of key climate and clean energy equipment, providing opportunities for U.S. workers. Across the $11.3 billion in discretionary DOE clean energy investments described above, the Budget reflects the importance of strategically supporting the U.S. domestic manufacturing base through innovation, technical assistance, and training. Specifically, the Budget includes $200 million for a new Solar Manufacturing Accelerator that would help create a robust domestic manufacturing sector capable of meeting the Administration's solar deployment goals without relying on imported goods manufactured using unacceptable labor practices. The Budget also funds a new ManufacturingUSA institute and increases support for Industrial Assessment Centers, giving students valuable experience conducting energy audits for small and medium-sized manufacturers. In addition, the Budget also proposes a $1 billion mandatory investment to launch a Global Clean Energy Manufacturing effort that would build resilient supply chains for climate and clean energy equipment through engagement with allies, enabling an effective global response to the climate crisis while creating economic opportunities for the United States to increase its share of the global clean technology market.

- **Advances Environmental Justice and Equity.** The Budget provides historic support for underserved communities, including: $34 million for the Office of Economic Impact and Diversity to play a critical role in implementing the Department's Justice40 efforts and equity action plan; $40 million in new resources for capacity building assistance in areas of persistent poverty around the Department's cleanup sites; and $13 million for the Office of Legacy Management to strengthen its environmental justice mission. New programs, including Funding for Accelerated, Inclusive Research, would train and support a diverse and inclusive scientific workforce for the future. In addition, the newly established Office of State and Community Programs would launch Low Income Home Energy Assistance Program Advantage with a $100 million pilot to retrofit low-income homes with efficient electric appliances and systems; and the Office of Energy Efficiency and Renewable Energy would lead a $31 million Equitable Clean Energy Transition initiative to build capacity and provide technical assistance to help energy and environmental justice communities navigate and benefit from the transition to a clean energy economy. These investments would build healthy, culturally vibrant, sustainable, and resilient communities.

- **Supports Energy Communities.** The Budget provides $893 million for DOE's Office of Fossil Energy and Carbon Management to advance technologies that can provide economic revitalization opportunities in energy communities. This includes dedicated funding for the Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization to coordinate interagency efforts and stakeholder engagement across at least 10 Federal agencies. This interagency effort would expand the delivery of Federal resources to those communities affected by the energy transition.

- **Advances Transformational Clean Energy and Climate Solutions.** The Budget provides $700 million for the Advanced Research and Projects Agency – Energy (ARPA-E). This investment in high-potential, high-impact research and development would help remove the technological barriers to advance energy and environmental missions. The Budget also proposes expanded authority for ARPA-E to more fully address innovation gaps around adaptation, mitigation, and resilience to the impacts of climate change.

- **Invests in Research and Innovation.** The Budget provides a historic investment of $7.8 billion for the Office of Science to support cutting-edge research at the national laboratories and universities to: advance the Nation's understanding of climate change; identify and accelerate novel technologies for clean energy solutions; provide new computing insight through quantum information science and artificial intelligence that would address scientific and environmental challenges; leverage data, analytics, and computational infrastructure to strengthen pandemic preparedness in support of U.S. biodefense and pandemic preparedness strategies and plans; and support the Nation's leading scientific user facilities. New programs would promote U.S. leadership in the industries of the future, including biotechnology and biomanufacturing, and support the Cancer Moonshot initiative.

- **Reduces Health and Environmental Hazards for At-Risk Communities.** The Budget includes $7.6 billion for the Environmental Management program to support the cleanup of communities used during the Manhattan Project and Cold War for nuclear weapons production. The Administration would ensure that investments in the remediation of legacy soil and groundwater contamination provide benefits to disadvantaged communities.

- **Strengthens the Nation's Nuclear Security, Biological Security, and Cybersecurity.** The Budget supports a safe, secure, and effective nuclear stockpile by robustly funding investments in the recapitalization of the National Nuclear Security Administration's physical infrastructure and essential facilities to modernize the U.S. nuclear deterrent. The Budget also increases funding for: key arms control and nuclear nonproliferation and counterterrorism programs; the Naval Nuclear Propulsion Program, which designs, builds, operates, maintains, and manages the reactor systems of the naval nuclear fleet; and biosecurity innovation, as well as highly-skilled staff capacity to carry out these missions. The Budget also invests in energy-sector cybersecurity through the Office of Cybersecurity, Energy Security, and Emergency Response.

DEPARTMENT OF HEALTH AND HUMAN SERVICES

The Department of Health and Human Services (HHS) is responsible for protecting the health and well-being of Americans through its research, public health, and social services programs. The President's 2023 Budget for HHS invests in: mental healthcare and suicide prevention; healthcare access and outcomes for vulnerable populations; health research and innovation; public health systems and pandemic preparedness; ending the HIV/AIDS epidemic; social service equity; access to child care and early learning programs; and support services for survivors of domestic violence.

The Budget requests $127.3 billion in discretionary funding for HHS, a $26.9 billion or 26.8-percent increase from the 2021 enacted level, excluding amounts requested for the Indian Health Service (IHS), which the Budget proposes to shift from discretionary to mandatory funding. This request includes appropriations for 21st Century Cures Act and program integrity activities.

The President's 2023 Budget:

- **Accelerates Innovation through the Advanced Research Projects Agency for Health (ARPA-H).** The Budget proposes a major investment of $5 billion for ARPA-H, significantly increasing direct Federal research and development spending in health. With an initial focus on cancer and other diseases such as diabetes and dementia, this major investment would drive transformational innovation in health research and speed application and implementation of health breakthroughs. Funding for ARPA-H, along with additional funding for the National Institutes of Health, total a $49 billion request to continue to support research that enhances health, lengthens life, reduces illness and disability, and spurs new biotechnology productions and innovation.

- **Advances the Cancer Moonshot Initiative.** The Budget proposes investments in ARPA-H, the National Cancer Institute, the Centers for Disease Control and Prevention (CDC), and the Food and Drug Administration (FDA) to accelerate the rate of progress against cancer by working toward reducing the cancer death rate by at least 50 percent over the next 25 years and improving the experience of people who are living with or who have survived cancer.

- **Transforms Mental Healthcare.** Mental health is essential to overall health, and the United States faces a mental health crisis that has been exacerbated by the COVID-19 pandemic. To address this crisis, the Budget proposes reforms to health coverage and major investments in the mental health workforce. For people with private health insurance, the Budget requires all health plans to cover mental health benefits and ensures that plans have an adequate network of behavioral health providers. For Medicare, TRICARE, the

Department of Veterans Affairs healthcare system, health insurance issuers, group health plans, and the Federal Health Employee Benefit Program, the Budget lowers patients' costs for mental health services. The Budget also requires parity in coverage between behavioral health and medical benefits, and expands coverage for behavioral health providers under Medicare. The Budget invests in increasing the number of mental health providers serving Medicaid beneficiaries, as well as in mental health workforce development and service expansion, including at primary care clinics and non-traditional sites. The Budget also provides sustained and increased funding for community-based centers and clinics, including a State option to receive enhanced Medicaid reimbursement on a permanent basis. In addition, the Budget makes historic investments in youth mental health and suicide prevention programs and in training, educational loan repayment, and scholarships that help address the shortage of behavioral health providers, especially in underserved communities. The Budget also strengthens access to crisis services by building out the National Suicide Prevention Lifeline, which will transition from a ten-digit number to 988 in July 2022.

- **Commits to Ending the HIV/AIDS Epidemic.** The *National HIV/AIDS Strategy for the United States 2022–2025* commits to a 75-percent reduction in HIV infection by 2025. To meet this ambitious target and ultimately end the HIV/AIDS epidemic in the United States, the Budget includes $850 million across HHS to aggressively reduce new HIV cases, increase access to pre-exposure prophylaxis (also known as PrEP), and ensure equitable access to services and supports for those living with HIV. This includes increasing access to PrEP among Medicaid beneficiaries, which is expected to improve health and lower Medicaid costs for HIV treatment. The Budget also proposes a new mandatory program to guarantee PrEP at no cost for all uninsured and underinsured individuals, provide essential wrap-around services through States, IHS, tribal entities, and localities, and establish a network of community providers to reach underserved areas and populations.

- **Guarantees Adequate and Stable Funding for IHS.** As part of the Administration's commitment to honor the United States' trust responsibility to tribal nations and strengthen the Nation-to-Nation relationship, the Budget significantly increases IHS's funding over time, and shifts it from discretionary to mandatory funding. For the first year of the proposal, the Budget includes $9.1 billion in mandatory funding, an increase of $2.9 billion from the 2021 enacted level. After the first year, IHS funding would automatically grow to keep pace with healthcare costs and population growth and gradually close longstanding service and facility shortfalls. By providing IHS stable and predictable funding, the proposal would improve access to high-quality healthcare, rectify historical underfunding of the Indian health system, reduce existing facility backlogs such as the Healthcare Facilities Construction Priority List, address health inequities, and modernize IHS' electronic health record system. This proposal has been informed by consultations with tribal nations on the issue of mandatory funding and will be refined based on ongoing consultation.

- **Prepares for Future Pandemics and Advances Health Security for Other Biological Threats.** While combatting the ongoing COVID-19 pandemic, the United States must catalyze advances in science, technology, and core capabilities to prepare the Nation for the next biological threat and strengthen U.S. and global health security. The Budget makes transformative investments in pandemic preparedness and biodefense across HHS public health agencies—$81.7 billion available over five years—to enable an agile, coordinated, and comprehensive public health response to future threats, and to protect American lives, families and the economy. The Budget provides $40 billion to the Office of the Assistant Secretary for Preparedness and Response to invest in advanced development and manufacturing of vaccines, therapeutics, and diagnostics for high priority threats. The Budget provides $28 billion for CDC to enhance public health system infrastructure, domestic and global threat surveillance, public health workforce development, public health laboratory capacity, and global health security. The Budget provides $12.1 billion to NIH for: research and development of vaccines, diagnostics, and therapeutics against high priority biological threats; biosafety and biosecurity research and innovation to prevent biological incidents; and safe and secure laboratory capacity and clinical trial infrastructure. The Budget also includes $1.6 billion for FDA to expand and modernize regulatory capacity information technology and laboratory infrastructure to support the evaluation of medical countermeasures. Further, the Budget encourages the development of innovative antimicrobial drugs through advance market commitments for critical-need antimicrobial drugs.

- **Builds Advanced Public Health Systems and Capacity.** The Budget includes $9.9 billion in discretionary funding to build capacity at CDC and at the State and local levels, an increase of $2.8 billion over the 2021 enacted level. These resources would: improve the core immunization program; expand public health infrastructure in States and Territories and strengthen the public health workforce; support efforts to modernize public health data collection; including at the Center for Forecasting and Outbreak Analytics; and conduct studies on long COVID conditions to inform diagnosis and treatment options. In addition, to advance health equity, the Budget invests in CDC programs related to viral hepatitis, youth mental health, and sickle cell disease. To address gun violence as a public health epidemic, the Budget invests in community violence intervention and firearm safety research.

- **Expands Access to Vaccines.** The Budget establishes a new Vaccines for Adults (VFA) program, which would provide uninsured adults with access to all vaccines recommended by the Advisory Committee on Immunization Practices at no cost. As a complement to the successful Vaccines for Children (VFC) program, the VFA program would reduce disparities in vaccine coverage and promote infrastructure for broad access to routine and outbreak vaccines. The Budget would also expand the VFC program to include all children under age 19 enrolled in the Children's Health Insurance Program and consolidate vaccine coverage under Medicare Part B, making more preventive vaccines available at no cost to Medicare beneficiaries.

- **Advances Maternal Health and Health Equity.** The United States has the highest maternal mortality rate among developed nations, and rates are disproportionately high for Black and American Indian and Alaska Native women. The Budget includes $470 million to: reduce maternal mortality and morbidity rates; expand maternal health initiatives in rural communities; implement implicit bias training for healthcare providers; create pregnancy medical home demonstration projects; and address the highest rates of perinatal health disparities, including by supporting the perinatal health workforce. The Budget also extends and increases funding for the Maternal, Infant, and Early Childhood Home Visiting program, which serves approximately 71,000 families at risk for poor maternal and child health outcomes each year, and is proven to reduce disparities in infant mortality. To address the lack of data on health disparities and further improve access to care, the Budget strengthens collection and evaluation of health equity data. Recognizing that maternal mental health conditions are the most common complications of pregnancy and childbirth, the Budget continues to support the maternal mental health hotline and the screening and treatment for maternal mental depression and related behavioral disorders.

- **Expands Access to Healthcare Services for Low-Income Women.** The Budget provides $400 million, an increase of nearly 40 percent from the 2021 enacted level, to the Title X Family Planning program, which provides family planning and other healthcare to low-income communities. This increase in Title X funding would improve overall access to vital reproductive and preventive health services and advance gender and health equity.

- **Expands Access to Affordable, High-Quality Early Child Care and Learning.** The Budget provides $20.2 billion for HHS's early care and education programs, an increase of $3.3 billion, or 19 percent, from the 2021 enacted level. This includes $7.6 billion for the Child Care and Development Block Grant, an increase of $1.7 billion from the 2021 enacted level to expand access to quality, affordable child care for families across the Nation. In addition, the Budget helps young children enter kindergarten ready to learn by providing $12.2 billion for Head Start, an increase of $1.5 billion from the 2021 enacted level. The Budget also helps States identify and fill gaps in early education programs by funding the Preschool Development Grants program at $450 million, an increase of $175 million from the 2021 enacted level.
- **Advances Child and Family Well-Being in the Child Welfare System.** The Budget proposes to expand and incentivize the use of evidence-based foster care prevention services to keep families safely together and to reduce the number of children entering foster care. For children who do need to be placed into foster care, the Budget provides States with support and incentives to place more children with relatives or other adults who have an existing emotional bond with the children and fewer children in group homes and institutions, while also providing additional funding to support youth who age out of care without a permanent caregiver. The Budget proposes to nearly double flexible funding for States through the Promoting Safe and Stable Families program, and proposes new provisions to expand access to legal representation for children and families in the child welfare system. The Budget also provides $100 million in competitive grants for States and localities to advance reforms that would reduce the overrepresentation of children and families of color in the child welfare system, address the disparate experiences and outcomes of these families, and provide more families with the support they need to remain safely together. Further, the Budget provides $215 million for States and community-based organizations to respond to and prevent child abuse.
- **Supports Survivors of Domestic Violence and Other Forms of Gender Based-Violence.** The Budget proposes significant increases to support and protect survivors of gender-based violence, including $519 million for the Family Violence Prevention and Services (FVPSA) program to support domestic violence survivors—more than double the 2021 enacted level. This amount continues funding availability for FVPSA-funded resource centers, including those that support the Lesbian, Gay, Bisexual, Transgender, Queer, and Intersex community. The Budget would provide additional funding for domestic violence hotlines and cash assistance for survivors of domestic violence, as well as funding to support a demonstration project evaluating services for survivors at the intersection of housing instability, substance use coercion, and child welfare. In addition, the Budget would provide over $66 million for victims of human trafficking and survivors of torture, an increase of nearly $21 million from the 2021 enacted level.
- **Supports America's Promise to Refugees.** The Budget provides $6.3 billion to the Office of Refugee Resettlement (ORR). This funding would help rebuild the Nation's refugee resettlement infrastructure and support the resettling of up to 125,000 refugees in 2023. The Budget would also help ensure that unaccompanied immigrant children are unified with relatives and sponsors as safely and quickly as possible and receive appropriate care and services while they are in ORR's custody. The Budget makes additional investments in services, including expanded access to counsel to help children navigate complex immigration court proceedings, and enhanced case management and post-release services. The Budget also includes mandatory investments in the Unaccompanied Children (UC) program, including a multiyear contingency

fund that would automatically provide additional resources when there are large increases in UC referrals, and a proposal to scale up to universal UC legal representation. The Budget redresses past wrongs by providing resources for critical reunification services—including trauma-related and mental health services—to children and families unduly separated from each other through policies of the previous administration.

- **Supports Families Struggling with Home Energy and Water Bills.** The Budget provides $4 billion, a $225 million increase from the 2021 enacted level, for the Low Income Home Energy Assistance Program (LIHEAP). LIHEAP helps families access home energy and weatherization assistance, vital tools for protecting vulnerable families' health in response to extreme weather and climate change. As part of the Justice40 pilot, HHS plans to increase efforts to prevent energy shutoffs and increase support for households with young children and older people, and high energy burdens. Since the Low Income Household Water Assistance Program (LIHWAP) expires at the end of 2023, the Budget proposes to expand LIHEAP to advance the goals of both LIHEAP and LIHWAP. Specifically, the Budget increases LIHEAP funding and gives States the option to use a portion of their LIHEAP funds to provide water bill assistance to low-income households.

DEPARTMENT OF HOMELAND SECURITY

The Department of Homeland Security (DHS) is responsible for safeguarding the American people by: preventing terrorism and countering domestic violent extremism; securing and managing U.S. borders; administering and enforcing U.S. immigration laws; defending and securing Federal cyberspace and critical infrastructure; and ensuring disaster resilience, response, and recovery. The President's 2023 Budget for DHS advances key Administration priorities by: investing in climate resilience; research and development; Federal cybersecurity; maritime security; and secure and humane border management. The Budget also enhances DHS's capacity to prepare for and respond to pandemics and other biological threats.

The Budget requests $56.7 billion in discretionary funding for the Department of Homeland Security, a $2.9 billion or 5.4-percent increase from the 2021 enacted level. Resources provided through the 2023 Budget complement investments in cybersecurity, hazard mitigation, and others areas provided in the Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Law).

The President's 2023 Budget:

- **Bolsters Federal Cybersecurity and Critical Infrastructure Security.** The Budget provides $2.5 billion to the Cybersecurity and Infrastructure Security Agency (CISA), a $486 million increase from the 2021 enacted level, to maintain critical cybersecurity capabilities implemented in the American Rescue Plan Act of 2021, expand network protection throughout the Federal Executive Branch, and bolster support capabilities, such as cloud business applications, enhanced analytics, and stakeholder engagement. The Budget also provides significant enhancements across DHS to modernize protection of systems, networks, assets, and information, as required by Executive Order 14028, "Improving the Nation's Cybersecurity." In addition to bolstering Federal cybersecurity, the Budget includes funding to ensure safe and secure elections, build and maintain critical public-private partnerships, enhance critical infrastructure protection, and prioritize and reinforce CISA's role as the national risk manager.

- **Enhances Natural Disaster Resilience.** The Budget provides $3.5 billion for DHS's climate resilience programs. This includes $507 million, a $93 million increase from the 2021 enacted level, for the Federal Emergency Management Agency's (FEMA) flood hazard mapping program to incorporate climate science and future risks. The Budget also makes robust investments in FEMA's hazard mitigation grant programs, including the Building Resilient Infrastructure and Communities grant program, which helps communities build resilience against natural disasters, including disadvantaged communities who are disproportionately at risk from climate crises.

- **Expands U.S. Coast Guard (USCG) Capabilities.** The Budget provides $11.5 billion for the USCG, a $564 million increase from the 2021 enacted level, to address emerging national security concerns and goals. This includes expanding USCG cyber operations capacity to protect and respond to cyber threats in the maritime sector, as well as expanding its presence in the Pacific, the Atlantic, and the Arctic—including procuring a commercially available icebreaker. These efforts would expand the capabilities of partners and deepen U.S. ties in each of the above-mentioned regions in order to strengthen maritime security and governance, which would protect economic activity and counter transnational criminal organizations.

- **Upgrades Research Laboratory Infrastructure.** The Budget makes historic investments in research and development infrastructure, providing $89 million to improve and modernize laboratories in the DHS Science and Technology Directorate (S&T). This funding would allow S&T to replace and enhance mission-critical equipment, make necessary information technology improvements, and allow DHS to construct the Detection Sciences Testing and Applied Research Center, which would enable DHS to more efficiently and effectively test and evaluate threat screening devices and counter homemade explosives to further secure transportation systems and other public venues.

- **Modernizes Transportation Security Administration (TSA) Pay and Workforce Policies.** The Budget provides a total of $7.1 billion for TSA pay and benefits, an increase of $1.6 billion from the 2021 enacted level, to compensate TSA employees at rates comparable to their peers in the Federal workforce. By establishing salary parity with other Federal employees, the Budget addresses retention issues faced by the Transportation Security Officer workforce, improving service delivery. The Budget also supports expanding TSA workforce access to labor benefits such as collective bargaining and merit systems protection. These enhancements support the President's commitment to fostering diversity, equity, and inclusion in the Federal workforce.

- **Ensures a Safe, Humane, and Efficient Immigration System.** The Administration is committed to ensuring the U.S. Citizenship and Immigration Services (USCIS) meets its mission administering the Nation's lawful immigration system and safeguarding its integrity and promise by efficiently and fairly adjudicating requests for immigration benefits. The Budget provides $765 million in discretionary funding for USCIS to: efficiently process increasing asylum caseloads; address the backlog of applications for work authorization, naturalization, adjustment of status, and other immigration benefits; and improve refugee processing.

- **Improves Border Processing and Management.** The Budget provides $15.3 billion for the U.S. Customs and Border Protection and $8.1 billion for the U.S. Immigration and Customs Enforcement to enforce immigration law, further secure U.S. borders and ports of entry, and effectively manage irregular migration along the Southwest border, including through $309 million in modern border security technology and $494 million for noncitizen processing and care costs.

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

The Department of Housing and Urban Development (HUD) is responsible for creating healthy, safe, sustainable, inclusive communities and affordable homes for all. The President's 2023 Budget for HUD: significantly expands rental assistance to low-income households; advances efforts to end homelessness; increases affordable housing supply; expands homeownership opportunities for underserved borrowers; improves affordable housing by increasing climate resilience and energy efficiency; strengthens communities facing underinvestment; and prevents and redresses housing-related discrimination.

The Budget requests $71.9 billion in discretionary funding for HUD, a $12.3 billion or 21-percent increase from the 2021 enacted level.

The President's 2023 Budget:

- **Expands the Housing Choice Voucher Program and Enhances Household Mobility.** The Housing Choice Voucher program currently provides 2.3 million low-income families with rental assistance to obtain housing in the private market. The Budget provides $32.1 billion, an increase of $6.4 billion (including emergency funding) over the 2021 enacted level, to maintain services for all currently assisted families and to expand assistance to an additional 200,000 households, particularly for those who are experiencing homelessness or fleeing, or attempting to flee, domestic violence or other forms of gender-based violence. The Budget also funds mobility-related supportive services to provide low-income families with greater options to move to higher-opportunity neighborhoods.
- **Increases Affordable Housing Supply.** To address the critical shortage of affordable housing in communities throughout the Nation, the Budget provides nearly $2 billion for the HOME Investment Partnerships Program (HOME), an increase of $600 million over the 2021 enacted level, to construct and rehabilitate affordable rental housing and provide homeownership opportunities. If enacted, this would be the highest funding level for HOME in nearly 15 years. In addition, the Budget provides $180 million to support 2,000 units of new permanently affordable housing specifically for the elderly and persons with disabilities, supporting the Administration's priority to maximize independent living for people with disabilities. To complement these investments, the Budget contains a total of $50 billion in mandatory funding and additional Low-Income Housing Tax Credits to increase affordable housing development. Specifically, the Budget provides $35 billion in HUD funding for State and local housing finance agencies and their partners to provide grants, revolving loan funds, and other streamlined financing tools that reduce transactional costs and increase housing

supply, as well as grants to advance State and local jurisdictions' efforts to remove barriers to affordable housing development.

- **Advances Efforts to End Homelessness.** To prevent and reduce homelessness, the Budget provides $3.6 billion, an increase of $580 million over the 2021 enacted level, for Homeless Assistance Grants to meet renewal needs and expand assistance to nearly 25,000 additional households, including survivors of domestic violence and homeless youth.

- **Promotes Equity by Preventing and Redressing Housing Discrimination.** The Budget provides $86 million in grants to support State and local fair housing enforcement organizations and to further education, outreach, and training on rights and responsibilities under Federal fair housing laws. The Budget also invests in HUD staff and operations capacity to deliver on the President's housing priorities, including to lift barriers that restrict housing and neighborhood choice, affirmatively further fair housing, and provide redress to those who have experienced housing discrimination.

- **Supports Access to Homeownership.** The Budget supports access to homeownership for underserved borrowers, including many first-time and minority homebuyers, through Federal Housing Administration (FHA) and Ginnie Mae credit guarantees. The Budget, via FHA and HOME, also provides $115 million for complementary loan and down payment assistance pilot proposals to expand homeownership opportunities for first-generation and/or low-wealth first-time homebuyers.

- **Invests in Resilience and Energy Efficiency across HUD Multifamily Programs.** Multifamily properties with HUD rental assistance and Public Housing provide 2.3 million affordable homes to low-income families. The Budget not only fully funds operating costs across this portfolio and provides critical Public Housing capital investments, but also provides about $900 million in resources across HUD programs for modernization activities aimed at energy efficiency and resilience to climate change impacts. These investments would help improve the quality of public and HUD-assisted housing while creating good-paying jobs.

- **Reduces Lead and Other Home Health Hazards for Vulnerable Families.** The Budget provides $400 million, an increase of $40 million above the 2021 enacted level, for States, local governments, and nonprofits to reduce lead-based paint and other health hazards in the homes of low-income families with young children. The Budget also includes $25 million to address lead-based paint in Public Housing. The Centers for Disease Control and Prevention identifies the risk for lead exposure as greatest for children from racial and ethnic minority groups and children in families living below the poverty level, and the Lead Hazard and Healthy Homes grants complement additional Government-wide lead remediation investments included in the Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Law), and target interventions to these most at-risk communities. In addition, the Budget targets $60 million specifically to prevent and mitigate housing-related health hazards, such as fire safety and mold, in HUD-assisted housing.

- **Supports Economic Development and Invests in Underserved Communities.** The Budget provides $3.8 billion for the Community Development Block Grant program to help communities modernize infrastructure, invest in economic development, create parks and other public amenities, and provide social services. The Budget includes a targeted increase of $195 million to spur equitable development and the removal of barriers to revitalization in 100 of the most underserved neighborhoods in the United States.

- **Invests in Affordable Housing in Tribal Communities.** Native Americans are seven times more likely to live in overcrowded conditions and five times more likely to have inadequate plumbing, kitchen, or heating systems than all U.S. households. The Budget helps address the poor housing conditions in tribal areas by providing $1 billion to fund tribal efforts to expand affordable housing, improve housing conditions and infrastructure, and increase economic opportunities for low-income families. Of this total, $150 million would prioritize activities that advance resilience and energy efficiency in housing-related projects.

MARCH 3, 1849

DEPARTMENT OF THE INTERIOR

The Department of the Interior (DOI) conserves and manages the Nation's natural resources and cultural heritage for the benefit and enjoyment of the American people. The President's 2023 Budget for DOI invests in climate change mitigation and adaptation, honors commitments to tribal nations, supports development in U.S. Territories and freely associated states, and funds reclamation and resilience work that ensures healthy lands and waters and creates good-paying jobs.

The Budget requests $17.5 billion in discretionary funding for DOI, a $2.8 billion or 19.3-percent increase from the 2021 enacted level, excluding amounts requested for Contract Support Costs and Indian Self-Determination and Education Assistance Act of 1975 Section 105(l) leases, which the Budget proposes to shift from discretionary to mandatory funding. Resources provided through the 2023 Budget complement major investments in wildfire management, tribal programs, methane emissions reduction, abandoned mine land reclamation, western water infrastructure, and ecosystem restoration through the Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Law).

The President's 2023 Budget:

- **Strengthens Climate Resilience for Communities and Ecosystems.** As steward for 20 percent of the Nation's lands and waters and with a primary responsibility to uphold the Nation's commitments to American Indians and Alaska Natives, DOI plays an integral role in addressing the climate crisis through strengthened conservation partnerships, including the Administration's America the Beautiful Initiative, and science-based ecosystem management. The Budget invests $5 billion in climate adaptation and resilience, including for several priorities listed below, to mitigate the impacts of climate change—such as drought, wildfire and severe storms—on America's communities, lands, waters, and wildlife. The Budget also sustains funding for key conservation and ecosystem management initiatives, including the Civilian Climate Corps, alongside a historic $1.4 billion investment in the Bipartisan Infrastructure Law for ecosystem restoration across America.
- **Honors Trust and Treaty Responsibilities to Tribal Communities through Robust Program Funding.** The Budget makes the largest annual investment in tribal nations in history, reflecting input received from the first Government-wide tribal consultation on the development of the President's Budget. With $4.5 billion for DOI's tribal programs, more than $1 billion above the 2021 enacted level, investments would support public safety and justice, social services, climate resilience, and educational needs to uphold Federal trust responsibilities and advance equity for Native communities. This includes a $156 million

increase to support construction work at seven Bureau of Indian Education schools, providing quality facilities for culturally-appropriate education with high academic standards, as well as $7 million for the Indian Boarding School Initiative, which takes preliminary steps to address the injustices of past Federal Indian boarding school policy. The Budget also includes $632 million in Tribal Public Safety and Justice funding at DOI, which collaborates closely with the Department of Justice, including on continued efforts to address the crisis of Missing and Murdered Indigenous Persons. The Budget also proposes to reclassify Contract Support Costs and Indian Self-Determination and Education Assistance Act of 1975 Section 105(l) leases as mandatory spending, providing certainty for tribal communities in meeting these ongoing needs through dedicated funding sources. The Budget further proposes to provide mandatory funding to the Bureau of Reclamation for operation and maintenance of previously enacted Indian Water Rights Settlements, and the Administration is interested in working with the Congress on an approach to provide a mandatory funding source for future settlements. The Budget also complements Bipartisan Infrastructure Law investments to address climate resilience needs in tribal communities.

- **Advances Climate Science.** The Budget invests $375 million at DOI to advance understanding of the impacts of climate change, unlock new opportunities to reduce climate risk through innovative mitigation and adaptation research, measure and monitor greenhouse gas emissions and sinks on Federal lands, and ensure that coastal, fire-prone, and other particularly vulnerable communities have accurate and accessible information to allow them to better respond to the climate crisis. The Budget also supports the development of a Federal climate data portal that would provide the public with accessible information on historical and projected climate impacts, inform decision-making, and strengthen community climate resilience.

- **Mitigates the Risk of Catastrophic Wildfires.** The Budget invests $325 million in Hazardous Fuels Management and Burned Area Rehabilitation programs to help reduce the risk and severity of wildfires, and restore lands that were devastated by catastrophic fire over the last several years. This funding complements the $878 million for hazardous fuels management and $325 million for burned area rehabilitation projects provided through the Bipartisan Infrastructure Law.

- **Invests in the Wildland Firefighting Workforce.** Protecting communities, ecosystems, and infrastructure from wildfire requires a resilient and reliable Federal workforce. The Budget includes $477 million, an increase of $130 million over the 2021 enacted level, to ensure that no Federal firefighter will make less than $15 an hour, to increase the Federal firefighting workforce, and to support these men and women with competitive compensation. This funding is further supported by $120 million made available in the Bipartisan Infrastructure Law to address firefighting workforce needs.

- **Increases Drought Resilience.** The Budget helps to ensure that all communities across the Nation have access to a resilient and reliable water supply by investing in water conservation, development of desalination technologies, and water recycling and reuse projects. In addition, nearly $1.7 billion provided through the Bipartisan Infrastructure Law for 2023, the Budget invests over $675 million in Western water resource infrastructure and to provide potable water to rural areas, serving both tribal and non-tribal communities. The Budget also provides funding to address the ongoing drought in the western United States, including funding to implement the Drought Contingency Plans to conserve water in the Colorado River System, which is at historically low levels.

- **Promotes Racial Justice and Equity.** The Budget supports DOI's ongoing work to advance racial justice and more equitably deliver services to all Americans with discrete investments in each bureau. The Budget provides over $3 billion to programs covered under the Justice40 initiative, such as tribal housing improvements, wildlife conservation grants, and energy infrastructure development in insular communities, which ensures that at least 40 percent of the overall benefits from certain Federal investments are delivered to disadvantaged communities. Moreover, the Budget includes a $48 million initiative to build a more equitable National Park System (NPS). Through this initiative, DOI would expand operations at parks that preserve and tell the story of historically underrepresented and marginalized groups, further integrate tribal viewpoints into park management, address transportation barriers to parks from underserved communities, and improve park accessibility for visitors and employees with disabilities.

- **Accelerates Renewable Energy Development on Public Lands.** The Budget includes $254 million, an increase of $151 million from the 2021 enacted level, to accelerate and expand activities that support economic development and the creation of thousands of good-paying jobs through clean energy deployment on public lands and offshore waters. Funding would support the leasing, planning, and permitting of solar, wind and geothermal energy projects, and associated transmission infrastructure that would help mitigate climate change impacts and meet the Administration's goal of deploying 30 gigawatts of offshore wind capacity by 2030.

- **Creates Jobs Remediating and Reclaiming Abandoned Wells and Mines.** The Budget provides over $321 million to remediate orphaned oil and gas wells and reclaim abandoned mine lands on Federal and non-Federal lands. The funding complements the $16 billion provided in the Bipartisan Infrastructure Law for orphaned well remediation and abandoned mine reclamation, and would help create good union jobs, mitigate climate change by reducing greenhouse gas emissions, and ultimately allow for more productive land uses.

- **Rebuilds Critical Capacity.** The Budget rebuilds core functions and capabilities across DOI, including science capacity at the U.S. Geological Survey, and land management operations of the NPS, Fish and Wildlife Service, and Bureau of Land Management.

DEPARTMENT OF JUSTICE

The Department of Justice (DOJ) is responsible for defending the interests of the United States and protecting all Americans as the chief enforcer of Federal laws. The President's 2023 Budget for DOJ invests in: combating gun crime and other violent crime, terrorism, violence against women, and cyber threats; protecting civil rights; implementing Federal, State, and local criminal justice reforms; improving the immigration court system; bolstering antitrust enforcement; and advancing environmental justice.

The Budget requests $37.7 billion in discretionary funding for DOJ, a $4.2 billion or nearly 13-percent increase from the 2021 enacted level.

The President's 2023 Budget:

- **Invests in Federal Law Enforcement to Combat Gun Crime and Other Violent Crime.** The Budget makes robust investments to bolster Federal law enforcement capacity. The Budget includes $17.4 billion, an increase of $1.7 billion above the 2021 enacted level, for DOJ law enforcement including a total of $1.7 billion for the Bureau of Alcohol, Tobacco, Firearms, and Explosives (ATF) to expand multijurisdictional gun trafficking strike forces with additional personnel, increase regulation of the firearms industry, enhance ATF's National Integrated Ballistic Information Network, and modernize the National Tracing Center. The Budget includes $1.8 billion for the U.S. Marshals Service to support personnel dedicated to fighting violent crime, including through fugitive apprehension and enforcement operations. The Budget also provides the Federal Bureau of Investigation (FBI) with an additional $69 million to address violent crime, including violent crimes against children and crime in Indian Country. In addition, the Budget provides the U.S. Attorneys with $72.1 million to prosecute violent crimes.
- **Supports State and Local Law Enforcement and Community Violence Prevention and Intervention Programs to Make Our Neighborhoods Safer.** The Budget provides $3.2 billion in discretionary resources for State and local grants and $30 billion in mandatory resources to support law enforcement, crime prevention, and community violence intervention.
- **Reinvigorates Federal Civil Rights Enforcement.** In order to address longstanding inequities and strengthen civil rights protections, the Budget invests $367 million, an increase of $101 million over the 2021 enacted level, in civil rights protection across DOJ. These resources would support police reform, the prosecution of hate crimes, enforcement of voting rights, and efforts to provide equitable access to justice. Investments also provide mediation

and conciliation services through the Community Relations Service. The Budget also continues investments in civil rights enforcement at the FBI by providing $18 million to expand civil rights investigations across the Nation, $8 million to the U.S. Attorneys to expand prosecutions of violations of civil rights, and nearly $1 million to the Criminal Division to expand investigations of election-related crimes, including voter suppression.

- **Reforms the Federal Criminal Justice System.** The Budget leverages the capacity of the Federal justice system to advance innovative criminal justice reform initiatives and serve as a model for reform that is not only comprehensive in scope, but evidence-informed and high-impact. The Budget supports key investments in First Step Act (FSA) implementation, including $100 million for a historic collaboration between the Bureau of Prisons (BOP) and the Department of Labor (DOL) for a national initiative to provide comprehensive workforce development services to people in the Federal prison system, both during their time in BOP facilities and after they are transferred to community placement. Thousands of incarcerated people would have access to a wide variety of evidence-informed models and practices, and in service of continuing to build the evidence base, DOL and BOP would oversee a ground-breaking, large-scale evaluation that assesses the impact of these programs on recidivism, labor market outcomes, and other key metrics. To support rehabilitative programming, improve conditions of confinement, and address augmentation in BOP facilities, the Budget proposes $151 million to hire additional staff, including $72 million for FSA-dedicated programmatic staff and $79 million for front-line correctional officers. In support of Federal law enforcement reform and oversight, the Budget also proposes $106 million to support the deployment of body-worn cameras (BWC) to DOJ's law enforcement officers, as well as an impact evaluation to assess the role of BWC in advancing criminal justice reform.

- **Reforms the Juvenile Justice System and Supports Existing Criminal Justice Reform Programs.** The Budget proposes $760 million for juvenile justice programs, an increase of $414 million over the 2021 enacted level, to bolster diversionary juvenile justice strategies. In addition to these resources, funding is provided to support existing reform programs such as the Second Chance Act of 2007, research and innovation programs, and alternative court systems.

- **Addresses Terrorism**. The Budget invests resources to address the threats of both foreign and domestic terrorism while respecting civil rights and civil liberties. The FBI is provided an increase of $33 million for domestic terrorism investigations.

- **Prioritizes Efforts to End Gender-Based Violence.** The Budget proposes a historic investment of $1 billion to support Violence Against Women Act of 1994 (VAWA) programs, a $487 million or 95-percent increase over the 2021 enacted level. The Budget supports substantial increases for longstanding VAWA programs, including key investments in legal assistance for victims, transitional housing, and sexual assault services. Resources are also provided for new programs to support transgender survivors, build community-based organizational capacity, combat online harassment and abuse, support community-based restorative practices, and address emerging issues in gender-based violence, including a new financial assistance program for survivors. The Budget strongly supports underserved and tribal communities by providing $35 million for culturally-specific services, $10 million for underserved populations, $5.5 million to assist enforcement of tribal special domestic violence jurisdiction, and $3 million to support tribal Special Assistant U.S. Attorneys. In addition, the Budget provides $120 million, an increase of $72 million above the 2021 enacted level, to the Office of Justice Programs for the Sexual Assault Kit Initiative to address the rape kit backlog, and for a new Regional Sexual Assault Investigative Training Academies Program.

- **Counters Cyber Threats.** The Budget expands DOJ's ability to pursue cyber threats through investments that support a multiyear effort to build cyber investigative capabilities at FBI field divisions nationwide. These investments include an additional $52 million for more agents, enhanced response capabilities, and strengthened intelligence collection and analysis capabilities. These investments are in line with the Administration's counter-ransomware strategy that emphasizes disruptive activity and combatting the misuse of cryptocurrency.

- **Improves Immigration Courts.** The Budget invests $1.4 billion, an increase of $621 million above the 2021 enacted level, in the Executive Office for Immigration Review (EOIR) to continue addressing the backlog of over 1.5 million cases that are currently pending in the immigration courts. This funding supports 100 new immigration judges, including the support personnel required to create maximum efficiencies in the court systems, as well as an expansion of EOIR's virtual court initiative. The Budget would also invest new resources in legal access programming, including $150 million in discretionary resources to provide access to representation for adults and families in the immigration proceedings. Complementing this new program is a proposal for $4.5 billion in mandatory resources to expand these efforts over a ten-year period. Providing resources to support legal representation in the immigration system would create greater efficiencies in processing cases while making the system fairer and more equitable.

- **Bolsters Antitrust Enforcement.** The Budget reflects the Administration's commitment to vigorous marketplace competition through robust enforcement of antitrust law by including a historic increase of $88 million over the 2021 enacted level for the Antitrust Division.

- **Supports Environmental Justice.** The Budget expands DOJ's work in environmental justice, providing $1.4 million to launch an Office for Environmental Justice. An additional $6.5 million funds the Environment and Natural Resources Division's work in securing environmental justice and combatting the climate crisis. These resources would be central to the Division and DOJ's execution of a comprehensive environmental justice strategy in support of the President's Executive Order 14008, "Tackling the Climate Crisis at Home and Abroad."

DEPARTMENT OF LABOR

The Department of Labor (DOL) is responsible for protecting the health, safety, wages, and income security of workers and retirees. The President's 2023 Budget for DOL invests in: building the skills of America's workers; protecting workers' rights, health and safety, and wages; strengthening the integrity and accessibility of the Unemployment Insurance (UI) program; and creating good, middle-class jobs that are safe, equitable, pay fair wages and benefits, empower workers, and offer opportunities for advancement.

The Budget requests $14.6 billion in discretionary funding for DOL, a $2.2 billion or 18-percent increase from the 2021 enacted level.

The President's 2023 Budget:

- **Empowers and Protects Workers.** To ensure workers are treated with dignity and respect in the workplace, the Budget invests $2.2 billion, an increase of $397 million above the 2021 enacted level, in the Department's worker protection agencies. Between 2016 and 2020, DOL worker protection agencies lost approximately 14 percent of their staff, limiting their ability to perform inspections and conduct investigations. The Budget would enable DOL to conduct the enforcement and regulatory work needed to ensure workers' wages and benefits are protected, address the misclassification of workers as independent contractors, and improve workplace health and safety. The Budget also ensures fair treatment for millions of workers by restoring resources to oversee and enforce the equal employment obligations of Federal contractors, including protections against discrimination based on race, gender, disability, gender identity, and sexual orientation.

- **Equips Workers with Skills They Need to Obtain High-Quality Jobs.** The Budget invests in effective, evidence-based training models to equip workers with the skills they need to obtain high-quality jobs. Community colleges play a critical role in providing accessible, low-cost, and high-quality training, and the Budget invests $100 million to build their capacity to work with the public workforce development system and employers to design and deliver high-quality workforce programs. The Budget also provides $100 million for a new Sectoral Employment through Career Training for Occupational Readiness program, which would support training programs focused on growing industries, enabling underserved and underrepresented workers to access good jobs and creating the skilled workforce the economy needs to thrive.

- **Expands Access to Registered Apprenticeships (RA).** RA is a proven earn-and-learn model that raises participants' wages and places them on a reliable path to the middle class.

The Budget invests $303 million, a $118 million increase above the 2021 enacted level, to expand RA opportunities in high-growth fields, such as technology, advanced manufacturing, healthcare, and transportation, while increasing access for historically underrepresented groups, including people of color and women, and diversifying the industry sectors involved. To improve access to RAs for women, the Budget doubles DOL's investment in its Women in Apprenticeship and Nontraditional Occupations grants, which provide pre-apprenticeship opportunities to boost women's participation in RA.

- **Provides Training and Employment Pathways for Youth.** The Budget invests in programs that provide youth with equitable access to high-quality training and career opportunities. The Budget invests $75 million for a new National Youth Employment Program, which would create high-quality summer and year-round job opportunities for underserved youth. The Budget also provides $145 million for YouthBuild, $48 million above the 2021 enacted level, to enable more at-risk youth to gain both the education and occupational skills they need to obtain good jobs. To further advance equity and inclusion, the Budget provides $15 million to test new ways to enable low-income youth with disabilities, including youth who are in foster care, involved in the justice system, or who are experiencing homelessness, to successfully transition to employment.

- **Supports Legacy Energy Communities.** In order to address changes in the energy economy, the Budget continues to invest in strategic planning, partnership development, and training and reemployment activities for displaced workers. The Budget provides $100 million to support DOL's role in the multi-agency POWER+ Initiative, which aims to assist displaced workers and transform local economies and communities transitioning away from fossil fuel production to new, sustainable industries. The Budget also includes $35 million, administered in partnership with the Appalachian Regional Commission and the Delta Regional Authority, to help Appalachian and Delta communities develop local and regional workforce development strategies that promote long-term economic stability and opportunities for workers, especially those connected to the energy industry. Further, the Budget provides $20 million for DOL to partner with AmeriCorps and other agencies to establish a Civilian Climate Corps program to help communities address the climate crisis by creating service opportunities and job training programs in emerging industries.

- **Modernizes, Protects, and Strengthens the UI Safety Net.** The UI program has helped millions of Americans through periods of unemployment during the COVID-19 pandemic. The Budget invests $3.4 billion, an increase of $769 million above the 2021 enacted level, to modernize, protect, and strengthen this critical program. This includes several investments aimed at tackling fraud in the UI program, including funding to support more robust identity verification for UI applicants, help States develop and test fraud-prevention tools and strategies, and allow the DOL Office of Inspector General to increase its investigations into fraud rings targeting the UI program. To allow States to serve claimants more quickly and effectively while strengthening program integrity, the Budget also updates the formula for determining the amount States receive to administer UI, the first comprehensive update in decades. The Budget also proposes principles to guide future efforts to reform the UI system, including improving benefit levels and access, scaling UI benefits automatically during recessions, expanding eligibility to reflect the modern labor force, improving State and Federal solvency through more equitable and progressive financing, expanding reemployment services, and safeguarding the program from fraud.

- **Strengthens Mental Health Parity Protections.** The Budget requires all health plans to cover mental health benefits, ensures that plans have an adequate network of behavioral health providers, and improves DOL's ability to enforce the law. In addition, the Budget includes $275 million over 10 years to increase the Department's capacity to ensure that large group market health plans and issuers comply with mental health and substance use disorder requirements, and expand the Agency's capacity to take action against plans and issuers that do not comply.

DEPARTMENT OF STATE AND OTHER INTERNATIONAL PROGRAMS

The Department of State (State), U.S. Agency for International Development (USAID), and other international programs advance the interests and security of the American people by using diplomatic and development tools to address global challenges and advance a free, peaceful, and prosperous world. The President's 2023 Budget for State, USAID, and other international programs strengthens American power and influence by working with allies and partners to solve global challenges including through the launch of the President's Build Back Better World Initiative. These investments would position the United States to compete with China, and any other nation, from a position of strength.

The Budget requests $67.6 billion in discretionary funding for the Department of State and other international programs, a $10.2 billion or 18-percent increase from the 2021 enacted level, excluding emergency funding. Within this total, the Budget includes $60.4 billion for the Department of State and USAID, an increase of $7.4 billion or 14 percent above the 2021 enacted levels. This Budget also includes $4.4 billion for the international programs at the Department of the Treasury, an increase of $2.5 billion or 131 percent above the 2021 enacted level.

The President's 2023 Budget:

- **Advances the President's Historic Climate Finance Pledge.** The Budget includes over $11 billion in international climate finance, meeting the President's pledge to quadruple international climate finance, a year early. This includes $5.3 billion in appropriations, including a $1.6 billion contribution to the Green Climate Fund, a critical multilateral tool for financing climate adaptation and mitigation projects in developing countries. The Budget also supports a $3.2 billion loan to the Clean Technology Fund to finance clean energy projects in developing countries. U.S. international climate assistance and financing would: accelerate the global energy transition to net zero emissions by 2050; help developing countries build resilience to the growing impacts of climate change, including through the *President's Emergency Plan for Adaptation and Resilience (PREPARE)* and other programs; and support the implementation of the President's *Plan to Conserve Global Forests: Critical Carbon Sinks*–while increasing energy independence by decreasing reliance on producers of non-renewable resources.

- **Advances American Leadership in Global Health, Including Global Health Security and Pandemic Preparedness.** The Budget includes $10.6 billion to bolster U.S. leadership in addressing global health and health security challenges, a $1.4 billion increase above the 2021 enacted level. Within this total, the Budget demonstrates U.S. leadership by supporting a $2 billion contribution for the Global Fund's seventh replenishment, for an intended pledge of $6 billion over three years, to save lives and continue the fight against HIV/AIDS, tuberculosis, and malaria, and to support the Global Fund's expanded response to COVID-19 and global health strengthening. This total also includes $1 billion to prevent, prepare for, and respond to infectious disease outbreaks, including the continued expansion of Global Health Security Agenda capacity-building programs and a multilateral financial intermediary fund for health security and pandemic preparedness. The Budget also invests in the global health workforce and systems to enhance countries' abilities to provide core health services, improve health systems resiliency, and respond to crises while mitigating the impacts of crises on routine health services. In addition, the Budget includes $6.5 billion in mandatory funding for State and USAID over five years to make transformative investments in pandemic and other biological threat preparedness globally in support of U.S. biodefense and pandemic preparedness strategies and plans. The pandemic preparedness funding would strengthen the global health workforce, support pandemic preparedness research and development (R&D), advance global R&D capacity, and support health security capacity and financing to strengthen global capacity to prevent, detect, and respond to future COVID-19 variants and other infectious disease outbreaks.

- **Revitalizes Alliances and Partnerships in the Indo-Pacific and Europe.** To strengthen and modernize America's alliances and partnerships in vital global regions and assert U.S. leadership in strategic competition, the Budget includes nearly $1.8 billion to support a free and open, connected, secure, and resilient Indo-Pacific Region and the Indo-Pacific Strategy, and $400 million for the Countering the People's Republic of China Malign Influence Fund. In addition, the Budget provides $682 million for Ukraine, an increase of $219 million above the 2021 enacted level, to continue to counter Russian malign influence and to meet emerging needs related to security, energy, cyber security issues, disinformation, macroeconomic stabilization, and civil society resilience.

- **Champions an Open and Secure Digital and Technological Ecosystem.** The Budget invests more than $350 million to expand reliable and affordable internet access through the development and deployment of secure digital and technological infrastructure. The Budget would improve international cybersecurity practices and promote the adoption of policies that support an open, interoperable, secure, and reliable internet. These resources would further development programming across sectors in line with the State's cyberspace and emerging technology diplomacy and USAID's digital development strategy. State and USAID will also seek to close the digital gender gap in low- and middle-income countries by increasing women and girls' access to information communication technologies and addressing online harassment and abuse globally.

- **Renews America's Leadership in International Institutions.** The Budget continues the Administration's efforts to lead through international organizations by meeting the Nation's commitments to fully fund U.S. contributions and to pay United Nations peacekeeping dues on time and in full. Strengthening the Nation's international partnerships is critical to meeting the Sustainable Development Goals, including global education, ending hunger and malnutrition, building more sustainable, equitable, and resilient food systems and addressing other global challenges.

- **Supports Democracy Globally.** In response to political fragility and increasing authoritarianism around the world, the Budget provides more than $3.2 billion to support global democracy, human rights, anti-corruption, and good governance programming, consistent with the commitments made during the President's Summit for Democracy. The Budget advances the Presidential Memorandum on Advancing the Human Rights of Lesbian, Gay, Bisexual, Transgender, Queer, and Intersex Persons Around the World, the U.S. Strategy on Countering Corruption, and the Presidential Initiative on Democratic Renewal.

- **Restores U.S. Leadership in International Development.** The Budget provides $1.4 billion for the World Bank's International Development Association (IDA). This investment restores the United States' historical role as the largest World Bank donor to support the development of low- and middle-income countries, which benefits the American people by increasing global stability, mitigating climate and health risks, and developing new markets for U.S exports. The U.S. contribution would also support the United States' $3.5 billion pledge to the next replenishment of the IDA, a critical component of the global response to the devastating impacts of the COVID-19 pandemic on developing countries. The Budget also funds bilateral partner capacity building efforts in key areas such as judicial sector strengthening, countering and preventing terrorism, and provision of basic services.

- **Continues Collaborative U.S. Leadership in Central America and Haiti.** As part of a comprehensive strategy to advance systemic reform while addressing the root causes of irregular migration from Central America to the United States, the Budget invests $987 million in the region to continue meeting the President's four-year commitment of $4 billion. Further, in response to deteriorating conditions and widespread violence in Haiti, the Budget invests $275 million to strengthen Haiti's recovery from political and economic shocks, such as strengthening the capacity of the Haitian National Police, combating corruption, strengthening the capacity of civil society, and supporting services for marginalized populations. These investments would ensure that the United States is able to revitalize partnerships that build economic resilience, democratic stability, and citizen security in the region.

- **Supports America's Allies in the Middle East.** The Budget fully supports the U.S.-Israel Memorandum of Understanding, provides $1.4 billion in economic and security assistance for Jordan, and includes $1.4 billion to support the U.S. diplomatic and security partnership with Egypt. As part of the Administration's commitment to advancing security, prosperity, and freedom for both Israelis and Palestinians, the Budget also provides $219 million for critical assistance to the Palestinian people in the West Bank and Gaza, as well as across the region, in support of a two-state solution with Israel.

- **Strengthens African Engagement.** The Budget includes more than $7.7 billion for sub-Saharan Africa, including more than $250 million to support the second United States-Africa Leaders' Summit to strengthen ties with African partners based on principles of mutual respect and shared interests and values. These investments would strengthen collaboration, trade and investment, electrification, ecosystems for mutual growth and prosperity, and the promotion of digital transformation in Africa.

- **Strengthens U.S. Leadership on Refugee and Humanitarian Issues.** The Budget provides more than $10 billion to respond to the unprecedented need arising from conflict and natural disasters around the world to serve over 70 countries and approximately 240 million people. The Budget continues rebuilding the Nation's refugee admissions program and supports up to 125,000 admissions in 2023.

- **Advances Equity and Equality Globally.** The Budget provides $2.6 billion to advance gender equity and equality across a broad range of sectors, more than doubling the gender attributions of the policies of this Administration. This includes $200 million for the Gender

Equity and Equality Action Fund to advance the economic security of women and girls. This total also includes funding to strengthen the participation of women in conflict prevention, resolution, and recovery through the implementation of the Women, Peace, and Security Act of 2017. To further implement the President's Executive Order 13985, "Advancing Racial Equity and Support for Underserved Communities," the Budget would better integrate equity through more inclusive policies, strategies, and practice including enhancing the ability of potential non-traditional partners to pursue Federal opportunities and address the barriers they face in the Federal award process, and new efforts to identify spaces to support and advance underserved population appropriate to the country context.

- **Addresses Food Insecurity and Fosters Inclusive and Sustainable Agriculture-led Economic Growth.** The Budget supports the President's pledge to alleviate global food insecurity by providing over $1 billion in bilateral agriculture and food security programming, and continuing robust support for the International Fund for Agricultural Development. These investments are key to increasing communities' access to nutritious food, strengthening their resilience to shocks and stresses, and lifting them from entrenched poverty.

- **Revitalizes and Expands the Diplomatic and Development Workforce.** Strengthening American diplomacy and development requires rebuilding and modernizing the State and USAID workforce. The 2023 Budget provides $7.6 billion to recruit, retain, and develop the diverse, highly capable workforce needed to support efforts around the world and manage increasingly complex national security issues, particularly in the Indo-Pacific region. The Budget also increases investments to diversify the workforce of foreign affairs agencies to reflect and draw on the richness and diversity of the United States, including through paid internships and targeted fellowship programs, and strengthening partnerships with Minority Serving Institutions, and expanded professional development opportunities.

DEPARTMENT OF TRANSPORTATION

The Department of Transportation (DOT) is responsible for ensuring that the United States has the safest, most equitable, reliable, and modern transportation system in the world. The President's 2023 Budget for DOT supports the historic investments in surface transportation, aviation, and maritime made by the Infrastructure and Investment Jobs Act (Bipartisan Infrastructure Law), which will strengthen the Nation's transportation system while tackling climate change and protecting environmental resources, addressing inequities and advancing environmental justice, and promoting good-paying jobs and economic vitality.

The Budget requests $26.8 billion in discretionary budget authority for 2023, a $1.5 billion or six-percent increase from the 2021 enacted level. Consistent with the Bipartisan Infrastructure Law, the Budget also includes $78.4 billion in mandatory funds, including contract authority and obligation limitations, and $36.8 billion in emergency-designated advance budget authority, for transportation infrastructure investments in 2023.

The President's 2023 Budget:

- **Modernizes and Upgrades Roads and Bridges.** To modernize, repair, and improve the safety and efficiency of the Nation's network of roads and bridges, the Budget provides $68.9 billion for the Federal-aid Highway program, a $19.8 billion increase from the 2021 enacted level. This includes $9.4 billion provided by the Bipartisan Infrastructure Law for 2023 and which also supports: $8 billion for new competitive and formula grant programs to rebuild the Nation's bridges; $1.4 billion to deploy a nationwide, publicly-accessible network of electric vehicle chargers and other alternative fueling infrastructure; $1.3 billion for a new carbon reduction grant program; and $1.7 billion for a new resiliency grant program to enhance the resilience of surface transportation infrastructure to hazards and climate change.

- **Improves Highway Safety.** The Budget provides more than $2.5 billion for the Federal Motor Carrier Safety Administration and the National Highway Traffic Safety Administration (NHTSA), an $857 million increase above the 2021 enacted level. The Budget also provides critical resources to support NHTSA's rulemaking efforts including those to address climate change and emerging technologies. This builds on the Agency's National Roadway Safety Strategy, which uses a safe system approach to address the crisis of roadway fatalities.

- **Provides High-Quality Transit Options to More Americans.** To strengthen the Nation's transit systems, reduce emissions, and improve transportation access for people with disabilities and historically disadvantaged communities, the Budget provides the Federal Transit Administration with $21.1 billion, an $8.2 billion increase over the 2021 enacted level. This includes $3.2 billion in additional funding on top of the $4.3 billion already provided by the Bipartisan Infrastructure Law for 2023. The Budget includes $4.5 billion for the Capital Investment Grant program, which would advance the construction of new, high-quality transit corridors to reduce travel time and increase economic development.

- **Invests in Reliable Passenger and Freight Rail.** To ensure the safety and performance of the rail industry today and deliver the passenger rail network of the future, the Budget provides the Federal Railroad Administration a historic investment of $17.9 billion, a $15 billion increase over the 2021 enacted level. This includes $4.7 billion in additional funding on top of $13.2 billion already provided by the Bipartisan Infrastructure Law for 2023. These resources would provide $7.4 billion to significantly improve Amtrak's rolling stock and facilities and $10.1 billion for existing and new competitive grant programs to support passenger rail modernization and expansion, address critical safety needs, and support the vitality of the freight rail network.

- **Reduces Bottlenecks and Commute Times through Investments in Competitive Programs.** The Budget provides robust support for transportation projects that reduce commute times, improve safety, reduce freight bottlenecks, better connect communities, and reduce transportation-related greenhouse gas emissions. Investments include $4 billion, $3 billion above the 2021 enacted level, for National Infrastructure Investments grant programs to support transportation projects with significant benefits across multiple modes, and $1.64 billion, a $640 million increase above the 2021 enacted level for the Infrastructure for Rebuilding America grants program which focuses on reducing freight and highway bottlenecks.

- **Advances Racial Equity and Supports Underserved Communities.** The Budget requests an additional $20 million above the 2021 enacted level for the Office of the Secretary to lead DOT's efforts to promote equity and inclusion. With these resources, DOT would better ensure that historic investments under the Bipartisan Infrastructure Law deliver resources and benefits equitably, including communities that have been historically underserved and adversely affected by persistent poverty or income inequality. DOT actions include workforce development, disadvantaged business enterprise procurement, data collection, reporting, public participation, and assistance measures mitigating or negating the effects of structural obstacles to building wealth.

- **Prioritizes Aviation Safety and Infrastructure.** The Budget provides $15.2 billion in discretionary budget authority for the Federal Aviation Administration (FAA) to improve aviation safety, transform the Nation's aviation infrastructure, and improve cybersecurity. These investments also promote environmental justice and climate change mitigation by prioritizing sustainable design and construction, and enhancing equity through more inclusive contracting and workforce development. The resources provided through the Budget complement the $5 billion already provided by the Bipartisan Infrastructure Law for 2023 to upgrade the FAA's air traffic control facilities and to improve the safety, capacity, accessibility, and efficiency of the Nation's airports.

- **Accelerates Efforts to Move More Goods Faster through the Nation's Ports and Waterways.** The Budget continues support for the historic levels of Federal investment to modernize America's port and waterway infrastructure initiated under the Bipartisan Infrastructure Law. The Budget includes $230 million for the Port Infrastructure Development Program to strengthen maritime freight capacity. In addition to keeping the Nation's supply chain moving by improving efficiency, DOT would prioritize projects that also lower emissions—reducing environmental impact in and around the Nation's ports.

- **Supports Pipeline and Hazardous Materials Safety.** The Budget improves pipeline and hazardous material transportation safety through new investments to hire additional safety inspectors and engineers, and for robust data collection to inform safety standards. The Budget would help reduce methane emissions and preserve the climate, with investments in new safety standards for pipelines and continued safety checks on underground natural gas storage facilities. The Budget also increases hazardous materials staffing for accident investigations and additional outreach and training to improve compliance with safety requirements.

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DEPARTMENT OF THE TREASURY

The Department of the Treasury (Treasury) is responsible for maintaining a strong economy, promoting conditions that enable economic growth and stability, protecting the integrity of the financial system, combating global financial crime and corruption, and managing the U.S. Government's finances and resources effectively. The President's 2023 Budget for Treasury invests in: a fair and robust tax system; enforcing the tax code and ensuring compliance by the wealthy and corporations; improving the taxpayer experience and customer service; providing resources to expand job-creating investments and access to credit in disadvantaged communities; and enhancing cybersecurity.

The Budget requests $16.2 billion in discretionary funding for Treasury, a $2.7 billion or 20-percent increase from the 2021 enacted level.

The President's 2023 Budget:

- **Improves Taxpayer Experience and Supports a Fair and Equitable Tax System.** Last year, the IRS delivered more than $600 billion in direct economic relief to American households and businesses through Economic Impact Payments, monthly advance child tax credit payments, and more. Yet the agency's funding and staffing levels have not kept pace with its expanding scope. To ensure that taxpayers receive the highest quality customer service and that all Americans are treated fairly by the U.S. tax system, the Budget provides a total of $14.1 billion for the Internal Revenue Service (IRS), $2.2 billion, or 18 percent, above the 2021 enacted level. This includes an increase of $798 million to improve the taxpayer experience and expand customer service outreach to underserved communities and the taxpaying public at large. The Budget also provides $310 million for IRS Business Systems Modernization, which is 39 percent above the 2021 enacted level, to accelerate the development of new digital tools to enable better communication between taxpayers and the IRS. Increased funding for the IRS would also facilitate more effective oversight of high-income and corporate tax returns. In addition to these resources, the Administration continues to support multiyear investments in IRS tax enforcement to increase tax compliance and revenues that the President has previously proposed. This investment reflects decades of analysis demonstrating that program integrity investments to enforce existing tax laws increase revenues in a progressive way by closing the tax gap—the difference between taxes owed and taxes paid.

- **Expands Lending in Disadvantaged Communities and Increases Affordable Housing Supply.** The Budget provides $331 million for the Community Development Financial Institutions (CDFI) Fund, an increase of $61 million, or 23 percent, above the

2021 enacted level. To address the critical shortage of affordable housing in communities, the Budget also proposes $5 billion in long-term mandatory funding for CDFI financing of new construction and substantial rehabilitation that creates net new units of affordable rental and for sale housing. CDFIs provide historically underserved and often low-income communities access to credit, capital, and financial support to grow businesses, increase affordable housing, and reinforce healthy neighborhood development.

- **Increases Corporate Transparency and Safeguards the Financial System.** Treasury plays a leading role in monitoring and disrupting corruption, money laundering, terrorist financing, and the use of the financial system by malicious actors domestically and abroad. Investment in Treasury staff and technical capabilities is critical to these efforts, including closing financial reporting loopholes that allow illicit actors to evade scrutiny, mask their dealings, and undermine corporate accountability. The Budget provides $210 million for the Financial Crimes Enforcement Network, $83 million above the 2021 enacted level, to increase oversight of the financial sector, strengthen corporate accountability, and provide adequate support to law enforcement and investigative entities. In addition, the Budget provides $212 million to the Office of Terrorism and Financial Intelligence, $37 million above the 2021 enacted level, to modernize and update the sanctions process consistent with the findings of the Treasury 2021 Sanctions Review.

- **Strengthens Enterprise Cybersecurity.** The Budget provides $215 million, an increase of $197 million above the 2021 enacted level, to protect and defend sensitive agency systems and information, including those designated as high-value assets. The Budget increases centralized funding to strengthen Treasury's overall cybersecurity efforts and establish a Zero Trust Architecture. These investments would protect Treasury systems from future attacks and accelerate Treasury's response to the SolarWinds incident and Log4j vulnerabilities.

- **Restores Critical Agency Capacity.** The Budget provides $293 million for Treasury's Departmental Offices, a 26-percent increase over the 2021 enacted level, to rebuild institutional capacity and strengthen the role of Treasury policy offices. Additional funding for Treasury's Climate Hub would support a sustainable economic recovery and advance climate goals both domestically and internationally, including domestic coal transition and engagement with international financial institutions. Increased staffing would also support assessments of climate-related financial risk arising from private insurance coverage gaps in regions of the Nation particularly vulnerable to climate change impacts. The Budget also builds institutional capacity to expand engagement with historically underrepresented and underserved groups and develop actionable goals to advance equity across all Treasury programs.

DEPARTMENT OF VETERANS AFFAIRS

The Department of Veterans Affairs (VA) is responsible for providing military veterans and VA survivors with the benefits, care, and support they have earned through sacrifice and service to the Nation. The President's 2023 Budget for VA honors the Nation's sacred obligation to veterans by investing in: world-class healthcare, including mental health, and enhancing veterans' general well-being; benefits delivery, including disability claims processing; education; employment training; and insurance, burial, and other benefits to enhance veterans' prosperity. The Budget ensures that all veterans, including women veterans, veterans of color, and Lesbian, Gay, Bisexual, Transgender, Queer, and Intersex veterans receive the care they have earned, and prioritizes addressing veteran homelessness, suicide prevention, and caregiver support.

The Budget requests $135 billion in discretionary funding for VA, a $31 billion or 29-percent increase, from the 2021 enacted level. The Budget also includes $128 billion in advance appropriations for VA medical care programs in 2024.

The President's 2023 Budget:

- **Prioritizes VA Medical Care.** The Budget provides $119 billion—a historic 32-percent increase above the 2021 enacted level for VA. In addition to fully funding inpatient, outpatient, mental health, and long-term care services, the Budget supports programs that improve VA healthcare quality and delivery, including investments in training programs for clinicians, health professionals, and medical students. The Budget also further supports VA's preparedness for regional and national public health emergencies.

- **Prioritizes Veteran Suicide Prevention.** The Budget provides $497 million to support the Administration's veteran suicide prevention initiatives, including implementation of: the Veterans Crisis Line's 988 expansion initiative; the suicide prevention 2.0 program to grow public health efforts in communities; a lethal means safety campaign in partnership with other agencies; and the Staff Sergeant Parker Gordon Fox Suicide Prevention Grant Program to enhance community-based prevention strategies.

- **Improves Veterans' Mental Healthcare Services.** The Budget provides $13.9 billion for VA mental healthcare, which offers a system of comprehensive treatments and services to meet the needs of each veteran and the family members involved in the veteran's care. The Budget focuses on increasing access to quality mental healthcare and lowering the cost of mental health services for veterans, with the goal of helping veterans take charge of their treatment and live full and meaningful lives.

- **Supports Women Veterans' Healthcare.** The Budget invests $9.8 billion for all of women veterans' healthcare, including $767 million toward women's gender specific care. More women are choosing VA healthcare than ever before, with women accounting for over 30 percent of the increase in veterans enrolled over the past five years. Investments support comprehensive specialty medical and surgical services for women veterans at a VA facility or through referrals to the community. The Budget proposes to increase access to infertility counseling and assisted reproductive technology and to eliminate copayments for contraceptive coverage. The Budget also improves the safety of women veterans seeking healthcare at VA facilities by supporting implementation of the zero-tolerance policy for sexual harassment and assault.

- **Bolsters Efforts to End Veteran Homelessness.** The Budget increases resources for veterans' homelessness programs to $2.7 billion, with the goal of ensuring every veteran has permanent, sustainable housing with access to healthcare and other supportive services to prevent and end veteran homelessness.

- **Invests in Caregivers Support Program.** The Budget recognizes the important role of family caregivers in supporting the health and wellness of veterans. The Budget provides funding for the Program of General Caregivers Support Services. The Budget also provides $1.8 billion for the Program of Comprehensive Assistance for Family Caregivers, which includes stipend payments and support services to help empower family caregivers of eligible veterans.

- **Invests in Overdose Prevention and Treatment Programs.** The Budget provides $663 million toward opioid use disorder prevention and treatment programs, including programs authorized in the Jason Simcakoski Memorial and Promise Act.

- **Supports Research Critical to Veterans' Health Needs.** VA conducts thousands of studies at VA medical centers, outpatient clinics, and nursing homes each year. This research has significantly contributed to advancements in healthcare for veterans and other Americans from every walk of life. The Budget provides $916 million to continue the development of VA's research enterprise, including research in support of *American Pandemic Preparedness: Transforming Our Capabilities* plan goals.

- **Addresses Environmental Exposures.** The Budget increases resources for new presumptive disability compensation claims related to environmental exposures from military service. The Budget also invests $51 million within VA research programs and $63 million within the VA medical care program for Health Outcomes Military Exposures to increase scientific understanding of and clinical support for veterans and healthcare providers regarding the potential adverse impacts from environmental exposures during military service.

- **Supports Cancer Moonshot and Precision Oncology.** The Budget invests $81 million within VA research programs, together with $167 million within the VA medical care program, for precision oncology to provide access to the best possible cancer care for veterans. Funds support research and programs that address cancer care, rare cancers, and cancers in women, as well as genetic counseling and consultation that advance tele-oncology and precision oncology care.

- **Provides Claims Processing Automation.** The Budget provides $120 million for VA to support automating the disability compensation claims process from submission to authorization. Investments in automation would increase VA's ability to deliver faster and more accurate claim decisions for veterans.

- **Supports VA Home Loan Programs.** The Budget provides $284 million for VA housing program administration to ensure that all eligible veterans receive maximum benefits and protections as new or existing homeowners, and enable VA to manage record growth in its home loan guaranty volume, which exceeded $860 billion in outstanding principal in 2021. In addition, in accordance with the President's Executive Order 14030, "Climate-Related Financial Risk," the VA housing program is working with the Departments of Agriculture and Housing and Urban Development to consider approaches to better integrate climate-related financial risk into Federal credit programs. Efforts to date include contracting for additional expert analytical support, identifying and sharing initial risk assessments in working groups comprised of credit representatives of these agencies, and exploring the financial sensitivity of proposed 2023 activity to adverse movements in default and recovery performance that could be related to climate-change risks.

- **Modernizes VA Information Technology.** The Budget includes $5.8 billion for VA's Office of Information Technology to prioritize cybersecurity, financial management business transformation, claims automation, and the Infrastructure Readiness program, with the mission to ensure a seamless customer experience for veterans. The Budget also provides $1.8 billion to continue modernizing VA's Electronic Health Record to ensure veterans receive world-class healthcare well into the future.

- **Invests in New and Replacement Medical and Cemetery Facilities.** The Budget includes $3 billion for construction and expansion of critical infrastructure and facilities. This funding supports seven major investments in new and replacement medical facilities and new or expanded cemeteries in three locations. In addition, VA would make improvements and alterations to existing medical facilities, further expanding healthcare capacities. These capital investments enable the delivery of high-quality healthcare, benefits, and services for veterans.

- **Honors the Memory of All Veterans.** The Budget includes $430 million to ensure veterans and their families have access to exceptional memorial benefits including two new and replacement national cemeteries. These funds maintain national shrine standards at the 158 VA managed cemeteries and provide the initial operational investment required to open new cemeteries.

CORPS OF ENGINEERS—CIVIL WORKS

The Army Corps of Engineers—Civil Works program (Corps) is responsible for: developing, managing, restoring, and protecting water resources primarily through the construction, operation and maintenance, and study of water-related infrastructure projects; regulating development in waters of the United States; and working with other Federal agencies to help communities respond to and recover from floods and other natural disasters. The President's 2023 Budget for the Corps invests in modernizing the Nation's water infrastructure, including U.S. coastal ports, increasing climate resilience, and advancing environmental justice.

The Budget requests $6.6 billion in discretionary funding for the Corps. Resources provided through the 2023 Budget complement historic investments in modernizing the Nation's ports and waterways and improving resilience of water resources infrastructure to climate change through the Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Law).

The President's 2023 Budget:

- **Restores Aquatic Ecosystems.** The Budget invests in the restoration of some of the Nation's most unique aquatic ecosystems, such as the Chesapeake Bay, Great Lakes, Upper Mississippi, and Columbia River. For Florida's Everglades restoration project, the Budget invests $407 million—building on the Bipartisan Infrastructure Law's single largest investment in history for Everglades restorations. This iconic American landscape provides drinking water supply for more than 8 million Floridians, supports the State's $90 billion tourism economy, and is home to dozens of endangered or threatened species.
- **Increases Resilience to Climate Change.** The Budget invests in programs and projects that would reduce the risk of damages from floods and storms and restore the Nation's aquatic ecosystems. The Budget also invests in helping local communities identify and address their risks associated with climate change and improve resilience of Corps' infrastructure to climate change, including taking climate resilience into account in developing options and selecting projects.
- **Facilitates Safe, Reliable, and Sustainable Commercial Navigation.** The Budget includes $1.7 billion for the Harbor Maintenance Trust Fund to facilitate safe, reliable, and environmentally sustainable navigation at the Nation's coastal ports.
- **Advances Equity and Environmental Justice.** The Budget invests in technical assistance, studies, and the construction of projects to address water resources challenges in disadvantaged and tribal communities in line with the President's Justice40 Initiative. For example, the Budget includes funding for remedial clean-up of the Bradford Island site on

the Columbia River to address decades of contamination, including in important tribal fishing areas.

- **Invests in High Return Projects.** The Budget invests in projects that would provide a high economic or environmental return or address a significant risk to public safety. For example, the Budget prioritizes funding to address the highest dam safety risks the Corps has identified at its dams, and to facilitate safe and efficient navigation on the highest use inland waterways.

ENVIRONMENTAL PROTECTION AGENCY

The Environmental Protection Agency (EPA) is responsible for protecting human health and the environment. The President's 2023 Budget for EPA: restores the Agency's capacity to carry out its mission; implements the President's historic Justice40 commitment; and funds a broad suite of recently authorized programs to improve the Nation's water infrastructure.

The Budget requests $11.9 billion in discretionary funding for EPA, a $2.6 billion or 29-percent increase from the 2021 enacted level. Resources provided through the 2023 Budget complement investments in water infrastructure, including lead pipe replacements, and in the remediation of contaminated and idle land provided in the Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Law).

The President's 2023 Budget:

- **Tackles the Climate Crisis with Urgency.** To help address greenhouse gas emissions and make the Nation's infrastructure more resilient, the Budget invests $100 million in grants to States and Tribes that would support the implementation of on-the-ground efforts in communities across the Nation, such as reducing methane emissions. The Budget proposes an additional $35 million over the 2021 enacted level to implement the recently enacted American Innovation and Manufacturing Act to continue phasing out potent greenhouse gases known as hydrofluorocarbons (HFCs). The Budget also invests an additional $13 million over the 2021 enacted level in wildfire prevention and readiness to bolster EPA's abilities to forecast where smoke will harm people and better communicate where smoke events are occurring.
- **Restores Critical Capacity to Carry Out EPA's Core Mission.** Staffing reductions under the previous administration continue to impact the Agency's ability to carry out its mission to protect human health and the environment. The Budget adds more than 1,900 Full Time Equivalents (FTEs) relative to 2021 levels, for a total of more than 16,200 FTEs, to help rebuild the Agency's capacity. Restoring staffing capacity across the Agency would allow EPA to help cut air, water, and climate pollution, and advance environmental justice. Staffing resources would also fund a significant expansion of EPA's paid student internship program to develop a pipeline of qualified staff.
- **Advances Environmental Justice.** The Administration continues to prioritize efforts to deliver environmental justice in communities across the United States, including meeting the President's Justice40 commitment to ensure at least 40 percent of the benefits of Federal investments in climate and clean energy reach disadvantaged communities. The Budget bolsters these efforts by investing nearly $1.5 billion across numerous programs that would help

create good-paying jobs, clean up pollution, implement Justice40, advance racial equity, and secure environmental justice for communities that too often have been left behind, including rural and tribal communities. This funding includes $100 million for support of a new community air quality monitoring and notification program and additional investments in protection for fenceline communities, civil rights compliance, and environmental permitting.

- **Upgrades Drinking Water and Wastewater Infrastructure Nationwide.** The Budget provides roughly $4 billion for water infrastructure, an increase of $1 billion over the 2021 enacted level. These resources would advance efforts to upgrade drinking water and wastewater infrastructure nationwide, with a focus on underserved communities that have historically been overlooked. The Budget funds all of the authorizations in the original Drinking Water and Wastewater Infrastructure Act of 2021, including the creation of 20 new targeted water grant programs and an increase of over $160 million above 2021 enacted levels for the Reducing Lead in Drinking Water grant program. The Budget also maintains funding for EPA's State Revolving Funds (SRF) at 2021 enacted levels, which would complement the $23.4 billion provided for the traditional SRF programs in the Bipartisan Infrastructure Law.

- **Protects Communities from Hazardous Waste and Environmental Damage.** Preventing and cleaning up environmental damage that harms communities and poses a risk to public health and safety continues to be a top priority for the Administration. The Budget provides nearly $1.2 billion for the Superfund program for EPA to continue cleaning up some of the Nation's most contaminated land and respond to environmental emergencies and natural disasters, and begins to adjust for revenue from the Superfund tax. The Budget also provides $215 million for EPA's Brownfields program to enable EPA to provide technical assistance and grants to communities, including disadvantaged communities, so they can safely clean up and reuse contaminated properties. These funds complement Brownfields funding provided in the Bipartisan Infrastructure Law. These programs also support presidential priorities such as the Cancer Moonshot initiative, by addressing contaminants that lead to greater cancer risk.

- **Strengthens the Administration's Commitment to Successfully Implement the Toxic Substances Control Act (TSCA) and Transform the Science of New Chemical Reviews.** The Budget provides $124 million and 449 FTE for TSCA efforts to deliver on the promises made to the American people by the Frank R. Lautenberg Chemical Safety for the 21st Century Act. These resources would provide resources to complete EPA-initiated chemical risk evaluations, issue protective regulations in accordance with statutory timelines and establish a pipeline of prioritized chemicals for risk evaluation.

- **Tackles Per- and Polyfluoroalkyl Substances (PFAS) Pollution.** PFAS are a set of man-made chemicals that threaten the health and safety of communities across the Nation, disproportionately impacting historically disadvantaged communities. As part of the President's commitment to tackling PFAS pollution, the Budget provides approximately $126 million, $57 million over the 2021 enacted level, for EPA to: increase the understanding of PFAS impacts to human health, as well as its ecological effects; restrict use to prevent PFAS from entering the air, land, and water; and remediate PFAS that have been released into the environment.

- **Enforces and Assures Compliance with the Nation's Environmental Laws.** The Budget provides $213 million for civil enforcement efforts, which includes funding to increase enforcement efforts in communities with high pollution exposure and to prevent the illegal importations and use of HFCs in the United States. The Budget also includes: $7 million to operate a coal combustion residuals compliance program; $148 million for compliance monitoring efforts, including funds to conduct inspections in underserved and overburdened communities; and $69 million for criminal enforcement efforts, which includes funding to increase outreach to victims of environmental crimes and to develop a specialized criminal enforcement task force to address environmental justice issues in partnership with the Department of Justice.

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

The National Aeronautics and Space Administration (NASA) inspires the Nation by sending astronauts and robotic missions to explore the solar system, advances the Nation's understanding of the Earth and space, and develops new technologies and approaches to improve aviation and space activities. The President's 2023 Budget for NASA invests in: human and robotic exploration of the Moon; new technologies to improve the Nation's space capabilities; and addressing the climate crisis through cutting-edge research satellites and green aviation research.

The Budget requests $26 billion in discretionary funding for NASA, a $2.7 billion or 11.6-percent increase from the 2021 enacted level.

The President's 2023 Budget:

- **Enhances U.S. Human Spaceflight Leadership.** The Budget provides $7.5 billion, $1.1 billion above the 2021 enacted level, for Artemis lunar exploration. Artemis would return American astronauts to the Moon as early as 2025, land the first woman and person of color on the Moon, deepen the Nation's scientific understanding of the Moon, and test technologies that would allow humans to safely and sustainably explore Mars. Lunar landing missions would also include astronauts from international partners.
- **Addresses the Climate Crisis.** The Budget invests $2.4 billion in Earth-observing satellites and related research to improve the Nation's understanding of climate change. The new satellite missions would form an Earth System Observatory that would provide a three-dimensional, holistic view of Earth that is needed to better understand natural hazards and climate change. In addition, NASA would collaborate with other agencies to enhance greenhouse gas monitoring and make greenhouse gas data more accessible to a broad range of users. The Budget also provides more than $500 million to reduce the climate impacts of the aviation industry as part of a $972 million request for NASA's Aeronautics program. This includes the Sustainable Flight National Partnership, through which NASA and U.S. companies would develop and fly a highly-efficient, next-generation airliner prototype as early as 2026.
- **Supports the Development of Commercial Space Stations.** The Budget supports operations of the International Space Station, paving the way for its continued operation through 2030, and allocates $224 million to support the development of commercial space stations

that NASA, other Government agencies, the Nation's international partners, and the private sector can use after the International Space Station is retired.

- **Advances Robotic Exploration of the Moon and Mars.** The Budget invests over $480 million in lunar robotic missions, including a rover to investigate ice deposits that could provide future astronauts with fuel and oxygen and the Commercial Lunar Payload Services initiative that supports low-cost deliveries to the Moon. The Budget also provides $822 million for the Mars Sample Return mission, which would return Martian rock and soil samples to Earth.

- **Spurs Research and Development.** The Budget increases funding for NASA's Space Technology research and development portfolio to more than $1.4 billion, a $338 million increase above the 2021 enacted level. This investment would support new technologies to help the commercial space industry grow, enhance mission capabilities, and reduce costs. NASA has a key role in better understanding the worsening orbital debris environment and supporting the development of innovative approaches to help protect the Nation's satellites and reduce the risk posed by space debris. The Budget provides over $30 million for orbital debris research, early-stage technology, and measurement technologies.

- **Broadens Participation in Science, Technology, Engineering, and Mathematics (STEM).** The Budget provides $150 million, $23 million above the 2021 enacted level, for NASA's Office of STEM Engagement in order to attract diverse groups of students to STEM through learning opportunities that spark interest and provide connections to NASA's mission and work. This effort includes targeted engagement of underserved populations, including underserved students and people of color.

NATIONAL SCIENCE FOUNDATION

The National Science Foundation (NSF) is responsible for promoting the progress of science and for science education. The President's 2023 Budget for NSF invests in combatting the climate crisis, strengthening U.S. leadership in emerging technologies, boosting research and development, and advancing equity.

The Budget requests $10.5 billion in discretionary funding for NSF, a $2 billion or 24-percent increase from the 2021 enacted level.

The President's 2023 Budget:

- **Spurs Climate Research and Development.** The Budget provides $1.6 billion for research and development, an increase of more than $500 million above the 2021 enacted level, to better understand and prepare for the adverse impacts of climate change. This robust investment would support research in atmospheric composition, water and carbon cycles, modeling climate systems, renewable energy technologies, materials sciences, plant genomics, climate resilience technologies for communities heavily affected by climate change, and social, behavioral, and economic research on human responses to climate change.

- **Strengthens U.S. Leadership in Emerging Technologies.** The Budget provides $880 million for the Directorate for Technology, Innovation, and Partnerships within NSF to help translate research into practical applications. The Directorate will work with programs across the Agency and with other Federal and non-Federal entities to expedite technology development in emerging areas that are crucial for U.S. technological leadership, including trustworthy artificial intelligence, high performance computing, disaster response and resilience, quantum information systems, robotics, advanced communications technologies, biotechnology, cybersecurity, advanced energy technologies, and materials science. The Budget provides an additional $10 million to build and strengthen the national cybersecurity workforce pipeline through education, K-12 programs, and funding to universities and colleges. These investments would help improve U.S. competitiveness in emerging technologies.

- **Advances Racial Equity in Science and Engineering.** The Budget provides $393 million, an increase of $172 million or 78 percent above the 2021 enacted level, for programs to increase the participation of historically underrepresented communities in science and engineering fields. Funding would support: curriculum design; research on successful recruitment and retention methods; development of outreach or mentorship programs; fellowships; and building science and engineering research and education capacity at Historically Black Colleges and Universities and other Minority-Serving Institutions. These investments would help ensure the U.S. science and technology workforce reflects the Nation as a whole.

- **Fosters Scientific and Technological Advances.** The Budget provides $2 billion for research infrastructure at NSF, an increase of $65 million above the 2021 enacted level. Funding would support the construction and procurement of research facilities and instrumentation across the Nation to enable scientific and technological advances. The Budget also supports major NSF research facilities, including long-term upgrades of NSF's major Antarctic infrastructure, construction of the Vera C. Rubin Observatory to support astronomy research, and upgrades to the Large Hadron Collider, the world's largest particle accelerator.

SMALL BUSINESS ADMINISTRATION

The Small Business Administration (SBA) helps to ensure that small businesses and entrepreneurs have access to the information and resources they need to start, grow, or recover their business. The President's 2023 Budget for SBA makes historic investments in counseling and training programs, expanding access to capital, supporting domestic manufacturing and innovation, and promoting access to Government contracting opportunities.

The Budget requests $914 million in discretionary funding for SBA, a $159 million or 21-percent increase from the 2021 enacted level.

The President's 2023 Budget:

- **Supports Underserved Entrepreneurs.** The Budget provides a $31 million increase over the 2021 enacted level to support women, people of color, veterans, and other underserved entrepreneurs through SBA's Entrepreneurial Development programs. This bold commitment ensures entrepreneurs have access to counseling, training, and mentoring services. Access to these services is essential to addressing inequities, expanding economic opportunity, and ensuring small businesses have the tools to succeed.

- **Expands Access to Capital for Small Businesses.** The Budget addresses the need for greater access to affordable capital, particularly in underserved communities. The Budget increases the authorized lending levels in SBA's flagship 7(a) loan guarantee program, the 504 loan program for fixed assets, Small Business Investment Companies, and the Secondary Market Guarantee program by a total of $9.5 billion. Increasing these lending levels would drive economic growth by significantly expanding the availability of working capital, fixed capital, and venture capital funding for small businesses.

- **Strengthens Domestic Manufacturing.** Investing in Growth Accelerators, Regional Innovation Clusters, as well as the Federal and State Technology Partnership Program is key to ensuring entrepreneurs have access to the tools, networks, and services they need to bring cutting-edge innovation to the market. The Budget provides $30 million, an $18 million increase over the 2021 enacted level, to build and strengthen these innovation ecosystems. The Budget also provides $4 million for the creation of a Manufacturing Hub to expand SBA's capacity to support domestic manufacturing by helping small businesses connect with service providers to commercialize innovation, automate processes, enter new markets, expand capacity, and strengthen their resiliency.

- **Implements a Government-Wide Certification Program for Veterans.** The Budget provides $20 million for a uniform certification process to enable veteran and service-disabled veteran-owned small businesses to access business opportunities across the Federal Government.
- **Engages Small Businesses in Combatting Climate Change.** The Budget provides $10 million to facilitate access to capital for investments to help small businesses become more resilient to climate change or support the clean energy economy.

SOCIAL SECURITY ADMINISTRATION

The Social Security Administration (SSA) provides essential benefits to retirees, survivors, individuals with disabilities, and older Americans with limited income and resources. The President's 2023 Budget for SSA invests in improving service delivery, advancing equity, and promoting program integrity.

The Budget requests $14.8 billion in discretionary funding for SSA, a $1.8 billion or 14-percent increase from the 2021 enacted level, including funding for program integrity activities.

The President's 2023 Budget:

- **Improves Service Delivery.** Each year, SSA processes more than six million retirement, survivors, and Medicare claims, as well as more than two million disability and Supplemental Security Income claims. The Budget provides an increase of $1.6 billion, or 14 percent over the 2021 enacted level, to improve services at SSA's field offices, State disability determination services, and teleservice centers for retirees, individuals with disabilities, and their families who rely on the Agency. The Budget also improves access to SSA's services by adding staff to speed disability claims processing and reduce wait times.
- **Advances Equity and Accessibility.** SSA remains committed to breaking down barriers to access experienced by people who rely on its services, including individuals experiencing homelessness, children with disabilities, and people with mental and intellectual disabilities. The Budget makes investments to decrease customer wait times, simplify application processes, and increase outreach to people who are difficult to reach. SSA will also continue to modernize its information technology systems to make more services available online and improve 800 Number access.
- **Promotes Program Integrity.** The Budget includes $1.8 billion, $224 million above the 2021 enacted level, for dedicated program integrity activities to promote responsible spending of Social Security funds and ensure that the Agency is providing the correct benefit amounts only to those who qualify. These funds also support actions to investigate and help prosecute fraud.

Summary Tables

Table S–1. Budget Totals[1]

(In billions of dollars and as a percent of GDP)

													Totals	
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2023–2027	2023–2032
Budget totals in billions of dollars:														
Receipts	4,047	4,437	4,638	4,874	5,076	5,406	5,696	5,969	6,227	6,500	6,795	7,083	25,690	58,264
Outlays	6,822	5,852	5,792	6,075	6,406	6,734	7,048	7,502	7,670	8,114	8,477	8,867	32,055	72,685
Deficit[2]	2,775	1,415	1,154	1,201	1,330	1,328	1,352	1,533	1,443	1,614	1,682	1,784	6,364	14,421
Debt held by the public	22,284	24,836	26,033	27,271	28,644	29,988	31,368	32,923	34,388	36,022	37,727	39,542		
Debt held by the public net of financial assets	20,673	22,085	23,238	24,439	25,769	27,097	28,449	29,982	31,425	33,045	34,732	36,516		
Gross domestic product (GDP)	22,358	24,256	25,567	26,694	27,787	28,912	30,080	31,307	32,615	34,018	35,498	37,041		
Budget totals as a percent of GDP:														
Receipts	18.1%	18.3%	18.1%	18.3%	18.3%	18.7%	18.9%	19.1%	19.1%	19.1%	19.1%	19.1%	18.5%	18.8%
Outlays	30.5%	24.1%	22.7%	22.8%	23.1%	23.3%	23.4%	24.0%	23.5%	23.9%	23.9%	23.9%	23.0%	23.4%
Deficit	12.4%	5.8%	4.5%	4.5%	4.8%	4.6%	4.5%	4.9%	4.4%	4.7%	4.7%	4.8%	4.6%	4.7%
Debt held by the public	99.7%	102.4%	101.8%	102.2%	103.1%	103.7%	104.3%	105.2%	105.4%	105.9%	106.3%	106.7%		
Debt held by the public net of financial assets	92.5%	91.0%	90.9%	91.6%	92.7%	93.7%	94.6%	95.8%	96.4%	97.1%	97.8%	98.6%		
Memorandum, real net interest:														
Real net interest in billions of dollars	–291	–514	–146	–48	20	73	129	181	221	254	298	337	29	1,319
Real net interest as a percent of GDP	–1.3%	–2.1%	–0.6%	–0.2%	0.1%	0.3%	0.4%	0.6%	0.7%	0.7%	0.8%	0.9%	0.0%	0.4%

[1] The Budget includes a reserve for legislation that reduces costs, expands productive capacity, and reforms the tax system. While the President is committed to reducing the deficit with this legislation, this allowance is shown as deficit neutral to be conservative for purposes of the budget totals. Because discussions with Congress continue, the Budget does not break down the reserve among specific policies or between revenues and outlays.

[2] The estimated deficit for 2022 is based on partial year actual data and generally incorporates actuals through February. At the time the 2023 Budget was prepared, 2022 appropriations remained incomplete. The baseline reflects annualized continuing appropriations for 2022.

Table S–2. Effect of Budget Proposals on Projected Deficits

(Deficit increases (+) or decreases (–) in billions of dollars)

													Totals	
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2023–2027	2023–2032
Projected deficits in the baseline[1]	**2,775**	**1,421**	**1,176**	**1,279**	**1,422**	**1,399**	**1,419**	**1,630**	**1,562**	**1,748**	**1,818**	**2,014**	**6,694**	**15,466**
Percent of GDP	12.4%	5.9%	4.6%	4.8%	5.1%	4.8%	4.7%	5.2%	4.8%	5.1%	5.1%	5.4%		
Proposals in the 2023 Budget:														
Reserve for legislation that reduces costs, expands productive capacity, and reforms the tax system[2]	....	....	....	....	....	....	....	....	....	....	....	....	....	....
Invest in K–12 education and college affordability	....	....	3	22	28	33	38	44	50	54	55	56	125	383
Improve public health by investing in preparedness, mental health, tribal health, and other areas	....	....	22	44	38	36	37	37	35	37	39	41	177	365
Increase affordable housing supply	....	....	1	3	6	7	8	8	6	4	3	2	25	48
Combat and prevent crime	....	....	1	2	3	4	5	4	3	2	2	2	15	28
Minimum tax on billionaires	....	....	....	–36	–40	–43	–43	–43	–43	–38	–36	–38	–163	–361
Additional investments and reforms	....	–6	–50	–112	–124	–103	–104	–137	–158	–176	–180	–269	–493	–1,413
Debt service and other interest effects	....	–*	–*	–1	–3	–5	–7	–9	–12	–15	–19	–24	–16	–95
Total proposals in the 2023 Budget[3]	**.........**	**–6**	**–22**	**–78**	**–93**	**–70**	**–67**	**–97**	**–119**	**–133**	**–136**	**–229**	**–330**	**–1,045**
Resulting deficits in the 2023 Budget	**2,775**	**1,415**	**1,154**	**1,201**	**1,330**	**1,328**	**1,352**	**1,533**	**1,443**	**1,614**	**1,682**	**1,784**	**6,364**	**14,421**
Percent of GDP	12.4%	5.8%	4.5%	4.5%	4.8%	4.6%	4.5%	4.9%	4.4%	4.7%	4.7%	4.8%		

*$500 million or less

[1] At the time the 2023 Budget was prepared, 2022 appropriations remained incomplete. The baseline reflects annualized continuing appropriations for 2022.

[2] The Budget includes a reserve for legislation that reduces costs, expands productive capacity, and reforms the tax system. While the President is committed to reducing the deficit with this legislation, this allowance is shown as deficit neutral to be conservative for purposes of the budget totals. Because discussions with Congress continue, the Budget does not break down the reserve among specific policies or between revenues and outlays.

[3] Reflects budget deficit reduction compared to a baseline that does not include the Consolidated Appropriations Act, 2022 (Public Law 117–103), which was enacted after the baseline was finalized. Deficit reduction relative to a baseline that incorporated that legislation would be significantly greater.

Table S–3. Baseline by Category[1]

(In billions of dollars)

													Totals	
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2023–2027	2023–2032
Outlays:														
Discretionary programs:														
Defense	742	766	766	784	802	815	828	847	866	886	906	927	3,995	8,426
Non-defense	895	928	873	949	931	935	952	974	994	1,013	1,033	1,055	4,641	9,710
Subtotal, discretionary programs	1,636	1,694	1,639	1,733	1,733	1,750	1,781	1,822	1,860	1,899	1,939	1,981	8,636	18,137
Mandatory programs:														
Social Security	1,129	1,214	1,313	1,398	1,482	1,571	1,663	1,760	1,858	1,958	2,061	2,167	7,427	17,231
Medicare	689	753	847	853	972	1,071	1,158	1,311	1,261	1,420	1,492	1,645	4,901	12,031
Medicaid	521	562	536	566	595	627	661	703	749	796	844	896	2,984	6,972
Other mandatory programs	2,495	1,272	954	852	854	870	862	929	915	962	989	1,035	4,393	9,222
Subtotal, mandatory programs	4,834	3,800	3,650	3,670	3,904	4,138	4,344	4,703	4,783	5,136	5,386	5,743	19,705	45,456
Net interest	352	357	396	477	567	653	736	818	891	963	1,038	1,116	2,829	7,655
Total outlays	6,822	5,852	5,685	5,880	6,204	6,540	6,861	7,342	7,534	7,998	8,363	8,840	31,171	71,248
Receipts:														
Individual income taxes	2,044	2,257	2,305	2,319	2,431	2,727	2,926	3,074	3,241	3,420	3,610	3,789	12,708	29,843
Corporation income taxes	372	383	412	447	454	437	445	468	465	457	454	455	2,196	4,495
Social insurance and retirement receipts:														
Social Security payroll taxes	952	1,047	1,101	1,158	1,208	1,264	1,315	1,381	1,439	1,505	1,575	1,644	6,046	13,590
Medicare payroll taxes	295	329	343	361	376	393	409	430	448	469	491	514	1,883	4,233
Unemployment insurance	57	58	55	55	55	55	56	56	60	62	62	64	275	580
Other retirement	10	12	12	13	13	14	15	15	16	16	17	18	67	149
Excise taxes	75	84	90	95	95	96	96	96	98	100	101	103	473	971
Estate and gift taxes	27	26	25	25	26	27	41	42	44	47	50	53	144	380
Customs duties	80	93	54	46	47	49	51	53	55	58	60	53	247	526
Deposits of earnings, Federal Reserve System	100	108	76	43	34	35	39	45	50	57	65	73	227	516
Other miscellaneous receipts	34	35	36	39	42	45	49	52	56	58	60	62	211	499
Total receipts	4,047	4,431	4,509	4,601	4,782	5,142	5,442	5,712	5,972	6,250	6,545	6,826	24,476	55,781
Deficit	**2,775**	**1,421**	**1,176**	**1,279**	**1,422**	**1,399**	**1,419**	**1,630**	**1,562**	**1,748**	**1,818**	**2,014**	**6,694**	**15,466**
Net interest	352	357	396	477	567	653	736	818	891	963	1,038	1,116	2,829	7,655
Primary deficit	2,423	1,064	780	801	855	746	683	813	672	784	780	898	3,865	7,812
On-budget deficit	2,724	1,381	1,090	1,164	1,277	1,224	1,220	1,406	1,300	1,456	1,495	1,656	5,976	13,289
Off-budget deficit/surplus (–)	52	41	86	115	145	174	198	225	262	292	323	357	718	2,178

[1] Baseline estimates are on the basis of the economic assumptions shown in Table S–9, which incorporate the effects of the Administration's fiscal policies and incorporate certain adjustments described in the "Current Services" chapter of the *Analytical Perspectives* volume. At the time the 2023 Budget was prepared, 2022 appropriations remained incomplete. The baseline reflects annualized continuing appropriations for 2022. See Tables S–7 and S–8 for more information about discretionary funding levels.

Table S–4. Proposed Budget by Category [1]

(In billions of dollars)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Totals 2023–2027	Totals 2023–2032
Outlays:														
Discretionary programs:														
Defense	742	766	795	822	837	843	853	864	872	879	885	891	4,150	8,541
Non-defense	895	928	915	1,022	1,012	1,019	1,026	1,030	1,039	1,051	1,065	1,083	4,993	10,261
Subtotal, discretionary programs	1,636	1,694	1,709	1,844	1,848	1,862	1,879	1,894	1,911	1,930	1,950	1,974	9,142	18,802
Mandatory programs:														
Social Security	1,129	1,214	1,313	1,398	1,482	1,570	1,662	1,759	1,857	1,957	2,059	2,165	7,425	17,222
Medicare	689	753	846	853	971	1,070	1,157	1,310	1,260	1,420	1,513	1,612	4,898	12,013
Medicaid	521	562	536	567	599	631	666	706	752	799	847	898	2,999	7,001
Other mandatory programs	2,495	1,272	993	937	942	953	954	1,024	1,012	1,060	1,088	1,126	4,778	10,089
Subtotal, mandatory programs	4,834	3,800	3,687	3,755	3,994	4,224	4,439	4,800	4,880	5,236	5,508	5,801	20,099	46,324
Net interest	352	357	396	476	564	648	729	808	879	948	1,019	1,092	2,813	7,559
Total outlays	6,822	5,852	5,792	6,075	6,406	6,734	7,048	7,502	7,670	8,114	8,477	8,867	32,055	72,685
Receipts:														
Individual income taxes	2,044	2,263	2,345	2,427	2,549	2,819	3,007	3,156	3,324	3,502	3,692	3,876	13,147	30,698
Corporation income taxes	372	383	501	616	633	612	620	644	638	627	623	625	2,982	6,139
Social insurance and retirement receipts:														
Social Security payroll taxes	952	1,047	1,101	1,158	1,208	1,264	1,315	1,381	1,439	1,505	1,575	1,644	6,046	13,590
Medicare payroll taxes	295	329	342	360	375	392	408	428	446	467	489	512	1,876	4,218
Unemployment insurance	57	58	55	55	55	55	56	56	60	62	62	64	275	579
Other retirement	10	12	12	13	13	14	15	15	16	16	17	18	67	149
Excise taxes	75	84	91	96	95	96	97	96	99	101	101	103	474	974
Estate and gift taxes	27	26	25	23	25	25	40	42	45	47	51	54	138	376
Customs duties	80	93	54	46	47	49	51	53	55	58	60	53	247	526
Deposits of earnings, Federal Reserve System	100	108	76	43	34	35	39	45	50	57	65	73	227	516
Other miscellaneous receipts	34	35	36	39	42	45	49	52	56	58	60	62	211	499
Total receipts	4,047	4,437	4,638	4,874	5,076	5,406	5,696	5,969	6,227	6,500	6,795	7,083	25,690	58,264
Deficit	**2,775**	**1,415**	**1,154**	**1,201**	**1,330**	**1,328**	**1,352**	**1,533**	**1,443**	**1,614**	**1,682**	**1,784**	**6,364**	**14,421**
Net interest	352	357	396	476	564	648	729	808	879	948	1,019	1,092	2,813	7,559
Primary deficit	2,423	1,058	758	724	766	680	622	725	565	667	663	692	3,551	6,862
On-budget deficit	2,724	1,374	1,068	1,085	1,184	1,153	1,153	1,308	1,181	1,323	1,360	1,428	5,643	12,243
Off-budget deficit/surplus (–)	52	41	86	116	146	175	199	225	262	292	322	356	721	2,178

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[1] The Budget includes a reserve for legislation that reduces costs, expands productive capacity, and reforms the tax system. While the President is committed to reducing the deficit with this legislation, this allowance is shown as deficit neutral to be conservative for purposes of the budget totals. Because discussions with Congress continue, the Budget does not break down the reserve among specific policies or between revenues and outlays.

Table S–5. Proposed Budget by Category as a Percent of GDP[1]

(As a percent of GDP)

													Averages	
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2023–2027**	**2023–2032**
Outlays:														
Discretionary programs:														
Defense	3.3	3.2	3.1	3.1	3.0	2.9	2.8	2.8	2.7	2.6	2.5	2.4	3.0	2.8
Non-defense	4.0	3.8	3.6	3.8	3.6	3.5	3.4	3.3	3.2	3.1	3.0	2.9	3.6	3.3
Subtotal, discretionary programs	7.3	7.0	6.7	6.9	6.7	6.4	6.2	6.0	5.9	5.7	5.5	5.3	6.6	6.1
Mandatory programs:														
Social Security	5.0	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.8	5.8	5.3	5.5
Medicare	3.1	3.1	3.3	3.2	3.5	3.7	3.8	4.2	3.9	4.2	4.3	4.4	3.5	3.8
Medicaid	2.3	2.3	2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.3	2.4	2.4	2.2	2.2
Other mandatory programs	11.2	5.2	3.9	3.5	3.4	3.3	3.2	3.3	3.1	3.1	3.1	3.0	3.5	3.3
Subtotal, mandatory programs	21.6	15.7	14.4	14.1	14.4	14.6	14.8	15.3	15.0	15.4	15.5	15.7	14.4	14.9
Net interest	1.6	1.5	1.5	1.8	2.0	2.2	2.4	2.6	2.7	2.8	2.9	2.9	2.0	2.4
Total outlays	30.5	24.1	22.7	22.8	23.1	23.3	23.4	24.0	23.5	23.9	23.9	23.9	23.0	23.4
Receipts:														
Individual income taxes	9.1	9.3	9.2	9.1	9.2	9.8	10.0	10.1	10.2	10.3	10.4	10.5	9.4	9.9
Corporation income taxes	1.7	1.6	2.0	2.3	2.3	2.1	2.1	2.1	2.0	1.8	1.8	1.7	2.1	2.0
Social insurance and retirement receipts:														
Social Security payroll taxes	4.3	4.3	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	4.4
Medicare payroll taxes	1.3	1.4	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.4
Unemployment insurance	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Other retirement	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Excise taxes	0.3	0.3	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Estate and gift taxes	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Customs duties	0.4	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2
Deposits of earnings, Federal Reserve System	0.4	0.4	0.3	0.2	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Other miscellaneous receipts	0.2	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total receipts	18.1	18.3	18.1	18.3	18.3	18.7	18.9	19.1	19.1	19.1	19.1	19.1	18.5	18.8
Deficit	**12.4**	**5.8**	**4.5**	**4.5**	**4.8**	**4.6**	**4.5**	**4.9**	**4.4**	**4.7**	**4.7**	**4.8**	**4.6**	**4.7**
Net interest	1.6	1.5	1.5	1.8	2.0	2.2	2.4	2.6	2.7	2.8	2.9	2.9	2.0	2.4
Primary deficit	10.8	4.4	3.0	2.7	2.8	2.4	2.1	2.3	1.7	2.0	1.9	1.9	2.6	2.3
On-budget deficit	12.2	5.7	4.2	4.1	4.3	4.0	3.8	4.2	3.6	3.9	3.8	3.9	4.1	4.0
Off-budget deficit/surplus (–)	0.2	0.2	0.3	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	1.0	0.5	0.7

*0.05 percent of GDP or less

[1] The Budget includes a reserve for legislation that reduces costs, expands productive capacity, and reforms the tax system. While the President is committed to reducing the deficit with this legislation, this allowance is shown as deficit neutral to be conservative for purposes of the budget totals. Because discussions with Congress continue, the Budget does not break down the reserve among specific policies or between revenues and outlays.

Table S–6. Mandatory and Receipt Proposals

(Deficit increases (+) or decreases (–) in millions of dollars)

												Totals	
	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2023–2027**	**2023–2032**
Mandatory initiatives and savings:													
Multi-agency proposals:													
Reserve for legislation that reduces costs, expands productive capacity, and reforms the tax system	....	....	....	....	....	....	....	....	....	....	....	....	....
Transform mental health & substance use disorder coverage and infrastructure:													
Department of Health and Human Services:													
Invest in behavioral health workforce and delivery	....	750	750	750	750	750	750	750	750	750	750	3,750	7,500
Expand and convert Medicaid demonstration programs to improve community behavioral health services into a permanent program	....	45	1,430	1,960	2,430	2,560	2,750	2,930	3,120	3,320	3,520	8,425	24,065
Establish Medicaid provider capacity grants for mental health & substance use disorder treatment	....	40	170	1,640	2,340	2,600	710	....	....	....	....	6,790	7,500
Utilize clinically appropriate criteria for Medicaid behavioral health services	....	190	200	210	220	230	240	250	270	280	290	1,050	2,380
Establish performance bonus fund to improve behavioral health in Medicaid	....	500	500	500	500	500	....	....	....	....	....	2,500	2,500
Apply the Mental Health Parity and Addiction Equity Act (MHPAEA) to Medicare	....	....	....	....	....	....	....	....	....	....	....	....	....
Eliminate the 190-day lifetime limit on psychiatric hospital services	....	30	90	110	110	120	120	130	140	140	150	460	1,140
Revise criteria for psychiatric hospital terminations from Medicare	....	....	....	....	....	....	....	....	....	....	....	....	....
Modernize Medicare mental health benefits[1]	....	....	....	....	....	....	....	....	....	....	....	....	....
Require Medicare to cover three behavioral health visits without cost-sharing	....	....	100	130	140	150	160	150	170	170	180	520	1,350
Increase access to consumer protections in self-insured non-federal governmental plans	....	....	....	....	....	....	....	....	....	....	....	....	....
Provide mandatory funding for state enforcement of mental health parity requirements	....	10	40	25	25	25	....	....	....	....	....	125	125
Permanently extend funding for Community Mental Health Centers (CMHCs)	....	124	289	372	413	413	413	413	413	413	413	1,611	3,676
Department of Labor:													
Authorize the Department of Labor (DOL) to pursue parity violations by entities that provide administrative services to Employee Retirement Income Security Act (ERISA) group health plans	....	....	....	....	....	....	....	....	....	....	....	....	....
Amend ERISA to allow participants and beneficiaries to recover losses due to parity violations	....	....	....	....	....	....	....	....	....	....	....	....	....
Authorize DOL to impose civil monetary penalties for MHPAEA noncompliance	....	....	–3	–4	–4	–4	–4	–4	–4	–4	–4	–15	–35

Table S–6. Mandatory and Receipt Proposals—Continued

(Deficit increases (+) or decreases (–) in millions of dollars)

												Totals	
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2023–2027	2023–2032
Provide mandatory funding for DOL to perform additional Non-Quantitative Treatment Limitations (NQTL) audits	....	2	5	25	25	34	35	36	37	38	38	91	275
Cross-Cutting proposals:													
Improve access to behavioral healthcare in the private insurance market[2]	....	1,881	2,664	2,842	2,933	3,052	3,184	3,354	3,503	3,661	3,847	13,371	30,920
Require coverage of three behavioral health visits and three primary care visits without cost-sharing[2]	....	1,202	1,740	1,823	1,937	2,025	2,117	2,229	2,316	2,388	2,506	8,728	20,284
Subtotal, transform mental health & substance use disorder coverage and infrastructure	....	4,774	7,975	10,383	11,819	12,455	10,475	10,238	10,715	11,156	11,690	47,406	101,680
Increase affordable housing supply:													
Department of Housing and Urban Development:													
Fund affordable housing production grants	....	500	2,000	3,500	4,500	5,000	4,500	3,000	1,500	500	....	15,500	25,000
Reduce affordable housing barriers	....	200	800	1,400	1,800	2,000	1,800	1,200	600	200	....	6,200	10,000
Department of the Treasury:													
Establish Community Development Financial Institutions Affordable Housing Supply Fund	....	500	500	500	500	500	500	500	500	500	500	2,500	5,000
Allow selective basis boosts for bond-financed Low-Income Housing Credit projects[2]	....	2	29	140	354	617	895	1,148	1,359	1,561	1,769	1,142	7,874
Subtotal, increase affordable housing supply	....	1,202	3,329	5,540	7,154	8,117	7,695	5,848	3,959	2,761	2,269	25,342	47,874
Protect our elections and the right to vote:													
Election Assistance Commission:													
Fund election grants to increase access and security	....	2,040	810	830	840	860	880	900	920	950	970	5,380	10,000
Postal Service:													
Expand affordability and reliability of election-related mail service	....	500	500	500	500	500	500	500	500	500	500	2,500	5,000
Subtotal, protect our elections and the right to vote	....	2,540	1,310	1,330	1,340	1,360	1,380	1,400	1,420	1,450	1,470	7,880	15,000
Expand legal representation for asylum seekers:													
Department of Health and Human Services:													
Provide unaccompanied children with legal representation	....	120	302	470	644	892	1,063	1,121	1,161	1,194	1,223	2,428	8,190
Department of Justice:													
Provide representation in the immigration court system	....	68	248	428	450	450	450	450	450	450	450	1,644	3,894
Subtotal, expand legal representation for asylum seekers	....	188	550	898	1,094	1,342	1,513	1,571	1,611	1,644	1,673	4,072	12,084
Advance child welfare:													
Department of Health and Human Services:													

Table S–6. Mandatory and Receipt Proposals—Continued

(Deficit increases (+) or decreases (–) in millions of dollars)

												Totals	
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2023–2027	2023–2032
Create new flexibilities and support in the Chafee program for youth who experienced foster care	....	100	100	100	100	100	100	100	100	100	100	500	1,000
Prevent and combat religious, sexual orientation, gender identity, gender expression, or sex discrimination in the child welfare system	....	....	....	....	....	....	....	....	....	....	....	....	....
Expand and encourage participation in the title IV-E Prevention Services and Kinship Navigator programs	161	280	318	376	445	389	457	539	628	701	767	1,808	4,900
Reauthorize, increase funding for, and amend the Promoting Safe and Stable Families program	....	78	250	292	295	300	300	300	300	300	300	1,215	2,715
Increase support for foster care placements with kin caregivers	....	91	100	108	116	126	136	145	155	162	169	541	1,308
Reduce reimbursement rates for foster care congregate care placements	....	–27	–24	–21	–18	–17	–16	–15	–14	–14	–14	–107	–180
Department of the Treasury:													
Make the adoption tax credit refundable and allow certain guardianship arrangements to qualify[2]	....	11	2,037	1,244	1,015	1,038	1,009	1,016	1,031	1,043	1,050	5,345	10,494
Subtotal, advance child welfare	161	533	2,781	2,099	1,953	1,936	1,986	2,085	2,200	2,292	2,372	9,302	20,237
Ensure future pandemic and public health preparedness:													
Department of Health and Human Services:													
Invest in development of medical countermeasures, surge capacity, and public health systems	....	13,509	28,734	17,183	10,354	6,627	4,449	723	120	....	....	76,407	81,699
Establish the Vaccines for Adults program	....	1,712	2,155	2,238	2,326	2,416	2,511	2,608	2,711	2,816	2,926	10,847	24,419
Expand Vaccines for Children (VFC) program to all Children's Health Insurance Program (CHIP) children and make program improvements	....	20	30	30	30	20	40	30	30	20	30	130	280
Authorize coverage for drugs and devices authorized for emergency use[1]	....	....	....	....	....	....	....	....	....	....	....	....	....
Encourage development of innovative antimicrobial drugs[1]	....	....	....	....	....	....	....	....	....	....	....	....	....
Consolidate all vaccine coverage under Medicare Part B	....	....	400	460	450	440	420	400	370	350	290	1,750	3,580
Ensure consistency and clarity of data reporting requirements for Medicare providers, suppliers, and contractors during public health emergencies	....	....	....	....	....	....	....	....	....	....	....	....	....
Enable the Secretary to temporarily modify or waive the application of specific requirements of the Clinical Laboratory Improvement Amendments of 1988 (CLIA) Act[1]	....	....	....	....	....	....	....	....	....	....	....	....	....
Department of State and United States Agency for International Development (USAID)													

Table S–6. Mandatory and Receipt Proposals—Continued

(Deficit increases (+) or decreases (–) in millions of dollars)

												Totals	
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2023–2027	2023–2032
Strengthen the global health workforce, advance research and development capacity, and increase health security financing	....	2,275	1,950	1,625	325	325	....	....	....	....	....	6,500	6,500
Subtotal, ensure future pandemic and public health preparedness	....	17,516	33,269	21,536	13,485	9,828	7,420	3,761	3,231	3,186	3,246	95,634	116,478
Reclassifications:													
Shift the Indian Health Service from discretionary to mandatory funding													
Technical Reclassification:													
Reduction in discretionary spending (non-add)	....	*–7,398*	*–8,977*	*–9,498*	*–9,716*	*–9,939*	*–10,170*	*–10,402*	*–10,641*	*–10,886*	*–11,136*	*–45,528*	*–98,763*
Shift to mandatory spending	....	7,398	8,977	9,498	9,716	9,939	10,170	10,402	10,641	10,886	11,136	45,528	98,763
Provide adequate funding and close service gaps	....	....	2,721	6,272	10,022	13,986	18,178	20,207	21,762	23,421	25,191	33,001	141,760
Total IHS Request (Budget authority) (non-add)	....	*9,121*	*12,731*	*16,535*	*20,545*	*24,777*	*29,246*	*30,956*	*32,771*	*34,697*	*36,741*	*83,709*	*248,120*
End Deficit Reduction Contributions from Passenger Security Fee	....	1,520	1,560	1,600	1,640	1,680	....	....	....	....	....	8,000	8,000
Discretionary effects (non-add)	....	*–1,520*	*–1,560*	*–1,600*	*–1,640*	*–1,680*	....	....	....	....	....	*–8,000*	*–8,000*
Provide mandatory funding for previously enacted Tribal Water Settlements Operations and Maintenance	....	20	34	34	34	34	34	34	34	34	34	156	326
Discretionary effects (non-add)	....	*–20*	*–34*	*–34*	*–34*	*–34*	*–34*	*–34*	*–34*	*–34*	*–34*	*–156*	*–326*
Reclassify Tribal Lease Payments	....	55	56	57	58	60	61	62	63	64	66	286	602
Discretionary effects (non-add)	....	*–55*	*–56*	*–57*	*–58*	*–60*	*–61*	*–62*	*–63*	*–64*	*–66*	*–286*	*–602*
Reclassify Contract Support Costs	....	237	397	410	422	434	447	456	466	474	484	1,900	4,227
Discretionary effects (non-add)	....	*–237*	*–397*	*–410*	*–422*	*–434*	*–447*	*–456*	*–466*	*–474*	*–484*	*–1,900*	*–4,227*
Subtotal, reclassifications	....	9,230	13,745	17,871	21,892	26,133	28,890	31,161	32,966	34,879	36,911	88,871	253,678
Program integrity proposals:													
Capture savings to Medicare and Medicaid from Health Care Fraud and Abuse Control (HCFAC) allocation adjustment	....	–1,119	–1,181	–1,246	–1,315	–1,354	–1,393	–1,435	–1,479	–1,523	–1,569	–6,215	–13,614
Implement HCFAC allocation adjustment, discretionary outlays (non-add)	....	*576*	*593*	*611*	*629*	*648*	*667*	*687*	*708*	*729*	*751*	*3,057*	*6,599*
Net effect of HCFAC allocation adjustment (non-add)	....	*–543*	*–588*	*–635*	*–686*	*–706*	*–726*	*–748*	*–771*	*–794*	*–818*	*–3,158*	*–7,015*
Capture savings to Unemployment Insurance (UI) from Reemployment Services and Eligibility Assessments (RESEA) allocation adjustment[2]	–290	–474	–684	–701	–630	–618	–597	–583	–574	–851	–911	–3,107	–6,623
Implement RESEA allocation adjustment, discretionary outlays (non-add)	*79*	*249*	*424*	*528*	*605*	*631*	*648*	*661*	*677*	*692*	*709*	*2,437*	*5,824*
Net effect of RESEA allocation adjustment (non-add)	*–211*	*–225*	*–260*	*–173*	*–25*	*13*	*51*	*78*	*103*	*–159*	*–202*	*–670*	*–799*
Capture savings from the Social Security Administration (SSA) allocation adjustments[3]	....	–112	–1,776	–3,142	–3,992	–4,885	–6,021	–6,289	–7,440	–8,242	–8,981	–13,907	–50,880
Implement SSA allocation adjustments, discretionary outlays (non-add)	....	*1,516*	*1,579*	*1,405*	*1,502*	*1,577*	*1,626*	*1,683*	*1,765*	*1,801*	*1,834*	*7,579*	*16,288*

Table S–6. Mandatory and Receipt Proposals—Continued

(Deficit increases (+) or decreases (–) in millions of dollars)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Totals	
												2023–2027	**2023–2032**
Net effect of SSA allocation adjustments (non-add)	....	*1,404*	*–197*	*–1,737*	*–2,490*	*–3,308*	*–4,395*	*–4,606*	*–5,675*	*–6,441*	*–7,147*	*–6,328*	*–34,592*
Subtotal, program integrity proposals	–290	–1,705	–3,641	–5,089	–5,937	–6,857	–8,011	–8,307	–9,493	–10,616	–11,461	–23,229	–71,117
Increase Afghan Special Immigrant Visas	....	52	81	80	72	66	64	58	52	53	54	351	632
Smooth and extend BBEDCA Section 251A sequestration	....	....	....	....	....	....	....	....	1,730	22,450	–36,537	....	–12,357
Proposals by Agency:													
Department of Defense--Military Programs:													
Extend authority to provide increased voluntary separation incentive pay for civilian employees of the Department of Defense	....	1	1	1	....	....	....	....	....	....	....	3	3
Authorize mandatory collection of Survivor Benefit Plan premiums from Veterans Disability Compensation	....	....	....	....	....	....	....	....	....	....	....	....	....
Expand the current Medicare Eligible Retiree Health Care Fund to include all uniformed services retiree health care costs	....	....	464	462	406	351	209	52	–99	–235	–355	1,683	1,255
Establish reserve component duty status reform	....	....	....	....	....	....	....	....	....	....	....	....	....
Department of Education													
Double the maximum Pell Grant by 2029	....	2,847	8,442	12,710	16,988	21,428	26,563	32,148	35,348	36,010	36,671	62,415	229,155
Increase the Pell Grant discretionary award (effect on mandatory costs)	....	....	54	125	125	126	135	148	148	149	150	430	1,160
Shift mandatory funds to support Pell award increase	....	....	–54	–125	–125	–126	–135	–148	–148	–149	–150	–430	–1,160
Increase Title I funding	....	640	13,455	15,205	16,354	17,050	17,442	17,844	18,252	18,674	19,102	62,704	154,018
Title I Mandatory Request (Budget authority) (non-add)	....	*16,000*	*16,368*	*16,745*	*17,130*	*17,523*	*17,927*	*18,338*	*18,761*	*19,192*	*19,634*	*83,766*	*177,618*
Department of Energy:													
Strengthen clean energy manufacturing	....	40	100	160	180	190	160	100	40	20	10	670	1,000
Department of Health and Human Services:													
Fund the Administration's HIV/AIDS strategy:													
Eliminate barriers to pre-exposure prophylaxis (PrEP) under Medicaid	....	–290	–310	–340	–370	–390	–430	–460	–500	–530	–580	–1,700	–4,200
Establish PrEP Delivery Program to end the HIV epidemic	....	213	371	526	687	853	1,027	1,206	1,394	1,587	1,789	2,650	9,653
Extend and expand the Maternal Infant Early Childhood Home Visiting (MIECHV) program	....	19	142	415	532	611	646	502	116	22	....	1,719	3,005
Provide CMS Program Management Implementation Funding	....	50	150	100	....	....	....	....	....	....	....	300	300
Standardize data collection to improve quality and promote equitable care	....	....	....	....	....	....	....	....	....	....	....	....	....
Add Medicare coverage of services furnished by community health workers[1]	....	....	....	....	....	....	....	....	....	....	....	....	....
Establish a Contingency Fund for the Unaccompanied Children Program	....	696	1,315	1,439	789	201	108	62	31	....	....	4,440	4,641

Table S–6. Mandatory and Receipt Proposals—Continued

(Deficit increases (+) or decreases (–) in millions of dollars)

											Totals	
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2023–2027	2023–2032
Treat certain populations as refugees for public benefit purposes	....	111	122	127	132	138	133	11	4	4	4	630	786
Prohibit unsolicited Medicare beneficiary contacts[1]	....	....	....	....	....	....	....	....	....	....	....	....	....
Expand tools to identify and investigate fraud in the Medicare Advantage program[1]	....	....	....	....	....	....	....	....	....	....	....	....	....
Hold long-term care facility owners accountable for noncompliant closures and substandard care	....	....	....	....	....	....	....	....	....	....	....	....	....
Increase transparency by disclosing accreditation surveys	....	....	....	....	....	....	....	....	....	....	....	....	....
Remove restrictions on the certification of new entities as Organ Procurement Organizations and increase enforcement flexibility	....	....	....	....	....	....	....	....	....	....	....	....	....
Enhance the physician fee schedule conversion factor update in CY 2025	....	....	....	250	380	410	430	460	480	500	540	1,040	3,450
Modify the Medicaid Drug Rebate Program in the Territories	....	....	....	....	....	....	....	....	....	....	....	....	....
Enhance Medicaid managed care enforcement	....	–100	–200	–200	–200	–200	–200	–200	–200	–300	–300	–900	–2,100
Medicaid interactions	....	....	....	60	100	100	30	....	....	....	....	260	290
Department of Homeland Security:													
Establish Electronic Visa Update System user fee[2]	....	....	....	....	....	....	....	....	....	....	....	....	....
Extend expiring Customs and Border Protection (CBP) user fees	....	....	....	....	....	....	....	....	....	....	–5,939	....	–5,939
Establish an affordability program for the National Flood Insurance Program	....	43	328	375	427	480	534	580	630	676	720	1,653	4,793
Department of Justice:													
Combat and prevent crime	....	1,064	2,055	3,289	4,157	4,535	3,551	2,875	2,249	1,992	1,892	15,100	27,662
Department of Labor:													
Shift timing of Pension Benefit Guarantee Corporation's Single Employer premiums	....	....	....	3,314	–3,314	....	....	....	....	....	....	....	....
Expand Foreign Labor Certification Fees	....	4	5	–40	–2	4	4	5	6	6	7	–29	–1
Department of the Treasury:													
Reduce paperwork burden by permanently authorizing current home to work transportation for the IRS Commissioner	....	....	....	....	....	....	....	....	....	....	....	....	....
Amend the Bank Merger Act to allow for the transition of Treasury-sponsored debit cards accounts	....	....	....	....	....	....	....	....	....	....	....	....	....
Fund the Federal Payment Levy Program via collections[2]	....	22	22	22	22	22	22	22	22	22	22	110	220
Department of Veterans Affairs:													
Modernize records management program	....	....	....	....	....	....	....	....	....	....	....	....	....
Extend authority for the Specially Adapted Housing Assistive Technology Grant Program	....	1	1	1	1	1	....	....	....	....	....	5	5
Extend authority for Specially Adapted Housing Temporary Residence Adaptation grant	....	1	1	1	1	1	1	1	1	1	1	5	10

Table S–6. Mandatory and Receipt Proposals—Continued

(Deficit increases (+) or decreases (–) in millions of dollars)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Totals 2023–2027	Totals 2023–2032
Environmental Protection Agency:													
Expand use of pesticide licensing user fees	....	2	2	2	2	1	1	1	....	....	....	9	11
General Services Administration:													
Establish and capitalize the Federal Capital Revolving Fund[4]	....	966	2,264	1,132	133	–133	83	–183	33	–47	–123	4,362	4,125
Expand the Disposal Fund authorities	....	1	1	1	1	1	1	1	1	1	1	5	10
International Assistance Programs:													
Fund renegotiated Compacts of Free Association[1]	....	....	....	....	....	....	....	....	....	....	....	....	....
National Aeronautics and Space Administration:													
Distribute the Science, Space, and Technology Education Trust Fund	....	16	....	....	....	....	....	....	....	....	....	16	16
Office of Personnel Management:													
Amend Administration of Tribal Federal Employees Health Benefits Program (FEHBP) Enrollment System	....	2	2	2	2	2	2	2	2	2	2	10	20
Expand Family Member Eligibility under the Federal Employees Dental and Vision Insurance Program (FEDVIP)	....	....	....	....	....	....	....	....	....	....	....	....	....
Expand FEDVIP to Tribal Employers	....	....	....	....	....	....	....	....	....	....	....	....	....
Expand FEHBP to Tribal Colleges and Universities	....	....	....	....	....	....	....	....	....	....	....	....	....
Small Business Administration:													
Support SBA COVID programs' oversight and servicing	....	....	....	....	....	....	....	....	....	....	....	....	....
Consumer Product Safety Commission:													
Strengthen mandatory recall authorities	....	....	....	....	....	....	....	....	....	....	....	....	....
Total, mandatory initiatives and savings	**–129**	**40,679**	**88,132**	**93,662**	**90,280**	**100,036**	**101,729**	**102,844**	**106,201**	**127,660**	**65,151**	**412,789**	**916,374**
Tax proposals:													
Reform business and international taxation:													
Raise the corporate income tax rate to 28 percent	....	–83,500	–138,893	–136,355	–134,942	–137,761	–139,987	–137,573	–135,244	–134,857	–135,448	–631,451	–1,314,560
Adopt the Undertaxed Profits Rule	....	....	–20,427	–33,464	–29,329	–26,655	–26,170	–25,638	–25,109	–25,665	–27,006	–109,875	–239,463
Provide tax incentives for locating jobs and business activity in the United States and remove tax deductions for shipping jobs overseas:													
Provide tax credit for inshoring jobs to the United States	....	8	13	14	14	15	16	16	17	18	18	64	149
Remove tax deductions for shipping jobs overseas	....	–8	–13	–14	–14	–15	–16	–16	–17	–18	–18	–64	–149
Subtotal, provide tax incentives for locating jobs and business activity in the United States and remove tax deductions for shipping jobs overseas	....	....	....	....	....	....	....	....	....	....	....	....	....
Prevent basis shifting by related parties through partnerships	....	–3,320	–5,676	–5,912	–6,153	–6,401	–6,621	–6,785	–6,887	–6,959	–7,025	–27,462	–61,739

Table S–6. Mandatory and Receipt Proposals—Continued

(Deficit increases (+) or decreases (–) in millions of dollars)

												Totals	
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2023–2027	2023–2032
Conform definition of "control" with corporate affiliation test	....	–761	–1,104	–1,125	–1,143	–1,158	–1,170	–1,179	–1,182	–1,182	–1,176	–5,291	–11,180
Expand access to retroactive qualified electing fund elections	....	....	–1	–2	–2	–3	–4	–5	–6	–7	–9	–8	–39
Expand the definition of foreign business entity to include taxable units	....	–300	–324	–290	–193	–89	–96	–103	–112	–120	–130	–1,196	–1,757
Subtotal, reform business and international taxation	....	–87,881	–166,425	–177,148	–171,762	–172,067	–174,048	–171,283	–168,540	–168,790	–170,794	–775,283	–1,628,738
Support housing and urban development:													
Make permanent the New Markets Tax Credit	....	....	....	....	97	278	483	716	990	1,290	1,602	375	5,456
Subtotal, support housing and urban development	....	....	....	....	97	278	483	716	990	1,290	1,602	375	5,456
Modify fossil fuel taxation:													
Eliminate fossil fuel tax preferences:													
Repeal the enhanced oil recovery credit	....	....	....	–31	–80	–130	–186	–237	–271	–301	–330	–241	–1,566
Repeal the deduction for costs paid or incurred for any tertiary injectant used as part of tertiary recovery method [5]	....	....	....	....	....	....	....	....	....	....	....	....	....
Repeal credit for oil and gas produced from marginal wells	....	....	–3	–52	–144	–219	–265	–288	–301	–317	–333	–418	–1,922
Repeal expensing of intangible drilling costs	....	–1,508	–2,231	–1,806	–1,401	–847	–600	–597	–601	–590	–561	–7,793	–10,742
Repeal exception to passive loss limitation provided to working interests in oil and natural gas properties	....	–10	–9	–9	–9	–8	–8	–8	–8	–7	–7	–45	–83
Repeal the use of percentage depletion with respect to oil and natural gas wells	....	–925	–1,037	–1,085	–1,178	–1,267	–1,351	–1,433	–1,510	–1,579	–1,649	–5,492	–13,014
Increase geological and geophysical amortization period for independent producers	....	–631	–831	–930	–1,008	–1,045	–1,086	–1,128	–1,158	–1,193	–1,218	–4,445	–10,228
Repeal expensing of mine exploration and development costs	....	–131	–194	–156	–122	–74	–52	–52	–52	–50	–49	–677	–932
Repeal percentage depletion for hard mineral fossil fuels	....	–163	–183	–191	–208	–224	–239	–253	–267	–279	–291	–969	–2,298
Repeal capital gains treatment for royalties	....	–27	–52	–54	–57	–62	–64	–66	–69	–71	–73	–252	–595
Repeal the exemption from the corporate income tax for fossil fuel publicly traded partnerships	....	....	....	....	....	....	–90	–176	–216	–253	–288	....	–1,023
Eliminate the Oil Spill Liability Trust Fund (OSLTF) excise tax exemption for crude oil derived from bitumen and kerogen-rich rock	....	–29	–38	–39	–40	–41	–41	–42	–43	–45	–46	–187	–404
Repeal accelerated amortization of air pollution control equipment	....	–14	–34	–54	–71	–88	–103	–117	–115	–103	–92	–261	–791
Subtotal, eliminate fossil fuel tax preferences	....	–3,438	–4,612	–4,407	–4,318	–4,005	–4,085	–4,397	–4,611	–4,788	–4,937	–20,780	–43,598
Modify OSLTF financing and Superfund excise taxes:													
Eliminate the tax exemption for crude oil from bitumen and kerogen-rich rock for the Superfund	....	–64	–85	–87	–88	–88	–89	–90	–92	–95	–95	–412	–873
Eliminate drawback for the OSLTF	....	–53	–70	–71	–72	–72	–72	–72	–72	–72	–72	–338	–698
Subtotal, modify OSLTF financing and Superfund excise taxes	....	–117	–155	–158	–160	–160	–161	–162	–164	–167	–167	–750	–1,571
Subtotal, modify fossil fuel taxation	....	–3,555	–4,767	–4,565	–4,478	–4,165	–4,246	–4,559	–4,775	–4,955	–5,104	–21,530	–45,169

Table S–6. Mandatory and Receipt Proposals—Continued

(Deficit increases (+) or decreases (–) in millions of dollars)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Totals	
												2023–2027	2023–2032
Strengthen taxation of high-income taxpayers:													
Increase the top marginal income tax rate for high earners	–5,861	–23,895	–39,877	–46,351	–19,648	–7,909	–8,573	–9,153	–9,796	–10,451	–11,156	–137,680	–186,809
Reform the taxation of capital income	–263	–5,464	–15,229	–17,487	–17,979	–17,969	–18,452	–19,224	–20,025	–20,885	–21,774	–74,128	–174,488
Impose a minimum income tax on the wealthiest taxpayers	....	....	–36,115	–40,478	–42,662	–43,395	–43,053	–42,591	–38,087	–36,047	–38,415	–162,650	–360,843
Subtotal, strengthen taxation of high-income taxpayers	–6,124	–29,359	–91,221	–104,316	–80,289	–69,273	–70,078	–70,968	–67,908	–67,383	–71,345	–374,458	–722,140
Support families and students:													
Provide income exclusion for student debt relief [6]	....	....	....	....	2	17	41	266	292	320	351	19	1,289
Subtotal, support families and students	....	....	....	....	2	17	41	266	292	320	351	19	1,289
Modify estate and gift taxation:													
Modify income, estate, and gift tax rules for certain grantor trusts	....	–452	–1,699	–2,405	–2,349	–3,950	–4,949	–5,504	–6,049	–6,912	–7,261	–10,855	–41,530
Require consistent valuation of promissory notes	....	–342	–716	–747	–697	–695	–658	–649	–637	–619	–601	–3,197	–6,361
Improve tax administration for trusts and decedents' estates	....	15	23	24	25	30	34	38	43	45	49	117	326
Limit duration of generation-skipping transfer tax exemption	....	....	....	....	....	....	....	....	....	....	....	....	....
Subtotal, modify estate and gift taxation	....	–779	–2,392	–3,128	–3,021	–4,615	–5,573	–6,115	–6,643	–7,486	–7,813	–13,935	–47,565
Close loopholes:													
Tax carried (profits) interests as ordinary income	....	–406	–677	–675	–674	–672	–679	–692	–706	–720	–735	–3,104	–6,636
Repeal deferral of gain from like-kind exchanges	....	–676	–1,857	–1,914	–1,971	–2,030	–2,091	–2,154	–2,218	–2,285	–2,354	–8,448	–19,550
Require 100 percent recapture of depreciation deductions as ordinary income for certain depreciable real property	....	–35	–113	–233	–364	–505	–657	–821	–1,000	–1,192	–1,400	–1,250	–6,320
Limit a partner's deduction in certain syndicated conservation easement transactions	....	–925	–4,689	–2,739	–2,114	–1,488	–1,261	–1,299	–1,337	–1,377	–1,419	–11,955	–18,648
Limit use of donor advised funds to avoid private foundation payout requirement	....	–16	–15	–10	–6	–3	–2	–3	–3	–3	–3	–50	–64
Extend the period for assessment of tax for certain Qualified Opportunity Fund investors	....	–4	–13	–15	–15	–13	–10	–9	–8	–6	–2	–60	–95
Establish an untaxed income account regime for certain small insurance companies	....	–908	–2,241	–1,017	–865	–795	–764	–757	–748	–739	–730	–5,826	–9,564
Expand pro rata interest expense disallowance for business-owned life insurance	....	–530	–540	–582	–619	–665	–704	–739	–774	–812	–850	–2,936	–6,815
Correct drafting errors in the taxation of insurance companies under the Tax Cuts and Jobs Act of 2017	....	–86	–112	–116	–100	–75	–70	–63	–59	–55	–51	–489	–787
Define the term "ultimate purchaser" for purposes of diesel fuel exportation	....	–4	–6	–9	–10	–13	–14	–17	–20	–22	–24	–42	–139
Subtotal, close loopholes	....	–3,590	–10,263	–7,310	–6,738	–6,259	–6,252	–6,554	–6,873	–7,211	–7,568	–34,160	–68,618
Improve tax administration and compliance:													
Enhance accuracy of tax information:													

Table S–6. Mandatory and Receipt Proposals—Continued

(Deficit increases (+) or decreases (–) in millions of dollars)

												Totals	
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2023–2027	2023–2032
Expand the Secretary's authority to require electroning filing for forms and returns	....	....	....	....	....	....	....	....	....	....	....	....	....
Improve information reporting for reportable payments subject to backup withholding	....	–38	–87	–148	–202	–211	–221	–231	–241	–252	–276	–686	–1,907
Subtotal, enhance accuracy of tax information	....	–38	–87	–148	–202	–211	–221	–231	–241	–252	–276	–686	–1,907
Address taxpayer noncompliance with listed transactions:													
Extend statute of limitations for listed transactions	....	–23	–51	–64	–78	–76	–74	–73	–72	–70	–69	–292	–650
Impose liability on shareholders to collect unpaid income taxes of applicable corporations	....	–430	–448	–466	–485	–505	–525	–548	–571	–596	–622	–2,334	–5,196
Subtotal, address taxpayer noncompliance	....	–453	–499	–530	–563	–581	–599	–621	–643	–666	–691	–2,626	–5,846
Amend the centralized partnership audit regime to permit the carryover of a reduction in tax that exceeds a partner's tax liability	....	5	5	5	5	6	6	7	7	7	7	26	60
Incorporate Chapters 2/2A in centralized partnership audit regime proceedings	....	....	....	....	....	....	....	....	....	....	....	....	....
Authorize limited sharing of business tax return information to measure the economy more accurately	....	....	....	....	....	....	....	....	....	....	....	....	....
Require employers to withhold tax on failed nonqualified deferred compensation plans	....	–555	–580	–605	–631	–658	–687	–718	–752	–787	–824	–3,029	–6,797
Impose an affirmative requirement to disclose a position contrary to a regulation	....	–5	–7	–11	–11	–12	–12	–14	–14	–15	–15	–46	–116
Extend to six years the statute of limitations for certain tax assessments	....	....	....	....	....	....	....	....	....	....	....	....	....
Expand and increase penalties for noncompliant return preparation and e-filing and authorize IRS oversight of paid preparers:													
Expand and increase penalties for noncompliant return preparation and e-filing [6]	....	–14	–31	–38	–45	–51	–53	–55	–58	–60	–63	–179	–468
Grant authority to IRS for oversight of all paid preparers [6]	....	–25	–34	–45	–51	–50	–54	–58	–64	–70	–76	–205	–527
Subtotal, expand and increase penalties for noncompliant return preparation and e-filing and authorize IRS oversight of paid preparers	....	–39	–65	–83	–96	–101	–107	–113	–122	–130	–139	–384	–995
Address compliance in connection with tax responsibilities of expatriates	....	....	–1	–1	–1	–1	–1	–2	–2	–2	–2	–4	–13
Simplify foreign exchange gain or loss rules and exchange rate rules for individuals	....	1	2	2	2	3	3	3	3	3	3	10	25
Increase threshold for simplified foreign tax credit rules and reporting	....	14	25	27	29	31	31	32	32	32	34	126	287
Subtotal, improve tax administration and compliance	....	–1,070	–1,207	–1,344	–1,468	–1,524	–1,587	–1,657	–1,732	–1,810	–1,903	–6,613	–15,302

Table S–6. Mandatory and Receipt Proposals—Continued

(Deficit increases (+) or decreases (–) in millions of dollars)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Totals 2023–2027	Totals 2023–2032
Modernize rules, including those for digital assets:													
Modernize rules treating loans of securities as tax-free to include other asset classes and address income inclusion	....	....	....	....	....	....	....	....	....	....	....	....	....
Provide for information reporting by certain financial institutions and digital asset brokers for purposes of exchange of information	....	–48	–95	–179	–209	–222	–237	–251	–267	–287	–303	–753	–2,098
Require reporting by certain taxpayers of foreign digital asset accounts	....	–50	–100	–188	–220	–234	–250	–264	–282	–302	–319	–792	–2,209
Amend the mark-to-market rules to include digital assets	....	–4,846	–133	–146	–161	–177	–194	–214	–235	–259	–284	–5,463	–6,649
Subtotal, modernize rules, including those for digital assets	....	–4,944	–328	–513	–590	–633	–681	–729	–784	–848	–906	–7,008	–10,956
Improve benefits tax administration:													
Clarify tax treatment of fixed indemnity health policies	....	....	....	....	....	....	....	....	....	....	....	....	....
Clarify tax treatment of on-demand pay arrangements	....	....	....	....	....	....	....	....	....	....	....	....	....
Rationalize funding for post-retirement medical and life insurance benefits	....	....	....	....	....	....	....	....	....	....	....	....	....
Subtotal, improve benefits tax administration	....	....	....	....	....	....	....	....	....	....	....	....	....
Total, receipt proposals	**–6,124**	**–131,178**	**–276,603**	**–298,324**	**–268,247**	**–258,241**	**–261,941**	**–260,883**	**–255,973**	**–256,873**	**–263,480**	**–1,232,593**	**–2,531,743**
Grand total, mandatory and receipt proposals	**–6,253**	**–90,499**	**–188,471**	**–204,662**	**–177,967**	**–158,205**	**–160,212**	**–158,039**	**–149,772**	**–129,213**	**–198,329**	**–819,804**	**–1,615,369**

[1] Estimates were not available at the time of Budget publication.

[2] The estimates for this proposal include effects on receipts. The receipt effects included in the totals above are as follows:

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Totals 2023–2027	Totals 2023–2032
Improve access to behavioral healthcare in the private insurance market	....	1,435	1,991	2,089	2,305	2,449	2,564	2,683	2,812	2,948	3,093	10,269	24,369
Require coverage of three primary care visits and three behavioral health visits without cost-sharing	....	916	1,271	1,335	1,490	1,585	1,657	1,738	1,822	1,909	2,005	6,597	15,728
Allow selective basis boosts for bond-financed Low-Income Housing Credit projects	....	2	29	140	354	617	895	1,148	1,359	1,561	1,769	1,142	7,874
Make adoption tax credit refundable and allow certain guardianship arrangements to qualify	....	11	42	42	42	42	42	42	42	42	42	179	389
Capture savings to UI from RESEA allocation adjustment	....	....	24	62	115	158	195	225	250	–12	–54	359	963
Establish user fee for Electronic Visa Update System	....	–47	–52	–58	–64	–72	–79	–88	–108	–118	–130	–293	–816
Fund the Federal Payment Levy Program via collections	....	22	22	22	22	22	22	22	22	22	22	110	220
Total, receipt effects of mandatory proposals	....	2,339	3,327	3,632	4,264	4,801	5,296	5,770	6,199	6,352	6,747	18,363	48,727

[3] Represents the savings associated with continuing to provide dedicated funding, through a discretionary allocation adjustment, for program integrity activities to confirm program participants remain eligible to receive benefits.

[4] This proposal includes an intragovernmental transfer between the Federal Capital Revolving Fund (FCRF) and the Federal Building Fund (FBF). The collections and spending in the FBF, the receiving account, are not counted for PAYGO purposes because the proposal expects the PAYGO cost to be recorded in the FCRF. The intragovernmental transfers net to zero and are as follows:

Table S–6. Mandatory and Receipt Proposals—Continued

(Deficit increases (+) or decreases (–) in millions of dollars)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Totals 2023–2027	Totals 2023–2032
Establish and capitalize the Federal Capital Revolving Fund	....	–1,004	104	217	321	259	103	....	....	....	....	....	....

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[5] Effects are included in the estimate of "Repeal the enhanced oil recovery credit."

[6] The estimates for this proposal includes effects on outlays. The outlay effects included in the totals above are as follows:

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2023–2027	2023–2032
Provide income exclusion for student debt relief	....	....	....	....	....	1	1	21	24	27	29	1	103
Expand and increase penalties for noncompliant return preparation and e-filing	....	....	–6	–6	–6	–7	–7	–7	–8	–8	–8	–25	–63
Grant authority to IRS for oversight of all paid preparers	....	–12	–14	–21	–23	–19	–20	–21	–23	–25	–27	–89	–205
Total, outlay effects of receipt proposals	....	–12	–20	–27	–29	–25	–26	–7	–7	–6	–6	–113	–165

Table S–7. Funding Levels for Appropriated (“Discretionary”) Programs by Category

(Budget authority in billions of dollars)

	Actual[1]	CR[2]	CAA[3]	Request	Outyears									Totals	
	2021	2022	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2023-2027	2023-2032
Base Discretionary Funding Allocation	**1,374**	**1,393**	**1,473**	**1,582**	**1,643**	**1,670**	**1,703**	**1,728**	**1,754**	**1,780**	**1,807**	**1,834**	**1,862**	**8,326**	**17,362**
Non-Defense Shifts to Mandatory[4]	....	....	....	**–10**	**–10**	**–10**	**–10**	**–10**	**–11**	**–11**	**–11**	**–11**	**–12**	**–50**	**–106**
Bureau of Indian Affairs	....	....	....	–*	–*	–*	–*	–1	–1	–1	–1	–1	–1	–2	–5
Indian Health Service	....	....	....	–9	–9	–10	–10	–10	–10	–10	–11	–11	–11	–48	–101
Non-Base Discretionary Funding (not included above):[5]															
Emergency and COVID–19 Supplemental Funding	198	45	58	....	....	....	....	....	....	....	....	....	....	....	....
Program Integrity	2	2	2	2	3	3	3	3	3	3	3	3	3	13	29
Disaster Relief	17	17	19	20	11	11	11	11	11	11	11	11	11	64	119
Wildfire Suppression	2	2	2	3	3	3	3	3	3	3	3	3	3	13	26
21st Century Cures Appropriations	*	*	1	1	*	*	*	....	....	....	....	....	....	2	2
Total, Non-Base Funding	**220**	**67**	**82**	**26**	**17**	**16**	**17**	**16**	**17**	**17**	**17**	**17**	**17**	**92**	**175**
Grand Total, Discretionary Budget Authority	**1,594**	**1,461**	**1,555**	**1,598**	**1,650**	**1,676**	**1,709**	**1,734**	**1,759**	**1,786**	**1,812**	**1,839**	**1,867**	**8,367**	**17,431**
Memorandum: Presentation of base discretionary by defense and non-defense[6]															
Defense Allocation[7]	*741*	*746*	*782*	*813*	*843*	*851*	*865*	*871*	*877*	*883*	*889*	*895*	*902*	*4,242*	*8,688*
Non-Defense Allocation	*544*	*551*	*594*	*650*	*665*	*680*	*696*	*712*	*728*	*745*	*762*	*780*	*797*	*3,402*	*7,215*
Veterans Affairs Medical Care Program	*90*	*96*	*97*	*119*	*136*	*139*	*142*	*145*	*149*	*152*	*156*	*159*	*163*	*681*	*1,459*
Memorandum: Presentation of base discretionary by security and nonsecurity[6]															
Security Allocation	*850*	*855*	*894*	*936*	*968*	*979*	*996*	*1,005*	*1,016*	*1,026*	*1,035*	*1,045*	*1,055*	*4,884*	*10,062*
Nonsecurity Allocation	*434*	*442*	*482*	*527*	*540*	*552*	*565*	*578*	*589*	*602*	*616*	*630*	*644*	*2,761*	*5,841*
Veterans Affairs Medical Care Program	*90*	*96*	*97*	*119*	*136*	*139*	*142*	*145*	*149*	*152*	*156*	*159*	*163*	*681*	*1,459*
Memorandum: Discretionary appropriations provided in the Infrastructure, Investment, and Jobs Act[8]	....	*174*	*N/A*	*69*	*69*	*68*	*66*	*2*	*2*	*2*	*2*	*2*	*2*	*273*	*283*

* Less than $500 million.

[1] The 2021 actual level includes changes that occur after appropriations are enacted that are part of budget execution such as transfers, reestimates, and the rebasing as mandatory any changes in mandatory programs (CHIMPs) enacted in appropriations bills. The 2021 levels are adjusted to add back OMB’s scoring of CHIMPs enacted in 2021 appropriations Acts for a better illustrative comparison with the 2023 request.

[2] At the time the 2023 Budget was prepared, 2022 appropriations remained incomplete and the 2022 column reflects at the account level annualized continuing appropriations provided under the Continuing Appropriations Act, 2022 (division A of Public Law 117-43, as amended by division A of Public Law 117-70, division A of Public Law 117-86, and Public Law 117-95; CR). The 2022 column also reflects enacted full-year emergency appropriations enacted in the Disaster Relief Supplemental Appropriations Act, 2022, the Afghanistan Supplemental Appropriations Act, 2022, and the Additional Afghanistan Supplemental Appropriations Act, 2022 (divisions B and C of Public Law 117-43 and division B of Public Law 117-70, respectively).

[3] The 2023 Budget was finalized before 2022 appropriations were completed. To allow a high-level comparison of the 2023 Budget with enacted appropriations, this column provides a preliminary summary of 2022 enacted appropriations in the Consolidated Appropriations Act, 2022 (Public Law 117-103; CAA), using the Congressional Budget Office (CBO) estimate of the legislation (see CBO estimate for H.R. 2471, the Consolidated Appropriations Act, 2022 on CBO’s website). CBO estimates of IIJA appropriations are not included since OMB includes its own estimate for 2022.

Table S–7. Funding Levels for Appropriated ("Discretionary") Programs by Category—Continued

(Budget authority in billions of dollars)

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[4] The 2023 Budget proposes to shift the Indian Health Service (IHS) in HHS as well as contract support costs and 105(l) leases within the Bureau of Indian Programs (BIA) in the Department of the Interior to the mandatory side of the Budget starting in 2023. See the "Budget Process" chapter of the *Analytical Perspectives* volume of the Budget for more information on these proposals.

[5] The 2023 Budget presents funding for anomalous or above-base activities such as emergency requirements, program integrity, disaster relief, wildfire suppression, and 21st Century Cures appropriations outside of base allocations, which is largely consistent with allocation adjustments in the FY 2022 Congressional Budget Resolution (H.Con.Res. 14).

[6] The section presents base discretionary funding by both defense and non-defense and by security and nonsecurity allocations. The definition of security and nonsecurity is the same as the definition specified in the Budget Control Act of 2011 with security including the Departments of Defense, Homeland Security, Veterans Affairs, the National Nuclear Security Administration, the International Budget Function (150), and the Intelligence Community Management Account and with all other discretionary programs in the nonsecurity category. This presentation of discretionary excludes the proposed shifts to mandatory.

[7] The amounts in the 2023 Budget are based on the forthcoming National Security and National Defense strategies and the Department of Defense Future Years Defense Program, which includes a five-year appropriations plan and estimated expenditures necessary to support the programs, projects, and activities of the Department of Defense. After 2027, the Budget mechanically extrapolates the growth rate from the final year of the five-year appropriations plan.

[8] Section 905(c) of division J of the Infrastructure Investment and Jobs Act (Public Law 117-58; IIJA) specified that amounts provided in division J and certain rescissions in section 90007 of IIJA should be considered as emergency discretionary appropriations. The amounts provided as discretionary appropriations in IIJA are summarized here, however, these amounts are kept separate from other discretionary amounts included above that are considered during the regular appropriations process.

Table S–8. 2023 Discretionary Request by Major Agency

(Budget authority in billions of dollars)

	2021	2022	2023	2023 Request Less 2021 Enacted	
	Actual[1]	CR[2]	Request	Dollar	Percent
Base Discretionary Funding:					
Cabinet Departments:					
Agriculture[3]	24.4	23.7	28.5	+4.2	+17.1%
Commerce	8.9	8.9	11.7	+2.8	+31.2%
Defense	703.7	709.2	773.0	+69.3	+9.8%
Education	73.0	73.0	88.3	+15.3	+20.9%
Energy (DOE)[4]	41.9	41.8	48.2	+6.3	+15.1%
Health and Human Services (HHS)[5]	108.6	110.4	138.0	+29.4	+27.1%
Proposed IHS Shift to Mandatory (non-add)[6]	*(6.5)*	*(6.6)*	*(9.1)*	*(+2.6)*	*N/A*
HHS, BA excluding IHS (non-add)	*(102.0)*	*(103.9)*	*(128.9)*	*(+26.9)*	*(+26.3%)*
Homeland Security (DHS)	53.8	52.7	56.7	+2.9	+5.4%
Housing and Urban Development (HUD):					
HUD program level	*59.6*	*60.3*	*71.9*	*+12.3*	*+20.5%*
HUD receipts	*–16.1*	*–13.1*	*–11.1*	*+5.0*	*N/A*
Interior (DOI)	14.9	15.1	17.9	+3.0	+20.5%
Proposed BIA Shift to Mandatory (non-add)[6]	*(0.2)*	*(0.4)*	*(0.5)*	*(+0.2)*	*N/A*
DOI, BA excluding BIA (non-add)	*(14.6)*	*(14.7)*	*(17.5)*	*(+2.8)*	*(+19.3%)*
Justice	33.5	33.6	37.7	+4.2	+12.5%
Labor	12.5	12.5	14.6	+2.2	+17.6%
State and International Programs[3, 7]	57.5	57.9	67.6	+10.2	+17.7%
Transportation (DOT)	25.3	25.5	26.8	+1.5	+6.0%
Treasury[7]	13.5	13.5	16.2	+2.7	+19.9%
Veterans Affairs	104.5	111.1	135.2	+30.7	+29.4%
Major Agencies:					
Corps of Engineers (Corps)	7.8	7.8	6.6	–1.2	–15.3%
Environmental Protection Agency	9.2	9.2	11.9	+2.6	+28.6%
General Services Administration	–0.9	–1.3	1.3	+2.2	N/A
National Aeronautics and Space Administration	23.3	23.3	26.0	+2.7	+11.6%
National Science Foundation	8.5	8.5	10.5	+2.0	+23.6%
Small Business Administration	0.8	0.8	0.9	+0.2	+21.0%
Social Security Administration[5]	9.0	8.9	10.1	+1.1	+12.8%
Other Agencies	23.3	23.3	28.1	+4.8	+20.7%
Changes in mandatory program offsets[8]	–26.0	–23.3	–34.7	–8.7	+33.5%
Subtotal, Base Discretionary Budget Authority (BA)	**1,374.2**	**1,393.5**	**1,582.0**	**+207.8**	**+15.1%**
Subtotal, BA excluding programs shifted to mandatory	*1,367.5*	*1,386.5*	*1,572.4*	*+205.0*	*+15.0%*

Table S–8. 2023 Discretionary Request by Major Agency—Continued

(Budget authority in billions of dollars)

	2021	2022	2023	2023 Request Less 2021 Enacted	
	Actual[1]	CR[2]	Request	Dollar	Percent
Non-Base Discretionary Funding:					
Emergency Requirements and COVID–19 Supplemental Funding:					
Agriculture	1.0	11.6	....	–1.0	N/A
Commerce	0.3	0.4	....	–0.3	N/A
Defense	1.0	7.4	....	–1.0	N/A
Education	81.6	....	....	–81.6	N/A
Energy	–2.3	0.0	....	+2.3	N/A
Health and Human Services	73.8	5.5	....	–73.8	N/A
Homeland Security	2.8	1.0	....	–2.8	N/A
Housing and Urban Development	0.7	5.0	....	–0.7	N/A
Interior	0.4	0.6	....	–0.4	N/A
Justice	0.6	0.1	....	–0.6	N/A
Labor	1.5	....	....	–1.5	N/A
State and International Programs	5.9	3.4	....	–5.9	N/A
Transportation	27.0	2.7	....	–27.0	N/A
Treasury	0.5	....	....	–0.5	N/A
Corps of Engineers (Corps)	....	5.7	....	....	N/A
Small Business Administration	2.0	1.2	....	–2.0	N/A
Other Agencies	0.9	0.4	....	–0.9	N/A
Subtotal, Emergency Requirements	197.8	45.1	....	–197.8	N/A
Program Integrity:					
Health and Human Services	0.5	0.5	0.6	+0.1	+16.1%
Labor	0.1	0.1	0.3	+0.2	+210.8%
Social Security Administration	1.3	1.3	1.5	+0.2	+16.1%
Subtotal, Program Integrity	1.9	1.9	2.3	+0.5	+24.7%
Disaster Relief:					
Homeland Security	17.1	17.1	19.7	+2.6	+15.2%
Small Business Administration	0.1	0.1	0.1	....	....
Subtotal, Disaster Relief	17.3	17.3	19.9	+2.6	+15.0%
Wildfire Suppression:					
Agriculture	2.0	2.0	2.2	+0.2	+8.3%
Interior	0.3	0.3	0.3	+*	+9.7%
Subtotal, Wildfire Suppression	2.4	2.4	2.6	+0.2	+8.5%
21st Century Cures appropriations:					
Health and Human Services	0.5	0.5	1.1	+0.7	+139.5%
Subtotal, Non-Base Discretionary Funding	**219.8**	**67.1**	**25.9**	**–193.9**	**–88.2%**

Table S–8. 2023 Discretionary Request by Major Agency—Continued

(Budget authority in billions of dollars)

	2021 Actual[1]	2022 CR[2]	2023 Request	2023 Request Less 2021 Enacted: Dollar	2023 Request Less 2021 Enacted: Percent
Total, Discretionary BA	**1,594.0**	**1,460.5**	**1,607.9**	**+13.9**	**+0.9%**
Total, BA excluding programs shifted to mandatory	*1,587.2*	*1,453.6*	*1,598.3*	*+11.1*	*+0.7%*

Memorandum - Comparison of 2022 Omnibus to 2023 Request:[9]	*2022 CAA*	*2023 Request*	*2023 Request Less 2022 CAA*	
Total, Base Discretionary Funding	*1,472.9*	*1,582.0*	*+109.0*	*+7.4%*
Base Discretionary by Defense and Non-Defense:				
Defense	*782.2*	*813.3*	*+31.2*	*+4.0%*
Non-Defense	*593.6*	*649.9*	*+56.3*	*+9.5%*
Veterans Affairs Medical Care Program	*97.2*	*118.7*	*+21.5*	*+22.2%*
Base Discretionary by Security and Nonsecurity:[10]				
Security	*894.2*	*935.9*	*+41.7*	*+4.7%*
Nonsecurity	*481.6*	*527.3*	*+45.8*	*+9.5%*
Veterans Affairs Medical Care Program	*97.2*	*118.7*	*+21.5*	*+22.2%*

* Less than $50 million.

[1] The 2021 actual level includes changes that occur after appropriations are enacted that are part of budget execution such as transfers, reestimates, and the rebasing as mandatory any changes in mandatory programs (CHIMPs) enacted in appropriations bills. The 2021 levels are adjusted to add back OMB's scoring of CHIMPs enacted in 2021 appropriations Acts for a better illustrative comparison with the 2023 request.

[2] At the time the 2023 Budget was prepared, 2022 appropriations remained incomplete and the 2022 column reflects at the account level annualized continuing appropriations provided under the Continuing Appropriations Act, 2022 (division A of Public Law 117–43, as amended by division A of Public Law 117–70, division A of Public Law 117–86, and Public Law 117–95; CR). The 2022 column also reflects enacted full-year emergency appropriations enacted in the Disaster Relief Supplemental Appropriations Act, 2022, the Afghanistan Supplemental Appropriations Act, 2022, and the Additional Afghanistan Supplemental Appropriations Act, 2022 (divisions B and C of Public Law 117–43 and division B of Public Law 117–70, respectively).

[3] Funding for Food for Peace Title II Grants is included in the State and International Programs total. Although the funds are appropriated to the Department of Agriculture, the funds are administered by the U.S. Agency for International Development (USAID).

[4] The Department of Energy base total in 2021 includes an appropriation of $2.3 billion that had been designated as emergency in Public Law 116–260 since the activities were for regular operations and not emergency purposes.

[5] Funding from the Hospital Insurance and Supplementary Medical Insurance trust funds for administrative expenses incurred by the Social Security Administration that support the Medicare program are included in the Health and Human Services total and not in the Social Security Administration total.

[6] The 2023 Budget proposes to shift the Indian Health Service (IHS) in HHS as well as contract support costs and 105(l) leases within the Bureau of Indian Programs (BIA) in DOI to the mandatory side of the Budget starting in 2023. See the "Budget Process" chapter of the *Analytical Perspectives* volume of the Budget for more information on these proposals.

[7] The State and International Programs total includes funding for the Department of State, USAID, Treasury International, and 11 international agencies while the Treasury total excludes Treasury's International Programs.

[8] The limitation enacted and proposed in the Justice Department's Crime Victims Fund program and cancellations in the Children's Health Insurance Program in HHS make up the bulk of these offsets.

[9] The 2023 Budget was finalized before 2022 appropriations were completed. To allow a high-level comparison of the 2023 Budget with enacted appropriations, this memorandum section provides a preliminary summary of 2022 enacted base appropriations in the Consolidated Appropriations Act, 2022 (Public Law 117–103; CAA), using the Congressional Budget Office (CBO) estimate of the legislation (see CBO estimate for H.R. 2471, the Consolidated Appropriations Act, 2022 on CBO's website). This presentation of discretionary excludes the proposed shifts to mandatory.

[10] The definition of security and nonsecurity is the same as the definition specified in the Budget Control Act of 2011 with security including the Departments of Defense, Homeland Security, Veterans Affairs, the National Nuclear Security Administration, the International Budget Function (150), and the Intelligence Community Management Account and with all other discretionary programs in the nonsecurity category.

Table S–9. Economic Assumptions[1]

(Calendar years)

	Actual	Projections											
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Domestic Product (GDP):													
Nominal level, billions of dollars	20,894	22,899	24,631	25,853	26,966	28,064	29,200	30,380	31,626	32,957	34,382	35,877	37,437
Percent change, nominal GDP, year/year	–2.2	9.6	7.6	5.0	4.3	4.1	4.0	4.0	4.1	4.2	4.3	4.3	4.3
Real GDP, percent change, year/year	–3.4	5.5	4.2	2.8	2.2	2.0	2.0	2.0	2.1	2.2	2.3	2.3	2.3
Real GDP, percent change, Q4/Q4	–2.3	5.1	3.8	2.5	2.1	2.0	2.0	2.0	2.1	2.2	2.3	2.3	2.3
GDP chained price index, percent change, year/year	1.3	3.9	3.3	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Consumer Price Index,[2] percent change, year/year	1.2	4.6	4.7	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Interest rates, percent:[3]													
91-day Treasury bills[4]	0.4	*	0.2	0.9	1.6	1.9	2.1	2.2	2.3	2.3	2.3	2.3	2.3
10-year Treasury notes	0.9	1.5	2.1	2.5	2.7	2.8	3.0	3.1	3.1	3.2	3.2	3.2	3.3
Unemployment rate, civilian, percent[3]	8.1	5.4	3.9	3.6	3.7	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8

* 0.05 percent or less

Note: A more detailed table of economic assumptions appears in Chapter 2, “Economic Assumptions and Overview,” in the *Analytical Perspectives* volume of the Budget.

[1] The Administration’s forecast was finalized on November 10, 2021.

[2] Seasonally adjusted CPI for all urban consumers.

[3] Annual average.

[4] Average rate, secondary market (bank discount basis).

Table S–10. Federal Government Financing and Debt

(Dollar amounts in billions)

	Actual	Estimate										
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Financing:												
Unified budget deficit:												
Primary deficit	2,423	1,058	758	724	766	680	622	725	565	667	663	692
Net interest	352	357	396	476	564	648	729	808	879	948	1,019	1,092
Unified budget deficit	2,775	1,415	1,154	1,201	1,330	1,328	1,352	1,533	1,443	1,614	1,682	1,784
As a percent of GDP	12.4%	5.8%	4.5%	4.5%	4.8%	4.6%	4.5%	4.9%	4.4%	4.7%	4.7%	4.8%
Other transactions affecting borrowing from the public:												
Changes in financial assets and liabilities:[1]												
Change in Treasury operating cash balance	–1,567	535	....	....	....	....	....	....	....	....	....	....
Net disbursements of credit financing accounts:												
Direct loan and Troubled Asset Relief Program (TARP) equity purchase accounts	–18	147	42	32	38	11	24	19	19	17	20	27
Guaranteed loan accounts	310	219	3	7	8	7	6	6	5	5	5	5
Net purchases of non-Federal securities by the National Railroad Retirement Investment Trust (NRRIT)	4	–1	–2	–2	–2	–2	–1	–1	–2	–2	–1	–1
Net change in other financial assets and liabilities[2]	–237	238	....	....	....	....	....	....	....	....	....	....
Subtotal, changes in financial assets and liabilities	–1,508	1,138	44	37	44	17	28	23	22	20	23	31
Seigniorage on coins	–*	–*	–1	–1	–1	–1	–1	–1	–1	–1	–1	–1
Total, other transactions affecting borrowing from the public	–1,508	1,137	43	37	43	16	28	23	22	20	23	30
Total, requirement to borrow from the public (equals change in debt held by the public)	1,267	2,552	1,197	1,237	1,373	1,344	1,380	1,555	1,465	1,634	1,705	1,815
Changes in Debt Subject to Statutory Limitation:												
Change in debt held by the public	1,267	2,552	1,197	1,237	1,373	1,344	1,380	1,555	1,465	1,634	1,705	1,815
Change in debt held by Government accounts	216	354	104	136	29	13	–146	–252	–148	–282	–281	–374
Change in other factors	–2	1	1	1	–*	*	1	1	*	–1	–1	–1
Total, change in debt subject to statutory limitation	1,481	2,907	1,302	1,374	1,402	1,358	1,235	1,304	1,317	1,352	1,423	1,440
Debt Subject to Statutory Limitation, End of Year:												
Debt issued by Treasury	28,365	31,271	32,572	33,945	35,347	36,704	37,938	39,241	40,558	41,909	43,332	44,772
Adjustment for discount, premium, and coverage[3]	36	38	39	40	40	40	41	42	43	43	43	43
Total, debt subject to statutory limitation[4]	28,401	31,309	32,611	33,984	35,386	36,744	37,979	39,283	40,600	41,952	43,374	44,814
Debt Outstanding, End of Year:												
Gross Federal debt:[5]												
Debt issued by Treasury	28,365	31,271	32,572	33,945	35,347	36,704	37,938	39,241	40,558	41,909	43,332	44,772
Debt issued by other agencies	21	21	21	21	22	22	22	22	22	23	24	25
Total, gross Federal debt	28,386	31,292	32,593	33,966	35,368	36,726	37,960	39,263	40,580	41,933	43,356	44,797
As a percent of GDP	127.0%	129.0%	127.5%	127.2%	127.3%	127.0%	126.2%	125.4%	124.4%	123.3%	122.1%	120.9%

Table S–10. Federal Government Financing and Debt—Continued

(Dollar amounts in billions)

	Actual	Estimate										
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Held by:												
Debt held by Government accounts	6,102	6,456	6,560	6,695	6,725	6,738	6,592	6,340	6,192	5,911	5,629	5,256
Debt held by the public[6]	22,284	24,836	26,033	27,271	28,644	29,988	31,368	32,923	34,388	36,022	37,727	39,542
As a percent of GDP	99.7%	102.4%	101.8%	102.2%	103.1%	103.7%	104.3%	105.2%	105.4%	105.9%	106.3%	106.7%
Debt Held by the Public Net of Financial Assets:												
Debt held by the public	22,284	24,836	26,033	27,271	28,644	29,988	31,368	32,923	34,388	36,022	37,727	39,542
Less financial assets net of liabilities:												
Treasury operating cash balance	215	750	750	750	750	750	750	750	750	750	750	750
Credit financing account balances:												
Direct loan and TARP equity purchase accounts	1,595	1,742	1,784	1,816	1,854	1,865	1,889	1,908	1,926	1,943	1,963	1,990
Guaranteed loan accounts	–156	63	66	72	80	87	93	99	105	110	115	120
Government-sponsored enterprise stock[7]	221	221	221	221	221	221	221	221	221	221	221	221
Air carrier worker support warrants and notes[8]	15	15	15	15	14	13	13	12	12	6	....	....
Emergency capital investment fund securities	....	3	3	3	3	3	3	3	3	3	2	2
Non-Federal securities held by NRRIT	28	26	25	23	22	20	19	17	16	14	13	11
Other assets net of liabilities	–307	–69	–69	–69	–69	–69	–69	–69	–69	–69	–69	–69
Total, financial assets net of liabilities	1,611	2,751	2,795	2,832	2,875	2,891	2,919	2,941	2,963	2,977	2,994	3,025
Debt held by the public net of financial assets	20,673	22,085	23,238	24,439	25,769	27,097	28,449	29,982	31,425	33,045	34,732	36,516
As a percent of GDP	92.5%	91.0%	90.9%	91.6%	92.7%	93.7%	94.6%	95.8%	96.4%	97.1%	97.8%	98.6%

* $500 million or less.

[1] A decrease in the Treasury operating cash balance (which is an asset) is a means of financing a deficit and therefore has a negative sign. An increase in checks outstanding (which is a liability) is also a means of financing a deficit and therefore also has a negative sign. More information on the levels and changes to the operating cash balance is available in Chapter 4, “Federal Borrowing and Debt” in the *Analytical Perspectives* volume of the Budget.

[2] Includes checks outstanding, accrued interest payable on Treasury debt, uninvested deposit fund balances, allocations of special drawing rights, and other liability accounts; and, as an offset, cash and monetary assets (other than the Treasury operating cash balance), other asset accounts, and profit on sale of gold.

[3] Consists mainly of debt issued by the Federal Financing Bank (which is not subject to limit), the unamortized discount (less premium) on public issues of Treasury notes and bonds (other than zero-coupon bonds), and the unrealized discount on Government account series securities.

[4] The statutory debt limit is $31,381 billion, as enacted on December 16, 2021.

[5] Treasury securities held by the public and zero-coupon bonds held by Government accounts are almost all measured at sales price plus amortized discount or less amortized premium. Agency debt securities are almost all measured at face value. Treasury securities in the Government account series are otherwise measured at face value less unrealized discount (if any).

[6] At the end of 2021, the Federal Reserve Banks held $5,433.2 billion of Federal securities and the rest of the public held $16,850.9 billion. Debt held by the Federal Reserve Banks is not estimated for future years.

[7] Treasury’s warrants to purchase 79.9 percent of the common stock of the enterprises expire after September 7, 2028. The warrants were valued at $5 billion at the end of 2021.

[8] Portions of the notes and warrants issued under the Air carrier worker support program (Payroll support program) are scheduled to expire in 2025, 2026, 2030, and 2031.

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COVID Omicron Variant Confuses Outlook, Especially Accompanied by High Inflation

Over the Thanksgiving holiday, a new variant of the COVID virus was reported, especially in South Africa and Botswana. South African doctors indicate that it has very mild symptoms, so that people can generally be treated at home. The World Health Organization has designated this as the "Omicron" variant and describes it as a "variant of concern." So far, at this writing, no cases have been reported in the United States, although there are some nearby in Canada.

Holiday Period Generates Erratic Financial Market Moves, then Fed Chair Powel Testifies. The first reports of this variant set off strong movements in financial markets on Friday, November 26, the day after Thanksgiving. Because of the post-holiday atmosphere, trading volume was light, which meant that price movements may have been exaggerated. Erratic movements in Treasury rates and other fixed-income sectors continued. Then on November 30th, Federal Reserve Chairman Powell testified before a Congressional committee and suggested that the current high inflation might prompt the Fed to quicken the pace of its bond-purchase "tapering."

The Blue Chip Financial Forecasts survey for December was taken on November 22 and 23, that is, the Monday and Tuesday before Thanksgiving. During the subsequent market whipsaws, no participants have asked to alter their forecasts. This likely stands to reason in light of the absence of comprehensive and definitive information about the Omicron variant and the fact that, as of November 29, it has not spread within the United States.

The forecasts as submitted continue to reflect the current strong inflationary environment, exacerbated by the continuing supply-chain issues. Some of the latter are starting to ease, for instance, as container ships are now being charged fees if they leave containers on docks in California.

Growth Expected to Improve, Inflation to Moderate. The Blue Chip panel's projections for GDP growth envision a rebound this quarter to a 5.1% seasonally adjusted annual rate from the meager 2.1% in Q3. In early 2022, Q1 would see 4.4% and Q2 3.8% with the following three quarters averaging 2.8%. While inflation is expected to remain undesirably strong this quarter and next, the panel believes that it would moderate later in 2022, staying just slightly higher than in last month's forecast. The personal consumption expenditure price index rose at a 5.3% annualized pace in Q3 and the Blue Chip panel estimates it at 4.5% this quarter. In 2022, it would moderate from 2.9% in Q1 to 2.3% in Q4; the result for the year would be 2.5%, compared to 2.4% in the November forecast.

The panel's interest rate forecasts indicate that the higher-than-expected inflation might, as Fed Chair Powell hinted in his testimony, encourage the Fed to raise the federal funds rate somewhat earlier than they have been expecting. So the December forecast expects that the rate would start to climb in Q3 2022 rather than Q4. By Q1 2023, the rate would be 0.6%, compared with 0.4% in the November forecast. The 10-year Treasury rate would be 2.2% by that early 2023 period, the same as projected in the November forecast. The Blue Chip panel thus see the earlier Fed actions as perhaps reducing market concerns sufficiently to keep investors comfortable.

Long-term Federal Funds Rate Just Above 2%. This month's survey also includes the semi-annual long-term projections. GDP growth in 2023 is projected at 2.6% and then easing to 2.0% by 2026. This is just 0.1% below the projections for 2028-2032 made at the end of May. Inflation, measured by the personal consumption expenditure price index, would be 2.5% in 2023 and then ease to 2.1% across the rest of the forecast horizon. The 2% long-term growth rate would be associated with a federal funds rate edging up to 2.2% by 2026 and hovering near there after that. The 10-year Treasury yield would be 3.2% by mid-decade.

+ + + + +

SOFR Forecast Preview

Here are the Consensus forecasts for 3-month LIBOR and for the Secured Overnight Financing Rate, i.e., SOFR. As we have explained in the last couple of months, the LIBOR rates will be discontinued starting in January and for representations of short-term private sector borrowing rates, markets will focus on SOFR. Thus, beginning in the January edition of the Blue Chip Financial Forecasts, we will include SOFR in the regular forecast tables and show the forecasts of individual survey participants, not just the consensus average.

We clearly invite questions from forecast participants and subscribers to the publication. Meantime, readers can refer to this link from the New York Federal Reserve Bank, which is the official source of the daily SOFR rates.

	LIBOR 3-Month	Secured Overnight Financing Rate (SOFR)
Q1 2021	0.20	0.04
Q2 2021	0.16	0.02
Q3 2021	0.13	0.05
Q4 2021	0.18	0.06
Q1 2022	0.21	0.07
Q2 2022	0.26	0.09
Q3 2022	0.37	0.18
Q4 2022	0.57	0.36
Q1 2023	0.73	0.48

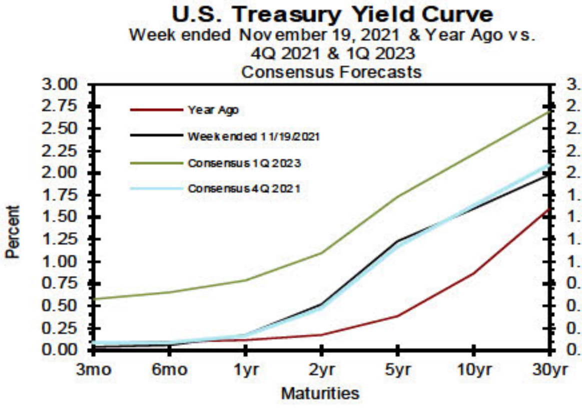
Carol Stone, CBE (Haver Analytics, New York, NY)

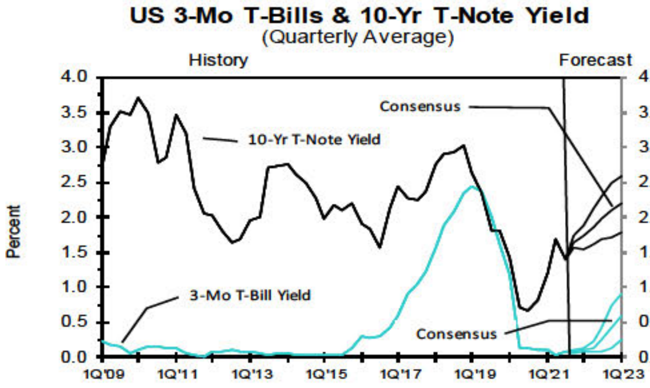
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

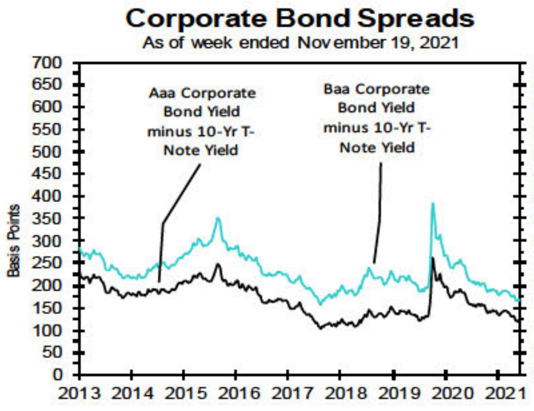
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	4Q	1Q	2Q	3Q	4Q	1Q
Interest Rates	Nov 19	Nov 12	Nov 5	Oct 29	Oct	Sep	Aug	3Q 2021	**2021**	**2022**	**2022**	**2022**	**2022**	**2023**
Federal Funds Rate	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	**0.1**	**0.1**	**0.1**	**0.3**	**0.4**	**0.6**
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	**3.3**	**3.3**	**3.3**	**3.4**	**3.5**	**3.7**
LIBOR, 3-mo.	0.16	0.15	0.14	0.13	0.13	0.12	0.12	0.13	**0.2**	**0.2**	**0.3**	**0.4**	**0.6**	**0.7**
Commercial Paper, 1-mo.	0.06	0.05	0.07	0.06	0.05	0.05	0.05	0.05	**0.1**	**0.1**	**0.2**	**0.3**	**0.5**	**0.6**
Treasury bill, 3-mo.	0.05	0.05	0.05	0.06	0.05	0.04	0.05	0.05	**0.1**	**0.1**	**0.1**	**0.2**	**0.4**	**0.6**
Treasury bill, 6-mo.	0.06	0.07	0.07	0.06	0.06	0.05	0.06	0.05	**0.1**	**0.1**	**0.2**	**0.3**	**0.5**	**0.7**
Treasury bill, 1 yr.	0.18	0.16	0.15	0.14	0.11	0.08	0.07	0.08	**0.2**	**0.2**	**0.3**	**0.4**	**0.6**	**0.8**
Treasury note, 2 yr.	0.53	0.48	0.45	0.48	0.39	0.24	0.22	0.23	**0.5**	**0.6**	**0.7**	**0.8**	**1.0**	**1.1**
Treasury note, 5 yr.	1.24	1.17	1.14	1.18	1.11	0.86	0.77	0.80	**1.2**	**1.3**	**1.4**	**1.5**	**1.6**	**1.7**
Treasury note, 10 yr.	1.60	1.53	1.54	1.59	1.58	1.37	1.28	1.32	**1.6**	**1.7**	**1.9**	**2.0**	**2.1**	**2.2**
Treasury note, 30 yr.	1.98	1.90	1.95	2.00	2.06	1.94	1.92	1.93	**2.1**	**2.2**	**2.3**	**2.5**	**2.6**	**2.7**
Corporate Aaa bond	2.82	2.72	2.77	2.80	2.85	2.72	2.72	2.72	**2.7**	**2.9**	**3.1**	**3.2**	**3.4**	**3.6**
Corporate Baa bond	3.29	3.18	3.22	3.25	3.31	3.16	3.16	3.16	**3.4**	**3.6**	**3.8**	**4.0**	**4.2**	**4.4**
State & Local bonds	2.56	2.56	2.60	2.61	2.59	2.67	2.64	2.64	**2.4**	**2.6**	**2.7**	**2.9**	**3.0**	**3.1**
Home mortgage rate	3.10	2.98	3.09	3.14	3.07	2.90	2.84	2.87	**3.1**	**3.2**	**3.4**	**3.5**	**3.7**	**3.8**

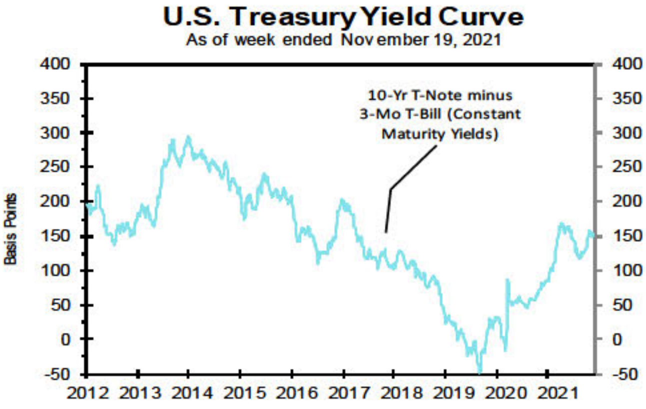
	History								Consensus Forecasts-Quarterly					
	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q
Key Assumptions	2019	2020	2020	2020	2020	2021	2021	2021	**2021**	**2022**	**2022**	**2022**	**2022**	**2023**
Fed's AFE $ Index	110.5	111.4	112.4	107.3	105.2	103.4	102.9	105.0	**106.5**	**106.9**	**106.8**	**106.6**	**106.3**	**106.1**
Real GDP	1.9	-5.1	-31.2	33.8	4.5	6.3	6.7	2.1	**5.1**	**4.4**	**3.8**	**3.3**	**2.6**	**2.4**
GDP Price Index	1.5	1.6	-1.5	3.6	2.2	4.3	6.1	5.9	**4.6**	**3.4**	**2.8**	**2.7**	**2.5**	**2.5**
Consumer Price Index	2.6	1.0	-3.1	4.7	2.4	3.7	8.4	6.6	**5.6**	**3.3**	**2.9**	**2.6**	**2.5**	**2.4**
PCE Price Index	1.7	1.3	-1.6	3.7	1.5	3.8	6.5	5.3	**4.5**	**2.9**	**2.5**	**2.5**	**2.3**	**2.3**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, PCE Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).


U.S. Treasury Yield Curve
Week ended November 19, 2021 & Year Ago vs.
4Q 2021 & 1Q 2023
Consensus Forecasts


US 3-Mo T-Bills & 10-Yr T-Note Yield
(Quarterly Average)


Corporate Bond Spreads
As of week ended November 19, 2021


U.S. Treasury Yield Curve
As of week ended November 19, 2021

Policy Rates[1]

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	0.13	0.13	0.13	**0.13**	**0.13**	**0.35**
Japan	-0.10	-0.10	-0.10	**-0.08**	**-0.08**	**-0.10**
U.K.	0.10	0.10	0.10	**0.23**	**0.31**	**0.54**
Switzerland	-0.75	-0.75	-0.75	**-0.75**	**-0.75**	**-0.67**
Canada	0.25	0.25	0.25	**0.25**	**0.35**	**0.80**
Australia	0.10	0.10	0.10	**0.10**	**0.10**	**0.07**
Euro area	0.00	0.00	0.00	**-0.05**	**-0.05**	**-0.05**

10-Yr. Government Bond Yields[2]

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	1.54	1.66	0.83	**1.77**	**1.93**	**2.17**
Germany	-0.34	-0.11	-0.59	**-0.13**	**-0.03**	**0.19**
Japan	0.08	0.10	0.02	**0.08**	**0.09**	**0.10**
U.K.	0.89	1.15	0.43	**1.10**	**1.23**	**1.49**
France	0.00	0.24	-0.35	**0.11**	**0.27**	**0.45**
Italy	0.86	0.95	0.60	**0.95**	**1.17**	**1.35**
Switzerland	-0.15	-0.04	-0.47	**-0.12**	**0.00**	**0.19**
Canada	1.66	1.65	0.65	**1.81**	**2.01**	**2.30**
Australia	1.81	1.80	0.86	**1.93**	**2.05**	**2.22**
Spain	0.46	0.51	0.07	**0.55**	**0.65**	**0.86**

Foreign Exchange Rates[3]

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	107.66	105.48	105.40	**107.3**	**107.4**	**107.4**
Japan	113.81	113.54	103.81	**113.9**	**114.2**	**114.4**
U.K.	1.35	1.37	1.33	**1.36**	**1.37**	**1.38**
Switzerland	0.93	0.92	0.91	**0.94**	**0.94**	**0.94**
Canada	1.26	1.24	1.31	**1.25**	**1.25**	**1.24**
Australia	0.73	0.75	0.73	**0.74**	**0.74**	**0.74**
Euro	1.13	1.16	1.19	**1.14**	**1.15**	**1.15**

Consensus Policy Rates vs. US Rate

	Now	In 12 Mo.
Japan	-0.23	**-0.45**
U.K.	-0.03	**0.18**
Switzerland	-0.88	**-1.02**
Canada	0.13	**0.45**
Australia	-0.03	**-0.28**
Euro area	-0.13	**-0.40**

Consensus 10-Year Gov't Yields vs. U.S. Yield

	Now	In 12 Mo.
Germany	-1.88	**-1.98**
Japan	-1.46	**-2.06**
U.K.	-0.65	**-0.68**
France	-1.54	**-1.71**
Italy	-0.68	**-0.81**
Switzerland	-1.69	**-1.98**
Canada	0.12	**0.13**
Australia	0.27	**0.05**
Spain	-1.08	**-1.31**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Monetary policy rates. [2]Government bonds are yields to maturity. [3]Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's AFE Dollar Index.

International. It's never over till it's over. On November 26, the World Health Organization classified a new variant of COVID and named it Omicron. At present the Omicron strain appears to be even more easily transmitted than the Delta variant. However, not much is yet known about whether it increases morbidity, risk of death or hospitalization or whether it meaningfully reduces the efficacy of existing vaccines. Nonetheless, the advent of another, potentially more potent COVID strain has roiled global financial markets with the major concern being that the new strain will reduce mobility and deliver a blow to economic activity. Some governments have already restricted travel. Even before Omicron, European economies were reeling from a sharp rise in Delta variant cases with some governments having reimposed some restrictions. Within the past couple of weeks, authorities in Austria, Belgium, Germany, the Netherlands and Ireland have tightened restrictions with Austria reimposing an economy-wide lockdown on November 22 (intended to last 20 days for those vaccinated).

The advent of a new COVID strain adds another concern to the one that has been dominating global financial markets—persistent and broadening inflation. Higher-than-expected inflation rates in the US, UK, Euro area, Canada, Australia and all across emerging market (EM) economies have led markets and policymakers to question their earlier view that the recent acceleration would be temporary. Rising global energy and food prices have been key sources of the increase but rebounding demand as economies reopen and lingering supply-chain bottlenecks are also playing major roles. Add to this still-accommodative monetary policy and you have the recipe for inflation that could be more than temporary. However, reopening-related supply-chain bottlenecks should eventually recede and there is already evidence of some reduction in monetary accommodation. EM central banks have been actively increasing policy interest rates over the past several months in the face of rising inflation. So far in November there have been 16 EM rate hikes, including a larger-than-expected 125bp hike by the central bank of the Czech Republic in early November and a 150bp hike in Pakistan.

Major developed market economy central banks have been less aggressive than their EM counterparts but nonetheless are beginning the journey toward less accommodation. Credit impulses have turned negative in much of DM, indicating that at the margin, financial conditions are tightening. Several central banks, including the US Fed, have recently announced either the end of their asset purchase programs or that they would end their programs in coming months. Moreover, a couple have already raised their policy interest rates. The Reserve Bank of New Zealand has raised its policy interest rate by 25bps at each of its last two meetings with more likely still to come. The Bank of England surprised markets at its November 4 meeting by not raising its policy rate. Comments by BoE officials prior to that meeting had been interpreted by financial markets as indicating that a rate hike was in the cards. Since then, indications of further labor-market tightening and another larger-than-expected inflation report have intensified market expectations that a rate hike could materialize as early as at the December 16 meeting.

In addition to expectations concerning BoE rate actions, financial markets have priced in policy interest rate increases from the US Federal Reserve, the European Central Bank (ECB), the Bank of Canada and the Reserve Bank of Australia, among others, before the end of 2022. While DM central banks have generally embraced the need for less monetary accommodation in the current environment, the ECB has not. President Lagarde has several times berated markets for expecting a policy rate hike next year, saying that the ECB's requirements for a policy rate increase are not likely to be met during 2022. Furthermore, the ECB continues to argue that the higher-than-expected rate of inflation currently being experienced is due mostly to temporary factors and will soon recede.

Fourth Quarter 2021

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	---Percent Per Annum -- Average For Quarter---															Avg. For	---(Q-Q % Change)---			
	---Short-Term---							---Intermediate-Term---			---Long-Term---					---Qtr.---	---(SAAR)---			
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
J.P. Morgan Chase	0.3 H	na	0.2	na	na	na	na	0.3 L	1.0	1.8 H	2.5 H	na	na	na	na	na	5.0	4.5	7.8	4.2
ACIMA Private Wealth	0.1 L	3.3 H	0.2	0.1 L	0.0 L	0.0 L	0.2	0.6	1.3 H	1.5 L	2.0	2.7	3.4	1.5 L	3.1	107.0	3.0	1.5 L	2.4	2.2
Action Economics	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.1 L	0.5	1.2	1.6	2.0	2.7	3.4	2.8 H	3.2	105.0	4.5	5.5	7.3	6.0
Amherst Pierpont Securities	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.2	0.5	1.2	1.6	2.1	2.7	3.4	2.2	3.2	107.1	8.5 H	4.9	7.8	6.0
Bank of America	0.1 L	na	0.2	na	0.1	na	na	0.5	1.3 H	1.7	2.1	na	na	na	na	na	6.0	5.4	7.4	5.3
Bank of the West	0.1 L	3.3 H	0.1 L	0.1 L	0.1	0.1	0.1 L	0.4	1.0	1.6	2.2	2.8	3.5	2.8 H	3.1	106.1	4.7	4.1	8.5 H	5.8
Barclays	0.1 L	3.3 H	na	na	na	na	na	na	na	na	na	na	na	na	na	na	5.0	5.2	7.1	5.5
BMO Capital Markets	0.1 L	3.3 H	0.1 L	na	0.1	0.1	0.2	0.5	1.2	1.6	2.0	na	na	na	3.1	106.8	4.5	5.2	7.5	7.2 H
BNP Paribas Americas	0.1 L	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	5.3	na	8.0	na
Chan Economics	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.1 L	0.4	1.1	1.6	2.2	2.9	3.6	2.5	3.1	106.0	4.8	3.5	3.9	3.5
Chmura Economics & Analytics	0.1 L	3.3 H	0.1 L	0.1 L	0.1	0.1	0.1 L	0.4	1.1	1.6	2.0	2.6	na	na	3.0	na	3.9	4.8	5.3	na
Daiwa Capital Markets America	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.2	0.5	1.3 H	1.6	2.0	2.7	3.3	na	3.1	106.0	5.0	5.0	6.7	5.0
DePrince & Assoc.	0.1 L	3.2 L	0.2	0.1 L	0.1	0.1	0.2	0.5	1.2	1.6	2.0	2.7	3.4	2.2	3.1	106.7	4.8	3.3	3.5	3.2
Economist Intelligence Unit	0.1 L	3.3 H	na	0.1 L	0.1	0.1	0.2	0.5	1.2	1.6	2.0	na	na	na	2.9 L	na	4.6	na	3.1	na
Fannie Mae	0.1 L	3.3 H	na	na	0.1	0.1	0.2	0.5	1.2	1.6	2.0	na	na	na	3.1	na	4.3	5.8	6.7	4.8
Georgia State University	0.1 L	3.3 H	na	na	0.0 L	0.0 L	0.1 L	0.4	1.2	1.7	2.1	2.7	3.6	na	3.2	na	2.7 L	3.6	6.1	3.6
GLC Financial Economics	0.1 L	3.3 H	0.2	0.1 L	0.0 L	0.1	0.1 L	0.5	1.2	1.6	2.1	2.9	3.4	2.7	3.0	104.7 L	4.0	4.3	3.7	3.2
Goldman Sachs & Co.	0.1 L	na	0.2	na	0.2 H	na	na	0.5	1.3 H	1.7	2.1	na	na	na	na	na	5.0	5.6	7.6	5.2
Grant Thornton/Diane Swonk	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.1 L	0.4	1.0	1.5 L	2.0	2.8	3.4	na	2.9 L	na	4.5	5.0	5.4	4.2
IHS Markit	0.1 L	3.3 H	0.1 L	na	0.1	0.1	0.1 L	0.5	1.2	1.6	2.1	na	na	na	3.1	na	4.4	3.6	4.6	3.7
ING	0.1 L	na	0.2	na	na	na	na	0.5	1.1	1.8 H	2.1	na	na	na	na	na	6.8	na	na	na
Loomis, Sayles & Company	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.2	0.4	1.2	1.6	2.0	2.7	3.3	2.6	3.0	105.7	4.2	5.6	7.7	5.3
MacroFin Analytics & Rutgers Bus School	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.2	0.6	1.3 H	1.6	2.0	2.8	3.3	2.6	3.1	106.8	4.8	4.0	4.9	3.4
Mizuho Research Institute	0.1 L	na	na	na	na	na	na	na	na	1.7	na	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1 L	3.2 L	0.2	0.1 L	0.1	0.1	0.2	0.5	1.2	1.6	2.4	2.9	3.6	2.3	3.2	na	6.6	2.8	4.4	3.9
Naroff Economic Advisors	0.1 L	3.3 H	na	0.1 L	0.1	0.1	0.2	0.6	1.3 H	1.6	2.0	2.7	3.4	1.8	3.0	105.7	3.6	3.9	4.6	4.2
NatWest Markets	0.1 L	3.3 H	0.2	0.2 H	0.1	0.2 H	0.3	0.5	1.3 H	1.7	2.2	na	na	na	na	na	4.0	6.2	7.4	5.2
Nomura Securities, Inc.	0.1 L	3.3 H	na	na	na	na	na	0.4	1.1	1.7	na	na	na	na	na	na	5.0	4.1	8.3	6.1
Oxford Economics	0.1 L	3.3 H	0.1 L	na	0.1	0.1	0.2	0.5	1.2	1.6	2.3	1.9 L	na	na	3.0	106.4	5.6	3.4	4.5	3.8
PNC Financial Services Corp.	0.1 L	3.3 H	0.2	na	0.1	0.1	0.1 L	0.5	1.2	1.6	2.0	na	3.3	2.2	3.1	105.1	4.9	2.4	2.2	2.2
RDQ Economics	0.1 L	3.3 H	0.2	0.2 H	0.1	0.1	0.3	0.5	0.9 L	1.6	2.0	2.7	3.4	2.6	3.1	106.8	7.5	6.0	7.0	6.0
Regions Financial Corporation	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.1 L	0.5	1.2	1.6	2.0	3.0 H	3.8 H	2.5	3.2	106.0	4.9	4.8	6.1	5.5
S&P Global	0.1 L	3.3 H	0.1 L	na	0.1	0.1	0.2	0.5	1.2	1.7	2.4	na	na	na	3.1	na	5.1	3.6	4.8	4.1
Scotiabank Group	0.1 L	3.3 H	na	na	0.1	na	na	0.5	1.2	1.8 H	2.1	na	na	na	na	na	6.3	3.9	1.9 L	2.1 L
Swiss Re	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.2	0.4	1.1	1.5 L	2.0	2.7	3.3	na	3.2	107.9	5.3	10.4 H	4.2	3.2
The Northern Trust Company	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.1 L	0.4	1.1	1.6	2.1	2.7	3.3	2.6	3.1	108.5 H	4.7	5.9	7.4	7.1
Thru the Cycle	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.2	0.5	1.2	1.6	2.0	2.8	3.3	2.8 H	3.1	107.2	5.3	3.9	6.6	5.5
TS Lombard	0.1 L	3.2 L	0.4 H	0.2 H	0.1	0.1	0.4 H	0.7 H	1.3 H	1.7	1.9 L	2.7	3.5	1.8	3.5 H	108.0	8.0	2.9	2.9	2.9
Via Nova Investment Mgt.	0.1 L	3.3 H	0.1 L	0.1 L	0.0 L	0.1	0.1 L	0.3 L	1.0	1.5 L	2.0	2.8	3.2 L	2.5	3.0	106.6	7.5	3.5	3.7	3.2
Wells Fargo	0.1 L	3.3 H	0.1 L	0.1 L	0.1	0.1	0.2	0.3 L	1.1	1.7	2.1	3.0 H	3.8 H	2.8 H	3.1	na	5.6	5.7	5.3	5.7
December Consensus	**0.1**	**3.3**	**0.2**	**0.1**	**0.1**	**0.1**	**0.2**	**0.5**	**1.2**	**1.6**	**2.1**	**2.7**	**3.4**	**2.4**	**3.1**	**106.5**	**5.1**	**4.6**	**5.6**	**4.5**
Top 10 Avg.	0.1	3.3	0.2	0.1	0.1	0.1	0.2	0.6	1.3	1.7	2.3	2.9	3.6	2.7	3.2	107.3	6.8	6.2	7.8	6.1
Bottom 10 Avg.	0.1	3.3	0.1	0.1	0.1	0.1	0.1	0.4	1.0	1.6	2.0	2.6	3.3	2.2	3.0	105.7	3.9	3.1	3.2	2.9
November Consensus	0.1	3.3	0.2	0.1	0.1	0.1	0.1	0.4	1.1	1.6	2.2	2.9	3.6	2.5	3.1	105.8	4.6	3.4	3.9	3.4
Number of Forecasts Changed From A Month Ago:																				
Down	0	0	5	0	2	1	2	5	3	12	22	12	12	8	12	3	12	4	3	3
Same	39	33	22	24	28	30	14	12	18	18	12	8	9	7	12	6	10	2	4	2
Up	1	1	4	0	4	0	15	20	16	8	2	2	1	3	6	12	17	30	30	30
Diffusion Index	51%	51%	48%	50%	53%	48%	71%	70%	68%	45%	22%	27%	25%	36%	40%	71%	56%	86%	86%	89%

First Quarter 2022

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For	(Q-Q % Change)			
	Short-Term							Intermediate-Term			Long-Term					---Qtr.---	(SAAR)			
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
J.P. Morgan Chase	0.3 H	na	0.2	na	na	na	na	0.4	1.1	1.8	2.5	na	na	na	na	na	2.5 L	3.0	3.7	3.4
ACIMA Private Wealth	0.1 L	3.3 H	0.2	0.1 L	0.0 L	0.0 L	0.1 L	0.6	1.3	1.3 L	1.9 L	2.8	3.6	1.4 L	2.9 L	105.0	3.0	1.2 L	2.0	2.2
Action Economics	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.3	0.6	1.2	1.7	2.2	2.9	3.6	2.8	3.4	106.3	5.2	3.1	3.2	2.9
Amherst Pierpont Securities	0.1 L	3.3 H	0.3	0.1 L	0.1	0.2 H	0.3	0.7	1.5 H	2.0	2.5	3.2	3.8	2.7	3.5	107.8	5.1	4.1	4.6	4.0
Bank of America	0.1 L	na	0.4 H	na	na	na	na	0.9 H	1.5 H	1.8	2.2	na	na	na	na	na	4.0	3.7	3.3	2.6
Bank of the West	0.1 L	3.3 H	0.1 L	0.1 L	0.1	0.1	0.1 L	0.4	1.1	1.7	2.4	3.0	3.7	3.0 H	3.3	105.6	3.7	3.0	3.2	3.0
Barclays	0.1 L	3.3 H	na	na	na	na	na	0.6	1.3	1.6	2.0	na	na	na	na	na	4.5	1.3	1.7	0.8 L
BMO Capital Markets	0.1 L	3.3 H	0.2	na	0.1	0.1	0.2	0.6	1.3	1.7	2.1	na	na	na	3.3	108.0	3.5	3.0	3.7	3.5
BNP Paribas Americas	0.1 L	na	na	na	na	na	na	0.8	na	1.7	2.1	na	na	na	na	na	5.7	na	4.1	na
Chan Economics	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.1 L	0.4	1.1	1.7	2.3	3.0	3.7	2.6	3.2	105.5	3.5	2.6	2.8	2.6
Chmura Economics & Analytics	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.2	0.5	1.1	1.6	2.0	2.6	na	na	3.1	na	4.1	4.2	5.4 H	na
Daiwa Capital Markets America	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.2	0.6	1.4	1.7	2.0	2.8	3.4	na	3.2	107.0	4.5	4.5	4.5	4.3 H
DePrince & Assoc.	0.1 L	3.2 L	0.2	0.1 L	0.1	0.1	0.2	0.6	1.4	1.8	2.1	3.0	4.1	2.6	3.3	106.5	3.9	2.9	3.1	2.8
Economist Intelligence Unit	0.1 L	3.3 H	na	0.1 L	0.1	0.1	0.2	0.7	1.4	1.6	2.1	na	na	na	3.0	na	3.9	na	2.4	na
Fannie Mae	0.1 L	3.3 H	na	na	0.1	0.2 H	0.4	0.8	1.4	1.7	2.0	na	na	na	3.2	na	4.8	4.2	2.4	2.8
Georgia State University	0.1 L	3.3 H	na	na	0.0 L	0.0 L	0.1 L	0.5	1.3	1.8	2.2	2.9	3.8	na	3.4	na	2.8	3.2	3.6	1.7
GLC Financial Economics	0.1 L	3.3 H	0.1 L	0.1 L	0.1	0.1	0.2	0.5	1.2	1.7	2.1	2.9	3.4	2.8	3.1	104.9 L	2.9	2.9	2.8	3.0
Goldman Sachs & Co.	0.1 L	na	0.2	na	0.2 H	na	na	0.7	1.5 H	1.8	2.2	na	na	na	na	na	4.5	2.8	4.1	2.6
Grant Thornton/Diane Swonk	0.1 L	3.3 H	0.1 L	0.1 L	0.1	0.1	0.1 L	0.4	1.1	1.5	2.0	2.8	3.4	na	3.0	na	5.0	4.9	5.0	4.0
IHS Markit	0.1 L	3.3 H	0.2	na	0.1	0.1	0.2	0.5	1.3	1.7	2.1	na	na	na	3.2	na	5.0	3.0	1.4 L	1.8
ING	0.1 L	na	0.2	na	na	na	na	0.6	1.3	2.0	2.2	na	na	na	na	na	5.1	na	na	na
Loomis, Sayles & Company	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.2	0.5	1.2	1.7	2.2	2.8	3.4	2.7	3.1	106.6	3.9	3.2	2.5	2.1
MacroFin Analytics & Rutgers Bus School	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.2	0.6	1.3	1.6	2.0	2.9	3.3	2.6	3.1	107.2	4.0	2.9	1.9	1.8
Mizuho Research Institute	0.1 L	na	na	na	na	na	na	na	na	1.7	na	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1 L	3.2 L	0.3	0.1 L	0.2 H	0.2 H	0.4	0.7	1.4	1.9	2.9 H	3.4 H	4.2 H	2.7	3.4	na	6.1	3.0	2.9	2.8
Naroff Economic Advisors	0.1 L	3.3 H	na	0.1 L	0.1	0.1	0.2	0.6	1.3	1.7	2.1	2.9	3.6	1.9	3.2	106.3	4.7	3.3	3.3	3.2
NatWest Markets	0.1 L	3.3 H	0.2	0.2 H	0.1	0.2 H	0.3	0.9 H	1.5 H	1.8	2.1	na	na	na	na	na	4.0	6.0	2.8	3.5
Nomura Securities, Inc.	0.1 L	3.3 H	na	na	na	na	na	0.4	1.1	1.8	na	na	na	na	na	na	5.6	2.8	5.4 H	3.5
Oxford Economics	0.1 L	3.3 H	0.2	na	0.1	0.1	0.2	0.6	1.3	1.8	2.5	2.0 L	na	na	3.2	106.2	6.2 H	1.8	2.6	2.1
PNC Financial Services Corp.	0.1 L	3.3 H	0.2	na	0.1	0.1	0.3	0.7	1.3	1.7	2.1	na	3.5	2.3	3.3	105.5	4.6	2.4	1.5	1.8
RDQ Economics	0.1 L	3.3 H	0.2	0.2 H	0.1	0.1	0.4	0.6	1.1	1.9	2.4	3.1	3.7	2.9	3.4	106.3	6.1	4.0	4.7	3.3
Regions Financial Corporation	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.2	0.6	1.3	1.7	2.1	3.2	3.9	2.6	3.3	107.1	5.4	4.0	4.2	4.3 H
S&P Global	0.1 L	3.3 H	0.2	na	0.1	0.1	0.2	0.5	1.2	1.8	2.6	na	na	na	3.2	na	5.1	2.3	2.7	2.3
Scotiabank Group	0.1 L	3.3 H	na	na	0.1	na	na	0.7	1.4	2.1 H	2.3	na	na	na	na	na	4.8	4.6	2.0	3.3
Swiss Re	0.1 L	3.3 H	0.4 H	0.1 L	0.1	0.2 H	0.3	0.5	1.0 L	1.5	1.9 L	2.7	3.2 L	na	3.2	108.8	4.1	7.3 H	3.7	3.6
The Northern Trust Company	0.1 L	3.3 H	0.3	0.1 L	0.1	0.2 H	0.2	0.5	1.3	1.8	2.4	3.0	3.7	2.9	3.3	108.0	4.6	3.4	3.5	3.7
Thru the Cycle	0.1 L	3.3 H	0.2	0.1 L	0.1	0.1	0.4	0.6	1.5 H	1.8	2.1	2.9	3.4	2.9	3.4	109.1	4.3	3.1	3.9	3.6
TS Lombard	0.1 L	3.2 L	0.4 H	0.2 H	0.2 H	0.2 H	0.5 H	0.8	1.5 H	1.8	2.4	3.2	4.0	2.3	3.6 H	110.0 H	4.4	3.0	3.0	3.0
Via Nova Investment Mgt.	0.1 L	3.3 H	0.1 L	0.1 L	0.1	0.1	0.1 L	0.2 L	1.0 L	1.4	2.0	2.9	3.3	2.6	2.9 L	107.5	4.0	2.5	2.7	2.7
Wells Fargo	0.1 L	3.3 H	0.1 L	0.1 L	0.1	0.2 H	0.3	0.5	1.2	1.8	2.2	3.0	3.8	2.8	3.2	na	4.4	3.8	3.8	3.8
December Consensus	**0.1**	**3.3**	**0.2**	**0.1**	**0.1**	**0.1**	**0.2**	**0.6**	**1.3**	**1.7**	**2.2**	**2.9**	**3.6**	**2.6**	**3.2**	**106.9**	**4.4**	**3.4**	**3.3**	**2.9**
Top 10 Avg.	0.1	3.3	0.3	0.1	0.1	0.2	0.4	0.8	1.5	1.9	2.5	3.1	3.9	2.8	3.4	108.1	5.6	4.8	4.6	3.8
Bottom 10 Avg.	0.1	3.3	0.2	0.1	0.1	0.1	0.1	0.4	1.1	1.6	2.0	2.7	3.4	2.4	3.1	105.8	3.4	2.3	2.0	1.9
November Consensus	0.1	3.3	0.2	0.1	0.1	0.1	0.2	0.5	1.2	1.8	2.3	3.0	3.7	2.7	3.2	105.6	4.2	2.7	2.9	2.6
Number of Forecasts Changed From A Month Ago:																				
Down	0	0	2	2	1	3	2	1	4	11	27	9	13	8	8	2	5	4	8	9
Same	39	33	28	22	31	26	15	14	14	27	9	10	7	9	18	2	9	6	6	4
Up	1	1	1	0	1	2	14	23	19	2	1	3	2	1	4	17	25	26	23	22
Diffusion Index	51%	51%	48%	46%	50%	48%	69%	79%	70%	39%	15%	36%	25%	31%	43%	86%	76%	81%	70%	69%

Second Quarter 2022

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	---Percent Per Annum -- Average For Quarter---															Avg. For ---Qtr.---	---(Q-Q % Change)--- ---(SAAR)---			
	---Short-Term---							---Intermediate-Term---			---Long-Term---									
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
Bank of America	0.4 H	na	0.6 H	na	na	na	na	1.0	1.6	1.9	2.2	na	na	na	na	na	4.0	3.7	3.2	2.4
TS Lombard	0.4 H	3.5 H	0.6 H	0.4 H	0.3 H	0.3	0.5	0.8	1.6	2.0	2.7	3.5	4.3	2.6	3.8	112.0 H	4.0	3.1	3.1	3.1
J.P. Morgan Chase	0.3	na	0.2	na	na	na	na	0.4	1.2	1.9	2.6	na	na	na	na	na	3.5	2.2	2.5	2.2
Amherst Pierpont Securities	0.2	3.3	0.5	0.2	0.3 H	0.5 H	0.6 H	0.9	1.7	2.3 H	2.9	3.6	4.3	3.0	3.9 H	108.5	4.5	3.6	3.7	3.3
Chmura Economics & Analytics	0.2	3.3	0.3	0.2	0.2	0.2	0.3	0.6	1.2	1.7	2.1	2.7	na	na	3.2	na	2.8	3.6	5.2	na
Regions Financial Corporation	0.2	3.3	0.3	0.2	0.1	0.2	0.3	0.7	1.4	1.9	2.2	3.3	4.1	2.7	3.5	107.8	4.8	3.6	2.9	2.9
Thru the Cycle	0.2	3.3	0.3	0.2	0.2	0.3	0.5	0.7	1.6	1.9	2.2	2.9	3.5	2.9	3.4	109.6	3.3	2.7	3.8	2.9
ACIMA Private Wealth	0.1 L	3.3	0.2	0.1 L	0.0 L	0.0 L	0.1 L	0.5	1.1	1.3 L	1.8 L	2.9	3.8	1.4 L	2.6 L	103.0 L	2.0 L	1.1	2.0	2.0
Action Economics	0.1 L	3.3	0.2	0.1 L	0.1	0.2	0.4	0.7	1.2	1.8	2.2	3.0	3.7	2.8	3.5	107.0	4.7	2.3	2.9	2.7
Bank of the West	0.1 L	3.3	0.2	0.1 L	0.1	0.1	0.2	0.4	1.1	1.8	2.4	3.0	3.8	3.1	3.3	105.0	2.8	2.6	2.5	2.4
Barclays	0.1 L	3.3	na	na	na	na	na	0.7	1.4	1.7	2.0	na	na	na	na	na	4.0	0.9 L	1.1 L	0.4 L
BMO Capital Markets	0.1 L	3.3	0.2	na	0.1	0.1	0.3	0.7	1.3	1.8	2.2	na	na	na	3.5	107.6	3.3	2.3	2.7	2.4
BNP Paribas Americas	0.1 L	na	na	na	na	na	na	1.0	na	1.8	2.2	na	na	na	na	na	5.5 H	na	2.2	na
Chan Economics	0.1 L	3.3	0.2	0.1 L	0.2	0.2	0.2	0.5	1.2	1.8	2.4	3.1	3.8	2.7	3.3	105.0	3.3	2.5	2.7	2.5
Daiwa Capital Markets America	0.1 L	3.3	0.2	0.1 L	0.1	0.1	0.2	0.7	1.4	1.7	2.1	2.9	3.5	na	3.3	108.0	3.7	3.7	4.0	3.7
DePrince & Assoc.	0.1 L	3.2 L	0.2	0.2	0.1	0.1	0.2	0.7	1.5	1.9	2.3	3.2	4.2	2.8	3.6	106.1	3.5	2.7	2.9	2.6
Economist Intelligence Unit	0.1 L	3.3	na	0.2	0.1	0.1	0.3	0.7	1.4	1.7	2.1	na	na	na	3.0	na	3.9	na	2.4	na
Fannie Mae	0.1 L	3.3	na	na	0.2	0.3	0.6 H	1.0	1.5	1.7	2.0	na	na	na	3.3	na	3.9	3.4	3.0	2.9
Georgia State University	0.1 L	3.3	na	na	0.1	0.1	0.2	0.6	1.5	2.0	2.4	3.1	4.2	na	3.6	na	4.2	2.2	2.5	1.9
GLC Financial Economics	0.1 L	3.3	0.2	0.1 L	0.1	0.1	0.2	0.5	1.2	1.7	2.2	2.9	3.5	2.8	3.3	104.7	3.5	3.5	2.4	2.9
Goldman Sachs & Co.	0.1 L	na	0.3	na	0.2	na	na	0.9	1.6	1.9	2.2	na	na	na	na	na	4.0	3.1	4.0	2.6
Grant Thornton/Diane Swonk	0.1 L	3.3	0.2	0.1 L	0.1	0.1	0.3	0.6	1.3	1.8	2.2	3.0	3.7	na	3.3	na	4.7	1.9	2.7	1.9
IHS Markit	0.1 L	3.3	0.2	na	0.1	0.1	0.2	0.6	1.3	1.8	2.2	na	na	na	3.3	na	4.7	2.3	2.1	2.0
ING	0.1 L	na	0.2	na	na	na	na	0.7	1.6	2.3 H	2.4	na	na	na	na	na	4.3	na	na	na
Loomis, Sayles & Company	0.1 L	3.3	0.2	0.1 L	0.1	0.1	0.2	0.5	1.2	1.8	2.3	2.9	3.5	2.7	3.2	106.6	3.6	2.2	2.3	2.1
MacroFin Analytics & Rutgers Bus School	0.1 L	3.3	0.2	0.1 L	0.1	0.1	0.2	0.6	1.3	1.6	2.0	2.9	3.3 L	2.6	3.1	107.4	2.8	2.2	2.2	2.1
Mizuho Research Institute	0.1 L	na	na	na	na	na	na	na	na	1.8	na	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1 L	3.2 L	0.4	0.1 L	0.2	0.3	0.5	0.9	1.6	2.2	3.2 H	3.7 H	4.6 H	3.0	3.7	na	3.6	2.8	2.5	2.6
Naroff Economic Advisors	0.1 L	3.3	na	0.2	0.2	0.2	0.3	0.7	1.4	1.8	2.2	3.0	3.7	2.0	3.3	105.6	3.5	2.6	2.9	2.7
NatWest Markets	0.1 L	3.3	0.2	0.2	0.1	0.2	0.3	1.2 H	1.8 H	2.0	2.2	na	na	na	na	na	3.0	4.8	3.0	2.9
Nomura Securities, Inc.	0.1 L	3.3	na	na	na	na	na	0.5	1.3	1.8	na	na	na	na	na	na	4.6	1.9	1.2	1.6
Oxford Economics	0.1 L	3.3	0.2	na	0.1	0.1	0.3	0.7	1.4	2.0	2.7	2.3 L	na	na	3.4	106.0	4.5	2.0	2.5	2.2
PNC Financial Services Corp.	0.1 L	3.3	0.3	na	0.2	0.2	0.4	0.9	1.4	1.8	2.3	na	3.7	2.4	3.4	106.0	4.2	2.4	2.2	2.1
RDQ Economics	0.1 L	3.3	0.3	0.2	0.1	0.2	0.5	0.7	1.3	2.3 H	2.9	3.5	4.1	3.5 H	3.8	105.5	4.2	3.7	4.2	3.2
S&P Global	0.1 L	3.3	0.2	na	0.1	0.1	0.3	0.6	1.4	2.1	2.8	na	na	na	3.3	na	2.3	2.2	2.7	2.5
Scotiabank Group	0.1 L	3.3	na	na	0.1	na	na	0.9	1.5	2.2	2.6	na	na	na	na	na	4.1	4.8	5.4 H	3.9 H
Swiss Re	0.1 L	3.3	0.4	0.1 L	0.1	0.2	0.3	0.5	1.0 L	1.6	2.1	2.8	3.4	na	3.4	108.4	3.8	5.7 H	2.4	2.8
The Northern Trust Company	0.1 L	3.3	0.3	0.1 L	0.1	0.2	0.3	0.6	1.4	1.9	2.7	3.3	4.0	3.2	3.5	106.0	4.0	2.9	3.0	2.8
Via Nova Investment Mgt.	0.1 L	3.3	0.1 L	0.1 L	0.1	0.1	0.1 L	0.2 L	1.0 L	1.4	2.0	2.9	3.4	2.6	2.9	107.0	3.5	2.5	2.7	2.4
Wells Fargo	0.1 L	3.3	0.1 L	0.1 L	0.2	0.3	0.4	0.7	1.4	1.9	2.3	3.2	4.1	3.0	3.3	na	3.3	2.8	3.1	2.8
December Consensus	**0.1**	**3.3**	**0.3**	**0.2**	**0.1**	**0.2**	**0.3**	**0.7**	**1.4**	**1.9**	**2.3**	**3.1**	**3.8**	**2.7**	**3.4**	**106.8**	**3.8**	**2.8**	**2.9**	**2.5**
Top 10 Avg.	0.2	3.3	0.4	0.2	0.2	0.3	0.5	1.0	1.6	2.1	2.8	3.4	4.2	3.0	3.6	108.3	4.7	4.1	4.0	3.2
Bottom 10 Avg.	0.1	3.3	0.2	0.1	0.1	0.1	0.2	0.5	1.1	1.6	2.0	2.8	3.5	2.5	3.1	105.3	2.9	1.9	2.0	1.8
November Consensus	0.1	3.3	0.2	0.1	0.1	0.2	0.2	0.6	1.3	1.8	2.4	3.0	3.8	2.8	3.4	105.4	3.8	2.6	2.6	2.4
Number of Forecasts Changed From A Month Ago:																				
Down	1	0	2	1	1	2	1	0	5	10	23	7	13	5	7	2	11	6	5	8
Same	34	32	23	19	26	25	14	16	15	21	11	12	6	10	17	3	8	7	11	9
Up	5	2	6	4	6	4	16	22	17	9	3	3	3	3	6	16	20	23	21	18
Diffusion Index	55%	53%	56%	56%	58%	53%	74%	79%	66%	49%	23%	41%	27%	44%	48%	83%	62%	74%	72%	64%

Third Quarter 2022

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For ---Qtr.---	(Q-Q % Change)			
	Short-Term							Intermediate-Term			Long-Term						(SAAR)			
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
Bank of America	0.6 H	na	0.8 H	na	na	na	na	1.2	1.7	1.9	2.2	na	na	na	na	na	3.0	3.6	2.5	2.1
BNP Paribas Americas	0.6 H	na	na	na	na	na	na	1.3	na	1.9	2.3	na	na	na	na	na	3.7	na	2.0	na
Daiwa Capital Markets America	0.6 H	3.7 H	0.5	0.4	0.4	0.4	0.5	1.2	1.7	2.0	2.4	3.2	3.8	na	3.6	108.0	3.0	3.0	3.5	3.3
Chmura Economics & Analytics	0.5	3.7 H	0.7	0.6 H	0.5	0.6	0.6	0.9	1.6	2.0	2.4	3.0	na	na	3.4	na	3.1	3.0	4.8 H	na
Amherst Pierpont Securities	0.4	3.6	0.8 H	0.5	0.6 H	0.7 H	0.9 H	1.1	1.9 H	2.6 H	3.3 H	4.0 H	4.8	3.3	4.2 H	109.0	3.7	3.4	3.4	3.1
Economist Intelligence Unit	0.4	3.5	na	0.4	0.4	0.4	0.6	1.0	1.7	2.0	2.4	na	na	na	3.3	na	3.5	na	1.6	na
Goldman Sachs & Co.	0.4	na	0.5	na	0.2	na	na	1.0	1.7	2.0	2.2	na	na	na	na	na	3.0	2.7	2.9	2.4
ING	0.4	na	0.5	na	na	na	na	0.8	1.6	2.3	2.3	na	na	na	na	na	3.8	na	na	na
J.P. Morgan Chase	0.4	na	0.2	na	na	na	na	0.5	1.4	2.1	2.7	na	na	na	na	na	3.5	2.1	2.4	2.1
Naroff Economic Advisors	0.4	3.5	na	0.5	0.4	0.5	0.5	0.9	1.6	2.0	2.4	3.2	4.0	2.3	3.5	105.0	3.0	2.5	2.6	2.5
Thru the Cycle	0.4	3.5	0.6	0.4	0.4	0.6	0.7	0.8	1.6	1.9	2.2	3.0	3.6	3.0	3.5	109.8	3.6	3.1	3.3	3.6 H
TS Lombard	0.4	3.5	0.6	0.4	0.3	0.3	0.5	0.8	1.6	2.3	3.0	3.8	4.6	2.9	4.1	114.0 H	3.4	3.1	3.1	3.1
Chan Economics	0.3	3.5	0.4	0.3	0.3	0.3	0.3	0.6	1.3	1.9	2.5	3.2	3.9	2.8	3.4	104.5	2.5	2.5	2.7	2.5
Grant Thornton/Diane Swonk	0.3	3.5	0.4	0.3	0.3	0.4	0.5	0.9	1.6	2.1	2.6	3.4	4.1	na	3.7	na	3.0	2.4	2.2	2.2
RDQ Economics	0.3	3.4	0.5	0.4	0.3	0.4	0.7	0.9	1.6	2.6 H	3.3 H	3.8	4.4	3.6 H	4.1	105.2	3.7	3.5	3.8	3.2
Action Economics	0.2	3.3	0.2	0.2	0.3	0.4	0.7	0.9	1.4	1.8	2.3	3.0	3.8	2.8	3.5	107.1	4.3	2.6	2.7	2.5
Bank of the West	0.2	3.3	0.2	0.2	0.2	0.2	0.2	0.5	1.2	1.9	2.6	3.2	4.0	3.2	3.5	104.7	2.7	2.4	2.3	2.2
BMO Capital Markets	0.2	3.3	0.2	na	0.1	0.1	0.3	0.8	1.4	1.9	2.3	na	na	na	3.6	107.3	3.0	2.4	2.9	2.6
DePrince & Assoc.	0.2	3.3	0.2	0.2	0.2	0.2	0.3	0.8	1.7	2.1	2.4	3.4	4.3	2.9	3.8	105.9	3.0	2.7	2.8	2.6
GLC Financial Economics	0.2	3.3	0.2	0.2	0.1	0.2	0.2	0.5	1.3	1.9	2.4	3.2	3.9	2.9	3.6	104.3	3.4	3.4	3.6	2.6
MacroFin Analytics & Rutgers Bus School	0.2	3.3	0.2	0.2	0.1	0.1	0.2	0.6	1.3	1.7	2.1	2.9	3.3 L	2.6	3.1	107.5	2.5	2.1	1.9	2.1
Oxford Economics	0.2	3.3	0.2	na	0.2	0.2	0.5	0.8	1.5	2.2	2.8	2.5 L	na	na	3.5	105.5	3.3	1.9	2.2	2.1
Regions Financial Corporation	0.2	3.3	0.4	0.3	0.2	0.3	0.4	0.8	1.6	2.0	2.4	3.4	4.2	2.8	3.6	108.4	4.6	2.5	2.5	2.5
S&P Global	0.2	3.3	0.2	na	0.2	0.2	0.5	0.7	1.5	2.2	2.9	na	na	na	3.4	na	3.1	2.1	2.4	2.3
Swiss Re	0.2	3.4	0.5	0.2	0.1	0.2	0.3	0.6	1.1	1.6	2.2	2.9	3.5	na	3.4	107.9	2.0 L	4.5	2.0	2.5
ACIMA Private Wealth	0.1 L	3.3	0.2	0.1 L	0.0 L	0.0 L	0.1 L	0.3	0.8 L	1.2 L	1.7 L	2.8	3.7	1.4 L	2.5 L	100.0 L	2.5	1.3 L	1.8	2.2
Barclays	0.1 L	3.3	na	na	na	na	na	0.8	1.4	1.7	2.0	na	na	na	na	na	3.0	2.4	2.1	2.2
Fannie Mae	0.1 L	3.3	na	na	0.4	0.6	0.8	1.2	1.6	1.8	2.0	na	na	na	3.4	na	3.0	3.3	3.1	3.1
Georgia State University	0.1 L	3.3	na	na	0.1	0.1	0.2	0.7	1.6	2.2	2.7	3.2	4.4	na	3.9	na	4.0	2.0	2.3	2.1
IHS Markit	0.1 L	3.3	0.3	na	0.1	0.1	0.3	0.7	1.4	1.9	2.4	na	na	na	3.5	na	4.0	2.2	2.2	2.1
Loomis, Sayles & Company	0.1 L	3.3	0.2	0.1 L	0.1	0.1	0.2	0.5	1.2	1.9	2.4	3.1	3.7	2.8	3.3	106.6	3.5	2.0	2.3	2.1
Mizuho Research Institute	0.1 L	na	na	na	na	na	na	na	na	1.8	na	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1 L	3.2 L	0.4	0.1 L	0.2	0.3	0.7	1.0	1.8	2.3	3.3 H	3.8	4.9 H	3.2	3.8	na	3.1	2.7	2.2	2.2
NatWest Markets	0.1 L	3.3	0.2	0.2	0.1	0.2	0.3	1.4 H	1.9 H	2.1	2.3	na	na	na	na	na	2.3	4.6 H	2.7	2.6
Nomura Securities, Inc.	0.1 L	3.3	na	na	na	na	na	0.6	1.4	1.8	na	na	na	na	na	na	2.7	1.9	1.3 L	1.7 L
PNC Financial Services Corp.	0.1 L	3.3	0.4	na	0.3	0.4	0.6	1.1	1.5	1.9	2.4	na	3.8	2.5	3.5	106.0	4.7 H	2.4	2.6	2.4
Scotiabank Group	0.1 L	3.3	na	na	0.1	na	na	1.1	1.6	2.3	2.6	na	na	na	na	na	3.3	4.3	3.5	3.2
The Northern Trust Company	0.1 L	3.3	0.3	0.1 L	0.2	0.3	0.4	0.6	1.5	2.0	2.7	3.5	4.4	3.4	3.7	104.5	2.9	2.7	2.7	2.4
Via Nova Investment Mgt.	0.1 L	3.3	0.1 L	0.1 L	0.1	0.1	0.1 L	0.2 L	1.0	1.5	2.0	3.0	3.5	2.7	3.0	106.5	3.5	2.5	2.6	2.2
Wells Fargo	0.5	3.5	0.5	0.4	0.4	0.5	0.5	0.9	1.6	2.0	2.4	3.3	4.2	3.1	3.5	na	3.6	2.4	2.1	2.4
December Consensus	**0.3**	**3.4**	**0.4**	**0.3**	**0.2**	**0.3**	**0.4**	**0.8**	**1.5**	**2.0**	**2.5**	**3.2**	**4.0**	**2.9**	**3.5**	**106.6**	**3.3**	**2.7**	**2.6**	**2.5**
Top 10 Avg.	0.5	3.6	0.6	0.4	0.4	0.5	0.7	1.2	1.7	2.3	2.9	3.6	4.4	3.2	3.9	108.6	4.0	3.7	3.5	3.0
Bottom 10 Avg.	0.1	3.3	0.2	0.2	0.1	0.1	0.2	0.5	1.2	1.7	2.1	2.9	3.7	2.6	3.2	104.6	2.6	2.0	1.9	2.1
November Consensus	0.1	3.3	0.3	0.2	0.2	0.2	0.3	0.6	1.4	1.9	2.5	3.2	4.0	2.9	3.5	105.1	3.3	2.5	2.5	2.3
Number of Forecasts Changed From A Month Ago:																				
Down	0	1	2	1	1	2	2	1	3	5	18	4	8	6	7	3	13	4	6	4
Same	22	23	16	10	20	17	13	11	11	28	14	11	10	10	17	4	11	9	15	12
Up	18	10	13	13	12	12	16	26	23	7	5	7	4	2	6	14	15	23	16	19
Diffusion Index	73%	63%	68%	75%	67%	66%	73%	83%	77%	53%	32%	57%	41%	39%	48%	76%	53%	76%	64%	71%

Fourth Quarter 2022

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)			
	Short-Term							Intermediate-Term			Long-Term									
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
Chmura Economics & Analytics	1.0 H	4.1 H	1.1 H	1.0 H	1.0 H	1.0 H	1.0	1.2	2.0	2.4	2.8	3.4	na	na	3.8	na	3.6	2.7	3.7	na
Bank of America	0.9	na	1.0	na	na	na	na	1.3	1.8	2.0	2.2	na	na	na	na	na	2.0	3.6	2.4	2.1
BNP Paribas Americas	0.9	na	na	na	na	na	na	1.5	na	2.0	2.3	na	na	na	na	na	2.7	na	2.3	na
Daiwa Capital Markets America	0.8	3.9	0.9	0.8	0.8	0.8	0.9	1.6 H	2.1	2.4	2.7	3.6	4.2	na	4.0	109.0	2.7	2.7	3.3	3.0
Amherst Pierpont Securities	0.7	3.8	1.0	0.8	0.9	1.0 H	1.2 H	1.3	2.2 H	2.8 H	3.6 H	4.3 H	5.0 H	3.6	4.5 H	109.5	3.4	3.2	3.3	3.0
Grant Thornton/Diane Swonk	0.7	3.8	0.7	0.6	0.6	0.6	0.7	1.0	1.8	2.5	2.9	3.8	4.5	na	4.1	na	2.0	1.9	1.7	1.6
ING	0.7	na	0.8	na	na	na	na	1.0	1.7	2.3	2.4	na	na	na	na	na	2.9	na	na	na
RDQ Economics	0.7	3.8	0.9	0.8	0.7	0.8	1.0	1.2	1.8	2.8 H	3.5	4.0	4.6	3.9 H	4.3	105.2	3.7 H	3.5	3.5	3.0
Thru the Cycle	0.7	3.8	0.9	0.7	0.7	0.9	0.9	1.0	1.7	2.0	2.3	3.1	3.7	3.0	3.2	109.8	3.0	2.5	4.1 H	3.0
Goldman Sachs & Co.	0.6	na	0.8	na	0.3	na	na	1.2	1.8	2.0	2.3	na	na	na	na	na	1.8	2.3	2.3	2.0
J.P. Morgan Chase	0.6	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.5	2.1	2.4	2.1
Naroff Economic Advisors	0.6	3.8	na	0.9	0.7	0.8	0.8	1.2	1.9	2.2	2.7	3.4	4.1	3.0	3.6	104.6	2.3	2.2	2.3	2.2
Wells Fargo	0.6	3.6	0.6	0.5	0.8	0.9	0.9	1.1	1.8	2.1	2.5	3.4	4.3	3.1	3.7	na	3.5	2.1	1.5	2.1
Action Economics	0.5	3.6	0.4	0.4	0.6	0.7	0.9	1.1	1.5	1.9	2.3	3.1	3.9	2.9	3.6	107.1	3.2	2.6	2.6	2.3
BMO Capital Markets	0.5	3.6	0.5	na	0.4	0.4	0.5	0.9	1.4	2.0	2.4	na	na	na	3.7	107.0	2.5	2.3	2.7	2.5
Chan Economics	0.5	3.8	0.6	0.5	0.5	0.5	0.5	0.8	1.5	2.1	2.7	3.4	4.1	3.0	3.6	104.0	2.3	2.4	2.6	2.3
Economist Intelligence Unit	0.5	3.6	na	0.5	0.5	0.5	0.7	1.1	1.8	2.1	2.5	na	na	na	3.4	na	2.9	na	1.2 L	na
Scotiabank Group	0.5	3.5	na	na	0.1	na	na	1.3	1.8	2.3	2.6	na	na	na	na	na	2.9	1.6	1.3	0.7 L
NatWest Markets	0.4	3.5	0.4	0.4	0.6	0.7	0.8	1.5	2.0	2.2	2.3	na	na	na	na	na	2.0	4.1 H	2.8	2.9
Nomura Securities, Inc.	0.4	3.5	na	na	na	na	na	0.8	1.5	1.9	na	na	na	na	na	na	1.4	2.2	2.3	2.2
Oxford Economics	0.4	3.5	0.6	na	0.4	0.4	0.8	0.9	1.5	2.3	2.8	2.7 L	na	na	3.5	104.8	1.6	2.0	2.0	2.0
PNC Financial Services Corp.	0.4	3.5	0.7	na	0.6	0.6	0.8	1.2	1.5	1.9	2.5	na	3.9	2.6	3.6	106.5	2.8	2.7	2.9	2.7
S&P Global	0.4	3.5	0.4	na	0.4	0.5	0.8	0.9	1.6	2.4	2.9	na	na	na	3.5	na	2.4	2.0	2.4	2.4
Swiss Re	0.4	3.6	0.6	0.4	0.3	0.4	0.5	0.7	1.2	1.6	2.2	3.0	3.7	na	3.5	107.5	1.2 L	3.9	1.7	2.1
TS Lombard	0.4	3.5	0.6	0.4	0.5	0.5	0.6	0.8	1.6	2.5	3.2	4.0	4.8	3.1	4.3	114.0 H	3.0	3.1	3.1	3.1 H
Bank of the West	0.3	3.5	0.4	0.4	0.3	0.4	0.4	0.6	1.4	2.2	2.8	3.5	4.3	3.5	3.7	104.5	2.6	2.3	2.2	2.1
DePrince & Assoc.	0.3	3.4	0.4	0.4	0.3	0.3	0.4	0.9	1.8	2.3	2.6	3.6	4.4	3.0	4.0	105.8	2.4	2.6	2.8	2.5
Regions Financial Corporation	0.3	3.3 L	0.5	0.4	0.3	0.4	0.5	1.0	1.7	2.1	2.5	3.5	4.4	3.0	3.7	108.2	3.4	2.4	2.3	2.4
Fannie Mae	0.2	3.4	na	na	0.7	0.8	1.1	1.3	1.7	1.8	2.0	na	na	na	3.5	na	2.4	3.2	3.0	2.8
GLC Financial Economics	0.2	3.4	0.3	0.2	0.2	0.3	0.3	0.6	1.5	2.0	2.7	4.0	4.6	3.0	3.8	104.0	3.3	3.3	3.6	2.3
MacroFin Analytics & Rutgers Bus School	0.2	3.3 L	0.2	0.2	0.1	0.1	0.2	0.6	1.3	1.7	2.1	2.9	3.4 L	2.6	3.2	107.7	2.1	2.0	2.0	2.0
Moody's Analytics	0.2	3.3 L	0.5	0.2	0.3	0.4	0.8	1.1	1.8	2.3	3.3	3.9	5.0 H	3.2	3.9	na	2.5	2.4	2.1	2.2
The Northern Trust Company	0.2	3.4	0.4	0.2	0.3	0.4	0.6	0.7	1.6	2.1	2.7	3.6	4.5	3.6	3.9	103.0	2.5	2.6	2.5	2.3
ACIMA Private Wealth	0.1 L	3.3 L	0.2	0.1 L	0.0 L	0.0 L	0.1 L	0.2 L	0.6 L	1.2 L	1.7 L	2.8	3.7	1.4 L	2.5 L	97.0 L	1.5	0.9 L	1.9	1.9
Barclays	0.1 L	3.3 L	na	na	na	na	na	0.9	1.5	1.8	2.0	na	na	na	na	na	2.5	2.8	2.3	2.6
Georgia State University	0.1 L	3.3 L	na	na	0.1	0.1	0.4	0.9	1.8	2.5	2.9	3.4	4.7	na	4.1	na	2.8	2.1	2.3	2.0
IHS Markit	0.1 L	3.3 L	0.3	na	0.1	0.1	0.4	0.7	1.5	2.0	2.5	na	na	na	3.6	na	2.8	2.1	2.1	1.9
Loomis, Sayles & Company	0.1 L	3.3 L	0.2	0.1 L	0.1	0.1	0.2	0.5	1.2	2.0	2.5	3.2	3.8	2.9	3.4	106.6	3.3	2.0	2.3	2.0
Mizuho Research Institute	0.1 L	na	na	na	na	na	na	na	na	1.8	na	na	na	na	na	na	na	na	na	na
Via Nova Investment Mgt.	0.1 L	3.3 L	0.1 L	0.1 L	0.1	0.1	0.1 L	0.3	1.1	1.6	2.1	3.1	3.6	2.8	3.1	106.0	3.0	2.5	2.6	2.0
December Consensus	**0.4**	**3.5**	**0.6**	**0.5**	**0.4**	**0.5**	**0.6**	**1.0**	**1.6**	**2.1**	**2.6**	**3.4**	**4.2**	**3.0**	**3.7**	**106.3**	**2.6**	**2.5**	**2.5**	**2.3**
Top 10 Avg.	0.8	3.8	0.9	0.7	0.8	0.8	1.0	1.3	1.9	2.5	3.1	3.8	4.7	3.3	4.1	108.6	3.3	3.3	3.3	2.9
Bottom 10 Avg.	0.1	3.3	0.3	0.2	0.1	0.2	0.3	0.6	1.3	1.7	2.1	3.1	3.8	2.7	3.3	103.9	1.8	1.9	1.8	1.8
November Consensus	0.3	3.4	0.4	0.3	0.3	0.3	0.5	0.8	1.5	2.0	2.6	3.3	4.1	3.0	3.6	104.9	2.6	2.4	2.5	2.2
Number of Forecasts Changed From A Month Ago:																				
Down	2	0	0	2	1	3	2	1	4	4	17	3	4	6	4	2	15	7	9	8
Same	20	21	15	9	14	12	10	12	12	25	15	11	14	9	17	6	12	10	12	11
Up	18	13	15	13	18	16	19	23	19	9	3	8	4	3	9	13	11	18	15	15
Diffusion Index	70%	69%	75%	73%	76%	71%	77%	81%	71%	57%	30%	61%	50%	42%	58%	76%	45%	66%	58%	60%

First Quarter 2023

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	-------Percent Per Annum -- Average For Quarter-------															Avg. For	------(Q-Q % Change)------			
	------Short-Term------							---Intermediate-Term---			------Long-Term------					---Qtr.---	------(SAAR)------			
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
Chmura Economics & Analytics	1.3 H	4.4 H	1.5 H	1.3 H	1.3 H	1.3 H	1.4 H	1.5	2.2	2.7	3.1	3.6	na	na	4.0	na	2.8	2.4	3.2 H	na
BNP Paribas Americas	1.1	na	na	na	na	na	na	1.6	na	2.1	2.4	na	na	na	na	na	2.6	na	1.4 L	na
Daiwa Capital Markets America	1.0	4.1	1.2	1.1	1.0	1.1	1.1	1.8 H	2.4 H	2.6	2.9	3.8	4.4	na	4.2	109.0	2.7	2.7	3.1	2.8
Amherst Pierpont Securities	0.9	4.0	1.3	1.0	1.1	1.3 H	1.4 H	1.5	2.4 H	3.0 H	3.8 H	4.5 H	5.3 H	3.7	4.7 H	109.5	3.2 H	3.3	3.1	2.8
Grant Thornton/Diane Swonk	0.9	4.0	0.9	0.8	0.7	0.8	0.8	1.1	1.9	2.6	3.0	3.9	4.5	na	4.2	na	1.7	2.9	2.9	2.4
ING	0.9	na	1.1	na	na	na	na	1.3	1.8	2.3	2.6	na	na	na	na	na	2.7	na	na	na
J.P. Morgan Chase	0.9	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.5	2.2	2.4	2.1
Thru the Cycle	0.9	4.0	1.1	0.9	0.8	0.9	0.9	0.9	1.7	2.0	2.2	3.0	3.8	3.0	3.6	108.2	2.4	2.3	3.0	2.6
Scotiabank Group	0.8	3.8	na	na	0.4	na	na	1.5	1.9	2.4	2.7	na	na	na	na	na	2.9	2.4	1.4 L	2.2
Action Economics	0.7	3.8	0.7	0.7	0.8	0.9	1.1	1.2	1.6	1.9	2.4	3.1	3.9	3.0	3.6	107.1	na	na	na	na
BMO Capital Markets	0.7	3.8	0.8	na	0.6	0.6	0.8	1.1	1.6	2.1	2.4	na	na	na	3.8	106.9	2.3	2.2	2.5	2.3
Chan Economics	0.7	4.0	0.8	0.7	0.7	0.8	0.7	1.0	1.7	2.3	2.9	3.6	4.3	3.2	3.8	104.0	2.3	2.4	2.6	2.3
Economist Intelligence Unit	0.7	3.8	na	0.8	0.7	0.7	0.9	1.3	2.0	2.3	2.7	na	na	na	3.6	na	1.7	na	2.7	na
PNC Financial Services Corp.	0.7	3.8	0.9	na	0.8	0.8	1.0	1.3	1.6	2.0	2.5	na	4.0	2.6	3.7	106.7	2.1	2.6	3.2 H	2.9
Goldman Sachs & Co.	0.6	na	0.8	na	0.3	na	na	1.3	1.9	2.1	2.3	na	na	na	na	na	1.8	2.3	2.3	2.0
Naroff Economic Advisors	0.6	3.8	na	1.0	0.7	0.8	0.9	1.3	2.0	2.5	2.9	3.8	4.5	3.2	3.8	103.9	1.8	2.3	2.2	1.9
NatWest Markets	0.6	3.8	0.6	0.7	0.9	1.0	1.1	1.7	2.1	2.2	2.4	na	na	na	na	na	2.0	4.0 H	2.5	2.8
S&P Global	0.6	3.7	0.6	na	0.6	0.6	0.8	1.0	1.7	2.4	3.0	na	na	na	3.5	na	2.9	2.2	2.7	2.7
TS Lombard	0.6	3.7	0.9	0.7	0.9	0.9	0.9	1.0	1.8	2.7	3.4	4.2	5.0	3.3	4.5	112.0 H	2.9	3.1	3.1	3.1 H
DePrince & Assoc.	0.5	3.6	0.7	0.7	0.6	0.5	0.7	1.2	2.1	2.5	2.8	3.9	4.6	3.2	4.2	105.9	2.3	2.6	2.8	2.5
Oxford Economics	0.5	3.7	0.7	na	0.6	0.6	0.8	1.0	1.6	2.4	2.9	2.8	na	na	3.6	104.2	2.1	2.3	2.4	2.4
Swiss Re	0.5	3.6	0.7	0.5	0.4	0.5	0.5	0.7	1.2	1.6	2.3	3.0	3.8	na	3.5	107.0	1.5 L	3.6	1.8	2.0
Fannie Mae	0.4	3.5	na	na	0.9	1.1	1.3	1.5	1.8	1.8	2.1	na	na	na	3.5	na	2.2	3.2	2.9	2.6
Georgia State University	0.4	3.5	na	na	0.3	0.3	0.7	1.1	2.0	2.6	3.0	3.4	4.8	na	4.2	na	2.5	2.3	2.1	1.8 L
MacroFin Analytics & Rutgers Bus School	0.4	3.5	0.5	0.4	0.3	0.3	0.5	0.8	1.5	1.9	2.3	3.1	3.6 L	2.9	3.4	107.9	2.0	2.0	2.0	1.9
Moody's Analytics	0.4	3.5	0.8	0.4	0.6	0.7	1.1	1.3	1.9	2.4	3.4	4.0	5.1	3.4	3.9	na	2.8	2.2	2.1	2.2
Nomura Securities, Inc.	0.4	3.5	na	na	na	na	na	0.9	1.6	1.9	na	na	na	na	na	na	1.5 L	2.2	2.6	2.2
Regions Financial Corporation	0.4	3.6	0.6	0.5	0.4	0.5	0.6	1.1	1.8	2.2	2.6	3.6	4.5	3.1	3.8	108.0	2.9	2.2	2.1	2.2
Bank of the West	0.3	3.5	0.5	0.4	0.4	0.4	0.4	0.6	1.4	2.2	2.8	3.5	4.4	3.5	3.8	104.6	2.5	2.1	2.0	2.0
GLC Financial Economics	0.3	3.4	0.4	0.3	0.3	0.3	0.4	0.6	1.7	2.3	3.2	4.2	4.9	3.5	4.4	104.5	2.3	2.3	2.4	2.9
The Northern Trust Company	0.3	3.5	0.6	0.3	0.4	0.6	0.8	0.9	1.7	2.3	2.7	3.8	4.7	3.9 H	4.1	102.5	2.5	2.5	2.3	2.3
Via Nova Investment Mgt.	0.3	3.3 L	0.4	0.3	0.3	0.4	0.5	0.6	1.3	2.0	2.5	3.5	4.0	3.2	3.6	106.0	3.0	2.5	2.5	2.0
ACIMA Private Wealth	0.1 L	3.3 L	0.2 L	0.1 L	0.0 L	0.0 L	0.0 L	0.1 L	0.4 L	1.0 L	1.6 L	2.7 L	3.7	1.3 L	2.4 L	97.0 L	2.0	1.1 L	2.0	2.0
Barclays	0.1 L	3.3 L	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.0	2.9	2.0	2.8
IHS Markit	0.1 L	3.3 L	0.3	na	0.1	0.2	0.5	0.9	1.6	2.2	2.6	na	na	na	3.8	na	2.4	2.2	2.0	1.8 L
Loomis, Sayles & Company	0.1 L	3.3 L	0.2 L	0.1 L	0.1	0.1	0.2	0.5	1.3	2.1	2.6	3.3	3.9	3.0	3.5	106.6	2.9	2.0	2.3	2.1
Mizuho Research Institute	0.1 L	na	na	na	na	na	na	na	na	1.8	na	na	na	na	na	na	na	na	na	na
Wells Fargo	0.1 L	3.3 L	0.2 L	0.1 L	0.1	0.2	0.3	1.1	1.8	2.2	2.6	3.5	4.4	3.2	3.8	na	2.8	1.6	1.4 L	1.6
December Consensus	**0.6**	**3.7**	**0.7**	**0.6**	**0.6**	**0.7**	**0.8**	**1.1**	**1.7**	**2.2**	**2.7**	**3.6**	**4.4**	**3.1**	**3.8**	**106.1**	**2.4**	**2.5**	**2.4**	**2.3**
Top 10 Avg.	0.9	4.0	1.1	0.9	0.9	1.0	1.1	1.5	2.1	2.6	3.2	4.0	4.8	3.4	4.2	108.2	2.9	3.2	3.0	2.8
Bottom 10 Avg.	0.2	3.4	0.4	0.3	0.3	0.3	0.4	0.7	1.4	1.8	2.2	3.1	3.9	2.9	3.4	103.9	1.8	2.0	1.9	2.0
November Consensus	0.4	3.6	0.6	0.5	0.4	0.5	0.6	0.9	1.6	2.2	2.7	3.6	4.4	3.1	3.8	104.9	2.3	2.3	2.4	2.3
Number of Forecasts Changed From A Month Ago:																				
Down	1	0	1	1	1	3	2	1	2	4	12	3	2	4	4	2	7	6	5	6
Same	18	19	10	9	12	9	10	15	16	22	14	10	15	10	16	6	16	11	14	10
Up	18	13	16	12	17	16	16	16	13	8	5	7	3	2	8	12	12	15	14	15
Diffusion Index	73%	70%	78%	75%	77%	73%	75%	73%	68%	56%	39%	60%	53%	44%	57%	75%	57%	64%	64%	65%

International Interest Rate And Foreign Exchange Rate Forecasts

United States

	Fed Fund Target Rate			10 Yr. Gov't Bond Yield %			Fed's AFE $ Index		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.13	0.13	--	1.69	1.65	--	--	--	--
BMO Capital Markets	0.13	0.13	0.38	1.65	1.75	1.95	108.1	107.7	107.0
IHSMarkit	--	--	--	1.77	1.83	2.09	--	--	--
ING Financial Markets	0.13	0.13	0.38	1.75	2.00	2.25	104.2	105.2	108.1
Mizuho Research Institute	0.13	0.13	0.13	1.70	1.75	1.75	--	--	--
Moody's Analytics	0.13	0.13	0.13	1.65	1.89	2.30	--	--	--
Northern Trust	0.13	0.13	0.25	1.75	1.90	2.10	108.0	106.0	103.0
Oxford Economics	0.13	0.13	0.38	1.81	2.08	2.32	106.2	106.0	104.8
S&P Global	0.12	0.12	0.38	1.84	2.07	2.37	--	--	--
Scotiabank	0.13	0.13	0.50	2.05	2.20	2.30	--	--	--
TS Lombard	0.13	0.13	0.63	1.80	2.00	2.30	110.0	112.0	114.0
Wells Fargo	0.13	0.13	0.38	1.80	2.00	2.10	--	--	--
December Consensus	**0.13**	**0.13**	**0.35**	**1.77**	**1.93**	**2.17**	**107.3**	**107.4**	**107.4**
High	0.13	0.13	0.63	2.05	2.20	2.37	110.0	112.0	114.0
Low	0.12	0.12	0.13	1.65	1.65	1.75	104.2	105.2	103.0
Last Months Avg.	0.13	0.13	0.23	1.69	1.85	2.16	105.0	104.2	103.5

Japan

	Policy-Rate Balance Rate			10 Yr. Gov't Bond Yield %			Yen per US$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.10	0.10	--	0.05	0.05	--	111.0	112.0	--
BMO Capital Markets	-0.10	-0.10	-0.10	0.10	0.10	0.10	114.0	114.0	113.0
IHSMarkit	--	--	--	--	--	--	114.4	113.6	111.6
ING Financial Markets	-0.10	-0.10	-0.10	0.00	0.00	0.00	114.0	114.0	118.0
Mizuho Research Institute	-0.10	-0.10	-0.10	0.10	0.11	0.11	113.0	113.0	113.0
Moody's Analytics	-0.10	-0.10	-0.10	0.03	0.02	0.01	111.0	110.0	108.7
Nomura Securities	--	--	--	--	--	--	116.0	117.0	115.0
Northern Trust	-0.10	-0.10	-0.10	0.10	0.10	0.10	114.0	112.0	110.0
Oxford Economics	-0.05	-0.05	-0.05	0.09	0.08	0.05	113.5	113.0	111.8
S&P Global	-0.10	-0.10	-0.10	0.08	0.08	0.06	114.5	114.5	115.0
Scotiabank	-0.10	-0.10	-0.10	--	--	--	113.0	115.0	116.0
TS Lombard	-0.10	-0.10	-0.10	0.10	0.20	0.30	115.0	118.0	120.0
Wells Fargo	-0.10	-0.10	-0.10	0.10	0.15	0.20	117.0	119.0	121.0
December Consensus	**-0.08**	**-0.08**	**-0.10**	**0.08**	**0.09**	**0.10**	**113.9**	**114.2**	**114.4**
High	0.10	0.10	-0.05	0.10	0.20	0.30	117.0	119.0	121.0
Low	-0.10	-0.10	-0.10	0.00	0.00	0.00	111.0	110.0	108.7
Last Months Avg.	-0.08	-0.08	-0.10	0.07	0.09	0.15	111.9	111.9	112.2

United Kingdom

	Official Bank Rate			10 Yr. Gilt Yields %			US$ per Pound Sterling		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.10	0.10	--	1.00	1.10	--	1.40	1.39	--
BMO Capital Markets	0.25	0.25	0.50	1.10	1.15	1.30	1.35	1.35	1.35
IHSMarkit	--	--	--	--	--	--	1.35	1.35	1.35
ING Financial Markets	0.25	0.25	0.50	1.10	1.10	1.10	1.38	1.37	1.34
Moody's Analytics	0.10	0.20	0.35	1.02	1.21	1.43	1.41	1.44	1.49
Nomura Securities	--	--	--	--	--	--	1.32	1.38	1.46
Northern Trust	0.25	0.25	0.50	1.20	1.30	1.55	1.34	1.37	1.39
Oxford Economics	0.25	0.25	0.50	1.10	1.23	1.53	1.37	1.38	1.41
S&P Global	0.23	0.43	0.50	1.11	1.21	1.50	1.36	1.36	1.36
Scotiabank	0.50	0.75	1.00	--	--	--	1.40	1.40	1.42
TS Lombard	0.10	0.10	0.25	1.00	1.40	1.90	1.35	1.31	1.29
Wells Fargo	0.25	0.50	0.75	1.25	1.40	1.60	1.31	1.29	1.28
December Consensus	**0.23**	**0.31**	**0.54**	**1.10**	**1.23**	**1.49**	**1.36**	**1.37**	**1.38**
High	0.50	0.75	1.00	1.25	1.40	1.90	1.41	1.44	1.49
Low	0.10	0.10	0.25	1.00	1.10	1.10	1.31	1.29	1.28
Last Months Avg.	0.20	0.28	0.48	1.02	1.18	1.52	1.38	1.39	1.41

Switzerland

	SNB Policy Rate			10 Yr. Gov't Bond Yield %			CHF per US$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	-0.75	-0.75	--	--	--	--	0.92	0.91	--
IHSMarkit	--	--	--	--	--	--	0.92	0.92	0.93
ING Financial Markets	-0.75	-0.75	-0.75	-0.15	-0.10	0.00	0.91	0.96	1.01
Moody's Analytics	-0.75	-0.75	-0.75	-0.20	-0.23	-0.10	0.91	0.88	0.82
Nomura Securities	--	--	--	--	--	--	1.00	0.97	0.96
Northern Trust	-0.75	-0.75	-0.75	-0.15	-0.05	0.10	0.93	0.92	0.91
Oxford Economics	-0.75	-0.75	-0.75	0.02	0.08	0.20	0.95	0.95	0.93
S&P Global	-0.75	-0.75	-0.75	-0.11	0.03	0.17	0.96	0.97	0.98
Scotiabank	--	--	--	--	--	--	0.94	0.95	0.97
TS Lombard	-0.75	-0.75	-0.25	-0.15	0.25	0.75	0.92	0.92	0.92
December Consensus	**-0.75**	**-0.75**	**-0.67**	**-0.12**	**0.00**	**0.19**	**0.94**	**0.94**	**0.94**
High	-0.75	-0.75	-0.25	0.02	0.25	0.75	1.00	0.97	1.01
Low	-0.75	-0.75	-0.75	-0.20	-0.23	-0.10	0.91	0.88	0.82
Last Months Avg.	-0.75	-0.75	-0.75	-0.12	-0.05	0.12	0.93	0.93	0.93

Canada

	O/N MMkt Financing Rate			10 Yr. Gov't Bond Yield %			C$ per US$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.25	0.25	--	--	--	--	1.24	1.23	--
BMO Capital Markets	0.20	0.20	0.70	1.75	1.85	2.00	1.26	1.25	1.23
IHSMarkit	--	--	--	--	--	--	1.27	1.27	1.25
ING Financial Markets	0.25	0.50	1.00	1.90	2.10	2.40	1.23	1.22	1.23
Moody's Analytics	0.25	0.25	0.50	1.72	1.89	2.32	1.24	1.23	1.22
Nomura Securities	--	--	--	--	--	--	1.23	1.22	1.21
Northern Trust	0.25	0.50	0.75	1.70	1.95	2.20	1.26	1.24	1.23
Oxford Economics	0.25	0.25	0.50	1.87	2.09	2.40	1.25	1.27	1.27
S&P Global	0.25	0.50	0.75	1.84	2.17	2.66	1.24	1.26	1.27
Scotiabank	0.25	0.25	1.25	1.75	1.85	2.05	1.22	1.22	1.20
TS Lombard	0.25	0.25	0.75	1.92	2.12	2.42	1.26	1.26	1.26
Wells Fargo	0.25	0.50	1.00	1.85	2.05	2.25	1.28	1.29	1.27
December Consensus	**0.25**	**0.35**	**0.80**	**1.81**	**2.01**	**2.30**	**1.25**	**1.25**	**1.24**
High	0.25	0.50	1.25	1.92	2.17	2.66	1.28	1.29	1.27
Low	0.20	0.20	0.50	1.70	1.85	2.00	1.22	1.22	1.20
Last Months Avg.	0.25	0.25	0.47	1.66	1.82	2.14	1.25	1.24	1.23

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

	Official Cash Rate			10 Yr. Gov't Bond Yield %			US$ per A$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.10	0.10	--	--	--	--	0.74	0.75	--
IHSMarkit	--	--	--	--	--	--	0.74	0.74	0.72
ING Financial Markets	0.10	0.10	0.10	1.75	1.80	1.85	0.73	0.75	0.75
Moody's Analytics	0.10	0.10	0.10	1.60	1.67	1.80	0.75	0.75	0.76
Nomura Securities	--	--	--	--	--	--	0.74	0.76	0.78
Northern Trust	0.10	0.10	0.10	1.90	2.00	2.20	0.72	0.74	0.75
Oxford Economics	0.08	0.10	0.10	2.15	2.30	2.48	0.74	0.74	0.75
S&P Global	0.10	0.10	0.10	2.11	2.28	2.44	0.74	0.74	0.74
Scotiabank	0.10	0.10	0.10	--	--	--	0.74	0.74	0.72
TS Lombard	0.10	0.10	-0.10	2.05	2.25	2.55	0.75	0.70	0.65
December Consensus	**0.10**	**0.10**	**0.07**	**1.93**	**2.05**	**2.22**	**0.74**	**0.74**	**0.74**
High	0.10	0.10	0.10	2.15	2.30	2.55	0.75	0.76	0.78
Low	0.08	0.10	-0.10	1.60	1.67	1.80	0.72	0.70	0.65
Last Months Avg.	0.10	0.10	0.12	1.69	1.85	2.15	0.73	0.75	0.76

Euro area

	Main Refinancing Rate			US$ per Euro		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.00	0.00	--	1.18	1.18	--
BMO Capital Markets	0.00	0.00	0.00	1.11	1.12	1.12
IHSMarkit	--	--	--	1.16	1.15	1.15
ING Financial Markets	0.00	0.00	0.00	1.17	1.15	1.11
Mizuho Research Institute	0.00	0.00	0.00	1.16	1.16	1.16
Moody's Analytics	0.00	0.00	0.00	1.17	1.20	1.27
Nomura Securities	--	--	--	1.10	1.14	1.18
Northern Trust	0.00	0.00	0.00	1.14	1.16	1.19
Oxford Economics	0.00	0.00	0.00	1.16	1.18	1.20
S&P Global	0.00	0.00	0.00	1.15	1.15	1.15
Scotiabank	0.00	0.00	0.00	1.15	1.14	1.12
TS Lombard	0.00	0.00	0.00	1.13	1.10	1.08
Wells Fargo	-0.50	-0.50	-0.50	1.09	1.08	1.07
December Consensus	**-0.05**	**-0.05**	**-0.05**	**1.14**	**1.15**	**1.15**
High	0.00	0.00	0.00	1.18	1.20	1.27
Low	-0.50	-0.50	-0.50	1.09	1.08	1.07
Last Months Avg.	-0.05	-0.05	-0.05	1.16	1.17	1.19

10 Yr. Gov't Bond Yields %

	Germany			France			Italy			Spain		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	-0.20	-0.15	--	--	--	--	--	--	--	--	--	--
BMO Capital Markets	-0.10	-0.05	0.15	--	--	--	--	--	--	--	--	--
ING Financial Markets	-0.15	-0.10	0.10	0.25	0.40	0.35	1.05	1.40	1.20	0.60	0.70	0.70
Mizuho Research Institute	0.15	0.15	0.15	--	--	--	--	--	--	--	--	--
Moody's Analytics	-0.25	-0.20	-0.03	0.09	0.11	0.24	0.89	0.92	1.06	0.37	0.36	0.54
Northern Trust	-0.25	-0.10	0.10	0.10	0.25	0.45	0.90	1.10	1.30	0.50	0.65	0.85
Oxford Economics	0.00	0.08	0.23	0.35	0.42	0.56	1.28	1.42	1.70	0.73	0.88	1.18
S&P Global	-0.16	-0.02	0.15	0.12	0.28	0.47	1.00	1.21	1.39	0.53	0.68	0.89
TS Lombard	-0.20	0.20	0.70	-0.25	0.15	0.65	0.57	0.97	1.47	0.55	0.65	1.00
Wells Fargo	-0.15	-0.10	0.15	--	--	--	--	--	--	--	--	--
December Consensus	**-0.13**	**-0.03**	**0.19**	**0.11**	**0.27**	**0.45**	**0.95**	**1.17**	**1.35**	**0.55**	**0.65**	**0.86**
High	0.15	0.20	0.70	0.35	0.42	0.65	1.28	1.42	1.70	0.73	0.88	1.18
Low	-0.25	-0.20	-0.03	-0.25	0.11	0.24	0.57	0.92	1.06	0.37	0.36	0.54
Last Months Avg.	-0.17	-0.08	0.13	0.12	0.28	0.49	0.91	1.09	1.32	0.47	0.63	0.86

Consensus Forecasts

10-year Bond Yields vs U.S. Yield

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-1.46	-1.70	-1.84	-2.06
United Kingdom	-0.65	-0.67	-0.69	-0.68
Switzerland	-1.69	-1.90	-1.93	-1.98
Canada	0.12	0.04	0.08	0.13
Australia	0.27	0.16	0.12	0.05
Germany	-1.88	-1.90	-1.96	-1.98
France	-1.54	-1.66	-1.66	-1.71
Italy	-0.68	-0.82	-0.76	-0.81
Spain	-1.08	-1.23	-1.27	-1.31

Consensus Forecasts

Policy Rates vs U.S. Target Rate

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.23	-0.21	-0.05	-0.45
United Kingdom	-0.03	0.10	0.18	0.18
Switzerland	-0.88	-0.88	-0.88	-1.02
Canada	0.13	0.12	0.22	0.45
Australia	-0.03	-0.03	-0.03	-0.28
Euro area	-0.13	-0.17	-0.17	-0.40

Viewpoints:

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

ECB to Slow But Not End Its Quantitative Easing Programs in 2022; Euro Interest Rates to Stay Negative for Many Years

The Eurozone's recovery finally hit its stride in mid-2021. Real GDP plunged 15% in the first half of 2020 (not annualized), rebounded in the summer and fall, and then fell for two straight quarters during the pandemic's winter wave. Real GDP finally rebounded a strong 8.9% annualized in the second and third quarters of 2021 as vaccinations accelerated and restrictions on activity lifted. Real GDP was just 0.6% lower in the third quarter than its pre-crisis level of the fourth quarter of 2019.

The recovery looks even stronger viewed through the labor market—employment in September was just 14,000 short of the pre-crisis peak (less than 0.1%). The Eurozone's statistics do not record furloughs as unemployment, and understated labor market slack at the bottom of the downturn. But firms are bringing back furloughed workers in 2021 as economic activity and demand recover. The Eurozone's labor protections maintained ties between employers and workers, preventing most of the dislocation experienced in the U.S. job market. Eurozone employment's quick bounce back from the Viral Recession stands in sharp contrast to the recovery after the 2009 recession, when eight and a half years passed before employment returned to its pre-crisis level.

Fiscal policy will provide much less support in 2022 as temporary aid programs and "automatic stabilizers" (unemployment insurance, furlough subsidies, and so forth) expire. Fiscal stimulus was a big tailwind in 2021; the EU estimates the Eurozone fiscal deficit was 8% of GDP in 2021, up from 7.2% in 2020 and 0.6% in 2019. But they forecast the deficit to fall to 4% of GDP in 2022. The deficit's shrinking share of GDP will be a net headwind to growth next year.

Against this backdrop, the Governing Council of the European Central Bank (ECB) has begun to rein in their crisis-era stimulus programs. They announced a taper of the main crisis-era quantitative easing program on September 9: Net purchases by the Pandemic Emergency Purchase Programme (PEPP) will slow to a "moderately lower pace" in the fourth quarter of 2021 than in the second and third quarters. "Moderately lower" means €65bn to €70bn per month—the ECB does not announce explicit quantitative targets for PEPP purchases. Monthly purchases averaged about €60 billion in the first quarter of 2021 and rose to about €80bn in the second and third quarters (called "a significantly higher" pace). The ambiguity leaves the ECB wiggle room to buy more if financial conditions worsen or buy less if the pandemic's drag on the economy ends faster than expected.

If the recovery goes well, the ECB will wind down its stimulus programs along several different timelines. They will probably slow PEPP purchases again in early 2022 and end them in March; the ECB also is likely to shorten the tenor of negative interest rate loans they make available to Eurozone commercial banks, called Pandemic Emergency Longer-Term Refinancing Operations, a.k.a. PELTROs.

Other unconventional stimulus programs will probably continue for much longer. The ECB's interest rate guidance commits to holding the negative deposit rate at -0.5% or lower until their three-year economic projections show inflation of 2% or more in the second and third years of the forecast, and also requires that "underlying" (core) inflation rise to be "consistent with inflation stabilizing at two per cent over the medium term." The ECB's projections do not expect these conditions in the next few years: Their staff economists' projections, published in September 2021, foresee inflation of 2.2% in 2021, 1.7% in 2022, and 1.5% in 2023.

Financial markets likewise price in inflation over 2% through the second half of 2022, then expect it to average below 2% for a decade. The ECB's guidance for the Asset Purchase Programme (APP) foresees purchases continuing until "shortly before" the ECB begins raising interest rates, so it too will likely stay active for many years. The APP has bought €20 billion assets per month on an open-ended basis since November 2019 and will likely continue at this rate in 2022, and could increase it if the end of PEPP starts to send sovereign bond yields higher. Over the next few years, the ECB will change its inflation basket to incorporate owner-occupied housing costs; Eurozone house price increases have risen rapidly since the pandemic began, so this change might add a few tenths of a percentage point to Eurozone inflation if the housing market stays hot. Even so, there is no end in sight for the ECB's quantitative easing and negative rate policies. PNC forecasts for the euro to be modestly weaker in coming years as the Federal Reserve normalizes U.S. policy more than the ECB, with targets of $1.15 per euro for year-end 2022 and $1.14 for year-end 2023.

There are three key downside risks to the Eurozone. The first is the risk of an energy price shock if Russia throttles back natural gas deliveries during the winter. The second is from the pandemic as European weather turns colder. The third is from the sovereign bond market: spreads between the yields of bonds issued by the Eurozone's weaker governments and its stronger ones could widen and fiscal vulnerabilities could return as a problem for the currency union after PEPP ends.

Gus Faucher (The PNC Financial Services Group)

A Faster Taper and a Slightly Earlier Liftoff

• Several FOMC participants have signaled over the last couple of weeks that they are open to accelerating the pace of tapering, including Vice Chair Clarida and most recently San Francisco Fed President Daly. The increased openness to accelerating the taper pace likely reflects both somewhat higher-than-expected inflation over the last two months and greater comfort among

Fed officials that a faster pace would not shock financial markets.

- We now expect the Fed to announce at its December meeting that it is doubling the pace of tapering to $30bn per month starting in January. In that scenario, the FOMC would announce the final two tapers at its January meeting and implement the final taper in mid-March, several days before the March FOMC meeting.

- While this faster pace of tapering would allow the FOMC to consider a rate hike as early as March, our best guess is that it will wait until June, when a few additional employment reports will be available. We now expect hikes in June, September, and December, for a total of three in 2022 (vs. two in July and November previously), followed by two hikes per year starting in 2023. We see an alternative path of hikes at the May, July, and November meetings as a realistic possibility too. The largest risk to our expectation of an early liftoff is that some participants might find it hard to square a still-large employment gap relative to the pre-pandemic level with the guidance that the FOMC will not hike until the labor market reaches maximum employment.

Over the last couple of weeks, several FOMC participants have indicated that they prefer a faster pace of tapering or are at least open to discussing it at the December meeting. Last week, Vice Chair Clarida said that it “may well be appropriate at [the December FOMC] meeting to have a discussion about increasing the pace at which we’re reducing our balance sheet,” the first such signal from the leadership. And yesterday, San Francisco Fed President Mary Daly—who has leaned dovish in the past—said that if labor market conditions continue to improve and inflation remains strong, she “would completely support an accelerated pace of tapering.” Other participants including Atlanta Fed President Bostic, St. Louis Fed President Bullard, and Governor Waller have also argued for accelerating the pace of tapering.

The increased openness to accelerating the taper pace likely reflects both somewhat higher-than-expected inflation over the last two months and greater comfort among Fed officials that a faster pace would not shock financial markets. Some Fed officials might be persuaded to accelerate the taper by the upside inflation surprises over the last two months, especially on the shelter component. Other Fed officials, especially in the leadership, might have already expected inflation prints to remain high through the winter, but—with market pricing of rate hikes in the first half of 2022 rising—might now feel more confident that accelerating the pace, which is already more than twice as fast as the pace last cycle, will not produce the sort of unexpected market turmoil that reductions in balance sheet accommodation have sometimes caused in the past.

We now expect the Fed to announce at its December meeting that it is doubling the pace of tapering to $30bn per month starting in January. In that scenario, the FOMC would announce the final two tapers at its January meeting and implement the final taper in mid-March, several days before the March FOMC meeting. This timeline would be consistent with comments from Waller, Bullard, and Bostic advocating ending the taper by the first quarter of 2022.

While this faster pace of tapering would allow the FOMC to consider a rate hike as early as its March 15-16 meeting, our best guess is that it will wait until the June meeting. By that point, a few additional employment reports will be available and will hopefully show a labor market that Fed officials feel more comfortable characterizing as having reached maximum employment. The FOMC might say at its March meeting that it is evaluating the impact of tapering and will begin the discussion of rate hikes soon, then hint at its May meeting that a hike is coming soon, before ultimately hiking in June.

We expect the FOMC to follow a June hike with hikes in September and December for a total of three in 2022, vs. our previous forecast of two hikes in July and November. While we expect inflation to gradually decline next year, at the time of the December meeting the latest available inflation prints would still be 2.6% year-on-year for core PCE and 3.6% for core CPI under our forecast. We continue to expect a pace of two hikes per year starting in 2023 and we have not made any change to our terminal rate forecast of 2.5-2.75%, so we are effectively pulling one future hike forward into 2022.

We see an alternative path of hikes in May, July, and November next year as a realistic possibility too.

The largest risk to our expectation of an early liftoff is that some participants might find it hard to square a still-large employment gap relative to the pre-pandemic level—1.8mn at the time of the June meeting—with the guidance in the FOMC statement that the committee will not raise interest rates until the labor market reaches maximum employment. But we expect the unemployment rate to have fallen to 3.7% by June 2022, and we think that most participants, even many of the doves, will conclude that after a prolonged period in which job opportunities have been plentiful, any decline in the participation rate that remains by the middle of next year is likely to be mostly voluntary or structural.

David Mericle, Jan Hatzius, Ronnie Walker (Goldman Sachs)

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Special Questions:

1. Will the Fed accelerate tapering of its asset purchases?

Yes	52%
No	48%

2. How long do you expect supply-chain bottlenecks to provide a significant boost to inflation?

0-6 months	33%
7-9 months	33%
10-12 months	30%
13-24 months	3%
More than 24 months	0%

Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2023 through 2027 and averages for the five-year periods 2023-2027 and 2028-2032. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		------------------------ Average For The Year				------------------------	Five-Year Averages	
		2023	**2024**	**2025**	**2026**	**2027**	**2023-2027**	**2028-2032**
1. Federal Funds Rate	**CONSENSUS**	**0.8**	**1.6**	**2.0**	**2.2**	**2.3**	**1.8**	**2.2**
	Top 10 Average	1.2	2.2	2.7	2.7	2.8	2.3	2.9
	Bottom 10 Average	0.4	1.0	1.4	1.7	1.8	1.2	1.5
2. Prime Rate	**CONSENSUS**	**4.0**	**4.7**	**5.1**	**5.3**	**5.4**	**4.9**	**5.3**
	Top 10 Average	4.3	5.3	5.8	5.8	5.9	5.4	6.0
	Bottom 10 Average	3.6	4.1	4.5	4.9	5.0	4.4	4.6
3. LIBOR, 3-Mo.	**CONSENSUS**	**1.0**	**1.7**	**2.2**	**2.4**	**2.5**	**1.9**	**2.4**
	Top 10 Average	1.3	2.1	2.7	2.9	3.0	2.4	3.1
	Bottom 10 Average	0.7	1.2	1.6	1.9	2.0	1.5	1.8
4. Commercial Paper, 1-Mo	**CONSENSUS**	**0.9**	**1.6**	**2.1**	**2.3**	**2.4**	**1.9**	**2.4**
	Top 10 Average	1.2	2.0	2.6	2.8	2.9	2.3	2.9
	Bottom 10 Average	0.6	1.2	1.6	1.9	2.0	1.5	1.8
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**0.8**	**1.4**	**1.8**	**2.0**	**2.3**	**1.7**	**2.2**
	Top 10 Average	1.2	1.9	2.5	2.6	2.8	2.2	2.9
	Bottom 10 Average	0.4	0.8	1.2	1.5	1.8	1.1	1.6
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**0.8**	**1.4**	**1.9**	**2.1**	**2.4**	**1.7**	**2.3**
	Top 10 Average	1.2	2.0	2.6	2.7	2.9	2.3	3.0
	Bottom 10 Average	0.4	0.9	1.2	1.6	1.9	1.2	1.7
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**1.0**	**1.6**	**2.1**	**2.4**	**2.5**	**1.9**	**2.4**
	Top 10 Average	1.4	2.1	2.7	2.8	3.0	2.4	3.1
	Bottom 10 Average	0.6	1.2	1.5	1.9	2.0	1.4	1.8
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**1.3**	**1.9**	**2.4**	**2.6**	**2.6**	**2.2**	**2.6**
	Top 10 Average	1.7	2.5	3.0	3.1	3.2	2.7	3.4
	Bottom 10 Average	0.8	1.4	1.8	2.0	2.1	1.6	1.9
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**1.9**	**2.4**	**2.8**	**2.9**	**2.9**	**2.6**	**3.0**
	Top 10 Average	2.3	3.0	3.4	3.5	3.6	3.1	3.8
	Bottom 10 Average	1.5	1.9	2.1	2.3	2.3	2.0	2.2
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**2.4**	**2.8**	**3.1**	**3.2**	**3.2**	**2.9**	**3.3**
	Top 10 Average	2.8	3.3	3.7	3.8	3.9	3.5	4.2
	Bottom 10 Average	2.0	2.3	2.4	2.5	2.5	2.3	2.4
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**2.9**	**3.3**	**3.6**	**3.7**	**3.7**	**3.4**	**3.8**
	Top 10 Average	3.4	3.9	4.3	4.4	4.4	4.1	4.6
	Bottom 10 Average	2.4	2.8	2.9	3.0	3.0	2.8	3.0
12. Corporate Aaa Bond Yield	**CONSENSUS**	**3.7**	**4.2**	**4.5**	**4.6**	**4.8**	**4.4**	**4.9**
	Top 10 Average	4.3	4.7	5.1	5.2	5.4	4.9	5.6
	Bottom 10 Average	3.2	3.7	3.9	4.1	4.2	3.8	4.2
13. Corporate Baa Bond Yield	**CONSENSUS**	**4.6**	**5.0**	**5.3**	**5.5**	**5.6**	**5.2**	**5.7**
	Top 10 Average	5.1	5.5	5.9	6.1	6.2	5.7	6.5
	Bottom 10 Average	4.0	4.5	4.8	4.9	5.0	4.7	5.0
14. State & Local Bonds Yield	**CONSENSUS**	**3.2**	**3.7**	**3.9**	**4.1**	**4.2**	**3.8**	**4.3**
	Top 10 Average	3.8	4.3	4.5	4.7	4.8	4.4	5.0
	Bottom 10 Average	2.7	3.2	3.4	3.5	3.6	3.3	3.6
15. Home Mortgage Rate	**CONSENSUS**	**4.0**	**4.4**	**4.7**	**4.8**	**4.8**	**4.5**	**4.9**
	Top 10 Average	4.5	5.0	5.3	5.4	5.4	5.1	5.7
	Bottom 10 Average	3.6	3.9	4.1	4.1	4.2	4.0	4.1
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**106.2**	**106.0**	**106.1**	**106.2**	**106.4**	**106.2**	**106.5**
	Top 10 Average	108.1	108.4	108.9	109.0	109.2	108.7	110.1
	Bottom 10 Average	104.4	104.0	103.7	103.7	103.9	103.9	103.1
		--------------------- Year-Over-Year, % Change				---------------------	Five-Year Averages	
		2023	**2024**	**2025**	**2026**	**2027**	**2023-2027**	**2028-2032**
B. Real GDP	**CONSENSUS**	**2.6**	**2.2**	**2.1**	**2.0**	**2.0**	**2.2**	**2.0**
	Top 10 Average	3.1	2.6	2.5	2.4	2.3	2.6	2.4
	Bottom 10 Average	2.2	1.7	1.7	1.7	1.7	1.8	1.7
C. GDP Chained Price Index	**CONSENSUS**	**2.5**	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**	**2.1**
	Top 10 Average	3.0	2.7	2.5	2.4	2.4	2.6	2.4
	Bottom 10 Average	2.0	1.9	1.9	1.9	1.9	1.9	1.8
D. Consumer Price Index	**CONSENSUS**	**2.6**	**2.3**	**2.3**	**2.2**	**2.2**	**2.3**	**2.2**
	Top 10 Average	3.2	2.8	2.6	2.5	2.5	2.7	2.5
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	1.9
E. PCE Price Index	**CONSENSUS**	**2.5**	**2.2**	**2.1**	**2.1**	**2.1**	**2.2**	**2.1**
	Top 10 Average	3.0	2.6	2.4	2.4	2.3	2.6	2.4
	Bottom 10 Average	2.0	1.9	1.9	1.9	1.9	1.9	1.9

Databank:

2021 Historical Data

Monthly Indicator	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Retail and Food Service Sales (a)	7.6	-2.9	11.3	0.9	-1.4	0.9	-1.6	1.2	0.8	1.7	····	····
Auto & Light Truck Sales (b)	16.78	15.93	17.64	18.30	16.89	15.47	14.67	13.09	12.22	12.99	····	····
Personal Income (a, current $)	9.9	-7.2	21.0	-13.3	-2.0	0.3	1.2	0.3	-1.0	0.5	····	····
Personal Consumption (a, current $)	3.3	-1.1	5.2	1.0	0.0	1.1	0.0	1.1	0.6	1.3	····	····
Consumer Credit (e)	-0.5	5.8	5.5	4.6	9.3	10.0	4.6	3.8	8.3	····	····	····
Consumer Sentiment (U. of Mich.)	79.0	76.8	84.9	88.3	82.9	85.5	81.2	70.3	72.8	71.7	67.4	····
Household Employment (c)	201	208	609	328	444	-18	1043	509	526	359	····	····
Nonfarm Payroll Employment (c)	233	536	785	269	614	962	1091	483	312	531	····	····
Unemployment Rate (%)	6.3	6.2	6.0	6.1	5.8	5.9	5.4	5.2	4.8	4.6	····	····
Average Hourly Earnings (All, cur. $)	29.92	30.00	29.97	30.17	30.31	30.44	30.55	30.67	30.85	30.96	····	····
Average Workweek (All, hrs.)	35.0	34.6	34.9	34.9	34.8	34.7	34.7	34.6	34.8	34.7	····	····
Industrial Production (d)	-1.7	-4.9	1.8	17.9	16.4	10.2	6.7	5.6	4.6	5.1	····	····
Capacity Utilization (%)	75.0	72.7	74.8	74.8	75.3	75.6	76.2	76.2	75.2	76.4	····	····
ISM Manufacturing Index (g)	58.7	60.8	64.7	60.7	61.2	60.6	59.5	59.9	61.1	60.8	····	····
ISM Nonmanufacturing Index (g)	58.7	55.3	63.7	62.7	64.0	60.1	64.1	61.7	61.9	66.7	····	····
Housing Starts (b)	1.625	1.447	1.725	1.514	1.594	1.657	1.562	1.573	1.530	1.520	····	····
Housing Permits (b)	1.883	1.726	1.755	1.733	1.683	1.594	1.630	1.721	1.586	1.653	····	····
New Home Sales (1-family, c)	993	823	873	796	733	683	704	693	742	745	····	····
Construction Expenditures (a)	3.0	-1.1	1.0	0.3	0.7	1.0	0.1	0.1	-0.5	····	····	····
Consumer Price Index (nsa, d)	1.4	1.7	2.6	4.2	5.0	5.4	5.4	5.3	5.4	6.2	····	····
CPI ex. Food and Energy (nsa, d)	1.4	1.3	1.6	3.0	3.8	4.5	4.3	4.0	4.0	4.6	····	····
PCE Chain Price Index (d)	1.4	1.6	2.5	3.6	4.0	4.0	4.1	4.2	4.4	5.0	····	····
Core PCE Chain Price Index (d)	1.5	1.5	2.0	3.1	3.5	3.6	3.6	3.6	3.7	4.1	····	····
Producer Price Index (nsa, d)	1.6	3.0	4.1	6.5	7.0	7.6	7.8	8.3	8.6	8.6	····	····
Durable Goods Orders (a)	2.4	1.3	1.3	-0.7	3.2	0.8	0.5	1.3	-0.4	-0.5	····	····
Leading Economic Indicators (a)	0.5	0.0	1.3	1.4	1.3	0.7	0.9	0.7	0.1	0.9	····	····
Balance of Trade & Services (f)	-65.7	-68.2	-72.2	-66.7	-68.5	-73.2	-70.3	-72.8	-80.9	····	····	····
Federal Funds Rate (%)	0.09	0.08	0.07	0.07	0.06	0.08	0.10	0.09	0.08	0.08	····	····
3-Mo. Treasury Bill Rate (%)	0.08	0.04	0.03	0.02	0.02	0.04	0.05	0.05	0.04	0.05	····	····
10-Year Treasury Note Yield (%)	1.08	1.26	1.61	1.64	1.62	1.52	1.32	1.28	1.37	1.58	····	····

2020 Historical Data

Monthly Indicator	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Retail and Food Service Sales (a)	0.6	-0.2	-8.6	-14.7	18.2	8.7	1.4	0.8	2.1	-0.1	-1.1	-1.2
Auto & Light Truck Sales (b)	16.87	16.88	11.25	8.61	12.13	13.10	14.71	15.25	16.28	16.40	15.87	16.31
Personal Income (a, current $)	1.1	0.7	-1.9	12.5	-4.0	-0.9	0.9	-2.9	0.7	-0.2	-1.0	0.7
Personal Consumption (a, current $)	0.6	0.1	-6.9	-12.6	8.6	6.4	1.7	1.0	1.5	0.4	-0.5	-0.5
Consumer Credit (e)	2.5	4.6	-5.2	-18.2	-4.3	5.8	3.8	-3.2	4.9	-0.1	3.1	3.2
Consumer Sentiment (U. of Mich.)	99.8	101.0	89.1	71.8	72.3	78.1	72.5	74.1	80.4	81.8	76.9	80.7
Household Employment (c)	-76	73	-3196	-22166	3854	4876	1677	3499	267	2126	140	21
Nonfarm Payroll Employment (c)	315	289	-1683	-20679	2833	4846	1726	1583	716	680	264	-306
Unemployment Rate (%)	3.5	3.5	4.4	14.8	13.3	11.1	10.2	8.4	7.8	6.9	6.7	6.7
Average Hourly Earnings (All, cur. $)	28.43	28.51	28.74	30.07	29.74	29.35	29.37	29.47	29.50	29.52	29.61	29.91
Average Workweek (All, hrs.)	34.3	34.4	34.1	34.2	34.7	34.6	34.6	34.7	34.8	34.8	34.8	34.7
Industrial Production (d)	-2.1	-1.4	-5.3	-17.7	-16.2	-11.0	-7.0	-6.6	-6.6	-4.7	-4.7	-3.3
Capacity Utilization (%)	76.1	76.3	73.4	63.4	64.7	68.7	71.5	72.3	72.1	72.9	73.3	74.1
ISM Manufacturing Index (g)	51.1	50.3	49.7	41.7	43.1	52.2	53.7	55.6	55.7	58.8	57.7	60.5
ISM Nonmanufacturing Index (g)	55.9	56.7	53.6	41.6	45.4	56.5	56.6	57.2	57.2	56.2	56.8	57.7
Housing Starts (b)	1.589	1.589	1.277	0.938	1.046	1.273	1.497	1.376	1.448	1.514	1.551	1.661
Housing Permits (b)	1.550	1.478	1.382	1.094	1.246	1.296	1.542	1.522	1.589	1.595	1.696	1.758
New Home Sales (1-family, c)	756	730	623	582	704	839	972	977	971	969	865	943
Construction Expenditures (a)	1.9	1.0	0.4	-3.6	-1.0	-0.2	0.3	1.1	0.3	0.9	1.0	1.1
Consumer Price Index (nsa, d)	2.5	2.3	1.5	0.3	0.1	0.6	1.0	1.3	1.4	1.2	1.2	1.4
CPI ex. Food and Energy (nsa, d)	2.3	2.4	2.1	1.4	1.2	1.2	1.6	1.7	1.7	1.6	1.6	1.6
PCE Chain Price Index (d)	1.9	1.9	1.3	0.4	0.5	0.9	1.0	1.3	1.4	1.2	1.1	1.3
Core PCE Chain Price Index (d)	1.8	1.9	1.7	0.9	1.0	1.1	1.3	1.5	1.6	1.4	1.4	1.5
Producer Price Index (nsa, d)	2.0	1.1	0.3	-1.5	-1.1	-0.7	-0.3	-0.3	0.3	0.6	0.8	0.8
Durable Goods Orders (a)	-4.8	0.9	-20.7	-11.6	10.6	11.3	9.8	2.0	1.6	1.0	2.2	1.5
Leading Economic Indicators (a)	0.5	-0.1	-7.6	-6.4	3.1	3.0	2.0	1.5	0.9	0.7	0.9	0.4
Balance of Trade & Services (f)	-45.5	-41.6	-47.2	-53.0	-54.9	-50.7	-60.7	-63.7	-62.6	-63.7	-67.3	-65.8
Federal Funds Rate (%)	1.55	1.58	0.65	0.05	0.05	0.08	0.09	0.10	0.09	0.09	0.09	0.09
3-Mo. Treasury Bill Rate (%)	1.55	1.54	0.30	0.14	0.13	0.16	0.13	0.10	0.11	0.10	0.09	0.09
10-Year Treasury Note Yield (%)	1.76	1.50	0.87	0.66	0.67	0.73	0.62	0.65	0.68	0.79	0.87	0.93

(a) month-over-month % change; (b) millions, saar; (c) month-over-month change, thousands; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Calendar of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
November 29 Texas Manufacturing Outlook Survey (Nov) Pending Home Sales (Oct)	**30** Case-Shiller HPI (Sep) FHFA HPI (Sep & Q3) Agricultural Prices (Oct) Chicago PMI (Nov) Texas Service Sector (Nov) Consumer Confidence (Nov)	**December 1** ADP Employment Report (Nov) Construction (Oct) ISM Manufacturing (Nov) IHS Markit Mfg PMI (Nov) EIA Crude Oil Stocks Mortgage Applications	**2** BEA Auto Sales (Nov) BEA Truck Sales (Nov) Challenger Employment Report (Nov) Weekly Jobless Claims	**3** Employment Situation (Nov) ISM Services PMI (Nov) IHS Markit Services PMI (Nov) Manufacturers' Shipments, Inventories & Orders (Oct)
6 Public Debt (Nov) NABE Outlook (Q4)	**7** International Trade (Oct) Productivity & Costs (Q3) QFR (Q3) Treasury Auction Allotments (Nov) Consumer Credit (Oct)	**8** JOLTS (Oct) Transportation Services Index (Oct) EIA Crude Oil Stocks Mortgage Applications	**9** Wholesale Trade (Oct) Financial Accounts (Q3) Kansas City Fed Labor Market Conditions Indicators (Nov) Kansas City Financial Stress Index (Nov) Weekly Jobless Claims	**10** CPI & Real Earnings (Nov) QSS (Q3) Consumer Sentiment (Dec, Preliminary) Cleveland Fed Median CPI (Nov) Monthly Treasury (Nov)
13	**14** Producer Prices (Nov) Manpower Survey (Q1) NFIB (Nov) FOMC Meeting	**15** Import & Export Prices (Nov) Advance Retail Sales (Nov) MTIS (Oct) Empire State Mfg Survey (Dec) Home Builders (Dec) TIC Data (Oct) FOMC Meeting EIA Crude Oil Stocks Mortgage Applications	**16** New Res Construction (Nov) IP & Capacity Utilization (Nov) ECEC (Q3) Philadelphia Fed Mfg Business Outlook Survey (Dec) Business Leaders Survey (Dec) Kansas City Fed Mfg (Dec) IHS Markit Flash Mfg & Services PMI (Dec) Weekly Jobless Claims	**17** Livingston Survey (Dec)
20 Composite Indexes (Nov)	**21** International Transactions (Q3) Philadelphia Fed Nonmanufacturing Business Outlook Survey (Dec)	**22** GDP & Corp Profits (Q3,3rd Est) GDP by Industry (Q3) Existing Home Sales (Nov) Treasury Auction (Dec) Chicago Fed National Activity Index (Nov) FRB Philadelphia Coincident Economic Activity Index(Nov) EIA Crude Oil Stocks Mortgage Applications	**23** Advance Durable Goods (Nov) Personal Income (Nov) Consumer Sentiment(Dec, Final) New Residential Sales (Nov) Dallas Fed Trimmed-Mean PCE (Nov) Final Building Permits (Nov) Weekly Jobless Claims	**24** **CHRISTMAS DAY OBSERVED** **ALL MARKETS CLOSED**
27 Texas Manufacturing Outlook Survey (Dec)	**28** Case-Shiller HPI (Oct) FHFA HPI (Oct) Consumer Confidence (Dec) H.6 Money Stock (Nov) Richmond Fed Mfg & Service Sector Surveys (Dec) Texas Service Sector Outlook Survey (Dec) Steel Imports (Nov)	**29** Advance Trade & Inventories (Nov) Pending Home Sales (Nov) EIA Crude Oil Stocks Mortgage Applications	**30** Strike Report (Dec) International Investment Position (Q3) Agricultural Prices (Nov) Chicago PMI (Dec) Weekly Jobless Claims	**31** **NEW YEAR'S DAY OBSERVED**
January 3 Construction (Nov)	**4** ISM Manufacturing (Dec) IHS Markit Mfg PMI (Dec)	**5** BEA Auto Sales (Dec) BEA Truck Sales (Dec) EIA Crude Oil Stocks Mortgage Applications	**6** Manufacturers' Shipments, Inventories & Orders (Nov) Challenger Employment Report (Dec) ISM Services PMI (Dec) IHS Markit Services PMI (Dec) Weekly Jobless Claims	**7** Employment Situation (Dec) Public Debt (Dec)

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PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 113

Value Line (VL)
Electric Utilities

June 22, 2022

April 22, 2022

ELECTRIC UTILITY (WEST) INDUSTRY

2200

All major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

With oil and natural gas prices at elevated levels, we examine how this affects companies in the Electric Utility Industry.

Electric utility stocks have turned in a mixed performance so far in 2022. As is to be expected, the equities in this Industry have been less volatile than the overall market.

INDUSTRY TIMELINESS: 86 (of 97)

High Prices Of Oil And Natural Gas

This year, the price of a barrel of oil rose above $100 for the first time since 2014. Natural gas prices rose above $6/mmbtu in early April. Investors might understandably wonder how this affects the companies whose stocks we cover in the Electric Utility Industry.

For most electric companies, oil is not a significant source of power generation. Some utilities have peaking units that run on oil or can operate on oil or gas. Among the companies whose stocks are covered in this Industry, only the three utility subsidiaries of *Hawaiian Electric Industries* use oil to generate a significant proportion of their electricity. The company has warned customers that they can expect a rise of 10%-20% in their bills due to the surge in oil prices. For most electric companies, some combination of coal, natural gas, nuclear, and purchased power is the source of their electricity. Renewable energy is increasing its share, but for most utilities, this is still below 10%.

High oil prices have a positive effect on companies that directly or indirectly have the oilpatch as part of their industrial customer base. This includes *Sempra Energy*, *Xcel Energy*, *PNM Resources*, CenterPoint Energy, American Electric Power, OGE Energy, and Entergy. (*Sempra* is based in California, but has an 80% equity interest in Oncor, a distribution utility in Texas.) Nobody knows how long these high oil prices will persist, but increased economic activity will boost these utilities' kilowatt-hour sales. This might well lead to an acceleration in customer growth, as well.

The high price of natural gas has much more effect on utilities. Most utilities use gas to generate a portion of their power. Gas prices also affect the price of merchant (uncontracted) power. Many utilities also have gas distribution operations. Among those in Issue 11, *Avista*, *Black Hills*, *NorthWestern*, *Sempra*, and *Xcel Energy* distribute natural gas. Given that utilities are usually able to pass their fuel and power costs through to customers, this might not seem like a problem. However, fuel and power costs are subject to a prudency review. The Minnesota regulators are reviewing a surge in fuel costs for a subsidiary of *Xcel* that followed a cold spell in February of 2021. A disallowance cannot be ruled out. In 2020, *NorthWestern* took a charge because the Montana commission disallowed some power costs that were incurred in a previous year. As is normally the case with utilities, the company had deferred these expenses in anticipation of eventual recovery.

There are other negative effects of high gas costs over and above the risk of a disallowance. Utilities file general rate cases from time to time to place capital in the rate base, recover higher costs, or make adjustments to their cost of capital. When gas prices are falling, requesting an increase in base rates (while never easy) is less challenging because the decline in the cost of gas will offset some of any hike in base rates. Thus, rising gas and power costs, by contrast, make obtaining rate relief more difficult. Another problem for companies with gas distribution operations arises from the increased working capital needed to pay for the gas that is injected into storage during the summer. Utilities don't get that cash back until the peak months after customers pay their bills.

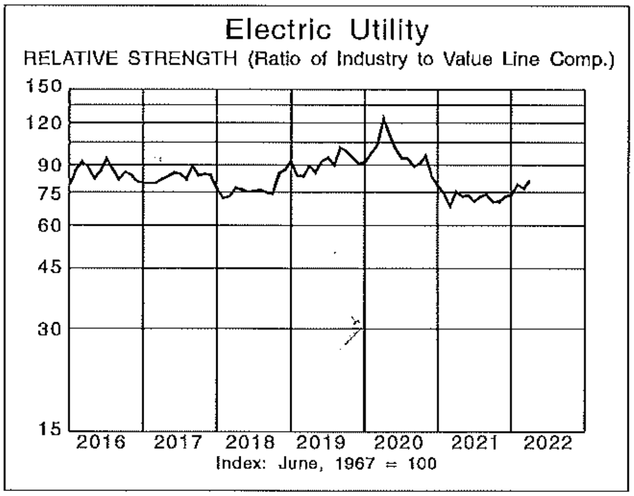
Conclusion

Electric utility stocks turned in a mixed performance in the first several weeks of 2022 before rallying in late March and early April. As is to be expected from this group, the equities have been less volatile than the overall market. The average Safety rank for issues in the Electric Utility Industry is 2 (Above Average), and most sport high marks for Price Stability. Because utility equities have outperformed the broader market averages, the gap between the Electric Utility Industry's dividend yield (3.1%) and the median yield of all dividend-paying stocks under our coverage (2.0%) is smaller than usual.

Interest rates have climbed lately, in anticipation of tightening by the Federal Reserve. The yield on the 10-year U.S. Treasury note reached levels that haven't been seen since 2019. Nevertheless, this hasn't hurt utility stocks because the market has anticipated rising rates.

There haven't been a lot of outliers among utility stocks so far this year, but *Sempra Energy* is one. The price has risen more than 25% as investors have focused on the company's presence in liquefied natural gas exporting. *Pinnacle West*, up more than 10% in price, has made a partial recovery after being the worst-performing utility equity in 2021 due to an unfavorable rate order for its utility subsidiary, Arizona Public Service.

Paul E. Debbas, CFA


Electric Utility
RELATIVE STRENGTH (Ratio of Industry to Value Line Comp.)

Index: June, 1967 = 100

ELECTRIC UTILITY (CENTRAL) INDUSTRY

INDUSTRY TIMELINESS: 88 (of 97)

All major electric utilities located in the central region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 11.

Each of the companies whose stocks we cover in the Electric Utility Industry has reported earnings for the fourth quarter of 2021. We discuss what the companies' managements stated in their press releases and conference calls with analysts.

Like other companies, electric utilities are dealing with rising inflation and supply-chain disruptions.

In the first two months of 2022, electric utility stocks, as a group, declined in price.

Earnings Releases And Conference Calls

As this report went to press in early March, each company covered in the Electric Utility Industry had reported its results for the fourth quarter of 2021. Almost all of these companies had conference calls with analysts in which management provided information beyond what was disclosed in the press releases. (Consolidated Edison and *MGE Energy* are the two electric companies that do not have conference calls.) What is most important about these releases and conference calls has less to do with what happened in the fourth quarter of 2021 and more to do with the company is saying about its plans and expectations for this year.

When utilities report fourth-period results, most of them provide a targeted range for their annual earnings. (*Fortis* and *MGE Energy* are exceptions, and some companies don't provide guidance when a major rate case is pending.) Some companies reiterate or update their long-term targets for yearly earnings and/or dividend growth. For instance, *American Electric Power* raised its goal for annual profit growth from 5%-7% to 6%-7%. But this is hardly the only relevant piece of information provided by management. Many companies are providing details about long-term (typically five years) capital forecasts. Not only do utilities provide a year-by-year breakdown, they discuss where the spending will be directed (renewables, transmission, etc.) and how this will be financed. Many utilities are communicating their plans for reducing coal-fired generation and adding renewable capacity. Inflation and supply-chain constraints are topics that have become more important in recent months, and companies are stating how they are dealing with these challenges.

Companies also provide the kinds of information that they do on conference calls held at other times of the year. They discuss management changes. update analysts on the status of mergers or acquisitions, or asset sales or purchases. Utilities with major projects under way disclose the status of construction (most notably, Southern Company with the nuclear units being built by its Georgia Power subsidiary). The progress of any rate cases or key legal matters is mentioned. Finally, companies provide information about matters that are relevant mainly for the specific utility. For instance, Edison International, the parent company of Southern California Edison, discussed wildfire mitigation efforts on its call in late February.

Inflation And Supply Chain Worries

As is true for companies in other industries, electric utilities are dealing with surging inflation and supply-chain problems. Some companies have delayed planned additions of renewable-energy capacity. Despite these challenges, utilities have various means of coping with them. For some major projects, they secured the materials before these problems emerged. Sempra Energy pointed out that the company has pass-through mechanisms on infrastructure projects. AVANGRID stated that its supply-chain elements for an offshore wind project were contracted for, and labor costs were fixed or capped. *Evergy* stated that is has been able to manage inflationary pressures on its operating and maintenance expenses. *CenterPoint Energy* continues to plan average annual reductions in O&M expenses, even with rising inflation. We remind investors that increased costs are recoverable in rates, as long as the regulators deem these prudent.

Conclusion

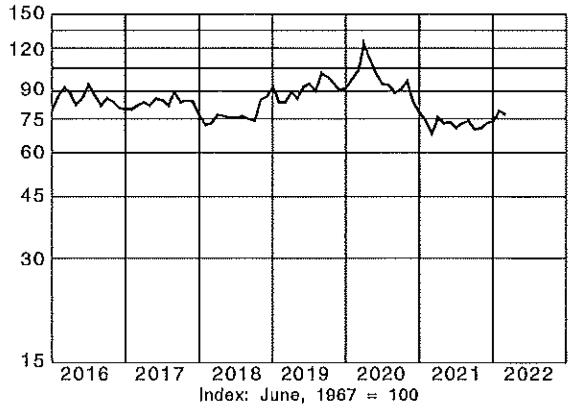
In the first two months of 2022, most stocks in the Electric Utility Industry declined in price. This is not surprising, given their stellar performance in 2021. Often, there is a reversion to the mean following an exceptionally good or poor year. This year, investors have also been concerned about the probability of rising interest rates. The price drops of *Otter Tail Corporation* and *MGE Energy* are noteworthy, having exceeded 10% through February 28th.

Despite the price decline, many of these issues are not cheap. As always, the Electric Utility Industry, as a group, offers an attractive dividend yield. At 3.4%, this is well above the median of all dividend-paying equities reviewed in *The Value Line Investment Survey*. However, prospects for most issues are subpar for the next 18 months and for the period to 2025-2027. The recent quotations of some utility stocks are within their 3- to 5-year Target Price Range.

Paul E. Debbas, CFA

Electric Utility

RELATIVE STRENGTH (Ratio of Industry to Value Line Comp.)



ELECTRIC UTILITY (EAST) INDUSTRY

All major electric utilities located in the eastern region of the United States are reviewed in this Issue; western electrics, in Issue 11; and the remaining utilities, in Issue 5.

In this Issue, we present our rankings of regulatory climates. The latest rankings include one change.

Most electric utility stocks declined in price in the first month of 2022. Investors are waiting to see what the Federal Reserve does about interest rates.

Ranking The Regulators

Whether an electric utility operates in a traditionally regulated state or one that has been partially deregulated, the regulatory function is an important consideration. State commissions set utilities' rates, establish allowed returns on equity, approve major capital projects, and rule on proposed mergers or acquisitions. The Federal Energy Regulatory Commission (FERC) regulates interstate transmission and also rules on proposed mergers and acquisitions.

Investors should note that a state's regulatory climate doesn't just reflect the regulatory commission (although that is the most important factor). The governor, legislature, and courts are also relevant.

Below, we categorize each state's regulatory climate (as well as that of the District of Columbia and FERC) as Above Average, Average, or Below Average. The list does not include Nebraska, Nevada, Rhode Island, Tennessee, Utah, and Vermont. These states either have few investor-owned utilities or do not have a company that is covered in *The Value Line Investment Survey.* Rhode Island will be added to the list if the proposed acquisition of Narragansett Electric by *PPL Corporation* is approved by the regulators in Rhode Island.

- *Above Average:* Alabama, Alaska, Florida, Georgia, Idaho, Indiana, Massachusetts, Michigan, Ohio, Wisconsin, FERC.

- *Average:* California, Colorado, Delaware, Iowa, Kansas, Kentucky, Louisiana, Maine, Minnesota, Mississippi, Missouri, New Hampshire, New Jersey, North Carolina, North Dakota, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Virginia, Wyoming.

- *Below Average:* Arizona, Arkansas, Connecticut, District of Columbia, Hawaii, Illinois, Maryland, Montana, New Mexico, New York, Washington, West Virginia.

Since our last report on regulatory climates, we have lowered Arizona from Average to Below Average. Arizona Public Service, the utility subsidiary of Pinnacle West, received a harsh rate order in late 2021. The utility is appealing the ruling to the courts; whether or not this will be fruitful remains to be seen. We made this move even though the other major electric company in the state, Tucson Electric Power (a subsidiary of Fortis) has fared better before the commission. Some states are under consideration for a change. Last month, Avista filed a rate case in Washington. If the rate order, expected in late 2022, is constructive, this might well lead to a change in ranking. Northern States Power (a subsidiary of Xcel Energy) has regulatory proceedings pending in Minnesota. This might lead to a change (in either direction), depending on the outcome of these matters. Another state that might go either way is Colorado. Coincidentally, another subsidiary of Xcel Energy has some regulatory matters pending there.

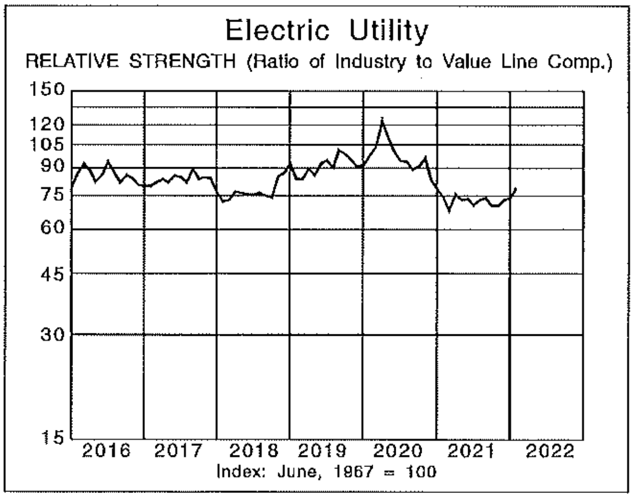
INDUSTRY TIMELINESS: 79 (of 97)

Conclusion

Most electric utility stocks fared well in 2021. An index of 39 equities compiled by the Edison Electric Institute (a group representing investor-owned utilities) produced a total return of 17.1% last year. In the first month of 2022, these issues' strong showing did not continue. Almost every electric company stock has declined in price so far this year. Most notably, *NextEra Energy* stock has fallen 16% in price. We think this is partly due to reversion to the mean and partly due to investors' concerns about the possibility of rising interest rates. The Federal Reserve has signaled its expectation of rate hikes. The extent of these increases is unknown, and this is a further source of uncertainty. We note, though, that interest rates have been very low for an extended period (especially since the spring of 2020), and will likely remain historically low even after the Fed is finished raising rates—whenever that is. Many utilities have been taking advantage of the low interest-rate environment by financing their capital budgets with debt and refinancing their borrowings. Some companies have been willing to incur charges for the early extinguishment of debt.

The average dividend yield of stocks in the Electric Utility Industry is 3.5%. This is nearly twice the median of all dividend-paying issues covered in *The Value Line Investment Survey.* There is a wide variance in the 18-month prospects of these equities. Some stocks have appeal for the period to 2025-2027, but for others, the recent quotation is within our 3- to 5-year Target Price Range.

Paul E. Debbas, CFA



ALLETE NYSE-ALE

RECENT PRICE **62.94** | P/E RATIO **16.7** (Trailing: 19.5 Median: 19.0) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **4.2%** | **VALUE LINE**

TIMELINESS 4 Raised 2/25/22
SAFETY 2 New 10/1/04
TECHNICAL 3 Raised 2/25/22
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$54-$86	$70 (10%)

2025-27 PROJECTIONS

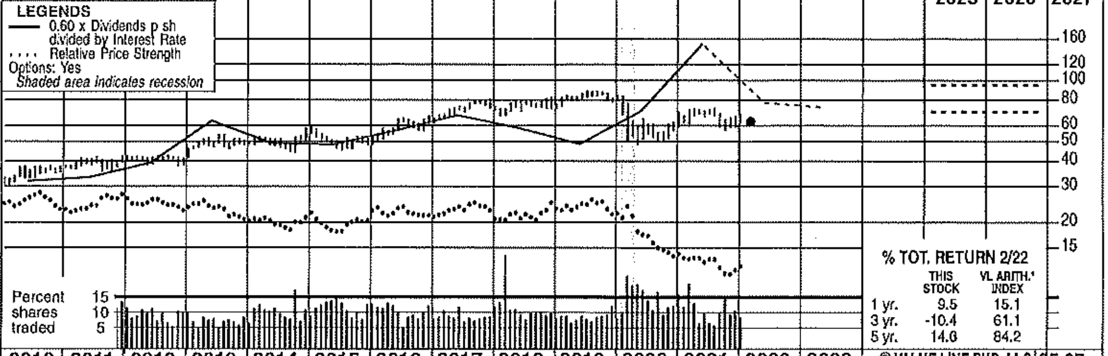
	Price	Gain	Ann'l Total Return
High	95	(+50%)	14%
Low	70	(+10%)	7%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	98	111	151
to Sell	131	111	109
Hld's(000)	37914	37923	37557

High:	42.5	42.7	54.1	58.0	59.7	66.9	81.2	82.8	88.6	84.7	73.1	68.6
Low:	35.1	37.7	41.4	44.2	45.3	48.3	61.6	66.6	72.5	48.2	56.8	58.4

Target Price Range
2025 | 2026 | 2027



% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.5	15.1
3 yr.	-10.4	61.1
5 yr.	14.0	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	27.78	29.10	23.99	22.44	26.68	*25.30*	*25.80*	Revenues per sh	*28.00*
4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	6.59	7.37	7.24	7.52	7.54	*8.15*	*8.55*	"Cash Flow" per sh	*10.00*
2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	3.13	3.38	3.33	3.35	3.23	*3.65*	*3.90*	Earnings per sh A	*4.75*
1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	2.08	2.14	2.24	2.35	2.47	2.52	*2.60*	*2.70*	Div'd Decl'd per sh B ■ †	*3.00*
3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	4.08	6.07	11.55	13.78	8.90	*3.60*	*6.25*	Cap'l Spending per sh	*7.50*
21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	40.47	41.86	43.17	44.04	45.36	*46.65*	*48.10*	Book Value per sh C	*53.25*
30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	51.10	51.50	51.70	52.10	53.20	*54.00*	*55.00*	Common Shs Outst'g D	*58.00*
16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	18.6	23.0	22.2	24.7	18.3	20.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.16	1.20	1.32	.94	1.10			Relative P/E Ratio	*.95*
3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.6%	3.0%	3.0%	2.9%	4.0%	3.8%			Avg Ann'l Div'd Yield	*3.7%*
						961.2	1018.4	1136.8	1486.4	1339.7	1419.3	1498.6	1240.5	1169.1	1419.2	*1365*	*1420*	Revenues ($mill)	*1625*
						97.1	104.7	124.8	163.4	155.3	159.2	174.1	172.4	174.2	169.2	*195*	*215*	Net Profit ($mill)	*275*
						28.1%	21.5%	22.6%	19.4%	11.3%	14.8%	- -	- -	NMF	NMF	*NMF*	*NMF*	Income Tax Rate	*NMF*
						5.3%	4.4%	6.3%	2.0%	1.4%	.8%	.7%	1.3%	1.1%	1.5%	*2.0%*	*1.0%*	AFUDC % to Net Profit	*1.0%*
						43.7%	44.6%	44.2%	46.3%	42.0%	41.0%	39.9%	38.6%	41.0%	42.2%	*41.0%*	*41.5%*	Long-Term Debt Ratio	*42.5%*
						56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	60.1%	61.4%	59.0%	57.8%	*59.0%*	*58.5%*	Common Equity Ratio	*57.5%*
						2134.6	2425.9	2882.2	3388.9	3263.4	3507.4	3584.3	3632.8	3887.8	4176.3	*4285*	*4510*	Total Capital ($mill)	*5350*
						2347.6	2576.5	3286.4	3669.1	3741.2	3822.4	3904.4	4377.0	4840.8	5100.2	*5065*	*5155*	Net Plant ($mill)	*5550*
						5.6%	5.3%	5.2%	5.8%	5.8%	5.5%	5.8%	5.6%	5.3%	4.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
						8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	7.6%	7.0%	*8.0%*	*8.0%*	Return on Shr. Equity	*9.0%*
						8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	7.6%	7.0%	*8.0%*	*8.0%*	Return on Com Equity E	*9.0%*
						2.3%	2.2%	2.5%	3.6%	2.8%	2.4%	2.7%	2.3%	2.0%	1.5%	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
						71%	72%	67%	60%	66%	68%	66%	70%	74%	78%	*71%*	*69%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $2026.8 mill. **Due in 5 Yrs** $842.2 mill.
LT Debt $1763.2 mill. **LT Interest** $69.7 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $5.1 mill.

Pension Assets-12/21 $745.7 mill.
Oblig $911.7 mill.

Pfd Stock None

Common Stock 53,243,671 shs.
as of 2/1/22

MARKET CAP: $3.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.5	-12.0	+11.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw) F	1573	1588	1557
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	277	230	219

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	- -	-2.5%	*2.5%*
"Cash Flow"	5.5%	2.5%	*5.0%*
Earnings	4.0%	1.0%	*6.0%*
Dividends	3.5%	4.0%	*3.5%*
Book Value	5.0%	3.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2019	357.2	290.4	288.3	304.6	1240.5
2020	311.6	243.2	293.9	320.4	1169.1
2021	339.2	335.6	345.4	399.0	1419.2
2022	*345*	*320*	*345*	*355*	*1365*
2023	*365*	*325*	*355*	*375*	*1420*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2019	1.18	.64	.60	.92	3.33
2020	1.28	.39	.78	.90	3.35
2021	.99	.53	.53	1.18	3.23
2022	*1.20*	*.60*	*.80*	*1.05*	*3.65*
2023	*1.30*	*.65*	*.85*	*1.10*	*3.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.56	.56	.56	.56	2.24
2019	.5875	.5875	.5875	.5875	2.35
2020	.6175	.6175	.6175	.6175	2.47
2021	.63	.63	.63	.63	2.52
2022	.65				

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 26%; paper/wood products, 9%; other industrial, 8%; residential, 13%; commercial, 13%; wholesale, 14%; other, 16%. ALLETE Clean Energy (ACE) owns renewable energy projects. Acq'd U.S. Water Services 2/15; sold it 3/19. Generating sources: coal, 28%; wind, 10%; other, 4%; purchased, 58%. Fuel costs: 40% of revs. '21 deprec. rate: 3.2%. Has 1,400 employees. Chairman, President & CEO: Bethany M. Owen. Inc.: Minnesota. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's largest utility subsidiary has a rate case pending. Minnesota Power is seeking an increase of $108 million (18%), based on return on equity of 10.25% and a common-equity ratio of 53.8%. An $87 million interim rate hike took effect at the start of 2022. The utility has been underearning its allowed ROE in recent years. Minnesota Power is also asking the commission for a true-up mechanism for the effects of industrial kilowatt-hour sales, which can fluctuate significantly from year to year. (This can been seen in the Electric Operating Statistics box, which shows a substantial decline in retail volume in 2020 followed by a partial recovery in 2021.) A final order is expected in late 2022. Note that ALLETE's utility subsidiary in Wisconsin plans to file a rate application this year, with new tariffs taking effect in 2023.

Earnings will likely improve significantly in 2022. The single biggest factor should be the effect of the interim rate hike. A return to normal wind conditions would help the company's nonutility subsidiary, ALLETE Clean Energy (ACE), after subpar conditions last year. A few unusual (but not nonrecurring) items in 2021 had a net negative effect of $0.05 on share net. Our share-earnings estimate of $3.65 for this year, which we cut by a nickel because average shares outstanding will be higher than we had expected in our December report, is near the low end of the company's targeted range of $3.60-$3.90.

We look for further growth in 2023. ALLETE's utility in Wisconsin should get some rate relief. We also expect growth at ACE as it adds projects. Our estimate of $3.90 a share is 7% above our expectation for 2022. Management's goal for annual profit growtb is 5%-7%.

The board of directors raised the dividend in the first quarter. The increase was $0.02 a share (3.2%) quarterly. This was below ALLETE's long-term goal of 5%-7% growth because the payout ratio is above the company's target of 60%-70%.

This stock is untimely, but offers a dividend yield that is above average, even for a utility. The equity does not stand out for the next 18 months, but total return potential to 2025-2027 is respectable.

Paul E. Debbas, CFA *March 11, 2022*

(A) Diluted EPS. Excl. nonrec. gains (loss): '15, (46¢); '17, 25¢; '19, 26¢; loss on disc. ops.: '06, 2¢. '19 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvest. plan avail. † Shareholder Invest. plan avail. (C) Incl. deferred charges. In '21: $9.62/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate all'd in MN on com. eq. in '18: 9.25%; earned on avg. com. eq., '21: 7.2%. Regul. Climate: Avg. (F) Summer peak in '21.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	90

ALLIANT ENERGY NDQ-LNT

RECENT PRICE 58.40 | P/E RATIO 21.9 (Trailing: 22.3 Median: 20.0) | RELATIVE P/E RATIO 1.22 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Raised 10/29/21
SAFETY 2 Raised 9/28/07
TECHNICAL 3 Lowered 3/11/22
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$50-$78	$64 (10%)

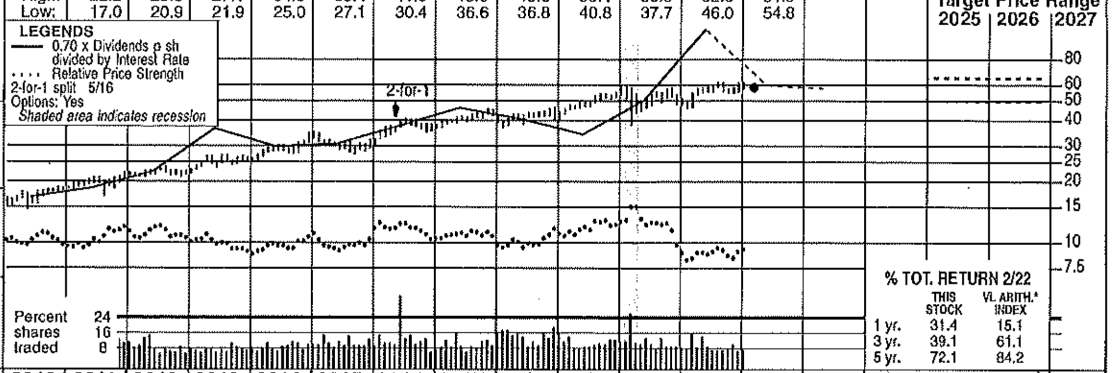
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+10%)	6%
Low	50	(-15%)	Nil

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	236	237	290
to Sell	237	232	244
Hld's(000)	191641	194869	195770

High:	22.2	23.8	27.1	34.9	35.4	41.0	45.6	46.6	55.4	60.3	62.3	61.9	
Low:	17.0	20.9	21.9	25.0	27.1	30.4	36.6	36.8	40.8	37.7	46.0	54.8	



% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	31.4	15.1
3 yr.	39.1	61.1
5 yr.	72.1	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
14.46	15.57	16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	14.97	14.89	13.67	14.65	*15.55*	*16.10*	Revenues per sh	*17.75*
2.16	2.56	2.28	2.10	2.60	2.75	2.95	3.34	3.49	3.45	3.43	3.97	4.32	4.59	4.92	5.25	*5.55*	*5.90*	"Cash Flow" per sh	*7.00*
1.03	1.35	1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	2.19	2.33	2.47	2.63	*2.75*	*2.90*	Earnings per sh A	*3.25*
.58	.64	.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	1.34	1.42	1.52	1.61	*1.71*	*1.81*	Div'd Decl'd per sh B ■ †	*2.15*
1.71	2.46	3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	6.92	6.69	5.47	4.67	*5.90*	*5.90*	Cap'l Spending per sh	*6.25*
11.42	12.15	12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	19.43	21.24	22.76	23.91	*25.00*	*26.15*	Book Value per sh C	*29.75*
232.25	220.72	220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	236.06	245.02	249.87	250.47	*251.00*	*251.50*	Common Shs Outst'g D	*253.00*
16.8	15.1	13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	19.1	21.2	21.2	21.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
.91	.80	.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.04	1.03	1.13	1.09	1.13			Relative P/E Ratio	*1.00*
3.3%	3.1%	4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	3.2%	2.9%	2.9%	2.9%			Avg Ann'l Div'd Yield	*3.7%*
						3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	3534.5	3647.7	3416.0	3669.0	*3900*	*4050*	Revenues ($mill)	*4500*
						337.8	382.1	395.7	390.9	384.0	466.1	522.3	567.4	624.0	674.0	*695*	*730*	Net Profit ($mill)	*845*
						21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	8.4%	10.8%	10.8%	NMF	*4.0%*	*4.0%*	Income Tax Rate	*4.0%*
						6.5%	8.1%	8.8%	9.4%	16.3%	10.7%	14.5%	16.3%	8.8%	3.7%	*4.0%*	*5.0%*	AFUDC % to Net Profit	*6.0%*
						48.4%	46.1%	49.7%	47.3%	51.5%	47.8%	52.3%	50.6%	53.5%	52.9%	*55.0%*	*55.0%*	Long-Term Debt Ratio	*56.0%*
						48.4%	50.8%	47.5%	50.0%	46.1%	49.8%	45.7%	47.6%	44.9%	47.1%	*45.0%*	*45.0%*	Common Equity Ratio	*44.0%*
						6476.6	6461.0	7257.2	7446.3	8377.6	8392.8	10032	10938	12657	12725	*14000*	*14550*	Total Capital ($mill)	*17100*
						7838.0	7147.3	6442.0	8970.2	9809.9	10798	12462	13527	14336	14987	*16000*	*17000*	Net Plant ($mill)	*19900*
						6.3%	7.0%	6.5%	6.3%	5.6%	6.7%	6.3%	6.3%	5.9%	6.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
						10.1%	11.0%	10.8%	10.0%	9.5%	10.6%	10.9%	10.5%	10.6%	11.3%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.0%*
						10.3%	11.3%	11.2%	10.2%	9.7%	10.9%	11.2%	10.7%	10.8%	11.0%	*11.0%*	*11.0%*	Return on Com Equity E	*11.0%*
						3.9%	4.9%	4.6%	3.6%	2.8%	4.0%	4.4%	4.2%	4.2%	4.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
						64%	57%	60%	66%	72%	64%	62%	61%	62%	62%	*62%*	*62%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $7883 mill. **Due in 5 Yrs** $2665 mill.
LT Debt $6735 mill. **LT Interest** $256 mill.
(LT interest earned: 3.2x)

Leases, Uncapitalized Annual rentals $2 mill.

Pension Assets-12/21 $1011 mill. **Oblig** $1251 mill.

Pfd Stock None

Common Stock 250,478,681 shs. **as of 1/31/22**
MARKET CAP: $15 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	-2.3	+3.7
Avg. Indust. Use (MWH)	11448	11134	NA
Avg. Indust. Revs. per KWH (¢)	6.98	7.55	7.64
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5626	5496	5486
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.6	+.8
Fixed Charge Cov. (%)	265	251	259

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	-.5%	*3.5%*
"Cash Flow"	7.0%	7.5%	*6.0%*
Earnings	7.0%	8.0%	*4.5%*
Dividends	6.5%	6.5%	*6.0%*
Book Value	5.5%	7.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	987.2	790.2	990.2	880.1	3647.7
2020	915.7	763.1	920.0	817.2	3416.0
2021	901	817	1024	927	3669.0
2022	*1000*	*850*	*1075*	*975*	*3900*
2023	*1050*	*875*	*1125*	*1000*	*4050*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.53	.40	.94	.46	2.33
2020	.72	.54	.94	.26	2.47
2021	.68	.57	1.02	.35	2.63
2022	*.70*	*.57*	*1.05*	*.43*	*2.75*
2023	*.75*	*.60*	*1.10*	*.45*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.335	.335	.335	.335	1.34
2019	.355	.355	.355	.355	1.42
2020	.38	.38	.38	.38	1.52
2021	.4025	.4025	.4025	.4025	1.61
2022	.4275				

BUSINESS: Alliant Energy Corporation (formerly Interstate Energy) is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity to 984,000 customers and gas to 423,000 customers in Wisconsin, Iowa, and Minnesota. Electric revenue by state: WI, 43%; IA, 56%. MN, 1%. Electric revenue: residential, 36%; commercial, 25%; industrial, 29%; wholesale, 8%; other, 2%. Generating sources: coal, 32%; gas, 32%; wind, 16%; other, 1%; purchased, 19%. Fuel costs: 25% of revs. '21 reported deprec. rates: 2.9%-6.1%. Has 3,300 employees. Chairman, President & CEO: John O. Larsen. Inc.: Wisconsin. Address: 4902 N. Billmore Lane, Madison, Wisconsin 53718-2148. Tel.: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy's utility subsidiary in Wisconsin received electric and gas rate increases at the start of 2022. Wisconsin Power and Light was granted hikes of $114 million for electricity and $15 million for gas. (The electric increase was above the initial settlement agreement of $70 million due to anticipated increases in fuel costs this year.) The allowed return on equity remained at 10% and the common-equity ratio was boosted from 52.5% to 53.8%. Note that WPL is operating under a mechanism that will share a portion of its earnings if its earned ROE is greater than 10.25%. Rate relief is a key factor in the earnings growth we expect this year. Our estimate is within Alliant Energy's targeted range of $2.67-$2.81 a share, up slightly from management's previous guidance of $2.65-$2.79 thanks to increased capital spending on solar power, which will be recovered through a rider (surcharge) on customers' bills.

We look for further profit growth in 2023. The additions of renewable capacity should help. Our earnings estimate would produce an increase of 5%, which is within the company's goal of 5%-7% annually.

Alliant Energy's utilities are seeking approval from the regulators in Wisconsin and Iowa to add renewable-energy projects. In the first half of 2022, WPL expects a ruling on its request for a certificate of need to add up to 414 megawatts of solar capacity. The utility also plans to ask the Wisconsin commission to approve up to an additional 300 mw of renewable capacity. In Iowa, the company expects a decision in the second half of 2022 on its proposed addition of up to 400 mw of solar capacity and 75 mw of battery storage.

The board of directors raised the dividend in the first quarter. The company had signaled that the increase would be $0.10 a share (6.2%) annually, and this is what occurred.

Alliant Energy stock is expensively priced. The dividend yield is below the utility average. The stock does not stand out for the next 18 months, and with the recent quotation well within our 2025-2027 Target Price Range, total return potential over that time frame is unspectacular.

Paul E. Debbas, CFA *March 11, 2022*

(A) Diluted EPS. Excl. nonrecurring losses: '11, 1¢; '12, 8¢. '20 & '21 EPS don't sum due to rounding. Next earnings report due early May. (B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '21: $1980 mill., $7.91/sh. (D) In millions, adj. for split. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '20: various; in WI in '22: 10%; earned on avg. com. eq., '21: 11.3%. Regulatory Climate: Wisconsin, Above Average; Iowa, Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	95

AMEREN NYSE-AEE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
85.95	21.1	(Trailing: 22.4 Median: 19.0)	1.18	2.8%	VALUE LINE

TIMELINESS	4	Lowered 12/10/21
SAFETY	1	Raised 9/10/21
TECHNICAL	2	Lowered 3/11/22

BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$75-$107	$91 (5%)

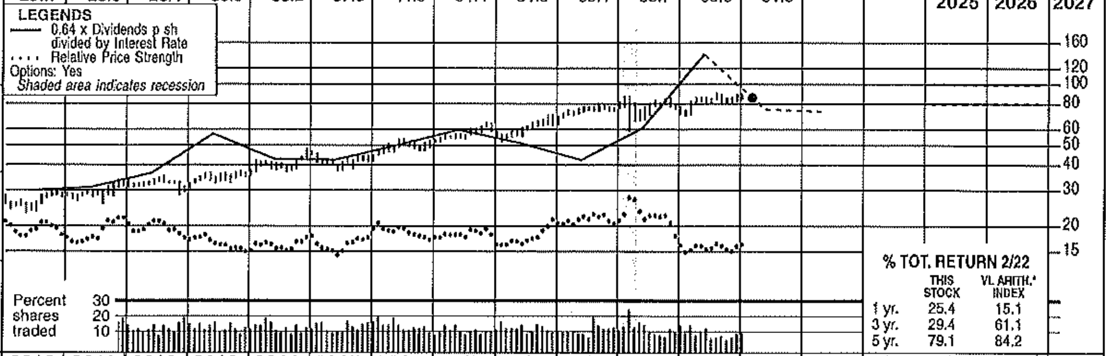
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+15%)	7%
Low	80	(-5%)	2%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	273	248	308
to Sell	226	246	227
Hld's(000)	194886	199566	198495

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	34.1	35.3	37.3	48.1	46.8	54.1	64.9	70.9	80.9	87.7	90.8	89.5
Low:	25.5	28.4	30.6	35.2	37.3	41.5	51.4	51.9	63.1	58.7	69.8	81.8



% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	25.4	15.1
3 yr.	29.4	61.1
5 yr.	79.1	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	25.73	24.00	22.87	24.81	*25.35*	*25.85*	Revenues per sh	*27.75*
6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	7.64	7.83	8.08	8.89	*9.35*	*9.90*	"Cash Flow" per sh	*11.75*
2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	3.32	3.35	3.50	3.84	*4.10*	*4.35*	Earnings per sh A	*5.25*
2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	1.85	1.92	2.00	2.20	*2.36*	*2.52*	Div'd Decl'd per sh B ■	*3.10*
4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	9.56	9.92	13.02	13.67	*12.90*	*12.55*	Cap'l Spending per sh	*13.00*
31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	31.21	32.73	35.29	37.64	*40.25*	*42.90*	Book Value per sh C	*51.50*
206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	244.50	246.20	253.30	257.70	*262.50*	*267.00*	Common Shs Outst'g D	*280.00*
19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	18.3	22.1	22.2	21.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	1.18	1.14	1.14			Relative P/E Ratio	*.95*
4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%	3.0%	2.6%	2.6%	2.7%			Avg Ann'l Div'd Yield	*3.4%*
						6828.0	5838.0	6053.0	6098.0	6076.0	6177.0	6291.0	5910.0	5794.0	6394.0	*6650*	*6900*	Revenues ($mill)	*7800*
						589.0	518.0	593.0	585.0	659.0	683.0	821.0	834.0	877.0	995.0	*1080*	*1165*	Net Profit ($mill)	*1500*
						36.9%	37.5%	38.9%	38.3%	36.7%	38.2%	22.4%	17.9%	15.0%	13.6%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
						6.1%	7.1%	5.7%	5.1%	4.1%	5.6%	6.9%	5.8%	5.5%	6.0%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
						49.5%	45.2%	47.2%	49.3%	47.7%	49.2%	50.3%	52.1%	55.0%	56.1%	*55.5%*	*53.5%*	Long-Term Debt Ratio	*51.0%*
						49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	44.3%	43.3%	*44.0%*	*46.0%*	Common Equity Ratio	*48.5%*
						13384	12190	12975	13968	13840	14420	15632	17116	20158	22391	*23900*	*24950*	Total Capital ($mill)	*29600*
						16096	16205	17424	18799	20113	21466	22810	24376	26807	29261	*31250*	*33125*	Net Plant ($mill)	*38800*
						6.0%	5.6%	5.8%	5.3%	6.0%	6.0%	6.4%	6.0%	5.3%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
						8.7%	7.7%	8.7%	8.3%	9.1%	9.3%	10.6%	10.2%	9.7%	10.1%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
						8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	9.7%	10.2%	*10.0%*	*10.0%*	Return on Com Equity E	*10.5%*
						3.0%	1.9%	2.9%	2.5%	3.3%	3.4%	4.8%	4.4%	4.2%	4.4%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
						66%	76%	67%	70%	64%	64%	56%	57%	57%	57%	*57%*	*58%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $13612 mill. **Due in 5 Yrs** $2890 mill.
LT Debt $12562 mill. **LT Interest** $436 mill.
(LT interest earned: 3.8x)
Pension Assets-12/21 $5745 mill.
Oblig $5457 mill.
Pfd Stock $129 mill. **Pfd Div'd** $5 mill.
607,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 487,508 sh. 4.00% to 5.16%, $100 par, redeem. $100-$104.30/sh.
Common Stock 257,724,783 shs.
as of 1/31/22
MARKET CAP: $22 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.5	-5.6	+2.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	307	291	325

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.5%	-1.0%	*2.5%*
"Cash Flow"	3.0%	6.0%	*6.0%*
Earnings	3.0%	7.5%	*6.5%*
Dividends	3.0%	4.0%	*7.0%*
Book Value	1.0%	4.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1556	1379	1659	1316	5910.0
2020	1440	1398	1628	1328	5794.0
2021	1566	1472	1811	1545	6394.0
2022	*1700*	*1500*	*1850*	*1600*	*6650*
2023	*1750*	*1550*	*1950*	*1650*	*6900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.78	.72	1.47	.38	3.35
2020	.59	.98	1.47	.46	3.50
2021	.91	.80	1.65	.48	3.84
2022	*.90*	*.85*	*1.85*	*.50*	*4.10*
2023	*.95*	*.90*	*1.95*	*.55*	*4.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.4575	.4575	.4575	.475	1.85
2019	.475	.475	.475	.495	1.92
2020	.495	.495	.495	.515	2.00
2021	.55	.55	.55	.55	2.20
2022	.59				

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric revenue breakdown: residential, 49%; commercial, 34%; industrial, 8%; other, 9%. Generating sources: coal, 73%; nuclear, 11%; hydro & other, 9%; purchased, 7%. Fuel costs: 25% of revenues. '21 reported deprec. rates: 3%-4%. Has 9,100 employees. Chairman: Warner L. Baxter. President & CEO: Martin J. Lyons, Jr. Inc.: Missouri. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren received rate orders in Missouri. The commission approved settlements that raised electric and gas rates by $220 million and $5 million, respectively. An allowed return on equity was not specified, but the common equity ratio for electric was set at 52%. New tariffs took effect on February 28th.

Earnings will likely advance in 2022. The rate increases in Missouri will be a key factor. Also, growth in the utility's rate base will boost the company's earning power. Ameren's transmission business and electric operations in Illinois operate under formula rate plans. Ameren will pick up a few cents a share from having a full year of a gas rate hike that was granted in Illinois last year. These factors should outweigh the effects of higher operating and maintenance costs, depreciation, and average shares outstanding. We are sticking with our 2022 estimate of $4.10 a share, which is within management's targeted range of $3.95-$4.15.

We expect further growth in 2023. Ameren will have a full year's effect of rate relief in Missouri and will continue to benefit from rate base growth. The company's goal for yearly profit growth is 6%-8%, and our estimate would produce an increase within this range.

There is a risk to the company's earning power. The Federal Energy Regulatory Commission (FERC) is considering the removal of a half percentage point incentive "adder" on the allowed ROE for electric transmission. This would cut Ameren's annual earning power by $0.05 a share. The timing of FERC's decision is unknown. Our estimates and projections are based on the utility maintaining its allowed ROE for transmission of 10.52%.

The board of directors raised the dividend in the first quarter. The hike was $0.04 a share (7.3%) quarterly. Dividend growth will likely be in line with profit growth. Ameren's target for the payout ratio is 55%-70%, and this figure is near the lower end of this range.

The dividend yield of this untimely but high-quality stock is below the utility mean. The equity's prospects for the next 18 months and the 3- to 5-year period are subpar. The recent quotation is within our 2025-2027 Target Price Range.

Paul E. Debbas, CFA *March 11, 2022*

(A) Diluted EPS. Excl. nonrec. gain (losses): '10, ($2.19); '11, (32¢); '12, ($6.42); '17, (63¢); gain (loss) from discontinued ops.: '13, (92¢); '15, 21¢. Next earnings report due early May.
(B) Div'ds paid late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '21: $6.60/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate allowed on com. eq. in MO in '22: elec. & gas, none specified; in IL: electric, varies; in '21: gas, 9.67%; earned on avg. com. eq., '21: 10.6%. Regulatory Climate: MO, Average; IL, Below Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	95

AMERICAN ELEC. PWR. NDQ-AEP

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD
90.65	17.9	(Trailing: 18.3 Median: 17.0)	1.00	3.6%

VALUE LINE

TIMELINESS 4 Lowered 3/4/22
SAFETY 1 Raised 3/17/17
TECHNICAL 2 Lowered 3/11/22
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$76-$110	$93 (5%)

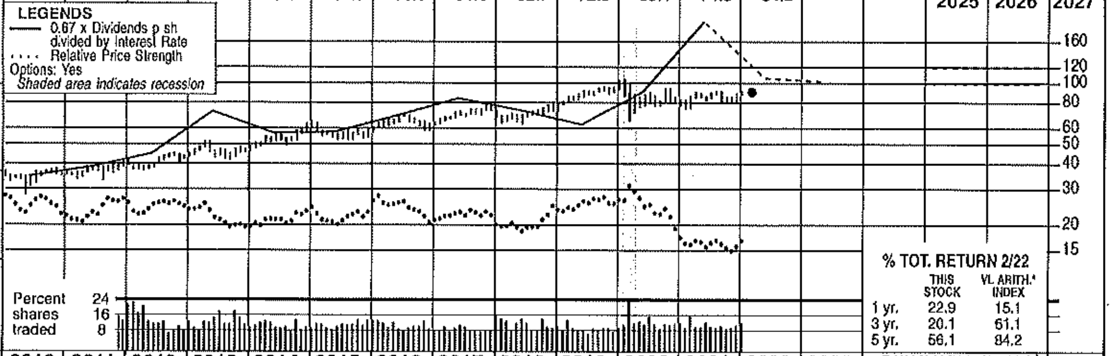
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+30%)	10%
Low	100	(+10%)	6%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	605	561	636
to Sell	431	433	473
Hld's(000)	371285	373255	373909

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	41.7	45.4	51.6	63.2	65.4	71.3	78.1	81.1	96.2	105.0	91.5	91.7
Low:	33.1	37.0	41.8	45.8	52.3	56.8	61.8	62.7	72.3	65.1	74.8	84.2



% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.9	15.1
3 yr.	20.1	61.1
5 yr.	56.1	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	32.84	31.49	30.04	33.30	33.25	34.05	Revenues per sh	36.75
6.67	6.60	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	8.77	9.35	10.28	10.98	11.20	11.75	"Cash Flow" per sh	13.75
2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.16	3.34	3.59	4.23	3.62	3.90	4.08	4.42	4.96	5.00	5.35	Earnings per sh A	6.50
1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	2.53	2.71	2.84	3.00	3.17	3.35	Div'd Decl'd per sh B ■	4.00
8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	12.89	12.43	12.72	11.43	15.35	14.15	Cap'l Spending per sh	14.00
23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	38.58	39.73	41.38	44.49	47.05	50.05	Book Value per sh C	58.75
396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	493.25	494.17	496.60	504.21	514.00	523.00	Common Shs Outst'g D	545.00
12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	18.0	21.4	19.6	17.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	17.0
.70	.87	.79	.67	.85	.75	.88	.81	.84	.60	.80	.97	.97	1.14	1.01	.91			Relative P/E Ratio	.95
4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	3.6%	3.1%	3.3%	3.5%			Avg Ann'l Div'd Yield	3.6%
						14945	15357	17020	16453	16380	15425	16196	15561	14919	16792	17100	17800	Revenues ($mill)	20000
						1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	1923.8	2019.0	2200.1	2488.1	2555	2790	Net Profit ($mill)	3585
						33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	5.8%	.7%	1.9%	4.6%	7.5%	7.5%	Income Tax Rate	7.5%
						11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	10.7%	12.7%	9.7%	7.8%	10.0%	9.0%	AFUDC % to Net Profit	7.0%
						50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	53.2%	56.1%	58.5%	58.3%	58.0%	58.5%	Long-Term Debt Ratio	57.5%
						49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	41.5%	41.7%	42.0%	41.5%	Common Equity Ratio	42.5%
						30823	32913	33001	35633	34775	37707	40677	44759	49537	53734	57650	62825	Total Capital ($mill)	75700
						38763	40997	44117	46133	45639	50262	55099	60138	63902	66001	70700	74725	Net Plant ($mill)	88000
						6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	5.9%	5.6%	5.6%	5.6%	5.5%	5.5%	Return on Total Cap'l	5.5%
						9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	10.5%	10.5%	Return on Shr. Equity	11.0%
						9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	10.5%	10.5%	Return on Com Equity E	11.0%
						3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	3.5%	3.4%	3.8%	4.3%	4.0%	4.0%	Retained to Com Eq	4.5%
						63%	62%	61%	60%	54%	67%	65%	67%	65%	61%	65%	64%	All Div'ds to Net Prof	62%

CAPITAL STRUCTURE as of 12/31/21
Total Debt $36069 mill. **Due in 5 Yrs** $12120 mill.
LT Debt $31301 mill. **LT Interest** $1083 mill.
Incl. $603.5 mill. securitized bonds. Incl. $500.7 mill. finance leases.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $119.6 mill.
Pension Assets-12/21 $5352.9 mill.
Oblig $5187.0 mill.

Pfd Stock None

Common Stock 504,212,015 shs.

MARKET CAP: $46 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	- -	+3.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+1.0	NA
Fixed Charge Cov. (%)	234	243	272

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-1.5%	2.5%
"Cash Flow"	4.5%	5.0%	5.0%
Earnings	4.5%	4.0%	6.5%
Dividends	5.0%	6.0%	6.0%
Book Value	4.0%	3.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	4056	3573	4315	3616	15561
2020	3747	3494	4066	3610	14918
2021	4281	3826	4623	4061	16792
2022	4350	3900	4700	4150	17100
2023	4550	4050	4900	4300	17800

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.16	.93	1.48	.51	4.08
2020	1.00	1.05	1.50	.87	4.42
2021	1.15	1.15	1.59	1.07	4.96
2022	1.20	1.15	1.65	1.00	5.00
2023	1.30	1.25	1.75	1.05	5.35

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.62	.62	.62	.67	2.53
2019	.67	.67	.67	.70	2.71
2020	.70	.70	.70	.74	2.84
2021	.74	.74	.74	.78	3.00
2022	.78				

BUSINESS: American Electric Power Company Inc. (AEP), through 10 operating utilities, serves 5.5 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Has a transmission subsidiary. Electric revenue breakdown: residential, 43%; commercial, 23%; industrial, 18%; wholesale, 10%; other, 6%. Sold commercial barge operation in '15. Generating sources not available. Fuel costs: 33% of revenues. '21 reported depreciation rates (utility): 2.6%-12.5%. Has 16,700 employees. Chairman, President & CEO: Nicholas K. Akins. COO: Lisa Barton. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power's sale of its Kentucky Power subsidiary is likely to be completed in the second quarter. The sale would raise $1.45 billion after taxes and transaction costs, and would offset the company's expected equity needs for 2022. (The estimated rise in the share count this year is due to the conversion of $805 million of equity units.)

The company wants to sell its nonregulated contracted renewable-energy assets. The company would reinvest the proceeds in regulated wind and solar projects and allocate to its transmission business capital that otherwise would have been used for nonregulated renewable expansion. Any gains on these sales will be *included* in our earnings presentation, although we have not assumed any in our estimates. AEP already has a presence in regulated renewables, and will soon complete the third phase of a $2 billion, 1,484-megawatt wind project.

Some regulatory matters are pending or have been concluded. SWEPCO filed a case for $56 million in Arkansas, based on a 10.35% return on equity and a 51.3% common-equity ratio. An order is expected in the second quarter. The utility is trying to reach a settlement in Louisiana, where it had requested $73 million, based on a 10.35% ROE and a 50.8% common-equity ratio. The Texas commission granted SWEPCO $23 million, based on a 9.25% ROE and a 49.4% common-equity ratio. The Indiana commission approved a settlement for Indiana Michigan Power calling for a $61 million increase, based on a 9.7% ROE and a 50% common-equity ratio.

We estimate modest profit growth this year and a larger increase in 2023. The comparison with the 2021 tally is tough because mark-to-market accounting gains added $0.14 to share net. Our estimate is within the company's targeted range of $4.87-$5.07 a share. Management narrowed its goal for annual earnings growth from 5%-7% to 6%-7%, and our 2023 estimate is within this range. Rate relief and volume growth are key factors boosting AEP's earning power.

This untimely but high-quality stock has an average dividend yield for a utility. The issue doesn't stand out for the next 18 months or the 2025-2027 period.

Paul E. Debbas, CFA *March 11, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; '19, (20¢); gains (loss) from disc. ops.: '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). Next earnings report due late April. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '21: $17.04/sh. (D) In mill. (E) Rate base: various. Rates allowed on com. eq.: 9.3%-10.9%; earned on avg. com. eq., '21: 11.6%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

AVANGRID, INC. NYSE-AGR

RECENT PRICE 46.72 | P/E RATIO 25.3 (Trailing: 21.3 Median: NMF) | RELATIVE P/E RATIO 1.43 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Lowered 7/30/21
SAFETY 2 Raised 2/17/17
TECHNICAL 3 Lowered 2/11/22
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$36-$55 $46 (-5%)

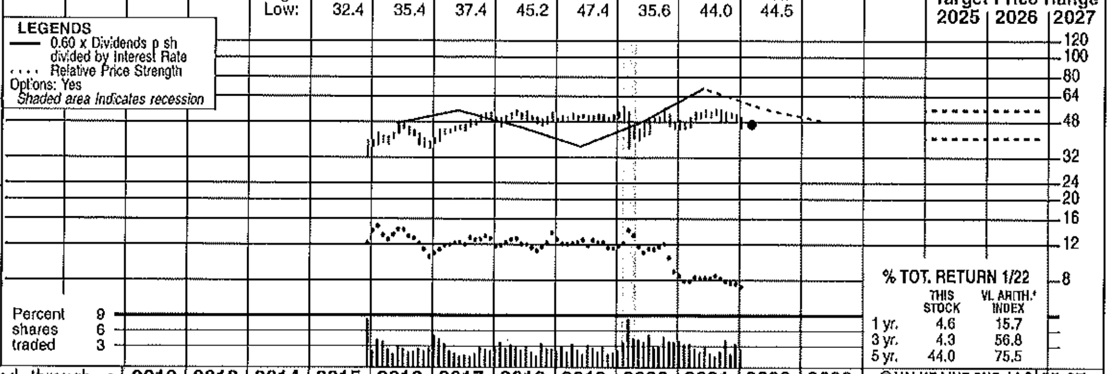
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+20%)	8%
Low	40	(-15%)	Nil

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	142	144	128
to Sell	128	120	110
Hld's(000)	41269	41701	41507

	2015	2016	2017	2018	2019	2020	2021	2022
High:	38.9	46.7	53.5	54.6	52.9	57.2	55.6	50.7
Low:	32.4	35.4	37.4	45.2	47.4	35.6	44.0	44.5



% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.6	15.7
3 yr.	4.3	56.8
5 yr.	44.0	75.5

AVANGRID, Inc. was formed through a merger between Iberdrola USA, Inc. and UIL Holdings Corporation in December of 2015. Iberdrola S.A., a worldwide leader in the energy industry, owns 81.5% of AVANGRID. The predecessor company was founded in 1852 and is headquartered in New Gloucester, Maine. It was incorporated in 1997 in New York under the name NGE Resources, Inc. AVANGRID began trading on the NYSE on December 17, 2015.

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
--	--	--	14.14	19.48	19.30	20.96	20.51	20.45	17.55	17.95	18.45	Revenues per sh	20.25
--	--	--	3.44	4.74	4.49	4.89	5.50	5.07	4.50	4.70	4.95	"Cash Flow" per sh	6.00
--	--	--	1.05	1.98	1.67	1.92	2.26	1.88	2.05	1.95	2.05	Earnings per sh A	2.50
--	--	--	--	1.73	1.73	1.74	1.76	1.76	1.76	1.76	1.76	Div'd Decl'd per sh B ■	1.90
--	--	--	3.50	5.52	7.82	5.78	8.87	9.00	7.50	8.25	8.65	Cap'l Spending per sh	9.50
--	--	--	48.74	48.90	48.79	48.88	49.31	49.21	49.95	50.15	50.40	Book Value per sh C	52.00
--	--	--	308.86	308.99	309.01	309.01	309.01	309.08	387.20	387.20	387.20	Common Shs Outst'g D	387.20
--	--	--	33.5	20.5	27.3	26.1	22.1	25.3	24.7	Bold figures are		Avg Ann'l P/E Ratio	19.0
--	--	--	1.69	1.08	1.37	1.41	1.18	1.30	1.30	Value	Line	Relative P/E Ratio	1.05
--	--	--	--	4.3%	3.8%	3.5%	3.5%	3.7%	3.5%	estim	ates	Avg Ann'l Div'd Yield	4.0%
--	--	4594.0	4367.0	6018.0	5963.0	6478.0	6338.0	6320.0	6800	6950	7150	Revenues ($mill)	7850
--	--	424.0	267.0	611.0	516.0	595.0	700.0	581.0	740	760	790	Net Profit ($mill)	965
--	--	39.9%	11.3%	37.4%	32.4%	22.1%	17.5%	5.1%	7.0%	7.0%	7.0%	Income Tax Rate	7.0%
--	--	6.8%	12.7%	7.5%	12.4%	9.4%	14.4%	18.4%	18.0%	17.0%	14.0%	AFUDC % to Net Profit	10.0%
--	--	16.8%	23.1%	23.0%	25.6%	26.2%	30.6%	40.8%	32.5%	34.5%	36.0%	Long-Term Debt Ratio	40.5%
--	--	83.2%	76.9%	77.0%	74.4%	73.8%	69.4%	59.2%	67.5%	65.5%	64.0%	Common Equity Ratio	59.5%
--	--	14956	19583	19619	20273	20472	21953	25687	28550	29575	30450	Total Capital ($mill)	33800
--	--	17099	20711	21548	22669	23459	25218	26751	28650	30775	33000	Net Plant ($mill)	40100
--	--	3.7%	2.1%	3.8%	3.1%	3.5%	3.8%	2.8%	3.0%	3.0%	3.0%	Return on Total Cap'l	3.5%
--	--	3.4%	1.8%	4.0%	3.4%	3.9%	4.6%	3.8%	4.0%	4.0%	4.0%	Return on Shr. Equity	5.0%
--	--	3.4%	1.8%	4.0%	3.4%	3.9%	4.6%	3.8%	4.0%	4.0%	4.0%	Return on Com Equity E	5.0%
--	--	3.4%	1.8%	1.4%	NMF	.4%	1.0%	.2%	.5%	.5%	.5%	Retained to Com Eq	1.0%
--	--	--	--	66%	104%	90%	78%	94%	83%	90%	86%	All Div'ds to Net Prof	76%

CAPITAL STRUCTURE as of 9/30/21
Total Debt $7920 mill. **Due In 5 Yrs** $2932 mill.
LT Debt $7486 mill. **LT Interest** $275 mill.
Incl. $99 mill. finance leases.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $15 mill.

Pension Assets-12/20 $3092 mill.
Oblig $3819 mill.

Pfd Stock None

Common Stock 387,204,556 shs.
as of 10/28/21
MARKET CAP: $18 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2018	2019	2020
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.8	+.9
Fixed Charge Cov. (%)	343	278	237

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	--	8.0%	-.5%
"Cash Flow"	--	8.5%	2.0%
Earnings	--	14.0%	3.0%
Dividends	--	--	1.0%
Book Value	--	--	1.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1842	1400	1487	1609	6338.0
2020	1789	1392	1470	1669	6320.0
2021	1966	1477	1598	1759	6800
2022	2000	1500	1650	1800	6950
2023	2050	1550	1700	1850	7150

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.70	.36	.48	.72	2.26
2020	.78	.28	.28	.54	1.88
2021	1.08	.28	.29	.40	2.05
2022	.80	.25	.40	.50	1.95
2023	.85	.25	.40	.55	2.05

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.432	.432	.432	.44	1.74
2019	.44	.44	.44	.44	1.76
2020	.44	.44	.44	.44	1.76
2021	.44	.44	.44	.44	1.76
2022	.44				

BUSINESS: AVANGRID, Inc. (formerly Iberdrola USA, Inc.), is a diversified energy and utility company that serves 2.3 million electric customers in New York, Connecticut, and Maine and 1 million gas customers in New York, Connecticut, Massachusetts & Maine. Has a nonregulated generating subsidiary focused on wind power, with 8.5 gigawatts of capacity. Revenue breakdown by customer class not available. Generating sources not available. Fuel costs: 24% of revenues. '20 reported depr. rate (utility): 2.9%. Ibardrola owns 81.5% of stock. Has 7,000 employees. Chairman: José Ignacio Sanchez Galan. CEO: Dennis V. Arriola. Deputy CEO & President: Robert Kump. Inc.: NY. Address: 180 Marsh Hill Road, Orange, CT 06477. Tel.: 207-629-1200. Web: www.avangrid.com.

The proposed acquisition of PNM Resources by AVANGRID was rejected by the New Mexico regulators, but the companies haven't given up. AVANGRID agreed to pay $4.3 billion in cash for PNM Resources, the parent company of electric utilities with 800,000 customers in New Mexico and Texas. The companies have appealed the commission's decision to the New Mexico Supreme Court; when this matter will be resolved is unknown. AVANGRID and PNM Resources have extended their merger agreement to April 20, 2023.

The company has already financed the deal in anticipation of its completion. In May of 2021, AVANGRID raised $4 billion through the sale of 78 million common shares. Because average shares outstanding will be higher in 2022, share earnings will probably decline, despite an expected increase in net profit. We think the company will repurchase this stock if the takeover attempt ultimately fails to win regulatory approval, but have not built this into our estimates and projections.

We expect share profits to recover in 2023. The utilities should benefit from rate relief, and the renewable-energy subsidiary should continue to add wind and solar projects. AVANGRID's earning power will benefit if its Central Maine Power subsidiary gets the state commission to remove a one percentage point penalty that was imposed for customer-service problems.

AVANGRID has a sizable presence in offshore wind. Construction of a 50%-owned 800-megawatt project has begun, with completion scheduled for 2024. The company now owns 100% of projects with capacity of 804 mw, 1,232 mw, and 2,500 mw. Investors should note that offshore wind has good profit potential, but comes with significant construction risk.

The dividend yield is just slightly higher than the average for electric utility stocks. This is despite the lack of near-term dividend growth potential and the disadvantage of operating in states with difficult regulatory climates. The recent quotation is well within the 3- to 5-year Target Price Range, so total return potential is low. The stock is untimely.

Paul E. Debbas, CFA *February 11, 2022*

(A) Diluted EPS. Excl. nonrecurring gain (loss): '16, 6¢; '17, (44¢). Next earnings report due late Feb. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Dividend reinvestment plan available. (C) Incl. intangibles. In '20: $5996 mill., $19.40/sh. (D) In millions. (E) Rate base: Not original cost. Rate allowed on com. eq. in NY in '20: 8.8%; in CT in '17: 9.1% elec.; in CT in '19: 9.3% gas; in ME in '20: 8.25%; earned on avg. common eq., '20: 3.8%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	55
Earnings Predictability	70

AVISTA CORP. NYSE-AVA

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
44.74	22.3 (Trailing: 21.4 Median: 19.0)	1.25	4.0%

VALUE LINE

TIMELINESS 4 Raised 4/1/22
SAFETY 2 Raised 5/7/10
TECHNICAL 2 Raised 4/22/22
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$30-$50	$40 (-10%)

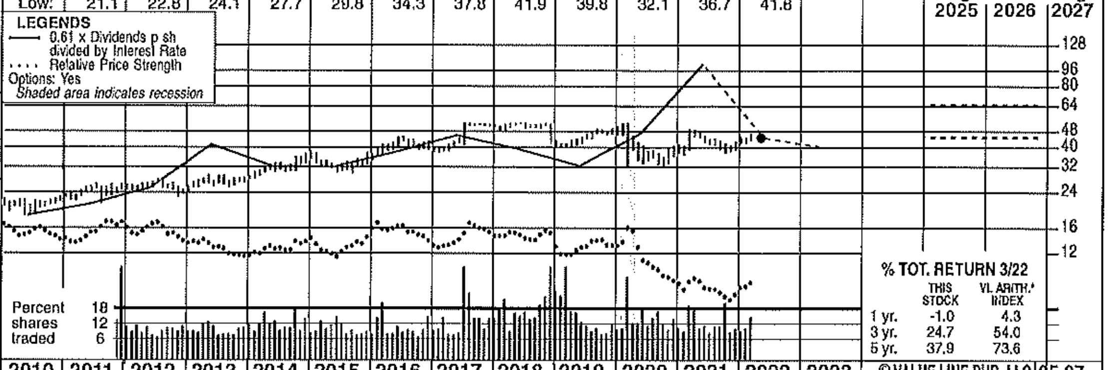
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+45%)	13%
Low	45	(Nil)	4%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	108	118	142
to Sell	107	103	102
Hld's(000)	57295	57202	58479

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	26.5	28.0	29.3	37.4	38.3	45.2	52.8	52.9	49.5	53.0	49.1	46.9
Low:	21.1	22.8	24.1	27.7	29.8	34.3	37.8	41.9	39.8	32.1	36.7	41.8



% TOT. RETURN 3/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.0	4.3
3 yr.	24.7	54.0
5 yr.	37.9	73.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
28.68	26.80	30.77	27.58	27.29	27.73	25.86	26.94	23.66	23.83	22.47	22.08	21.27	20.03	19.09	20.13	*20.15*	*20.80*	Revenues per sh	*21.00*
4.27	2.93	3.98	4.45	3.62	3.78	3.70	4.36	4.36	4.92	5.30	4.87	5.01	6.06	5.16	5.34	*5.25*	*5.80*	"Cash Flow" per sh	*6.50*
1.47	.72	1.36	1.58	1.65	1.72	1.32	1.85	1.84	1.89	2.15	1.95	2.07	2.97	1.90	2.10	*2.00*	*2.45*	Earnings per sh A	*2.75*
.57	.60	.69	.81	1.00	1.10	1.16	1.22	1.27	1.32	1.37	1.43	1.49	1.55	1.62	1.69	*1.76*	*1.83*	Div'd Decl'd per sh B ■	*2.05*
3.14	4.04	4.09	3.86	3.64	4.20	4.61	5.05	5.47	6.46	6.34	6.30	6.46	6.59	5.84	6.15	*6.30*	*6.10*	Cap'l Spending per sh	*5.75*
17.46	17.27	18.30	19.17	19.71	20.30	21.06	21.61	23.84	24.53	25.69	26.41	26.99	28.87	29.31	30.14	*30.75*	*31.80*	Book Value per sh C	*34.75*
52.51	52.91	54.49	54.84	57.12	58.42	59.81	60.08	62.24	62.31	64.19	65.49	65.69	67.18	69.24	71.50	*74.50*	*77.00*	Common Shs Outst'g D	*83.00*
15.4	30.9	15.0	11.4	12.7	14.1	19.3	14.6	17.3	17.6	18.8	23.4	24.5	15.0	21.2	20.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*20.0*
.83	1.64	.90	.76	.81	.88	1.23	.82	.91	.89	.99	1.18	1.32	.80	1.09	1.11			Relative P/E Ratio	*1.10*
2.5%	2.7%	3.4%	4.5%	4.8%	4.5%	4.6%	4.5%	4.0%	4.0%	3.4%	3.1%	2.9%	3.5%	4.0%	4.0%			Avg Ann'l Div'd Yield	*3.7%*
						1547.0	1618.5	1472.6	1484.8	1442.5	1445.9	1396.9	1345.6	1321.9	1438.9	*1500*	*1600*	Revenues ($mill)	*1750*
						78.2	111.1	114.2	118.1	137.2	126.1	136.4	197.0	129.5	147.3	*145*	*185*	Net Profit ($mill)	*230*
						34.4%	36.0%	37.6%	36.3%	36.3%	36.5%	16.0%	13.8%	5.2%	7.5%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
						8.3%	8.8%	11.1%	10.1%	8.1%	7.9%	7.7%	5.5%	8.5%	7.5%	*8.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
						50.8%	51.4%	51.0%	50.0%	51.2%	47.2%	50.5%	49.4%	50.4%	47.5%	*50.5%*	*50.0%*	Long-Term Debt Ratio	*48.5%*
						49.2%	48.6%	49.0%	50.0%	48.8%	52.8%	49.5%	50.6%	49.6%	52.5%	*49.5%*	*50.0%*	Common Equity Ratio	*51.5%*
						2561.2	2669.7	3027.3	3060.3	3379.0	3273.2	3580.3	3834.6	4089.8	4104.7	*4625*	*4880*	Total Capital ($mill)	*5625*
						3023.7	3202.4	3620.0	3898.6	4147.5	4398.8	4648.9	4797.0	4991.6	5225.5	*5450*	*5660*	Net Plant ($mill)	*6200*
						4.3%	5.4%	4.9%	5.1%	5.3%	5.0%	4.8%	6.2%	4.2%	4.7%	*4.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
						6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	10.2%	6.4%	6.8%	*6.5%*	*7.5%*	Return on Shr. Equity	*8.0%*
						6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	10.2%	6.4%	6.8%	*6.5%*	*7.5%*	Return on Com Equity E	*8.0%*
						.8%	2.9%	2.4%	2.3%	3.0%	1.9%	2.2%	4.9%	.9%	1.4%	*.5%*	*2.0%*	Retained to Com Eq	*2.0%*
						88%	66%	69%	70%	64%	73%	72%	52%	85%	80%	*88%*	*75%*	All Div'ds to Net Prof	*74%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $2483.9 mill. **Due In 5 Yrs** $562.5 mill.
LT Debt $1949.9 mill. **LT Interest** $82.2 mill.
Incl. $51.5 mill. debt to affiliated trusts; $48.8 mill. finance leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $4.8 mill.
Pension Assets-12/21 $751.0 mill. **Oblig** $799.0 mill.

Pfd Stock None

Common Stock 71,572,570 shs.
as of 1/31/22
MARKET CAP: $3.2 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+.8	-2.4	+4.3
Avg. Indust. Use (MWH)	1296	1265	1383
Avg. Indust. Revs. per KWH (¢)	6.26	6.38	6.41
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1656	1721	1889
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.8	+1.4
Fixed Charge Cov. (%)	202	221	215

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.5%	-3.5%	*1.0%*
"Cash Flow"	3.5%	2.5%	*3.0%*
Earnings	3.5%	3.5%	*3.0%*
Dividends	5.5%	4.0%	*4.0%*
Book Value	4.0%	3.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	396.5	300.8	283.8	364.5	1345.6
2020	390.2	278.6	272.6	380.5	1321.9
2021	412.9	298.2	296.0	431.8	1438.9
2022	*440*	*320*	*315*	*425*	*1500*
2023	*465*	*345*	*340*	*450*	*1600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.76	.38	.08	.76	2.97
2020	.72	.26	.07	.85	1.90
2021	.98	.20	.20	.71	2.10
2022	*.90*	*.30*	*.10*	*.70*	*2.00*
2023	*1.10*	*.35*	*.15*	*.85*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.3725	.3725	.3725	.3725	1.49
2019	.3875	.3875	.3875	.3875	1.55
2020	.405	.405	.405	.405	1.62
2021	.4225	.4225	.4225	.4225	1.69
2022	.44				

BUSINESS: Avista Corporation (formerly The Washington Water Power Company) supplies electricity & gas in eastern Washington & northern Idaho. Supplies electricity to part of Alaska & gas to part of Oregon. Customers: 423,000 electric, 372,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 41%; commercial, 34%; industrial, 11%; wholesale, 9%; other, 5%. Generating sources: gas & coal, 30%; hydro, 29%; purch., 41%. Fuel costs: 35% of revs. '21 reported depr. rate (Avista Utilities): 3.5%. Has 1,900 employees. Chairman: Scott L. Morris. Pres. & CEO: Dennis Vermillion. Inc.: WA. Address: 1411 E. Mission Ave., Spokane, WA 99202-2600. Tel.: 509-489-0500. Internet: www.avistacorp.com.

Avista has a major rate case pending in Washington. This is the utility's first filing under the state's new law that requires multiyear applications. The utility is seeking electric increases of $52.9 million (9.6%) in the first year and $17.1 million (2.8%) in the second. For gas, Avista requested hikes of $10.9 million (9.5%) in the first year and $2.2 million (1.7%) in the second. The utility's filing is based on a return on equity of 10.25% and a common-equity ratio of 48.5%. For several years, the company has underearned its allowed ROE due to the effects of regulatory lag. A reasonable order in the pending case would help address this problem. New tariffs are expected to take effect in late 2022.

Earnings are likely to decline in 2022. Last year, Avista benefited from favorable power costs under Washington's energy recovery mechanism. This will probably swing to a negative factor this year. Also, the company's nonutility investments provided $0.21 a share of income, which is well above normal. An increase in shares outstanding will affect share net, as well. Avista plans to issue $120 million of common equity in 2022. Our estimate is within the company's targeted range of $1.93-$2.13 a share.

We estimate a significant profit increase in 2023. This is based on reasonable regulatory treatment in the Washington rate case. Avista will also benefit from a full year's effect of electric and gas rate hikes totaling $8.9 million effective in Idaho in September of 2022 and a $1.6 million gas increase effective in Oregon in August of 2022. Rate relief might happen in Alaska, as well. Our estimate is within management's guidance of $2.42-$2.62 a share, albeit near the low end.

The board of directors raised the dividend in the first quarter. As we had expected, the increase was $0.07 a share (4.1%) annually. The payout ratio is above Avista's target of 65%-75%, but should be within this range next year as earnings benefit from rate relief.

This untimely stock has a dividend yield that is above the utility average. However, total return potential is negative for the next 18 months and below average for the 3- to 5-year period.

Paul E. Debbas, CFA *April 22, 2022*

(A) Diluted EPS. Excl. nonrec. gain (loss): '14, 9¢; '17, (16¢); gains on discont. ops.: '14, $1.17; '15, 8¢. '19 & '21 EPS don't sum due to rounding. Next earnings report due early May.
(B) Div'ds paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred chgs. In '21: $913.1 mill., $19.22/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in WA in '21: 9.4%; in ID in '21: 9.4%; in OR in '21: 9.4%; earned on avg. com. eq., '21: 7.0%. Regulatory Climate: WA, Below Average; ID, Above Average.

Company's Financial Strength	B++
Stock's Price Stability	70
Price Growth Persistence	45
Earnings Predictability	60

Staff/113
Muldoon/10

Docket No: UE 399

BLACK HILLS CORP. NYSE-BKH

RECENT PRICE	77.31	P/E RATIO	20.0 (Trailing: 20.6 Median: 18.0)	RELATIVE P/E RATIO	1.12	DIV'D YLD	3.2%	VALUE LINE

TIMELINESS 4 Lowered 4/16/21
SAFETY 2 Raised 5/1/15
TECHNICAL 3 Raised 4/22/22
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$51-$79	$65 (-15%)

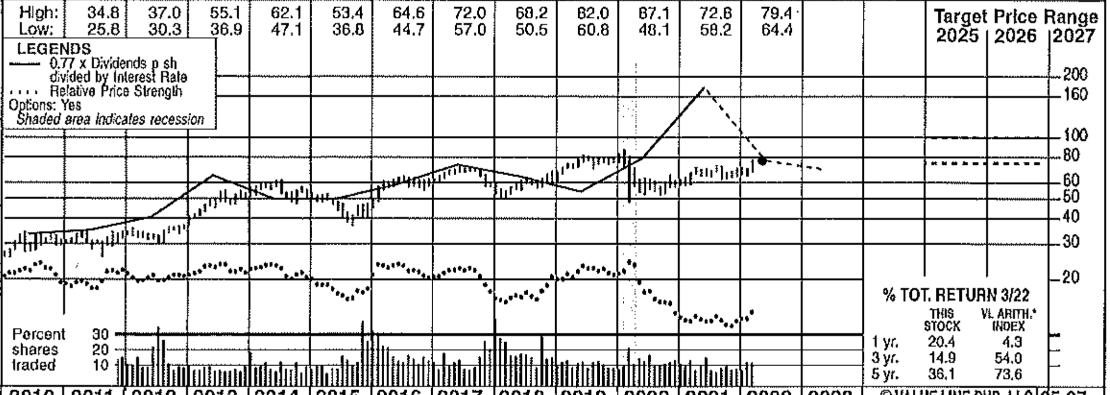
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+30%)	10%
Low	75	(-5%)	3%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	91	120	168
to Sell	163	129	105
Hld's(000)	55341	55119	55367

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	34.8	37.0	55.1	62.1	53.4	64.6	72.0	68.2	82.0	87.1	72.8	79.4
Low:	25.8	30.3	36.9	47.1	36.8	44.7	57.0	50.5	60.8	48.1	58.2	64.4



% TOT. RETURN 3/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.4	4.3
3 yr.	14.9	54.0
5 yr.	36.1	73.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
19.69	18.41	26.03	32.58	33.29	28.96	26.55	28.67	31.20	25.48	29.47	31.38	29.24	28.22	27.02	30.11	30.10	30.35	Revenues per sh	32.50
5.04	5.29	2.95	5.41	4.88	4.01	5.59	5.93	6.25	5.67	6.28	7.15	6.61	7.02	7.41	7.41	7.85	8.25	"Cash Flow" per sh	9.50
2.21	2.68	.18	2.32	1.66	1.01	1.97	2.61	2.89	2.83	2.63	3.38	3.47	3.53	3.73	3.74	4.05	4.25	Earnings per sh A	5.00
1.32	1.37	1.40	1.42	1.44	1.46	1.48	1.52	1.56	1.62	1.68	1.81	1.93	2.05	2.17	2.29	2.41	2.53	Div'd Decl'd per sh B ■	2.95
9.24	6.92	8.51	8.90	12.04	10.03	7.90	7.97	8.92	8.90	8.89	6.09	7.62	13.31	12.22	10.47	9.20	8.90	Cap'l Spending per sh	9.25
23.68	25.66	27.19	27.84	28.02	27.53	27.88	29.39	30.80	28.63	30.25	31.92	36.36	38.42	40.79	43.05	45.35	47.55	Book Value per sh C	54.75
33.37	37.80	38.64	38.97	39.27	43.92	44.21	44.50	44.67	51.19	53.38	53.54	60.00	61.48	62.79	64.74	66.50	67.50	Common Shs Outst'g D	71.00
15.8	15.0	NMF	9.9	18.1	31.1	17.1	18.2	19.0	16.1	22.3	19.5	16.8	21.2	17.0	17.7	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	17.5
.85	.80	NMF	.66	1.15	1.95	1.09	1.02	1.00	.81	1.17	.98	.91	1.13	.87	.97			Relative P/E Ratio	.95
3.8%	3.4%	4.2%	6.2%	4.8%	4.6%	4.4%	3.2%	2.8%	3.5%	2.9%	2.7%	3.3%	2.7%	3.4%	3.5%			Avg Ann'l Div'd Yield	3.4%
						1173.9	1275.9	1393.6	1304.6	1573.0	1680.3	1754.3	1734.9	1696.9	1949.1	2000	2050	Revenues ($mill)	2300
						86.9	115.8	128.8	128.3	140.3	186.5	192.5	214.5	232.9	236.7	265	285	Net Profit ($mill)	360
						35.5%	34.7%	33.7%	35.8%	25.1%	28.7%	19.2%	13.0%	12.2%	2.8%	8.5%	8.5%	Income Tax Rate	8.5%
						5.4%	2.4%	2.4%	2.7%	5.3%	2.7%	1.4%	3.3%	2.5%	2.0%	2.0%	1.0%	AFUDC % to Net Profit	1.0%
						43.2%	51.6%	47.9%	56.0%	66.5%	64.5%	57.5%	57.1%	57.9%	59.7%	54.5%	53.0%	Long-Term Debt Ratio	45.5%
						56.8%	48.4%	52.1%	44.0%	33.5%	35.5%	42.5%	42.9%	42.1%	40.3%	45.5%	47.0%	Common Equity Ratio	54.5%
						2171.4	2704.7	2643.6	3332.7	4825.8	4818.4	5132.4	5502.2	6089.5	6914.0	6615	6815	Total Capital ($mill)	7125
						2742.7	2990.3	3239.4	3259.1	4469.0	4541.4	4854.9	5503.2	6019.7	6449.2	6805	7130	Net Plant ($mill)	8225
						5.5%	5.5%	6.1%	4.9%	4.0%	5.2%	5.0%	4.9%	5.0%	4.5%	5.0%	5.0%	Return on Total Cap'l	6.0%
						7.1%	8.9%	9.4%	8.8%	8.7%	10.9%	8.8%	9.1%	9.1%	8.5%	9.0%	9.0%	Return on Shr. Equity	9.0%
						7.1%	8.9%	9.4%	8.8%	8.7%	10.9%	8.8%	9.1%	9.1%	8.5%	9.0%	9.0%	Return on Com Equity E	9.0%
						1.8%	3.7%	4.3%	3.8%	3.3%	5.3%	3.9%	3.8%	3.8%	3.3%	3.5%	3.5%	Retained to Com Eq	4.0%
						75%	58%	54%	57%	62%	52%	55%	58%	58%	61%	60%	59%	All Div'ds to Net Prof	58%

CAPITAL STRUCTURE as of 12/31/21
Total Debt $4547.1 mill. **Due in 5 Yrs** $1845.2 mill.
LT Debt $4126.9 mill. **LT Interest** $147.8 mill.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $2.2 mill.

Pension Assets-12/21 $458.4 mill.
Oblig $478.3 mill.

Pfd Stock None

Common Stock 64,738,725 shs.
as of 1/31/22

MARKET CAP: $5.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+2.1	-.7	+1.5
Avg. Indust. Use (MWH)	21406	21624	21358
Avg. Indust. Revs. per KWH (¢)	7.38	7.31	8.51
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1022	1050	1078
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+.9	+1.0
Fixed Charge Cov. (%)	278	285	259

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	- -	2.0%
"Cash Flow"	4.5%	3.5%	4.5%
Earnings	8.0%	5.5%	5.5%
Dividends	4.0%	6.0%	5.5%
Book Value	4.0%	6.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	597.8	333.9	325.5	477.7	1734.9
2020	537.0	326.9	346.6	486.4	1696.9
2021	633.4	372.6	380.6	562.5	1949.1
2022	650	400	400	550	2000
2023	675	400	400	575	2050

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.73	.24	.44	1.13	3.53
2020	1.59	.33	.58	1.23	3.73
2021	1.54	.40	.70	1.11	3.74
2022	1.65	.45	.65	1.30	4.05
2023	1.75	.45	.65	1.40	4.25

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.475	.475	.475	.505	1.93
2019	.505	.505	.505	.535	2.05
2020	.535	.535	.535	.565	2.17
2021	.565	.565	.565	.595	2.29
2022	.595				

BUSINESS: Black Hills Corporation is a holding company for Black Hills Energy, which serves 218,000 electric customers in CO, SD, WY and MT, and 1.1 million gas customers in NE, IA, KS, CO, WY, and AR. Has coal mining sub. Acq'd utility ops. from Aquila 7/08; SourceGas 2/16. Discontinued gas marketing in '11; gas & oil E&P in '17. Electric rev. breakdown: residential, 31%; commercial, 34%; industrial, 19%; other, 16%. Generating sources: coal, 34%; gas, 25%; wind, 11%; purchased, 30%. Fuel costs: 38% of revs. '21 deprec. rate: 3.1%. Has 2,900 employees. Chairman: David R. Emery. President & CEO: Linn Evans. Inc.: SD. Address: 7001 Mount Rushmore Rd., P.O. Box 1400, Rapid City, SD 57709-1400. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

Black Hills Corporation should post a solid earnings increase in 2022. The company will benefit from a full year's effect of rate relief that was granted last year. In addition, a significant portion of the utilities' capital spending is recoverable through riders (surcharges) on customers' bills. We assume normal weather patterns after unfavorable weather hurt earnings by $0.16 a share in the fourth quarter of 2021 and by $0.07 for the full year, which helps explain why the profit growth Black Hills posted last year was minimal. The economy in the service area is healthy. There are some negative factors for the share-net comparison, namely a cut in the price of a power-sales contract, which took effect at the start of 2022, and a rise in average shares outstanding stemming from equity issuances that occurred last year and are planned for this year ($100 million-$120 million issued through an at-the-market program). Our estimate is at the midpoint of management's targeted range of $3.95-$4.15 a share.

A gas rate case is pending in Arkansas, and other applications are upcoming. The utility filed for an increase of $21.6 million, based on a return on equity of 10.2% and a common-equity ratio of 50.9%. New tariffs are expected to take effect in the fourth quarter of 2022. Wyoming Electric plans to file a case by midyear, and Rocky Mountain Natural Gas, Black Hills' midstream gas subsidiary in Colorado, expects to file a petition later this year. Orders on these two cases are expected in 2023.

We estimate a solid profit increase again in 2023. Rate relief and additional rider revenues should be contributing factors. Our estimate of $4.25 a share would provide bottom-line growth within Black Hills' annual goal of 5%-7%.

The company is proposing a significant transmission project in Wyoming. The estimated cost is $260 million. If the state commission issues a certificate of need, construction of the line will begin in early 2023 and proceed in multiple segments through 2025.

This untimely stock has a dividend yield that is about average for a utility. The equity does not stand out for the next 18 months or the 3- to 5-year period.

Paul E. Debbas, CFA *April 22, 2022*

(A) Dil. EPS. Excl. nonrec. gains (losses): '08, ($1.55); '09, (28¢); '10, 10¢; '15, ($3.54); '18, ($1.26); '17, 14¢; '18, $1.31; '19, (25¢); '20, (8¢); discont. ops.: '08, $4.12; '09, 7¢; '11, 23¢; '12, (16¢); '17, (31¢); '18, (12¢). '19 & '21 EPS don't sum due to rounding. Next egs. due early May. (B) Div'ds pd. early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '21: $28.20/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '15: none; in CO in '17: 9.37%; earn. on avg. com. eq., '21: 8.9%. Regul. Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	45
Earnings Predictability	90

CENTERPOINT EN'RGY NYSE-CNP

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
27.35	26.6 (Trailing: 29.1) (Median: 19.0)	1.49	2.6%

VALUE LINE

TIMELINESS 3 Raised 3/4/22
SAFETY 3 Lowered 12/18/15
TECHNICAL 2 Raised 2/25/22
BETA 1.15 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$16-$31	$24 (-15%)

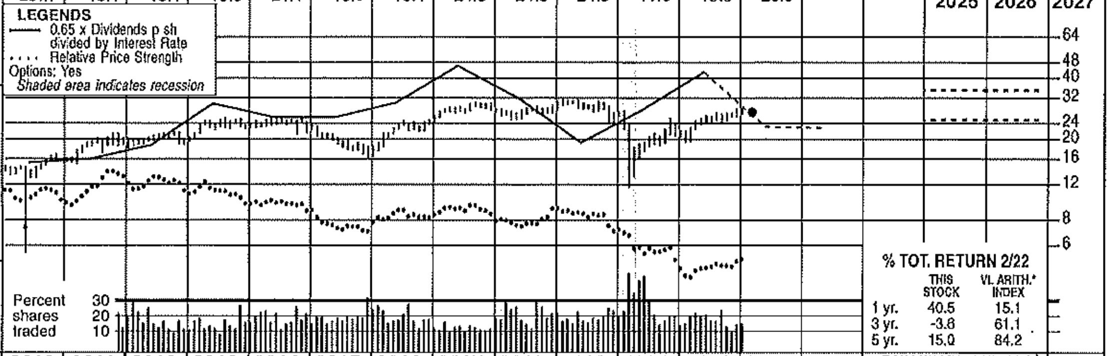
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+30%)	9%
Low	25	(-10%)	1%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	259	244	310
to Sell	225	208	192
Hld's(000)	543976	573708	573458

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	21.5	21.8	25.7	25.8	23.7	25.0	30.5	29.6	31.4	27.5	28.4	28.5
Low:	15.1	18.1	19.3	21.1	16.0	16.4	24.5	24.8	24.3	11.6	19.3	26.0



% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	40.5	15.1
3 yr.	-3.8	61.1
5 yr.	15.0	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
29.71	29.82	32.71	21.14	20.69	19.83	17.43	18.90	21.51	17.18	17.48	22.30	21.13	24.49	13.45	13.28	*13.35*	*13.95*	Revenues per sh	*15.75*
3.47	3.39	3.42	2.94	3.14	3.43	3.89	3.54	3.85	3.40	3.68	4.03	3.24	4.12	3.46	3.00	*3.45*	*3.70*	"Cash Flow" per sh	*4.50*
1.33	1.17	1.30	1.01	1.07	1.27	1.35	1.24	1.42	1.08	1.00	1.57	.74	1.49	1.29	.94	*1.25*	*1.35*	Earnings per sh A	*1.65*
.60	.68	.73	.76	.78	.79	.81	.83	.95	.99	1.03	1.35	1.12	.86	.90	.66	*.71*	*.77*	Div'd Decl'd per sh B ■	*.95*
3.21	3.45	2.95	2.96	3.55	3.06	2.84	3.00	3.20	3.68	3.28	3.31	3.29	4.99	4.71	5.03	*5.55*	*7.45*	Cap'l Spending per sh	*7.25*
4.96	5.61	5.89	6.74	7.53	9.91	10.06	10.09	10.60	8.05	8.03	10.88	12.53	13.10	10.78	13.70	*14.25*	*14.85*	Book Value per sh C	*16.75*
313.65	322.72	346.09	391.75	424.70	426.03	427.44	429.00	429.00	430.00	430.68	431.04	501.20	502.24	551.36	628.92	*630.00*	*631.00*	Common Shs Outst'g D	*634.00*
10.3	15.0	11.3	11.8	13.8	14.6	14.8	18.7	17.0	18.1	21.9	17.9	37.0	19.5	15.9	26.1	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.56	.80	.68	.79	.88	.92	.94	1.05	.89	.91	1.15	.90	2.00	1.04	.82	1.39	*Value Line*		Relative P/E Ratio	*.95*
4.4%	3.9%	5.0%	6.4%	5.3%	4.3%	4.0%	3.6%	3.9%	5.1%	4.7%	4.8%	4.1%	3.0%	4.4%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $16103 mill. **Due in 5 Yrs** $7852 mill.
LT Debt $15558 mill. **LT Interest** $482 mill.
Incl. $393 mill. securitized transition & system restoration bonds.
(LT interest earned: 2.3x)
Leases, Uncapitalized Annual rentals $6 mill.
Pension Assets-12/21 $2072 mill.
Oblig $2298 mill.
Pfd Stock $790 mill. **Pfd Div'd** $49 mill.
800,000 shs. 6.125%, cumulative, with liquidation value of $1000.
Common Stock 628,936,067 shs. as of 2/15/22
MARKET CAP: $17 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
7452.0	8106.0	9226.0	7386.0	7528.0	9614.0	10589	12301	7418.0	8352.0	*8400*	*8800*	Revenues ($mill)	*10000*
581.0	536.0	611.0	465.0	432.0	679.0	368.0	871.0	863.0	668.0	*840*	*900*	Net Profit ($mill)	*1080*
33.4%	31.4%	31.0%	35.1%	37.0%	36.1%	28.4%	14.9%	13.4%	14.1%	*14.0%*	*14.0%*	Income Tax Rate	*14.0%*
2.6%	3.5%	4.1%	4.7%	3.5%	2.9%	5.4%	6.7%	6.0%	9.3%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
66.0%	64.4%	63.8%	69.5%	68.5%	63.6%	51.9%	63.0%	58.0%	62.3%	*62.5%*	*60.0%*	Long-Term Debt Ratio	*61.5%*
34.0%	35.6%	36.2%	30.5%	31.5%	36.4%	37.5%	29.1%	29.9%	34.5%	*34.5%*	*37.0%*	Common Equity Ratio	*38.0%*
12658	12146	12557	11362	10992	12883	16740	22603	19869	24973	*26225*	*25325*	Total Capital ($mill)	*29700*
13597	9593.0	10502	11537	12307	13057	14044	20945	22362	23484	*25575*	*28825*	Net Plant ($mill)	*35400*
6.8%	6.3%	6.7%	6.1%	5.8%	6.8%	3.4%	5.1%	5.6%	3.8%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
13.5%	12.4%	13.4%	13.4%	12.5%	14.5%	4.6%	10.4%	10.3%	7.1%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
13.5%	12.4%	13.4%	13.4%	12.5%	14.5%	5.3%	11.5%	11.6%	6.7%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
5.5%	4.2%	4.5%	1.1%	NMF	4.7%	NMF	2.7%	5.0%	2.2%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
60%	66%	67%	92%	103%	68%	NMF	80%	66%	72%	*59%*	*59%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+6.7	+1.8	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+7.9	+2.5	NA
Fixed Charge Cov. (%)	152	135	181

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.0%	-2.0%	*-1.5%*
"Cash Flow"	1.0%	-.5%	*4.0%*
Earnings	1.0%	1.0%	*5.0%*
Dividends	.5%	-4.0%	*2.5%*
Book Value	4.5%	7.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2019	3531	2798	2742	3230	12301
2020	2167	1575	1622	2054	7418
2021	2547	1742	1749	2314	8352
2022	*2450*	*1800*	*1800*	*2350*	*8400*
2023	*2550*	*1900*	*1900*	*2450*	*8800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2019	.28	.33	.47	.41	1.49
2020	.56	.17	.29	.27	1.29
2021	.41	.29	.21	.03	.94
2022	*.45*	*.30*	*.25*	*.25*	*1.25*
2023	*.50*	*.32*	*.26*	*.26*	*1.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.2775	.2775	.2775	.2775	1.11
2019	.2875	.2875	.2875	.2875	1.15
2020	.29	.15	.15	.15	.74
2021	.16	.16	.16	.17	.65
2022	.17				

BUSINESS: CenterPoint Energy, Inc. is a holding company for Houston Electric, which serves 2.7 million customers in Houston and environs, Indiana Electric, which serves 150,000 customers, and gas utilities with 4.2 million customers in Texas, Minnesota, Louisiana, Mississippi, Indiana, and Ohio. Acquired Vectren 2/19. Sold nonutility operations in '20. Sold most of its stake in Energy Transfer in '21. Electric revenue breakdown not available. Fuel costs: 28% of revenues. '21 depreciation rate: 3.9%. Has 9,400 employees. Chairman: Martin H. Nesbitt. President & CEO: David J. Lesar. Incorporated: Texas. Address: 1111 Louisiana, P.O. Box 4567, Houston, Texas 77210-4567. Telephone: 713-207-1111. Internet: www.centerpointenergy.com.

CenterPoint Energy completed the sale of two of its gas utilities in early 2022. The company sold its gas companies in Arkansas and Oklahoma at an attractive valuation, fetching 2.5 times rate base and 38 times 2020 earnings. The transaction brought in $1.6 billion, including $400 million to compensate CenterPoint for extraordinary gas costs following a cold spell in the Gulf Coast in February of 2021. The company used the proceeds to retire $725 million of debt and will use the remainder to fund capital spending. We will *exclude* from our earnings presentation any gain on the sale as a nonrecurring item.

The company is exiting its position in midstream gas. In December, Energy Transfer completed the acquisition of Enable Midstream Partners. CenterPoint sold 75% of its common units and 50% of its preferred units, and expects to sell the rest of its stake (currently valued at nearly $700 million) by yearend. CenterPoint used the proceeds (nearly $800 million after taxes) to pay down debt.

A gas rate case is pending in Minnesota. CenterPoint requested $67.1 million, based on a return on equity of 10.2% and a common-equity ratio of 51%. An interim hike of $42 million took effect at the start of 2022. An order is expected in October. Separately, the state commission is examining the prudence of utilities' extraordinary gas costs following the aforementioned cold spell last February.

Due in part to the aforementioned transactions, the year-to-year earnings comparisons won't be of much significance this year. In 2023, earnings should advance thanks to solid demand growth at the utilities. This is especially noteworthy for Houston Electric, which also obtains revenues for transmission and distribution every year through regulatory mechanisms. Note that mark-to-market accounting items affect earnings annually. We *include* these in our earnings presentation because they are an ongoing part of CenterPoint's results.

This stock's valuation is high. The market has applauded the moves CenterPoint is making. The dividend yield is well below the utility average. Total return potential is negative for the next 18 months and low for the 3- to 5-year period.

Paul E. Debbas, CFA *March 11, 2022*

(A) Dil. EPS. Excl. nonrecur. gains (losses): '11, $1.89; '12, (38¢); '13, (52¢); '15, ($2.69); '17, $2.56; '20, ($2.74); gain (loss) on disc. ops.: '20, (34¢); '21, $1.34. Next earnings report due early May. (B) Div'ds histor. paid in early Mar., June, Sept. & Dec. 5 declarations in '17 & '20, 3 in '19. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $10.52/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. (elec.) in '20: 9.4%; (gas): 9.45%-11.25%; earned on avg. com. eq., '21: 7.9%. Regulatory Climate: TX, Avg.; IN, Above Avg.

Company's Financial Strength	B+
Stock's Price Stability	70
Price Growth Persistence	25
Earnings Predictability	50

CMS ENERGY CORP. NYSE-CMS

RECENT PRICE **64.01** P/E RATIO **23.7** (Trailing: 24.8 Median: 20.0) RELATIVE P/E RATIO **1.32** DIV'D YLD **2.9%** VALUE LINE

TIMELINESS	4	Lowered 12/17/21
SAFETY	2	Raised 3/21/14
TECHNICAL	3	Raised 1/21/22

BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$56-$83	$70 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+15%)	7%
Low	55	(-15%)	*Nil*

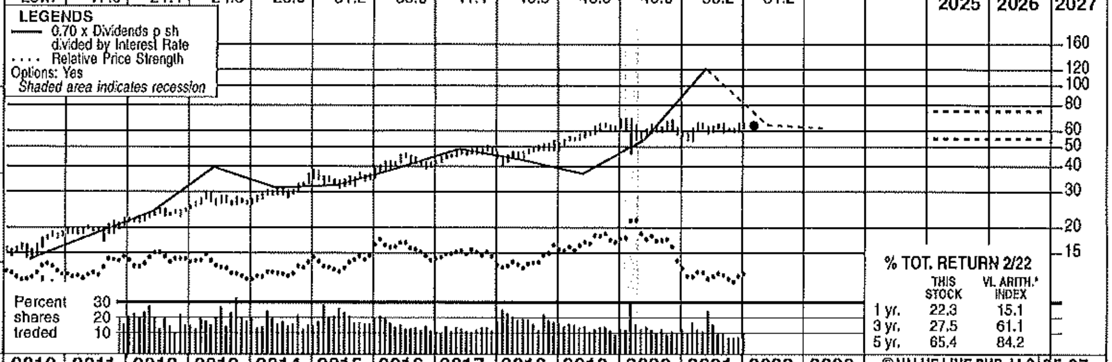
Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	293	261	249
to Sell	245	244	277
Hld's(000)	263668	270396	270027

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	22.4	25.0	30.0	36.9	38.7	46.3	50.8	53.8	65.3	69.2	65.8
Low:	17.0	21.1	24.6	26.0	31.2	35.0	41.1	40.5	48.0	46.0	53.2

	2022
High:	65.8
Low:	61.2

Target Price Range 2025 | 2026 | 2027



% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.3	15.1
3 yr.	27.5	61.1
5 yr.	65.4	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
30.57	28.95	30.13	27.23	25.77	25.59	23.90	24.68	26.09	23.29	22.92	23.37	24.25	24.11	23.12	25.29	*25.90*	*26.55*	Revenues per sh	*28.25*
3.22	3.08	3.88	3.47	3.70	3.65	3.82	4.06	4.22	4.59	4.88	5.29	5.61	5.89	6.24	6.42	*6.95*	*7.40*	"Cash Flow" per sh	*8.75*
.64	.64	1.23	.93	1.33	1.45	1.53	1.66	1.74	1.89	1.98	2.17	2.32	2.39	2.64	2.58	*2.85*	*3.05*	Earnings per sh A	*3.75*
--	.20	.36	.50	.66	.84	.96	1.02	1.08	1.16	1.24	1.33	1.43	1.53	1.63	1.74	*1.84*	*1.94*	Div'd Decl'd per sh B ■	*2.30*
3.01	5.61	3.50	3.59	3.29	3.47	4.65	4.98	5.73	5.64	5.99	5.91	7.32	7.41	8.02	7.16	*8.95*	*10.00*	Cap'l Spending per sh	*9.75*
10.03	9.46	10.88	11.42	11.19	11.92	12.09	12.98	13.34	14.21	15.23	15.77	16.76	17.68	19.02	22.11	*23.10*	*24.25*	Book Value per sh C	*29.00*
222.78	225.15	226.41	227.89	249.60	254.10	264.10	266.10	275.20	277.16	279.21	281.65	283.37	283.86	288.94	289.76	*289.80*	*289.80*	Common Shs Outst'g D	*300.00*
22.2	26.8	10.9	13.6	12.5	13.6	15.1	16.3	17.3	18.3	20.9	21.3	20.3	24.3	23.3	23.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
1.20	1.42	.68	.91	.80	.85	.96	.92	.91	.92	1.10	1.07	1.10	1.29	1.20	1.26			Relative P/E Ratio	*.95*
--	1.2%	2.7%	4.0%	4.0%	4.3%	4.2%	3.8%	3.6%	3.4%	3.0%	2.9%	3.0%	2.6%	2.6%	2.9%			Avg Ann'l Div'd Yield	*3.5%*
						6312.0	6566.0	7179.0	6456.0	6399.0	6583.0	6873.0	6845.0	6680.0	7329.0	*7500*	*7700*	Revenues ($mill)	*8500*
						413.0	454.0	479.0	525.0	553.0	610.0	659.0	682.0	757.0	751.0	*835*	*900*	Net Profit ($mill)	*1120*
						39.4%	39.9%	34.3%	34.0%	33.1%	31.2%	14.9%	17.7%	15.0%	11.5%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
						2.9%	2.0%	2.3%	2.7%	3.1%	1.1%	1.4%	2.1%	1.1%	1.5%	*1.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
						67.9%	67.5%	68.7%	68.3%	67.1%	67.3%	69.0%	70.4%	71.2%	64.5%	*64.0%*	*64.0%*	Long-Term Debt Ratio	*61.5%*
						31.6%	32.2%	31.0%	31.4%	32.6%	32.4%	30.7%	29.4%	28.6%	34.2%	*34.5%*	*35.0%*	Common Equity Ratio	*37.0%*
						10101	10730	11846	12534	13040	13692	15476	17082	19223	18760	*19375*	*20125*	Total Capital ($mill)	*23400*
						11551	12246	13412	14705	15715	16761	18126	18926	21039	22352	*23775*	*25400*	Net Plant ($mill)	*29900*
						5.9%	6.0%	5.7%	5.7%	5.8%	5.9%	5.6%	5.3%	5.2%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
						12.8%	13.0%	12.9%	13.2%	12.9%	13.6%	13.8%	13.5%	13.7%	11.3%	*12.0%*	*12.5%*	Return on Shr. Equity	*12.5%*
						12.9%	13.1%	13.0%	13.3%	13.0%	13.7%	13.8%	13.6%	13.7%	11.6%	*12.5%*	*12.5%*	Return on Com Equity E	*13.0%*
						5.0%	5.2%	5.0%	5.2%	4.8%	5.2%	5.3%	4.9%	5.3%	3.8%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
						61%	60%	62%	61%	63%	62%	62%	64%	62%	68%	*65%*	*64%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $12474 mill. **Due in 5 Yrs** $2324 mill.
LT Debt $12092 mill. **LT Interest** $439 mill.
Incl. $46 mill. finance leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $5 mill.
Pension Assets-12/21 $3599 mill.
Oblig $3070 mill.
Pfd Stock $261 mill. **Pfd Div'd** $11 mill.
Incl. 373,148 shs. $4.50 $100 par, cum., callable at $110.00; 9,200,000 shs. 4.2%, $25 par, cum.
Common Stock 289,760,265 shs.
as of 1/14/22
MARKET CAP: $19 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.7	-3.1	+2.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.94	8.14	8.46
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	8039	8215	7951
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+1.0	*+1*
Fixed Charge Cov. (%)	235	240	223

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	--	*2.5%*
"Cash Flow"	5.5%	6.5%	*6.0%*
Earnings	7.5%	6.5%	*6.5%*
Dividends	9.5%	7.0%	*6.0%*
Book Value	5.5%	6.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2059	1445	1546	1795	6845.0
2020	1864	1443	1575	1798	6680.0
2021	2013	1558	1725	2033	7329.0
2022	*2100*	*1600*	*1750*	*2050*	*7500*
2023	*2150*	*1650*	*1800*	*2100*	*7700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.75	.33	.73	.58	2.39
2020	.85	.48	.76	.55	2.64
2021	1.09	.55	.54	.40	2.58
2022	*.95*	*.60*	*.75*	*.55*	*2.85*
2023	*1.00*	*.65*	*.80*	*.60*	*3.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec. 31	Full Year
2018	.3575	.3575	.3575	.3575	1.43
2019	.3825	.3825	.3825	.3825	1.53
2020	.4075	.4075	.4075	.4075	1.63
2021	.435	.435	.435	.435	1.74
2022	.46				

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.9 million electric, 1.8 million gas customers. Has 1,234 megawatts of nonregulated generating capacity. Sold EnerBank in '21. Electric revenue breakdown: residential, 48%; commercial, 32%; industrial, 13%; other, 7%. Generating sources: coal, 31%; gas, 16%; renewables, 6%; purchased, 47%. Fuel costs: 42% of revenues. '21 reported deprec. rates: 3.9% electric, 2.9% gas, 9.4% other. Has 8,500 full-time employees. Chairman: John G. Russell. President & CEO: Garrick Rochow. Inc.: Michigan. Address: One Energy Plaza, Jackson, Michigan 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy's utility subsidiary received an electric rate order. Consumers Energy had sought an electric increase of $201 million, based on a return on equity of 10.5% and a common-equity ratio of 52%. The commission's order was somewhat disappointing, granting a hike of $54 million, based on an ROE of 9.9% (unchanged) and a common-equity ratio of 51%. New tariffs took effect at the start of 2022. The utility plans to file another electric application early in the second quarter, with a ruling due 10 months after the filing. Frequent rate cases are necessary for Consumers Energy because it has a large system with a lot of aged equipment that needs replacing. Similarly . . .

Consumers Energy has a gas rate case pending. The utility is seeking an increase of $278 million, based on an ROE of 10.5% and a common-equity ratio of 52%. A ruling is due by the start of October.

We expect a significant earnings increase this year. The company will benefit from the electric rate increase and a partial year of new gas tariffs. Consumers Energy is seeing a recovery in commercial kilowatt-hour sales. The fourth-quarter comparison will be easy because CMS Energy booked a $0.07-a-share charge for a fleet impairment in 2021. Our estimate is at the low end of management's targeted range of $2.85-$2.89 a share (adjusted from the previous guidance of $2.85-$2.87).

Further profit growth is likely in 2023. The company should benefit from additional rate relief. We look for a 7% rise in earnings, which is within management's goal of 6%-8% annually.

CMS Energy won't need to issue equity until 2025. The sale of the EnerBank subsidiary last year raised $1 billion that will help fund the capital budget.

The board of directors boosted the dividend in the first quarter. The increase was $0.10 a share (5.7%) annually. Dividend growth is likely to lag earnings growth until the payout ratio reaches CMS Energy's target of 60%.

This untimely stock has a dividend yield that is below average for a utility. The equity doesn't stand out for the next 18 months, and total return potential to 2025-2027 is low.

Paul E. Debbas, CFA *March 11, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, ($1.08); '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); '17, (53¢); gains (losses) on discont. ops.: '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢; '21, $2.08. Next earnings report due late April. (B) Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '21: $7.80/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '22: 9.9% elec.; in '19: 9.9% gas; earned on avg. com. eq., '21: 13.2%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	95

CON. EDISON NYSE-ED

RECENT PRICE 86.45 | **P/E RATIO** 19.5 (Trailing: 19.4 Median: 17.0) | **RELATIVE P/E RATIO** 1.10 | **DIV'D YLD** 3.7%

VALUE LINE

TIMELINESS 3 Raised 1/7/22
SAFETY 1 New 7/27/90
TECHNICAL 3 Lowered 2/11/22
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$60-$89	$75 (-15%)

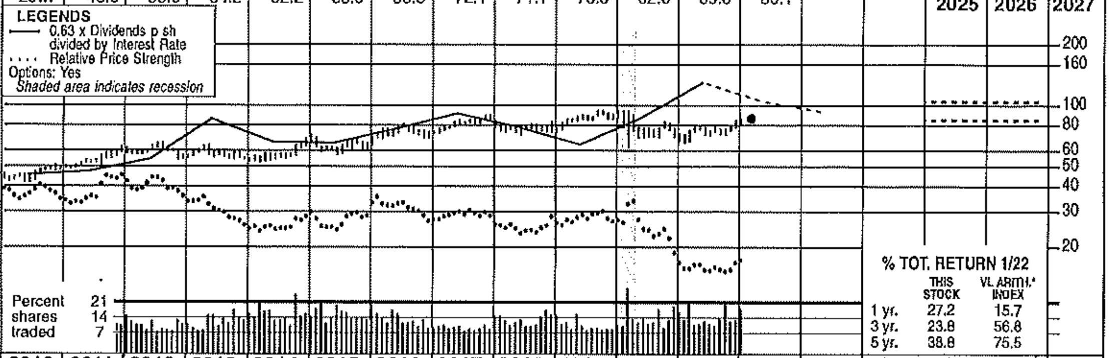
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+20%)	9%
Low	85	(Nil)	4%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	403	471	446
to Sell	425	348	338
Hld's(000)	208737	216551	219342

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	62.7	66.0	64.0	68.9	72.3	81.9	89.7	84.9	95.0	95.1	85.6	86.6	
Low:	48.6	53.6	54.2	52.2	56.9	63.5	72.1	71.1	73.3	62.0	65.6	80.1	



% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.2	15.7
3 yr.	23.8	56.8
5 yr.	38.8	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
47.14	48.23	49.62	46.36	45.69	44.17	41.62	42.27	44.11	42.85	39.59	38.82	38.44	37.80	35.78	*38.15*	*38.90*	*39.60*	Revenues per sh	*43.00*
5.28	5.77	5.99	5.86	6.24	6.61	7.15	7.45	7.30	7.93	7.89	8.41	8.92	9.10	9.48	*10.05*	*10.40*	*10.70*	"Cash Flow" per sh	*12.25*
2.95	3.48	3.36	3.14	3.47	3.57	3.86	3.93	3.62	4.05	3.94	4.10	4.55	4.08	3.94	*4.45*	*4.50*	*4.65*	Earnings per sh A	*5.25*
2.30	2.32	2.34	2.36	2.38	2.40	2.42	2.46	2.52	2.60	2.68	2.76	2.86	2.96	3.06	3.10	*3.16*	*3.24*	Div'd Decl'd per sh B ■	*3.50*
7.17	7.09	8.50	7.80	6.96	6.72	7.06	8.67	8.26	10.42	12.07	11.11	10.90	10.48	11.42	*11.60*	*11.70*	*12.05*	Cap'l Spending per sh	*12.25*
31.09	32.58	35.43	36.46	37.93	39.05	40.53	41.81	42.94	44.55	46.88	49.74	52.11	54.18	55.06	*56.55*	*58.20*	*59.85*	Book Value per sh C	*65.25*
257.46	272.02	273.72	281.12	291.62	292.89	292.87	292.87	292.88	293.00	305.00	310.00	320.96	332.63	342.30	*354.00*	*360.00*	*366.00*	Common Shs Outst'g D	*372.00*
15.5	13.8	12.3	12.5	13.3	15.1	15.4	14.7	15.9	15.6	18.8	19.8	17.1	21.1	20.1	*16.9*	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.84	.73	.74	.83	.85	.95	.98	.83	.84	.79	.99	1.00	.92	1.12	1.03	*.90*	*Value Line*		Relative P/E Ratio	*1.00*
5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	4.1%	4.3%	4.4%	4.1%	3.6%	3.4%	3.7%	3.4%	3.9%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*
						12188	12381	12919	12554	12075	12033	12337	12574	12246	*13500*	*14000*	*14500*	Revenues ($mill)	*16000*
						1141.0	1157.0	1066.0	1193.0	1189.0	1266.0	1424.0	1343.0	1324.0	*1550*	*1620*	*1700*	Net Profit ($mill)	*1960*
						34.5%	31.8%	34.0%	33.6%	35.3%	36.6%	20.1%	17.1%	12.0%	*16.0%*	*16.0%*	*16.0%*	Income Tax Rate	*16.0%*
						.5%	.5%	.3%	.7%	1.3%	1.5%	1.5%	2.0%	2.3%	*2.0%*	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
						45.9%	46.1%	48.0%	47.9%	50.8%	48.9%	51.1%	50.7%	52.0%	*53.0%*	*52.0%*	*51.5%*	Long-Term Debt Ratio	*51.0%*
						54.1%	53.9%	52.0%	52.1%	49.2%	51.1%	48.9%	49.3%	48.0%	*47.0%*	*48.0%*	*48.5%*	Common Equity Ratio	*49.0%*
						21933	22735	24207	25058	29033	30149	34221	36549	39229	*42575*	*43475*	*45075*	Total Capital ($mill)	*49700*
						26939	28436	29827	32209	35216	37600	41749	43889	46555	*48650*	*50725*	*52925*	Net Plant ($mill)	*58900*
						6.5%	6.4%	5.6%	6.0%	5.3%	5.4%	5.3%	4.9%	4.5%	*5.0%*	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
						9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	8.5%	7.5%	7.0%	*7.5%*	*7.5%*	*8.0%*	Return on Shr. Equity	*8.0%*
						9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	8.5%	7.5%	7.0%	*7.5%*	*7.5%*	*8.0%*	Return on Com Equity E	*8.0%*
						3.6%	3.6%	2.6%	3.5%	3.0%	3.0%	3.5%	2.3%	1.9%	*2.5%*	*2.5%*	*2.5%*	Retained to Com Eq	*2.5%*
						62%	62%	69%	61%	64%	63%	59%	69%	74%	*68%*	*68%*	*67%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 9/30/21
Total Debt $23316 mill. **Due in 5 Yrs** $5069 mill.
LT Debt $21841 mill. **LT Interest** $867 mill.
(LT interest earned: 3.3x)

Leases, Uncapitalized Annual rentals $79 mill.

Pension Assets-12/20 $17022 mill.
Oblig $18965 mill.

Pfd Stock None

Common Stock 353,748,736 shs.
as of 10/31/21
MARKET CAP: $31 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2018	2019	2020
% Change Retail Sales (KWH)	+2.8	-2.9	-6.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	14156	13835	13170
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	306	267	257

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	-2.5%	-3.0%	*2.0%*
"Cash Flow"	4.5%	4.0%	*4.0%*
Earnings	2.5%	1.5%	*3.5%*
Dividends	2.5%	3.0%	*2.5%*
Book Value	4.0%	4.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3514	2744	3365	2951	12574
2020	3234	2719	3333	2960	12246
2021	3677	2971	3613	*3239*	*13500*
2022	*3800*	*3100*	*3750*	*3350*	*14000*
2023	*3950*	*3200*	*3900*	*3450*	*14500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.31	.46	1.42	.88	4.08
2020	1.12	.57	1.47	.78	3.94
2021	1.58	.56	1.52	*.79*	*4.45*
2022	*1.45*	*.60*	*1.60*	*.85*	*4.50*
2023	*1.50*	*.60*	*1.65*	*.90*	*4.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.715	.715	.715	.715	2.86
2019	.74	.74	.74	.74	2.96
2020	.765	.765	.765	.765	3.06
2021	.775	.775	.775	.775	3.10
2022	.79				

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R), which operates in New York and New Jersey. Has 3.7 mill. electric, 1.2 mill. gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Entered into midstream gas joint venture 6/16; sold it 7/21. Purchases most of its power. Fuel costs: 18% of revenues. '20 reported deprec. rates: 3.2%-3.5%. Has 14,100 employees. Chairman, President & CEO: Timothy Cawley. Inc.: NY. Address: 4 Irving Place, New York, NY 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

Consolidated Edison's largest utility subsidiary has filed a rate case. Consolidated Edison Company of New York requested electric and gas rate increases totaling $1.2 billion and $500 million, respectively, for 2023, 2024, and 2025. Assuming that the utility gets reasonable rate treatment, this will help boost the company's earning power in 2023.

We estimate that share earnings will advance just slightly in 2022. The comparison will likely be difficult. In the first nine months of 2021, accounting income associated with renewable-energy investments and mark-to-market accounting items boosted share profits by $0.28. In addition, average shares outstanding will be higher due to the effects of equity issuances in 2021 and those expected in 2022. Still, ConEd will benefit from the third phase of a three-year rate plan at CECONY. Electric and gas rate hikes of $326 million and $167 million, respectively, took effect at the start of the year. ConEd's smaller utility subsidiaries should obtain some rate relief, too.

Orange and Rockland reached a settlement of its rate case, and another application is pending. The agreement, if approved by the New York State Public Service Commission, will raise electric rates $4.9 million in 2022, $16.2 million in 2023, and $23.1 million in 2024. Gas tariffs will be hiked $0.7 million in 2022, $7.4 million in 2023, and $9.9 million in 2024. The allowed return on equity will be 9.2% and the common-equity ratio 48%. Separately, Rockland Electric is seeking a $19.5 million electric increase in New Jersey, based on a 10% ROE and a 48.8% common-equity ratio. New tariffs are expected to take effect this month.

The board of directors raised the dividend in the first quarter. The increase was $0.06 a share (1.9%) annually. This was greater than the hike in 2021, but still below the norm for the electric utility industry. ConEd's goal is a payout ratio of 60%-70% of the company's definition of adjusted earnings.

The dividend yield of this top-quality stock is slightly above the utility average. Total return potential is negative for the next 18 months and unspectacular for the 3- to 5-year period, however.

Paul E. Debbas, CFA *February 11, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '13, (32¢); '14, 9¢; '16, 15¢; '17, 84¢; '18, (13¢); '20, (66¢); '21, (43¢); gain on disc. operations: '08, $1.01. '19 EPS don't sum due to rounding. Next earnings report due mid-Feb.
(B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '20: $24.50/sh.
(D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '20: 8.8%; O&R in '19: 9.0%; earned on avg. com. eq., '20: 7.1%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	100

DOMINION ENERGY NYSE-D

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
80.66	20.2	(Trailing: 25.4 Median: 22.0)	1.14	3.3%	VALUE LINE

TIMELINESS 4 Lowered 2/5/21
SAFETY 2 Raised 9/11/98
TECHNICAL 4 Raised 1/28/22
BETA .85 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	53.6	55.6	68.0	80.9	79.9	79.0	85.3	81.7	83.9	90.9	81.1	81.1
Low:	42.1	48.9	51.9	63.1	64.5	66.3	70.9	61.5	67.4	57.8	67.9	76.8

18-Month Target Price Range

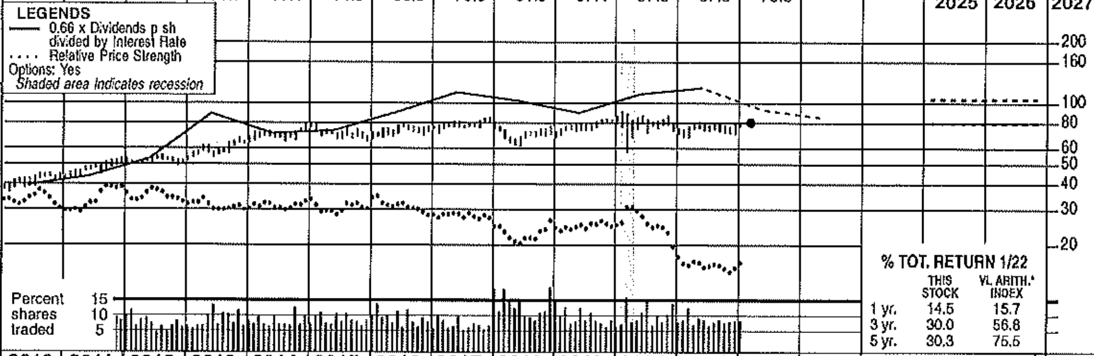
Low-High	Midpoint (% to Mid)
$70-$100	$85 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+30%)	*10%*
Low	80	(Nil)	*4%*

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	626	634	613
to Sell	731	635	616
Hld's(000)	533190	536264	546775



% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.5	15.7
3 yr.	30.0	56.8
5 yr.	30.3	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
23.61	27.17	27.93	25.24	26.17	25.24	22.73	22.56	21.25	19.59	18.70	19.53	19.63	19.78	17.58	*17.30*	*17.15*	*17.45*	Revenues per sh	*18.25*
4.91	5.08	5.07	4.82	5.11	5.04	5.24	5.47	5.71	5.98	6.33	6.90	6.48	5.73	5.48	*6.55*	*7.60*	*8.05*	"Cash Flow" per sh	*9.25*
2.40	2.13	3.04	2.64	2.89	2.76	2.75	3.09	3.05	3.20	3.44	3.53	3.25	2.19	1.82	*3.10*	*4.10*	*4.35*	Earnings per sh A	*5.25*
1.38	1.46	1.58	1.75	1.83	1.97	2.11	2.25	2.40	2.59	2.80	3.04	3.34	3.67	3.45	2.52	*2.67*	*2.83*	Div'd Decl'd per sh B ■	*3.40*
5.81	6.89	6.09	6.40	5.89	6.41	7.20	7.06	9.13	9.35	9.69	8.54	6.25	5.94	7.47	*8.50*	*8.75*	*10.10*	Cap'l Spending per sh	*12.00*
18.50	16.31	17.28	18.66	20.66	20.09	18.34	20.02	19.74	21.24	23.26	26.59	29.53	35.33	29.44	*30.40*	*33.30*	*35.15*	Book Value per sh C	*41.50*
698.00	576.80	583.20	599.40	580.80	569.70	576.10	581.50	585.30	596.30	627.80	644.60	680.90	838.00	806.00	*810.00*	*835.00*	*842.00*	Common Shs Outst'g D	*870.00*
16.0	20.6	13.8	12.7	14.3	17.3	18.9	19.2	23.0	22.1	21.3	22.2	21.8	35.2	NMF	*24.3*	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
.86	1.09	.83	.85	.91	1.09	1.20	1.08	1.21	1.11	1.12	1.12	1.18	1.88	NMF	*1.30*			Relative P/E Ratio	*.95*
3.6%	3.3%	3.8%	5.2%	4.4%	4.1%	4.1%	3.8%	3.4%	3.7%	3.8%	3.9%	4.7%	4.8%	4.3%	3.3%			Avg Ann'l Div'd Yield	*3.7%*
						13093	13120	12436	11683	11737	12586	13366	16572	14172	*14000*	*14300*	*14700*	Revenues ($mill)	*15900*
						1594.0	1806.0	1793.0	1899.0	2123.0	2244.0	2130.0	1838.0	1648.0	*2595*	*3485*	*3745*	Net Profit ($mill)	*4560*
						36.2%	33.0%	28.1%	32.0%	22.8%	27.2%	17.7%	21.8%	5.9%	*10.0%*	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
						5.7%	3.7%	4.5%	5.3%	7.5%	10.5%	6.3%	4.8%	6.3%	*4.0%*	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
						60.9%	61.9%	65.4%	65.1%	67.4%	64.4%	60.8%	51.4%	56.5%	*57.0%*	*56.0%*	*57.0%*	Long-Term Debt Ratio	*57.0%*
						38.2%	37.3%	34.6%	34.9%	32.6%	35.6%	39.2%	45.0%	39.5%	*38.0%*	*41.0%*	*40.5%*	Common Equity Ratio	*41.0%*
						27676	31229	33360	36280	44836	48090	51251	65818	60074	*65000*	*67625*	*72825*	Total Capital ($mill)	*88500*
						30773	32628	36270	41554	49964	53758	54560	69082	57848	*61950*	*66275*	*71650*	Net Plant ($mill)	*92500*
						7.5%	7.3%	6.6%	6.5%	6.0%	5.9%	5.5%	4.0%	3.9%	*5.0%*	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
						14.7%	15.2%	15.5%	15.0%	14.5%	13.1%	10.6%	5.7%	6.3%	*9.0%*	*11.5%*	*11.5%*	Return on Shr. Equity	*12.0%*
						14.9%	15.4%	15.4%	15.0%	14.5%	13.1%	10.6%	6.2%	6.7%	*10.0%*	*12.0%*	*12.5%*	Return on Com Equity E	*12.5%*
						3.5%	4.2%	3.3%	2.9%	2.7%	1.8%	NMF	NMF	NMF	*2.0%*	*4.5%*	*4.5%*	Retained to Com Eq	*4.0%*
						77%	73%	79%	81%	81%	86%	103%	NMF	NMF	*84%*	*66%*	*66%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 9/30/21
Total Debt $41505 mill. **Due In 5 Yrs** $13667 mill.
LT Debt $34775 mill. **LT Interest** $1337 mill.
(LT interest earned: 2.0x)
Leases, Uncapitalized Annual rentals $64 mill.

Pension Assets-12/20 $10979 mill.
Oblig $11363 mill
Pfd Stock $2387 mill. **Pfd Divd** $65 mill.
2 mill. shs. 1.75%, cum., convert. In 2022. 800,000 shs. 4.65%, cum., redeemable not before 12/15/24.
Common Stock 809,908,408 shs.
as of 10/29/21
MARKET CAP: $65 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2018	2019	2020
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	219	166	128

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	-3.5%	-2.0%	*-.5%*
"Cash Flow"	1.5%	.5%	*6.5%*
Earnings	-1.5%	-5.0%	*11.5%*
Dividends	7.5%	7.5%	*-.5%*
Book Value	5.0%	9.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3858	3970	4269	4475	16572
2020	3938	3106	3607	3521	14172
2021	3870	3038	3178	*3916*	*14000*
2022	*4000*	*3100*	*3200*	*4000*	*14300*
2023	*4100*	*3200*	*3300*	*4100*	*14700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	d.37	.13	1.23	1.22	2.19
2020	d.57	.90	.42	.98	1.82
2021	1.19	.30	.71	*.90*	*3.10*
2022	*1.15*	*.85*	*1.10*	*1.00*	*4.10*
2023	*1.25*	*.90*	*1.15*	*1.05*	*4.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.835	.835	.835	.835	3.34
2019	.9175	.9175	.9175	.9175	3.67
2020	.94	.94	.94	.63	3.45
2021	.63	.63	.63	.63	2.52
2022	.6675				

BUSINESS: Dominion Energy, Inc. (formerly Dominion Resources) is a holding company for Virginia Power, North Carolina Power, & South Carolina E&G, which serve 3.5 mill. customers in VA, SC, & NC. Serves 3.4 mill. gas customers in OH, WV, UT, SC, & NC. Other ops. incl. independent power production. Acq'd Questar 9/16; SCANA 1/19. Elec. rev. breakdown: residential, 50%; commercial, 32%; industrial, 8%; other, 10%. Generating sources: gas, 48%; nuclear, 32%; coal, 9%; other, 4%; purchased, 7%. Fuel costs: 22% of revs. '20 reported deprec. rates: 1.6%-5.1%. Has 19,100 employees. Chairman, President & CEO: Robert M. Blue. Inc.: VA. Address: 120 Tredegar St., P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Internet: www.dominionenergy.com.

Dominion Energy completed the sale of midstream natural gas assets at the end of 2021. The transaction was valued at $1.975 billion, including the assumption of $430 million of debt. Any gain or loss recorded on the sale will be excluded from our earnings presentation as discontinued operations. The sale proceeds will be used mostly for debt retirement. Following the divestiture of most of Dominion Energy's midstream gas assets, the company is largely a regulated electric and gas utility.

We think earnings will improve solidly in 2022, followed by further growth in 2023. The comparison is easy this year because in 2021 the company incurred some charges related to Virginia Power's rate review, which are *included* in our earnings presentation. A full year's effect of an electric rate hike in South Carolina and a gas tariff increase in North Carolina will help this year's results. Also, much of the company's capital spending is recoverable through riders (surcharges) on customers' bills, instead of having to wait for recovery via a general rate case. Finally, the utilities in Virginia and South Carolina are seeing respectable kilowatt-hour sales growth. Management planned to disclose plans and guidance for 2022 upon releasing fourth-quarter results shortly after this report went to press.

The Virginia commission approved a program for the installation of advanced electric meters. This is part of a $776 million grid transformation plan. The utility will be able to recover this investment in a future rate proceeding.

Virginia Power expects orders from the state commission regarding renewable energy this year. The utility is proposing the addition of 1,000 megawatts of solar capacity and battery storage and over 2,600 mw of offshore wind.

The board of directors raised the dividend in the first quarter. The increase was $0.15 a share (6.0%) annually. We think Dominion Energy will maintain a similar growth rate of the disbursement through mid-decade. The company's long-term target for the payout ratio is 65%.

The untimely stock's dividend yield is about average for a utility. Total return prospects don't stand out for the 18-month span or the 3- to 5-year period.

Paul E. Debbas, CFA *February 11, 2022*

(A) Dil. egs. Excl. nonrec. gains (losses): '08, 12¢; '09, (47¢); '10, $2.18; '11, (7¢); '12, ($1.70); '14, (76¢); '17, $1.19; '18, 43¢; '19, (58¢); gain (losses) from disc. ops.: '10, (26¢); '12, (4¢); '13, (16¢); '20, ($2.39); '21, 15¢. '20 EPS don't add due to chg. in shs. Next egs. due early May. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. Intang. In '20: $21.44/sh. (D) In mill. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in VA in '22: 9.35%; in SC in '21: 9.5%; earned on avg. com. eq., '20: 5.9%. Regul. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	55

Docket No: UE 399

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Muldoon/15

DTE ENERGY CO. NYSE-DTE

RECENT PRICE 121.59 | P/E RATIO 19.6 (Trailing: 29.7 Median: 18.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS — Suspended 6/11/21
SAFETY 2 Raised 12/21/12
TECHNICAL — Suspended 6/11/21
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$99-$152	$126 (5%)

2025-27 PROJECTIONS

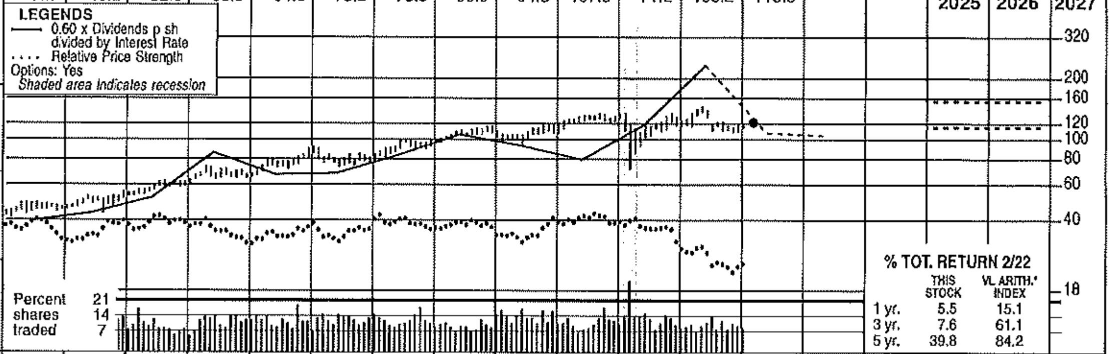
	Price	Gain	Ann'l Total Return
High	155	(+25%)	9%
Low	115	(-5%)	2%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	317	305	307
to Sell	279	270	272
Hld's(000)	141476	141144	140364

High:	55.3	62.6	73.3	90.8	92.3	100.4	116.7	121.0	134.4	135.7	145.4	122.2
Low:	43.2	52.5	60.3	64.8	73.2	78.0	96.6	94.3	107.3	71.2	108.2	113.8

LEGENDS
—— 0.60 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.5	15.1
3 yr.	7.6	61.1
5 yr.	39.8	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
50.93	54.28	57.23	48.45	50.51	52.57	51.01	54.56	69.50	57.60	59.24	70.28	78.12	65.91	62.84	77.23	70.25	72.75	Revenues per sh	80.50
8.19	8.48	8.26	9.38	9.78	9.57	9.77	10.13	11.85	9.44	10.60	11.77	12.58	12.97	14.70	11.94	13.45	14.50	"Cash Flow" per sh	17.00
2.45	2.66	2.73	3.24	3.74	3.67	3.88	3.76	5.10	4.44	4.83	5.73	6.17	6.31	7.08	4.10	5.90	6.30	Earnings per sh A	7.50
2.08	2.12	2.12	2.12	2.18	2.32	2.42	2.59	2.69	2.84	3.06	3.36	3.59	3.85	4.12	3.88	3.60	3.84	Div'd Decl'd per sh B ■	4.65
7.92	7.96	8.42	6.26	6.49	8.77	10.56	10.59	11.58	11.26	11.40	12.54	14.91	15.59	19.91	19.47	18.05	17.05	Cap'l Spending per sh	18.50
33.02	35.86	36.77	37.96	39.67	41.41	42.78	44.73	47.05	48.88	50.22	53.03	56.27	60.73	64.12	44.93	50.95	53.55	Book Value per sh C	61.75
177.14	163.23	163.02	165.40	169.43	169.25	172.35	177.09	176.99	179.47	179.43	179.39	181.93	192.21	193.77	193.75	205.00	205.50	Common Shs Outst'g D	206.00
17.4	18.3	14.8	10.4	12.3	13.5	14.9	17.9	14.9	18.1	19.0	18.6	17.4	19.9	16.3	30.0	Bold figures are		Avg Ann'l P/E Ratio	17.5
.94	.97	.89	.69	.78	.85	.95	1.01	.78	.91	1.00	.94	.94	1.06	.84	1.60	Value Line		Relative P/E Ratio	.95
4.9%	4.4%	5.2%	6.3%	4.8%	4.7%	4.2%	3.8%	3.5%	3.5%	3.3%	3.2%	3.3%	3.1%	3.6%	3.2%	estimates		Avg Ann'l Div'd Yield	3.5%
						8791.0	9661.0	12301	10337	10630	12607	14212	12669	12177	14964	14400	14950	Revenues ($mill)	16600
						666.0	661.0	905.0	796.0	868.0	1029.0	1120.0	1169.0	1368.0	796.0	1155	1290	Net Profit ($mill)	1530
						29.8%	27.5%	28.5%	25.6%	24.5%	21.8%	8.1%	11.5%	10.9%	10.9%	15.0%	15.0%	Income Tax Rate	15.0%
						3.0%	3.5%	4.1%	4.3%	3.6%	3.5%	3.8%	3.3%	3.4%	4.9%	4.0%	3.0%	AFUDC % to Net Profit	3.0%
						48.8%	47.7%	50.0%	50.2%	55.6%	56.2%	54.2%	57.7%	60.5%	62.5%	63.0%	61.5%	Long-Term Debt Ratio	60.5%
						51.2%	52.3%	50.0%	49.8%	44.4%	43.8%	45.8%	42.3%	39.5%	37.5%	37.0%	38.5%	Common Equity Ratio	39.5%
						14387	15135	16670	17607	20280	21697	22371	27607	31426	23236	28200	28425	Total Capital ($mill)	32400
						14684	15800	16820	18034	19730	20721	21650	25317	27969	26944	29050	30850	Net Plant ($mill)	36300
						6.1%	5.7%	6.6%	5.7%	5.3%	5.9%	6.1%	5.3%	5.4%	4.7%	5.0%	5.5%	Return on Total Cap'l	5.5%
						9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	11.0%	9.1%	11.0%	11.5%	Return on Shr. Equity	12.0%
						9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	11.0%	9.1%	11.0%	11.5%	Return on Com Equity E	12.0%
						3.5%	2.7%	5.2%	3.4%	3.7%	4.6%	4.9%	4.1%	4.9%	.1%	4.0%	4.5%	Retained to Com Eq	4.5%
						61%	67%	52%	63%	61%	58%	55%	59%	56%	99%	62%	61%	All Div'ds to Net Prof	63%

CAPITAL STRUCTURE as of 12/31/21
Total Debt $18163 mill. **Due in 5 Yrs** $6995 mill.
LT Debt $14531 mill. **LT Interest** $558 mill.
Incl. $19 mill. finance leases.
(LT interest earned: 2.1x)

Leases, Uncapitalized Annual rentals $16 mill.

Pension Assets-12/21 $5507 mill. Oblig $5857 mill.

Pfd Stock None

Common Stock 193,745,891 shs. as of 1/31/22

MARKET CAP: $24 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.9	-3.4	+2.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	260	268	233

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	3.0%	2.0%	2.5%
"Cash Flow"	3.5%	4.5%	4.5%
Earnings	5.0%	4.0%	4.5%
Dividends	6.0%	6.5%	3.0%
Book Value	3.5%	3.0%	1.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3514	2888	3119	3148	12669
2020	3022	2583	3284	3288	12177
2021	3581	3021	3715	4647	14964
2022	3700	3100	3800	3800	14400
2023	3850	3200	3950	3950	14950

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2.19	.99	1.73	1.40	6.31
2020	1.76	1.44	2.46	1.42	7.08
2021	1.65	.60	.30	1.55	4.10
2022	1.75	1.20	1.70	1.25	5.90
2023	1.85	1.30	1.80	1.35	6.30

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.8825	.8825	.8825	.8825	3.53
2019	.945	.945	.945	.945	3.78
2020	1.0125	1.0125	1.0125	1.0125	4.05
2021	.9225	.9225	.9225	.825	3.59
2022	.885				

BUSINESS: DTE Energy Company is a holding company for DTE Electric (formerly Detroit Edison), which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and DTE Gas (formerly Michigan Consolidated Gas). Customers: 2.2 mill. electric, 1.3 mill. gas. Has various nonutility operations. Electric revenue breakdown: residential, 50%; commercial, 33%; industrial, 11%; other, 6%. Generating sources: coal, 67%; nuclear, 17%; gas, 1%; purchased, 15%. Fuel costs: 62% of revenues. '21 reported deprec. rates: 4.2% electric, 2.9% gas. Has 10,600 employees. Chairman: Gerard M. Anderson. President & CEO: Jerry Norcia. Inc.: MI. Address: One Energy Plaza, Detroit, MI 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's earnings will probably return to a more-typical level in 2022. Last year was one of transition for the company. DTE Energy spun off its midstream natural gas subsidiary into a new company, DT Midstream (NYSE: DTM), which was reported as a discontinued operation. Also, September-quarter earnings were depressed due to a $384 million pretax charge for the early extinguishment of debt. Our 2022 share-earnings estimate is at the midpoint of management's targeted range of $5.80-$6.00. Although DTE Energy is paying a lesser dividend than before the corporate separation, shareholders are receiving more dividend income when the payout from DT Midstream is combined with that of DTE Energy. The Timeliness rank of DTE Energy stock is suspended due to the spinoff of DT Midstream.

DTE Gas received a rate order. Tariffs were raised by $84 million at the start of 2022. The allowed return on equity was unchanged at 9.9% and the common-equity ratio was set at 51%.

DTE Electric filed a rate case. The utility requested an increase of $388 million, based on a 10.25% ROE and a 50% common-equity ratio. An order is expected in November. Assuming reasonable regulatory treatment, this will have just a modest effect on results in 2022, but will help lift profits next year. We estimate an increase of 7%, which is within DTE Energy's yearly target of 5%-7%.

The company does not plan to issue much common equity in the next few years. The increase in shares outstanding this year will come from the conversion of convertible securities in November. DTE Energy expects to add little or no equity in 2023 and 2024.

DTE Energy's energy-trading business is profitable, but hard to predict. Mark-to-market accounting items can cause swings in year-to-year earnings comparisons. We *include* these in our earnings presentation because this is an ongoing part of the company's reported results.

DTE Energy stock has a dividend yield that is below the mean for utilities. The equity does not stand out for the 18-month span or the 3- to 5-year period. The recent quotation is within our 2025-2027 Target Price Range.

Paul E. Debbas, CFA *March 11, 2022*

(A) Diluted EPS. Excl. nonrec. gains (loss): '07, $1.96; '08, 50¢; '11, 51¢; '15, (39¢); '17, 59¢; gains (losses) on disc. ops.: '06, (2¢); '07, $1.20; '08, 13¢; '12, (33¢); '21, 57¢. Next earnings report due late Apr. (B) Div'ds paid mid-Jan., Apr., July & Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $29.17/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '20: 9.9% elec.; in '22: 9.9% gas; earned on avg. com. eq., '21: 7.6%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	60
Earnings Predictability	80

DUKE ENERGY NYSE-DUK

RECENT PRICE 105.06 | P/E RATIO 19.6 (Trailing: 27.1 Median: 18.0) | RELATIVE P/E RATIO 1.11 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Raised 12/24/21
SAFETY 2 New 6/1/07
TECHNICAL 3 Raised 1/14/22
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$82-$116	$99 (-5%)

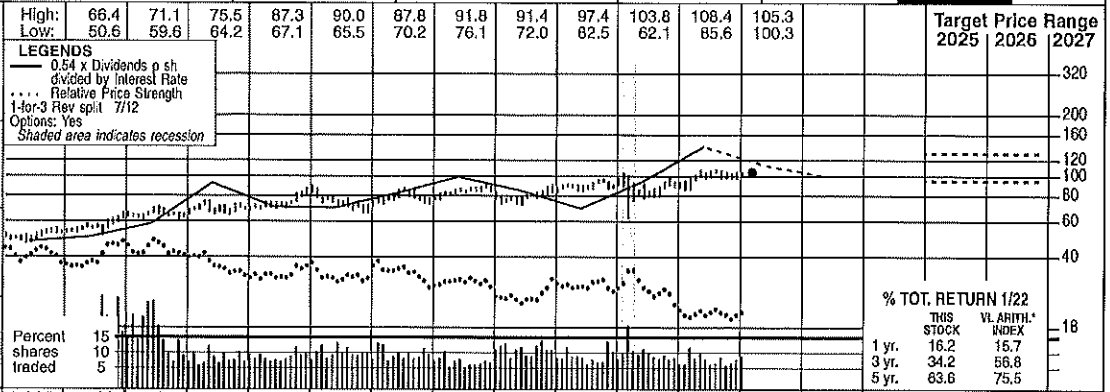
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+25%)	9%
Low	95	(-10%)	2%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	796	823	803
to Sell	681	623	615
Hld's(000)	483371	483062	481215

High:	66.4	71.1	75.5	87.3	90.0	87.8	91.8	91.4	97.4	103.8	108.4	105.3
Low:	50.6	59.6	64.2	67.1	65.5	70.2	76.1	72.0	82.5	62.1	85.6	100.3


LEGENDS
— 0.54 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
1-for-3 Rev split 7/12
Options: Yes
Shaded area indicates recession

% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.2	15.7
3 yr.	34.2	56.8
5 yr.	83.6	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	33.73	34.21	31.04	32.40	33.30	34.30	Revenues per sh	37.50
7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	10.49	12.13	10.89	12.40	13.30	14.00	"Cash Flow" per sh	16.50
2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.13	5.07	3.92	4.95	5.45	5.80	Earnings per sh A	7.00
--	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	3.64	3.75	3.82	3.90	3.98	4.06	Div'd Decl'd per sh B ■	4.35
8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	12.91	15.17	12.88	13.60	16.60	15.70	Cap'l Spending per sh	15.50
62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	60.27	61.20	59.82	60.90	62.40	64.15	Book Value per sh C	71.00
418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	727.00	733.00	769.00	770.00	770.00	770.00	Common Shs Outst'g D	770.00
--	16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	19.4	17.7	22.4	20.1	Bold figures are		Avg Ann'l P/E Ratio	16.0
--	.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	1.05	.94	1.15	1.05	Value Line		Relative P/E Ratio	.90
--	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	4.5%	4.2%	4.4%	3.9%	estimates		Avg Ann'l Div'd Yield	3.9%
						19624	24598	23925	23459	22743	23565	24521	25079	23868	24950	25650	26400	Revenues ($mill)	28850
						2136.0	2813.0	2934.0	2854.0	2560.0	2963.0	2928.0	3755.0	2996.0	3910	4320	4565	Net Profit ($mill)	5415
						30.2%	32.6%	30.6%	32.2%	31.0%	30.4%	14.2%	12.7%	4.9%	7.5%	7.0%	7.0%	Income Tax Rate	7.0%
						22.3%	8.8%	7.2%	9.2%	11.7%	12.3%	13.0%	7.9%	8.9%	8.0%	7.0%	7.0%	AFUDC % to Net Profit	6.0%
						47.0%	48.0%	47.7%	48.6%	52.6%	54.0%	53.8%	54.0%	53.7%	54.5%	54.5%	55.0%	Long-Term Debt Ratio	55.0%
						52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	44.4%	44.0%	43.5%	43.5%	Common Equity Ratio	43.5%
						77307	79482	78088	77222	86609	90774	94940	101807	103589	106950	110075	113525	Total Capital ($mill)	125600
						68558	69490	70046	75709	82520	86391	91694	102127	106782	111500	118275	124025	Net Plant ($mill)	138800
						3.6%	4.6%	4.8%	4.8%	4.0%	4.3%	4.2%	4.8%	3.9%	4.5%	5.0%	5.0%	Return on Total Cap'l	5.5%
						5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	8.0%	6.2%	8.0%	8.5%	9.0%	Return on Shr. Equity	9.5%
						5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	8.3%	6.3%	8.0%	9.0%	9.0%	Return on Com Equity E	9.5%
						.9%	1.5%	1.7%	1.5%	.6%	1.2%	1.0%	2.4%	.4%	1.5%	2.5%	2.5%	Retained to Com Eq	3.5%
						82%	78%	76%	79%	91%	83%	84%	71%	94%	79%	73%	71%	All Div'ds to Net Prof	64%

CAPITAL STRUCTURE as of 9/30/21
Total Debt $64900 mill. **Due in 5 Yrs** $19594 mill.
LT Debt $57929 mill. **LT Interest** $2211 mill.
Incl. $845 mill. finance leases.
(LT interest earned: 2.1x)
Leases, Uncapitalized Annual rentals $229 mill.
Pension Assets-12/20 $9337 mill.
Oblig $8634 mill.
Pfd Stock $1962 mill. **Pfd Div'd** $107 mill.
40 mill. shs. 5.75%, cum., $25 liq. value, redeemable at $25.50 prior to 6/15/24; 1 mill. shs. 4.875%, cum., $1000 liq. value.
Common Stock 769,343,372 shs. **as of** 10/31/21
MARKET CAP: $81 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2018	2019	2020
% Change Retail Sales (KWH)	+3.9	-.9	-2.3
Avg. Indust. Use (MWH)	2953	2934	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+1.4	+1.5	NA
Fixed Charge Cov. (%)	218	233	183

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	.5%	-1.0%	2.0%
"Cash Flow"	3.5%	4.5%	5.5%
Earnings	2.5%	1.5%	7.0%
Dividends	3.0%	3.5%	2.0%
Book Value	2.0%	1.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	6163	5873	6940	6103	25079
2020	5949	5421	6721	5777	23868
2021	6150	5758	6951	6091	24950
2022	6350	5900	7150	6250	25650
2023	6550	6050	7130	6450	26400

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.24	1.12	1.82	.89	5.07
2020	1.24	1.08	1.74	d.13	3.92
2021	1.25	.96	1.79	.95	4.95
2022	1.35	1.15	1.90	1.05	5.45
2023	1.45	1.25	2.00	1.10	5.80

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.89	.89	.9275	.9275	3.64
2019	.9275	.9275	.945	.945	3.75
2020	.945	.945	.965	.965	3.82
2021	.965	.965	.985	.985	3.90
2022	.985				

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, & KY, and 1.6 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 45%; commercial, 28%; industrial, 13%; other, 14%. Generating sources: gas, 31%; nuclear, 30%; coal, 18%; other, 2%; purchased, 19%. Fuel costs: 27% of revs. '20 reported deprec. rate: 3.0%. Has 27,500 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

Duke Energy's earnings will likely advance significantly in 2022. The comparison shouldn't be difficult, especially in the June quarter, when the company took an $0.18-a-share charge for a workforce realignment in 2021. Duke will benefit from increased rates. A $67 million hike took effect in Florida at the start of 2022. Piedmont Natural Gas received a $67 million increase on November 1st. Duke received a small gas hike in Kentucky at the start of 2022. The company should get a partial year of rate relief in Ohio (see below). Duke also obtains revenues every year from riders (surcharges) on customers' bills. Finally, the utility is benefiting from healthy growth in volume (especially from the industrial sector) and customers. Management put forth its expectations for the current year shortly before this report went to press.

An electric rate case is pending in Ohio. Duke is seeking an increase of $55 million (3.3%), based on a 10.3% return on equity. An order is expected this summer.

We look for another year of solid profit growth in 2023. Duke will get the next phase of multiyear rate relief ($49 million) in Florida at the start of the year. The company will benefit from a full year of rate relief in Ohio. We estimate a bottom-line increase of 6%, within management's annual target of 5%-7%.

Duke is awaiting regulatory outcomes in North Carolina. This involves performance-based ratemaking and securitization for coal-fired assets that will be retired early. Developments from the state commission should come forth as the year progresses.

Duke entered into a cooperation agreement with Elliott Investment Management. This involves the addition of two board members and a standstill agreement through November 13, 2022 (the one-year anniversary of the cooperation agreement). Elliott had been critical of Duke's management. There is some speculative interest for stockholders once the cooperation agreement expires.

The untimely stock has a dividend yield that is a bit above the utility mean. But, dividend growth potential is low, and the stock lacks appeal for the next 18 months and the 2025-2027 period.

Paul E. Debbas, CFA *February 11, 2022*

(A) Dil. EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; '17, 15¢; '18, 41¢; '20, $2.21; losses on disc. ops.: '14, 80¢; '16, 60¢. '20 EPS don't sum due to rounding. Next egs. due early May. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '20: $41.25/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '21 in NC: 9.6%; in '19 in SC: 9.5%; in '20 in FL: 9.5%-11.5%; in '20 in IN: 9.7%; earn. on avg. com. eq., '20: 9.9%. Reg. Clim.: NC, SC Avg.; OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	85

EDISON INTERNAT'L NYSE-EIX

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
70.80	15.6	(Trailing: NMF / Median: 17.0)	0.88	4.1%	VALUE LINE

TIMELINESS	3	Raised 9/17/21
SAFETY	3	Lowered 11/23/18
TECHNICAL	3	Lowered 3/18/22

BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$54-$84	$69 (-5%)

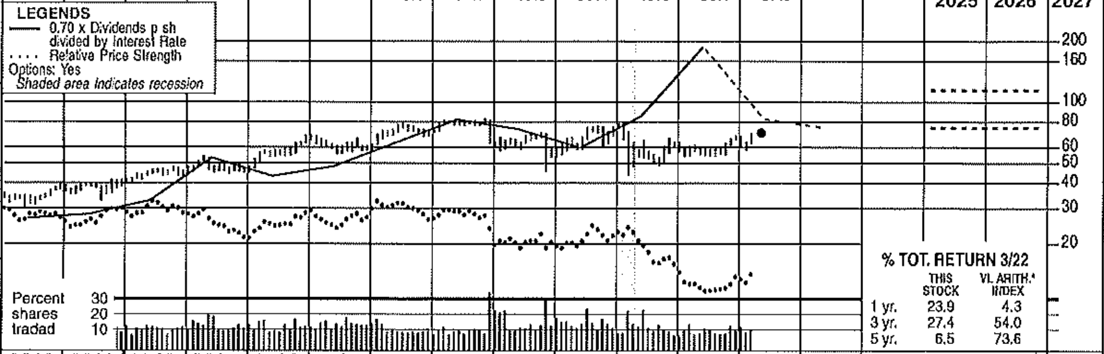
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+60%)	16%
Low	75	(+5%)	6%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	320	298	356
to Sell	249	263	252
Hld's(000)	330984	332161	335565

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	41.6	48.0	54.2	68.7	69.6	78.7	83.4	71.0	76.4	78.9	68.6	72.0
Low:	32.6	39.6	44.3	44.7	55.2	58.0	62.7	45.5	53.4	43.6	53.9	57.9



% TOT. RETURN 3/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.9	4.3
3 yr.	27.4	54.0
5 yr.	6.5	73.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	37.81	38.65	34.11	35.83	39.18	*40.05*	*41.50*	Revenues per sh	*46.75*
7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	4.69	9.15	7.94	8.58	*10.85*	*11.25*	"Cash Flow" per sh	*13.00*
3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	d1.26	3.98	1.72	2.00	*4.15*	*4.40*	Earnings per sh A	*6.00*
1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	2.43	2.48	2.58	2.69	*2.84*	*3.00*	Div'd Decl'd per sh D ■	*3.55*
7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	11.75	13.84	13.47	14.47	14.47	*16.25*	*14.90*	Cap'l Spending per sh	*16.75*
23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	35.82	32.10	36.75	37.08	36.57	*38.00*	*39.45*	Book Value per sh C	*47.00*
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	361.99	378.91	380.38	*382.00*	*382.00*	Common Shs Outst'g D	*385.00*
13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	--	16.7	34.9	29.7	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
.70	.85	.75	.65	.66	.74	.62	.71	.68	.75	.94	.87	--	.89	1.79	1.63			Relative P/E Ratio	*.90*
2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	2.9%	3.8%	3.7%	4.3%	4.5%			Avg Ann'l Div'd Yield	*3.7%*
						11862	12581	13413	11524	11869	12320	12657	12347	13578	14905	*15300*	*15850*	Revenues ($mill)	*18000*
						1594.0	1344.0	1539.0	1480.0	1422.0	1603.0	d290.0	1477.0	775.0	925.0	*1775*	*1890*	Net Profit ($mill)	*2515*
						14.3%	25.2%	22.4%	6.6%	11.1%	5.0%	--	--	--	--	*5.0%*	*5.0%*	Income Tax Rate	*5.0%*
						8.5%	7.8%	5.8%	8.0%	6.8%	7.2%	--	11.1%	22.5%	18.5%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*7.0%*
						45.2%	45.7%	44.1%	45.0%	41.8%	45.6%	53.6%	53.5%	55.2%	57.6%	*58.5%*	*59.5%*	Long-Term Debt Ratio	*63.5%*
						46.2%	46.2%	47.2%	46.7%	49.2%	45.8%	38.3%	39.9%	39.5%	33.2%	*32.0%*	*31.5%*	Common Equity Ratio	*34.0%*
						20422	21516	23216	24352	24362	25506	27284	33360	35581	41959	*45575*	*48050*	Total Capital ($mill)	*50000*
						30273	30455	32981	35085	37000	39050	41348	44285	47839	50700	*54350*	*57450*	Net Plant ($mill)	*64900*
						8.9%	7.3%	7.7%	7.1%	6.9%	7.3%	.1%	5.6%	3.4%	3.3%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
						14.2%	11.5%	11.9%	11.1%	10.0%	11.6%	NMF	9.5%	4.9%	5.2%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
						15.9%	12.5%	13.0%	12.0%	10.8%	12.7%	NMF	10.2%	4.6%	5.5%	*11.0%*	*11.0%*	Return on Com Equity E	*12.0%*
						11.4%	8.1%	8.8%	7.2%	5.6%	6.6%	NMF	4.1%	NMF	NMF	*3.5%*	*3.5%*	Retained to Com Eq	*4.5%*
						32%	40%	37%	44%	53%	52%	NMF	63%	NMF	125%	*71%*	*71%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $27601 mill. **Due in 5 Yrs** $9770 mill.
LT Debt $24170 mill. **LT Interest** $882 mill.
(LT interest earned: 1.7x)
Leases, Uncapitalized Annual rentals $623 mill.
Pension Assets-12/21 $4296 mill.
Oblig $4171 mill.
Pfd Stock $3878 mill. **Pfd Div'd** $211 mill.
350,000 sh. 6.25%, $1000 liq. value; 636,020 sh. 5.0%-5.75%, $2500 liq. value; 1,250,000 sh. 5.375%, 750,000 sh. 5%, $1000 liq. value, all cum.
Common Stock 380,696,945 shs.
as of 2/17/22
MARKET CAP: $27 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.7	+.7	-3.9
Avg. Indust. Use (MWH)	657	589	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	22009	23133	21190
Annual Load Factor (%)	49.6	46.7	52.7
% Change Customers (yr-end)	+.5	+.6	+.3
Fixed Charge Cov. (%)	172	NMF	113

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	-.5%	4.0%
"Cash Flow"	--	-3.5%	7.0%
Earnings	-2.5%	-9.0%	NMF
Dividends	7.5%	8.5%	5.5%
Book Value	1.5%	1.0%	4.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2824	2812	3741	2970	12347
2020	2790	2987	4644	3157	13578
2021	2960	3315	5299	3331	14905
2022	*3100*	*3450*	*5300*	*3450*	*15300*
2023	*3250*	*3550*	*5500*	*3550*	*15850*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.64	1.57	1.35	.45	3.98
2020	.50	.85	d.76	1.13	1.72
2021	.68	.84	d.90	1.38	2.00
2022	*.80*	*.90*	*1.45*	*1.00*	*4.15*
2023	*.85*	*.95*	*1.55*	*1.05*	*4.40*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.605	.605	.605	.605	2.42
2019	.6125	.6125	.6125	.6125	2.45
2020	.6375	.6375	.6375	.6375	2.55
2021	.6625	.6625	.6625	.6625	2.65
2022	.70				

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 5.2 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 43%; commercial, 45%; industrial, 3%; other, 9%. Generating sources: nuclear, 8%; gas, 3%; hydro, 3%; purch., 86%. Power costs: 37% of revs. '21 reported depr. rate: 3.7%. Has 13,000 empls. Chairman: William P. Sullivan. Pres. & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

Edison International's utility subsidiary is awaiting an order on a cost-of-capital filing. A mechanism in the current cost-of-capital scheme indicates that Southern California Edison's allowed return on equity for 2022 is to be reduced from 10.3% to 9.72%. This would cut the company's earning power by $0.23 a share. SCE is arguing that the interest-rate cuts to address coronavirus-related disruptions constituted extraordinary circumstances that should prevent triggering of the mechanism. When the California Public Utilities Commission will rule on this matter is unknown, but the order will be retroactive to the start of 2022. The allowed ROE for 2023 through 2025 will be determined in a separate regulatory proceeding.

Our earnings estimate for 2022 is based on the utility maintaining an allowed ROE of 10.3%. This is also the basis of management's profit guidance of $4.40-$4.70 a share. However, the company excludes amortization expense for its payments to the wildfire insurance fund, but we *include* this because it is part of ongoing results. This amounted to $155 million ($0.41 a share) in 2021, and we look for a similar figure this year. Our estimate in January of $4.50 a share was probably too high, so we lowered it to $4.10. We are not assuming any additional charges for claims related to wildfires and mudslides in 2017 and 2018, but these cannot be ruled out. (This is why the bottom line fell into the red in the third quarter of 2020 and 2021.) Note that Edison International's earning power rises as the rate base of SCE increases, and this is the source of the profit growth we expect in 2023.

A rising capital budget will result in significant financing. SCE will add long-term debt to finance capital spending of at least $6 billion this year. This is above the $5.5 billion spent in 2021 because the utility is adding battery storage. In addition, the parent company will issue common and preferred equity.

The stock has an above-average dividend yield, even for a utility. This reflects the lingering uncertainties stemming from wildfires. Total return potential is low for the next 18 months and below the median for the 2025-2027 period.

Paul E. Debbas, CFA *April 22, 2022*

(A) Dil. EPS. Excl. nonrec. gains (losses): '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); '18, (15¢); '19, (21¢); '20, 25¢; gains (loss) from disc. ops.: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢; '18, 10¢. '19 EPS don't sum due to change in shs. Next earnings report due early May. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '21: $20.14/sh. (D) In mill. (E) Rate base: net orig. cost. Rate all'd on com. eq. in '20: 10.3%; earned on avg. com. eq., '21: 5.4%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	75
Price Growth Persistence	35
Earnings Predictability	10

ENTERGY CORP. NYSE-ETR

RECENT PRICE 105.21 | P/E RATIO 15.4 (Trailing: 15.3 Median: 14.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 3.9%

VALUE LINE

TIMELINESS 4 Lowered 12/10/21
SAFETY 2 Raised 12/13/19
TECHNICAL 2 Raised 3/4/22
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$88-$132	$110 (5%)

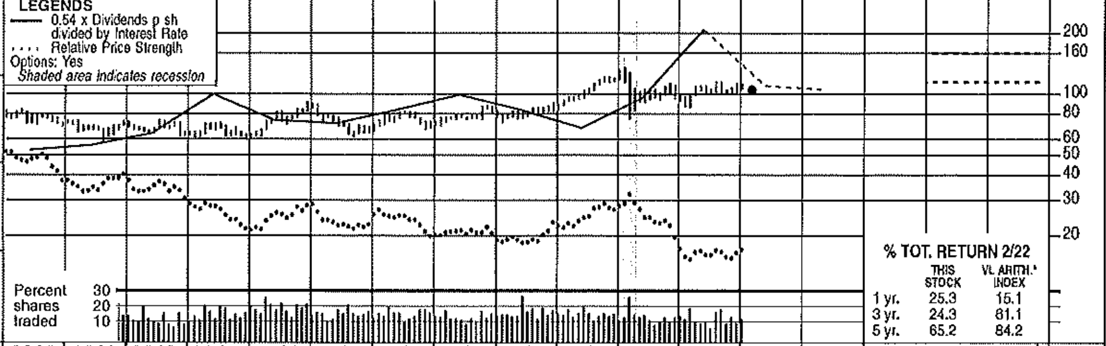
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+50%)	14%
Low	115	(+10%)	6%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	306	264	352
to Sell	273	275	244
Hld's(000)	174484	183072	182168

High:	74.5	74.5	72.6	92.0	90.3	82.1	87.9	90.8	122.1	135.5	115.0	113.1
Low:	57.6	61.6	60.2	60.4	61.3	65.4	69.6	71.9	83.2	75.2	85.8	100.2


LEGENDS
—— 0.54 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	25.3	15.1
3 yr.	24.3	81.1
5 yr.	65.2	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
53.94	59.47	69.15	56.82	64.27	63.67	57.94	63.86	69.71	64.54	60.55	61.35	58.23	54.63	50.51	57.95	*54.85*	*55.00*	Revenues per sh	*59.25*
10.69	11.73	12.89	13.29	16.54	17.53	15.98	16.25	17.68	17.71	18.72	16.70	16.50	17.19	18.21	17.90	*17.75*	*18.50*	"Cash Flow" per sh	*21.25*
5.36	5.60	6.20	6.30	6.66	7.55	6.02	4.96	5.77	5.81	6.88	5.19	5.88	6.30	6.90	6.87	*6.30*	*6.70*	Earnings per sh A	*8.00*
2.16	2.58	3.00	3.00	3.24	3.32	3.32	3.32	3.32	3.34	3.42	3.50	3.58	3.66	3.74	3.86	*4.09*	*4.30*	Div'd Decl'd per sh B ■ †	*5.10*
9.44	10.29	13.92	12.99	13.33	15.21	18.18	15.73	14.82	16.79	17.28	22.07	22.45	21.72	24.52	30.86	*18.15*	*19.00*	Cap'l Spending per sh	*19.75*
40.45	40.71	42.07	45.54	47.53	50.81	51.73	54.00	55.83	51.89	45.12	44.28	46.78	51.34	54.56	57.42	*60.20*	*63.45*	Book Value per sh C	*73.00*
202.67	193.12	189.36	189.12	178.75	176.36	177.81	178.37	179.24	178.39	179.13	180.52	189.06	199.15	200.24	202.65	*206.00*	*209.00*	Common Shs Outst'g D	*214.00*
14.3	19.3	16.6	12.0	11.6	9.1	11.2	13.2	12.9	12.5	10.9	15.0	13.8	16.5	15.3	15.0	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.77	1.02	1.00	.80	.74	.57	.71	.74	.68	.63	.57	.75	.75	.88	.79	.80	*Value Line*		Relative P/E Ratio	*.95*
2.8%	2.4%	2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	4.5%	4.6%	4.6%	4.5%	4.4%	3.5%	3.6%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $27082 mill. **Due in 5 Yrs** $10975 mill.
LT Debt $24842 mill. **LT Interest** $780.0 mill.
Incl. $83.6 mill. of securitization bonds.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $65.3 mill.
Pension Assets-12/21 $6993.1 mill.
Oblig $8409.6 mill.
Pfd Stock $254.4 mill. **Pfd Div'd** $18.3 mill.
200,000 shs. 6.25%-7.5%, $100 par; 250,000 shs. 8.75%, 1.4 mill. shs. 5.375%; all cum., without sinking fund.
Common Stock 203,027,662 shs. **as of 1/31/22**
MARKET CAP: $21 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
10302	11391	12495	11513	10846	11074	11009	10879	10114	11743	*11300*	*11500*	Revenues ($mill)	*12700*
1091.9	904.5	1060.0	1061.2	1249.8	950.7	1092.1	1258.2	1406.7	1402.8	*1320*	*1420*	Net Profit ($mill)	*1735*
13.0%	26.7%	37.8%	2.2%	11.3%	1.8%	NMF	NMF	NMF	16.1%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
11.9%	10.1%	9.3%	7.4%	8.1%	14.7%	17.5%	16.7%	12.2%	7.1%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
55.8%	55.1%	54.9%	57.8%	63.6%	63.6%	63.2%	62.0%	65.5%	67.6%	*66.5%*	*66.5%*	Long-Term Debt Ratio	*66.5%*
42.9%	43.6%	43.8%	40.8%	35.5%	35.5%	35.9%	37.1%	33.7%	31.7%	*32.5%*	*33.0%*	Common Equity Ratio	*33.0%*
21432	22109	22842	22714	22777	22528	24602	27557	32386	36733	*38025*	*40175*	Total Capital ($mill)	*47000*
27299	27882	28723	27824	27921	29664	31974	35183	38853	42244	*43675*	*45250*	Net Plant ($mill)	*49900*
6.4%	5.4%	6.0%	6.0%	6.9%	5.7%	5.8%	5.9%	5.6%	4.8%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
11.5%	9.1%	10.3%	11.1%	15.1%	11.6%	12.0%	12.0%	12.6%	11.6%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
11.6%	9.2%	10.4%	11.2%	15.2%	11.7%	12.2%	12.1%	12.7%	11.9%	*10.5%*	*10.5%*	Return on Com Equity E	*11.0%*
5.2%	3.0%	4.4%	4.8%	7.7%	3.9%	4.9%	5.2%	5.9%	5.2%	*3.5%*	*4.0%*	Retained to Com Eq	*4.0%*
56%	68%	58%	58%	50%	68%	61%	58%	55%	57%	*65%*	*64%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.4	-4.1	+3.2
Avg. Indust. Use (MWH)	1070	1017	1015
Avg. Indust. Revs. per KWH(¢)	5.24	4.95	5.91
Capacity at Peak (Mw)	23887	25665	NA
Peak Load, Summer (Mw)	21598	21340	NA
Annual Load Factor (%)	64	62	NA
% Change Customers (yr-end)	+.8	+1.0	+1.0
Fixed Charge Cov. (%)	165	202	243

ANNUAL RATES of change (per sh)	**Past** 10 Yrs.	**Past** 5 Yrs.	**Est'd '19-'21** to '25-'27
Revenues	-1.0%	-3.5%	*1.5%*
"Cash Flow"	1.0%	-.5%	*3.0%*
Earnings	--	1.5%	*3.0%*
Dividends	1.5%	2.0%	*5.0%*
Book Value	1.5%	1.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2610	2666	3141	2462	10879
2020	2427	2413	2904	2370	10114
2021	2845	2822	3353	2723	11743
2022	*2700*	*2700*	*3200*	*2700*	*11300*
2023	*2750*	*2750*	*3250*	*2750*	*11500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.32	1.22	1.82	1.94	6.30
2020	.59	1.79	2.59	1.93	6.90
2021	1.66	1.30	2.63	1.28	6.87
2022	*1.25*	*1.60*	*2.70*	*.75*	*6.30*
2023	*1.35*	*1.70*	*2.85*	*.80*	*6.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.89	.89	.89	.91	3.50
2019	.91	.91	.91	.93	3.66
2020	.93	.93	.93	.95	3.74
2021	.95	.95	.95	1.01	3.86
2022	1.01				

BUSINESS: Entergy Corporation supplies electricity to 3 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 206,000 customers in Louisiana. Has a nonutility subsidiary that owns one nuclear unit (scheduled to be sold after shutdown in 5/22). Electric revenue breakdown: residential, 37%; commercial, 24%; industrial, 27%; other, 12%. Generating sources: gas, 46%; nuclear, 30%; coal, 6%; purchased, 18%. Fuel costs: 32% of revenues. '21 reported depreciation rate: 2.7%. Has 12,400 employees. Chairman & CEO: Leo P. Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Tel.: 504-576-4000. Internet: www.entergy.com.

Entergy is seeking to recover costs associated with severe storms in 2020 and 2021. In 2020, three hurricanes caused more than $2 billion of damage in Louisiana and Texas. Hurricane Ida last year resulted in restoration costs of $2.7 billion, above the previous estimate of $2.1 billion-$2.5 billion. In the coming months, Entergy will issue more than $3 billion of securitized bonds, which includes $1 billion for Hurricane Ida. The utility will seek recovery from the regulatory commissions in Louisiana and New Orleans (regulated separately from the rest of the state) for the remainder of the costs from Hurricane Ida. However, Entergy received criticism last year in New Orleans for its performance following the hurricane, which might affect the regulatory process.

The company's exit from the merchant power business should be completed by mid-2022. Entergy has closed and sold its nonregulated nuclear units over the past few years. Its last nonutility nuclear plant, Palisades in Michigan, will be shut down in May. The sale of the plant is expected to close in midyear. (The point of these deals is that the buyer gets the nuclear decommissioning trust at a sizable discount and the seller is relieved of the responsibility of decommissioning the facility.) Entergy's business risk has lessened as the company winds down its presence in nonregulated power generation.

An earnings decline is likely in 2022, followed by improvement in 2023. Entergy's nonutility subsidiary contributed $0.61 to share net last year, so this income will likely be less this year. Another negative factor will be an increase in average shares outstanding. Our 2022 estimate is at the midpoint of Entergy's targeted range of $6.15-$6.45 a share. Even so, Entergy's industrial sector is experiencing an economic recovery, and the company is benefiting from rate relief in several jurisdictions (much of which comes via formula rate plans). We think profits will advance to $6.70 a share in 2023. Management's guidance for next year is $6.55-$6.85.

This untimely stock has a dividend yield that is slightly above the utility average. Total return prospects are subpar for the next 18 months and don't stand out for the 3- to 5-year period.

Paul E. Debbas, CFA *March 11, 2022*

(A) Diluted EPS. Excl. nonrec. losses: '12, $1.26; '13, $1.14; '14, 56¢; '15, $6.99; '16, $10.14; '17, $2.91; '18, $1.25; '21, $1.33. Next earnings report due early May. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '21: $35.95/sh. (D) In mill. (E) Rate base: Net original cost. Allowed ROE (blended): 9.95%; earned on avg. com. eq., '21: 12.1%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	70

EVERGY, INC. NYSE-EVRG

RECENT PRICE 62.41 | P/E RATIO 17.9 (Trailing: 16.3 Median: NMF) | RELATIVE P/E RATIO 1.00 | DIV'D YLD 3.8% | **VALUE LINE**

TIMELINESS 5 Lowered 12/31/21
SAFETY 2 New 9/14/18
TECHNICAL 2 Lowered 3/11/22
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$50-$73	$62 (0%)

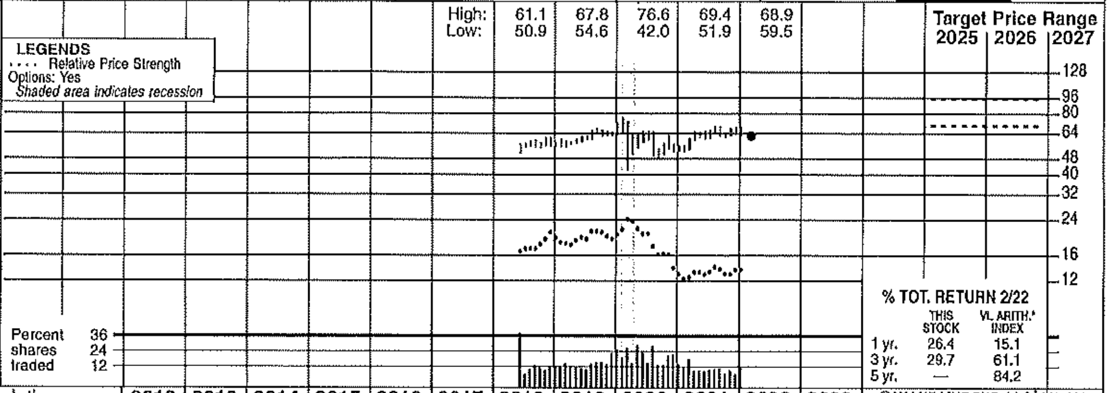
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+50%)	14%
Low	70	(+10%)	7%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	291	262	308
to Sell	220	240	237
Hld's(000)	198932	204443	206094

	2018	2019	2020	2021	2022
High:	61.1	67.8	76.6	69.4	68.9
Low:	50.9	54.6	42.0	51.9	59.5



% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.4	15.1
3 yr.	29.7	61.1
5 yr.	—	84.2

Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Great Plains Energy holders received .5981 of a share of Evergy for each of their shares, and Westar Energy holders received one share of Evergy for each of their shares. The merger was completed on June 4, 2018. Shares of Evergy began trading on the New York Stock Exchange one day later.

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
--	--	--	--	--	--	16.75	22.71	21.66	24.36	*23.05*	*23.70*	Revenues per sh	*26.50*
--	--	--	--	--	--	4.89	7.18	7.06	8.18	*8.05*	*8.45*	"Cash Flow" per sh	*10.00*
--	--	--	--	--	--	2.50	2.79	2.72	3.83	*3.55*	*3.80*	Earnings per sh A	*4.75*
--	--	--	--	--	--	1.74	1.93	2.05	2.18	*2.33*	*2.48*	Div'd Decl'd per sh B ■	*3.05*
--	--	--	--	--	--	4.19	5.34	6.88	8.60	*8.60*	*9.20*	Cap'l Spending per sh	*9.50*
--	--	--	--	--	--	39.28	37.82	38.50	40.32	*41.45*	*42.75*	Book Value per sh C	*47.75*
--	--	--	--	--	--	255.33	226.64	226.84	229.30	*230.00*	*230.00*	Common Shs Outst'g D	*230.00*
--	--	--	--	--	--	22.7	21.8	21.7	16.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
--	--	--	--	--	--	1.23	1.16	1.11	.87			Relative P/E Ratio	*.95*
--	--	--	--	--	--	3.1%	3.2%	3.5%	3.5%			Avg Ann'l Div'd Yield	*3.7%*
--	--	--	--	--	--	4275.9	5147.8	4913.4	5586.7	*5300*	*5450*	Revenues ($mill)	*6100*
--	--	--	--	--	--	535.8	669.9	618.3	879.7	*835*	*895*	Net Profit ($mill)	*1130*
--	--	--	--	--	--	9.8%	12.6%	14.1%	11.7%	*10.0%*	*10.0%*	Income Tax Rate	*10.0%*
--	--	--	--	--	--	2.5%	2.5%	5.5%	5.0%	*5.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
--	--	--	--	--	--	40.0%	50.6%	51.3%	50.1%	*51.5%*	*51.5%*	Long-Term Debt Ratio	*53.0%*
--	--	--	--	--	--	60.0%	49.4%	48.7%	49.9%	*48.5%*	*48.5%*	Common Equity Ratio	*47.0%*
--	--	--	--	--	--	16716	17337	17924	18542	*19675*	*20200*	Total Capital ($mill)	*23400*
--	--	--	--	--	--	18952	19346	20106	21150	*22100*	*23150*	Net Plant ($mill)	*26300*
--	--	--	--	--	--	4.0%	4.8%	4.5%	5.7%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
--	--	--	--	--	--	5.3%	7.8%	7.1%	9.5%	*8.5%*	*9.0%*	Return on Shr. Equity	*10.0%*
--	--	--	--	--	--	5.3%	7.8%	7.1%	9.5%	*8.5%*	*9.0%*	Return on Com Equity E	*10.0%*
--	--	--	--	--	--	.6%	2.4%	1.8%	4.1%	*3.0%*	*3.0%*	Retained to Com Eq	*4.0%*
--	--	--	--	--	--	89%	69%	75%	57%	*64%*	*64%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $11166 mill. Due in 5 Yrs $4100.3 mill.
LT Debt $9297.9 mill. LT Interest $332.8 mill.
Incl. $40.9 mill. finance leases.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $18.8 mill.

Pension Assets-12/21 $1714.7 mill.
Oblig $2561.7 mill.

Pfd Stock None

Common Stock 229,311,689 shs.
as of 2/18/22
MARKET CAP: $14 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	NA	-3.9	+3.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.25	7.14	6.94
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	305	286	350

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	--	*2.5%*
"Cash Flow"	--	--	*5.0%*
Earnings	--	--	*7.5%*
Dividends	--	--	*7.0%*
Book Value	--	--	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1217	1222	1578	1131	5147.8
2020	1117	1185	1517	1094	4913.4
2021	1612	1236	1617	1122	5586.7
2022	*1250*	*1250*	*1650*	*1150*	*5300*
2023	*1300*	*1300*	*1700*	*1150*	*5450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.39	.57	1.56	.28	2.79
2020	.31	.59	1.60	.22	2.72
2021	.84	.81	1.95	.23	3.83
2022	*.55*	*.85*	*1.85*	*.30*	*3.55*
2023	*.60*	*.90*	*2.00*	*.30*	*3.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.40	.40	.46	.475	1.74
2019	.475	.475	.475	.505	1.93
2020	.505	.505	.505	.535	2.05
2021	.535	.535	.535	.5725	2.18
2022	.5725				

BUSINESS: Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Through its subsidiaries (now doing business under the Evergy name), provides electric service to 1.6 million customers in Kansas and Missouri, including the greater Kansas City area. Electric revenue breakdown: residential, 34%; commercial, 30%; industrial, 11%; wholesale, 13%; other, 12%. Generating sources: coal, 54%; nuclear, 17%; purchased, 29%. Fuel costs: 28% of revenues. '21 reported deprec. rate: 3%. Has 4,900 employees. Chairman: Mark A. Ruelia. President & CEO: David A. Campbell. COO: Kevin E. Bryant. Inc.: Missouri. Address: 1200 Main Street, Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.evergy.com.

Evergy's utilities in Missouri have filed general rate cases. The company's Missouri Metro utility requested an increase of $43.9 million (5.2%), based on a return on equity of 10% and a common-equity ratio of 51.2%. Its Missouri West utility filed for a hike of $27.7 million (3.8%), based on a 10% ROE and a 51.8% common-equity ratio. These are the first rate cases Evergy has filed since the company was formed through a merger in June of 2018. Capital additions and updated depreciation rates are driving the petitions, partly offset by reductions in operating and maintenance expenses. New tariffs are expected to take effect on December 6th, 11 months after the filing date. This will be too late to have a significant effect on earnings in 2022. Note that the company plans to file rate applications in Kansas in 2023.

The earnings decline that is probable for 2022 should not be troubling for investors. Last year, a cold spell in the Gulf Coast region in February was a boon for Evergy's energy-marketing subsidiary. This boosted pretax income by $86.6 million in the first quarter. We expect no repeat of these auspicious conditions this year. A return to normal weather patterns would also be negative for the year-to-year comparison, as favorable weather boosted share net by $0.08 in 2021. Still, there should be some positive factors, including increased income from the company's transmission system. We are sticking with our 2022 earnings estimate of $3.55 a share, which is within Evergy's targeted range of $3.43-$3.63.

We expect earnings to improve in 2023. Rate relief in Missouri should be a key factor. Modest growth in kilowatt-hour sales should help, as well. Our estimate of $3.80 a share would produce an increase of 7%. This is within Evergy's annual goal of 6%-8%.

This untimely stock has a dividend yield that is about average for a utility. Total return potential is subpar for the next 18 months and somewhat below average for the 3- to 5-year period. A standstill agreement with two investors expires after the 2022 annual meeting (normally held in the first week of May), so there is some speculative appeal.

Paul E. Debbas, CFA *March 11, 2022*

(A) Diluted earnings. '19 EPS don't sum to full-year total due to rounding. Next earnings report due early May. (B) Dividends paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. (C) Incl. intangibles. In '21: $4327.7 mill., $18.87/sh. (D) In millions. (E) Rate base: Original cost depreciated. Rate allowed on common equity in Missouri in '18: none specified; in Kansas in '18: 9.3%. Earned on average common equity, '21: 9.8%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	NMF
Earnings Predictability	NMF

EVERSOURCE ENERGY NYSE-ES

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
89.49	22.8 (Trailing: 26.0 Median: 19.0)	1.29	2.9%

VALUE LINE

TIMELINESS	3	Raised 1/14/22
SAFETY	1	Raised 5/22/15
TECHNICAL	2	Lowered 2/11/22

BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$72-$121	$97 (10%)

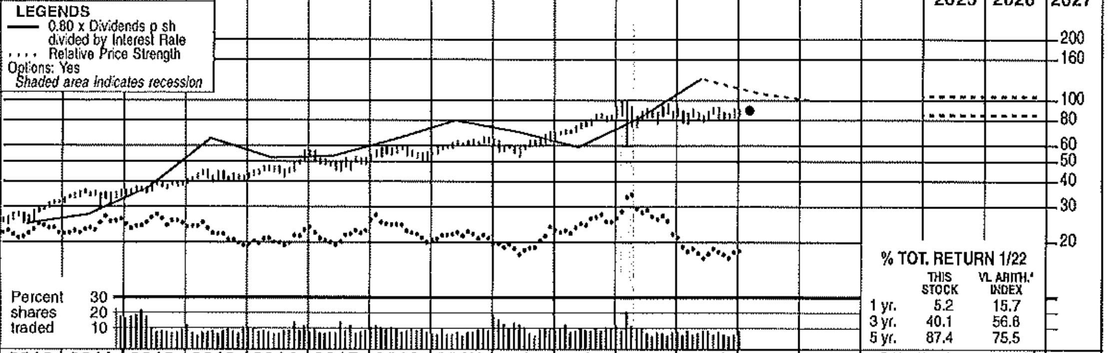
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+15%)	7%
Low	65	(-5%)	2%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	331	360	328
to Sell	369	326	308
Hld's(000)	266387	266114	272358

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	36.5	40.9	45.7	56.7	56.8	60.4	66.1	70.5	86.6	99.4	92.7	90.9
Low:	30.0	33.5	38.6	41.3	44.6	50.0	54.1	52.8	63.1	60.7	76.6	84.0



% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.2	15.7
3 yr.	40.1	56.8
5 yr.	87.4	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB, LLC	25-27
44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	25.08	24.11	24.46	26.66	25.85	25.96	*28.45*	*28.80*	*29.50*	Revenues per sh	*32.25*
3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	4.94	5.46	5.84	6.64	6.65	6.89	*6.80*	*7.55*	*7.85*	"Cash Flow" per sh	*9.25*
.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	2.76	2.96	3.11	3.25	3.45	3.55	*3.45*	*4.05*	*4.25*	Earnings per sh A	*5.00*
.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	1.67	1.78	1.90	2.02	2.14	2.27	2.41	*2.56*	*2.72*	Div'd Decl'd per sh B ■	*3.20*
5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	5.44	6.24	7.41	7.96	8.83	8.58	*10.25*	*10.20*	*10.10*	Cap'l Spending per sh	*8.50*
18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	32.64	33.80	34.99	36.25	38.29	41.01	*42.20*	*44.05*	*46.00*	Book Value per sh C	*52.25*
154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	317.19	316.89	316.89	316.89	329.88	342.95	*344.30*	*347.00*	*351.00*	Common Shs Outst'g D	*360.00*
27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	18.1	18.7	19.5	18.7	22.1	24.3	*24.8*	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
1.46	.99	.82	.80	.85	.97	1.27	.95	.94	.91	.98	.98	1.01	1.18	1.25	*1.35*	*Value Line*		Relative P/E Ratio	*1.10*
3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	3.3%	3.2%	3.1%	3.3%	2.8%	2.6%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 9/30/21
Total Debt $19427 mill. **Due in 5 Yrs** $7090.6 mill.
LT Debt $17874 mill. **LT Interest** $619.8 mill.
(LT interest earned: 3.7x)
Leases, Uncapitalized Annual rentals $11.4 mill.
Pension Assets-12/20 $5409.2 mill.
Oblig $7045.3 mill.
Pfd Stock $155.6 mill. **Pfd Div'd** $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption, call. at $50.50-$54.00; 430,000 shs 4.25%-4.78% not subject to mandatory redemption, call. at $102.80-$103.63.
Common Stock 343,805,812 shs. as of 10/31/21
MARKET CAP: $31 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB, LLC	25-27
6273.8	7301.2	7741.9	7954.8	7639.1	7752.0	8448.2	8526.5	8904.4	*9800*	*10000*	*10350*	Revenues ($mill)	*11650*
533.0	793.7	827.1	886.0	949.8	995.5	1040.5	1121.0	1212.7	*1195*	*1405*	*1485*	Net Profit ($mill)	*1800*
34.0%	35.0%	36.2%	37.9%	36.9%	36.8%	21.7%	19.7%	22.2%	*24.5%*	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
2.3%	1.4%	2.4%	2.9%	3.9%	4.7%	6.1%	6.3%	5.4%	*5.0%*	*5.0%*	*4.0%*	AFUDC % to Net Profit	*4.0%*
43.7%	44.3%	45.9%	45.6%	44.8%	51.2%	52.4%	52.8%	52.4%	*55.0%*	*55.5%*	*55.5%*	Long-Term Debt Ratio	*57.0%*
55.4%	54.8%	53.2%	53.6%	54.4%	48.2%	46.9%	46.6%	47.1%	*44.5%*	*44.0%*	*44.0%*	Common Equity Ratio	*42.5%*
16675	17544	18738	19313	19697	23018	24474	27097	29842	*32700*	*34675*	*36825*	Total Capital ($mill)	*44000*
16605	17576	18647	19892	21351	23617	25610	27585	30883	*33400*	*35875*	*38300*	Net Plant ($mill)	*43900*
4.2%	5.5%	5.3%	5.5%	5.8%	5.2%	5.2%	5.1%	5.0%	*5.0%*	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
5.7%	8.1%	8.2%	8.4%	8.7%	8.9%	8.9%	8.8%	8.5%	*8.5%*	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
5.7%	8.2%	8.2%	8.5%	8.8%	8.9%	9.0%	8.8%	8.6%	*8.5%*	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
1.6%	3.4%	3.5%	3.4%	3.5%	3.5%	3.4%	3.6%	3.3%	*2.5%*	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
72%	59%	58%	61%	60%	61%	62%	60%	62%	*70%*	*64%*	*64%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2018	2019	2020
% Change Retail Sales (KWH)	+2.2	-3.3	-2.7
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.7	+.8
Fixed Charge Cov. (%)	319	319	345

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	-2.0%	1.5%	*3.0%*
"Cash Flow"	2.0%	6.5%	*4.5%*
Earnings	5.5%	5.5%	*5.5%*
Dividends	8.5%	6.5%	*6.0%*
Book Value	6.5%	4.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2415	1884	2175	2050	8526.5
2020	2373	1953	2343	2233	8904.4
2021	2826	2122	2461	*2391*	*9800*
2022	*2850*	*2200*	*2550*	*2400*	*10000*
2023	*2950*	*2250*	*2650*	*2500*	*10350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.97	.74	.98	.76	3.45
2020	1.01	.75	1.01	.78	3.55
2021	1.06	.77	.82	*.80*	*3.45*
2022	*1.17*	*.87*	*1.08*	*.93*	*4.05*
2023	*1.25*	*.90*	*1.13*	*.97*	*4.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.505	.505	.505	.505	2.02
2019	.535	.535	.535	.535	2.14
2020	.5675	.5675	.5675	.5675	2.27
2021	.6025	.6025	.6025	.6025	2.41
2022					

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities with 3.2 mill. electric, 881,000 gas, 216,000 water customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to 3/4 of New Hampshire's population; supplies power to western Massachusetts and parts of eastern MA & gas to central & eastern MA; supplies water to CT, MA, & NH. Acq'd NSTAR 4/12; Aquarion 12/17; Columbia Gas 10/20. Electric rev. breakdown: residential, 56%; commercial, 33%; industrial, 5%; other, 6%. Fuel costs: 34% of revs. '20 reported deprec. rate: 3.0%. Has 9,300 employees. Chairman: James J. Judge. President & CEO: Joe Nolan. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource Energy will likely post a significant earnings increase in 2022. The comparison is easy. In 2021, the company took a charge of $0.07 a share in the first quarter for a service-related penalty in Connecticut (stemming from an outage in August of 2020) and a charge of $0.17 a share in the third period to reflect bill credits and assistance. In addition, costs associated with the acquisition of a gas utility lowered the bottom line by $0.05 a share in the first nine months of 2021. Besides the absence of these costs, Eversource should continue to benefit from investments in its electric transmission system. The utility will have a full year's benefit from a gas rate hike in Massachusetts that took effect on November 1, 2021 and a partial year of an increase taking effect on November 1, 2022. All told, we figure profits will exceed $4.00 a share.

We look for further growth in 2023. Ongoing transmission investment should be a factor, although we note that there is some lingering uncertainty about transmission rates. Our estimate would produce an increase of 5%, within Eversource's annual goal of 5%-7%.

The board of trustees will probably increase the dividend soon. This is the usual timing of the board's announcement. We estimate an increase of $0.15 a share (6.2%) annually. Eversource's target for yearly dividend growth is 5%-7%, the same as for profit growth.

Eversource has several significant projects in various stages of development. Most notably, the company is planning to add 1,758 megawatts of offshore wind through a joint venture with Orsted, a European company, by 2025. This is expected to enhance its annual earnings growth rate, but also entails construction risk. The company also wants to add advanced meters in Connecticut at an expected cost of $475 million and in Massachusetts at an expected cost of $575 million. NSTAR Gas and Yankee Gas are replacing old gas mains. All of this will result in debt and equity financing.

This high-quality stock's dividend yield is below the mean for the electric utility industry. Total return potential does not stand out for the next 18 months or the 3- to 5-year period.

Paul E. Debbas, CFA *February 11, 2022*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '08, (19¢); '10, 9¢; '19, (64¢). Next earnings report due late Feb. (B) Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '20: $9939.3 mill., $28.98/sh. (D) In mill. (E) Rate allowed on com. eq. in MA: (elec.) '18, 10.0%; (gas) '20, 9.7%-9.9%; in CT: (elec.) '18, 9.25%; (gas) '18, 9.3%; in NH: '21, 9.3%; earned on avg. com. eq., '20: 9.0%. Regulatory Climate: CT, Below Average; NH, Average; MA, Above Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	100

EXELON CORP. NDQ-EXC

RECENT PRICE **41.06** F | P/E RATIO **NMF** (Trailing: NMF Median: NMF) | RELATIVE P/E RATIO **NMF** | DIV'D YLD **3.3%** | **VALUE LINE**

TIMELINESS — Suspended 2/4/22
SAFETY 2 Raised 8/13/21
TECHNICAL — Suspended 2/4/22
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$40-$65	$53 (-10%)

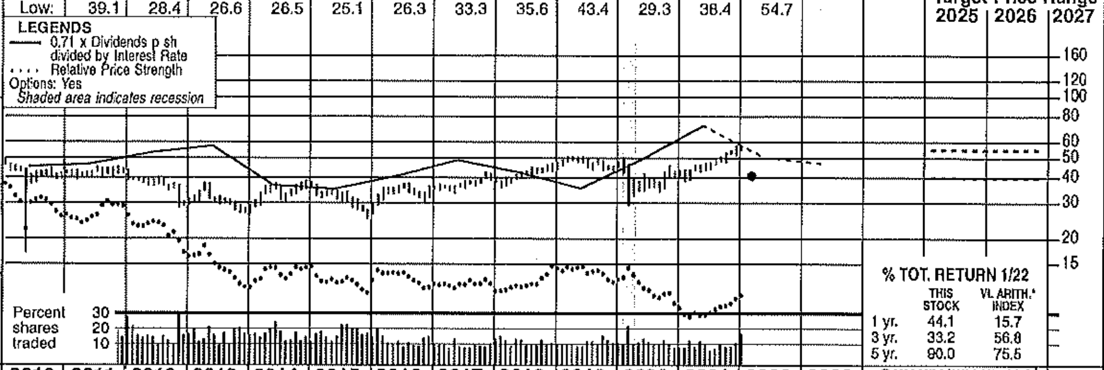
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+35%)	10%
Low	40	(-5%)	3%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	415	408	413
to Sell	409	387	379
Hld's(000)	774798	790477	794682

High:	45.4	43.7	37.8	38.9	38.3	37.7	42.7	47.4	51.2	50.5	58.0	58.0
Low:	39.1	28.4	26.6	26.5	25.1	26.3	33.3	35.6	43.4	29.3	38.4	54.7



% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	44.1	15.7
3 yr.	33.2	56.8
5 yr.	90.0	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
23.37	28.62	28.65	26.25	28.17	28.53	27.48	29.03	31.90	32.01	33.94	34.81	37.17	35.39	33.85	35.70	17.80	18.20	Revenues per sh	19.50
6.71	7.43	7.64	8.25	8.32	7.23	6.61	6.72	6.61	6.80	7.01	8.37	8.24	8.96	9.02	9.60	6.50	6.75	"Cash Flow" per sh	7.50
3.50	4.03	4.10	4.29	3.87	3.75	1.92	2.31	2.10	2.54	1.80	2.78	2.07	3.01	2.60	2.60	2.25	2.40	Earnings per sh A	3.00
1.64	1.82	2.05	2.10	2.10	2.10	2.10	1.46	1.24	1.24	1.26	1.31	1.38	1.45	1.53	1.53	1.35	1.45	Div'd Decl'd per sh B ■	1.75
3.61	4.05	4.74	4.96	5.03	6.09	6.77	6.29	7.07	8.29	9.26	7.87	7.84	7.45	8.25	7.25	6.80	7.00	Cap'l Spending per sh	7.25
14.89	15.34	16.78	19.16	20.49	21.68	25.07	26.52	26.29	28.04	27.96	30.99	31.77	33.12	33.39	34.05	23.85	24.95	Book Value per sh C	28.50
669.86	660.88	658.15	659.76	661.85	663.37	854.78	857.29	859.83	919.92	924.04	963.34	968.19	973.00	976.00	980.00	984.00	988.00	Common Shs Outst'g D	1000.00
16.5	18.2	18.0	11.5	11.0	11.3	19.1	13.4	16.0	12.6	18.7	13.4	20.1	15.7	15.4	18.1	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	16.0
.89	.97	1.08	.77	.70	.71	1.22	.75	.84	.63	.98	.67	1.09	.84	.79	.95			Relative P/E Ratio	.90
2.8%	2.5%	2.8%	4.3%	4.9%	5.0%	5.7%	4.7%	3.7%	3.9%	3.7%	3.5%	3.3%	3.1%	3.8%	3.3%			Avg Ann'l Div'd Yield	3.7%
						23489	24888	27429	29447	31360	33531	35985	34438	33039	35000	17500	18000	Revenues ($mill)	19500
						1579.0	1999.0	1826.0	2282.0	1677.0	2636.0	2010.0	2936.0	2538.0	2530	2210	2355	Net Profit ($mill)	2910
						32.4%	36.5%	27.2%	32.2%	38.5%	34.2%	5.4%	19.4%	16.4%	12.5%	20.0%	20.0%	Income Tax Rate	20.0%
						5.8%	4.5%	5.5%	5.4%	12.3%	6.5%	7.0%	5.3%	6.8%	6.0%	7.0%	6.0%	AFUDC % to Net Profit	5.0%
						45.8%	44.4%	46.7%	48.3%	55.5%	52.2%	52.8%	49.6%	52.1%	51.0%	60.0%	60.0%	Long-Term Debt Ratio	59.0%
						53.5%	55.2%	52.8%	51.3%	44.5%	47.8%	47.2%	50.4%	47.9%	49.0%	40.0%	40.0%	Common Equity Ratio	41.0%
						40057	41196	42811	50272	58053	62422	65229	63943	68068	68250	58525	61375	Total Capital ($mill)	69600
						45186	47330	52087	57439	71555	74202	76707	80233	82584	83275	66225	69325	Net Plant ($mill)	79000
						5.1%	5.9%	5.3%	5.5%	4.1%	5.3%	4.2%	5.7%	4.8%	5.0%	5.0%	5.0%	Return on Total Cap'l	5.5%
						7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	6.5%	9.1%	7.8%	7.5%	9.5%	9.5%	Return on Shr. Equity	10.0%
						7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	6.5%	9.1%	7.8%	7.5%	9.5%	9.5%	Return on Com Equity E	10.0%
						NMF	3.2%	3.3%	4.5%	1.9%	4.7%	2.2%	4.7%	3.2%	3.0%	4.0%	4.0%	Retained to Com Eq	4.0%
						109%	63%	59%	49%	70%	47%	66%	48%	59%	56%	60%	61%	All Div'ds to Net Prof	60%

CAPITAL STRUCTURE as of 9/30/21
Total Debt $41701 mill. **Due In 5 Yrs** $11466 mill.
LT Debt $35659 mill. **LT Interest** $1450 mill.
Includes $390 mill. nonrecourse transition bonds.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $239 mill.

Pension Assets-12/20 $20344 mill.
Oblig $24894 mill.

Pfd Stock None

Common Stock 978,317,787 shs.

MARKET CAP: $40 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2018	2019	2020
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	236	257	211

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	2.5%	2.5%	NMF
"Cash Flow"	1.0%	5.5%	NMF
Earnings	-4.5%	2.0%	NMF
Dividends	-3.5%	2.0%	NMF
Book Value	5.5%	4.0%	NMF

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	9477	7689	8929	8343	34438
2020	8747	7322	8853	8117	33039
2021	9890	7915	8910	8285	35000
2022	4800	3900	4550	4250	17500
2023	4950	4000	4700	4350	18000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.93	.50	.79	.79	3.01
2020	.60	.74	.89	.37	2.60
2021	d.30	.79	1.23	.88	2.60
2022	.60	.45	.70	.50	2.25
2023	.65	.50	.75	.50	2.40

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.345	.345	.345	.345	1.38
2019	.3625	.3625	.3625	.3625	1.45
2020	.3825	.3825	.3825	.3825	1.53
2021	.3825	.3825	.3825	.3825	1.53
2022					

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison, PECO Energy, Baltimore Gas and Electric, Pepco, Delmarva Power, & Atlantic City Electric. Has 9.1 mill. elec., 1.3 mill. gas customers. Spun off nonregulated generating & energy-marketing operations 2/22. Acq'd Constellation Energy 3/12; Pepco Holdings 3/16. Elec. revenue breakdown: residential, 54%; small commercial & industrial, 16%; large commercial & industrial, 17%; other, 13%. Fuel costs: 43% of revs. '20 deprec. rates: 2.8%-7.0% elec., 2.1% gas. Has 18,000 empls. Chairman: Mayo A. Shattuck III. Pres. & CEO: Christopher M. Crane. Inc.: PA. Address: 10 S. Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Exelon completed the spinoff of its nonutility operations on February 1st. Stockholders received one share of the new company, Constellation Energy Corporation (NASDAQ: CEG) for every three shares of Exelon. The remaining Exelon is a regulated transmission and distribution utility serving 9.1 million electric customers and 1.3 million gas customers over seven regulatory jurisdictions (including the Federal Energy Regulatory Commission for transmission). As part of the separation agreement, Exelon made a $1.75 billion cash payment to Constellation. In recent years, the nonutility activities have been hampered by a difficult operating environment, and the remaining Exelon businesses will be more stable and predictable.

Management is targeting 6%-8% annual earnings and dividend growth through 2025. Exelon estimates that its profits (adjusted for the spinoff) wound up in a range of $2.06-$2.14 a share in 2021. The company's profit guidance for this year is $2.18-$2.32 a share. Exelon's utilities have been active in the regulatory arena in recent years, and we believe this, along with modest load growth and capital investments recovered contemporaneously through various regulatory mechanisms, will continue to expand the company's income. Exelon's long-term target for the payout ratio is 60%, and the company expects a disbursement of $1.35 a share in 2022. Investors should note that figures through 2020 and our estimates for 2021 are for Exelon in its previous configuration. Thus, we are not showing a price-earnings ratio at the top of the page.

Our 2022 earnings estimate of $2.25 a share is at the midpoint of Exelon's targeted range. Ongoing rate relief and normal utility growth should produce an increase, to $2.40 a share, in 2023.

Delmarva Power has an electric rate case pending in Maryland. The utility is seeking a $27.4 million increase, based on a 10.1% return on equity and a 50.7% common-equity ratio. An order is expected in late March.

Due to the corporate separation, the stock is unranked for Timeliness. The dividend yield is about average for a utility, as is 3- to 5-year total return potential.

Paul E. Debbas, CFA *February 11, 2022*

(A) Diluted egs. Excl. nonrec. gain (losses): '06, ($1.15); '09, (20¢); '12, (50¢); '13, (31¢); '14, 23¢; '16, (58¢); '17, $1.19; '20, (58¢). Next earnings report due late Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. deferred charges. In '20: $15.82/sh. (D) In mill. (E) Rate all'd on com. eq. in IL in '15: 9.25%; in MD in '16: 9.75% elec., 9.65% gas; in NJ in '16: 9.75%; earned on avg. com. eq., '20: 7.8%. Reg. Climate: PA, NJ Avg.; IL, MD, Below Avg. (F) Price as of 9:30 EST on 2/2/22.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	65

FIRSTENERGY NYSE-FE

RECENT PRICE 41.96 | P/E RATIO 17.7 (Trailing: 18.2 Median: 20.0) | RELATIVE P/E RATIO 1.00 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 2 Raised 12/3/21
SAFETY 3 Lowered 7/31/20
TECHNICAL 3 Raised 1/21/22
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$21-$48	$35 (-20%)

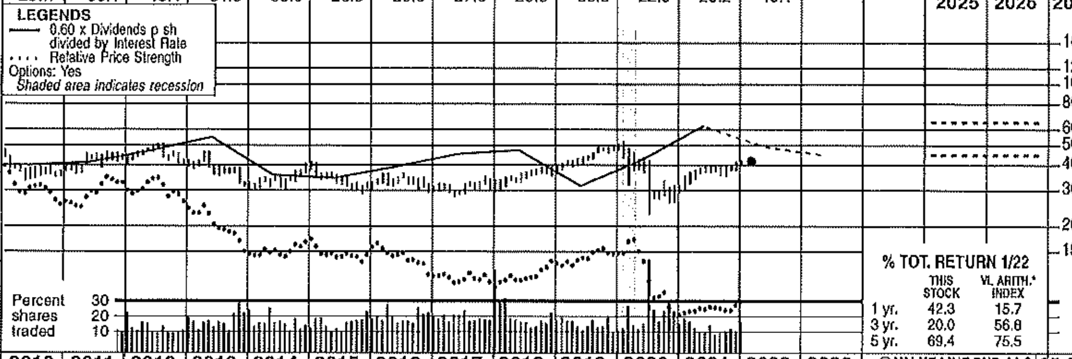
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+55%)	14%
Low	45	(+5%)	6%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	312	312	340
to Sell	285	263	211
Hld's(000)	445916	449120	447567

High:	46.5	51.1	46.8	40.8	41.7	36.6	35.2	39.9	49.1	52.5	41.8	42.0
Low:	36.1	40.4	31.3	30.0	28.9	29.3	27.9	29.3	36.3	22.9	29.2	40.1



% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	42.3	15.7
3 yr.	20.0	56.8
5 yr.	69.4	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
36.03	42.00	44.70	41.70	43.76	38.87	36.57	35.60	35.74	35.48	32.92	31.49	22.00	20.41	19.87	19.45	19.90	20.85	Revenues per sh	23.75
7.22	8.34	9.04	8.80	8.50	5.75	6.05	6.30	4.55	6.33	6.53	6.54	3.98	3.94	4.05	4.50	4.70	5.10	"Cash Flow" per sh	6.00
3.82	4.22	4.38	3.32	3.25	1.88	2.13	2.97	.85	2.00	2.10	2.73	1.33	1.84	1.85	2.40	2.40	2.65	Earnings per sh A	3.25
1.85	2.05	2.20	2.20	2.20	2.20	2.20	1.65	1.44	1.44	1.44	1.44	1.82	1.53	1.56	1.56	1.56	1.64	Div'd Decl'd per sh B ■	2.00
4.12	5.36	9.47	7.23	6.44	5.45	7.09	6.90	8.42	6.83	6.93	6.38	5.23	4.93	4.89	5.25	5.75	5.90	Cap'l Spending per sh	6.25
28.30	29.45	27.17	28.08	28.03	31.75	31.29	30.32	29.49	29.33	14.11	8.81	13.17	12.90	13.33	15.10	16.05	17.15	Book Value per sh C	21.00
319.21	304.84	304.84	304.84	304.84	418.22	418.22	418.63	421.10	423.56	442.34	445.33	511.92	540.65	543.12	570.00	572.50	575.00	Common Shs Outst'g D	582.00
14.2	15.6	15.6	13.0	11.7	22.4	21.1	13.1	NMF	17.0	15.9	11.4	26.5	23.8	20.2	15.2	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	16.5
.77	.83	.94	.87	.74	1.41	1.34	.74	NMF	.86	.83	.57	1.43	1.27	1.04	.80			Relative P/E Ratio	.90
3.4%	3.1%	3.2%	5.1%	5.8%	5.2%	4.9%	4.3%	4.3%	4.2%	4.3%	4.6%	5.2%	3.5%	4.2%	4.3%			Avg Ann'l Div'd Yield	3.7%
						15294	14903	15049	15029	14562	14022	11261	11035	10790	11100	11400	12000	Revenues ($mill)	13800
						891.0	1245.0	356.0	844.0	892.0	1213.0	726.0	995.0	1003.0	1315	1380	1525	Net Profit ($mill)	1865
						41.1%	36.1%	5.6%	35.7%	37.8%	37.2%	32.4%	19.0%	11.2%	21.0%	21.0%	21.0%	Income Tax Rate	21.0%
						8.1%	6.0%	33.1%	13.9%	11.5%	6.5%	9.0%	7.1%	7.7%	6.0%	6.0%	5.0%	AFUDC % to Net Profit	4.0%
						53.7%	55.5%	60.7%	60.7%	74.5%	84.3%	72.3%	73.8%	75.4%	73.0%	70.5%	70.0%	Long-Term Debt Ratio	68.0%
						46.3%	44.5%	39.3%	39.3%	25.5%	15.7%	27.4%	26.2%	24.6%	27.0%	29.5%	30.0%	Common Equity Ratio	32.0%
						28263	28523	31596	31613	24433	25040	24565	26593	29368	31725	31400	32925	Total Capital ($mill)	38200
						32903	33252	35783	37214	29387	28879	29911	31650	33294	35075	37100	39150	Net Plant ($mill)	45500
						4.9%	6.0%	2.7%	4.3%	5.7%	7.0%	4.9%	5.4%	5.0%	5.5%	6.0%	6.0%	Return on Total Cap'l	6.5%
						6.8%	9.8%	2.9%	6.8%	14.3%	30.9%	10.7%	14.3%	13.9%	15.5%	15.5%	15.5%	Return on Shr. Equity	15.5%
						6.8%	9.8%	2.9%	6.8%	14.3%	30.9%	9.7%	14.2%	13.9%	15.5%	15.5%	15.5%	Return on Com Equity E	15.5%
						NMF	2.6%	NMF	1.9%	4.5%	14.6%	NMF	2.5%	2.2%	5.0%	5.5%	6.0%	Retained to Com Eq	6.0%
						103%	74%	NMF	72%	68%	53%	108%	82%	84%	66%	65%	62%	All Div'ds to Net Prof	62%

CAPITAL STRUCTURE as of 9/30/21
Total Debt $23733 mill. **Due in 5 Yrs** $5771 mill.
LT Debt $22503 mill. **LT Interest** $1000 mill.
Incl. $45 mill. finance leases.
(LT interest earned: 2.0x)
Leases, Uncapitalized Annual rentals $50 mill.

Pension Assets-12/20 $8968 mill.
Oblig $11935 mill.

Pfd Stock None

Common Stock 544,419,619 shs.

MARKET CAP: $23 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2018	2019	2020
% Change Retail Sales (KWH)	+4.2	-2.7	-4.0
Avg. Indust. Use (MWH)	NMF	NMF	NMF
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.4	+.3	+.6
Fixed Charge Cov. (%)	199	249	203

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	-7.0%	-10.0%	2.0%
"Cash Flow"	-7.5%	-7.0%	6.0%
Earnings	-7.5%	-3.0%	10.0%
Dividends	-3.0%	1.5%	3.0%
Book Value	-7.0%	-15.0%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2883	2516	2963	2673	11035
2020	2709	2522	3022	2537	10790
2021	2726	2622	3124	2628	11100
2022	2800	2700	3200	2700	11400
2023	2950	2850	3350	2850	12000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.66	.63	.75	d.20	1.84
2020	.05	.57	.85	.38	1.85
2021	.62	.53	.76	.49	2.40
2022	.60	.52	.76	.52	2.40
2023	.66	.57	.85	.57	2.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.36	.36	.36	.36	1.44
2019	.38	.38	.38	.38	1.52
2020	.39	.39	.39	.39	1.56
2021	.39	.39	.39	.39	1.56
2022					

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, Jersey Central Power & Light, West Penn Power, Potomac Edison, & Mon Power. Provides electric service to 6.2 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown: residential, 61%; commercial, 25%; industrial, 13%; other, 1%. Purchases most of its power. Fuel costs: 28% of revenues. '20 reported depreciation rate: 2.7%. Has 12,200 employees. Chairman: Donald T. Misheff. CEO and President: Steven E. Strah. Incorporated: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Telephone: 800-736-3402. Internet: www.firstenergycorp.com.

FirstEnergy has announced a major financing plan. The company has agreed to sell a 19.9% stake in its electric transmission subsidiary and sold $1 billion of common stock (25.6 million shares) to an investor. The transmission sale requires regulatory approval and is expected to be completed in the first half of 2022.

The company is awaiting a ruling from the Ohio commission on a regulatory settlement. If the regulators approve the agreement, FirstEnergy's utilities in Ohio will provide $96 million in revenue refunds in 2022, and $210 million in rate credits from 2022 through 2025. We will *include* these in our earnings presentation. We assume in our estimates and projections that the commission approves the settlement. An order is expected this year.

We estimate that share earnings will be flat this year. FirstEnergy will benefit from rate relief, including capital spending that is recoverable through riders (surcharges) on customers' bills. Modest growth in kilowatt-hour sales should help, as well. However, the revenue refunds will amount to $0.13 a share. In addition, average shares outstanding will be significantly higher due to the aforementioned stock sale in 2021. (Keep in mind that this occurred late in the year, so there wasn't much effect on average shares outstanding for 2021.) Our estimate is at the midpoint of management's targeted range of $2.30-$2.50 a share.

We expect earnings improvement in 2023. The absence of any revenue refund, and a decline in rate credits, will help the year-to-year comparison. FirstEnergy's goal for average annual earnings growth is 6%-8%.

When will the board of directors raise the dividend? FirstEnergy has stated that the annual disbursement will be kept at $1.56 a share in 2022. With earnings growth in the offing for 2023, however, we look for a $0.08 a share (5.1%) hike annually. The company's target for the payout ratio is 55%-65%.

The dividend yield of this timely stock is somewhat above the utility average. Total return potential is negative for the next 18 months, but respectable for the 3- to 5-year period.

Paul E. Debbas, CFA *February 11, 2022*

(A) Dil. EPS. Excl. nonrec. losses: '13, $2.07; '14, 17¢; '15, 63¢; '16, $16.59; '17, $6.61; '21, 42¢; gains (loss) from disc. ops.: '14, 20¢; '18, 66¢; '19, (17¢); '20, 14¢; '21, 9¢. '18, '20 EPS don't sum due to chg. in shs. Next egs. report due late Feb. (B) Div'ds pd. early Mar., June, Sept., & Dec. 3 div'ds in '13, 5 in '18. ■ Div'd reinv. avail. (C) Incl. intang. In '20: $10.49/sh. (D) In mill. (E) Rate base: Depr. orig. cost. Rates all'd on com. eq.: 9.6%-11.7%; earned on avg. com. eq., '20: 14.2%. Reg. Clim.: OH, Above Avg.; PA, NJ Avg.; MD, WV Below Avg.

Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	25
Earnings Predictability	50

FORTIS INC. TSE-FTS.TO A

RECENT PRICE 58.08 | P/E RATIO 21.3 (Trailing: 22.3 Median: 20.0) | RELATIVE P/E RATIO 1.19 | DIV'D YLD 3.8% | **VALUE LINE**

TIMELINESS 4 Lowered 8/13/21
SAFETY 2 Raised 7/17/15
TECHNICAL 2 Raised 2/25/22
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$53-$74	$64 (10%)

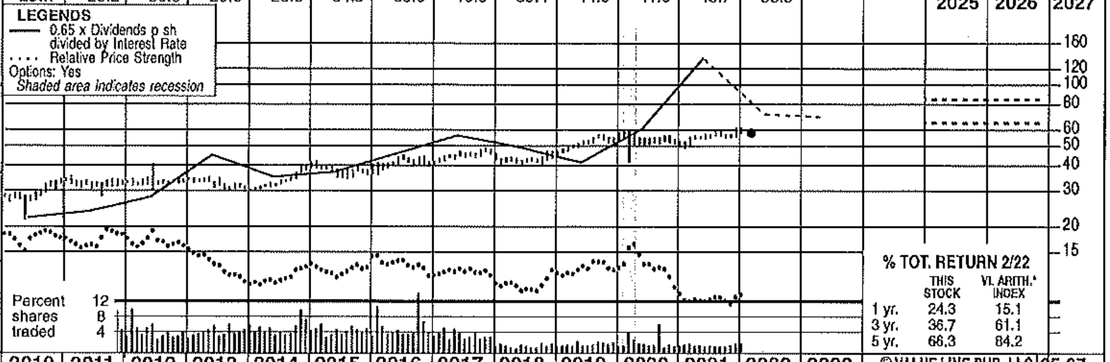
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+45%)	13%
Low	65	(+10%)	7%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	133	100	126
to Sell	113	112	105
Hld's(000)	221982	226561	232396

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	35.4	40.7	35.1	40.5	42.1	45.1	46.7	47.4	56.9	59.3	61.6
Low:	28.2	30.5	29.6	29.8	34.5	36.0	40.6	39.4	44.0	41.6	48.7



% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	24.3	15.1
3 yr.	36.7	61.1
5 yr.	66.3	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
14.14	17.48	23.07	21.24	21.01	19.84	19.07	18.99	19.57	23.89	17.03	19.71	19.58	18.96	19.14	19.90	20.00	20.25	Revenues per sh	21.50
3.05	2.96	3.51	3.66	3.99	3.90	4.10	4.10	3.62	5.21	3.91	5.43	5.40	5.44	5.65	5.76	6.15	6.40	"Cash Flow" per sh	7.50
1.36	1.29	1.52	1.51	1.62	1.74	1.65	1.63	1.38	2.11	1.89	2.66	2.52	2.68	2.60	2.61	2.80	2.90	Earnings per sh B	3.50
.67	.82	1.00	1.04	1.12	1.17	1.21	1.25	1.30	1.43	1.55	1.65	1.75	1.86	1.97	2.08	2.21	2.35	Div'd Decl'd per sh C ■	2.80
4.80	5.16	5.34	5.79	5.89	5.91	5.68	5.32	6.00	7.97	5.13	7.18	7.51	8.03	8.65	7.13	8.25	7.85	Cap'l Spending per sh	7.75
12.26	16.72	18.00	16.57	16.95	20.53	20.84	22.39	24.90	28.63	32.32	31.77	34.60	36.49	36.58	37.21	38.85	40.55	Book Value per sh D	46.00
104.09	155.52	169.19	171.26	174.39	188.83	191.57	213.17	276.00	281.56	401.49	421.10	428.50	463.30	466.80	474.80	482.00	489.00	Common Shs Outst'g E	510.00
17.7	21.1	17.5	16.4	18.2	18.8	20.1	20.0	24.3	18.0	21.6	16.8	17.1	19.2	20.6	21.2	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	21.5
.96	1.12	1.05	1.09	1.16	1.18	1.28	1.12	1.28	.91	1.13	.84	.92	1.02	1.06	1.13			Relative P/E Ratio	1.20
2.8%	3.0%	3.8%	4.2%	3.8%	3.6%	3.6%	3.8%	3.9%	3.8%	3.8%	3.7%	4.1%	3.6%	3.7%	3.8%			Avg Ann'l Div'd Yield	3.7%
						3654.0	4047.0	5401.0	6727.0	6838.0	8301.0	8390.0	8783.0	8935.0	9448.0	9650	9900	Revenues ($mill)	11000
						362.0	390.0	374.0	672.0	660.0	1174.0	1136.0	1238.0	1274.0	1294.0	1410	1475	Net Profit ($mill)	1825
						14.1%	7.4%	14.6%	21.3%	16.9%	25.8%	13.4%	12.5%	14.3%	14.3%	14.5%	14.5%	Income Tax Rate	14.5%
						5.0%	5.9%	7.2%	7.4%	10.0%	9.5%	8.4%	9.2%	9.3%	9.0%	8.0%	8.0%	AFUDC % to Net Profit	7.0%
						55.1%	53.5%	54.8%	53.3%	59.3%	58.4%	58.8%	54.2%	55.6%	55.5%	54.5%	53.5%	Long-Term Debt Ratio	51.5%
						35.1%	37.0%	35.7%	38.1%	36.2%	37.1%	37.2%	41.8%	40.5%	40.8%	41.5%	43.0%	Common Equity Ratio	45.0%
						11358	12892	19235	21151	35874	36108	40082	40445	42141	43328	44950	46325	Total Capital ($mill)	51900
						10249	12267	17816	19595	29337	29668	32654	33988	35998	37816	40175	42300	Net Plant ($mill)	48400
						4.8%	4.6%	3.4%	4.5%	2.8%	4.5%	4.1%	4.4%	4.3%	4.2%	4.5%	4.5%	Return on Total Cap'l	5.0%
						7.1%	6.5%	4.3%	6.8%	4.5%	7.8%	6.9%	6.7%	6.8%	6.7%	7.0%	7.0%	Return on Shr. Equity	7.5%
						7.9%	7.0%	4.5%	7.4%	4.5%	8.3%	7.2%	6.9%	7.1%	7.0%	7.0%	7.0%	Return on Com Equity F	7.5%
						3.7%	3.2%	1.7%	4.5%	2.1%	5.2%	4.1%	4.0%	2.5%	3.5%	4.0%	3.5%	Retained to Com Eq	4.0%
						60%	61%	68%	46%	59%	41%	46%	45%	67%	52%	46%	47%	All Div'ds to Net Prof G	47%

CAPITAL STRUCTURE as of 12/31/21
Total Debt $25915 mill. **Due in 5 Yrs** $7596 mill.
LT Debt $24040 mill. **LT Interest** $1000 mill.
Incl. $333 mill. finance leases.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $8 mill.

Pension Assets-12/21 $3722 mill. Oblig $3922 mill.
Pfd Stock $1623 mill. **Pfd Div'd** $65 mill.

Common Stock 474,800,000 shs.

MARKET CAP: $28 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	204	207	211

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	-1.0%	2.0%
"Cash Flow"	4.0%	6.0%	5.0%
Earnings	5.0%	8.0%	5.0%
Dividends	6.0%	6.5%	6.0%
Book Value	6.5%	5.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2436	1970	2051	2326	8783.0
2020	2391	2077	2121	2346	8935.0
2021	2539	2130	2196	2583	9448.0
2022	2600	2200	2250	2600	9650
2023	2700	2250	2300	2650	9900

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.72	.54	.63	.77	2.68
2020	.67	.59	.63	.71	2.60
2021	.76	.54	.62	.69	2.61
2022	.77	.59	.68	.76	2.80
2023	.80	.62	.70	.78	2.90

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.425	.425	.425	.45	1.73
2019	.45	.45	.45	.4775	1.83
2020	.4775	.4775	.4775	.505	1.94
2021	.505	.505	.505	.535	2.05
2022	.535				

BUSINESS: Fortis Inc.'s main focus is electricity, hydroelectric, and gas utility operations (both regulated and nonregulated) in the United States, Canada, and the Caribbean. Has 2 mill. electric, 1.3 mill. gas customers. Owns UNS Energy (Arizona), Central Hudson (New York), FortisBC Energy (British Columbia), FortisAlberta (Central Alberta), and Eastern Canada (Newfoundland). Sold commercial real estate and hotel property assets in 2015. Acquired ITC Holdings 10/16. Fuel costs: 31% of revs. '21 reported deprec. rate: 2.6%. Has 9,100 employees. Chairman: Douglas J. Haughey. President & CEO: David G. Hutchens. Inc.: Canada. Address: Fortis Place, Suite 1100, 5 Springdale St., PO Box 8837, St. John's, NL, Canada, A1B 3T2. Tel.: 709-737-2800. Internet: www.fortisinc.com.

We expect Fortis' earnings to advance in 2022 and 2023. The company's ITC transmission subsidiary benefits from a forward-looking regulatory plan that boosts its income as the rate base grows and enables the utility to recover increases in most kinds of expenses. Central Hudson Gas & Electric, based in New York State, will receive the second and third phases of a three-year rate plan in mid-2022 (a total of $25.8 million for electricity and gas) and mid-2023 ($27.1 million). Fortis' Caribbean utilities are experiencing higher volume as tourism rebounds there, and the company's Tucson Electric Power subsidiary should see increased kilowatt-hour sales if it has a normal summer, compared with a milder-than-normal summer in 2021. Finally, the company is planning lower generation maintenance costs this year. We are not assuming any rate relief at Tucson Electric Power, but the utility is evaluating the timing of its next rate application. One small negative factor for share profits is an increase in average shares outstanding each year as common stock is issued to satisfy the dividend reinvestment plan. However . . . **There are some sources of uncertainty.** The exchange rate between the US and Canadian dollars can cause fluctuations in Fortis' earnings. (This resulted in a negative $0.10-a-share swing in 2021.) The Federal Energy Regulatory Commission is considering removing a half percentage point incentive "adder" on ITC's allowed return on equity. This would lower Fortis' earning power by approximately $0.05 a share annually. The regulatory commissions in British Columbia and Alberta are reviewing utilities' cost of capital. The outcome of these reviews won't necessarily be negative for Fortis.

The company's earned return on equity is below that of most utilities in the U.S. This is because allowed ROEs in Canada are lower. Also, Canadian utilities have lower common-equity ratios.

This untimely stock offers a dividend yield that is slightly above the utility average. Investors interested in dividend reinvestment should note that Fortis offers a 2% discount on reinvested shares. The equity does not stand out for the next 18 months or for the 3- to 5-year period.

Paul E. Debbas, CFA *March 11, 2022*

(A) Also trades on NYSE (symbol FTS). All data in Canadian $. (B) Dil. egs. Excl. nonrecur. gains (loss): '07, 3¢; '14, 2¢; '15, 48¢; '17, (35¢); '18, 7¢. '19, $1.12. '19 EPS don't sum due to chng. in shs. Next egs. report due late Apr. (C) Div'ds histor. pd. early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. (2% disc.). (D) Incl. intang. In '21: $34.04/sh. (E) In mill. (F) Rates all'd on com. eq.: 8.3%-10.32%; earn. on avg. com. eq., '21: 7.1%. Reg. Clim.: FERC, Above Avg.; AZ, Below Avg.; NY, Below Avg. (G) Excl. div'ds pd. via reinv. plan.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	85

HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE 43.46 **P/E RATIO** 20.7 (Trailing: 19.3 Median: 18.0) **RELATIVE P/E RATIO** 1.16 **DIV'D YLD** 3.2% **VALUE LINE**

TIMELINESS	3 Raised 3/18/22
SAFETY	2 Raised 11/2/12
TECHNICAL	3 Raised 1/7/22

BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$30-$49	$40 (-10%)

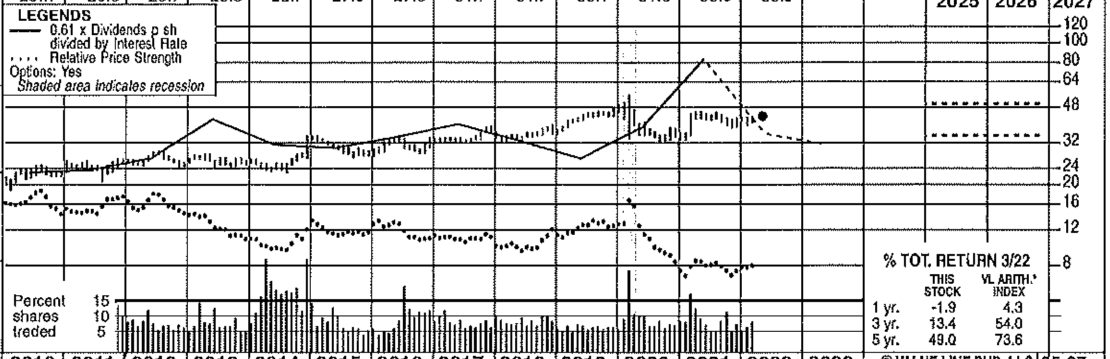
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+15%)	7%
Low	35	(-20%)	-1%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	122	125	156
to Sell	143	117	120
Hld's(000)	57704	57595	56043

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	26.8	29.2	28.3	35.0	34.9	35.0	38.7	39.3	47.6	55.2	46.0	43.9	
Low:	20.6	23.7	23.8	22.7	27.0	27.3	31.7	31.7	35.1	31.8	33.0	38.9	



% TOT. RETURN 3/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.9	4.3
3 yr.	13.4	54.0
5 yr.	49.0	73.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
30.21	30.40	35.56	24.96	28.14	33.76	34.46	31.98	31.59	24.22	21.92	23.49	26.28	26.38	23.63	26.08	29.20	29.10	Revenues per sh	31.00
3.19	3.01	2.72	2.59	2.88	3.18	3.28	3.22	3.41	3.31	4.17	3.68	4.20	4.55	4.48	4.80	4.75	4.85	"Cash Flow" per sh	5.50
1.33	1.11	1.07	.91	1.21	1.44	1.67	1.62	1.64	1.50	2.29	1.64	1.85	1.99	1.81	2.25	2.10	2.10	Earnings per sh A	2.50
1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.28	1.32	1.36	1.40	1.44	Div'd Decl'd per sh B ■	1.60
2.58	2.62	3.12	3.29	1.92	2.45	3.32	3.49	3.31	3.39	3.04	4.55	4.94	4.20	3.52	2.88	3.65	4.10	Cap'l Spending per sh	4.00
13.44	15.29	15.35	15.58	15.67	15.95	16.28	17.06	17.47	17.94	19.03	19.28	19.86	20.93	21.41	21.87	22.55	23.30	Book Value per sh C	26.25
81.46	83.43	90.52	92.52	94.69	96.04	97.93	101.26	102.57	107.46	108.58	108.79	108.88	108.97	109.18	109.31	109.50	110.00	Common Shs Outst'g D	113.00
20.3	21.6	23.2	19.8	18.6	17.1	15.8	16.2	15.9	20.4	13.6	20.7	18.9	21.3	21.5	18.2	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	17.5
1.10	1.15	1.40	1.32	1.18	1.07	1.01	.91	.84	1.03	.71	1.04	1.02	1.13	1.10	1.00			Relative P/E Ratio	.95
4.6%	5.2%	5.0%	6.9%	5.5%	5.0%	4.7%	4.7%	4.8%	4.1%	4.0%	3.7%	3.5%	3.0%	3.4%	3.3%			Avg Ann'l Div'd Yield	3.7%
						3375.0	3238.5	3239.5	2603.0	2380.7	2555.6	2860.8	2874.6	2579.8	2850.4	3200	3200	Revenues ($mill)	3500
						104.9	163.4	170.2	161.8	250.1	180.6	203.7	219.8	199.7	248.1	230	235	Net Profit ($mill)	280
						35.9%	34.0%	35.0%	36.5%	33.1%	34.7%	20.0%	19.0%	17.0%	20.2%	19.0%	19.0%	Income Tax Rate	19.0%
						6.9%	4.8%	5.5%	5.8%	4.6%	9.6%	7.7%	7.5%	5.9%	5.2%	6.0%	7.0%	AFUDC % to Net Profit	6.0%
						45.7%	44.0%	45.2%	43.5%	41.6%	43.4%	47.5%	44.6%	46.5%	46.4%	44.5%	46.0%	Long-Term Debt Ratio	46.0%
						53.1%	55.0%	53.8%	55.5%	57.5%	55.7%	51.7%	54.6%	52.7%	52.8%	55.0%	53.5%	Common Equity Ratio	53.5%
						3001.0	3142.9	3332.3	3473.5	3595.1	3765.5	4182.3	4176.9	4435.9	4524.1	4505	4790	Total Capital ($mill)	5525
						3594.8	3858.9	4148.8	4377.7	4603.5	5025.9	4830.1	5109.6	5265.7	5392.1	5500	5650	Net Plant ($mill)	5925
						6.7%	6.4%	6.2%	5.7%	7.9%	5.8%	5.9%	6.3%	5.5%	6.4%	6.0%	6.0%	Return on Total Cap'l	6.0%
						10.1%	9.3%	9.3%	8.2%	11.9%	8.5%	9.3%	9.5%	8.4%	10.2%	9.0%	9.0%	Return on Shr. Equity	9.5%
						10.2%	9.4%	9.4%	8.3%	12.0%	8.5%	9.3%	9.6%	8.5%	10.3%	9.5%	9.0%	Return on Com Equity E	9.5%
						4.2%	3.7%	2.3%	1.5%	6.3%	2.1%	3.1%	3.4%	2.3%	4.1%	3.0%	3.0%	Retained to Com Eq	3.5%
						59%	61%	75%	83%	48%	76%	67%	64%	73%	61%	67%	69%	All Div'ds to Net Prof F	65%

CAPITAL STRUCTURE as of 12/31/21
Total Debt $2375.9 mill. **Due in 5 Yrs** $681.0 mill.
LT Debt $2098.9 mill. **LT Interest** $92.0 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 4.5x)
Leases, Uncapitalized Annual rentals $11.0 mill.
Pension Assets-12/21 $2320.8 mill.
Oblig $2644.6 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par, call. $20 to $21; 120,000 shs. 7⅝%, $100 par, call. $100. Sinking fund ended 2018.
Common Stock 109,311,785 shs. as of 2/11/22
MARKET CAP: $4.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+.6	-7.1	+1.7
Avg. Indust. Use (MWH)	5225	4474	4561
Avg. Indust. Revs. per KWH (¢)	25.52	24.21	26.88
Capacity at Yearend (Mw)	2254	2254	2278
Peak Load, Winter (Mw)	1601	1471	1471
Annual Load Factor (%)	65.2	66.2	67.2
% Change Customers (yr-end)	+.5	+.6	+.5
Fixed Charge Cov. (%)	368	337	393

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.5%	-.5%	3.5%
"Cash Flow"	5.0%	5.0%	3.0%
Earnings	5.5%	2.0%	3.5%
Dividends	.5%	1.5%	3.5%
Book Value	3.0%	3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	661.6	715.5	771.5	726.0	2874.6
2020	677.2	609.0	641.4	652.2	2579.8
2021	642.9	680.3	756.9	770.3	2850.4
2022	750	800	850	800	3200
2023	800	800	825	775	3200

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.42	.39	.58	.61	1.99
2020	.31	.45	.59	.46	1.81
2021	.59	.58	.58	.50	2.25
2022	.50	.50	.60	.50	2.10
2023	.50	.50	.60	.50	2.10

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.31	.31	.31	.31	1.24
2019	.32	.32	.32	.32	1.28
2020	.33	.33	.33	.33	1.32
2021	.34	.34	.34	.34	1.36
2022	.35				

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company, Inc. (HECO), American Savings Bank (ASB), and Pacific Current. HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 471,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Elec. rev. breakdown: residential, 34%; commercial, 34%; large light & power, 32%; other, less than 1%. Generating sources: oil, 52%; purch., 48%. Fuel costs: 46% of revs. '21 reported deprec. rate (utility): 3.2%. Has 3,600 employees. Chairman: Tom Fargo. Pres. & CEO: Scott Seu. Inc.: HI. Address: 1001 Bishop St., Suite 2900, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Internet: www.hei.com.

Investors should not be alarmed by the moderate earnings decline that is likely for Hawaiian Electric Industries in 2022. The company's utilities are benefiting from the state's performance-based ratemaking plan, which provides revenues annually to compensate for inflation and recover expenses and certain kinds of capital spending. There is the potential for additional income from performance incentive mechanisms. All told, profits from HEI's three utilities are likely to advance. By contrast, the American Savings Bank subsidiary will almost certainly see a decline in its income, even though the bank would benefit from rising interest rates. That's because ASB expects to book provisions for credit losses of as much as $10 million this year. In 2021, this figure was a *credit* of $25.8 million as reserves taken in 2020 (during the recession) were reversed. However, because the charge for loan losses will probably be less than we expected in our January report, we raised our 2022 share-earnings estimate by $0.10, to $2.10. Our revised estimate is at the midpoint of HEI's targeted range of $2.00-$2.20.

Much of the company's capital spending is for renewable energy. Customers' rates are volatile due to fluctuations in the price of oil. System reliability is another area of focus. Several projects for the next three years have been approved by the state commission or are awaiting the regulators' approval.

We look for flat earnings in 2023. We expect continued growth from the utility operations. However, we also think the provision for loan losses at ASB will return to a normal level ($17 million-$22 million), offsetting the growth from the utilities.

The board of directors raised the dividend in the first quarter. The increase was one cent a share (2.9%) quarterly, the same as in recent years. We project modest dividend growth to continue through mid-decade.

The dividend yield of this stock is about average for a utility. The recent quotation is well within our 2025-2027 Target Price Range. Total return potential is negative for the 18-month span and low for the 3- to 5-year period.

Paul E. Debbas, CFA *April 22, 2022*

(A) Diluted EPS. Excl. nonrec. losses: '07, 9¢; '12, 25¢; '17, 12¢. '19 EPS don't sum due to rounding. Next earnings report due early May.
(B) Div'ds paid early Mar., June, Sept., & Dec.
■ Div'd reinvestment plan avail. (C) Incl. intang. In '21: $5.32/sh. (D) In mill., adj. for split.
(E) Rate base: Orig. cost. Rate allowed on com. eq. in '18: HECO, 9.5%; in '18: HELCO, 9.5%; in '18: MECO, 9.5%; earned on avg. com. eq., '21: 10.4%. Regulat. Climate: Below Avg. (F) Excl. div'ds paid through reinv. plan.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	45
Earnings Predictability	75

IDACORP, INC. NYSE-IDA

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
116.19	23.5 (Trailing: 24.0 / Median: 19.0)	1.32	2.7%

VALUE LINE

TIMELINESS 4 Lowered 8/13/21
SAFETY 1 Raised 1/22/21
TECHNICAL 3 Lowered 3/25/22
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$88-$131	$110 (-5%)

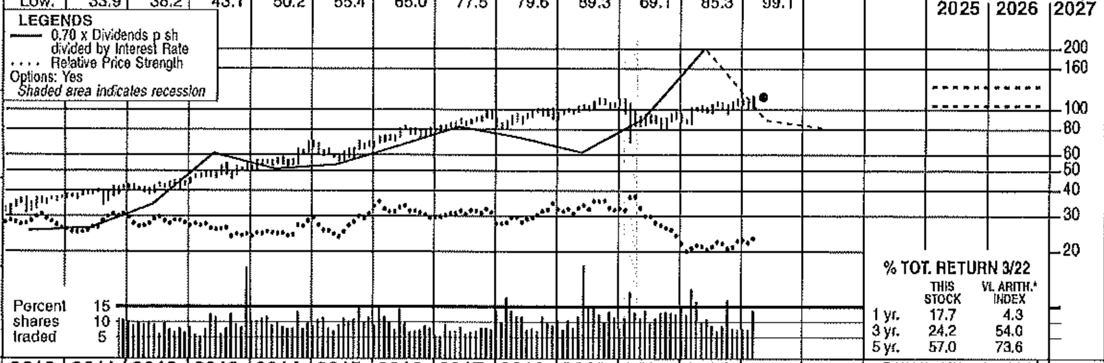
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+10%)	6%
Low	105	(-10%)	1%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	145	163	208
to Sell	186	145	137
Hld's(000)	39928	39867	39410

High:	42.7	45.7	54.7	70.1	70.5	83.4	100.0	102.4	114.0	113.6	113.8	118.9
Low:	33.9	38.2	43.1	50.2	55.4	65.0	77.5	79.6	89.3	69.1	85.3	99.1



% TOT. RETURN 3/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.7	4.3
3 yr.	24.2	54.0
5 yr.	57.0	73.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	27.19	26.70	26.77	28.86	*29.70*	*30.70*	Revenues per sh	*34.50*
4.58	4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	7.85	8.07	8.19	8.41	*8.75*	*9.10*	"Cash Flow" per sh	*10.25*
2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	4.49	4.61	4.69	4.85	*5.05*	*5.25*	Earnings per sh A	*6.00*
1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	2.40	2.56	2.72	2.88	*3.05*	*3.25*	Div'd Decl'd per sh B ■ †	*4.00*
5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	5.51	5.53	6.16	5.94	*10.60*	*14.95*	Cap'l Spending per sh	*10.00*
25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	44.65	47.01	48.88	50.73	52.82	*54.85*	*56.85*	Book Value per sh C	*64.00*
43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	50.42	50.42	50.46	50.52	*50.50*	*50.50*	Common Shs Outst'g D	*52.00*
15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	20.5	22.3	19.9	20.8	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	1.11	1.19	1.02	1.14	*Value Line*		Relative P/E Ratio	*1.10*
3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%	2.6%	2.5%	2.9%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*
						1080.7	1246.2	1282.5	1270.3	1262.0	1349.5	1370.8	1346.4	1350.7	1458.1	*1500*	*1550*	Revenues ($mill)	*1800*
						168.9	182.4	193.5	194.7	198.3	212.4	226.8	232.9	237.4	245.6	*255*	*265*	Net Profit ($mill)	*310*
						13.4%	28.3%	8.0%	19.0%	15.5%	18.6%	7.1%	9.5%	10.8%	13.1%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
						20.3%	12.3%	13.6%	16.3%	16.3%	13.9%	15.2%	16.2%	17.3%	17.7%	*20.0%*	*21.0%*	AFUDC % to Net Profit	*16.0%*
						45.5%	46.6%	45.3%	45.6%	44.8%	43.7%	43.6%	41.3%	43.9%	42.8%	*44.5%*	*48.5%*	Long-Term Debt Ratio	*51.0%*
						54.5%	53.4%	54.7%	54.4%	55.2%	56.3%	56.4%	58.7%	56.1%	57.2%	*55.5%*	*51.5%*	Common Equity Ratio	*49.0%*
						3225.4	3465.9	3567.6	3783.3	3898.5	3997.5	4205.1	4201.3	4560.4	4669.1	*4995*	*5570*	Total Capital ($mill)	*6800*
						3536.0	3665.0	3833.5	3992.4	4172.0	4283.9	4395.7	4531.5	4709.5	4901.8	*5250*	*5810*	Net Plant ($mill)	*6700*
						6.5%	6.4%	6.6%	6.2%	6.1%	6.3%	6.4%	6.5%	6.1%	6.2%	*6.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
						9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
						9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
						5.7%	5.6%	5.4%	4.8%	4.3%	4.4%	4.4%	4.2%	3.9%	3.7%	*3.5%*	*3.5%*	Retained to Com Eq	*3.0%*
						41%	43%	46%	50%	53%	53%	54%	56%	58%	60%	*60%*	*62%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $2000.6 mill. Due in 5 Yrs $260.1 mill.
LT Debt $2000.6 mill. LT Interest $83.4 mill.
(LT interest earned: 3.8x)

Pension Assets-12/21 $984.5 mill.
Oblig $1346.5 mill.

Pfd Stock None

Common Stock 50,523,810 shs.
as of 2/11/22

MARKET CAP: $5.9 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.3	+2.0	+3.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.32	5.38	5.62
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3242	3392	3751
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.5	+2.7	+2.8
Fixed Charge Cov. (%)	307	313	334

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	2.5%	1.5%	*4.0%*
"Cash Flow"	4.5%	4.0%	*3.5%*
Earnings	4.5%	4.0%	*4.0%*
Dividends	8.5%	7.0%	*6.5%*
Book Value	5.0%	4.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	350.3	316.9	386.3	292.9	1346.4
2020	291.0	318.8	425.3	315.6	1350.7
2021	316.1	360.1	446.9	335.0	1458.1
2022	*330*	*355*	*465*	*350*	*1500*
2023	*345*	*360*	*480*	*365*	*1550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.84	1.05	1.78	.93	4.61
2020	.74	1.19	2.02	.74	4.69
2021	.89	1.38	1.93	.65	4.85
2022	*.95*	*1.25*	*2.10*	*.75*	*5.05*
2023	*1.00*	*1.30*	*2.20*	*.75*	*5.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.59	.59	.59	.63	2.40
2019	.63	.63	.63	.67	2.56
2020	.67	.67	.67	.71	2.72
2021	.71	.71	.71	.75	2.88
2022	.75				

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 604,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.3 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 45%; commercial, 24%; industrial, 15%; irrigation, 13%; other, 3%. Generating sources: hydro, 30%; coal, 17%; gas, 15%; purchased, 38%. Fuel costs: 36% of revenues. '21 reported depreciation rate: 2.9%. Has 2,000 employees. Chairman: Richard J. Dahl. President & CEO: Lisa Grow. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

We expect IDACORP to continue its solid performance in 2022. The company has been producing steady earnings growth for the past several years. IDACORP's utility subsidiary, Idaho Power, is benefiting from its service area's healthy economy and population growth. Customer growth has been accelerating, and was 2.8% in 2021. Besides growth in the region's traditional industries, such as food processing and mining (a cobalt mine is scheduled to begin operating in mid-2022), new industrial customers such as data centers are entering the service area. The company has controlled operating and maintenance expenses effectively, even with inflationary pressures. All told, we estimate earnings of $5.05 a share this year, which is at the upper end of IDACORP's targeted range of $4.85-$5.05 a share. Management's guidance is typically conservative, and is usually raised as the year progresses. The same positive factors should produce additional profit growth in 2023. Our estimate is $5.25 a share.

The capital budget has increased significantly. Two things are driving this rise. Idaho Power plans to boost its ownership in a $1.0 billion-$1.2 billion transmission line from 21% to 45%. The utility plans to spend $400 million for 120 megawatts of battery storage, which is expected to be in service by June of 2023. This will require financing. Initially, the company will use debt, but by 2024, IDACORP will probably issue equity.

Rate cases might well be upcoming. Idaho Power's rapid customer growth has enabled the utility to go for more than 10 years without filing a rate application. However, the company's capital spending since then will need to be placed in rates, especially in view of the increased capital budget. The utility will probably file both in Idaho and Oregon. Any rate relief won't come until 2023.

The untimely stock's dividend yield is below the utility average. The market has recognized IDACORP's consistency. (Note the Earnings Predictability score.) Total return potential does not stand out for the next 18 months or the 3- to 5-year period. The recent quotation is within our 2025-2027 Target Price Range.

Paul E. Debbas, CFA *April 22, 2022*

(A) Diluted EPS. Excl. nonrecurring gain: '06, 17¢. '19 earnings don't sum due to rounding. Next earnings report due late April. (B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '21: $1,462.4 mill., $28.95/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on common equity in '12: 10% (imputed); earned on avg. com. eq., '21: 9.4%. Regulatory Climate: Above Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	100

MGE ENERGY INC. NDQ-MGEE

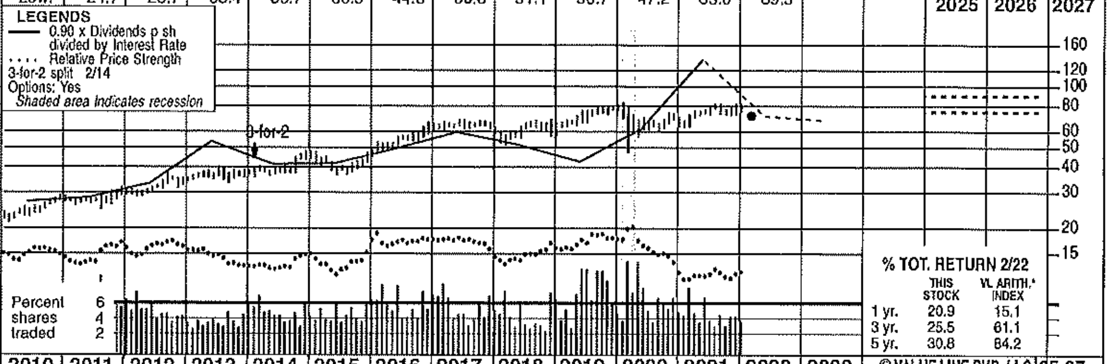
RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
72.02	25.2 (Trailing: 24.6 Median: 24.0)	1.41	2.2%

VALUE LINE

TIMELINESS	4	Lowered 3/11/22
SAFETY	1	New 1/3/03
TECHNICAL	2	Lowered 3/4/22

BETA .75 (1.00 = Market)

High:	31.9	37.4	40.5	48.0	48.0	66.9	68.7	66.9	80.8	83.3	82.9	82.5
Low:	24.7	28.7	33.4	35.7	36.5	44.8	60.3	51.1	56.7	47.2	83.0	69.5



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$64-$95	$80 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+25%)	8%
Low	75	(+5%)	4%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	58	69	87
to Sell	85	62	57
Hld's(000)	18080	18137	18213

% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.9	15.1
3 yr.	25.5	61.1
5 yr.	30.8	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
16.13	16.33	17.35	15.40	15.36	15.76	15.61	17.04	17.88	16.27	15.71	16.24	16.15	16.41	14.89	16.77	*17.30*	*17.85*	Revenues per sh	*20.00*
2.34	2.46	2.68	2.66	2.76	2.94	2.98	3.28	3.49	3.33	3.47	3.73	4.06	4.57	4.61	5.05	*5.25*	*5.45*	"Cash Flow" per sh	*6.00*
1.37	1.51	1.59	1.47	1.67	1.76	1.86	2.16	2.32	2.06	2.18	2.20	2.43	2.51	2.60	2.92	*3.00*	*3.15*	Earnings per sh A	*3.50*
.93	.94	.96	.97	.99	1.01	1.04	1.07	1.11	1.16	1.21	1.26	1.32	1.38	1.45	1.52	*1.59*	*1.66*	Div'd Decl'd per sh B ■ †	*1.90*
2.94	4.14	3.08	2.35	1.76	1.88	2.84	3.43	2.67	2.08	2.41	3.12	6.12	4.73	5.62	4.24	*5.65*	*6.60*	Cap'l Spending per sh	*5.50*
11.93	12.99	13.92	14.47	15.14	15.89	16.71	17.81	19.02	19.92	20.89	22.45	23.56	24.68	26.99	28.41	*29.85*	*31.35*	Book Value per sh C	*36.25*
31.46	32.93	34.36	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	36.16	36.16	*36.16*	*36.16*	Common Shs Outst'g D	*36.16*
15.9	15.0	14.2	15.1	15.0	15.8	17.2	17.0	17.2	20.3	24.9	29.4	25.1	28.4	26.4	25.5	*Bold figures are*		Avg Ann'l P/E Ratio	*23.5*
.86	.80	.85	1.01	.95	.99	1.09	.96	.91	1.02	1.31	1.48	1.36	1.51	1.36	1.36	*Value Line*		Relative P/E Ratio	*1.45*
4.3%	4.1%	4.2%	4.4%	4.0%	3.6%	3.2%	2.9%	2.8%	2.8%	2.2%	2.0%	2.2%	1.9%	2.1%	2.0%	*estimates*		Avg Ann'l Div'd Yield	*2.3%*
						541.3	590.9	619.9	564.0	544.7	563.1	559.8	568.9	538.6	606.6	*625*	*645*	Revenues ($mill)	*725*
						64.4	74.9	80.3	71.3	75.6	76.1	84.2	86.9	92.4	105.8	*110*	*115*	Net Profit ($mill)	*130*
						37.7%	37.5%	37.5%	36.7%	36.0%	36.4%	24.6%	18.5%	17.4%	3.7%	*16.0%*	*16.0%*	Income Tax Rate	*16.0%*
						--	5.6%	5.7%	1.3%	2.1%	2.1%	5.2%	3.6%	8.7%	6.3%	*7.0%*	*9.0%*	AFUDC % to Net Profit	*6.0%*
						38.2%	39.3%	37.5%	36.2%	34.6%	33.8%	37.7%	38.0%	35.5%	38.1%	*39.5%*	*41.0%*	Long-Term Debt Ratio	*43.5%*
						61.8%	60.7%	62.5%	63.8%	65.4%	66.2%	62.3%	62.0%	64.5%	61.9%	*60.5%*	*59.0%*	Common Equity Ratio	*56.5%*
						937.9	1016.9	1054.7	1081.5	1106.9	1176.3	1310.0	1379.4	1512.8	1659.0	*1785*	*1915*	Total Capital ($mill)	*2325*
						1073.5	1160.2	1208.1	1243.4	1282.1	1341.4	1509.4	1642.7	1769.4	1878.8	*2005*	*2160*	Net Plant ($mill)	*2500*
						7.9%	8.3%	8.6%	7.5%	7.7%	7.3%	7.2%	7.1%	6.8%	7.1%	*7.0%*	*7.0%*	Return on Total Cap'l	*6.5%*
						11.1%	12.1%	12.2%	10.3%	10.4%	9.8%	10.3%	10.2%	9.5%	10.3%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
						11.1%	12.1%	12.2%	10.3%	10.4%	9.8%	10.3%	10.2%	9.5%	10.3%	*10.0%*	*10.0%*	Return on Com Equity D	*10.0%*
						4.9%	6.1%	6.4%	4.5%	4.7%	4.2%	4.7%	4.6%	4.2%	5.0%	*5.0%*	*5.0%*	Retained to Com Eq	*4.5%*
						56%	50%	48%	56%	55%	57%	54%	55%	56%	52%	*52%*	*53%*	All Div'ds to Net Prof	*53%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $641.9 mill. Due in 5 Yrs $95.6 mill.
LT Debt $631.5 mill. LT Interest $25.3 mill.
Incl. $17.3 mill. finance leases.
(LT interest earned: 5.3x)
Leases, Uncapitalized Annual rentals $.4 mill.

Pension Assets-12/21 $474.0 mill.
Oblig $460.7 mill.
Pfd Stock None

Common Stock 36,163,370 shs.
as of 1/31/22
MARKET CAP: $2.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.3	-3.5	+3.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.43	7.16	7.70
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	465	429	454

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-.5%	*4.0%*
"Cash Flow"	5.5%	6.5%	*4.0%*
Earnings	5.0%	4.0%	*4.5%*
Dividends	4.0%	4.5%	*4.5%*
Book Value	6.0%	6.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	167.6	122.2	138.2	140.9	568.9
2020	149.9	117.0	135.2	136.5	538.6
2021	167.9	130.7	145.9	162.1	606.6
2022	*180*	*140*	*150*	*155*	*625*
2023	*185*	*145*	*155*	*160*	*645*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.69	.45	.88	.48	2.51
2020	.75	.53	.88	.44	2.60
2021	.97	.63	.97	.36	2.92
2022	*.95*	*.60*	*.95*	*.50*	*3.00*
2023	*1.00*	*.65*	*1.00*	*.50*	*3.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.3225	.3225	.3375	.3375	1.32
2019	.3375	.3375	.3525	.3525	1.38
2020	.3525	.3525	.37	.37	1.45
2021	.37	.37	.3875	.3875	1.52
2022					

BUSINESS: MGE Energy, Inc. is a holding company for Madison Gas and Electric Company (MGE), which provides electric service to 159,000 customers in Dane County and gas service to 169,000 customers in seven counties in Wisconsin. Electric revenue breakdown: residential, 36%; commercial, 50%; industrial, 3%; other, 11%. Generating sources: coal, 51%; gas, 12%; purchased and other, 37%. Fuel costs: 32% of revenues. '21 reported depreciation rates: electric, 3.2%; gas, 2.2%; nonregulated, 2.4%. Has about 700 employees. Chairman, President & CEO: Jeffrey M. Keebler. Incorporated: Wisconsin. Address: 133 South Blair Street, P.O. Box 1231, Madison, Wisconsin 53701-1231. Telephone: 608-252-7000. Internet: www.mgeenergy.com.

MGE Energy's utility subsidiary received electric and gas rate increases at the start of 2022. The Wisconsin commission granted Madison Gas and Electric an electric rate increase of $35.0 million (8.8%) and a gas tariff hike of $4.2 million (2.2%). The electric increase was greater than the $20.5 million agreed to in a settlement because fuel prices rose following the agreement. The allowed return on equity was set at 9.8%, and the common-equity ratio was established at 55.6%. These were the figures MGE requested. The order specified no electric hike for 2023, but included a provision for a limited reopener. MGE will use this provision to file an application seeking to place projects beginning commercial operation next year in the rate base, with an order due in late 2022. At the start of 2023, the utility will receive an additional gas tariff hike of $1.8 million (1.0%). We consider the rate order constructive.

We estimate a modest earnings increase in 2022, followed by further growth in 2023. The electric and gas rate increases are positive factors for the company's earning power. However, weather patterns were favorable in 2021, and we assume normal weather for the remainder of this year (although January was colder than normal). MGE's service area is healthy and recovering from coronavirus-related restrictions, which were stricter in Dane County than in surrounding areas. Note that the probable return to a normal tax rate in 2022 won't be a factor because tax benefits that made the rate low last year were passed through to customers.

The utility is adding renewable generating capacity. MGE has a 50 megawatt stake in a solar project with an expected cost of $65 million. The expected date of commercial operation has slipped from the fourth quarter of 2022 to the first period of 2023, but this did not affect the cost. Besides this project, from 2022 through 2024 MGE's plans call for the addition of 127 mw of solar, wind, and battery storage at a cost of $285 million.

Although the price of this untimely stock has fallen 12% this year, the valuation is still high. The dividend yield is well below the utility average. Total return potential to 2025-2027 is low.

Paul E. Debbas, CFA *March 11, 2022*

(A) Diluted earnings. Excludes nonrecurring gain: '17, 62¢. '19 & '21 earnings don't sum due to rounding. Next earnings report due early May. (B) Dividends historically paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Includes regulatory assets. In '21: $193.9 mill., $5.36/sh. (D) In millions, adjusted for split. (E) Rate allowed on common equity in '22: 9.8%; earned on common equity, '21: 10.6%. Regulatory Climate: Above Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	100

NEXTERA ENERGY NYSE-NEE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD
78.12	26.8	(Trailing: 43.2 Median: 19.0)	1.51	2.2%

VALUE LINE

TIMELINESS 2 Raised 12/31/21
SAFETY 1 Raised 2/16/18
TECHNICAL 2 Raised 1/28/22
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$66-$117	$92 (15%)

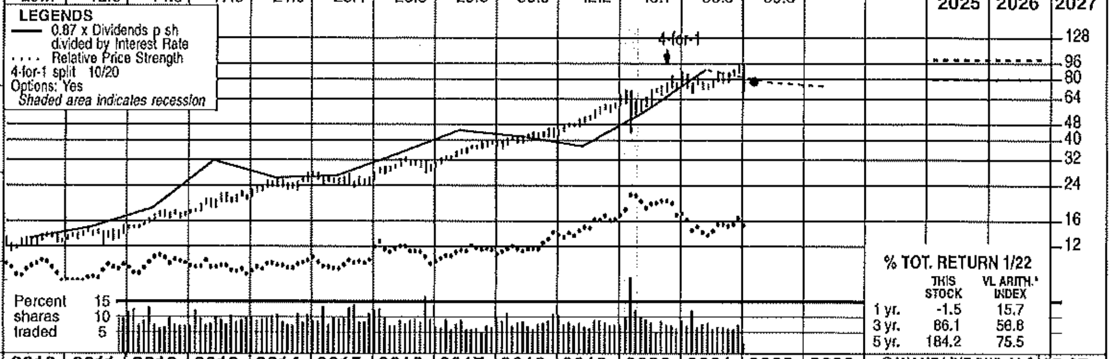
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+30%)	9%
Low	80	(Nil)	3%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	1105	1106	1025
to Sell	856	799	850
Hld's(000)	1473629	1473629	1493769

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	15.3	18.1	22.4	27.7	28.2	33.0	39.8	46.1	61.3	83.3	93.7	93.6
Low:	12.3	14.6	17.5	21.0	23.4	25.5	29.3	36.3	42.2	43.7	68.3	69.8



% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.5	15.7
3 yr.	86.1	56.8
5 yr.	184.2	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
9.69	9.37	10.03	9.45	9.10	9.22	8.41	8.70	9.61	9.48	8.63	9.13	8.75	9.82	9.18	*8.70*	*9.10*	*9.45*	Revenues per sh	*11.50*
1.69	1.71	2.01	2.19	2.41	2.32	2.17	2.63	3.03	3.23	3.24	3.03	3.84	4.22	4.31	*3.95*	*5.05*	*5.25*	"Cash Flow" per sh	*6.50*
.81	.82	1.02	.99	1.19	1.21	1.14	1.21	1.40	1.52	1.45	1.63	1.67	1.94	2.10	1.81	*2.80*	*3.00*	Earnings per sh A	*4.00*
.38	.41	.45	.47	.50	.55	.60	.66	.73	.77	.87	.98	1.11	1.25	1.40	1.54	*1.70*	*1.87*	Div'd Decl'd per sh B ■ †	*2.45*
2.31	3.08	3.20	3.63	3.47	3.98	5.58	3.84	3.96	4.54	5.15	5.70	6.80	6.29	7.45	*8.20*	*8.10*	*8.40*	Cap'l Spending per sh	*10.00*
6.12	6.59	7.14	7.84	8.59	8.98	9.47	10.37	11.24	12.24	13.00	14.97	17.86	18.92	18.63	*18.95*	*20.65*	*23.55*	Book Value per sh C	*27.50*
1621.6	1629.4	1635.7	1654.5	1683.4	1664.0	1696.0	1740.0	1772.0	1844.0	1872.0	1884.0	1912.0	1956.0	1960.0	*1963.0*	*1980.0*	*2025.0*	Common Shs Outst'g D	*2025.0*
13.7	18.9	14.5	13.4	10.8	11.5	14.4	16.6	17.3	16.9	20.7	21.6	24.8	26.8	31.8	44.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*22.5*
.74	1.00	.87	.89	.69	.72	.92	.93	.91	.85	1.09	1.09	1.34	1.43	1.63	2.36			Relative P/E Ratio	*1.25*
3.4%	2.7%	3.0%	3.5%	3.9%	4.0%	3.6%	3.3%	3.0%	3.0%	2.9%	2.8%	2.7%	2.4%	2.1%	1.9%			Avg Ann'l Div'd Yield	*2.7%*
						14256	15136	17021	17486	16155	17195	16727	19204	17997	17069	*18000*	*19100*	Revenues ($mill)	*23400*
						1911.0	2062.0	2465.0	2752.0	2693.0	3074.0	3200.0	3769.0	4127.0	3573.0	*5015*	*5445*	Net Profit ($mill)	*7420*
						26.6%	26.9%	32.3%	30.8%	29.3%	24.4%	28.6%	11.7%	9.0%	11.0%	*11.0%*	*11.0%*	Income Tax Rate	*11.0%*
						10.8%	7.0%	6.7%	6.9%	8.2%	6.7%	6.6%	3.9%	4.2%	*7.0%*	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
						59.1%	57.1%	55.0%	54.2%	53.3%	52.7%	44.0%	50.4%	53.5%	*58.0%*	*57.5%*	*55.5%*	Long-Term Debt Ratio	*56.0%*
						40.9%	42.9%	45.0%	45.8%	46.7%	47.3%	56.0%	49.6%	46.5%	*42.0%*	*42.5%*	*44.5%*	Common Equity Ratio	*44.0%*
						39245	42009	44283	49255	52159	59671	60926	74548	78457	*88150*	*95875*	*107450*	Total Capital ($mill)	*126500*
						49413	52720	55705	61386	66912	72416	70334	82010	91803	*99350*	*110925*	*123300*	Net Plant ($mill)	*165200*
						6.2%	6.2%	7.0%	6.8%	6.3%	6.3%	6.3%	6.0%	6.0%	*5.0%*	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
						11.9%	11.4%	12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	11.3%	*9.5%*	*12.5%*	*11.5%*	Return on Shr. Equity	*13.5%*
						11.9%	11.4%	12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	11.3%	*9.5%*	*12.5%*	*11.5%*	Return on Com Equity E	*13.5%*
						5.6%	5.2%	6.0%	6.1%	4.4%	4.4%	3.2%	3.7%	3.8%	*1.5%*	*5.5%*	*4.5%*	Retained to Com Eq	*5.5%*
						53%	54%	51%	50%	60%	60%	66%	64%	66%	*85%*	*67%*	*69%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 9/30/21
Total Debt $55341 mill. **Due in 5 Yrs** $29786 mill.
LT Debt $48092 mill. **LT Interest** $1322 mill.

(LT interest earned: 4.0x)

Pension Assets-12/20 $5314 mill.
Oblig $3607 mill.

Pfd Stock None

Common Stock 1,962,137,094 shs.
MARKET CAP: $153 billion (Large Cap)

ELECTRIC OPERATING STATISTICS F

	2018	2019	2020
% Change Retail Sales (KWH)	+1.4	+1.7	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.40	6.39	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	+1.8	NA
Fixed Charge Cov. (%)	266	230	235

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	-.5%	- -	*3.0%*
"Cash Flow"	6.5%	7.0%	*6.5%*
Earnings	6.0%	6.5%	*11.0%*
Dividends	10.0%	12.0%	*10.0%*
Book Value	9.0%	10.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	4075	4970	5572	4587	19204
2020	4613	4204	4785	4395	17997
2021	3726	3927	4370	5046	17069
2022	*4200*	*4500*	*4900*	*4400*	*18000*
2023	*4450*	*4800*	*5200*	*4650*	*19100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.35	.64	.45	.50	1.94
2020	.21	.65	.62	.62	2.10
2021	.84	.13	.23	.61	1.81
2022	*.70*	*.75*	*.85*	*.50*	*2.80*
2023	*.80*	*.80*	*.90*	*.50*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.2775	.2775	.2775	.2775	1.11
2019	.3125	.3125	.3125	.3125	1.25
2020	.35	.35	.35	.35	1.40
2021	.385	.385	.385	.385	1.54
2022					

BUSINESS: NextEra Energy, Inc. (formerly FPL Group, Inc.) is a holding company for Florida Power & Light Company (FPL), which provides electricity to 5.6 million customers in eastern, southern, & northwestern Florida. NextEra Energy Resources is a nonregulated power generator with nuclaar, gas, & renewable ownership. Has 57.2% stake in NextEra Energy Partners. Revenue breakdown: residential, 58%; commercial, 32%; industrial & other, 10%. Generating sources: gas, 73%; nuclear, 22%; other, 3%; purchased, 2%. Fuel costs: 20% of revs. '20 reported depr. rate (utility): 3.7%. Has 14,900 employees. Chairman, President and CEO: James L. Robo. Inc.: FL. Address: 700 Universe Blvd., Juno Beach, FL 33408. Tel.: 561-694-4000. Internet: www.nexteraenergy.com.

NextEra Energy raised its earnings guidance for 2022 and 2023 upon reporting fourth-quarter results in late January. The company is faring well in both the utility and nonutility segments of its business. Florida Power & Light received a rate increase of $692 million at the start of 2022 and will get $540 million more next year. The utility completed the first phase of a solar addition (1,500 megawatts) and is building 409 mw of battery storage. In 2024 and 2025, FPL will get additional revenues of up to $140 million each year to place solar projects in rates. Customer growth is healthy. NextEra Energy Resources is adding solar and battery storage projects, too. This nonutility subsidiary is benefiting from the low interest-rate environment, and also sells assets from time to time to raise funds for reinvestment. Its transmission business is growing rapidly. Management raised its targeted range for 2022 from $2.55-$2.75 a share to $2.75-$2.85. Its guidance for 2023 is $2.93-$3.08, up from $2.77-$2.97.

Mark-to-market accounting charges can skew earnings comparisons. These reduced pretax income by $2 billion in 2021. We include these in our earnings presentation because they are an ongoing part of NextEra's results.

We expect a dividend increase later this month. We look for a hike of $0.16 a share (10.4%) in the annual payout. NextEra has stated its expectation of 10% yearly dividend growth through 2022.

Despite the company's good prospects, the timely and high-quality stock has gotten off to a rocky start in 2022. The price is down 16%. Perhaps this is partly due to reversion to the mean. The equity posted an industry-leading total return of 30.2% in 2020 (a bad year for most utility issues), followed by a 23.4% total return last year, above the median for electric equities. Even following the early 2022 decline, this issue's valnation is much higher than those of most stocks in this industry. The dividend yield is more than a percentage point below the mean and not much higher than the median of all dividend-paying issues under onr coverage. Total return potential is better for the next 18 months than for the 3- to 5-year period.

Paul E. Debbas, CFA *February 11, 2022*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '11, (6¢); '13, (20¢); '16, 12¢; '17, 23¢; '18, $1.80; '20, (61¢); gain on discontinued ops.: '13, 11¢. Next earnings report due late April. (B) Div'ds historically paid in mid-Mar., mid-June, mid-Sept., & mid-Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '20: $4.94/sh. (D) In mill., adj. for stock split. (E) Rate all'd on com. eq. in '22 (FPL): 9.7%-11.7%; earned on avg. com. eq., '20: 11.0%. Regulatory Climate: Average. (F) FPL only.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	100
Earnings Predictability	80

NORTHWESTERN NDQ-NWE

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
60.10	18.7 (Trailing: 16.7 Median: 17.0)	1.05	4.2%

VALUE LINE

TIMELINESS	5	Lowered 2/25/22
SAFETY	2	Raised 7/27/18
TECHNICAL	4	Raised 4/8/22

BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$49-$74	$62 (0%)

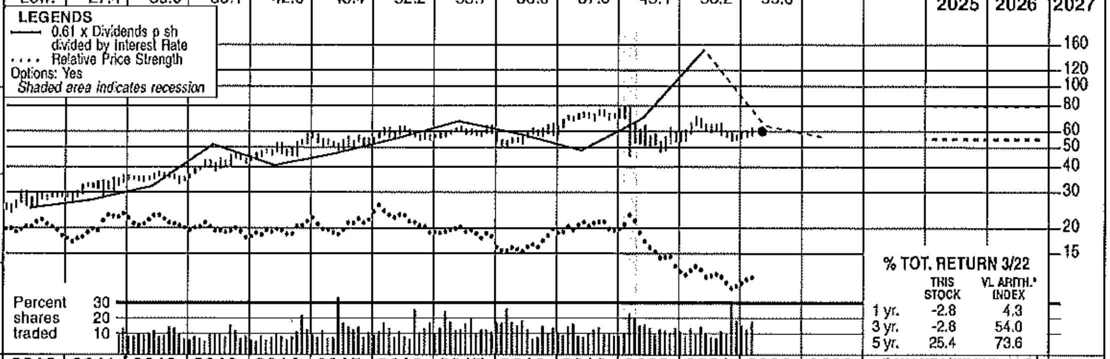
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+35%)	11%
Low	55	(-10%)	2%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	118	121	170
to Sell	125	112	105
Hld's(000)	47852	49375	56973

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	36.6	38.0	47.2	58.7	59.7	63.8	64.5	65.7	76.7	80.5	70.0	62.6
Low:	27.4	33.0	35.1	42.6	48.4	52.2	55.7	50.0	57.3	45.1	53.2	55.6



% TOT. RETURN 3/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.8	4.3
3 yr.	-2.8	54.0
5 yr.	25.4	73.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45	23.81	24.93	23.70	25.38	*24.15*	*23.40*	Revenues per sh	*25.75*
3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	6.96	7.07	6.72	7.02	*6.65*	*6.70*	"Cash Flow" per sh	*8.00*
1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	3.40	3.53	3.06	3.60	*3.30*	*3.40*	Earnings per sh A	*4.00*
1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	2.20	2.30	2.40	2.46	*2.52*	*2.56*	Div'd Decl'd per sh B ■ †	*2.70*
2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.69	5.96	5.60	5.64	6.26	8.02	8.03	*10.05*	*9.10*	Cap'l Spending per sh	*6.50*
20.85	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	38.60	40.42	41.10	43.28	*44.55*	*46.15*	Book Value per sh C	*49.50*
35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	50.32	50.45	50.59	54.06	*58.00*	*62.00*	Common Shs Outst'g D	*62.00*
26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	16.8	19.9	19.5	16.9	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.90	.91	1.06	1.00	.93	*Value Line*		Relative P/E Ratio	*.95*
3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%	3.9%	3.3%	4.0%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*
						1070.3	1154.5	1204.9	1214.3	1257.2	1305.7	1198.1	1257.9	1198.7	1372.3	*1400*	*1450*	Revenues ($mill)	*1600*
						83.7	94.0	120.7	138.4	164.2	162.7	171.1	179.3	155.2	186.8	*185*	*205*	Net Profit ($mill)	*250*
						9.6%	13.2%	--	13.7%	--	7.6%	--	1.6%	1.6%	1.8%	*1.5%*	*3.0%*	Income Tax Rate	*12.0%*
						9.4%	8.7%	8.9%	9.8%	4.3%	5.2%	3.4%	4.6%	6.3%	14.4%	*16.0%*	*14.0%*	AFUDC % to Net Profit	*10.0%*
						53.8%	53.5%	53.4%	53.1%	52.0%	50.2%	52.2%	52.5%	52.8%	52.2%	*50.0%*	*49.5%*	Long-Term Debt Ratio	*49.0%*
						46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	47.8%	47.5%	47.2%	47.8%	*50.0%*	*50.5%*	Common Equity Ratio	*51.0%*
						2020.7	2215.7	3168.0	3408.6	3493.9	3614.5	4064.6	4289.8	4409.1	4893.1	*5190*	*5660*	Total Capital ($mill)	*6025*
						2435.6	2690.1	3758.0	4059.5	4214.9	4358.3	4521.3	4700.9	4952.9	5247.2	*5630*	*5980*	Net Plant ($mill)	*6550*
						5.5%	5.5%	4.8%	5.2%	5.9%	5.6%	5.2%	5.2%	4.5%	4.7%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
						9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.5%	8.0%	*7.0%*	*7.0%*	Return on Shr. Equity	*8.0%*
						9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.5%	8.0%	*7.0%*	*7.0%*	Return on Com Equity E	*8.0%*
						3.2%	3.5%	3.8%	3.0%	4.1%	3.4%	3.2%	3.1%	1.7%	2.5%	*1.5%*	*2.0%*	Retained to Com Eq	*2.5%*
						65%	61%	54%	65%	58%	62%	64%	64%	78%	69%	*76%*	*75%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $2556.2 mill. **Due in 5 Yrs** $1037.4 mill.
LT Debt $2553.4 mill. **LT Interest** $87.8 mill.
Incl. $11.9 mill. finance leases.
(LT interest earned: 2.8x)

Pension Assets-12/21 $605.5 mill.
Oblig $696.8 mill.

Pfd Stock None

Common Stock 54,082,096 shs.
as of 2/4/22

MARKET CAP: $3.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+4.6	-4.4	+.7
Avg. Indust. Use (MWH)	37808	33526	31792
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2237	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.2	+1.6
Fixed Charge Cov. (%)	284	237	252

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.5%	-1.0%	*.5%*
"Cash Flow"	3.5%	3.0%	*2.5%*
Earnings	4.5%	2.0%	*3.0%*
Dividends	5.5%	5.5%	*2.0%*
Book Value	6.0%	4.5%	*3.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	384.2	270.7	274.8	328.2	1257.9
2020	335.3	269.4	280.6	313.4	1198.7
2021	400.8	298.2	326.0	347.3	1372.3
2022	*410*	*305*	*330*	*355*	*1400*
2023	*430*	*315*	*340*	*365*	*1450*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.44	.49	.42	1.18	3.53
2020	1.00	.43	.58	1.06	3.06
2021	1.24	.72	.68	.96	3.60
2022	*1.15*	*.50*	*.60*	*1.05*	*3.30*
2023	*1.20*	*.50*	*.60*	*1.10*	*3.40*

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.55	.55	.55	.55	2.20
2020	.575	.575	.575	.575	2.30
2021	.60	.60	.60	.60	2.40
2022	.62	.62	.62	.62	2.48
2023	.63				

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 456,000 electric customers in Montana and South Dakota and 298,000 gas customers in Montana (85% of gross margin), South Dakota (14%), and Nebraska (1%). Electric revenue breakdown: residential, 43%; commercial, 49%; industrial, 4%; other, 4%. Generating sources: coal, 28%; hydro, 27%; wind, 6%; other, 4%; purchased, 35%. Fuel costs: 31% of revenues. '21 reported deprec. rate: 2.8%. Has 1,500 employees. Chairman: Dana J. Dykhouse. CEO: Robert C. Rowe. President & COO: Brian B. Bird. Inc.: DE. Address: 3010 West 69th Street, Sioux Falls, SD 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern's share earnings will likely decline this year. Dilution from an increase in average shares outstanding is a key reason. Last year, the company issued $200 million in common equity, and will issue $300 million more in 2022 and/or early 2023 through a forward equity sale. NorthWestern wants to finance its capital budget and strengthen its balance sheet. Other factors are higher property and other taxes and increased depreciation. Our estimate is at the midpoint of management's targeted range of $3.20-$3.40 a share.

We look for a partial earnings recovery in 2023. NorthWestern plans to file a rate case in Montana later in 2022, and thus should obtain some rate relief next year. However, average shares outstanding will once again rise due to the equity that will be issued through the forward sale agreement. Our estimate of $3.40 a share would produce a 3% increase. This is at the low end of the company's goal for annual earnings growth of 3%-6%.

The board of directors raised the dividend in the first quarter. However, the increase, at one cent a share (1.6%) quarterly, was half of the hike of last year (which itself was below increases in recent years). Even if share net reaches the upper end of the company's guidance in 2022, the payout ratio will still be above its target of 60%-70%. In the long run, dividend growth will probably approximate earnings growth.

NorthWestern is adding generating capacity. Last year, the company purchased 35% of its power, and wind or solar energy cannot be dispatched. An $80 million, 58-megawatt gas-fired plant in South Dakota is on schedule for completion soon. The utility plans to build a $275 million, 175-mw facility in Montana, but litigation has been filed challenging the air-quality permit that was issued. This plant is scheduled to begin commercial operation during the 2023-2024 winter season.

The dividend yield of this untimely stock is about a percentage point above the utility mean. However, total return potential does not stand out for the next 18 months or for the 3- to 5-year period. The recent quotation is within our 2025-2027 Target Price Range.

Paul E. Debbas, CFA *April 22, 2022*

(A) Diluted EPS. Excl. nonrecurring gains: '12, 39¢ net; '15, 27¢; '18, 52¢; '19, 45¢. '20 EPS don't sum due to rounding. Next earnings report due late April. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd charges. In '21: $19.39/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '19 (elec.): 9.65%; in '17 (gas): 9.55%; in SD in '15: none specified; in NE in '07: 10.4%; earned on avg. com. eq., '21: 8.5%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	90

OGE ENERGY CORP. NYSE-OGE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD
37.55	15.2	(Trailing: 16.0 Median: 17.0)	0.85	4.4%

VALUE LINE

TIMELINESS	4	Lowered 12/17/21
SAFETY	2	Lowered 12/18/15
TECHNICAL	2	Lowered 3/11/22

BETA 1.05 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$27-$43	$35 (-5%)

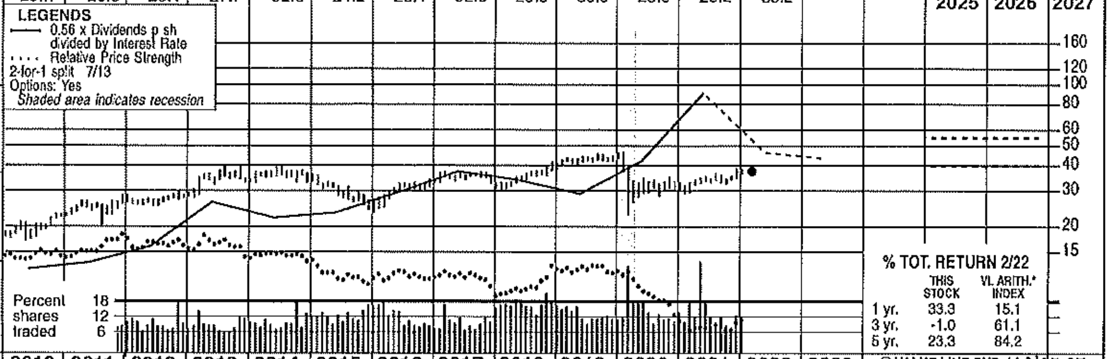
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+45%)	13%
Low	40	(+5%)	6%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	165	188	230
to Sell	229	157	150
Hld's(000)	125366	126167	128749

High:	28.6	30.1	40.0	39.3	36.5	34.2	37.4	41.8	45.8	46.4	38.6	38.5
Low:	20.3	25.1	27.7	32.8	24.2	23.4	32.6	29.6	38.0	23.0	29.2	35.2



% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	33.3	15.1
3 yr.	-1.0	61.1
5 yr.	23.3	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	11.37	11.15	10.61	18.26	14.00	15.00	Revenues per sh	18.25
2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	3.74	4.02	4.03	4.44	4.70	4.95	"Cash Flow" per sh	6.25
1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	2.12	2.24	2.08	2.36	2.50	2.65	Earnings per sh A	3.25
.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.51	1.58	1.63	1.66	1.70	Div'd Decl'd per sh B ■	1.85
2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	2.87	3.18	3.25	3.89	4.75	4.75	Cap'l Spending per sh	4.75
8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	20.06	20.69	18.15	20.27	21.10	22.05	Book Value per sh C	25.75
182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	199.70	200.10	200.10	200.10	200.10	200.10	Common Shs Outst'g D	200.10
13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	16.5	19.0	16.2	14.3	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	14.0
.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	1.01	.83	.76			Relative P/E Ratio	.80
4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%	4.0%	3.5%	4.7%	4.8%			Avg Ann'l Div'd Yield	4.0%
						3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	2270.3	2231.6	2122.3	3653.7	2800	3000	Revenues ($mill)	3650
						355.0	387.6	395.8	337.6	338.2	384.3	425.5	449.6	415.9	472.5	500	530	Net Profit ($mill)	660
						26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	14.5%	7.4%	13.2%	11.5%	12.0%	12.0%	Income Tax Rate	12.0%
						2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	8.3%	1.6%	1.6%	2.2%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
						50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	42.0%	43.6%	49.0%	52.6%	47.5%	53.0%	Long-Term Debt Ratio	50.5%
						49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	51.0%	47.4%	52.5%	47.0%	Common Equity Ratio	49.5%
						5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	6902.0	7334.7	7126.2	8552.7	8020	9360	Total Capital ($mill)	10375
						8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	8643.8	9044.6	9374.6	9832.9	10345	10830	Net Plant ($mill)	12075
						7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	7.3%	7.1%	6.9%	6.4%	7.5%	6.5%	Return on Total Cap'l	7.5%
						12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	12.0%	12.0%	Return on Shr. Equity	13.0%
						12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	12.0%	12.0%	Return on Com Equity E	13.0%
						7.2%	7.3%	6.5%	4.0%	3.3%	3.5%	3.8%	3.6%	2.8%	3.6%	4.0%	4.5%	Retained to Com Eq	5.5%
						44%	43%	47%	61%	67%	64%	64%	67%	76%	69%	66%	64%	All Div'ds to Net Prof	56%

CAPITAL STRUCTURE as of 12/31/21
Total Debt $4983.3 mill. **Due In 5 Yrs** $1486.9 mill.
LT Debt $4496.4 mill. **LT Interest** $158.7 mill.
(LT interest earned: 4.4x)

Leases, Uncapitalized Annual rentals $5.7 mill.

Pension Assets-12/21 $486.0 mill.
Oblig $502.9 mill.

Pfd Stock None

Common Stock 200,201,818 shs.
as of 1/31/22
MARKET CAP: $7.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.1	-4.9	+2.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.69	4.40	7.68
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6817	6437	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.1	+1.4
Fixed Charge Cov. (%)	335	326	336

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.0%	3.0%	5.5%
"Cash Flow"	3.5%	4.5%	7.0%
Earnings	4.0%	4.5%	6.5%
Dividends	8.0%	8.5%	3.0%
Book Value	5.5%	3.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	490.0	513.7	755.4	472.5	2231.6
2020	431.3	503.5	702.1	485.4	2122.3
2021	1630.6	577.4	864.4	581.3	3653.7
2022	600	650	900	650	2800
2023	650	700	950	700	3000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.24	.50	1.25	.26	2.24
2020	.23	.51	1.04	.30	2.08
2021	.26	.56	1.26	.27	2.36
2022	.27	.60	1.33	.30	2.50
2023	.30	.65	1.40	.30	2.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.3325	.3325	.3325	.365	1.36
2019	.365	.365	.365	.388	1.48
2020	.3875	.3875	.3875	.4025	1.57
2021	.4025	.4025	.4025	.41	1.62
2022	.41				

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 878,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 3% of Energy Transfer's limited partnership units. Electric revenue breakdown: residential, 44%; commercial, 25%; industrial, 11%; oilfield, 10%; other, 10%. Generating sources: gas, 25%; coal, 21%; wind, 6%; purchased, 48%. Fuel costs: 58% of revenues. '21 reported depreciation rate (utility): 2.6%. Has 2,200 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321. Tel.: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary filed a general rate case in Oklahoma. Oklahoma Gas and Electric requested a hike of $163.5 million, based on a 10.2% return on equity and a 53.4% common-equity ratio. The utility is seeking to place capital spending from the past three years into the rate base and asking the commission for a performance-based ratemaking plan, similar to what gas utilities have in the state. An order is expected in time for new tariffs to take effect in mid-2022.

A rate matter is pending in Arkansas. OG&E reached a settlement calling for a $4.2 million increase on April 1st under the state's formula rate plan. The utility also requested a five-year extension to this plan, and expects a decision in April.

The company wants to sell its stake in Energy Transfer. OGE Energy owns 95 million units (valued at $931 million) of the master limited partnership, which completed the acquisition of Enable Midstream Partners in December. OGE Energy booked an aftertax gain of $264.8 million ($1.32 a share) on the transaction, which we *excluded* from our earnings presentation as a nonrecurring item. The company plans to use the proceeds from the unit sales to reinvest in OG&E. The sale process will be gradual and might not be completed until 2023.

Our earnings estimates require an explanation. We are including equity income from OGE Energy's stake in Energy Transfer until the units are sold. Management is giving earnings guidance only for its OG&E subsidiary. The utility earned $1.80 a share last year, and the company's guidance for 2022 is $1.87-$1.97. The service area's economy is healthy, and customer growth is accelerating. OG&E's long-term earnings growth rate target is 5%-7% annually. Dividend hikes will lag profit growth for a while because the payout ratio is higher than OGE Energy wants. Note that the steep revenue decline likely this year is not a concern because a surge in gas and power prices, passed through to customers, caused a hig jump in the top line in the first quarter of 2021.

This stock is nntimely, but has an attractive dividend yield. Total return prospects are below the median for the 18-month span and the 3- to 5-year period.

Paul E. Debbas, CFA *March 11, 2022*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '15, (33¢); '17, $1.18; '19, (8¢); '20, ($2.95); '21, $1.32; gain on discont. ops.: '06, 20¢. '19 & '21 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '21: $6.15/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in OK in '19: 9.5%; in AR in '18: 9.5%; earned on avg. com. eq., '21: 12.7%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	90

OTTER TAIL CORP., NDQ-OTTR

RECENT PRICE 61.86 **P/E RATIO** 13.8 (Trailing: 14.6 Median: 20.0) **RELATIVE P/E RATIO** 0.77 **DIV'D YLD** 2.7% **VALUE LINE**

TIMELINESS 2 Raised 12/17/21
SAFETY 2 Raised 6/17/16
TECHNICAL 2 Lowered 2/25/22
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$51-$79	$65 (5%)

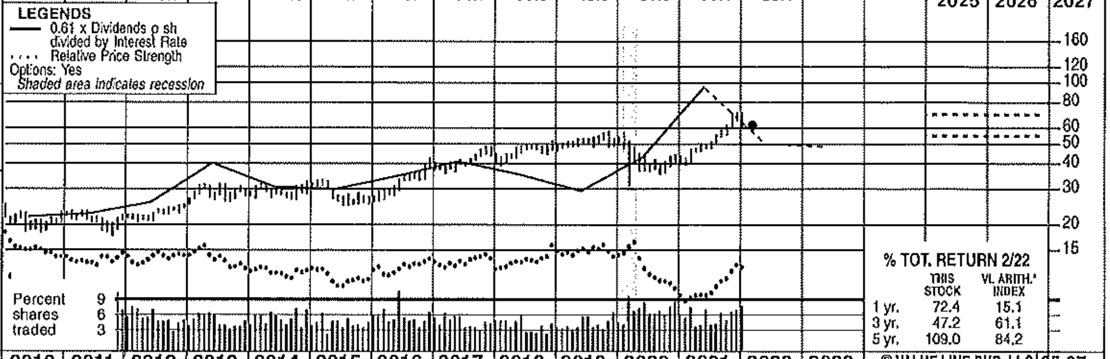
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+15%)	6%
Low	55	(-10%)	Nil

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	85	94	112
to Sell	72	66	84
Hld's(000)	19170	19727	19393

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	23.5	25.3	31.9	32.7	33.4	42.6	48.7	51.9	57.7	56.9	71.7	71.9	
Low:	17.5	20.7	25.2	26.5	24.8	25.8	35.7	39.0	45.9	31.0	39.4	59.1	



% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	72.4	15.1
3 yr.	47.2	61.1
5 yr.	109.0	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
37.43	41.50	37.06	29.03	31.08	29.66	23.76	24.63	21.46	20.60	20.42	21.47	23.10	22.90	21.46	28.80	*28.55*	*28.35*	Revenues per sh	*33.50*
3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	3.14	3.44	3.70	3.96	4.11	4.29	6.45	*6.30*	*5.35*	"Cash Flow" per sh	*6.50*
1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	1.56	1.60	1.86	2.06	2.17	2.34	4.23	*3.95*	*2.90*	Earnings per sh A	*3.75*
1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	1.23	1.25	1.28	1.34	1.40	1.48	1.56	*1.65*	*1.75*	Div'd Decl'd per sh D ■	*2.10*
2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	4.23	4.10	3.36	2.66	5.16	8.96	4.14	*4.35*	*4.75*	Cap'l Spending per sh	*6.25*
16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	15.98	17.03	17.62	18.38	19.46	21.00	23.84	*26.10*	*27.20*	Book Value per sh C	*31.50*
29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	37.86	39.35	39.56	39.66	40.16	41.47	41.55	*41.70*	*41.80*	Common Shs Outst'g D	*42.00*
17.3	19.0	30.1	31.2	NMF	NMF	21.7	21.1	18.8	18.2	20.2	22.1	22.2	23.5	18.3	12.3	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*16.5*
.93	1.01	1.81	2.08	NMF	NMF	1.38	1.19	.99	.92	1.06	1.11	1.20	1.25	.94	.66	*estimates*		Relative P/E Ratio	*.90*
3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	4.3%	3.9%	3.1%	2.9%	2.7%	3.5%	3.0%			Avg Ann'l Div'd Yield	*3.4%*
						859.2	893.3	799.3	779.8	803.5	849.4	916.4	919.5	890.1	1196.8	*1190*	*1185*	Revenues ($mill)	*1410*
						39.0	50.2	56.9	58.6	62.0	73.9	82.3	86.8	95.9	176.8	*165*	*120*	Net Profit ($mill)	*160*
						5.2%	21.3%	22.5%	27.0%	24.5%	25.5%	15.0%	16.7%	17.4%	16.9%	*17.0%*	*17.0%*	Income Tax Rate	*17.0%*
						1.7%	5.6%	3.9%	3.5%	2.2%	2.3%	4.1%	4.9%	6.4%	.8%	*3.0%*	*4.0%*	AFUDC % to Net Profit	*4.0%*
						44.0%	42.1%	46.5%	42.4%	43.0%	41.3%	44.7%	46.9%	41.8%	42.6%	*43.0%*	*42.0%*	Long-Term Debt Ratio	*39.0%*
						54.4%	57.9%	53.5%	57.6%	57.0%	58.7%	55.3%	53.1%	58.2%	57.4%	*57.0%*	*58.0%*	Common Equity Ratio	*61.0%*
						959.2	924.4	1071.3	1051.0	1175.4	1187.3	1318.9	1471.1	1495.4	1724.8	*1910*	*1960*	Total Capital ($mill)	*2175*
						1049.5	1167.0	1268.5	1387.8	1477.2	1539.6	1581.1	1753.8	2049.3	2124.6	*2210*	*2305*	Net Plant ($mill)	*2675*
						5.7%	6.8%	6.7%	6.8%	6.5%	7.3%	7.3%	7.0%	7.4%	11.1%	*9.5%*	*7.0%*	Return on Total Cap'l	*8.0%*
						7.3%	9.4%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	11.0%	17.8%	*15.5%*	*10.5%*	Return on Shr. Equity E	*12.0%*
						7.3%	9.3%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	11.0%	17.8%	*15.5%*	*10.5%*	Return on Com Equity	*12.0%*
						NMF	1.2%	2.2%	2.0%	2.1%	3.3%	4.0%	4.0%	4.1%	11.3%	*9.0%*	*4.5%*	Retained to Com Eq	*5.5%*
						113%	87%	78%	79%	78%	69%	65%	64%	63%	37%	*41%*	*60%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $855.2 mill. **Due in 5 Yrs** $201.2 mill.
LT Debt $734.0 mill. **LT Interest** $31.6 mill.
(LT interest earned: 7.8x)

Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-12/21 $387.2 mill.
Oblig $416.7 mill.

Pfd Stock None

Common Stock 41,605,742 shs.
as of 2/7/22

MARKET CAP: $2.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.2	-3.9	+.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.1	NA	NA
Fixed Charge Cov. (%)	407	405	651

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.0%	3.0%	*5.5%*
"Cash Flow"	7.0%	9.0%	*4.5%*
Earnings	19.0%	13.0%	*4.5%*
Dividends	2.0%	4.0%	*6.0%*
Book Value	2.0%	6.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	246.0	229.2	228.6	215.7	919.5
2020	234.7	192.8	235.8	226.8	890.1
2021	261.7	285.6	316.3	333.2	1196.8
2022	*350*	*300*	*280*	*260*	*1190*
2023	*310*	*300*	*300*	*275*	*1185*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.66	.39	.62	.51	2.17
2020	.60	.42	.87	.45	2.34
2021	.73	1.01	1.26	1.23	4.23
2022	*1.35*	*.90*	*1.00*	*.70*	*3.95*
2023	*.75*	*.60*	*.90*	*.65*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.335	.335	.335	.335	1.34
2019	.35	.35	.35	.35	1.40
2020	.37	.37	.37	.37	1.48
2021	.39	.39	.39	.39	1.56
2022	.4125				

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to 133,000 customers in Minnesota (52% of retail electric revenues), North Dakota (38%), and South Dakota (10%). Electric rev. breakdown: residential, 32%; commercial & farms, 36%; industrial, 30%; other, 2%. Generating sources: coal, 38%; wind & other, 18%; purchased, 44%. Fuel costs: 10% of revenues. Also has operations in manufacturing and plastics (62% of '20 operating income). '21 deprec. rate: 2.9%. Has 2,500 employees. Chairman: Nathan I. Partain. President & CEO: Charles S. MacFarlane. Inc.: Minnesota. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Tel.: 866-410-8780. Internet: www.ottertail.com.

Otter Tail Corporation's earnings will likely remain at an elevated level in 2022. Last year, unusually favorable conditions for the Plastics division raised the top and bottom lines considerably. The demand for PVC pipe is greater than the supply, which was held back by weather-related disruptions last year for producers of PVC resin in the Gulf Coast region. Management's earnings guidance for 2022 is $3.78-$4.08 a share. This is below the 2021 tally of $4.23, but well above the company's results prior to 2021. Prospects for the Plastics division should remain strong in the first quarter, followed by a return to more-normal conditions. Even so, our previous estimate of $3.55 was probably not optimistic enough, so we raised it by $0.40 a share.

We expect another earnings decline in 2023. This will likely be a normal year for the Plastics segment. We expect growth in Utility and Manufacturing income.

The stock has given back some of the steep gains in price experienced in 2021. The quotation soared 68% last year, as Otter Tail's expected earnings continued to advance. So far in 2022, the price has declined 13%. We think this is due to profit taking and the market's recognition that the company's earning power will eventually return to a more typical level.

The Minnesota commission issued a rate order. The allowed return on equity was increased slightly, from 9.41% to 9.48%, and the allowed common-equity ratio was 52.5%. Residential and commercial volume will be decoupled from revenues. The amount of the final increase, to be implemented by mid-2022, is to be determined. Currently, the utility is collecting an interim increase of $6.9 million.

The board of directors raised the dividend in the first quarter. The increase, at $0.09 a share (5.8%) annually, was slightly greater than those of the previous two years. The company's long-term targets are a payout ratio of 60%-70% and a yearly growth rate of 5%-7%. The payout ratio will remain well below Otter Tail's goal as long as earnings remain well above a normal level.

This timely stock has an average dividend yield for a utility. Total return potential to 2025-2027 is low.

Paul E. Debbas, CFA *March 11, 2022*

(A) Dil. EPS. Excl. nonrec. gains (loss): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from disc. ops.: '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢; '15, 2¢; '16, 1¢; '17, 1¢. '19 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds histor. pd. in early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $4.14/sh. (D) In mill. (E) Rate all'd on com. eq. in MN in '22: 9.48%; in ND in '18: 9.77%; in SD in '19: 8.75%; earned on avg. com. eq., '21: 19.2%. Regul. Climate: MN, ND, Avg.; SD, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	90

PORTLAND GENERAL NYSE-POR

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
55.34	19.6	(Trailing: 20.3 Median: 18.0)	1.10	3.3%	VALUE LINE

TIMELINESS	3	Raised 3/18/22
SAFETY	2	Raised 10/22/21
TECHNICAL	3	Lowered 3/25/22

BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$34-$58	$46 (-15%)

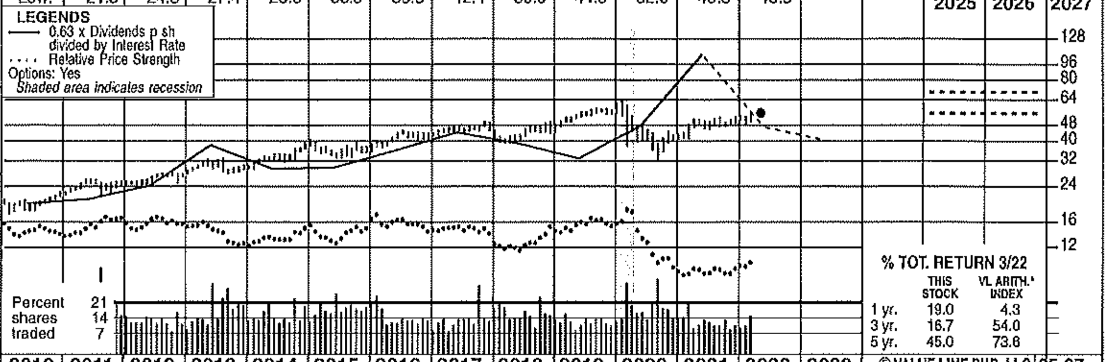
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+25%)	9%
Low	55	(Nil)	4%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	157	142	149
to Sell	142	145	141
Hld's(000)	81434	82480	81443

High:	26.0	28.1	33.3	40.3	41.0	45.2	50.1	50.4	58.4	63.1	53.1	57.0
Low:	21.3	24.3	27.4	29.0	33.0	35.3	42.4	39.0	44.0	32.0	40.8	48.3


LEGENDS
—— 0.63 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2025 | 2026 | 2027

% TOT. RETURN 3/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.0	4.3
3 yr.	16.7	54.0
5 yr.	45.0	73.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	22.30	23.75	23.96	26.80	27.95	28.75	Revenues per sh	31.25
4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	6.65	6.97	6.80	7.25	7.70	8.15	"Cash Flow" per sh	9.50
1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	2.37	2.39	1.72	2.72	2.90	3.05	Earnings per sh A	3.50
.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	1.43	1.52	1.59	1.70	1.80	1.90	Div'd Decl'd per sh B ■ †	2.30
5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	6.67	6.78	8.76	7.11	7.65	7.55	Cap'l Spending per sh	7.50
19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	28.07	28.99	29.18	30.28	31.35	32.50	Book Value per sh C	36.25
62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	89.27	89.39	89.54	89.41	89.50	89.50	Common Shs Outst'g D	89.50
23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	18.4	22.3	26.6	17.7	Bold figures are		Avg Ann'l P/E Ratio	18.0
1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	.99	1.19	1.37	.97	Value Line		Relative P/E Ratio	1.00
2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%	3.3%	2.8%	3.5%	3.5%	estimates		Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 12/31/21
Total Debt $3578 mill. **Due in 5 Yrs** $186 mill.
LT Debt $3558 mill. **LT Interest** $128 mill.
Incl. $273 mill. finance leases.
(LT interest earned: 2.9x)
Leases, Uncapitalized Annual rentals $4 mill.
Pension Assets-12/21 $800 mill. **Oblig** $972 mill.

Pfd Stock None

Common Stock 89,426,860 shs.
as of 2/7/22

MARKET CAP: $4.9 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
1805.0	1810.0	1900.0	1898.0	1923.0	2009.0	1991.0	2123.0	2145.0	2396.0	2500	2575	Revenues ($mill)	2800
141.0	137.0	175.0	172.0	193.0	204.0	212.0	214.0	155.0	244.0	260	275	Net Profit ($mill)	320
31.4%	23.2%	26.0%	20.7%	20.6%	25.3%	7.4%	11.2%	11.2%	8.6%	17.5%	17.5%	Income Tax Rate	17.5%
7.1%	14.6%	33.7%	19.8%	16.6%	8.8%	8.0%	7.0%	15.5%	10.2%	10.0%	9.0%	AFUDC % to Net Profit	8.0%
47.1%	51.3%	52.7%	47.8%	48.4%	50.1%	46.5%	51.3%	53.6%	56.8%	55.5%	56.0%	Long-Term Debt Ratio	57.5%
52.9%	48.7%	47.3%	52.2%	51.6%	49.9%	53.5%	48.7%	46.4%	43.2%	44.5%	44.0%	Common Equity Ratio	42.5%
3264.0	3735.0	4037.0	4329.0	4544.0	4842.0	4684.0	5323.0	5628.0	6265.0	6320	6580	Total Capital ($mill)	7600
4392.0	4880.0	5679.0	6012.0	6434.0	6741.0	6887.0	7161.0	7539.0	8005.0	8060	8480	Net Plant ($mill)	9000
5.9%	5.1%	5.8%	5.4%	5.6%	5.5%	5.8%	5.1%	4.0%	4.9%	5.0%	5.0%	Return on Total Cap'l	5.5%
8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	5.9%	9.0%	9.5%	9.5%	Return on Shr. Equity	10.0%
8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	5.9%	9.0%	9.5%	9.5%	Return on Com Equity E	10.0%
3.5%	2.9%	4.6%	3.3%	3.5%	3.6%	3.5%	3.1%	.6%	3.5%	3.5%	3.5%	Retained to Com Eq	3.5%
57%	61%	50%	56%	57%	58%	59%	63%	90%	61%	62%	62%	All Div'ds to Net Prof	65%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.2	+.4	+5.1
Avg. Indust. Use (MWH)	17827	18472	20002
Avg. Indust. Revs. per KWH (¢)	4.75	4.99	5.22
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3765	3771	4447
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.5	+.6
Fixed Charge Cov. (%)	265	187	261

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	2.0%	4.0%
"Cash Flow"	4.5%	4.0%	5.0%
Earnings	3.5%	1.5%	7.5%
Dividends	4.5%	6.0%	6.0%
Book Value	3.5%	3.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	573.0	460.0	542.0	548.0	2123.0
2020	573.0	469.0	547.0	556.0	2145.0
2021	609.0	537.0	642.0	608.0	2396.0
2022	645	560	660	635	2500
2023	675	575	675	650	2575

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.82	.28	.61	.68	2.39
2020	.91	.43	d.19	.57	1.72
2021	1.07	.36	.56	.73	2.72
2022	1.05	.45	.60	.80	2.90
2023	1.10	.45	.65	.85	3.05

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.34	.34	.3625	.3625	1.41
2019	.3625	.3625	.385	.385	1.50
2020	.385	.385	.385	.4075	1.56
2021	.4075	.4075	.43	.43	1.68
2022	.43	.43			

BUSINESS: Portland General Electric Company (PGE) provides electricity to 917,000 customers in 51 cities in a 4,000-square-mile area of Oregon, including Portland and Salem (population: 1.9 million). The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 29%; industrial, 11%; other, 13%. Generating sources: gas, 37%; wind, 9%; coal, 8%; hydro, 4%; purchased, 42%. Fuel costs: 34% of revenues. '21 reported depreciation rate: 3.4%. Has 2,800 full-time employees. Chairman: Jack E. Davis. President and Chief Executive Officer: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, OR 97204. Tel.: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric will soon get an order on its general rate case. Some matters have already been settled. The revenue increase would be $74 million, $64 million of which would be for recovery of higher power costs. The extra $10 million doesn't seem like much, but under the agreement PGE would retain $50 million in rates for the Boardman coal-fired plant, which is no longer in the rate base. The allowed return on equity and common-equity ratio would remain at 9.5% and 50%, respectively. Other matters have yet to be settled, such as whether a project still under construction should be included in this case, and whether the decoupling mechanism will be eliminated. An order from the Oregon commission is due in time for new tariffs to take effect no later than May 9th.

Earnings growth is likely in 2022 and 2023. A partial year of rate relief this year and a full year's effect next year will be one factor. Another is accelerating load growth, thanks to the healthy economy of the utility's service territory, where there is a vibrant tech sector. Our 2022 estimate is at the upper end of PGE's targeted range of $2.75-$2.90 a share. We estimate 5% profit growth in 2023, which is within management's long-term goal of 4%-6%.

The utility is awaiting decisions on its request for proposals. PGE wants to add renewables and "nonemitting" capacity. The short list should be known soon and the goal is for contracts to be executed with the winning bidders by yearend. If PGE winds up building some of this capacity, it might have to issue equity—something the company has not done since 2015.

We think the board of directors will raise the dividend soon. This was the timing of the increase in the disbursement in 2021. We estimate that the board will boost the dividend $0.025 a share (5.8%). PGE's targets are a long-term growth rate of 5%-7% and a payout ratio of 60%-70%.

The dividend yield of this stock is about average for a utility. Total return potential is negative for the next 18 months and low for the 3- to 5-year period. Like many utility issues, the recent quotation is near our 2025-2027 Target Price Range.

Paul E. Debbas, CFA *April 22, 2022*

(A) Diluted earnings. Excludes nonrecurring losses: '13, 42¢; '17, 19¢. Next earnings report due April 28. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. deferred charges. In '21: $533 mill., $5.96/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on common equity in '19: 9.5%; earned on avg. com. eq., '21: 9.2%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	80

PINNACLE WEST NYSE-PNW

RECENT PRICE **78.21** P/E RATIO **19.9** (Trailing: 14.3 Median: 17.0) RELATIVE P/E RATIO **1.12** DIV'D YLD **4.4%** VALUE LINE

TIMELINESS **4** Raised 3/18/22
SAFETY **2** Lowered 10/22/21
TECHNICAL **5** Lowered 3/25/22
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$60-$99	$80 (0%)

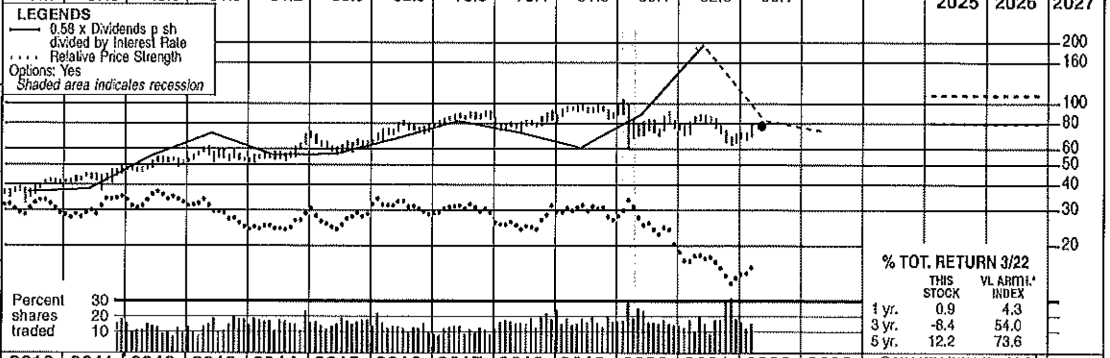
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+40%)	12%
Low	80	(Nil)	5%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	224	247	228
to Sell	230	214	265
Hld's(000)	97250	94972	90979

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	48.9	54.7	61.9	71.1	73.3	82.8	92.5	92.6	99.8	105.5	86.5	80.5
Low:	37.3	45.9	51.5	51.2	56.0	62.5	75.8	73.4	81.6	60.1	62.8	66.1



% TOT. RETURN 3/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.9	4.3
3 yr.	-8.4	54.0
5 yr.	12.2	73.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	31.42	31.90	32.93	30.87	31.81	33.66	*34.95*	*36.75*	Revenues per sh	*39.00*
9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	9.79	11.41	11.13	10.86	12.23	*11.05*	*11.75*	"Cash Flow" per sh	*14.00*
3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	3.95	4.43	4.54	4.77	4.87	5.47	*3.95*	*4.30*	Earnings per sh A	*5.50*
2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	2.70	2.87	3.04	3.23	3.36	*3.44*	*3.52*	Div'd Decl'd per sh B ■	*3.80*
7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	11.64	12.80	10.73	10.76	11.93	13.04	*14.10*	*14.10*	Cap'l Spending per sh	*14.50*
34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	43.15	44.80	46.59	48.30	49.96	52.26	*52.80*	*53.55*	Book Value per sh C	*59.25*
99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	111.34	111.75	112.10	112.44	112.76	113.01	*113.00*	*113.00*	Common Shs Outst'g D	*118.00*
13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	18.7	19.3	17.8	19.4	16.7	14.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
.74	.79	.97	.91	.80	.92	.91	.86	.84	.81	.98	.97	.96	1.03	.86	.77			Relative P/E Ratio	*.95*
4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%	3.2%	3.5%	3.3%	4.0%	4.3%			Avg Ann'l Div'd Yield	*4.0%*
						3301.8	3454.6	3491.6	3495.4	3498.7	3565.3	3691.2	3471.2	3587.0	3803.8	*3950*	*4150*	Revenues ($mill)	*4600*
						387.4	406.1	397.6	437.3	442.0	497.8	511.0	538.3	550.6	618.7	*445*	*485*	Net Profit ($mill)	*650*
						36.2%	34.4%	34.2%	34.3%	33.9%	32.5%	20.2%	--	12.1%	14.8%	*13.5%*	*13.5%*	Income Tax Rate	*13.5%*
						9.7%	10.0%	11.6%	11.8%	14.1%	13.9%	15.2%	9.3%	9.5%	10.1%	*14.0%*	*13.0%*	AFUDC % to Net Profit	*11.0%*
						44.6%	40.0%	41.0%	43.0%	45.6%	48.9%	47.0%	47.1%	52.8%	53.9%	*55.0%*	*54.5%*	Long-Term Debt Ratio	*54.5%*
						55.4%	60.0%	59.0%	57.0%	54.4%	51.1%	53.0%	52.9%	47.2%	46.1%	*45.0%*	*45.5%*	Common Equity Ratio	*45.5%*
						7171.9	6990.9	7398.7	8046.3	8825.4	9796.4	9861.1	10263	11948	12820	*13275*	*13375*	Total Capital ($mill)	*15375*
						10396	10889	11194	11809	12714	13445	14030	14523	15159	15987	*16775*	*17525*	Net Plant ($mill)	*19875*
						6.8%	7.1%	6.4%	6.4%	6.0%	6.1%	6.2%	6.3%	5.5%	5.8%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
						9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	*7.5%*	*8.0%*	Return on Shr. Equity	*9.5%*
						9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	*7.5%*	*8.0%*	Return on Com Equity E	*9.5%*
						4.1%	4.1%	3.5%	3.9%	3.5%	4.2%	3.9%	3.8%	3.5%	4.2%	*1.0%*	*1.5%*	Retained to Com Eq	*3.0%*
						58%	58%	62%	59%	62%	58%	60%	61%	64%	60%	*87%*	*82%*	All Div'ds to Net Prof	*69%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $7355.7 mill. Due in 5 Yrs $1892.0 mill.
LT Debt $6913.7 mill. LT Interest $244.1 mill.
(LT interest earned: 3.9x)

Leases, Uncapitalized Annual rentals $13.1 mill.

Pension Assets-12/21 $3812.0 mill.
Oblig $3716.8 mill.

Pfd Stock None

Common Stock 112,931,929 shs.
as of 2/17/22

MARKET CAP: $8.8 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.4	+5.4	+2.8
Avg. Indust. Use (MWH)	714	583	808
Avg. Indust. Revs. per KWH (¢)	7.88	7.49	8.11
Capacity at Peak (Mw)	8241	9094	8726
Peak Load, Summer (Mw)	7115	7660	7580
Annual Load Factor (%)	47.1	45.5	45.9
% Change Customers (yr-end)	+2.0	+2.1	+2.2
Fixed Charge Cov. (%)	286	318	317

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	.5%	*3.5%*
"Cash Flow"	4.5%	5.0%	*3.5%*
Earnings	6.0%	5.5%	*1.5%*
Dividends	4.5%	5.5%	*3.0%*
Book Value	4.0%	4.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	740.5	869.5	1190.8	670.4	3471.2
2020	661.9	929.6	1254.5	741.0	3587.0
2021	696.5	1000.2	1308.2	798.9	3803.8
2022	*750*	*1025*	*1350*	*825*	*3950*
2023	*775*	*1050*	*1450*	*875*	*4150*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.16	1.28	2.77	.57	4.77
2020	.27	1.71	3.07	d.17	4.87
2021	.32	1.91	3.00	.24	5.47
2022	*.25*	*1.30*	*2.15*	*.25*	*3.95*
2023	*.25*	*1.30*	*2.45*	*.30*	*4.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.695	.695	.695	.737	2.82
2019	.737	.738	.738	.782	3.00
2020	.783	.783	.783	.83	3.18
2021	.83	.83	.83	.85	3.34
2022	.85				

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.3 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 51%; commercial, 38%; industrial, 5%; other, 6%. Generating sources: gas & other, 30%; nuclear, 27%; coal, 20%; purchased, 23%. Fuel costs: 30% of revenues. '21 reported deprec. rate: 2.9%. Has 5,900 employees. Chairman, President & CEO: Jeffrey B. Guldner. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's earnings will almost certainly decline in 2022. The primary reason is an unfavorable rate order that the company's utility subsidiary, Arizona Public Service, received last year. In 2019, APS filed for a rate hike of $169 million (5.1%), based on a 10% return on equity and a 54.7% common-equity ratio. The Arizona Corporation Commission (ACC) wound up reducing the utility's tariffs $4.8 million (effective December 1st), based on an ROE of just 8.7% and a common-equity ratio of 54.7%. The ruling cut the company's annual earning power by $0.90 a share. The regulators also disallowed $215.5 million (more than half) of the cost of an environmental remediation project. This disallowance would result in a $154.4 million aftertax charge if upheld. The credit-rating agencies have a negative outlook on the company's securities. Our earnings estimate is within management's guidance of $3.90-$4.10 a share.

The utility appealed the order to the courts and will file another rate case. A request for a rehearing from the ACC was denied. So, APS filed an appeal with the state Court of Appeals and a petition for special action with the state Supreme Court, but the latter filing was unsuccessful. When the Court of Appeals will act is unknown. The company plans to file another rate case by midyear, but the timing is subject to change. Note that Pinnacle West has no plans to issue equity until after its next rate case.

We look for a slight earnings recovery in 2023. We aren't assuming any rate relief. However, the utility should benefit from solid kilowatt-hour sales growth. APS expects weather-normalized retail volume growth of 1.5%-2.5%, driven by the same range of expected customer additions. Although we project solid profit growth beginning next year, we think share net will not return to the 2021 level until the 2025-2027 period.

The price of this untimely stock has made a partial recovery in 2022. The quotation has risen 11% so far this year after falling 12% in 2021. The dividend yield is more than a percentage point above the utility mean. But total return potential is low for the next 18 months and subpar for the 3- to 5-year period.

Paul E. Debbas, CFA *April 22, 2022*

(A) Diluted EPS. Excl. nonrec. gain (loss): '09, ($1.45); '17, 8¢; gains (losses) from discont. ops.: '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '19 & '20 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '21: $23.60/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '21: 8.7%; earned on avg. com. eq., '21: 10.7%. Regulatory Climate: Below Avg.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	95

PNM RESOURCES NYSE-PNM

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
47.84	20.2 (Trailing: 21.1, Median: 20.0)	1.13	2.9%

VALUE LINE

TIMELINESS 4 New 12/31/21
SAFETY 2 Raised 4/23/21
TECHNICAL 5 Lowered 4/1/22
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$42-$63	$53 (10%)

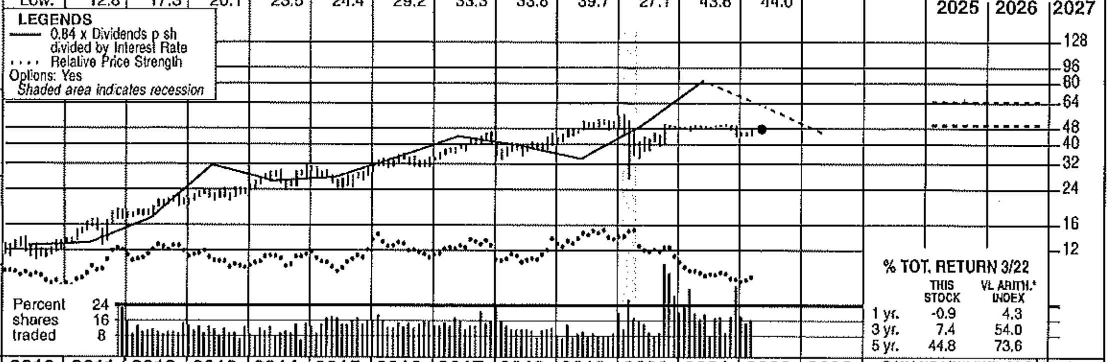
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+35%)	10%
Low	50	(+5%)	4%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	126	110	145
to Sell	105	123	116
Hld's(000)	71685	72629	74354

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	19.2	22.5	24.5	31.6	31.2	36.2	46.0	45.3	53.0	56.1	50.1	48.3
Low:	12.8	17.3	20.1	23.5	24.4	29.2	33.3	33.8	39.7	27.1	43.8	44.0



% TOT. RETURN 3/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.9	4.3
3 yr.	7.4	54.0
5 yr.	44.8	73.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	17.11	18.14	18.04	18.30	17.74	20.74	*21.00*	*21.10*	Revenues per sh	*23.25*
3.57	2.54	1.76	2.32	2.67	3.18	3.39	3.52	4.09	4.28	4.51	5.30	5.13	6.07	5.68	6.01	*6.45*	*6.60*	"Cash Flow" per sh	*8.00*
1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.48	1.46	1.92	1.66	2.28	2.15	2.27	*2.55*	*2.65*	Earnings per sh A	*3.00*
.86	.91	.61	.50	.50	.50	.58	.68	.76	.82	.90	.99	1.09	1.18	1.25	.98	*1.76*	*1.49*	Div'd Decl'd per sh B ■ †	*1.80*
4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	7.53	6.28	6.29	7.74	7.91	10.89	*10.20*	*10.55*	Cap'l Spending per sh	*9.00*
22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.78	21.04	21.28	21.20	21.08	23.88	25.25	*26.90*	*28.45*	Book Value per sh C	*32.00*
76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	85.83	85.83	*88.00*	*90.00*	Common Shs Outst'g D	*90.00*
15.6	NMF	NMF	18.1	14.0	14.5	15.0	16.1	18.7	18.7	22.4	20.4	23.4	21.1	20.8	21.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*19.0*
.84	NMF	NMF	1.21	.89	.91	.95	.90	.98	.94	1.18	1.03	1.26	1.12	1.07	1.18			Relative P/E Ratio	*1.05*
3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	3.0%	2.8%	2.5%	2.8%	2.5%	2.8%	2.0%			Avg Ann'l Div'd Yield	*3.2%*
						1342.4	1387.9	1435.9	1439.1	1363.0	1445.0	1436.6	1457.6	1523.0	1779.9	*1850*	*1900*	Revenues ($mill)	*2100*
						106.1	114.0	116.8	118.8	117.4	154.4	133.4	182.8	173.3	196.4	*235*	*250*	Net Profit ($mill)	*285*
						31.4%	31.6%	34.8%	36.9%	32.4%	33.0%	13.8%	9.4%	9.9%	13.3%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
						7.1%	1.3%	10.7%	17.0%	11.0%	11.9%	14.5%	9.2%	9.4%	9.3%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*7.0%*
						50.9%	50.0%	47.8%	54.1%	55.7%	56.1%	61.1%	59.8%	56.9%	61.8%	*60.0%*	*59.0%*	Long-Term Debt Ratio	*60.0%*
						48.7%	49.7%	51.9%	45.5%	44.0%	43.6%	38.6%	39.9%	42.9%	38.0%	*39.5%*	*41.0%*	Common Equity Ratio	*40.0%*
						3277.9	3344.0	3437.1	3633.3	3806.8	3887.5	4370.0	4207.7	4780.6	5698.6	*5975*	*6265*	Total Capital ($mill)	*7175*
						3746.5	3933.9	4270.0	4535.4	4904.7	4980.2	5234.6	5466.0	5965.1	6752.9	*7305*	*7895*	Net Plant ($mill)	*9050*
						5.1%	5.2%	5.1%	4.8%	4.7%	5.3%	4.3%	5.8%	4.7%	4.3%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
						6.6%	6.8%	6.5%	7.1%	7.0%	9.0%	7.8%	10.8%	8.4%	9.0%	*9.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
						6.6%	6.8%	6.5%	7.1%	7.0%	9.1%	7.9%	10.9%	8.4%	9.0%	*9.5%*	*9.0%*	Return on Com Equity E	*9.5%*
						3.8%	3.8%	3.2%	3.3%	2.8%	4.5%	2.9%	5.4%	3.6%	3.8%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
						43%	45%	51%	54%	61%	51%	64%	51%	57%	58%	*56%*	*56%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $3761.6 mill. **Due in 5 Yrs** $2046.4 mill.
LT Debt $3519.6 mill. **LT Interest** $92.6 mill.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $28.4 mill.
Pension Assets-12/21 $639.6 mill.
Oblig $643.7 mill.
Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par without mandatory redemption. Sinking fund began 2/1/84.

Common Stock 85,834,874 shs.
as of 2/18/22
MARKET CAP: $4.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+5.0	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2761	NA	NA
Peak Load, Summer (Mw)	1937	1974	1968
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	228	237	299

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	1.5%	*3.5%*
"Cash Flow"	8.0%	6.5%	*5.0%*
Earnings	10.0%	9.0%	*5.0%*
Dividends	8.5%	6.5%	*8.0%*
Book Value	2.5%	2.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	349.7	330.2	433.6	344.1	1457.6
2020	333.6	357.6	472.5	359.3	1523.0
2021	364.7	426.5	554.6	434.1	1779.9
2022	*385*	*445*	*575*	*445*	*1850*
2023	*400*	*455*	*590*	*455*	*1900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.23	.36	1.29	.40	2.28
2020	d.19	.72	1.52	.10	2.15
2021	.20	.62	1.32	.13	2.27
2022	*.41*	*.53*	*1.30*	*.31*	*2.55*
2023	*.43*	*.55*	*1.35*	*.32*	*2.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.265	.265	.265	.265	1.06
2019	.29	.29	.29	.29	1.16
2020	.3075	.3075	.3075	.3075	1.23
2021	.3275	.3275	.3275	.3275	1.31
2022	.3475				

BUSINESS: PNM Resources, Inc. is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves 538,000 customers in north central New Mexico, including Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to 261,000 customers in Texas. Electric revenue breakdown: residential, 42%; commercial, 36%; industrial, 8%; other, 14%. Generating sources not available. Fuel costs: 36% of revenues. '21 reported depreciation rates: 2.5%-7.9%. Has 1,600 employees. Chairman, President & CEO: Patricia K. Collawn. Incorporated: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, New Mexico 87102-3289. Telephone: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources and AVANGRID are appealing the New Mexico commission's rejection of their proposed deal. The agreement calls for PNM Resources stockholders to receive $50.30 in cash for each of their shares. However, the New Mexico regulators rejected a settlement agreement. In February, the companies appealed this to the state Supreme Court. This is expected to take 12-18 months.

We think the stock is trading as if the transaction will not be completed. The stock has moved up in price of late mainly because utility stocks in general have fared well in recent weeks. The recent quotation is 5% below the buyout price.

Another appeal is pending before the New Mexico Supreme Court. This involves the utility's request to abandon its stake in the Four Corners and recover its undepreciated investment by issuing securitized bonds. However, the commission denied PNM's request.

We expect significant earnings improvement in 2022, followed by further growth in 2023. The key factor this year is a $285 million acquisition of transmission assets in late 2021. This is likely to add $0.17-$0.18 to share net. The company will also benefit from load growth and rate relief for TNMP, its utility in Texas, thanks to regulatory mechanisms for transmission and distribution spending. TNMP was granted $14.2 million, effective March 25th. Our share-net estimates are within the company's guidance of $2.50-$2.60 for 2022 and $2.60-$2.75 for 2023. Note that Public Service of New Mexico plans to file a rate case in December, but any rate relief won't come in time to help boost 2023 profits much, if at all.

The board of directors raised the dividend in the first quarter. The hike was $0.02 a share (6.1%) quarterly. The timing of the declaration was delayed from December because PNM Resources was anticipating completion of the deal with AVANGRID. Thus, there will probably be five declarations this year, versus only three in 2021.

This untimely stock's dividend yield does not stand out among utilities. It isn't notable for 3- to 5-year total return potential, either. The difficult regulatory climate in New Mexico is a disadvantage.

Paul E. Debbas, CFA *April 22, 2022*

(A) Dil. EPS. Excl. nonrec. gain (losses): '08, ($3.77); '10, ($1.36); '11, 88¢; '13, (16¢); '15, ($1.28); '17, (92¢); '18, (59¢); '19, ($1.31). Excl. gains from disc. ops.: '08, 42¢; '09, 78¢. Next egs. report due late April. (B) Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinv. plan avail. 3 div'ds decl. in '21, 5 expected in '22. (C) Incl. intang. In '21: $10.86/sh. (D) In mill., adj. for split. (E) Rate base: net orig. cost. Rate all'd on com. eq. in NM in '18: 9.575%; in TX in '11: 10.125%; earned on avg. com. eq., '21: 9.3%. Reg. Climate: NM, Below Avg.; TX, Avg.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	75
Earnings Predictability	75

PPL CORPORATION NYSE-PPL

RECENT PRICE 29.68 | P/E RATIO 21.7 (Trailing: 41.8 Median: 13.0) | RELATIVE P/E RATIO 1.23 | DIV'D YLD 3.4-5.6% | VALUE LINE

TIMELINESS 5 Lowered 11/26/21
SAFETY 2 Raised 8/21/15
TECHNICAL 3 Raised 2/4/22
BETA 1.10 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	30.3	30.2	33.6	38.1	36.7	39.9	40.2	32.5	36.3	36.8	30.7	30.4
Low:	24.1	26.7	28.4	29.4	29.2	32.1	30.7	25.3	27.8	18.1	26.2	28.9

18-Month Target Price Range

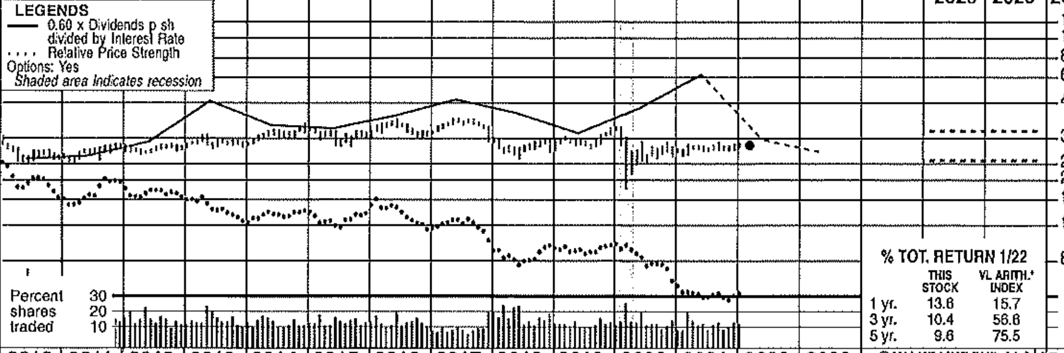
Low-High	Midpoint (% to Mid)
$18-$33	$26 (-15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+20%)	7%
Low	25	(-15%)	Nil

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	368	410	389
to Sell	352	326	331
Hld's(000)	507894	497392	491851



% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.8	15.7
3 yr.	10.4	56.8
5 yr.	9.6	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
17.92	17.41	21.47	20.03	17.63	22.02	21.11	18.82	17.27	11.38	11.06	10.74	10.81	10.13	9.89	7.90	8.15	8.40	Revenues per sh	9.25
4.26	5.10	4.71	3.47	3.66	4.59	4.84	4.64	4.58	3.78	4.28	3.68	4.16	3.94	3.81	2.20	3.15	3.25	"Cash Flow" per sh	3.75
2.29	2.63	2.45	1.19	2.29	2.61	2.61	2.38	2.38	2.37	2.79	2.11	2.58	2.37	2.04	.60	1.45	1.50	Earnings per sh A	1.80
1.10	1.22	1.34	1.38	1.40	1.40	1.44	1.47	1.49	1.50	1.52	1.58	1.64	1.65	1.66	1.66	1.00	1.00	Div'd Decl'd per sh B ■	1.10
3.62	4.51	3.79	3.25	3.30	4.30	5.34	6.68	6.14	5.24	4.30	4.52	4.50	4.02	4.23	2.85	2.15	1.90	Cap'l Spending per sh	1.75
13.30	14.88	13.55	14.57	16.98	18.72	18.01	19.78	20.47	14.72	14.56	15.52	16.18	16.93	17.39	10.70	11.25	11.80	Book Value per sh C	14.00
385.04	373.27	374.58	377.18	483.39	578.41	581.94	630.32	665.85	673.86	679.73	693.40	720.32	767.23	768.91	735.00	737.00	739.00	Common Shs Outst'g D	745.00
14.1	17.3	17.6	25.7	11.9	10.5	10.9	12.8	14.1	13.9	12.8	17.6	11.3	13.3	13.9	NMF	Bold figures are		Avg Ann'l P/E Ratio	16.5
.76	.92	1.06	1.71	.76	.66	.69	.72	.74	.70	.67	.89	.61	.71	.71	NMF	Value Line		Relative P/E Ratio	.90
3.4%	2.7%	3.1%	4.5%	5.1%	5.1%	5.1%	4.8%	4.4%	4.5%	4.2%	4.2%	5.6%	5.2%	5.8%	5.8%	estimates		Avg Ann'l Div'd Yield	3.7%
						12286	11860	11499	7669.0	7517.0	7447.0	7785.0	7769.0	7607.0	5800	6000	6200	Revenues ($mill)	6800
						1536.0	1541.0	1583.0	1603.0	1902.0	1449.0	1827.0	1746.0	1571.0	450	1075	1120	Net Profit ($mill)	1345
						26.2%	23.1%	33.0%	22.5%	25.4%	24.2%	20.0%	19.0%	20.3%	22.0%	22.0%	22.0%	Income Tax Rate	22.0%
						4.1%	3.7%	2.8%	1.6%	1.6%	1.9%	2.0%	1.9%	1.8%	7.0%	3.0%	3.0%	AFUDC % to Net Profit	2.0%
						64.1%	62.3%	58.0%	65.2%	64.3%	64.8%	63.3%	61.5%	61.7%	54.5%	56.0%	59.0%	Long-Term Debt Ratio	59.5%
						35.9%	37.7%	42.0%	34.8%	35.7%	35.2%	36.7%	38.5%	38.3%	45.5%	44.0%	41.0%	Common Equity Ratio	40.5%
						29205	33058	32484	28482	27707	30608	31726	33712	34926	17275	18825	21375	Total Capital ($mill)	25700
						30032	33087	34597	30382	30074	33092	34458	36482	38892	25425	25800	25900	Net Plant ($mill)	25600
						7.0%	6.2%	6.5%	7.1%	8.4%	6.2%	7.2%	6.6%	5.9%	5.5%	6.5%	6.5%	Return on Total Cap'l	6.5%
						14.7%	12.4%	11.6%	16.2%	19.2%	13.5%	15.7%	13.4%	11.7%	9.5%	13.0%	13.0%	Return on Shr. Equity	13.0%
						14.6%	12.4%	11.6%	16.2%	19.2%	13.5%	15.7%	13.4%	11.7%	9.5%	13.0%	13.0%	Return on Com Equity E	13.0%
						6.7%	5.3%	4.5%	6.0%	8.8%	3.5%	6.0%	4.3%	2.2%	NMF	4.0%	4.5%	Retained to Com Eq	5.0%
						54%	57%	61%	63%	54%	74%	62%	66%	81%	NMF	68%	66%	All Div'ds to Net Prof	61%

CAPITAL STRUCTURE as of 9/30/21
Total Debt $11139 mill. **Due In 5 Yrs** NA
LT Debt $10665 mill. **LT Interest** $427 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value.
(LT interest earned: 2.4x)

Leases, Uncapitalized Annual rentals $27 mill.
Pension Assets-12/20 $14038 mill.
Oblig $13549 mill.

Pfd Stock None
Common Stock 750,715,902 shs.
as of 10/31/21
MARKET CAP: $22 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2018	2019	2020
% Change Retail Sales (KWH)	+2.0	-3.4	-5.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	292	283	278

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	-6.5%	-8.5%	NMF
"Cash Flow"	--	-1.5%	NMF
Earnings	1.5%	-.5%	NMF
Dividends	2.0%	2.0%	NMF
Book Value	1.0%	-1.5%	NMF

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2079	1803	1933	1954	7769.0
2020	2054	1739	1885	1929	7607.0
2021	1498	1288	1512	1502	5800
2022	1550	1400	1525	1525	6000
2023	1600	1450	1575	1575	6200

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.64	.60	.65	.48	2.37
2020	.72	.45	.50	.38	2.04
2021	.26	d.20	.27	.27	.60
2022	.35	.35	.40	.35	1.45
2023	.36	.36	.42	.36	1.50

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.395	.41	.41	.41	1.63
2019	.41	.4125	.4125	.4125	1.65
2020	.4125	.415	.415	.415	1.66
2021	.415	.415	.415	.415	1.66
2022	.415				

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Electric Utilities (formerly Pennsylvania Power & Light Company), which distributes electricity to 1.4 million customers in eastern & central PA. Acq'd Kentucky Utilities and Louisville Gas and Electric (1.3 mill. customers) 11/10. Sold gas distribution sub. in '08. Spun off power-generating sub. in '15. Sold electric distribution sub. in U.K. in '21. Electric rev. breakdown: residential, 46%; commercial, 21%; industrial, 11%; other, 22%. Fuel costs: 17% of revs. '20 reported deprec. rate: 2.8%. Has 12,500 employees. Chairman: William H. Spence. Pres. & CEO: Vincent Sorgi. Inc.: PA. Address: Two North Ninth St., Allentown, PA 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

PPL Corporation expects to complete its acquisition of Narragansett Electric soon. PPL has agreed to pay $3.8 billion in cash for the utility, which serves about 780,000 electric and gas customers in Rhode Island. The transaction requires the approval of the Rhode Island regulators. Their decision is targeted for February 25th. If the order is favorable, the deal is expected to close shortly thereafter. Our figures will not include Narragansett Electric until after the acquisition is completed, so our estimates and projections do not reflect PPL's earning power after the deal is completed. We think our figures understate the company's post-acquisition earning power by about $0.20 a share. For the 12-month period that ended on March 31, 2021, the utility's net profit was about $140 million.

The purchase is one of the company's intended uses of the cash it raised from the sale of its operations in the United Kingdom last year. The divestiture raised $10.4 billion. PPL retired $3.5 billion in debt, planned to repurchase $1 billion of common stock by year-end 2021, and intends to increase its utility capital investment in Pennsylvania and Kentucky by at least $1 billion through 2025. Management plans to share additional details of its plans following completion of the Narragansett acquisition.

The Federal Energy Regulatory Commission approved a settlement concerning PPL's transmission rates. This is expected to reduce net income by $25 million-$30 million annually. The settlement was already reflected in the company's results for the first nine months of 2021.

A dividend cut is coming. The sale of the U.K. businesses reduced PPL's regulatory, political, and currency risks, but also lowered the company's earning power. Once the Narragansett purchase is completed, the board of directors will reset the dividend to reflect a payout ratio of 60%-65%. Our estimate is that the annual disbursement will be cut from $1.66 a share to $1.00. This would give the stock a dividend yield that is about average for a utility. We advise investors to wait for more clarity from the company after the acquisition is completed. The stock is untimely.

Paul E. Debbas, CFA *February 11, 2022*

(A) Dil. EPS. Excl. nonrec. gain (losses): '07, (12¢); '10, (8¢); '11, 8¢; '13, (62¢); '20, (13¢); '21, (50¢); gains (losses) on disc. ops.: '07, 19¢; '08, 3¢; '09, (10¢); '10, (4¢); '12, (1¢); '14, 23¢; '15, ($1.36); '21, ($1.94). '20 EPS don't sum due to rounding. Next earnings report due mid-Feb. (B) Div'ds paid in early Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. Intang. In '20: $6.89/sh. (D) In mill. (E) Rate base: Fair val. Rate all'd on com. eq. in PA in '16: none spec.; in KY in '19: 9.725%; earned on avg. com. eq., '20: 11.9%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	75
Price Growth Persistence	15
Earnings Predictability	60

P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE 66.53 | P/E RATIO 18.3 (Trailing: 26.4 / Median: 14.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.2% | **VALUE LINE**

TIMELINESS 4 Lowered 12/17/21

SAFETY 1 Raised 11/23/12

TECHNICAL 3 Lowered 2/11/22

BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High Midpoint (% to Mid)

$50-$74 $62 (-5%)

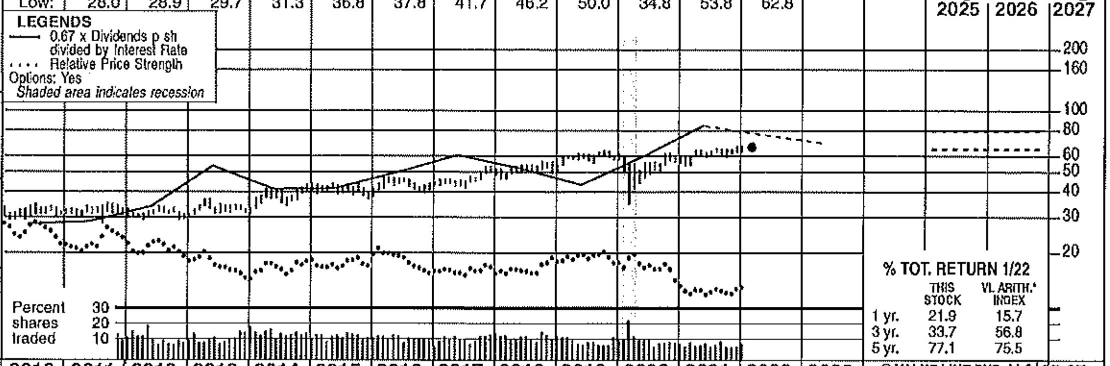
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+20%)	8%
Low	65	(Nil)	3%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	378	399	397
to Sell	366	331	333
Hld's(000)	353937	358196	363353

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	35.5	34.1	37.0	43.8	44.4	47.4	53.3	56.7	63.9	62.2	67.1	67.6	
Low:	28.0	28.9	29.7	31.3	36.8	37.8	41.7	46.2	50.0	34.8	53.8	62.8	



% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.9	15.7
3 yr.	33.7	56.8
5 yr.	77.1	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.07	25.28	27.94	24.57	23.31	22.42	19.33	19.71	21.52	20.61	18.22	18.14	19.24	19.99	19.05	*17.15*	*16.05*	*16.85*	Revenues per sh	*19.50*
3.91	4.36	4.68	4.98	5.27	5.36	4.87	5.17	5.82	6.15	5.07	5.30	5.44	6.76	6.54	*5.40*	*6.85*	*7.20*	"Cash Flow" per sh	*8.25*
1.85	2.59	2.90	3.08	3.07	3.11	2.44	2.45	2.99	3.30	2.83	2.82	2.76	3.90	3.61	*2.30*	*3.60*	*3.80*	Earnings per sh A	*4.50*
1.14	1.17	1.29	1.33	1.37	1.37	1.42	1.44	1.48	1.56	1.64	1.72	1.80	1.88	1.96	2.04	*2.16*	*2.28*	Div'd Decl'd per sh B ■†	*2.65*
2.01	2.65	3.50	3.55	4.27	4.12	5.09	5.56	5.58	7.65	8.32	8.30	7.76	6.28	5.80	*6.65*	*7.45*	*7.65*	Cap'l Spending per sh	*7.25*
13.35	14.35	15.36	17.37	19.04	20.30	21.31	22.95	24.09	25.86	26.01	27.42	28.53	29.94	31.71	*27.80*	*28.95*	*30.50*	Book Value per sh C	*35.75*
505.29	508.52	506.02	505.99	505.97	505.95	505.89	505.86	505.84	505.28	504.87	505.00	504.00	504.00	504.00	*502.00*	*498.00*	*498.00*	Common Shs Outst'g D	*498.00*
17.8	16.5	13.6	10.0	10.4	10.4	12.8	13.5	12.6	12.4	15.3	16.3	18.7	15.1	14.9	*28.0*	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
.96	.88	.82	.67	.66	.65	.81	.76	.66	.62	.80	.62	1.01	.80	.77	*1.50*			Relative P/E Ratio	*.90*
3.5%	2.7%	3.3%	4.3%	4.3%	4.2%	4.6%	4.4%	3.9%	3.8%	3.8%	3.7%	3.5%	3.2%	3.6%	3.2%			Avg Ann'l Div'd Yield	*3.7%*
						9781.0	9968.0	10886	10415	9198.0	9161.0	9696.0	10076	9603.0	*8600*	*8000*	*8400*	Revenues ($mill)	*9250*
						1239.0	1243.0	1518.0	1679.0	1436.0	1431.0	1399.0	1979.0	1829.0	*1175*	*1805*	*1910*	Net Profit ($mill)	*2145*
						36.2%	39.5%	38.2%	37.4%	31.7%	37.3%	22.3%	15.9%	16.1%	*20.0%*	*20.0%*	*20.0%*	Income Tax Rate	*21.0%*
						4.8%	4.6%	4.5%	5.5%	8.4%	10.6%	9.8%	5.5%	7.2%	*11.0%*	*7.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
						38.3%	40.4%	40.4%	40.3%	45.3%	46.6%	47.8%	47.7%	47.6%	*53.5%*	*54.5%*	*55.0%*	Long-Term Debt Ratio	*52.0%*
						61.7%	59.6%	59.6%	59.7%	54.7%	53.4%	52.2%	52.3%	52.4%	*46.5%*	*45.5%*	*45.0%*	Common Equity Ratio	*48.0%*
						17467	19470	20446	21900	24025	25915	27545	28832	30480	*29950*	*31725*	*33900*	Total Capital ($mill)	*41300*
						19736	21645	23589	26539	29286	31797	34363	35844	37585	*37450*	*39600*	*41800*	Net Plant ($mill)	*47400*
						8.1%	7.5%	8.4%	8.6%	6.8%	6.4%	6.0%	7.8%	6.9%	*5.0%*	*6.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
						11.5%	10.7%	12.5%	12.9%	10.9%	10.3%	9.7%	13.1%	11.4%	*8.5%*	*12.5%*	*12.5%*	Return on Shr. Equity	*12.5%*
						11.5%	10.7%	12.5%	12.9%	10.9%	10.3%	9.7%	13.1%	11.4%	*8.5%*	*12.5%*	*12.5%*	Return on Com Equity E	*12.5%*
						4.8%	4.4%	6.3%	6.8%	4.6%	4.1%	3.4%	6.8%	5.2%	*1.0%*	*5.0%*	*5.0%*	Retained to Com Eq	*5.0%*
						58%	59%	49%	47%	58%	61%	65%	48%	54%	*87%*	*60%*	*59%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 9/30/21
Total Debt $19780 mill. **Due in 5 Yrs** $10706 mill.
LT Debt $14425 mill. **LT Interest** $498 mill.
(LT interest earned: 4.2x)

Leases, Uncapitalized Annual rentals $45 mill.

Pension Assets-12/20 $6368 mill.
Oblig $7507 mill.

Pfd Stock None

Common Stock 505,663,672 shs.
as of 10/19/21
MARKET CAP: $34 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2018	2019	2020
% Change Retail Sales (KWH)	+2.8	-2.9	-2.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH(¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	9978	9753	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	413	361	298

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	-2.5%	-1.0%	*Nil*
"Cash Flow"	2.5%	2.0%	*4.0%*
Earnings	1.5%	3.5%	*4.0%*
Dividends	3.5%	4.5%	*5.0%*
Book Value	5.5%	4.5%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2980	2316	2302	2478	10076
2020	2781	2050	2370	2402	9603.0
2021	2889	1874	1903	*1934*	*8600*
2022	*2450*	*1550*	*2000*	*2000*	*8000*
2023	*2550*	*1650*	*2100*	*2100*	*8400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.38	.86	.80	.86	3.90
2020	.88	.89	.99	.85	3.61
2021	1.28	.39	--	*.63*	*2.30*
2022	*1.25*	*.80*	*.95*	*.60*	*3.60*
2023	*1.30*	*.85*	*1.00*	*.65*	*3.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.45	.45	.45	.45	1.80
2019	.47	.47	.47	.47	1.88
2020	.49	.49	.49	.49	1.96
2021	.51	.51	.51	.51	2.04
2022					

BUSINESS: Public Service Enterprise Group Incorporated is a holding company for Public Service Electric and Gas Company (PSE&G), which serves 2.3 million electric and 1.9 million gas customers in New Jersey, and PSEG Power LLC, a nonregulated power generator with nuclear, gas, and coal-fired plants in the Northeast. PSEG Energy Holdings is involved in renewable energy. The company no longer breaks out data on electric and gas operating statistics. Fuel costs: 32% of revenues. '20 reported depreciation rates (utility): 1.8%-2.6%. Has 12,800 employees. Chairman, President & CEO: Dr. Ralph Izzo. COO: Ralph A. LaRosse. Inc.: New Jersey. Address: 80 Park Plaza, P.O. Box 1171, Newark, New Jersey 07101-1171. Tel.: 973-430-7000. Internet: www.pseg.com.

Public Service Enterprise Group is awaiting the closing of the sales of its nonregulated fossil-fueled generating assets. The company made a strategic decision to focus on its regulated utility subsidiary, Public Service Electric and Gas, and its nonregulated nuclear facilities. The sales are expected to raise $2.5 billion in cash. However, because the sale prices were lower than the assets' carrying value, PSEG recorded impairment charges in the second and third quarters of 2021. These amounted to $3.84 a share, which we *excluded* from our earnings presentation as nonrecurring items. PSEG plans to use the proceeds to retire debt and repurchase $500 million of common stock. Initially, the company planned to wait for the deals to be completed before buying back any stock, but in mid-November the board of directors authorized management to repurchase the stock at its discretion, even if this preceded completion of the asset sales (which is expected soon).

An earnings recovery is likely in 2022, followed by further growth in 2023. After the aforementioned asset sales are completed, some 90% of PSEG's income will come from PSE&G. The utility's earnings are advancing thanks to regulatory mechanisms that allow recovery of much of its capital spending (such as for improving system reliability) contemporaneously. We note that the comparison with the expected 2021 tally is easy because mark-to-market accounting charges reduced pretax income by $1 billion in the first nine months. We *include* these items in our earnings presentation because they are an ongoing part of PSEG's results. The stock buyback is reflected in our estimates.

We expect a healthy dividend increase at the board meeting later this month. In September, PSEG indicated its expectation of a $0.12-a-share (5.9%) boost in the annual disbursement. This is an acceleration from the growth rate seen in recent years. We project that the company will maintain this growth rate through mid-decade.

The dividend yield of this untimely but top-quality stock is about average, by utility standards. Total return potential is unappealing for the next 18 months and the 3- to 5-year period.

Paul E. Debbas, CFA *February 11, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, (35¢); '08, (96¢); '09, 6¢; '11, (34¢); '12, 7¢; '16, (30¢); '17, 28¢ (net); '18, 8¢; '19, (62¢); '20, 15¢; '21, ($3.84); gains from disc. ops.: '06, 12¢; '07, 3¢; '08, 40¢; '11, 13¢. Next earnings report due late Feb. (B) Div'ds historically paid in late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '20: $8.00/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '18: 9.6%; earned on avg. com. eq., '20: 11.8%. Regulatory Climate: Avg.

Company's Financial Strength	A++
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	80

SEMPRA ENERGY NYSE-SRE

RECENT PRICE 168.25 | P/E RATIO 20.1 (Trailing: NMF Median: 21.0) | RELATIVE P/E RATIO 1.13 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Raised 1/14/22
SAFETY 2 Raised 7/29/16
TECHNICAL 3 Raised 4/22/22
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$119-$182	$151 (-10%)

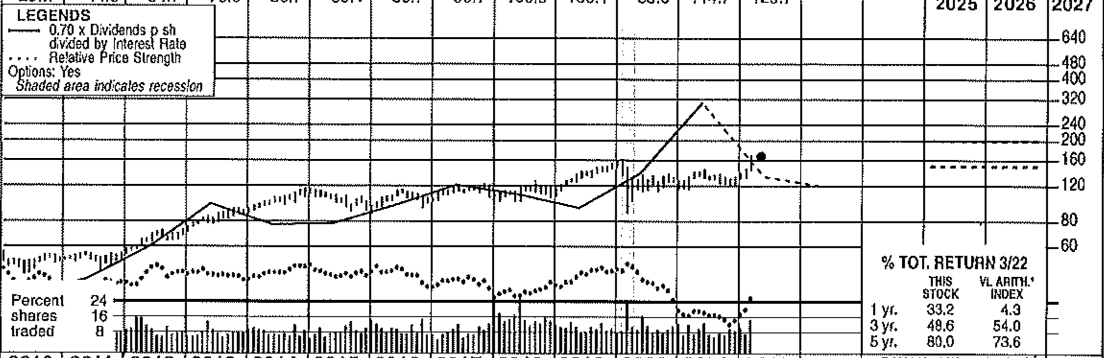
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	200	(+20%)	7%
Low	150	(-10%)	1%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	434	404	453
to Sell	272	305	315
Hld's(000)	266791	272986	269538

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	56.0	72.9	93.0	116.3	116.2	114.7	123.0	127.2	154.5	161.9	144.9	170.8
Low:	44.8	54.7	70.6	86.7	89.4	86.7	99.7	100.5	106.1	88.0	114.7	129.7



% TOT. RETURN 3/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	33.2	4.3
3 yr.	48.6	54.0
5 yr.	80.0	73.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
44.89	43.79	44.21	32.88	37.44	41.83	39.80	43.18	44.80	41.20	40.71	44.59	42.69	37.12	39.41	40.57	44.45	48.20	Revenues per sh	55.75
6.74	6.93	7.40	7.94	7.76	8.58	8.92	8.87	9.41	10.32	9.50	10.57	11.07	11.14	12.41	9.81	14.75	16.15	"Cash Flow" per sh	19.50
4.23	4.26	4.43	4.78	4.02	4.47	4.35	4.22	4.63	5.23	4.24	4.63	5.48	5.97	6.58	4.01	8.35	8.90	Earnings per sh A	10.75
1.20	1.24	1.37	1.56	1.56	1.92	2.40	2.52	2.64	2.80	3.02	3.29	3.58	3.87	4.18	4.40	4.58	4.76	Div'd Decl'd per sh B ■	5.60
7.28	7.70	8.47	7.76	8.58	11.85	12.20	10.52	12.68	12.71	16.85	15.71	13.82	12.71	16.21	15.82	16.05	13.75	Cap'l Spending per sh	13.75
28.66	31.87	32.75	36.54	37.54	41.00	42.42	45.03	45.98	47.56	51.77	50.41	54.35	60.58	70.11	79.17	82.85	86.50	Book Value per sh C	101.00
262.01	261.21	243.32	246.51	240.45	239.93	242.37	244.46	246.33	248.30	250.15	251.36	273.77	291.71	288.47	316.92	315.00	305.00	Common Shs Outst'g D	305.00
11.5	14.0	11.8	10.1	12.6	11.8	14.9	19.7	21.9	19.7	24.4	24.3	20.4	22.5	19.6	32.4	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	16.5
.62	.74	.71	.67	.80	.74	.95	1.11	1.15	.99	1.28	1.22	1.10	1.20	1.01	1.78			Relative P/E Ratio	.90
2.5%	2.1%	2.6%	3.2%	3.1%	3.6%	3.7%	3.0%	2.6%	2.7%	2.9%	2.9%	3.2%	2.9%	3.2%	3.4%			Avg Ann'l Div'd Yield	3.2%
						9647.0	10557	11035	10231	10183	11207	11687	10829	11370	12857	14000	14700	Revenues ($mill)	17000
						1079.0	1060.0	1162.0	1314.0	1065.0	1169.0	1607.0	1825.0	2083.0	1318.0	2845	2965	Net Profit ($mill)	3480
						18.2%	26.5%	19.7%	19.2%	14.4%	24.5%	20.1%	17.9%	16.7%	45.2%	19.0%	19.0%	Income Tax Rate	19.0%
						17.2%	11.2%	14.4%	15.3%	22.2%	21.9%	12.6%	10.0%	9.7%	16.5%	8.0%	8.0%	AFUDC % to Net Profit	7.0%
						52.8%	50.5%	51.7%	52.6%	52.7%	56.4%	55.7%	51.0%	48.2%	44.8%	46.0%	47.5%	Long-Term Debt Ratio	46.5%
						46.7%	49.4%	48.2%	47.3%	47.3%	43.5%	38.4%	43.4%	44.8%	53.3%	52.0%	51.0%	Common Equity Ratio	52.0%
						22002	22281	23513	24963	27400	29135	38769	40734	45174	47049	50000	51750	Total Capital ($mill)	59300
						25191	25460	25902	28039	32931	36503	36796	36452	40003	43894	46950	49000	Net Plant ($mill)	54000
						6.1%	6.0%	6.1%	6.4%	5.0%	5.1%	5.1%	5.5%	5.5%	3.7%	6.5%	6.5%	Return on Total Cap'l	7.0%
						10.4%	9.6%	10.2%	11.1%	8.2%	9.2%	9.4%	9.1%	8.9%	5.1%	10.0%	10.5%	Return on Shr. Equity	10.5%
						10.4%	9.6%	10.3%	11.1%	8.2%	9.2%	10.0%	9.5%	9.5%	5.0%	10.0%	10.5%	Return on Com Equity E	10.5%
						5.1%	4.1%	5.0%	5.8%	2.9%	3.3%	4.1%	3.9%	3.7%	NMF	4.5%	5.0%	Retained to Com Eq	5.0%
						52%	58%	52%	48%	65%	65%	62%	62%	64%	106%	55%	54%	All Div'ds to Net Prof	53%

CAPITAL STRUCTURE as of 12/31/21
Total Debt $24645 mill. **Due in 5 Yrs** $7358 mill.
LT Debt $21068 mill. **LT Interest** $791 mill.
Incl. $1335 mill. finance leases.
(LT interest earned: 2.6x)

Leases, Uncapitalized Annual rentals $73 mill.
Pension Assets-12/21 $3182 mill.
Oblig $3857 mill.
Pfd Stock $889 mill. **Pfd Div'd** $45 mill.
900,000 shs. 4.875%, cumulative.
Common Stock 315,653,893 shs.
as of 2/18/22
MARKET CAP: $53 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-4.3	-.4	-3.7
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.8	+.8	+.9
Fixed Charge Cov. (%)	181	159	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-1.5%	6.0%
"Cash Flow"	3.0%	2.5%	10.0%
Earnings	2.0%	3.5%	11.5%
Dividends	9.5%	8.0%	5.0%
Book Value	6.0%	7.5%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2898	2230	2758	2943	10829
2020	3029	2526	2644	3171	11370
2021	3259	2741	3013	3844	12857
2022	3900	3000	3200	3900	14000
2023	4100	3150	3350	4100	14700

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.78	.85	2.00	1.34	5.97
2020	2.30	1.58	1.23	1.43	6.58
2021	2.87	1.37	d2.03	1.90	4.01
2022	2.60	1.90	1.95	1.90	8.35
2023	2.85	2.00	2.05	2.00	8.90

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.8225	.895	.895	.895	3.51
2019	.895	.9675	.9675	.9675	3.80
2020	.9675	1.045	1.045	1.045	4.10
2021	1.045	1.10	1.10	1.10	4.35
2022	1.10	1.145			

BUSINESS: Sempra Energy is a holding company for San Diego Gas & Electric Company, which sells electricity & gas mainly in San Diego County, & Southern California Gas Company, which distributes gas to most of Southern Californie. Owns 80% of Oncor (acq'd 3/18), which distributes electricity in Texes. Customers: 5.2 million electric, 7.0 million gas. Electric revenue breakdown not available. Purchases most of its power; the rest is gas. Has non-utility subsidiaries, incl. IEnova in Mexico. Sold commodities business in '10. Power costs: 20% of revenues. '21 reported deprec. rates: 2.6%-7.2%. Has 15,400 employees. Chairman, President & CEO: Jeffrey W. Martin. Inc.: CA. Address: 488 8th Ave., San Diego, CA 92101. Tel.: 619-696-2000. Internet: www.sempra.com.

Sempra Energy stock has been the top performer in tbe electric utility industry so far in 2022. The price has risen more than 25%. We attribute this to investor interest in the company's liquefied natural gas export business, which is part of Sempra Infrastructure Partners. The demand for LNG is increasing due to sanctions on Russia. However, any benefit to Sempra from increased LNG demand will be seen over the long term as the company increases its capacity. Its current capacity is under long-term contracts.

Earnings will likely rebound this year and advance in 2023 after a depressed result in 2021. The bottom line fell into the red in the September quarter due to a $1.6 billion pretax charge related to litigation that arose from a leak in a gas storage facility several years ago. Besides the absence of this charge, Sempra will benefit from rate relief at its utility subsidiaries in California and growth at its utility in Texas. These factors should help lift profits in 2023, as well. We are assuming no change in the allowed return on equity at the utilities (see below). Our share-earnings estimates are within the company's targeted ranges of $8.10-$8.70 and $8.60-$9.20 in 2022 and 2023, respectively.

A cost-of-capital case is pending in California. A provision under the state's regulatory mechanism would force a cut in the allowed ROEs for San Diego Gas and Electric from 10.2% to 9.62%. However, the utility is arguing that the mechanism should not take effect due to the extremely low interest rates from the easing that happened two years ago as the economy was under lockdown. In fact, SDG&E is proposing to increase its allowed ROE to 10.55% and its common-equity ratio from 52% to 54%. Any change would be in effect only for 2022 and would be retroactive to the start of the year.

An asset sale will probably be completed this summer. Sempra has agreed to sell a 10% interest in its infrastructure unit for $1.8 billion. It plans to use the cash for capital spending and stock buybacks.

We think the stock is overbought. The dividend yield is below the utility average, and the recent quotation is well within our 3- to 5-year Target Price Range.

Paul E. Debbas, CFA *April 22, 2022*

(A) Dil. EPS. Excl. nonrec. gains (losses): '09, (26¢); '10, ($1.05); '11, $1.15; '12, (98¢); '13, (30¢); '15, 14¢; '16, $1.23; '17, (17¢); '18, ($2.06); '19, 16¢; gains from disc. ops.: '19, 95¢; '20, $6.32. '20 & '21 EPS don't sum due to chg. in shs. Next egs. report due early May. (B) Div'ds paid mid-Jan., Apr., July, Oct. ■ Div'd reinv. avail. (C) Incl. intang. In '21: $12.57/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq.: SDG&E in '20: 10.2%; SoCalGas in '20: 10.05%; earned on avg. com. eq., '21: 5.5%. Reg. Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	75

SOUTHERN COMPANY NYSE-SO

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
69.49	19.2 (Trailing: 19.6 Median: 16.0)	1.08	3.9%

VALUE LINE

TIMELINESS	4	Lowered 8/13/21
SAFETY	2	Lowered 2/21/14
TECHNICAL	3	Raised 1/28/22

BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$56-$78	$67 (-5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+10%)	6%
Low	55	(-20%)	-1%

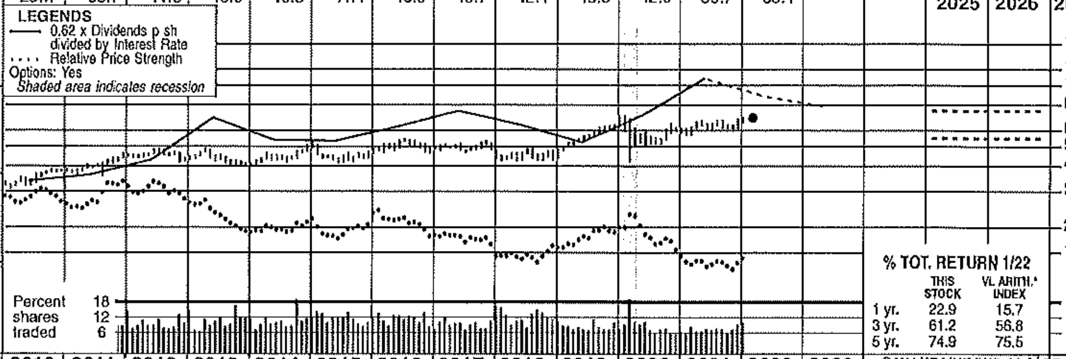
Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	676	743	676
to Sell	649	580	598
Hld's(000)	627954	629680	633336

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	46.7	48.6	48.7	51.3	53.2	54.6	53.5	49.4	64.3	71.1	68.9
Low:	35.7	41.8	40.0	40.3	41.4	46.0	46.7	42.4	43.3	42.0	56.7

High:	69.8
Low:	65.4

Target Price Range
2025 | 2026 | 2027



% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.9	15.7
3 yr.	61.2	56.8
5 yr.	74.9	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
19.24	20.12	22.04	19.21	20.70	20.41	19.06	19.26	20.34	19.18	20.09	22.86	22.73	20.34	19.29	*21.50*	*22.55*	*23.70*	Revenues per sh	*27.50*
4.01	4.22	4.43	4.43	4.51	4.91	5.18	5.27	5.28	5.47	5.69	6.64	6.41	6.33	6.98	*7.20*	*7.40*	*7.75*	"Cash Flow" per sh	*9.00*
2.10	2.28	2.25	2.32	2.36	2.55	2.67	2.70	2.77	2.84	2.83	3.21	3.00	3.17	3.25	*3.50*	*3.60*	*3.80*	Earnings per sh A	*4.50*
1.54	1.60	1.68	1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	2.30	2.38	2.46	2.54	2.62	*2.70*	*2.78*	Div'd Decl'd per sh B ■	*3.02*
4.01	4.65	5.10	5.70	4.85	5.23	5.54	6.16	6.58	6.22	7.38	7.37	7.74	7.17	7.04	*7.65*	*6.55*	*6.55*	Cap'l Spending per sh	*6.25*
15.24	16.23	17.08	18.15	19.21	20.32	21.09	21.43	21.98	22.59	25.00	23.98	23.92	26.11	26.48	*26.75*	*27.65*	*28.70*	Book Value per sh C	*32.75*
746.27	763.10	777.19	819.65	843.34	865.13	867.77	887.09	907.78	911.72	990.39	1007.6	1033.8	1053.3	1056.5	*1070.0*	*1070.0*	*1070.0*	Common Shs Outst'g D	*1070.0*
16.2	16.0	16.1	13.5	14.9	15.8	17.0	16.2	16.0	15.8	17.8	15.5	15.1	17.6	17.9	*18.0*	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
.87	.85	.97	.90	.95	.99	1.08	.91	.84	.80	.93	.78	.82	.94	.92	*.95*			Relative P/E Ratio	*.85*
4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	4.8%	4.4%	4.6%	5.3%	4.4%	4.4%	4.2%			Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 9/30/21
Total Debt $52836 mill. **Due in 5 Yrs** $13952 mill.
LT Debt $48843 mill. **LT Interest** $1682 mill.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $300 mill.
Pension Assets-12/20 $15367 mill.
Oblig $16646 mill.
Pfd Stock $291 mill. **Pfd Div'd** $15 mill.
Incl. 10 mill. shs. 5.83% cum. pfd. ($25 stated value); 475,115 shs. 4.2%-5.44% cum. pfd. ($100 par).
Common Stock 1,059,803,931 shs.

MARKET CAP: $74 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
16537	17087	18467	17489	19896	23031	23495	21419	20375	*23000*	*24150*	*25350*	Revenues ($mill)	*29350*
2415.0	2439.0	2567.0	2647.0	2757.0	3269.0	3096.0	3354.0	3481.0	*3750*	*3840*	*4085*	Net Profit ($mill)	*4870*
35.6%	34.8%	33.8%	33.4%	28.5%	25.2%	21.3%	15.9%	14.3%	*13.5%*	*14.0%*	*14.0%*	Income Tax Rate	*14.0%*
9.4%	11.6%	13.9%	13.2%	11.9%	7.6%	6.8%	6.0%	6.6%	*7.0%*	*6.0%*	*6.0%*	AFUDC % to Net Profit	*4.0%*
49.9%	51.5%	49.5%	52.8%	61.5%	64.5%	62.0%	60.1%	61.5%	*63.5%*	*63.5%*	*63.5%*	Long-Term Debt Ratio	*63.0%*
47.3%	45.8%	47.3%	44.0%	35.7%	35.0%	37.6%	39.5%	38.1%	*36.0%*	*36.5%*	*36.0%*	Common Equity Ratio	*37.0%*
38653	41483	42142	46788	69359	68953	65750	69594	73336	*79250*	*81475*	*84925*	Total Capital ($mill)	*95300*
48390	51208	54868	61114	78446	79872	80797	83080	87634	*91875*	*94825*	*97625*	Net Plant ($mill)	*104100*
7.3%	6.8%	7.1%	6.6%	4.9%	5.9%	5.9%	6.0%	5.9%	*6.0%*	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
12.5%	12.1%	12.1%	12.0%	10.3%	13.3%	12.4%	12.1%	12.3%	*13.0%*	*13.0%*	*13.5%*	Return on Shr. Equity	*14.0%*
12.8%	12.5%	12.5%	12.6%	11.0%	13.4%	12.5%	12.1%	12.4%	*13.0%*	*13.0%*	*13.5%*	Return on Com Equity E	*14.0%*
3.6%	3.2%	3.2%	3.1%	2.5%	3.9%	2.6%	2.8%	2.8%	*3.5%*	*3.5%*	*3.5%*	Retained to Com Eq	*4.5%*
73%	75%	75%	76%	78%	72%	79%	77%	78%	*75%*	*76%*	*73%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2018	2019	2020
% Change Retail Sales (KWH)	+3.6	-8.5	-5.3
Avg. Indust. Use (MWH)	3048	2947	NA
Avg. Indust. Revs. per KWH (¢)	6.04	6.03	NA
Capacity at Yearend (Mw)	45824	41940	NA
Peak Load, Summer (Mw) F	36429	34209	NA
Annual Load Factor (%)	61.2	60.3	NA
% Change Customers (yr-end)	+1.0	-8.9	+1.3
Fixed Charge Cov. (%)	280	281	270

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	--	1.0%	*4.0%*
"Cash Flow"	4.0%	4.5%	*4.5%*
Earnings	3.0%	2.5%	*5.5%*
Dividends	3.5%	3.5%	*3.0%*
Book Value	3.5%	3.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	5412	5098	5995	4914	21419
2020	5018	4620	5620	5117	20375
2021	5910	5198	6238	*5654*	*23000*
2022	*6200*	*5600*	*6600*	*5750*	*24150*
2023	*6500*	*5900*	*6900*	*6050*	*25350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.75	.85	1.25	.32	3.17
2020	.81	.75	1.18	.51	3.25
2021	1.09	.73	1.22	*.46*	*3.50*
2022	*1.05*	*.80*	*1.30*	*.45*	*3.60*
2023	*1.10*	*.85*	*1.40*	*.45*	*3.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.58	.60	.60	.60	2.38
2019	.60	.62	.62	.62	2.46
2020	.62	.64	.64	.64	2.54
2021	.64	.66	.66	.66	2.62
2022					

BUSINESS: The Southern Company, through its subs., supplies electricity to 4.3 mill. customers in GA, AL, and MS. Also has a competitive generation business. Acq'd AGL Resources (renamed Southern Company Gas, 4.3 mill. customers in GA, NJ, IL, VA, & TN) 7/16. Sold Gulf Power 1/19. Electric rev. breakdown: residential, 37%; commercial, 30%; industrial, 19%; other, 14%. Retail revs. by stete: GA, 56%; AL, 38%; MS, 6%. Generating sources: gas, 47%; coal, 20%; nuclear, 15%; other, 9%; purchased, 9%. Fuel costs: 23% of revs. '20 reported depr. rates (util.): 2.6%-3.7%. Has 27,700 empls. Chairman, Pres. and CEO: Thomas A. Fanning. Inc.: DE. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, GA 30308. Tel.: 404-506-0747. Internet: www.southerncompany.com.

Southern Company's Georgia Power subsidiary expects to complete Units 3 and 4 of the Vogtle nuclear station in the third quarter of 2022 and the second quarter of 2023, respectively. The project has had significant delays and cost overruns. In the first nine months of 2021, the company took aftertax charges totaling $0.54 a share for the estimated loss on construction, which is not recoverable in rates. We *excluded* these charges from our earnings presentation as nonrecurring. The latest capital cost estimate is $9.5 billion for Georgia Power's 45.7% share of the project. As of September 30th, $1.3 billion remained to be spent. There might well be additional delays and cost overruns, but Wall Street has taken these in stride. In 2021, Southern Company stock posted a total return of 16.3%, not far below the median for this industry.

Southern Company has issued equity and sold assets to finance the rising capital costs of its nuclear project. Most notably, it sold its Gulf Power electric utility in Florida a few years ago, and has also sold some gas companies. Most recently, Southern Company sold some leveraged leases. (This will result in a $100 million aftertax gain in the fourth quarter of 2021.) Other asset sales are under consideration. For now, we do not anticipate any equity additions in the next few years, and are not assuming any asset sales.

Earnings should advance this year and next. The company's utilities are benefiting from rate relief and growth in their service areas. Nicor Gas in Illinois will record a full year's effect of a $240 million rate hike, based on a 9.75% return on equity and a 54.5% common-equity ratio, that went into place on December 1st. Atlanta Gas Light received $49 million at the start of 2022. Note that Georgia Power expects to file a rate case on July 1st.

We expect a dividend increase in the second quarter. We think the board will raise the quarterly payout $0.02 a share (3.0%), the same as in recent years.

The dividend yield is somewhat above average for a utility. Dividend growth prospects are subpar, and investors must be able to accept the uncertainties arising from the nuclear construction project. The stock is untimely.

Paul E. Debbas, CFA *February 11, 2022*

(A) Diluted EPS. Excl. nonrec. gain (losses): '09, (25¢); '13, (83¢); '14, (59¢); '15, (25¢); '16, (28¢); '17, ($2.37); '18, (78¢); '19, $1.30; '20, (17¢); '21, (54¢). Next earnings report due mid-Feb. (B) Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. (C) Incl. def'd charges. In '20: $18.91/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on common eq. (blended): 12.5%; earned on avg. com. eq., '20: 12.5%. Regulatory Climate: GA, AL Above Average; MS, FL Average. (F) Winter peak in '18.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	95

WEC ENERGY GROUP NYSE-WEC

RECENT PRICE 90.88 | P/E RATIO 21.3 (Trailing: 22.1 Median: 20.0) | RELATIVE P/E RATIO 1.19 | DIV'D YLD 3.3% | **VALUE LINE**

TIMELINESS 3 Raised 1/7/22
SAFETY 1 Raised 3/23/12
TECHNICAL 1 Raised 2/25/22
BETA .80 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$80-$120 $100 (10%)

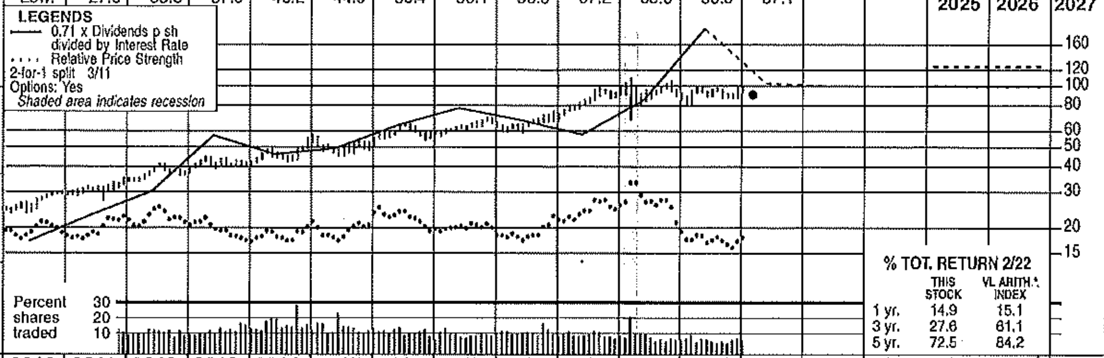
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	125	(+40%)	*11%*
Low	100	(+10%)	*6%*

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	405	366	473
to Sell	378	387	362
Hld's(000)	231367	236130	237652

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	35.4	41.5	45.0	55.4	58.0	66.1	70.1	75.5	98.2	109.5	99.9	98.7
Low:	27.0	33.6	37.0	40.2	44.9	50.4	56.1	58.5	67.2	68.0	80.6	87.1



% TOT. RETURN 2/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.9	15.1
3 yr.	27.6	61.1
5 yr.	72.5	84.2

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
17.08	18.12	18.95	17.65	17.98	19.46	18.54	20.00	22.16	18.77	23.68	24.24	24.34	23.85	22.96	26.36	*26.00*	*27.10*	Revenues per sh	*30.50*
2.90	2.98	2.95	3.11	3.30	3.68	4.01	4.33	4.47	3.87	5.39	5.69	6.04	6.53	6.90	7.53	*8.10*	*8.70*	"Cash Flow" per sh	*10.75*
1.32	1.42	1.52	1.60	1.92	2.18	2.35	2.51	2.59	2.34	2.96	3.14	3.34	3.58	3.79	4.11	*4.35*	*4.65*	Earnings per sh A	*5.50*
.46	.50	.54	.68	.80	1.04	1.20	1.45	1.56	1.74	1.98	2.08	2.21	2.36	2.53	2.71	*2.91*	*3.11*	Div'd Decl'd per sh B ■	*3.80*
4.17	5.28	4.86	3.50	3.41	3.60	3.09	3.04	3.26	4.01	4.51	6.21	6.71	7.17	7.10	7.14	*9.35*	*9.30*	Cap'l Spending per sh	*9.25*
12.35	13.25	14.27	15.26	16.26	17.20	18.05	18.73	19.60	27.42	28.29	29.98	31.02	32.06	33.19	34.60	*35.90*	*37.25*	Book Value per sh C	*41.75*
233.94	233.89	233.84	233.82	233.77	230.49	229.04	225.96	225.52	315.68	315.62	315.57	315.52	315.43	315.43	315.43	*315.43*	*315.43*	Common Shs Outst'g D	*315.43*
16.0	16.5	14.8	13.3	14.0	14.2	15.8	16.5	17.7	21.3	19.9	20.0	19.6	23.5	24.9	22.3	*Bold figures are*		Avg Ann'l P/E Ratio	*20.5*
.86	.88	.89	.89	.89	.89	1.01	.93	.93	1.07	1.04	1.01	1.06	1.25	1.28	1.19	*Value Line*		Relative P/E Ratio	*1.15*
2.2%	2.1%	2.4%	3.2%	3.0%	3.3%	3.2%	3.5%	3.4%	3.5%	3.4%	3.3%	3.4%	2.8%	2.7%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $15590 mill. **Due in 5 Yrs** $5058.7mill.
LT Debt $13524 mill. **LT Interest** $453.6 mill.
Incl. $12.1 mill. finance leases.
(LT interest earned: 4.2x)
Leases, Uncapitalized Annual rentals $6.8 mill.
Pension Assets-12/21 $3328.9 mill.
Oblig $3136.6 mill.
Pfd Stock $30.4 mill. **Pfd Div'd** $1.2 mill.
260,000 shs. 3.60%, $100 par, callable $101;
44,498 shs. 6%, $100 par.
Common Stock 315,434,531 shs.
as of 1/31/22
MARKET CAP: $29 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
4246.4	4519.0	4997.1	5926.1	7472.3	7648.5	7679.5	7523.1	7241.7	8316.0	*8200*	*8550*	Revenues ($mill)	*9600*
547.5	578.6	589.5	640.3	940.2	998.2	1060.5	1134.2	1201.1	1301.5	*1380*	*1470*	Net Profit ($mill)	*1760*
35.9%	36.9%	38.0%	40.4%	37.6%	37.2%	13.8%	9.9%	15.9%	13.4%	*13.5%*	*13.5%*	Income Tax Rate	*13.5%*
9.4%	4.5%	1.3%	4.5%	3.8%	1.6%	2.1%	1.8%	2.4%	1.9%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
51.7%	50.6%	48.5%	51.2%	50.5%	48.0%	50.4%	52.5%	52.8%	55.3%	*55.0%*	*55.0%*	Long-Term Debt Ratio	*54.5%*
48.0%	49.1%	51.2%	48.6%	49.3%	51.9%	49.4%	47.4%	47.1%	44.6%	*45.0%*	*45.0%*	Common Equity Ratio	*45.5%*
8619.3	8626.6	8636.5	17809	18118	18238	19813	21355	22228	24467	*25225*	*26050*	Total Capital ($mill)	*29000*
10572	10907	11258	19190	19916	21347	22001	23620	25707	26982	*28750*	*30425*	Net Plant ($mill)	*34600*
7.9%	8.1%	8.1%	4.5%	6.3%	6.6%	6.5%	6.5%	6.5%	6.3%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
13.1%	13.6%	13.2%	7.4%	10.5%	10.5%	10.8%	11.2%	11.4%	11.9%	*12.0%*	*12.5%*	Return on Shr. Equity	*13.5%*
13.2%	13.6%	13.3%	7.4%	10.5%	10.5%	10.8%	11.2%	11.5%	11.9%	*12.0%*	*12.5%*	Return on Com Equity E	*13.5%*
6.5%	5.9%	5.3%	2.1%	3.5%	3.6%	3.7%	3.8%	3.8%	4.1%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
51%	57%	60%	71%	67%	66%	66%	68%	67%	66%	*67%*	*67%*	All Div'ds to Net Prof	*68%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.5	-2.6	+3.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Lg. C&I Revs. per KWH (¢)	7.25	6.61	7.51
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.7	+.2
Fixed Charge Cov. (%)	300	338	357

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	3.0%	2.5%	*4.0%*
"Cash Flow"	7.5%	9.0%	*7.5%*
Earnings	7.5%	8.0%	*6.0%*
Dividends	11.5%	7.5%	*7.0%*
Book Value	7.5%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2377	1590	1608	1947	7523.1
2020	2108	1548	1651	1933	7241.7
2021	2691	1676	1746	2201	8316.0
2022	*2500*	*1700*	*1750*	*2250*	*8200*
2023	*2600*	*1775*	*1825*	*2350*	*8550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.33	.74	.74	.77	3.58
2020	1.43	.76	.84	.76	3.79
2021	1.61	.87	.92	.71	4.11
2022	*1.70*	*.90*	*.95*	*.80*	*4.35*
2023	*1.80*	*.95*	*1.00*	*.90*	*4.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.552	.552	.553	.553	2.21
2019	.59	.59	.59	.59	2.36
2020	.632	.632	.633	.633	2.53
2021	.677	.677	.678	.678	2.71
2022	.728	.728			

BUSINESS: WEC Energy Group, Inc. (formerly Wisconsin Energy) is a holding company for utilities that provide electric, gas & steam service in WI & gas service in IL, MN, & MI. Customers: 1.6 mill. elec., 2.9 mill. gas. Acq'd Integrys Energy 6/15. Sold Point Beach nuclear plant in '07. Electric revenue breakdown: residential, 39%; small commercial & industrial, 32%; large commercial & industrial, 21%; other, 8%. Generating sources: coal, 36%; gas, 28%; renewables, 5%; purchased, 31%. Fuel costs: 40% of revenues. '21 reported deprec. rates: 2.4%-3.1%. Has 6,900 employees. Chairman: Gale E. Klappa. President & CEO: Scott J. Lauber. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wecenergygroup.com.

WEC Energy will likely post another year of solid earnings growth in 2022. The company is experiencing modest increases in electric and gas volume. Operating and maintenance expenses are under control, despite inflationary pressures. WEC Energy will benefit from some gas rate hikes granted in recent months. The company's Peoples Gas subsidiary in Chicago has a program that allows recovery of gas-main replacement costs ($280 million-$300 million annually) through a rider on customers' bills. A nonutility subsidiary is adding renewable-energy projects. We estimate that profits will advance 6%, to $4.35. We are sticking with our estimate, even though this is slightly above WEC Energy's targeted (and narrow) range of $4.29-$4.33 a share. The company's guidance is typically conservative, and management usually winds up raising it as the year progresses.

We estimate a 7% rise in profits in 2023. The same factors that should help boost the bottom line in 2022 should remain present next year. Note that the utilities in Wisconsin will file a rate case this spring, with new tariffs taking effect at the start of 2023. WEC Energy's goal for annual earnings growth is 6%-7%.

WEC Energy's nonutility wind capacity is increasing the company's earning power. The company has 1,574 megawatts operating or under construction, for an investment of $2.3 billion. Management expects to invest an additional $1.1 billion through 2026. The return on investment from these assets exceeds that of the regulated utility business.

The board of directors raised the dividend in the first quarter. The hike was $0.05 a share (7.4%) quarterly, a bit larger than we expected. WEC Energy's goals are a payout ratio of 65%-70% and dividend growth in line with earnings growth.

Conservative utility investors might want to consider this stock. Despite the company's good performance in 2021, the stock underperformed most electric equities. The dividend yield is just slightly below the industry average, which is still appealing in view of the top-notch Safety rank and the company's consistency. Total return potential to 2025-2027 is just modest, however.

Paul E. Debbas, CFA *March 11, 2022*

(A) Diluted EPS. Excl. gain on discontinued ops.: '11, 6¢; nonrecurring gain: '17, 65¢. Next earnings report due early May. (B) Div'ds paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. in '21: $20.03/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in WI in '15: 10.0%-10.3%; in IL in '21: 9.67%; in MN in '19: 9.7%; in MI in '22: 9.85%; earned on avg. com. eq., '21: 12.2%. Regulatory Climate: WI, Above Average; IL, Below Average; MN & MI, Average.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	100

XCEL ENERGY NDQ-XEL

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
74.36	23.9 (Trailing: 25.1 Median: 19.0)	1.34	2.7%	

TIMELINESS 3 Raised 12/31/21
SAFETY 1 Raised 5/1/15
TECHNICAL 3 Lowered 4/8/22
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$58-$89	$74 (0%)

2025-27 PROJECTIONS

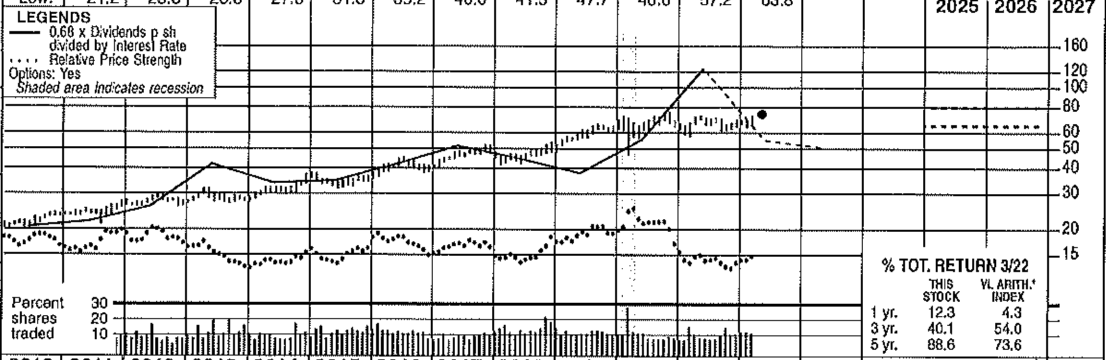
	Price	Gain	Ann'l Total Return
High	80	(+10%)	5%
Low	65	(-15%)	Nil

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	381	355	449
to Sell	344	343	338
Hld's(000)	412491	411220	413762

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	27.8	29.9	31.8	37.6	38.3	45.4	52.2	54.1	66.1	76.4	72.9
Low:	21.2	25.8	26.8	27.3	31.8	35.2	40.0	41.5	47.7	46.6	57.2

	2023
High:	75.5
Low:	63.8



% TOT. RETURN 3/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.3	4.3
3 yr.	40.1	54.0
5 yr.	88.6	73.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	22.44	21.98	21.45	24.69	*26.50*	*27.25*	Revenues per sh	*29.50*
3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	5.92	6.25	6.61	7.08	*7.75*	*8.30*	"Cash Flow" per sh	*10.00*
1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	2.47	2.64	2.79	2.96	*3.15*	*3.35*	Earnings per sh A	*4.00*
.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	1.52	1.62	1.72	1.83	*1.95*	*2.08*	Div'd Decl'd per sh B ■ †	*2.50*
4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	7.70	8.05	9.99	7.80	*9.65*	*9.00*	Cap'l Spending per sh	*9.00*
14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	23.78	25.24	27.12	28.70	*30.15*	*31.65*	Book Value per sh C	*37.00*
407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	514.04	524.54	537.44	544.03	*547.00*	*550.00*	Common Shs Outst'g D	*561.00*
14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	18.9	22.3	23.9	22.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.5*
.80	.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	1.19	1.23	1.23			Relative P/E Ratio	*1.05*
4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	3.3%	2.7%	2.6%	2.8%			Avg Ann'l Div'd Yield	*3.4%*
						10128	10915	11686	11024	11107	11404	11537	11529	11526	13431	*14500*	*15000*	Revenues ($mill)	*16500*
						905.2	948.2	1021.3	1063.6	1123.4	1171.0	1261.0	1372.0	1473.0	1597.0	*1720*	*1855*	Net Profit ($mill)	*2260*
						33.2%	33.8%	33.9%	35.8%	34.1%	30.7%	12.6%	8.5%	8.5%	--	*NMF*	*NMF*	Income Tax Rate	*NMF*
						10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	12.4%	8.3%	10.7%	6.2%	*7.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
						53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	56.4%	56.8%	57.4%	58.2%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*58.0%*
						46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	42.6%	41.8%	*42.0%*	*42.0%*	Common Equity Ratio	*42.0%*
						19018	20477	21714	23092	25216	25975	28025	30646	34220	37391	*39150*	*41600*	Total Capital ($mill)	*49200*
						23809	26122	28757	31206	32842	34329	36944	39483	42950	45457	*48225*	*50475*	Net Plant ($mill)	*57000*
						6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	5.7%	5.6%	5.4%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
						10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
						10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	*10.5%*	*10.5%*	Return on Com Equity E	*11.0%*
						4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	4.3%	4.4%	4.2%	4.2%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
						54%	54%	55%	57%	61%	62%	58%	58%	58%	59%	*62%*	*62%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $23385 mill. **Due in 5 Yrs** $4911 mill.
LT Debt $21779 mill. **LT Interest** $809 mill.
Incl. $73 mill. finance leases.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $69 mill.
Pension Assets-12/21 $3670 mill.
Oblig $3718 mill.

Pfd Stock None

Common Stock 544,213,730 shs.
as of 2/17/22
MARKET CAP: $40 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.2	-2.3	+1.4
Large C & I Use (MWH)	NA	NA	NA
Large C & I Revs. per KWH (¢)	5.96	5.78	6.60
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	20146	19665	19849
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	NA	NA
Fixed Charge Cov. (%)	272	252	262

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	.5%	4.5%
"Cash Flow"	6.5%	7.5%	7.0%
Earnings	6.0%	6.0%	6.0%
Dividends	5.5%	6.0%	6.5%
Book Value	5.0%	5.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3141	2577	3013	2798	11529
2020	2811	2586	3182	2947	11526
2021	3541	3068	3467	3355	13431
2022	*3850*	*3250*	*3800*	*3600*	*14500*
2023	*3950*	*3400*	*3950*	*3700*	*15000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.61	.46	1.01	.56	2.64
2020	.56	.54	1.14	.54	2.79
2021	.67	.58	1.13	.58	2.96
2022	*.71*	*.62*	*1.20*	*.62*	*3.15*
2023	*.75*	*.65*	*1.30*	*.65*	*3.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.36	.38	.38	.38	1.50
2019	.38	.405	.405	.405	1.60
2020	.405	.43	.43	.43	1.70
2021	.43	.4575	.4575	.4575	1.80
2022	.4575	.4875			

BUSINESS: Xcel Energy Inc. is tha parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota & Michigan & gas to Minnesota, Wisconsin, North Dakota & Michigan; P.S. of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.7 mill. elec., 2.1 mill. gas. Elec. rev. breakdown: res'l, 31%; sm. comm'l & ind'l, 36%; lg. comm'l & ind'l, 18%; other, 15%. Generating sources not avail. Fuel costs: 43% of revs. '21 reported deprec. rate: 3.5%. Has 11,300 employees. Chairman: Ben Fowke. President & CEO: Bob Frenzel. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

As usual, Xcel Energy is active in the regulatory arena. The company's largest rate case is that of Northern States Power in Minnesota. NSP filed for electric rate hikes of $396 million in 2022, $150 million in 2023, and $131 million in 2024, based on a return on equity of 10.2% and a common-equity ratio of 52.5%. NSP also filed for a gas increase of $36 million, based on a 10.5% ROE and the same equity ratio. Interim hikes of $247 million (electric) and $25 million (gas) took effect at the start of 2022. Public Service of Colorado filed for a gas increase of $107 million (excluding revenues now being recovered through surcharges), followed by $40 million in 2023 and $41 million in 2024, based on an ROE of 10.25% and a common-equity ratio of 55.7%. New tariffs are expected to take effect in November. Southwestern Public Service is awaiting a ruling in Texas on a settlement that would raise rates by $89 million, retroactive to March 15, 2021. Besides these pending cases, the company received rate relief in Wisconsin at the start of 2022, in New Mexico at the end of February, and in Colorado (electric) at the start of April.

Rate relief is helping produce steady earnings growth. Some of the increases are for placing renewable-energy projects in the rate base. Management is also controlling operating expenses effectively, despite inflationary pressures. Our 2022 earnings estimate is at the midpoint of Xcel's guidance of $3.10-$3.20 a share. We assume no disallowance of the extraordinary gas costs that NSP incurred last year; the Minnesota commission is considering whether there was any imprudence.

We expect another solid profit increase in 2023. Once again, rate relief should be a key factor. The earnings growth we look for would be within the company's annual goal of 5%-7%.

The board raised the dividend, effective with the April payment. The increase was $0.03 a share (6.6%) quarterly. Xcel's goals for the dividend are 5%-7% growth and a payout ratio of 60%-70%.

This high-quality stock has a dividend yield that is a cut below the utility average. The issue doesn't stand out for the next 18 months or the 3- to 5-year period.

Paul E. Debbas, CFA *April 22, 2022*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '10, 5¢; '15, (16¢); '17, (5¢); gains (loss) on discontinued ops.: '06, 1¢; '09, (1¢); '10, 1¢. '20 EPS don't sum due to rounding. Next earnings report due April 28. (B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '21: $2738 mill., $4.42/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on com. eq. (blended): 9.6%; earned on avg. com. eq., '21: 10.6%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	100

CASE: UE 399
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 114

Discussion of:
Capital Structure

June 22, 2022

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Regulatory risk, market uncertainties, and firm financing choices: Evidence from U.S. Electricity Market Restructuring[☆]

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ABSTRACT

Based on the universe of rate-regulated electric utilities in the U.S., we examine why firms alter their financing decisions when transitioning from a regulated to a competitive market regime. We find that the significant increase in regulatory risk after the passage of the Energy Policy Act, state-level restructuring legislations, and divestiture policies have reduced leverage by 15 percent. Policies that encouraged competition, and hence increased market uncertainty, lowered leverage by another 13 percent on average. The ability to exercise market power allowed some firms to counter this competitive threat. In aggregate, regulatory risk and market uncertainty variables reduce leverage between 24.6 and 26.7 percent. We also confirm findings in the literature that firms with higher profitability and higher asset growth have lower leverage, and those with more tangible assets are more levered. Firms with greater access to internal capital markets and those with a footloose customer segment use less debt, while those actively involved in trading power in the wholesale market use more debt.

> "Our goals are to control costs while maintaining superior customer service, extract maximum value from our existing wholesale and utility assets, implement a long-term plan for generating capacity and fuel stability, lead Louisiana in service reliability and protect our investment-grade credit rating by reducing debt". Quote from Cleco Corp (Louisiana)
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> "In a nutshell, the government that had created this regulated industry was saying, "We don't want to regulate you anymore. Here's your business. Good luck." However, the restructuring process initially generated more questions than answers, as the various players in the market tried to understand how the configuration of this industry might need to change." C. John Wilder (CEO, TXU)[1]

0. Introduction

Regulated firms traditionally display a high leverage ratio (Spiegel & Spulber, 1997) compared to competitive firms, and this paper shows how various policy instruments can align a regulated firm's capital structure with those of competitive industries. We find that policies that increase the effective competitive pressure on firms, or increase the risk of financial distress lower leverage. However, firms with market power have the ability to counter this competitive threat and take on more debt. These findings are particularly relevant for today's financial environment. A significant blame for the recession that began in 2007 can be attributed to the high leverage ratio of banks, and the policy discussion on ways to reduce this leverage is a hot button issue. This paper offers important insights into how leverage can be reduced without a command and control type of mandated cap on bank leverage.

Capital structure decisions are at the core of a firm's financial strategy and have important long-term implications for firm behavior. Cash-constrained firms can either use equity or debt financing when they borrow from the market to finance their investments. Each choice has associated costs and benefits, and

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[1] "Leading change: An interview with TXU's CEO" by Warren L. Strickland. The McKinsey Quarterly, 29th March 2007.

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influences risk-taking and investment behavior,[2,3] agency issues,[4] and impacts R&D, innovation and technology adoption decisions.[5] Hence understanding a firm's capital structure choice is a crucial step to understanding how a firm evolves and survives in a given environment.

Leverage (total debt/total assets) is perhaps, the most common variable used to characterize a firm's capital structure choice (Bradley, Jarrell, & Kim,1984; Fama & French, 2002; Rajan & Zingales, 1995; Titman & Wessels, 1988). In the U.S., rate-regulated electric utilities have experienced two sharp drops in leverage ratios (Fig. 1) that appear to have coincided with two federal restructuring orders – the 1992 Energy Policy Act and the 1996 FERC retail competition orders – that formally deregulated the electricity industry and instituted wholesale competition.

We have a unique 'natural experiment' with the deregulation of electric utilities in the U.S., that allows us to observe financing choices for the same firm in both the regulated and competitive regimes. The restructuring process changed the stable operating environment of utilities by altering regulatory conditions and the market environment, and engendered two types of uncertainties: (1) regulatory risk arising from uncertainties about the emerging institutional structure and the policy environment, and (2) market uncertainties arising from demand fluctuations, price competition and threats to market share. Non-regulated manufacturing firms have to primarily contend with the latter type of uncertainty when making capital structure decisions. Utilities on the other hand, have to respond to both kinds of uncertainty simultaneously. Most existing literature has focused on financing decisions of non-regulated or purely regulated firms. We add an important missing piece to the literature by showing how the transition from regulation to competition alters the financing structure of firms. The experience of the U.S. electric utility industry can serve as a valuable lesson for other industries in transition.

This study is one of the few papers that document the impact of restructuring on a firm's capital structure. Additionally, to the best of our knowledge, this is the first to show what specific policies and aspects of the competitive process put pressure on firms to lower their dependence of debt-financing.[6] We find that deregulation and its associated restructuring policies have led to a 25–27 percent decrease in leverage ratios. We find that any policy that decreases earnings stability, or increases competition and threatens market share, lowers debt levels. Additionally, the existence of effective competition has a greater effect on firm financing than the mere size of the competitive segment. Firms with market power have the ability to counter this competitive threat and are willing to take on more debt. We also confirm earlier findings that firms with higher profitability and higher asset growth have lower leverage, and firms with greater tangible assets are more leveraged. In addition firms that have greater access to internal capital markets, or ones with a footloose customer base, use less debt.

The remainder of the paper is organized as follows. Section 1 provides a review of financing decisions of non-regulated versus regulated firms, and documents the theoretical and empirical findings in the literature. Section 2 briefly discusses the transition of the U.S. electricity industry from a regulated to a competitive regime, and the changes associated with the restructuring process. Section 3 describes the data and key variable construction. Section 4 explains the empirical methodology and results, and the last section concludes.

1. Literature review

1.1. *Financing choices of non-regulated firms*

There is a large literature that studies the capital structure decisions of non-regulated manufacturing firms, and attempts to explain why the internal–external financing shares and the debt–equity ratio of various firms differ.[7] The seminal work in this area by Modigliani and Miller (1958) showed that in perfect capital markets, the choice between debt and equity financing does not affect firm value or the cost of capital. However, their results hold under stringent conditions of competitive, frictionless and complete capital markets where capital flows to its most efficient use, and the cost of capital is determined by business risk alone. These conditions are not often found in reality, and empirical evidence suggests that financing does matter.

There are several theories that explain the observed capital structure choices of firms. The tradeoff theory posits that firms 'tradeoff' between value-enhancing tax savings and the potential for financial distress when determining the mix of debt and equity financing. In the U.S., interest is tax-deductible. Thus a firm that pays interest on debt also pays lower taxes because of this 'interest tax shield'. This in turn increases the value of a firm with a greater proportion of debt to equity financing. However there is also a cost attached to high debt levels, specifically, a greater threat of bankruptcy. Thus, this theory predicts moderate debt-levels for firms. Empirical evidence shows that the tax shield motivation (MacKie-Mason, 1990) and factors related to financial distress risk, such as the amount of tangible assets (which can be used as loan collateral for example), are significantly related to leverage ratios. The problem with the tradeoff theory however, is that it cannot explain the existence of very low debt-levels in very profitable companies (Myers, 1984). If the interest tax shield is indeed enough motivation to hold more debt, then we should observe the opposite relationship between leverage and profits. The pecking order theory attempts to explain this empirical regularity to some extent.

The pecking order theory (Myers, 1984; Myers and Maljuf, 1984) suggests that firms have a preference ordering, and use internal funds first, followed by debt, and they resort to equity last. If capital investment requirements are greater than internal funds then firms prefer issuing debt, since with debt the asymmetric information problem between managers and new shareholders is less severe than with equity. The documented negative empirical relationship between leverage and profitability is consistent with a preference for internals funds over debt financing, although overall evidence for this theory has been mixed (Bulan & Yan, 2009; Frank & Goyal, 2003; Helwege & Liang, 1996; Shyam-Sunder & Myers, 1999). Moreover, Myers (2001) argues that this theory does not show how information asymmetry affects firm financing, and

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[2] Hirth and Uhrig-Homburg (2010a,b), Kale and Noe (1995), Kühn (2002a,b), Mauer and Sarkar (2005), Norton (1985).

[3] The earliest work on this topic assumes that investment should be independent of a firm's financial structure (Modigliani & Miller, 1958). However, the vast amount of research that followed has shown that although this works in theory, in practice this may not be the case. See Myers (2001).

[4] Baumol (1965), Jensen and Meckling (1976), Myers (1977), Myers and Maljuf (1984), Shleifer and Vishny (1989), and Childs et al. (2005).

[5] Hall et al. (1990), Himmelberg and Peterson (1994), and Spiegel (1996).

[6] While Ovtchinnikov (2010) also examines the capital structure decisions of newly deregulated firms, his focus is on how deregulation affects the "traditional" determinants of leverage (e.g. profitability, asset tangibility, earnings volatility and growth opportunities) and how a firm's leverage responds to these factors after deregulation.

[7] Harris and Raviv (1991) review the theoretical literature. Myers (2001) provides a more recent perspective on the state of capital structure theory and empirical evidence, from which we draw on for our discussion in this section.

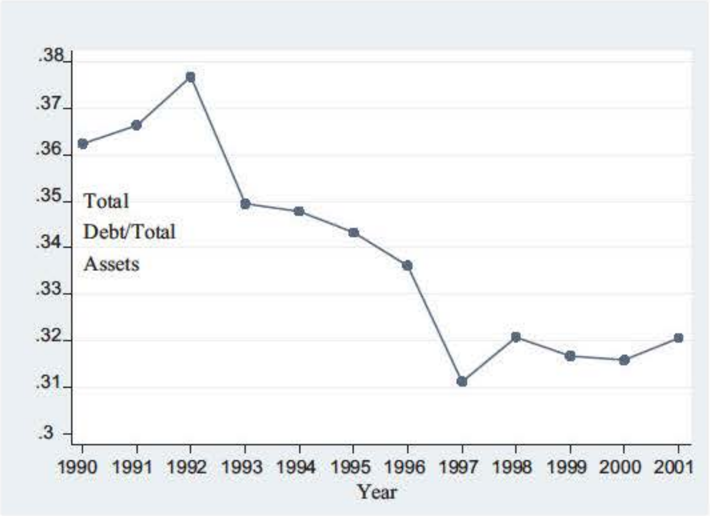

Fig. 1. Mean leverage ratio (195 U.S. Electric Utilities) 1990–2001.

why firms do not use other available alternatives to alleviate such information problems.

The two above theories assume that the incentives of managers are aligned to that of shareholders. However, it is well understood that even the best crafted incentive contracts cannot perfectly align interests, and managers will take action according to their self-interest. Jensen's free cash flow theory (1986) holds that a firm with large amounts of free cash flow, that significantly exceeds its profitable investment opportunities, may hold higher levels of debt since this may increase their value, despite higher threats of bankruptcy. Debt in this case, forces managers to pay out the extra cash instead of investing it in inefficient 'empire-building'. These three main theories in conjunction provide valuable insights into a non-regulated firm's financing behavior.[8]

1.2. Regulation and capital structure decisions

The capital structure choices of regulated firms are significantly different from that of non-regulated firms.[9] For regulated utilities, where prices are influenced by debt levels, the incentives for holding debt may be quite different. Bradley, Jarell, and Kim (1984) document that regulated industries have the highest debt-to-value ratios with electric and gas utilities second only to airlines. In the literature, three alternative hypotheses have been proposed to explain the level of debt held by utilities. Two are based on regulators treating the capital structure of regulated firms as exogenous, and the third treating it as an endogenous variable.

According to Klein, Phillips, and Shiu (2002), both theory and empirical research suggests that "the existence of price regulation in the output market provides the regulated entity with incentives to utilize additional levels of debt to finance the operations of the firm". Several studies have shown that regulated utilities choose high debt levels to induce rate (price) increases since regulators set rates at a level that accounts for the firm's costs which includes the cost of debt, thereby insuring the firm against possible financial distress (Chen & Fanara, 1992; Rao & Moyer, 1994; Spiegel & Spulber, 1994, 1997; Taggart, 1981). Taggart (1985) provides a second explanation and attributes such high debt levels to the "safer business environment" created by regulation. Both the above explanations assume that the capital structure of the regulated firm is exogenous to the regulator, who reacts passively to the given mix of debt and equity while setting prices.

De Fraja & Stones (2004) provide a third alternative explanation for high leverage ratios in regulated firms. They model the regulator's price setting behavior under two assumptions, when the utility's capital structure is exogenous, and when regulator decisions can influence such financing choices. They show that there is a tradeoff between lower prices and higher price volatility as debt levels increase. When the capital structure is endogenous, a social welfare maximizing regulator sets a low price that is subject to some volatility. This implies that the optimal capital structure is one with higher debt-levels, given that debt finance is cheaper than equity. They argue that this is the case in countries such as the U.K., where regulatory actions induce firms to hold higher levels of debt (sometimes 70–80 percent) when compared to U.S. utilities (35–40 percent), where regulators typically take the capital structure as given.

Other empirical work has also indirectly investigated the link between regulation and financing by focusing on cross-country institutional factors.[10] However, Rajan and Zingales (1995) have shown that certain fundamental institutional differences between the G-7 countries cannot adequately explain the observed differences in capital structure across these countries. Thus there is a need to focus on industries within a country to understand the effect of regulation on capital structure, and particularly how the financing structure changes when firms transition from a regulated to a deregulated regime.

There is paucity of papers that investigate this issue, i.e. what happens to a firm's capital structure when a regulated industry is deregulated, and subject to competitive forces. Extending the logic from the earlier studies that focus on why regulated industries carry high leverage ratios, we should expect a decrease in leverage since the incentive to induce rate increases by carrying higher leverage will no longer be present. Additionally, the change from a regulated and hence safer environment, to a competitive and uncertain one will result in more conservative financial

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[8] More recently, the trend has been to combine the insights of all three models into a unified theory of capital structure.

[9] In a sample of Compustat firms from 1990 to 2001, on average, debt is 22 percent of assets for non-regulated manufacturing firms, compared to 34 percent for regulated utilities. See Table 3A.

[10] See for example, Booth, Aivazian, Demirguc-Kunt, and Maksimovic (2001) and La Porta, Lopez-de-Silanes, Shleifer, and Vishny (1998).

choices for the firm and lead to a further decline in leverage. This is supported by Dewenter and Malatesta (2001) who compare state-owned and private firms, and find that government backed firms lower their debt levels following privatization. A similar conclusion is reported by Ovtchinnikov (2010). Based on a sample of all non-financial firms in Compustat from 1966 to 2006, he finds that deregulation changes the operating environment of firms by affecting their profitability, asset tangibility, earnings volatility and growth opportunities. The combined changes in these capital structure determinants led to a decline in leverage. On average, he finds that regulated firms decreased their leverage from 42.3 percent in the regulated phase to 31.9 percent in the deregulated phase.

This inter-industry research on how deregulation impacts the leverage ratio of companies is important in increasing our understanding of what general factors influence the financial decision-making of firms when they migrate from a regulated to a competitive regime. However, as MacKay and Phillips (2005) find, most of the variation in firm financial structure is due to intra-industry variation. Our paper contributes to understanding this intra-industry variation. The deregulation of the U.S. electric utility industry provides an unique opportunity to observe financing choices for the same firm in both the regulated and competitive regimes. By focusing on a single industry during a time when the institutional environment changed, we can isolate the effect of specific regulatory and market factors that influence a firm's capital structure. Moreover, we can exploit the considerable variation in inter-state deregulation speed and modality in the U.S. electric utility industry to get a more powerful test of the impact of deregulation on leverage decisions. Since our findings have broad policy implications, the experience of the U.S. electric utility industry can also serve as a valuable lesson for other industries in transition.

2. U.S. electricity restructuring

The electric utility industry in the U.S. has been traditionally organized as a vertically integrated regulated monopoly.[11] The main players in the market were the investor owned utilities (IOUs), which accounted for more than three-quarters of the energy generated. These firms were for-profit privately owned entities who had service monopolies in particular geographical regions, and controlled generation, transmission and distribution of electricity. They were overseen by the Federal Energy Regulatory Commission (FERC) and state regulators (public utility commissions or PUCs) whose primary task was to set prices and determine the price structure.[12,13] The PUCs in each state were also responsible for scrutinizing major investments in generation, transmission and distribution by the utilities. The price setting mechanism used was the "cost of service ratemaking"[14] and the rates were fixed and could not be changed without PUC authorization. The regulators determined the "revenue requirement"[15] of utilities based on their operating costs, depreciation, taxes and its "rate-base" (total net investment or capital costs) and a regulator determined rate of return that was considered a 'fair' return on investment. Then based on the total revenues required by the utility, retail rates were set for different groups of customers. Thus if an utility carried more debt and had to service the interest, it's operating costs would increase, leading regulators to increase the 'revenue requirement' predictions, and hence increase rates. Additionally, this type of regulation provided a stable earnings environment and insured the utilities against bankruptcy, leading to even higher leverage ratios.

All this changed during the nineties when "cost-based" regulation paradigms gave way to competitive electricity markets (DOE/EIA, 2000; Joskow, 1999, 1997; Hogan, 1995, 1997).[16] The Energy Policy Act (EPAct) of 1992 gave rise to open-access transmission grids for wholesale transactions[17] and made retail wheeling[18] (or retail access) possible. In 1996 FERC Orders 888 & 889[19] furthered wholesale competition by providing open access non-discriminatory transmission tariffs and provided the groundwork to begin retail wheeling. Order 888 stated that utilities which own transmission networks must provide transmission services to other power generators at cost-based non-discriminatory prices. Provisions were also laid out governing the recovery of stranded costs by utilities. Stranded costs are potential losses that a utility may face due to "the decline in value of electricity-generating assets' (CBO, 1998) when the industry is restructured. Order 889 required each public utility to participate in an Open Access Same-Time Information System (OASIS). This was done to facilitate wheeling by third parties that did not own transmission capacities. Regulators in many states also took a pro-active role in promoting competition in the generating sector[20] in response to these legal changes.

The passing of the EPAct and the FERC orders led to major changes in the incentive structure of IOUs and altered the organizational structure of the electricity industry (restructuring). Each state followed a different trajectory regarding restructuring the industry. Some, like California and New York, were at the forefront of restructuring while others, such as Alabama, had not taken any

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[11] This was predicated on the view that efficient generation, transmission and distribution were a natural monopoly (Scherer, 1980).

[12] The PUCs determined the rates for each customer group (price structure) such as homeowners, businesses, large industrial customer, etc.

[13] "Regulation can be viewed as an administered contract between the regulated firm and the ratepayers, with the regulatory agency serving as the arbitrator of this contract" (Pechman, 1993).

[14] This involved five main steps. The first four taken together determined the total revenue that a utility may earn – this was termed the "revenue requirement". The fifth step was the "rate structure" – that determined how much different customers would be charged such that the "revenue requirement is fulfilled.

[15] Thus the revenue requirement equation was given by: Revenue Requirement = Operating costs + depreciation + taxes + (rate base) × regulator determined rate of return).

[16] Utilities began trading power amongst themselves since the 1970s. This was done by informal agreements since FERC did not allow utilities to wheel power. However, the movement towards deregulation had started more than a decade earlier. In 1978, the Public Utility Regulatory Policies Act (PURPA) required utilities to purchase power from non-utility generators at 'avoided cost" prices that were determined by the state. This was done to give a boost to small renewable energy producers. Following PURPA, there was a steady increase in the number of independent power producers, and by the early 1990s more than half of the new plants being built were owned by non-utilities. Thus on one hand, there was an increased demand from independent power producers (IPP) to sell in the open market and not be tied to utility contracts. On the other hand, smaller utilities such as municipal power plants and coops wanted to buy power from these IPPs.

[17] On the wholesale side FERC took several steps to ensure increased competition. It required utilities to provide a detailed account of their transmission capacities, it expanded the range of services that the utilities were required to provide to wholesale traders and it made it clear that approval of application for mergers or charging competitive rates by IOUs were subject to their filing open access transmission tariffs with comparable service provisions.

[18] With retail wheeling, retail consumers could shop around for the best rates while purchasing power much like the present telecom situation. After the California fiasco in 2001, some states suspended deregulation activities while others slowed down the pace of restructuring. In the analysis that follows, we exclude such cases by looking at the time period from 1990-2000 only. For details on the California case please see: Borenstein, Bushnell, and Wolak (2002a), Borenstein, Bushnell, andlak (2002b) and Cohen, Weinberg, Peck, and Sanyal (2004).

[19] FERC Order 888 – "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities" and Order 889 – "Open-Access Same-Time Information System". For a detailed provision of the orders please refer to DOE/EIA (1997).

[20] Competition has been focused on the generation sector with distribution and transmission still being viewed as natural monopolies.

Table 1A
Deregulation/restructuring orders.

Year	Investigations ongoing or order pending	Order issued for retail access	Legislation enacted to implement retail access
1994	California		
1995	Connecticut, Louisiana, Vermont, Washington	California	
1996	Alabama, Colorado, Connecticut, Hawaii, Iowa, Kansas, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Virginia, Washington	New York, Vermont	California, New Hampshire, Pennsylvania, Rhode Island, Texas
1997	Alabama, Arizona, Arkansas, Colorado, Connecticut, Dc, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Louisiana, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, North Carolina, North Dakota, Oregon, South Carolina, Tennessee, Virginia, Washington, West Virginia, Wisconsin	Illinois, Maryland, New York, Vermont	California, Maine, Massachusetts, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, Rhode Island, Texas
1998	Alabama, Alaska, Arkansas, Colorado, Delaware, Hawaii, Idaho, Indiana, Iowa, Kansas, Louisiana, Minnesota, Missouri, New Mexico, North Carolina, North Dakota, Oregon, South Carolina, South Dakota, Tennessee, West Virginia	Arizona, DC, Georgia, Illinois, Maryland, Michigan, Mississippi, New Jersey, Vermont, Washington	California, Connecticut, Maine, Massachusetts, Montana, Nevada, New Hampshire, New York, Oklahoma, Pennsylvania, Rhode Island, Texas, Virginia, Wisconsin
1999	Alabama, Alaska, Colorado, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Missouri, North Carolina, North Dakota, South Carolina, South Dakota, Tennessee	Arkansas, DC, Georgia, Michigan, Minnesota, Mississippi, Vermont, Washington	Arizona, California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, West Virginia, Wisconsin
2000	Alabama, Alaska, Colorado, Florida, Hawaii, Idaho, Indiana, Kansas, Kentucky, Louisiana, Missouri, North Carolina, North Dakota, South Dakota, Tennessee	Arkansas, Georgia, Minnesota, South Carolina, Vermont, Washington	Arizona, California, Connecticut, Delaware, DC, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, West Virginia, Wisconsin
2001	Alabama, Colorado, Florida, Hawaii, Idaho, Indiana, Kansas, Louisiana, North Carolina, North Dakota, South Dakota, Tennessee	Arkansas, Georgia, Missouri, Minnesota, South Carolina, Vermont	Arizona, California, Connecticut, Delaware, DC, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, West Virginia, Wisconsin

concrete steps towards restructuring by 2001. However, even in states that were taking a cautious approach towards restructuring, there was an expectation that eventually the market would be competitive and firms tried to position themselves to better take advantage of the changing market structure. Expectations about restructuring policies and future competition gave rise to waves of asset divestitures, mergers and acquisitions. One major consequence of the restructuring process was the voluntary divestiture of generating capacity by IOUs. States promoted this trend because the simultaneous ownership of generation and transmission capacity may engender market power. Furthermore, in the late 1990s mergers became quite frequent in the industry as companies strove to achieve the "critical mass" that was necessary to survive in a competitive environment.

The onset of restructuring also altered the nature of financial distress costs for the U.S. electric utility: firms were subjected to the volatility of market transactions and increased uncertainty about their future earnings. A utility's expectations of future earnings were likely to be lower than their stable pre-deregulation levels, and the precision of their expectations were likely lower as well. This would increase the probability that debt payments may not be met and thus decrease a firm's incentives to undertake debt (Bradley, Jarrell, & Kim, 1984; Titman & Wessels, 1988). In addition, the financial market was also uncertain about how the industry was going to change and hence, may have undervalued these firms reducing its debt-capacity, and lowering leverage after restructuring. This paper analyzes the transition of firms from a regulated to a competitive environment and models the impact of regulatory changes and market uncertainties on its financing decisions. This is a step towards furthering our understanding of the financing choices of regulated versus competitive firms, and has implications for future investments and the emerging industry structure.

Table 1B
Dates for stranded cost recovery acts.

States with no date (i.e. no policy)	Alaska, Colorado, DC, Florida, Hawaii, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Missouri, North Carolina, North Dakota, Oregon, South Dakota, Tennessee, Vermont, Washington, West Virginia, Wisconsin
Year	
1996	Alabama, New Hampshire, New York
1997	Arkansas, California, Idaho, Illinois, Maine, Maryland, Massachusetts, Mississippi, Montana, Nevada, New Jersey, Ohio, Oklahoma, Pennsylvania
1998	Arizona, Connecticut, Delaware, Georgia, Rhode Island, South Carolina, Texas
1999	New Mexico, Virginia
2000	Michigan

3. Data and key variables

Based on all regulated U.S. electric utilities[21] that filed FERC Form 1 from 1990 to 2001, we model the leverage ratio (L_{ijt}) of firm i in state j in year t, as a function of regulatory risk (R_t and R_{jt}), market uncertainty (M_{jt}), firm characteristics (F_{ijt}), and firm (u_i), state (S) and year fixed effects (T).

$$L_{ijt} = (R_t, R_{jt}, M_{jt}, F_{ijt}, u_i, S, T) \tag{1}$$

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[21] It would have been interesting to compare privately owned utilities not subject to regulation and see whether post-restructuring these IOUs behave the same manner as the existing unregulated firms. However, the lack of data prevents us from undertaking this exercise.

Table 2
Summary statistics for regressions.

Dependent variables	Mean	SD	Min	Max
Leverage = total debt/total assets	0.334	0.109	0.009	0.772
Logit transformation of (total debt/total assets)[a]	−0.749	0.630	−4.744	1.217
Regressors				
Restructuring characteristics (dummies)	Percentage of ones			
Deregulation investigation dummy	48.31			
Retail competition order dummy	31.53			
Legislation enactment dummy	25.58			
Stranded cost recovery dummy	27.10			
Divestiture policy dummy	18.88			
Performance based regulation (PBR) dummy	10.02			
High price state dummy	37.59			
Effective competition dummy	6.00			
Potential market power dummy	23.08			
Restructuring characteristics (continuous variable)	Mean	SD	Min	Max
Size of the competitive segment	13.408	33.387	0	100
No. of competitors in neighboring states	5.276	8.872	0	33
Firm characteristics (dummies)	Percentage of ones			
Holding company dummy	73.78			
Merger dummy	3.55			
Generation company dummy: lag (1 year)	48.78			
Mixed regulation dummy	18.59			
Firm characteristics (continuous vars.) lag (1 year)	Mean	SD	Min	Max
Log (total assets)	21.039	1.729	15.545	24.015
Return on assets	0.140	0.042	−0.007	0.278
Tangible assets/total assets	0.674	0.177	0.024	0.958
Asset growth	0.013	0.139	−0.909	1.848
Holding company size[b]	3.216	3.413	0	15
Share of industrial sales	0.200	0.138	0	0.954
Input-cost volatility proxy	0.714	0.329	0	1
Wholesale market participation	0.260	0.349	0	1
Sh. of capital expend. on nuclear Plts	0.040	0.121	0	1
Share of purchased power from IPPs	0.007	0.036	0	0.473

[a] All summary statistics are based on the estimation sample. Observation = 1724, Range: 1990–2001.
[b] The holding company size variable is not lagged.

We need two types of data to estimate the above model: (1) information on federal and state-level restructuring policies that capture the regulatory and market uncertainties, and (2) firm level data on financial and other firm characteristics. The state-level restructuring variables are constructed from the Energy Information Administration's (EIA) "Status of State Electric Industry Restructuring Activity as of February 2004″.[22] Tables 1A and 1B provide the summary statistics and the dates for the restructuring and stranded cost recovery policies respectively. Firm level data is primarily drawn from FERC Form 1, and comprise detailed financial data (derived from accounting statements) and operational data such as the amount of electricity generated and sold, the fuel mix, and share of sales of residential, commercial and industrial customers.[23] Our final estimation sample has 183 utilities and a total of 1724 firm-year observations. The unbalanced nature of the panel arises partly because of mergers, but mainly due to random missing observations. Table 2 provides the summary statistics for regulatory, market and firm characteristics. The following sections discuss the dependent and explanatory variables in detail.

3.1. *Leverage*

We use book leverage (total debt/total assets where total debt equals long-term debt plus short-term debt or notes payable) as our key dependent variable.[24,25] To illustrate the differences between regulated utilities and other firms, we use non-regulated U.S. manufacturing firms[26] as a benchmark (Table 3A). We find that the median utility has a leverage ratio of 33 percent compared to 18 percent for the median manufacturing firm, for our sample period. This confirms earlier findings that leverage ratios are significantly higher for regulated firms (Bradley, Jarrell, & Kim, 1984). To further explore the differences between firms in a regulated versus competitive environment, we split the electric utilities into two cohorts[27] based on restructuring status (Table 3B). The pre-

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[22] This publication outlines the regulatory orders, legislations and the investigative studies that have been undertaken by each state till present.

[23] We also use several EIA publications from 1990 to 2003 to validate and supplement the Form 1 data.

[24] We believe that this is the relevant leverage measure for our analysis since the variation in non-debt liabilities is minimized in this measure due to our single industry focus. For a more detailed discussion on this issue and on alternative leverage measures, see Rajan and Zingales (1995).

[25] Many companies in our sample are wholly owned by a holding company and hence, we do not observe their stock price and cannot construct a market leverage ratio as other studies do.

[26] We use COMPUSTAT data for SIC codes 2000–3999. We exclude outliers.

[27] This is only one way to slice the data – we could have compared the pre and post 1996 leverage ratios of all firms to see if the FERC orders had any impact irrespective of what the states did. Or we could have separated the sample by the date when a

Table 3A
Leverage comparison.

Leverage (Total debt/total assets)		
Sample	US IOUs	US manufacturing
Obs.	1981	24,918
Mean	0.338	0.224
Median	0.329	0.183
Standard deviation	0.117	0.212
Minimum	0.009	0
Maximum	0.772	1

Note: Leverage statistics is based on all available data. US manufacturing firms are obtained from the COMPUSTAT dataset for SIC 2000-3999 and are corrected for outliers. Range: 1990–2001.

Table 3B
Pre and post restructuring leverage comparison.

Leverage (total debt/total assets)		
	Pre-restructuring	Post-restructuring
Obs.	1277	447
Mean	0.345	0.301
Median	0.330	0.304
Standard deviation	0.104	0.115
Minimum	0.009	0.009
Maximum	0.772	0.772

Note: Leverage statistics is based on the regression sample. The pre-restructuring period covers firms in states (for those years) when the state has not enacted a restructuring legislation, i.e. the legislation enactment dummy equals 0. The post-restructuring period comprises firm-year observations when the legislation enactment dummy equals 1. Kruskal–Wallis equality-of-populations rank test rejects the null hypothesis of equality for the pre and post leverage mean and medians for US IOUs. Range: 1990–2001.

restructuring group comprises firms located in states that have not passed a final restructuring legislation, and are thus the regulated entities. The post-restructuring cohort includes utilities located in states that have passed such legislation,[28] and hence face competitive market forces. We find significant differences between these groups on two dimensions.

First, both mean and median leverage is lower for utilities that face potential competition, i.e. they are located in states that have passed a restructuring legislation. Second, these utilities also display a higher standard deviation when compared to those in regulated states. Along similar lines, Dewenter and Malatesta's (2001) find that state-owned enterprises are usually more leveraged than privately held ones and leverage decreases with privatization. Although IOUs were not state-owned as such, the reasons for which state-owned firms hold more debt apply to them, such as a very low or non-existent probability of default and borrowing at a favorable interest rate. Such systematic differences hint at underlying changes in the capital structure decisions of the IOUs that we study and form the basis of our inquiry into factors that can explain these observed patterns.

3.2. *Regulatory risk and market uncertainties*

3.2.1. *Regulatory risk*

Restructuring did not happen in a monolithic fashion, and was not achieved by any single law change. We thus use multiple variables that measure *regulatory risk* and codify the formal rules and bylaws in state restructuring bills and federal orders.[29] These include the formal passing of restructuring legislation at the state and federal level, expected restructuring, stranded cost recovery procedures and divestiture policies. First, to capture the different stages of the legislative process, we construct five dummy variables, two at the federal level, and three showing the progression of restructuring in each state. At the federal level, the *EPAct dummy* equals 1 after the Energy Policy Act was passed in 1992, and the *FERC Order dummy* equals 1 after 1996. These capture the overall effect of federal law changes that made wholesale competition possible. It was only after these changes that customers such as municipalities could shop around for power and move away from the vertically integrated utilities that had served all their needs previously. The threat of losing a portion of their captive customers and consequently losing a stable revenue base would increase the probability of financial distress. Thus we should observe a decrease in utility leverage, especially after the EPAct that formalized the wholesale competition process.

As alluded to earlier, there is considerable heterogeneity in the nature and pace of restructuring activity at the state level. For utilities, state-level policies are very important since they determine the amount of regulatory risk and market uncertainty that the firms are going to face in the emerging competitive landscape. There are three common stages that each state traverses along its journey from regulation to restructuring. These stages are captured by three dummies: (i) the *deregulation investigation dummy* takes the value 1 if the state has "Investigations Ongoing or Orders and Legislation Pending", (ii) the *retail competition order dummy* takes the value 1 if there is an "Order Issued for Retail Competition", and (iii) the *legislation enactment dummy* equals 1 if the state has "Legislation Enacted to Implement Retail Access". The base case is given by states that exhibit "No Activity" regarding deregulation.[30] Each stage of the legislative process has different levels of uncertainty associated with it, and we use the three alternative dummies to investigate which stage has a greater effect on a firm's capital structure decision. We expect a negative relationship between these dummies and leverage since movement away from a stable regulated environment increases the probability of financial distress, and hence makes debt less attractive.

To construct the above dummies a utility is uniquely assigned to the state where it has service territories since it will be subject to the regulations of that state. In the current scenario, a holding company can own utilities in several states, but each of those individual utilities has service territories primarily in one state. For example, Entergy has five regional utilities under its umbrella (Entergy Gulf States, Entergy Louisiana, Entergy Arkansas, Entergy Mississippi, Entergy New Orleans). Each utility operates as a separate entity in its geographical location and is bound by the regulations of that particular state, i.e. Entergy Gulf States operates in Texas only and no other state. Our data is at the utility level. Therefore for majority of the utilities we do not have the complication of a utility having a part of its operations in a restructured state, and another part in a regulated state. For utilities with multiple service areas, we assign them to the state in which they are incorporated.[31]

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state begins a deregulation investigation. However, for the purpose of this paper, we believe that this current scheme is appropriate.

[28] Firms enter the post-restructuring cohort only when their specific state passes a restructuring legislation. Some firms are only in the pre-restructuring group if they are located in a state that never passes such legislation, while other firms may switch groups when the legislation is passed by their home state.

[29] Grout and Zalewska (2006) study regulated UK firms and find that the regulation change (from price-cap to profit-sharing between firms and customers) significantly impacted the systematic risk of firms. Similarly, we argue that the regulatory changes introduced during restructuring changes affected the risk that firms faced, which could potentially impact their leverage decisions.

[30] These classifications are taken from EIA's "Status of State Electric Industry Restructuring Activity", May, 2000.

[31] FERC Form 1 provides both the state where the utility is incorporated and the states where it has service areas. Later in the paper we create a dummy variable that accounts for utilities with multiple service areas (mixed regulation dummy).

Next we construct a *stranded cost recovery dummy* that captures a state's policy on stranded cost recovery. Stranded costs are potential losses stemming from earlier large-scale capital expenditures in generation assets that were often incurred at the behest of regulators.[32] How much of this loss can be recouped after restructuring will affect firm value. This dummy is 1 if either a 'reasonable' or full recovery is allowed and is 0 if the recovery type has not been specified or there is no policy on the recovery of such costs.[33] This dummy turns on when the stranded cost policies are passed (Table 1B). The existence of a specific recovery policy should have a positive impact on leverage as firms are assured of recouping some cost.

Next we use a *divestiture dummy* that shows whether regulators wanted to spur market competition by encouraging the divestiture of generation assets by utilities that wanted to remain in the regulated transmission and distribution segments of the business.[34] This dummy equals 1 if a state encourages or mandates divestiture of generation assets and is 0 otherwise. It turns on when formal legislation that lays out the divestiture policies in a state is passed. It is quite likely that generation assets will be undervalued by the market during this period of uncertainty, thus lowering the collateral value of divesting firm assets, and constraining their ability to incur more debt.

The last regulatory risk variable is a *performance based regulation (PBR) dummy*. Before restructuring, states had traditionally adopted cost-of-service regulation, where utilities could pass on their costs to customers. This dampened incentives to increase efficiency and lower costs since a lower cost would result in lower electricity rates for the utilities. By 2001, eight states[35] adopted some form of performance based regulation, the most typical of which were the adoption of price caps. Under a price cap regulation, rates cannot rise above the mandated ceiling, but the utility can reap the benefits of efficiency if it lowers costs. The initial rates are periodically adjusted to reflect inflation and productivity improvements. Imposition of price caps would affect the profitability of firms, and consequently their capital structure decisions.

The aforementioned restructuring variables capture the legislative changes when they occur. However, utilities may have formed a fairly good expectation about the emerging status of restructuring in their home states. Since leverage can potentially affect the future decisions of a firm, expectations about future changes in the institutional structure of the industry should affect the capital structure decision today. Additionally, firm unobservables may influence both the leverage decision and the restructuring legislation, making them endogenous. To capture this expectation-driven endogenous behavior we use two alternative variables. First, we use a dummy variable to capture states whose electricity price was higher than the national average in a particular year *(high electricity price state dummy)*. The state electricity price is a good predictor of the varied status of electricity reform in different states (Ando & Palmer, 1998; Sanyal, 2006). Utilities could have made a fairly good prediction about the possibility of restructuring in their states by surveying these prices since higher-priced states had a greater chance of embarking on a restructuring program in an attempt to decrease these rates. This dummy is 1 if the average electricity price per megawatt-hour in the state was greater than the average US price between 1990 and 1996 and takes the value 0 otherwise.[36] We expect this variable to have a negative impact due to the reasons cited above for the deregulation investigation dummy.

Additionally, we also construct the *probability of restructuring* to capture a firm's expectation about the status of restructuring in the state in 1998.[37] This probability is obtained from an ordered probit specification that models the state restructuring status (as captured by the restructuring dummies) in 1998 as a function of state economic and political factors and the financial characteristics of utilities prevalent in 1993.[38] This variable captures the single realization of a firm's expectation about legislation being enacted to initiate retail access in the state in 1998 based on the information in 1993. It is zero before 1993, takes the constant probability value from the model for all periods after 1993 until the state enacts retail access legislation, after which the probability becomes 1. We discuss this variable in greater depth when we discuss endogeneity issues later in the paper. We expect this variable to lower leverage ratios for the same reasons actual restructuring decreased leverage.

3.2.2. *Market uncertainty*

In addition to regulatory risk, utilities are exposed to *market uncertainty*, i.e. varying degrees of potential competitive threat. It is conceivable that two utilities with exactly the same regulatory risk may organize their capital structures differently if they face different levels of market uncertainty.[39] We construct three measures based on potential market share changes due to: size of the competitive segment, existence of effective competition, and increased market power. To measure the *size of the competitive segment*, i.e. the potential market share loss due to competition, we use the percentage of customers eligible to switch providers once retail access is implemented.[40] All else equal, a utility which may potentially lose a greater number of customers will face higher market uncertainty and greater pressures to decrease prices. This would adversely affect its earnings and consequently hamper its ability to undertake debt, lowering the leverage ratio. As a robustness check we also use the percentage of customers who have already switched providers. Till 2001 14 states had mandated the

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[32] Examples of such are investments in nuclear power plants and alternative power generating plants. Under regulation, firms were guaranteed to recoup their investment over a certain period of time. However, restructuring may leave such assets 'stranded', i.e. firms may not be able to recoup their investments when the market opens, since in the restructured environment market forces determine the price of generating assets.

[33] Some states such as Massachusetts, New Jersey and Ohio have a 'fixed' recovery mechanism implying that utilities in those states can recover all their stranded costs by levying a 'fixed' competitive transition charge (CTC) on customers, leading to very low regulatory risk. Other states such as California, New York and Texas allow for the recovery of 'reasonable' stranded costs only, while some states like Minnesota and Washington have not specified the type of recovery, leading to greater regulatory risk.

[34] It was felt that the simultaneous ownership of generation and transmission capacity by the same company could lead them to discriminate against third parties who wanted to use their transmission networks.

[35] California, Connecticut, Maryland, Massachusetts, Nevada, Oregon, Rhode Island, West Virginia.

[36] We choose 1996 as the cutoff date because this variable loses its information content after that year. States such as California began their restructuring in 1996, and this dummy is no longer a good predictor of restructuring due to endogeneity between electricity prices and restructuring policies.

[37] See Ando and Palmer (1998).

[38] We cannot use any information after 1993 since electricity price, one of the primary predictors of restructuring, is endogenous after state initiate investigations into restructuring, which began after EPAct (1992).

[39] All market uncertainty variables have values equal to zero before the announcement of a start date for retail access, i.e. the date when residential customers are free to choose their electricity providers. For states which have not announced retail access dates, the values are zero.

[40] For example, if only10 percent of the customers can freely choose power providers then the competitive threat to the incumbent utility is not that large. In the worst case, all of the eligible customers switch to a competitor and the incumbent loses 10 percent of its market. However, if say, all customers are free to choose then potentially the incumbent could lose its entire market.

percentage of customers eligible to switch from their incumbent utility.[41]

Enacting a retail access order may have little effect on financing decisions if firms know that after the order it is going to be business as usual, and there is no real threat from new entrants. To capture whether the threat of competition is real, we construct an *effective competition dummy* based on default provider policies that the state has adopted. These policies specify which company gets to supply power to a customer who has not actively chosen an electricity provider. High inertia and transaction costs may prevent customers from switching providers[42] if the incumbent utility is the mandated default provider, or there is no policy in place. The dummy equals 0 in this case. If states have decreed that any company, including non-utilities can be default providers, then there will be more competition since the incumbent utility will not automatically be the default, and will have to compete for customers. The dummy is 1 in this case.[43] We expect a negative coefficient on this dummy since a utility's debt capacity is reduced if it is not the mandated default provider, and is therefore subject to more volatile future earnings.

For some utilities the threat of competition may come from out of state utilities. For example, a utility located in a state that has restructured will not only face potential competition for its customers from utilities and independent power producers in its own state, but if neighboring states that have also restructured then out of state utilities may find it profitable to enter. Thus we create the *number of competitors from neighboring states* as the number of utilities in neighboring states if the neighboring state has at least passed a retail competition order and if the state belongs to the same regional transmission authority (RTO). The threat of losing a large number of customers to outside competition is greater if there are more potential competitors. Thus we expect a negative coefficient on this variable since utilities may face higher market risks and greater pressures to decrease prices in the face of competition and this will adversely affect their debt capacity.

Last, we use a *potential market power dummy* to gauge whether the utility may have the opportunity to exercise market power after restructuring to counteract the instability in earnings flow. If an incumbent utility owns both the transmission wires and competitive generation assets, there may be a tendency to favor its own competitive affiliates during network congestion,[44] thereby pricing out other generators. This may prevent competitors from entering the market. Thus the potential market power dummy is 1 if states have no policy about separating the regulated-monopoly and competitive segments of a utility's business,[45] and is zero otherwise.[46] If there is no separation, then there is a potential for protecting its market share by exercising market power and hence utilities may be more willing to take on debt in these states. One caveat of this measure of market power is that vertically integrated companies are the larger firms that also tend to be publicly traded. The sharp increase in stock prices in the latter half of our sample period might affect these firms' perceptions regarding their optimal leverage ratios.[47] To address this concern, we include a dummy variable that equals one if the firm is publicly traded on an exchange. In unreported analysis, we find that this variable is insignificant while our findings continue to hold.

3.3. Firm characteristics

3.3.1. Financial attributes

Following Rajan and Zingales (1995), we construct several firm financial characteristics that have been shown to impact capital structure decisions: *firm size* (total assets[48]); *asset growth* (annual growth in total assets[49] or excess generation capacity[50]); *return on assets*, ROA (earnings before interest, taxes, depreciation and amortization/total assets) and *tangible assets* (net plant and nuclear fuel/total assets). All dollar variables are in 2000 constant dollars. We expect larger firms and ones with more tangible assets to have higher leverage since their debt capacity is higher (consistent with the tradeoff theory). Profitability should have a negative impact on leverage since more profitable firms have a lesser need to undertake debt and can finance their investments from cheaper internal funds (consistent with the pecking order theory). In addition, growing firms should have lower leverage ratios either because they mitigate the debt overhang problem by using more equity financing, or they may accumulate financial slack today in order to take advantage of future opportunities (Myers, 1977, 1984; Myers & Maljuf, 1984).

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[41] Arizona, California, Connecticut, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island.

[42] Being under a regulated monopoly for decades, with all charges consolidated under a single bill, switching to a new provider may prove difficult for customers (especially residential) due to inertia. Hence even with all the competitive apparatus in place, there may be no real competition in the market. Foreseeing such an outcome, many states have adopted policies about which generating companies can be the default provider.

[43] We do not have information on the exact dates that these default provider policies were passed. So they are turned on when a state passes the retail competition order. Thus, this dummy is 1 if any company can be a default provider and the state has passed a retail competition order (i.e. the retail competition order dummy = 1). It is zero otherwise.

[44] Two important features differentiate network infrastructures such as transmission lines in the electric utility industry. First, like all networks they suffer from congestion, and second, they are owned by private utilities that provide transmission and distribution service to competing generators.

[45] This measure is based on how states view the separation of powers between different segments on a utility that operate in both the competitive generation and regulated transmission market. Some states have mandated that there must be either 'corporate' or 'functional' separation (Malloy & Amer, 2000) between the monopoly and competitive segments of a company.

[46] Again, the exact date of the policy announcement is not known, hence we assume that the announcement date coincides with the passing of the retail competition order. Thus, the dummy is 1 if there is no policy and the state has passed a retail competition order (i.e. the retail competition order dummy = 1), and is zero otherwise.

[47] We thank an anonymous referee for pointing this out.

[48] We have also used total sales instead of total assets: our results are unchanged.

[49] Growth opportunities are commonly defined as discretionary, future investments. We follow Fama and French (2002) and Titman and Wessels (1988) and use asset growth as a measure of growth opportunities. The most common proxy for growth opportunities is the market-to-book ratio (or average *q*). Recall however that we cannot observe stock prices and hence are unable to construct this measure. Both studies also use the ratio of research and development (R&D) to total assets or sales as a proxy for growth opportunities. Due to missing data for R&D, we lose a lot of observations using this measure. The results with R&D, however, are similar to those reported here.

[50] We thank the anonymous referee for this suggestion. For generating plants, a better measure of growth opportunities may be the annual amount of excess capacity (total nameplate capacity – total generation) each plant has (we aggregate up the excess capacity of each plant to the utility level). If a utility has a large amount of excess capacity then its growth opportunities may be limited. Thus firms with substantial excess capacity are unlikely to be undertaking much investment in the foreseeable future and so might be expected to have relatively high leverage. In contrast, those firms that are currently operating at close to full capacity would anticipate future investment and potentially factor that into their capital structure decision. Thus this capacity-utilization measure might do a better job of capturing anticipated future investment. Additionally we can also use the change in capacity utilization in each year (i.e. excess capacity growth) and the results are similar.

In addition, many utilities belong to holding companies and we include two variables to characterize this: a *holding company dummy*[51] that is 1 when a utility joins a holding company, or is acquired by a holding company, or was a part of the holding company before our sample period; and a *holding company size* variable that captures the size of the parent in terms of the number of its subsidiaries. Holding companies vary greatly in size. Some like the American Electric Power Corporation have twelve utilities under its umbrella while others have just one utility. Being part of a large holding company may allow the utility greater access to financing sources both from within and outside the holding company structure, consequently altering their debt capacity, i.e. a utility may be able to borrow more as its holding company serves as its "guarantor". Moreover, a greater number of utilities under a holding company could potentially provide some diversification benefits, resulting in a great debt capacity overall. On the other hand, the holding company structure also permits the use of net operating losses of one utility to offset positive income of another utility, resulting in lower overall (federal) taxes at the holding company level. In this case, a greater number of utilities under the holding company could dampen the tax shield benefits of debt.

Last we include a *merger dummy* to control for the post restructuring merger wave in the electric utility industry, since mergers significantly altered the size and debt capacity of firms. This dummy equals 1 when a firm is part of a merger in a particular year. A priori the effect of mergers on leverage is unclear, since a merger may either increase or decrease leverage depending on the financial structure of the two companies and the nature of the merger.

To investigate whether these firm characteristics were affected by restructuring, we divide the observations into pre and post-restructuring cohorts (Table 3C) and find some systematic differences between the two groups. First, the ratio of tangible assets to total assets, and asset growth are both lower for utilities in restructured states. It is quite plausible that because of the heightened uncertainty during the period of deregulation, firms were more cautious in their investment decisions (McDonald & Siegel, 1986), as reflected in this slow down of asset growth. Second, mean holding company size is greater for restructured firms and this may be due to the increased mergers and acquisitions in the restructured phase. Third, profitability is lower for restructured firms, although the difference is not significant. Prior work has shown that the efficiency of U.S. electric utilities increased after restructuring (Delmas & Tokat, 2003; Fabrizio, Rose, & Wolfram, 2007),[52] and we find that this reported productivity increase does not translate to higher profitability for the period under consideration.[53] Last, we note that firm size is not significantly different in the two periods.

3.3.2. Non-financial firm attributes

For the power industry, non-financial firm characteristics also play a crucial role in determining how each utility reacts to the regulatory and competitive forces. We specify five firm-specific traits that we believe may directly impact a utility's financial decisions in light of industry restructuring. The first variable is *wholesale market participation* and is constructed as the ratio of electricity sales for resale[54] to total electricity sales for a company. The higher this resale share the greater the company presence in the wholesale market. The wholesale market had been deregulated for some time before the passing of the two FERC Orders in 1996. Thus, utilities which have a strong presence in the wholesale market are already familiar with the workings of a competitive electricity market and should be better positioned to take advantage of deregulation in the retail market and manage the market risks better. On average, we expect this variable to have a non-negative impact on leverage since firms with greater wholesale market experience may find ways to reduce their exposure to market risks and thus may be willing to take on more debt. However, the reverse may also be true. Greater exposure to wholesale competition implies greater revenue uncertainty, thus adversely affecting leverage.

Second, we use two proxies to capture the amount of *potential stranded costs* for a particular utility. The expected amount of stranded costs faced by a firm is important in determining how it reacts to the various regulatory risks vis-à-vis its capital structure decision. For instance, a utility with very low stranded costs may not alter its leverage even if located in a state with stringent stranded cost recovery policies as opposed to another utility with high levels of stranded costs. We use the *share of capital expenditure on nuclear plants* as one such proxy, and construct this as the amount (in dollars) of capital expenditure on nuclear plants as a proportion of total capital expenditure in that year. Newly built nuclear facilities are one of the largest sources of costs that utilities may not be able to recover once the state transitions away from the regulatory environment and this variable captures a portion of such stranded costs.[55] In addition, we use the *share of IPP supplied power* as the other proxy.[56] This is measured by the amount of megawatt hours supplied by independent power producers to a particular utility as a share of total power sold by the utility. After PURPA was passed in 1978, major utilities were obligated to buy all the power that qualifying[57] IPPs could supply at "avoided cost" rates. If a utility is locked into a long-term contract with an IPP at above market rates, then they would be unable to pass this cost to their customers after deregulation and the difference between the market rate and the contract rate would be "stranded".

Third, we use the *share of industrial sales* as measured by megawatt hours of electricity sold to industrial customers as a proportion of the total electricity sold by the firm. In most states that began retail competition, industrial customers were the first segment that could choose a retail provider, and unlike residential customers, were more likely to switch providers if competing generators could provide lower rates. Thus the higher the share of industrial customers, the greater is the exposure to market uncertainty and lower expected debt to asset ratios after restructuring. From Table 3C we find that utilities have been losing industrial customers after restructuring.

Restructuring was primarily aimed at generating companies and utilities whose primary business was distribution should be unaffected. Thus generation companies should have lower leverage ratios compared to distribution companies. This is captured by a *generation company dummy* that takes the value 1 if the sale of the utility's own generation is more than 75 percent of the total

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[51] When we could identify the exact date when the utility joined the holding company, the dummy is 1 from that date. Otherwise, if we know that a certain utility belongs to a holding company, the dummy is 1 through out the sample period.

[52] There is a substantial theoretical and empirical literature that shows deregulation to be productivity enhancing (Baily et al., 1993; Bertoletti & Poletti, 1997; Djankov & Hoekman, 2000; Evans & Kessides, 1993).

[53] One possible explanation could be that in the short-term costs associated with restructuring may put downward pressure on profits.

[54] Sales for resale are sales to other electric utilities.

[55] This variable is an upper bound on the nuclear stranded cost variable as some utilities may already have fully recovered the cost of building their nuclear facilities.

[56] This variable is not a clean proxy for stranded costs since this variable also shows how strong the IPP presence is in the state, and hence the potential competition that utilities may face once the state has restructured. But either way, we expect the coefficient to be negative.

[57] Most of the qualifying facilities were renewable generation sources or various co-generation facilities.

Table 3C
Pre and post restructuring comparison of means of firm characteristics.

	Pre-restructuring		Post-restructuring	
	Mean	Median	Mean	Median
Log (total assets): lag (1 year)	21.081	21.396	20.918	21.482
Return on assets: lag (1 year)	0.141	0.145	0.138	0.141
Tangible assets/total assets: lag (1 year)	0.703	0.737	0.589	0.648
Asset growth: lag (1 year)	0.019	0.002	−0.006	−0.019
Holding company size	3.057	2.000	3.677	2.000
Share of industrial sales: lag (1 year)	0.207	0.205	0.180	0.168
Input-cost volatility proxy: lag (1 year)	0.728	0.854	0.674	0.800
Wholesale market participation: lag (1 year)	0.264	0.103	0.248	0.095
Sh. of capital expend. on Nuc. Plts: lag (1 year)	0.003	0	0.001	0
Sh. of purchased power from IPPs: lag (1 year)	0.001	0	0.026	0

Note: The statistics reported are sample means based on the regression sample. The pre-restructuring period covers firms in states (for those years) when the state has not enacted a restructuring legislation, i.e. the legislation enactment dummy equals 0. The post-restructuring period comprises firm-year observations when the legislation enactment dummy equals 1. There are 1277 observations before restructuring and 447 observations after. Range: 1990–2001.

electricity sold and zero otherwise.[58] Additionally, we construct an *input-cost volatility proxy* given by the ratio of fossil fuel generation to total generation for each utility. Compared to hydro and nuclear utilities, fossil fuel based plants[59] are often subject to fuel price shocks, and thus suffer from greater cost-side uncertainties making them less willing to undertake debt. Comparing pre and post-restructuring periods (Table 3C) we find that the share of fossil fuel in total generation is lower in the restructured phase,[60] and thus the effect of this variable on leverage may be different in the two periods.

Last, we account for the fact that some utilities have multiple service areas, and may thus be subject to multiple regulatory regimes. In our data there are 33 utilities[61] that have service areas in multiple states. To account for this we follow the strategy adopted by Fabrizio et al. (2007 – footnote 38). We assign these utilities to the state where they are incorporated and then create a dummy (*mixed regulation dummy*) to account for cross-state service areas and for "mixed regulation" that these utilities are subject to. It is possible that firms that are subject to multiple sets of regulation face greater uncertainty which would lower leverage.

4. Empirical methodology and results

4.1. Difference-in-difference model

Prior to estimating the effect of various restructuring policies on firm leverage, we first confirm that the decline in leverage ratios was not just a secular downward trend having little to do with the restructuring policies, and then investigate which stage of the restructuring process had the greatest impact on the financial structure of the utilities. We estimate a simple difference-in-difference model[62] given in (2).

$$L_{ijt} = \alpha + \theta Treat_{jt} + \sum_{t=1992,1996} \lambda_t R_t + \sum_{P=1}^{p} \delta_P F_{ijt-1} + \sum_{J=1}^{j} \chi_j S + \sum_{k=1}^{K} \pi_k RTO + \sum_{t=1}^{8} \phi_t T + u_i + \varepsilon_{ijt-1} \quad (2)$$

where L_{ijt} is the leverage ratio for firm i in state j in year t, and is a function of state restructuring activity ($Treat_{jt}$), federal deregulation orders (R_t), lagged firm characteristics (F_{ijt-1}), and state (S), regional transmission authority (RTO), and year (T) dummies. u_i is the firm fixed effect and ε_{ijt-1} is the first-order autocorrelated idiosyncratic error which we include due to the persistence in leverage ratios over time. $Treat_{jt}$ is the treatment dummy that captures whether a state has undergone a particular restructuring stage in the given year. In our estimations in Table 4, we use three alternative treatment dummies: the deregulation investigation dummy (column 1), the retail competition order dummy (column 2), and the legislation enactment dummy (column 3) to investigate which stage of restructuring activity had the greatest impact on firm financial decisions. θ is the difference-in-difference coefficient that captures the effect of the treatment on the treated. If any of the restructuring stages was responsible for significant changes in the financial structure of firms and the decline in leverage, we expect θ to have a negative sign.

When estimating the model shown in Eq. (2), we have to choose the appropriate technique that will yield unbiased coefficient and standard error estimates. As mentioned above, there is persistence in leverage (especially in our data), and we hypothesize that past errors may influence current ones. This implies that errors may be autocorrelated and we cannot assume that the errors are identically and independently distributed. Additionally, it is not unreasonable to assume that in our model errors are heteroscedastic, i.e. each firm (panel) has a specific variance–covariance matrix, and that the disturbances are contemporaneously correlated across panels. To estimate the parameters of such models where the errors are autocorrelated and heteroscedastic, Beck and Katz (1995) propose the following: first, use the Prais-Winsten methodology to correct for autocorrelation, and second, to use the Beck and Katz technique to obtain heteroscedasticity-consistent standard errors. We use this

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[58] The generation company dummy = 1 if generation in MWH/total sales in MWH. 75 percent. For robustness purposes we vary this definition and construct the dummy so that it takes the value 1 if the generation share is 80, 85 or 90 percent. This makes no substantive change in the results.

[59] Those that relied primarily on coal and natural gas as their major source of fuel.

[60] Most restructuring activity was aimed primarily at fossil-fuel based plants and a number of utilities sold these off, especially in states that encouraged or mandated divestiture. Thus input-cost volatility for these firms would decrease after restructuring.

[61] Alcoa, Appalachian Pwr. Co., Black Hills Pwr. Inc., Carolina Pwr. & Light Co., Delmarva Power and Light, Duke Pwr. Co., El Paso Electric Co, Interstate Pwr. Co., Idaho Pwr. Co., Electric Energy Inc., Indiana Michigan Pwr. Co., Indiana-Kentucky Elec. Corp., Kansas City Pwr. & Light Co., Kentucky Utilities Co., MDU Resources Group, Monangahela Pwr. Co., Montana Pwr. Co., New England Pwr. Co., Oklahoma Gas and Elec. Co., Old Dominion Elec. Coop, Otter Tail Pwr. Co., Pacificorp, Potomac Edison Co., Potomac Electric Power Co., Sierra Pacific Pwr. Co., South Beloit Water Gas & Elec. Co., Southwestern Elec. Pwr. Co., Southwestern Public Service Co., Susquehanna Electric Co, Texas-New Mexico Pwr. Co., Union Elec. Co., Wisconsin Electric Power Co, Wisconsin Public Service Corp.

[62] We refer the reader to Bertrand et al. for a detailed discussion of this specification.

Table 4
Difference in difference model (dependent variable: total debt/total assets).

	(1)	(2)	(3)
Regulatory variables			
EPAct dummy	−0.028*** (0.005)	−0.028*** (0.005)	−0.028*** (0.005)
FERC order dummy	0.0001 (0.0002)	−0.002 (0.007)	−0.006 (0.006)
deregulation investigation dummy	0.002 (0.004)		
Retail competition order dummy		−0.008** (0.004)	
Legislation enactment dummy			−0.011** (0.005)
Firm characteristics			
Log (total assets): lag (1 year)	−0.007 (0.022)	−0.007 (0.022)	−0.008 (0.022)
Return on assets: lag (1 year)	−0.244*** (0.083)	−0.240*** (0.083)	−0.240*** (0.083)
Tangible assets/total assets: lag (1 year)	0.150*** (0.027)	0.151*** (0.027)	0.148*** (0.027)
Asset growth: lag (1 year)	−0.037** (0.015)	−0.037** (0.015)	−0.037** (0.015)
Holding company dummy	−0.006 (0.008)	−0.005 (0.008)	−0.005 (0.008)
Holding company size	−0.004*** (0.001)	−0.004*** (0.001)	−0.004*** (0.001)
Merger dummy	0.007 (0.006)	0.006 (0.006)	0.006 (0.006)
Share of industrial sales: lag (1 year)	−0.175*** (0.066)	−0.177*** (0.066)	−0.178*** (0.066)
Generation company dummy: lag (1 year)	−0.001 (0.005)	−0.001 (0.005)	−0.001 (0.005)
Input-cost volatility proxy: lag (1 year)	−0.012 (0.011)	−0.013 (0.011)	−0.014 (0.011)
Wholesale market participation: lag (1 year)	0.034*** (0.011)	0.034*** (0.011)	0.035*** (0.011)
Sh. of capital expend. on nuclear Plts: lag (1 year)	−0.030 (0.020)	−0.030 (0.020)	−0.030 (0.021)
Share of purchased power from IPPs: lag (1 year)	−0.085 (0.054)	−0.083 (0.054)	−0.081 (0.054)
Relevant statistics			
Observations	1724	1724	1724
Number of firms	183	183	183
R-square	0.769	0.770	0.770
Rho(AR1)	0.473	0.462	0.464

Note: Prais-Winsten panel model. Standard errors (in parenthesis) corrected for first-order auto-correlation and panel level heteroscedasticity. All equations contain a constant, year, firm, state and RTO fixed effects. Range: 1990–2001. 'Rho(AR1)' denotes the common autocorrelation coefficient.

** Significant at 5%.

*** Significant at 1%.

methodology in our main regressions. In the tables that follow, we report the common autocorrelation coefficient (rho).

In addition, we also correct for time-invariant characteristics of firms, states and the broader transmission areas. In the model, firm fixed effects will capture all firm unobservables that do not vary by year, such as say a particular corporate culture that may make a firm more or less likely to undertake debt. The state fixed effects capture attributes such as a high-electricity price state that is more predisposed towards deregulation (Ando & Palmer, 1998), or very proactive regulators in state such as California and New York. The RTO dummies capture the common characteristics of each transmission networks shared by utilities that belong to that network. The year dummies absorb the macro shocks (excludes 1993 and 1997 since these are collinear with the federal regulatory order dummies.

We find that the estimate for θ is insignificant in column (1), and is negative and significant in columns (2) and (3). This indicates that preliminary investigations in a state had little impact on a firm's financing choices. Leverage ratios declined when an actual order was passed or legislation enacted, since at that point restructuring was probably inevitable, and firms expected a competitive landscape in the future. When an order is passed leverage ratios decline by 2.4 percent and after legislation is enacted it drops by 3.4 percent.[63]

Table 4 also shows that the 1992 Energy Policy Act had a much larger impact on leverage than the state-level restructuring plans. An average firm experienced an 8.5 percent decrease in leverage after EPAct. As discussed earlier, EPAct formalized the process of wholesale competition in the electricity market and thus exposed utilities to greater earnings volatility and higher uncertainty about future income potential. This may have made utilities unwilling to hold more debt, since the financial safety net of regulated rates was significantly smaller as they increased their participation in the wholesale market. In addition, the financial market may have also been uncertain about how the industry is going to change and hence, may have undervalued these firms, decreasing their debt capacity.

Surprisingly, in the estimated model, the 1996 FERC orders had no impact on leverage as may have been expected from Fig. 1 which showed a sharp decline after 1996. One reason may be that these orders were little more than follow-on orders to the 1992 EPAct, and firms had already adjusted their leverage after EPAct. It could also be that the negative and highly significant year dummies after 1997 are capturing the effect of the FERC Orders on leverage.

4.2. *Firm characteristics*

All coefficients on firm characteristics are remarkably robust across specifications in all tables, and are consistent with previous findings (Barclay, Smith, & Watts, 1995; Bradley, Jarrell, & Kim, 1984; Fama & French, 2002; Rajan & Zingales, 1995; Titman & Wessels, 1988). First, we find that firm size does not affect the capital structure decisions of firms. This result, although different from that of non-regulated firms, may not be entirely surprising given that our sample consists of rate-regulated utilities. Usually one observes a positive effect of size on leverage since large firms may have lower default probabilities and hence higher debt levels. However, if default probabilities are near zero, as with regulated utilities, one should not expect a significant effect of size on leverage.

Second, more profitable firms rely less on debt to finance investments, and a 1 percent increase in profitability decreases leverage by 0.1 percent, suggesting that more profitable firms use internal funds and less debt. Third, the coefficient on the ratio of tangible assets to total assets is positive and significant, and a 1 percent increase in the ratio, increases leverage by 0.3 percent. Tangible assets are used as collateral for borrowings and hence more collateral value translates into higher debt capacities and higher debt

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[63] However, when both order and legislation dummies are included, we find that firms change their financing decisions only after states enacted formal restructuring legislation and leverage decreases by 3 percent.

levels. Last, the negative coefficient on asset growth, lends support to the hypothesis that firms with high growth opportunities are more likely to forego profitable investments if they are highly levered (Myers, 1977).

The holding company size variable is negative and significant, suggesting that firms belonging to large holding companies may have greater access to internal capital markets and use less external debt. In addition, we also find that firms with a larger industrial customer base have lower debt ratios. (Recall that industrial customers were the first to experience retail competition.) If utility A has 10 percent more industrial customers than utility B, we would expect A's leverage to be 1.1 percent lower that that of B. We attribute this to the greater competitive pressure faced by utility A. To retain this low-inertia (or footloose) customer segment, it had to lower its price or risk losing market share. The wholesale market participation variable is positive and significant implying that utilities that were large players in the wholesale market were more leveraged. Last, being a generation company, having undergone a merger, input-cost volatility, or the proxies for stranded costs[64] did not influence a utility's financing choices.

4.3. Extended model

The earlier model indicates that restructuring lowered leverage ratios. However, using one dummy variable to characterize the restructuring policies fails to capture their complexity and omits other associated policy changes. We have explained that states differed not only in their pace of deregulation, but also in terms of laying the groundwork for future competition and in other regulatory provisions. In addition, the summary statistics (Table 3C) show that firm characteristics are different for regulated and restructured firms, and should influence leverage differentially in the pre and post-restructured regimes. The specifications that follow, augment the earlier model by adding several regulatory risk (R_{jt}) and market uncertainty (M_{jt}) variables in

$$L_{ijt} = \alpha + \lambda R_{1992} + \sum_{K=1}^{3} \beta_K R_{jt} + \sum_{H=1}^{3} \gamma_H M_{jt} + \sum_{P=1}^{p} \delta_P F_{ijt-1} + \sum_{J=1}^{j} \chi_J S + \sum_{k=1}^{K} \pi_k RTO + \sum_{T=1}^{8} \phi_T T + u_i + \varepsilon_{ijt-1} \qquad (3)$$

addition to the EPAct and restructuring dummies. Similar to the difference-in-difference model, we estimate the equation outlined below using the Prais-Winsten methodology and correct the errors for first-order autocorrelation and panel heteroscedasticity, and control for firm (u_i), state (S) and year (T) fixed effects.

Table 5 (column 1) presents the results for this extended model.[65] As before, firms decreased leverage by 8.7 percent after the 1992 Energy Policy Act. However, with the additional regulatory and market uncertainty variables, the legislation enactment dummy becomes insignificant. The primary regulatory risk seems to arise from the policies regarding the divestiture of generation assets. We find that utilities whose state encouraged divestiture of generation assets, reduced leverage by 6.3 percent. This could either be due to the market undervaluing the assets and reducing a firm's debt capacity, or firms reacting to future earning instability brought about by these policies. Stranded cost recovery and performance based regulation policies show no significant effect on financing decisions although they are in the direction we expect. In aggregate, the regulatory risk factors decreased leverage by about 15 percent.

The market uncertainty variables show that a firm with higher market uncertainty holds less debt. As the size of the competitive segment increased by 1 percent, firms reduced their debt ratios by 0.06 percent. This effect is apparently small but it is of great economic significance since 9 out of the 14 states had mandated that 90 percent or more of customers were eligible to switch.[66] This implied that their entire market was in play, and utilities serving these markets would face greater competitive pressures, more earnings volatility and hence greater default probabilities, which in turn would decrease leverage. For instance, a utility would decrease its leverage by 6 percent if it was located in a state where 100 percent of the customers could choose their electricity providers, compared to a utility in a state where no customers had such a choice. The other 7 states allowed between 0.3 and 91.4 percent of customers to switch. When all 14 states are taken into account, on average, 60 percent of customers were allowed to switch. This implies that leverage would decline by 3.6 percent.

We also find that if the state encouraged competition by allowing any company to be the default provider, thus intensifying competition for customers who had not chosen a provider, firms decreased leverage. Introducing effective competition reduced debt levels by 7.8 percent, one of the largest policy effects. In addition, if the number of competitors in neighboring states increases by one, utilities decrease their leverage by only 0.3 percent. On average, the number of competitors increased by 5.3, hence we would expect a 1.6 percent decrease in leverage. Thus policies that encouraged competition, and hence increased market uncertainty, lowered leverage by 13 percent on average. In addition, if utilities expected to exercise greater market power in the future, they were more likely to take on higher debt, i.e. about 2.1 percent higher, when compared to utilities in states where there was no potential for exercising market power. Overall, we find that the regulatory risk and market uncertainty variables are associated with a 28 percent decline in leverage.

In sum, we find that deregulation and its associated restructuring policies have led to significant lowering of debt ratios. Particularly, any policy that decreased the earnings stability, or increased competition and threatened market share lowered debt ratios. We also find that the existence of effective competition had a greater effect on firm financing than the size of the competitive segment. Firms with market power had the ability to counter this competitive threat and stabilize earnings, and were thus willing to take on more debt. We also confirm earlier findings that firms with higher profitability and asset growth have lower leverage, and firms with greater tangible assets and higher wholesale market participation were more leveraged. In addition, firms belonging to a holding company, or ones with a footloose customer segment used less debt.

In column 2, we add the high price state dummy to account for the expectation a firm may have had about the status of restructuring in its home state. As discussed earlier, a high price state was more likely to restructure than a low price one. However, we do not find any effect of this variable on leverage. In column 3, we add the mixed regulation dummy to control for utilities whose service areas span multiple states, thus subjecting them to multiple regulatory

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[64] The coefficient on the share of IPP power is significant at 12 percent showing a weak negative effect of the variable on leverage.

[65] The table presents the coefficients. Using those values, for dummy variables we calculate the semi-elasticity and for continuous variables we calculate the elasticities. All are evaluated at the mean.

[66] California, Connecticut, Maine, Massachusetts, New Jersey, Pennsylvania, Rhode Island had made 100 percent customers eligible while New York and Maryland made more than 90 percent of customer eligible to switch.

Table 5
Extended model (dependent variable: total debt/total assets).

	(1)	(2)	(3)	(4)
Regulatory risk				
EPAct dummy	−0.028 (0.005)***	−0.029 (0.005)***	−0.029 (0.005)***	−0.032 (0.005)***
Legislation Enact. Dum.	0.008 (0.005)	0.008 (0.005)	0.008 (0.005)	0.007 (0.005)
Strand. cost Reco Dum.	0.002 (0.005)	0.002 (0.005)	0.002 (0.005)	0.003 (0.005)
Divestiture Pol. Dum.	−0.021 (0.009)**	−0.021 (0.009)**	−0.021 (0.009)**	−0.019 (0.009)**
PBR dummy	0.012 (0.011)	0.014 (0.011)	0.014 (0.011)	0.014 (0.011)
High price state Dum		−0.007 (0.008)	−0.007 (0.008)	−0.007 (0.008)
Market uncertainty				
Size of Comp. segment	−0.0002 (0.0001)**	−0.0003 (0.0001)***	−0.0003 (0.0001)***	−0.0003 (0.0001)***
Effective Comp. Dum.	−0.026 (0.014)*	−0.026 (0.014)**	−0.026 (0.014)**	−0.026 (0.015)*
No. Comp Neigh states	−0.001 (0.0003)**	−0.001 (0.0003)**	−0.001 (0.0003)***	−0.001 (0.0003)***
Potential Mkt Pwr Dum	0.007 (0.004)*	0.007 (0.005)*	0.007 (0.005)*	0.007 (0.005)
Firm characteristics: lag 1 year[a]				
Log (total assets)	−0.012 (0.022)	−0.012 (0.022)	−0.012 (0.022)	0.003 (0.019)
Return on assets	−0.252 (0.084)***	−0.248 (0.085)***	−0.248 (0.085)***	−0.252 (0.093)***
Tangible Ast/Tot Ast	0.123 (0.026)***	0.124 (0.026)***	0.124 (0.026)***	0.113 (0.026)***
Asset growth	−0.038 (0.015)**	−0.038 (0.015)**	−0.038 (0.015)**	
Excess capacity				0.0002 (0.0001)***
Holding Co. dummy	−0.006 (0.008)	−0.006 (0.008)	−0.006 (0.007)	−0.005 (0.008)
Holding company size	−0.004 (0.001)***	−0.004 (0.001)***	−0.004 (0.001)***	−0.004 (0.001)***
Merger dummy	0.006 (0.006)	0.005 (0.006)	0.005 (0.006)	0.004 (0.006)
Sh. of industrial sales	−0.162 (0.065)**	−0.161 (0.066)**	−0.161 (0.066)**	−0.161 (0.062)***
Generation Co. dummy	−0.002 (0.005)	−0.002 (0.005)	−0.002 (0.005)	−0.002 (0.005)
Input-cost Volat. proxy	−0.013 (0.011)	−0.013 (0.011)	−0.013 (0.011)	−0.016 (0.011)
Wholesale Mkt Particip	0.034 (0.011)***	0.034 (0.011)***	0.034 (0.011)***	0.033 (0.011)***
Sh. of nuclear Gen.	−0.028 (0.022)	−0.028 (0.022)	−0.028 (0.022)	−0.031 (0.022)
Sh. of IPP Supp. Pwr	0.002 (0.057)	0.005 (0.057)	0.005 (0.057)	0.006 (0.057)
Mixed regulation Dum			−0.060 (0.082)	0.295 (0.447)
Relevant statistics				
Observations	1724	1724	1724	1724
Number of firms	183	183	183	183
Rho(AR1)	0.452	0.452	0.452	0.441
R-square	0.779	0.779	0.779	0.778

Note: Prais-Winsten panel model. Standard errors (in parenthesis) are corrected for first-order autocorrelation and panel level heteroscedasticity. All equations contain a constant, year, firm, state and RTO fixed effects. 'Rho(AR1)' denotes the common autocorrelation coefficient.

[a] The holding company and merger dummies, and holding company size are not lagged.

* Significant at 10%.

** Significant at 5%.

*** Significant at 1%.

regimes. This variable has no measurable effect on our findings, a result which Fabrizio et al. (2007) have found in their analysis as well. Thus we drop these two variables from latter specifications. In column 4, we use the annual amount of excess capacity as an alternative measure for asset growth. As explained earlier, firms with higher excess capacities will have low future growth opportunities, and thus might be expected to have relatively high leverage and vice versa. We find that this is indeed the case. All other results remain unchanged.

4.4. *Robustness checks – alternative specifications and truncation corrections*

To check the robustness of the above results we use three alternative estimation techniques in Table 6.[67] Column (1) presents a linear fixed effects model as a benchmark. This does not correct for correlated errors or panel-level hetroscedasticity. We find that the main results from Table 5 hold, and correcting the errors for first-order auto-correlation and panel-level hetroscedasticity, and including state fixed effects in Table 5 may be responsible for the minor differences.[68] The Prais-Winsten or fixed effects models however, do not account for the specific nature of the dependent variable, which is in shares (total debt/total assets), and is thus bound between zero and one. Columns 2 and 3 in Table 6 correct for this truncation.

In column 2, we use a logit transformation[69] of the dependent variable and estimate the specification using the Prais-Winsten method used for Table 5. The coefficients presented in column 2 are for the transformed dependent variable. When we calculate the elasticities with reference to the original variable we find that the results are almost identical to those in Table 5, except for the share of nuclear generation which is now negative. Since this share was a proxy for the amount of stranded costs, it implies that utilities with greater amounts of such costs had lower leverage. In column 3 we use a truncated regression model to further check the robustness of our results, and again find that all coefficients of interest are similar to those presented in Table 5. Finally, in column 4, we use feasible generalized least squares estimation (FGLS) with standard errors corrected for autocorrelation and panel level heteroscedasticity, as an alternative to the Prais-Winsten methodology. Our main findings are robust to these alternative specifications.

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[67] We have estimated several other models (random effects with clustered errors, linear fixed effects with AR(1) and a random effects tobit) and for brevity, do not present them here. The results are very robust to these alternative specifications.

[68] The potential market power variable has no impact on leverage in the fixed effects model, and the input-cost volatility variable is negative and significant showing that higher volatility implies a lower leverage ratio.

[69] The dependent variable for the logit transformation is $\log(y/(1-y))$ where y denotes the leverage ratio.

Table 6
Robustness check.

Dependent variable	(1) FE Leverage	(2) Prais-Winsten Logit transform.	(3) Trunc. Reg Leverage	(4) FGLS w/AR(1) Leverage
Regulatory risk				
EPAct dummy	-0.026^{***}	-0.115^{*}	-0.028^{***}	-0.024^{***}
Legislation enactment dummy	0.011	-0.048^{*}	0.011	−0.001
Stranded cost recovery dummy	0.002	0.006	0.002	0.003
Divestiture policy dummy	-0.028^{*}	-0.124^{**}	-0.028^{**}	−0.003
PBR dummy	−0.001	0.073	−0.0004	0.008
Market risk				
Size of the competitive segment	-0.0002^{*}	-0.001^{**}	-0.0002^{*}	-0.000^{***}
Effective competition dummy	-0.029^{*}	-0.154^{**}	-0.033^{*}	−0.016
No. of Comp. in Neigh. states	-0.001^{*}	-0.005^{**}	−0.004	-0.001^{***}
Potential market power dummy	0.006	0.039^{*}	0.006	0.004
Firm characteristics				
Log (total assets): lag (1 year)	−0.002	−0.180	−0.001	0.003
Return on assets: lag (1 year)	-0.316^{***}	-1.376^{**}	-0.312^{***}	-0.125^{***}
Tang. asset/tot. asset: lag (1 year)	0.187^{***}	0.564^{***}	0.183^{***}	0.114^{***}
Asset growth:lag (1 year)	−0.050	-0.357^{***}	−0.051	-0.048^{***}
Holding company dummy	−0.001	−0.054	−0.001	-0.012^{**}
Holding company size	-0.004^{**}	-0.020^{***}	-0.004^{**}	-0.004^{***}
Merger dummy	0.005	0.045	0.006	0.007^{*}
Sh. of industrial sales: lag (1 year)	-0.175^{*}	-0.809^{**}	-0.179^{*}	−0.040
Gen. Com. dummy:lag (1 year)	−0.005	−0.010	−0.005	−0.002
Input-cost Volat. proxy: lag (1 year)	-0.035^{*}	−0.063	-0.035^{*}	−0.005
Wholesale Mkt Partic.: lag (1 year)	0.037^{**}	0.180^{***}	0.037^{**}	0.035^{***}
Sh. of Nuc. Gen.: lag (1 year)	−0.021	-0.290^{**}	−0.021	−0.009
Sh. of IPP Supp. power: lag (1 year)	0.038	0.129	0.031	−0.020
State fixed effects	No	Yes	Yes	Yes
Observations	1724	1724	1724	1716
R-square/log likelihood/rho	0.278	0.766	2860.412	0.747

Note: Columns contain coefficients. Standard errors not reported. Col(1) is estimated by a fixed effects within estimator with robust standard errors and year fixed effects. Mixed regulation dummy is dropped since there is no annual variation. The next two columns correct for truncation. Col (2) performs a logit transformation of the dependent variable and is estimated by Prais-Winsten methodology of Table 5. Leverage (the dependent variable) is a proportion and is bounded between 0 and 1 and using traditional OLS based estimation techniques may not yield the correct solution, since the distributional assumptions for this model are based on an unrestricted normal distribution. An usual solution, is to perform a logit transformation of the dependent variable y: $\ln(y/(1-y))$. This maps the original variable to the real line. One can now estimate this model using traditional techniques. This specification includes a constant, year, firm and RTO fixed effects. Col(3) is estimated using a truncated regression with year, firm and RTO fixed effects, with robust standard errors clustered by state. Col(4) is estimated using feasible generalized least squares (FGLS) with AR(1) errors and panel level heteroskedasticity. This specification also includes a constant, year, firm and RTO fixed effects.

* Significant at 10%.
** Significant at 5%.
*** Significant at 1%.

5. Firm attributes and restructuring policies

5.1. 5.l Pre and post restructuring effects

The specification in Table 7 augments the model in Table 5 by adding interaction terms between the legislation enactment dummy and firm attributes. These interactions capture the differential impact of regulatory policies on leverage depending on individual firm characteristics. For firm attributes, column 1 shows the pre-restructuring effect and column 2 shows if the effect is different after restructuring. From column 1 we find that the results are similar in sign, significance and magnitude to those of Table 5 column 1, except the market power dummy and asset growth variable which are not significant in Table 7 column 1, and profitability, which now has an even greater negative effect on leverage. Most of these variables have the same effect on leverage before and after restructuring as evident from the insignificant coefficients of the interaction terms in column 2. However, the pre and post results are significantly different for three firm characteristics.

All else equal, we observe that firms with a higher share of industrial customers had a lower leverage ratio before restructuring when compared to the after restructuring period. In the pre-restructuring phase the leverage of say, utility A, would be 0.9 percent lower than that of another utility B, which had 10 percent less industrial customers than A. However, after restructuring, the difference would only be half that number. As discussed earlier, industrial customers were willing to switch providers if rates are favorable. Thus, utilities whose primary constituents were such large customers were under greater price pressure, which would lower their incentives for holding debt. However, after restructuring, the industrial customer segment may have less of an effect on leverage since a majority of states did not open large portions of their market to competition and utilities did not feel threatened about losing their industrial customer base, at least in the short-term. This would lead to continued earnings stability in the future, and reduce the need to lower debt levels.

The next two variables relate to the stranded cost proxies. The capital expenditure on nuclear plants has a negative and significant effect on leverage after restructuring. It shows that after restructuring, firms with a larger share of stranded costs lowered their debt levels since they would presumably take a hit in their earnings if the costs could not be recovered. In addition, the share of IPP supplied power however, has a negative and significant coefficient in the pre-restructuring period, with a 1 percent increase in IPP supplied power leading to a 0.02 percent decrease. As mentioned before, this decrease could be a result of the anticipated stranded costs that utilities may have to bear because of the above-market contracts with the IPPs or this may signal the reaction of utilities to potential competitive threat. On the other hand, in the post-restructuring period, the coefficient on this variable is positive, although small (0.009), implying that utilities with a larger share of IPP contracts may have had to borrow greater amounts to service the contracts after markets are restructured.

Table 7
Pre and post-restructuring effect (dependent variable: total debt/total assets).

	(1)		(2)
Regulatory risk		Market risk	
EPAct dummy	−0.028*** (0.005)	Size of the competitive segment	−0.0002* (0.0001)
Legislation enactment dummy	0.026* (0.013)	Effective competition dummy	−0.029** (0.014)
Stranded cost recovery dummy	0.004 (0.005)	Number of competitors in neighboring states	−0.001* (0.0003)
Divestiture policy dummy	−0.019** (0.010)	Potential market power dummy	0.005 (0.005)
PBR dummy	0.009 (0.012)		
Firm characteristics		Interactions	
Log (total assets): lag (1 year)	−0.010 (0.022)	Legis. Enact. Dum. × Log (total assets): lag (1 year)	−0.001 (0.001)
Return on assets: lag (1 year)	−0.341*** (0.103)	Legis. Enact. Dum. × ROA: lag (1 year)	0.154 (0.126)
Tangible assets/total assets: lag (1 year)	0.148*** (0.030)	Legis. Enact. Dum. × Tang. Ast/Tot Ast.: lag (1 year)	−0.047 (0.033)
Asset growth: lag (1 year)	−0.022 (0.020)	Legis. Enact. Dum. × asset growth: lag (1 year)	−0.018 (0.026)
Holding company dummy	−0.003 (0.008)	Legis. Enact. Dum. × holding company dummy	−0.002 (0.010)
Holding company size	−0.004** (0.001)	Legis. Enact. Dum. × holding company size	−0.001 (0.001)
Merger dummy	0.009 (0.007)	Legis. Enact. Dum. × merger dummy	−0.009 (0.010)
Share of industrial sales: lag (1 year)	−0.147** (0.061)	Legis. Enact. Dum. × Sh. of industrial sales: lag (1 year)	0.080* (0.042)
Generation company dummy: lag (1 year)	−0.003 (0.005)	Legis. Enact. Dum. × Gen. Com. Dum.: lag (1 year)	0.003 (0.008)
Input-cost volatility proxy: lag (1 year)	−0.012 (0.013)	Legis. Enact. Dum.* Sh. of Foss. fuel in Gen: lag (1 year)	−0.008 (0.013)
Wholesale market participation: lag (1 year)	0.035*** (0.011)	Legis. Enact. Dum. × Whl. Mkt. Part.: lag (1 year)	−0.007 (0.014)
Sh. of capital expend. on nuclear Plts: lag (1 year)	−0.011 (0.021)	Legis. Enact. Dum. × Sh. of Capex. Nuc.: lag (1 year)	−0.983*** (0.162)
Share of IPP supplied power: lag (1 year)	−0.558** (0.272)	Legis. Enact. Dum. × Sh. of IPP Supp. Pwr: lag (1 year)	0.567** (0.268)
Relevant statistics			
Observations	1724	Rho(AR1)	0.425
Number of firms	183	*R*-square	0.790

Note: Prais-Winsten panel model. Standard errors (in parenthesis) corrected for first-order autocorrelation and panel level heteroscedasticity. Interactions with the legislation enactment dummy shows if the effect of firm characteristics on leverage is different pre and post restructuring. All equations contain a constant, year, firm, state and RTO fixed effects. 'Rho(AR1)' denotes the common autocorrelation coefficient.

* Significant at 10%.
** Significant at 5%.
*** Significant at 1%.

5.1.1. *Policy interactions*

In Table 8 we investigate additional interactions between some policy variables and firm characteristics. It is conceivable that certain restructuring policies will only affect particular sets of firms depending on their individual characteristics. For example, larger firms may be able to handle market competition better than their smaller firm counterparts and leverage may not be as adversely affected. For column (2) we find that larger firms actually increase their leverage as the number of competitors in neighboring states increase. Next, we interact the potential market power dummy with the return on assets and the share of tangible assets variable and investigate whether having market power increases firm profitability and tangible assets. We find that profitability is unaffected, but firms with a high ratio of tangible assets decrease their leverage after they have market power. This is counter intuitive since their debt capacity should have increased, as they could have ensured earnings stability if they had market power.

Next we investigate whether utilities with a smaller share of footloose industrial customers or a higher wholesale market participation rate have higher leverage compared to firms with a less stable customer base or a lower wholesale market participation depending on the size of the competitive segment after restructuring. We find no effect. We also hypothesize that the divestiture policies should affect generation firms and not distribution companies. Again there is no difference between these two types of companies. Last, the stranded cost recovery policies should only affect utilities that are expected to have a high level of stranded costs. For example, in California, the stranded costs policies would affect the Pacific Gas and Electric Company much more that San Diego Gas and Electric since the former had large stranded costs in part due to its Diablo Canyon nuclear facilities while San Diego Gas and Electric had negligible stranded costs. Indeed, we find that the interaction tern between the stranded cost recovery policy dummy and the share of capital expenditure on nuclear facilities is negative and significant. From these results we may argue that most of the policies affected utilities across the board, and there was limited differential impact between various different types of utilities.

6. Attempts at solving endogeneity

All the above specifications show that firms did indeed change leverage ratios in response to federal and state-level restructuring policies. However, there are two drawbacks to these models. First, the restructuring policy dummies capture the legislative changes when they occur, and a firm's expectations about restructuring are not factored into the model. Additionally, these specifications treat the state-level legislations as exogenous to the firm's operations. Utilities are usually large players in state regulatory politics may actually influence restructuring legislation. To capture the expectation-driven behavior of firms and correct for endogeneity of state policies we use a two stage model in Table 9A.

Based on research by a number of scholars in the field (Ando & Palmer, 1998; Peltzman, 1976; Stigler, 1971; White, 1996) we first estimate an ordered probit specification[70] that models the state restructuring status in 1998 as a function of state economic and political factors and the financial characteristics of utilities prevalent in 1993. As the dependent variable we consider the status of

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[70] The framework is based on a latent regression model. Suppose we have a model: $u^* = \beta' x + \varepsilon$, u^* is unobserved, β is a vector of parameters to be estimated, x is a vector of explanatory variables and ε is the error term. For the restructuring model, suppose the regulator is a social welfare maximizer and perceives an increase in social welfare if the power industry is restructured. He will restructure only when the utility from changing the status quo is positive. Let his original utility be zero and new utility level be u^*. The regulator also has a thresh-hold utility level that determines whether he will move to the next stage or not. When each thresh-hold is crossed due to factors previously mentioned, restructuring progresses from one level to another. Therefore what we observe is the actual level of deregulation (denoted by *restruc*) and utility function of the regulator. Therefore we have: $restruc = 0$ if $u^* \leq 0$, $restruc = 1$ if $0 < u^* \leq \lambda_1$, $restruc = 2$ if $\lambda_1 < u^* \leq \lambda_2$, $restruc = 3$ if $\lambda_2 \leq u^*$. The cut-off points (λs) are estimated along with the β. We assume that ε follows a standard normal distribution with mean 0 and variance 1.

Table 8
Policy interactions (dependent variable: total debt/total assets).

	(1)		(2)
Regulatory risk		Market uncertainties	
EPAct dummy	−0.028*** (0.005)	Size of the competitive segment	−0.0002* (0.0001)
Legislation enactment dummy	0.006 (0.005)	Effective competition dummy	−0.024* (0.014)
Stranded cost recovery dummy	0.005 (0.005)	Number of competitors in neighboring states	−0.008** (0.003)
Divestiture policy dummy	−0.021** (0.011)	Potential market power dummy	0.090*** (0.023)
PBR dummy	0.010 (0.011)		
Firm characteristics		Interactions	
Log (total assets): lag (1 year)	−0.013 (0.023)	Comp. Neigh. St. × Log (total assets): lag (1 year)	0.0003** (0.0002)
Return on assets: lag (1 year)	−0.232*** (0.086)	Pot. Mkt. Pwr. Dum. × ROA: lag (1 year)	−0.035 (0.091)
Tangible assets/total assets: lag (1 year)	0.162*** (0.028)	Pot. Mkt. Pwr. Dum. × Tang. Ast/Tot Ast.: lag (1 year)	−0.109*** (0.028)
Asset growth: lag (1 year)	−0.030** (0.015)		
Holding company dummy	−0.008 (0.008)		
Holding company size	−0.005*** (0.001)		
Merger dummy	0.006 (0.005)		
Share of industrial sales: lag (1 year)	−0.154** (0.064)	Size of the Comp. Seg. × Sh. of Ind. sales: lag (1 year)	0.003 (0.002)
Generation company dummy: lag (1 year)	−0.0004 (0.005)	Dives. policy Dum. × Gen. Com. Dum.: lag (1 year)	0.004 (0.011)
Input-cost volatility proxy: lag (1 year)	−0.016 (0.011)		
Wholesale market participation: lag (1 year)	0.031*** (0.011)	Size of the Comp. Seg. × Whl. Mkt. Part.: lag (1 year)	0.0001 (0.0001)
Sh. of capital expend. on nuclear Plts: lag (1 year)	−0.007 (0.020)	Str. Cost. Reco. × Sh. of Capex. Nuc.: lag (1 year)	−1.027*** (0.136)
Share of IPP supplied power: lag (1 year)	0.181 (0.483)	Str. Cost. Reco. × Sh. of IPP Supp. Pwr: lag (1 year)	−0.175 (0.490)
Relevant statistics			
Observations	1724	Rho(AR1)	0.441
Number of firms	183	*R*-square	0.788

Note: Prais-Winsten panel model. Standard Errors (in parenthesis) are corrected for first-order autocorrelation and panel level heteroscedasticity. Interactions with the market and regulatory risk dummies show if the effect of these risk variables is different depending on firm characteristics. All equations contain a constant, year, firm, state and RTO fixed effects. 'Rho(AR1)' denotes the common autocorrelation coefficient.

[*] Significant at 10%.

[**] Significant at 5%.

[***] Significant at 1%.

electricity restructuring in a state at the end of 1998, and is constructed as follows: *the status of restructuring (legislation enactment) in 1998* is a continuous index that equals 0 if states exhibit "No Activity" regarding deregulation, it equals 1 if the state has "Investigations Ongoing or Orders and Legislation Pending", it equals 2 if there is an "Order Issued for Retail Competition", and the restructuring index equals 3 if the state has "Legislation Enacted to Implement Retail Access". The independent variables, which we

Table 9A
Two stage model.

Stage 1 (dependent variable: status of restructuring (legislation enactment) in 1998)		Stage 2 (dependent variable: total debt/total assets)	
Price variables		Regulatory variables	
Price (1993)	5.185*** (1.002)	EPAct dummy	0.020 (0.060)
"Import" price gap (1993)	−6.366*** (1.086)	FERC order dummy	−0.006 (0.006)
"Export" price gap (1993)	1.673** (0.872)	Probability of legislation enactment	−0.021*** (0.006)
Weighted standard deviation of price	0.034 (0.037)		
Customer characteristics		Firm characteristics	
Share of industrial customers (1993)	−0.924 (1.266)	Log (total assets): lag (1 year)	−0.008 (0.022)
Share of Munis & Co-ops (1992)	−2.320*** (0.827)	Return on assets: lag (1 year)	−0.239*** (0.082)
State characteristics		Tangible assets/total assets: lag (1 year)	0.145*** (0.026)
Green state proxy	−0.013 (0.010)	Asset growth: lag (1 year)	−0.037** (0.015)
Party in state congress	−0.346 (0.345)	Holding company dummy	−0.005 (0.008)
Utility financial characteristics		Holding company size	−0.004*** (0.001)
Stranded cost (1995) (billions of dollars)	0.0001*** (0.00004)	Merger dummy	0.007 (0.006)
Mean leverage (1993)	−0.349 (0.263)	Share of industrial sales: lag (1 year)	−0.179*** (0.067)
		Generation company dummy: lag (1 year)	−0.0004 (0.005)
		Input-cost volatility proxy: lag (1 year)	−0.014 (0.011)
		Wholesale market participation: lag (1 year)	0.034*** (0.011)
		Sh. of capital expend. on nuclear Plts: lag (1 year)	−0.030 (0.021)
		Share of IPP supplied power: lag (1 year)	−0.085 (0.054)
Relevant statistics		Relevant statistics	
Observations	47	Observations	1717
		Number of firms	183
		R-square	0.771
		Rho(AR1)	0.469

Note: First stage is estimated using an Ordered Probit model. The second stage uses a Prais-Winsten panel fixed effects model. Bootstrapped standard errors (in parenthesis) are corrected for first-order autocorrelation and panel level heteroscedasticity. Column 2 contains a constant, year and state fixed effects. Range: 1990–2001. 'Rho(AR1)' denotes the common autocorrelation coefficient.

[**] Significant at 5%.

[***] Significant at 1%.

discuss below,[71] are from 1993 – before EPAct had any significant influence and this avoids further endogeneity problems.

The results of the estimation of the ordered probit model are given in Table 9A(column 1). Prior work has shown that the most important factor that spurred the restructuring process is the *level of electricity prices* in different states. Evidence suggests that the high priced states (California, the New England states) were the first to begin restructuring, thus the average price level in a state is included as an explanatory variable. The coefficient of price in 1993 is positive and significant at 1 percent. This validates the claim that high priced states were the first ones to restructure. This result is intuitively appealing as theory suggests that if the price gets high enough such that it can no longer be supported within any regulatory framework – restructuring occurs (White, 1996).

The price level is not the sole factor determining the pace of restructuring – what also matters is the price in neighboring states. Ando and Palmer argue that IOUs will have an incentive to push for deregulation if the price in the neighboring states is high and they perceive that a profit could be made by selling power to these states. The coefficient of ‘*export*’ *price gap* (difference between the state's price and that of the highest price neighbor bounded at zero) is positive and significant implying that the utilities were favorable to restructuring when the ‘export’ price gap was large.

The incentive of retail customers to push for restructuring is measured by the ‘*import price gap*’ (difference between the state's price and lowest price in a neighboring state bounded below at zero). Customers will exert pressure for restructuring if they perceive that their own state's price is far higher than that of the neighboring state's as they expected restructuring to lead to a decrease in prices. The ‘import’ price gap however, is negative and significant implying that customers discouraged restructuring as this gap widened. The *weighted standard deviation of utility-level average prices* is used as another explanatory variable. The weight used is the utility-level electricity sales revenue. If the variance in prices is large within the state, then customers of high priced utilities would pressure for restructuring. On the other hand, the customers of low priced utilities would be against such a move as it may increase their price. A priori the effect of this variable on restructuring is ambiguous. We find that this variable had little impact on restructuring. Theory suggests that since residential customers are dispersed and atomistic it would be difficult for them to mobilize a critical mass to exert any meaningful influence. Thus the large industrial and commercial customers, who are fewer in number, would have more influence. To measure this effect, the *share of industrial customers* is constructed as the amount of revenue generated from the industrial customers divided by the total electricity revenue. However we find that the industrial customers have little effect on the state restructuring status.

In addition, Ando and Palmer (1998) argue that a larger presence of municipalities and electric co-operatives obviates the need for restructuring. The size and strength of munis and co-ops (*share of munis and co-ops*) is measured by the share of state electricity revenue attributed to municipalities and electric co-operatives. The coefficient on this variable is significant and negative. This implies that in states where the municipalities and electric co-operatives account for a large amount of power sold, the pace of restructuring has been slow. We also include a *green state proxy* variable to measure the power of environmental groups in each state. A pro-active and strong environmental group may affect the deregulatory process is a different way than a weak group. This is constructed from the League of Conservation Voter's dataset that tracks the voting record of state house and senate members on ‘green’ issues and rates states according to it. It is conceivable that a strong environmental group may hinder restructuring as it may adversely affect the environment through a decrease in environmental R&D, which the regulators will no longer be able to influence. In addition, we include a dummy for the *party in state congress* that takes the value 1 if the Republicans were in power in the state congress. Republicans in power may hasten the restructuring process since it signals less involvement of government in business. The environmental group proxy and the party in congress are insignificant, implying that neither environmental groups nor the affiliation of the party in state congress had much influence on the restructuring process.

Next, Ando and Palmer (1998) use the *stranded costs* of the state utilities as an explanatory variable for two reasons. First, utilities perceiving a benefit from restructuring coupled with full stranded cost recovery may pressure the regulatory commission to move towards deregulation. Second, consumers in high stranded cost states may apply pressure for restructuring on the belief that there will be less than full stranded cost recovery and they will stand to gain from restructuring. However, we believe that a third explanation may be more appropriate. Large stranded costs are manifestations of past regulatory decisions gone wrong (like the high priced long-term contracts under which the California IOUs were obliged to buy power from the ‘Qualifying Facilities’[72]). This led to high electricity prices. The regulators perceiving this imbalance may move towards restructuring faster to prevent a political debacle. The amount of stranded costs has a positive and significant (at 10 percent) coefficient implying that states with high stranded costs had a faster pace of restructuring.

Last, we use the *average leverage of the utilities* in each state as a dependent variable. It could be argued that a highly leveraged utility would put pressure on the regulators not to restructure since earnings volatility would adversely affect their debt capacity. We find that the coefficient is negative but insignificant, implying that the debt structure of utilities had little influence on the restructuring process.

We then generate the predicted probabilities of legislation enactment (i.e. restructuring index = 3) from this model and use it instead of the actual legislation enactment dummy in the second-stage leverage regression from Eq. (2) to correct for forward looking expectations and endogeneity issues. We estimate this second stage using the Prais-Winsten methodology and bootstrap the standard errors to account for prediction errors from the first stage. From column (2) in Table 9A we find that the predicted probability of restructuring is negative and significant and very similar in magnitude to the restructuring dummy in Table 4, column (3). All other variables are unchanged in sign and relatively similar in magnitude to Table 4. This indicates that endogeneity may not be a significant issue when estimating the effect of restructuring on firm leverage for the US electric utility industry.

As an alternative, we also estimate a more traditional instrumental variables model in a panel data setting in Table 9B. We first estimate a panel data probit model with the *Legislation Enactment Dummy* as the dependent variable. The biggest drawback of using the panel model is that we cannot use the average electricity price

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[71] The price data and the share of municipals and cooperatives were collected from EIA-861 data file: 1993 “Annual Electric Utility data”. The share of revenue from industrial customers was obtained from EIA-826 data file, which contained 1993 state level “Monthly Electric Utility Sales/Revenue Data”. The rating about legislators in a state is from the League of Conservation Voters “national Environmental Scorecard” for 1993. We use both the senate and the house rating. Stranded cost estimates are from Moody's publication “New Moody's Survey Shows Many Changes in Estimated stranded Costs and Prices”.

[72] Qualifying facilities were small power generators that generated a major portion of their power from renewables and incumbent utilities were mandated to buy this power at “avoided cost”.

Table 9B
Instrumental variables model.

Stage 1 (dependent variable: legislation enactment dummy)		Stage 2 (dependent variable: total debt/total assets)	
Price variables		Regulatory variables	
High price state dummy	−49.818 (321.01)	EPAct dummy	0.496 (0.500)
Customer characteristics		FERC order dummy	−0.0005 (0.007)
Share of industrial customers	−95.741** (38.970)	Predicted legislation enactment dummy	−0.016*** (0.004)
Share of Munis & Co-ops & IPPs	−120.72** (9.261)	Firm characteristics	
State characteristics		Log (total assets): lag (1 year.)	−0.009 (0.022)
Size of electricity sector	−3.992*** (1.213)	Return on assets: lag (1 year)	−0.241*** (0.083)
No. of Neighbor. states with Dereg. investigation	1.183** (0.657)	Tangible assets/total assets: lag (1 year)	0.147*** (0.027)
Green state proxy	−0.057 (0.060)	Asset growth: lag (1 year)	−0.037** (0.015)
Party in state congress	6.458 (12.072)	Holding company dummy	−0.004 (0.008)
Utility financial characteristics		Holding company size	−0.004*** (0.001)
Stranded cost proxy	0.0000001* (0.00000005)	Merger dummy	0.006 (0.006)
Mean leverage	5.838 (9.512)	Share of industrial sales: lag (1 year)	−0.180** (0.066)
		Generation company dummy: lag (1 year)	−0.001 (0.005)
		Input-cost volatility proxy: lag (1 year)	−0.014 (0.011)
		Wholesale market participation: lag (1 year)	0.035*** (0.011)
		Sh. of capital expend. on nuclear Plts: lag (1 year)	−0.029 (0.021)
		Share of IPP supplied power: lag (1 year)	−0.075 (0.054)
Relevant statistics		Relevant statistics	
Observations	564	Observations	1724
Number of States	47	Number of firms	183
Log likelihood	−13.981	*R*-square	0.772
		Rho(AR1)	0.463

Note: First stage is estimated using a panel data probit model with state fixed effects. The second stage uses a Prais-Winsten panel fixed effects model. Bootstrapped standard errors (in parenthesis) are corrected for first-order autocorrelation and panel level heteroscedasticity. Column 1 specification also includes state fixed effects and a constant. Column 2 contain a constant, year, firm, state and RTO fixed effects. Range: 1990–2001. 'Rho(AR1)' denotes the common autocorrelation coefficient.

* Significant at 10%.
** Significant at 5%.
*** Significant at 1%.

in the state as an explanatory variable. In the previous ordered probit model, we found a very strong correlation between the level of restructuring and the electricity price in a state. However, once restructuring takes effect, prices are endogenous and cannot be used as a right hand side variable. To solve this problem, we use the *high price state dummy* that is 1 if the average electricity price is the state was greater than the average US electricity price before the state began any investigations into the deregulation process. From column (1) in Table 9B, we find that being a high price state has no impact on whether restructuring legislation is going to be enacted in the state. This could be due to the inclusion of state fixed effects in this model.

We include two similar customer characteristics from the ordered probit model: the *share of industrial customers* in the state and the *share of munis, co-ops and IPPs* in the state. We find that both the variables have coefficients that are negative and significant implying that as the share of industrial customers increases, it has a negative effect on restructuring. We argue that utilities that have a larger share of industrial customers could potentially lose a large part of their customer base after restructuring and may pressure the regulators not to restructure. Similar to the ordered probit model we find that as the share of other types of power generators in the state increase, it is less probable that states will restructure due to reasons explained above.[73]

We include four state characteristics in column 1 of Table 9B. First, we include the *share of the electricity sector* to measure the importance and power that utilities may have in influencing the restructuring process. This is measured by the share of electricity revenue in total gross state product. We find that the larger the electricity sector, the less likely it is that a state enacts restructuring legislation. We also include the *number of neighboring states with deregulation investigation* to measure how states react to peer effects. We hypothesize that if a large number of neighboring states have begun the process of restructuring then a particular state will be more likely to restructure. This is borne out by the positive and significant coefficient of the variable. Similar to the ordered probit model, the *green state proxy* and the *party in state congress* have no impact on the restructuring process. Last we include the two utility characteristics: a *stranded cost proxy* as measured by the average level of capital expenditure on nuclear plants and the mean leverage ratio of state utilities. As in Table 9A, we find that states with larger stranded costs were more likely to restructure, while the mean leverage ratio had no impact.

In column (2) of Table 9B, we estimate the second stage model with leverage as the dependent variable. In this specification, instead of using the legislation enactment dummy, we use the *predicted legislation enactment dummy* that we obtain from the first stage equation. We estimate this second stage using the Prais-Winsten methodology with bootstrapped standard errors. We find that the predicted legislation enactment dummy has a negative and significant coefficient at the 1 percent level. All other variables are similar to those reported in Table 4, column (3). Thus the results from Tables 9A and 9B show that endogeneity and expectations are probably not significant problems in our econometric specification.

7. Conclusion

There has been substantial research investigating the capital structure decisions of firms and some investigation on the financing decisions of regulated ones. However, this is one of the very few papers that document how the financing decisions are altered when a firm transitions from a regulated to a competitive regime,

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[73] We also separated this variable into the share of munis and co-ops and the share of IPPs. One can argue that the larger share of IPPs in the state would lead to greater pressure towards restructuring, however, this variable was very imprecisely estimated, hence, we aggregated the munis, co-ops and IPPs into one variable.

and has to respond to both regulatory and market uncertainties. This study provides a new window into the financial effects of restructuring, and adds to our understanding of firm financing behavior in general. The restructuring of the U.S. electric utilities in the 1990s provides a unique opportunity to study these issues. We find that regulatory risk and market uncertainty variables reduce leverage between 24.6 and 26.7 percent approximately.

We find that any policy that decreased earnings stability, or increased competition and threatened market share, lowered debt levels. First, the introduction of the 1992 Energy Policy Act decreased leverage by 8.7 percent. In a rate-based regulated regime, earnings were stable and firms were insulated, for the most part, from demand and supply-side shocks. Restructuring forced these firms to assess the risks inherent in their capital structure decisions and optimize accordingly. The uncertainties associated with a market environment, and the absence of the safety-net of regulation limited the amount of debt a firm was willing to undertake. When other restructuring policies are added, we find that the legislation enactment dummy has no influence on leverage. Rather policies on divestiture impact the debt levels of the firm. Utilities in states that encouraged divestiture of generation assets reduced leverage by 6.3 percent. This could either be due to the market undervaluing the assets and reducing a firm's debt capacity, or firms reacting to future earning instability brought about by these policies.

We also show that firms facing higher market uncertainty have lower leverage. As the size of the competitive segment increased, firms reduced their debt ratios by 3.6 percent assuming that on average 60 percent of customers were eligible to switch. Introducing effective competition reduced debt levels by 7.8 percent, one of the larger policy effects. In addition, if the numbers of competitors in neighboring states increases by 1, utilities decrease their leverage by only 0.3 percent. Firms with market power would have the ability to counter such competitive threats to some extent, and were thus willing to take on more debt, increasing leverage by 2.1 percent (although this is not robust across specifications).

In addition, more profitable firms rely less on debt to finance investments suggesting that more profitable firms use internal funds and less debt. In addition, since tangible assets are used as collateral for borrowings, more collateral value translates into higher debt capacities and higher debt levels. The negative coefficient on asset growth, lends support to the hypothesis that firms with high growth opportunities are more likely to forego profitable investments if they are highly levered. Last, firms having greater access to internal capital markets, or ones with a footloose customer segment, used less debt.

We also document that in limited cases firms react differently to restructuring policies depending on their individual attributes. For example, firms with greater levels of stranded costs leading to the decrease in leverage after restructuring. However, we also find that most of the policies affect utilities across the board and do not depend on firm characteristics. Last, we address the issue of endogeneity between the state level restructuring policies and utility leverage ratios. Based on two alternative instrumental variables models, we show that our results are consistent and endogeneity may not be a significant problem for our empirical specification.

This paper makes two important contributions to the literature. First, it builds on previous capital structure research by adding an important piece about the financing decisions of regulated firms. Second, by studying firms that are transitioning from a regulated to a competitive environment, it provides a unique window into how changing incentive structures influence financial choices of firms. This is a step towards a better understanding of the determinants of capital structure across various types of firms, and may further our knowledge about firm investment and risk-taking behavior.

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Capital Structure with Countervailing Incentives

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Capital structure with countervailing incentives

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The regulated firm's choice of capital structure is affected by countervailing incentives: the firm wishes to signal high value to capital markets to boost its market value while also signalling high cost to regulators to induce rate increases. When the firm's investment is large, countervailing incentives lead both high- and low-cost firms to choose the same capital structure in equilibrium, thus decoupling capital structure from private information. When investment is small or medium-sized, the model may admit separating equilibria in which high-cost firms issue greater equity and low-cost firms rely more on debt financing.

1. Introduction

■ The capital structure of regulated firms is a key determinant of regulated rates. Under traditional cost-of-service regulation and some forms of price-cap regulation, commissions set regulated rates so as to ensure firms a "fair" rate of return on their equity (see e.g., Bonbright, Danielson, and Kamerschen, 1988; Phillips, 1988; and Spulber, 1989).[1] Consequently, regulated firms have an incentive to choose their capital structure in anticipation of its effect on their rates. Given the size and political sensitivity of the regulated sector and the fact that the stocks of regulated firms are so widely held, it is clear that an understanding of strategic interaction between the firm's capital structure and the rate setting process is needed.[2,3] In this article, we examine

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[1] For example, the Federal Communications Commission sets price caps on interstate access rates to ensure local exchange carriers a rate of return of 11.25% on their investments (FCC, CC Docket 89-624). Similarly, the FCC has established an interim industrywide rate-of-return factor of 11.25% for cable television cost-of-service proceedings (FCC, MM Docket No. 93-215).

[2] The regulated public utilities sector in the United States, including telecommunications, electricity, natural gas, and sanitary services, accounted for about 5% of gross domestic product in 1994 (Bureau of Economic Analysis, 1996).

[3] Among the *New York Times* list of favorite stocks, which reports the fifteen issues with the most shareholders, ten are stocks of regulated utilities.

two key aspects of the financing strategies of regulated firms. First, due to the limited commitment ability of regulators, a regulated firm may have an incentive to become leveraged, since debt may deter regulators from lowering rates because they seek to minimize the likelihood that the firm will go bankrupt and incur a deadweight loss. Second, asymmetries in the information that regulators, investors, and the regulated firm possess about the firm's costs significantly complicate the leverage effect. Recognizing the information conveyed by its capital structure fundamentally alters the financing incentives of the regulated firm.

In the last decade, a large literature has emerged that studies optimal rate regulation under asymmetric information (e.g., Baron and Myerson, 1982; Laffont and Tirole, 1986; Lewis and Sappington, 1988; and Spulber, 1989). These models assume that regulators can precommit to optimal regulatory mechanisms and apply the principal-agent framework to derive incentive schedules. But are the commitments of regulators credible? Historically, the courts have given regulators a great deal of leeway in setting rates.[4] According to the Supreme Court in the landmark *Hope Natural Gas* case of 1944, a regulatory agency is "not bound to the use of any single formula or combination of formulae in determining rates," since it is the net effect that matters.[5] Since regulatory agencies can exercise substantial discretion in setting rates, and since the commissioners change over time, their commitment ability is limited. Through prudency reviews and rate rehearings, regulators are able to change what capital expenditures are allowed in the rate base as well as the allowed rate of return on capital. Moreover, as deregulation proceeds in electric power, natural gas, and telecommunications, many state and federal regulatory agencies are questioning whether or not they are bound by any "regulatory contract."[6]

In Spiegel and Spulber (1994) we studied the strategic interaction between the firm's capital structure and the rate-setting process, finding that rate regulation induces firms to become leveraged. An important aspect of rate regulation missing from that study was the presence of asymmetric information. This aspect is the main focus of the current article. To explore the effects on capital structure of limited commitment under asymmetric information, we follow Banks (1992) and Besanko and Spulber (1992) by modelling the regulatory process as a sequential game between a firm and a regulator. In the first stage of this game, the firm chooses its capital structure by issuing a mix of equity and debt to outside investors in order to raise funds to invest in a project. In the second stage, the firm's securities are priced in the capital market according to the expectations of outside investors about the outcome of the regulatory process. In the third stage, the regulator chooses rates to maximize a welfare function defined over consumers' surplus and firm's profits. The fact that the regulator moves after the firm reflects the lack of regulatory commitment to rates. The regulator responds to an increase in the firm's debt level by increasing rates, thereby reducing the probability that the firm will go bankrupt. Anticipating the regulator's response, the firm chooses an optimal debt target by trading off the benefits of having higher rates (a leverage effect) against the increase in its expected cost of bankruptcy.

Under asymmetric information about its expected costs, the firm can use its capital structure not only to create a leverage effect, but also to signal its private information. But unlike the typical Spence-style signalling model, the firm signals to two receivers: the regulator and outside investors. We show that the presence of two receivers creates

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[4] In *United Railways,* the Supreme Court stated in 1930 that "[w]hat will formulate a fair return in a given case is not capable of exact mathematical demonstration." *United Railways & Elec. Co.* v. *West,* 280 U.S. 234, 249, 251 (1930).

[5] See *Federal Power Comm.* v. *Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944).

[6] See Sidak and Spulber (1996) on the problem of deregulatory takings and breach of the regulatory contract.

countervailing incentives for the firm.[7] On the one hand, the firm wishes to signal low expected costs and therefore high profits to the capital market to boost the market value of its securities (a securities pricing effect). But on the other hand, the firm also wishes to convince the regulator that its expected costs are high because the regulated price is based on costs (a cost effect). Since the two effects work in opposite directions, our model has the interesting feature that the cost of signalling information to one receiver is due not to "burning money" but to the negative response of the second receiver.

As is common in signalling models, our model admits multiple perfect Bayesian equilibria. To eliminate equilibria supported by "unreasonable" out-of-equilibrium beliefs of the regulator and outside investors, we apply the refinement of undefeated equilibria proposed by Mailath, Okuno-Fujiwara, and Postlewaite (1993). This refinement is appealing because it requires out-of-equilibrium beliefs to be "globally" consistent, thereby avoiding the logical problems inherited in alternative belief-based refinements, in which out-of-equilibrium beliefs are adjusted separately from the beliefs at other information sets, including those along the equilibrium path. In the current model, the refinement eliminates all equilibria except for the Pareto-dominant equilibria, that is, those that give both high- and low-cost types the highest payoffs among all equilibria.

There is evidence to suggest that regulators generally allow firms to issue new securities only if external funds are needed to cover the cost of investment in physical assets (Phillips, 1988). This implies that in our model, the size of the firm's investment project imposes a restriction on the amount of new equity and debt that the firm can issue, and therefore on its ability to signal information. Thus the equilibrium choice of capital structure depends critically on the size of the project. When the project is small in the sense that firms cannot issue debt to the point where there is a positive leverage effect, the model may admit both a pooling equilibrium and a continuum of separating equilibria, all of which are payoff-equivalent. In the separating equilibria, firms with low probability of a cost shock (*l*-types) issue relatively little equity, so firms with a high probability of cost shock (*h*-types) have little to gain by mimicking *l*-types. At the same time, *h*-types issue relatively high levels of equity to outsiders, thereby ensuring that if *l*-types mimic them, they will face a significant equity-underpricing effect. In a pooling equilibrium, both types issue the same debt level that completely offsets the benefits and costs from separation for both *l*-types and *h*-types.

When the size of the project is medium, in the sense that under full information there would be a positive leverage effect for *l*-type firms but not for *h*-types, the model admits a unique undefeated separating equilibrium. In this equilibrium, *l*-type firms finance the project entirely with debt, thereby fully exploiting the leverage effect, while *h*-type firms separate themselves by issuing to outsiders enough equity. This strategy allows *h*-types to separate themselves because it ensures that should *l*-types mimic them, their equity will be sufficiently underpriced to render mimicking unprofitable.

Finally, if the project is large in the sense that both types face a positive leverage effect, the model admits a unique undefeated equilibrium, which is pooling. So long as the project is not too large, both *l*-type firms and *h*-type firms finance it entirely with debt in order to fully exploit the leverage effect. Then, the resulting regulated price does not depend on the firms' type, so there are no countervailing incentives (only the beliefs of equityholders matter, and both types try to convince equityholders

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[7] The countervailing incentives discussed in this article differ substantially from those identified in the mechanism design literature (e.g., Lewis and Sappington, 1989), where countervailing incentives arise due to technological reasons (e.g., a tradeoff between marginal and fixed costs) rather than the presence of two uninformed players.

that their type is *l* in order to boost the market value of their equity). As a result, *l*-types cannot separate themselves and the equilibrium must be pooling. It should be noted that this result is independent of the specific refinement we use; the application of undefeated equilibrium only allows us to eliminate all Pareto-dominated pooling equilibria.

When the project is larger still, the presence of countervailing incentives leads to a unique undefeated equilibrium that is again pooling. This time however, firms use a mix of debt and equity: they first issue debt up to a debt target, and then use equity financing on the margin. The pooling result is due to the fact that relatively large projects have the property that the potential gains for each type of firm from revealing its identity to one receiver are outweighed by the loss associated with the negative response of the second receiver; consequently, no type of firm has an incentive to distinguish itself. Although the result depends on the refinement we use, it nonetheless seems intuitive, since all separating equilibria in the case of relatively large projects are Pareto dominated by the pooling equilibrium.

In practice, regulated firms make large investments in infrastructure and generally use a mix of debt and equity to finance them. Our model shows that in such cases, the capital structure of firms is uncorrelated with their expected values, reflecting the pooling of diverse firm types. This result suggests that countervailing incentives should be taken into account in future empirical studies of capital structure and cost of capital of regulated firms. Moreover, this result can explain why Miller and Modigliani (1966), in their classic study of the electric utility industry, found "no evidence of sizeable leverage or dividend effect [on firm value] of the kind assumed in much of the traditional finance literature."[8] While this empirical result supports the Modigliani and Miller irrelevance theorem (1958), it conflicts with later financial signalling models in which capital structure conveys the firm's private information about its value (see Harris and Raviv (1991) for a literature survey). The countervailing incentives identified in this article can serve to reconcile these two approaches in the case of regulated industries.

The effects of countervailing incentives on the capital structure of firms have not been studied before, with the notable exception of Gertner, Gibbons, and Scharfstein (1989). They examine a model in which a firm uses its capital structure to signal private information to both the product and the capital markets. Their article, however, differs from ours in at least two important ways. First, in their model the firm competes in an oligopolistic product market, while in ours the firm is a regulated monopolist. Second and more important, they assume away the possibility of bankruptcy, which plays a key role in our analysis.

A leverage effect is identified by Taggart (1981) although not in a strategic setting. This effect has been observed empirically by Taggart (1985) and by Dasgupta and Nanda (1993). The effects of regulatory opportunism in a full-information setting were considered by Spiegel and Spulber (1994) and Spiegel (1994) in the context of capital structure and by Spiegel (1997) in the context of the choice of technology. Lewis and Sappington (1995) examine optimal incentive regulation under asymmetric information when the firm obtains investment funds from the capital market. Their article addresses normative issues in an agency setting, while ours considers positive issues within a signalling framework.

The article proceeds as follows. In Section 2 we present the basic model and define the equilibrium concept. In Section 3 we solve the regulator's problem, and in Section 4 we set out the capital market equilibrium. Then we fully characterize the equilibrium

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[8] Miller and Modigliani examine data on the electric utility industry from 1954 to 1957. They do not account, however, for the effects of rate regulation on the firm's capital structure choice, as our model.

strategies of the regulated firm in Section 5. Additional properties of the equilibrium are examined in Section 6. Section 7 concludes. All proofs are in the Appendix.

2. The model and the equilibrium concept

■ We present a sequential model of rate regulation that examines the interaction between the regulator's pricing strategy and the capital structure of the firm. In stage 1 of the model, the firm decides whether or not to undertake a project that requires a sunk cost, k. If the firm forgoes the project, it does not produce anything, and the payoffs of its equityholders and consumers are both equal to zero. If the firm undertakes the project, it issues a mix of debt and equity to finance it. Then, in stage 2, the market value of the firm's securities is determined in a perfectly competitive capital market. In stage 3, the regulator sets the regulated price, taking the capital structure of the firm as given. Finally, the firm's operating cost is realized, output is produced, and payments are made.

The sequential structure of the model allows us to examine the effects of the limited regulatory commitment to rates that, as argued in the Introduction, characterizes the regulatory framework in the United States. Moreover, the model considers the consequences of firms exercising discretion in choosing their capital structures. This conforms with general practice in which regulators limit their interference in these types of management decisions.[9] Empirical studies suggest that regulated firms indeed exercise such discretion (Taggart, 1985; Hagerman and Ratchford, 1978).

☐ **Consumers.** The demand for the output of the project is inelastic, i.e., consumers demand a fixed quantity, which we normalize to one unit, with V representing consumers' total willingness to pay. Using p to denote the regulated price, the payoff of consumers is represented by consumers' surplus, $CS(p) = V - p$.

☐ **The regulated firm.** The firm's operating cost, C, may be subject to a shock, representing for example, a fuel price increase, equipment failure, or a cost overrun. The cost shock is equal to c and it occurs with probability θ, where θ can be either low, θ^l, or high, θ^h, $0 < \theta^l < \theta^h < 1$. Normalizing the firm's operating cost absent a cost shock to zero, the expected operating cost is equal to θc. Assume that $c < V$, so production is *ex post* efficient even if the cost shock occurs. The probability θ, referred to as the firm's type, is the firm's private information.

To model the choice of capital structure, we assume that the firm is initially owned by a set of equityholders and has neither outstanding debt nor financial reserves. Let E be the market value of the new equity representing a fraction $\alpha \in [0, 1]$ of the firm's equity, and let B be the market value of debt with face value D. The firm needs to raise funds to cover the cost of the project, $k \leq E + B$. Evidence suggests that regulatory commissions generally do not allow regulated firms to raise external funds in excess of the costs of investment in physical assets (Phillips, 1988). Thus, the firm's budget constraint is

$$k = E + B. \tag{1}$$

The financial strategy of the firm is a mapping from its type, θ, to a pair $(\alpha(\theta), D(\theta))$, such that (1) is satisfied. The firm chooses its financial strategy (independently of the regulator) to maximize the expected payoff of its initial equityholders, which we specify below.

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[9] For example, Phillips (1988, p. 226) argues that with respect to financial decisions, "few commissions are willing to substitute their judgments for those of the management except in reorganization cases."

The firm's earnings are $p - C$.[10] For a given debt obligation D and a regulated price p, the firm can pay its debt if and only if $p - C \geq D$.[11] The firm then remains solvent, and its equityholders are the residual claimants, receiving a payoff of $p - C - D$. If $p - C < D$, the firm declares bankruptcy, and debtholders become the residual claimants. This reflects the concept of limited liability: the firm cannot be forced to pay debtholders more than its income. Since C equals c with probability θ and equals zero otherwise, the probability of bankruptcy as a function of debt and the regulated price, given the firm's type, is

$$L(p, D \mid \theta) = \begin{cases} 0, & D \leq p - c, \\ \theta, & p - c < D \leq p. \end{cases} \tag{2}$$

When $D < p - c$, the firm never goes bankrupt because its cash flow is sufficiently high to cover the debt payments even if the cost shock is realized. On the other hand, when $p - c \leq D < p$, the firm goes bankrupt if and only if the cost shock is realized, an event that occurs with probability θ. Debt levels above p are dominated strategies for the firm and will never be observed in equilibrium, since equityholders are certain to get a zero payoff. In what follows, we therefore need not consider such debt levels.

Bankruptcy imposes extra costs on the firm such as legal fees and reorganization costs. We let these costs be proportional to the shortfall of earnings from the debt obligation, with a unit bankruptcy cost equal to t.[12] The expected bankruptcy costs are therefore given by

$$T(p, D \mid \theta) = t \times L(P, D \mid \theta) \times (D - p + c). \tag{3}$$

We assume that t and c are sufficiently small so that the payoff of debtholders in the event of bankruptcy, $p - C - t(D - p - C)$, is nonnegative in the relevant range. This ensures that the debtholders limited liability constraint is never binding. In the Appendix we provide a sufficient condition on t and c for this assumption to hold.

The expected *ex post* profit of the firm as a function of the regulated price and the firm's debt, given the firm's type, θ, is

$$\Pi(p, D \mid \theta) = p - \theta c - T(p, D \mid \theta). \tag{4}$$

The expected profit equals the expected earnings of the firm net of expected bankruptcy costs. It represents the combined expected *ex post* return to equityholders (both old and new) and debtholders and is divided between them according to their respective claims. Since the marginal operating income is deterministic, there is no conflict of interests between equityholders and debtholders. We can treat them in the regulatory process as if they were one group (both would like p to be as high as possible). In a more general model this need not be the case. For instance, Brander and Lewis (1986, 1988) show that when the marginal operating income is stochastic, equityholders and debtholders have conflicting interests, since the firm's expected operating income over solvent states of nature differs from the expected operating income over states of nature in which the firm goes bankrupt. Therefore, if the marginal operating income, for example, is larger in good states of nature than it is in bad states of nature, the optimal regulated price from equityholders' point of view will be higher than the optimal regulated price from debtholders' point of view.

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[10] Throughout, taxes are assumed away. For a survey of tax-based theories of capital structure, see, e.g., Myers (1984).

[11] We assume that k represents sunk costs rather than an investment in durable physical capital. This assumption means that the firm cannot use k to repay its debt when its cash flow is low.

[12] Assuming instead that bankruptcy costs are constant does not change any of the results, but it complicates the analysis because the objective function of the firm becomes discontinuous.

The objective of the regulated firm is to maximize the expected payoff of its initial equityholders. If the firm undertakes the project, the payoff of initial equityholders is given by

$$Y(p, \alpha, D|\theta) = (1 - \alpha) \times (1 - L(p, D|\theta)) \times [p - \theta c + L(p, D|\theta)c - D]. \qquad (5)$$

If the firm forgoes the project, the initial equityholders receive a zero payoff.

□ **The capital market.** We assume that the capital market is perfectly competitive. Given the information available to outside investors, the firm's securities will be fairly priced in equilibrium in the sense that each investor earns a zero net expected return on his investment. Thus, in what follows, we impose the competitive market constraint on the equilibrium rather than specifying an investment strategy for outside investors.

□ **The regulatory commission.** The regulator chooses the regulated price to maximize the expected social welfare function $W(p, D|\theta) = CS(p)^{\gamma/(1-\gamma)} \cdot \Pi(p, D|\theta)$, where γ is a parameter between zero and one. The parameter γ measures the degree to which the regulator cares about the *ex post* profits of the firm relative to consumer surplus. The resulting regulated price allocates the expected social surplus according to the asymmetric Nash bargaining solution for the regulatory process.

This approach follows models of the rate-setting process as a bargaining problem between consumers and investors (Spulber, 1989; Besanko and Spulber, 1992). It is also consistent with Peltzman's (1976) political economy model of rate regulation, where W can be viewed as the regulator's Cobb-Douglas utility function. These studies are consistent with regulatory case law, such as *Hope Natural Gas,* in which "[t]he fixing of 'just and reasonable' rates, involves a balancing of the investor's and the consumers' interests" that should result in rates "[w]ithin a range of reasonableness." According to the Supreme Court decision, "[t]he return to equity owners should be commensurate with returns on investment in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[13] Also, as explained by the Pennsylvania Public Utilities Commission, this range "[i]s bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service."[14]

In writing the welfare function, we assume that the regulator takes into account the firm's operating profits rather than its accounting profits, that is, we exclude the sunk cost of investment. Our model therefore represents a case of regulatory opportunism as the regulator completely ignores the firm's sunk cost of investment. One could adopt a less extreme view of regulatory opportunism by assuming that the welfare function is given by $CS(p)^{\gamma/1-\gamma}(\Pi(p, D|\theta) - sk)$, where s is a parameter between zero and one that measures the degree of regulatory opportunism; as s increases toward one, the regulator becomes less opportunistic. However, since k in our model is constant, assuming that $s = 0$, as we do, does not involve any loss of generality. The use of operating profit is consistent with the notion that the regulated firm will continue to provide service as long as its operating profit is positive.

Substituting for profit and consumer surplus, the regulator's social welfare function is

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[13] *Federal Power Comm.* v. *Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944).

[14] See *Pennsylvania Pub. Utility Comm.* v. *Bell Telph. Co. of Pennsylvania,* 43 PUR3d 241, 246 (Pa., 1962).

$$W(p, D|\theta) = (V - p)^{\gamma/(1-\gamma)}(p - \theta c - T(p, D|\theta)). \tag{6}$$

By increasing p, the regulator increases the social surplus because $T(p, D|\theta)$ is decreasing in p, and at the same time, he shifts part of the surplus from consumers to claimholders. To simplify the regulator's maximization problem, we shall impose the following restriction on γ:

$$\gamma < \bar{\gamma} \equiv \min\left\{\frac{V - c}{V - \theta c}, \frac{c(1 + \theta t)}{tV}\right\}.$$

This restriction implies that the regulator is not too pro-consumer. It simplifies the exposition considerably and ensures that countervailing incentives are present at all levels of debt.

Outside investors and the regulator share a common prior, b^0, on the firm's being the high type. Given b^0, the expected likelihood of a cost shock is $\theta^0 = b^0\theta^h + (1 - b^0)\theta^l$. After observing the financial strategy of the firm, outside investors and the regulator update their prior beliefs about θ. Let b^I and b^R respectively be the posterior probability assigned by outside investors and by the regulator to the firm's type being θ^h. The outside investors' posterior probability of a cost shock is $\theta^I \equiv b^I\theta^h + (1 - b^I)\theta^l$, and that of the regulator is $\theta^R \equiv b^R\theta^h + (1 - b^R)\theta^l$.

☐ **The equilibrium concept.** We restrict attention to pure strategies. A perfect Bayesian equilibrium (PBE) in pure strategies in the three-stage asymmetric information game is a pair of strategies, $\langle p^*(D|\theta^R), (\alpha^*(\theta), D^*(\theta))\rangle$, a zero net expected return condition on outside investors, and a pair of belief functions, $\langle b^I, b^R\rangle$ that satisfy the following four conditions:

(i) Given the financial strategy of the firm, (α, D), and given his posterior beliefs, b^R, the regulator chooses $p^*(D|\theta^R)$ to maximize expected social welfare; hence, for all D,

$$p^*(D|\theta^R) \in \underset{p}{\operatorname{argmax}}\; b^R W(p, D|\theta^h) + (1 - b^R)W(p, D|\theta^l). \tag{7}$$

(ii) Given the financial strategy of the firm, (α, D), their correct expectations about the regulated price, $p^*(D|\theta^R)$, and their posterior beliefs, b^I, the market values of equity and debt, $E^* \equiv E^*(p^*(D|\theta^R), \alpha, D|\theta^I)$ and $B^* \equiv B^*(p^*(D|\theta^R), \alpha, D|\theta^I)$, are determined such that outside investors earn a zero net expected return on the firm's securities.

(iii) Given its correct expectations about the regulated price, $p^*(D|\theta^R)$, and the capital market equilibrium, a θ-type firm chooses its financial strategy to maximize the expected payoff of its initial equityholders, subject to the firm's budget constraint:

$$(\alpha^*(\theta), D^*(\theta)) \in \underset{(\alpha, D)}{\operatorname{argmax}}\; Y(p^*(D|\theta^R), \alpha, D|\theta) \qquad \theta \in \{\theta^h, \theta^l\} \tag{8}$$

subject to

$$k = E^* + B^*.$$

(iv) Outside investors and the regulator have the same posterior beliefs on and off the equilibrium path, which are derived from the Bayes rule whenever it is applicable. In particular, on the equilibrium path, these beliefs are correct:

$$\theta^I = \theta^R = \begin{cases} \theta & \text{if } D^*(\theta^l) \neq D^*(\theta^h), \\ \theta^0 & \text{if } D^*(\theta^l) = D^*(\theta^h). \end{cases} \tag{9}$$

If the top line of (9) holds, the equilibrium is separating; if the bottom line holds, it is pooling.

As is often the case in signalling models, the current model admits multiple perfect Bayesian equilibria because the belief function defined above places no restrictions on the beliefs of outside investors and the regulator off the equilibrium path. To eliminate equilibria that are supported by "unreasonable" beliefs, we apply the refinement of undefeated equilibrium due to Mailath, Okuno-Fujiwara, and Postlewaite (1993). This refinement is appealing because it ensures that any adjustment of out-of-equilibrium beliefs is consistent with beliefs at other information sets, including some information sets along the equilibrium path.[15] Thus, undefeated equilibrium is immune to the so-called Stiglitz critique (see Cho and Kreps, 1987). This property distinguishes this refinement from other belief-based refinements such as the intuitive criterion (Cho and Kreps, 1987) and perfect sequential equilibrium (Grossman and Perry, 1986). Moreover, this refinement is not biased against pooling equilibria like other belief-based refinements (e.g., the intuitive criterion, or the D2 criterion, Banks and Sobel (1987)). The formal definition of the refinement is presented in the Appendix. Intuitively, the refinement works as follows: consider a putative equilibrium, σ, and suppose that the capital structure is chosen by some type in an alternative equilibrium, σ', but is never played in σ. Then if the firm chooses the pair (α'', D'), outside investors and the regulator interpret this choice as a message sent by the firm. When only one type prefers σ' to σ, outside investors and the regulator reason that the message was sent by this type. When both types prefer σ' to σ, outside investors and the regulator find the message uninformative (both types are equally likely to have sent it), so they do not revise their prior beliefs. Finally, when one type strongly prefers σ' to σ while the other type prefers it weakly, outside investors and the regulator believe that the former type surely played (α'', D'), while the latter type may or may not have played it; the prior beliefs are therefore revised by increasing the weight assigned to the type that surely played (α'', D').

3. The regulator's pricing strategy

■ Since the equilibrium strategies are sequentially rational, we characterize the equilibrium by solving the game backwards, beginning with the regulator's stage 3 pricing strategy. To this end, we first assume that the firm's type is common knowledge and solve for the regulator's pricing strategy under full information. Given the structure of our model, the pricing strategy of the regulator under asymmetric information then follows immediately from his full-information pricing strategy. Given the firm's type, the equilibrium pricing strategy of the regulator as a function of the firm's debt level is given by

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[15] For a detailed discussion on the properties of undefeated equilibria and a comparison between this refinement concept and other refinements, see Mailath, Okuno-Fujiwara, and Postlewaite (1993).

$$p^*(D \mid \theta) = \begin{cases} \hat{D}(\theta) + c, & D \leq \hat{D}(\theta), \\ D + c, & \hat{D}(\theta) < D < \bar{D}(\theta), \\ \hat{D}(\theta) + c + \dfrac{\gamma\theta t(D + c(1 - \theta))}{1 + \theta t}, & D \geq \bar{D}(\theta), \end{cases} \tag{10}$$

where

$$\hat{D}(\theta) \equiv (1 - \gamma)(V - \theta c) - c(1 - \theta) \tag{11}$$

and

$$\bar{D}(\theta) = \frac{(1 - \gamma)(V - \theta c)(1 + \theta t)}{1 + (1 - \gamma)\theta t} - c(1 - \theta). \tag{12}$$

The assumption that $\gamma < \bar{\gamma} \leq (V - c)/(V - \theta c)$ ensures that $\hat{D}(\theta) > 0$ for all θ, while the assumption that $V > \theta c$ implies that $\bar{D}(\theta^h) > \hat{D}(\theta^l)$.

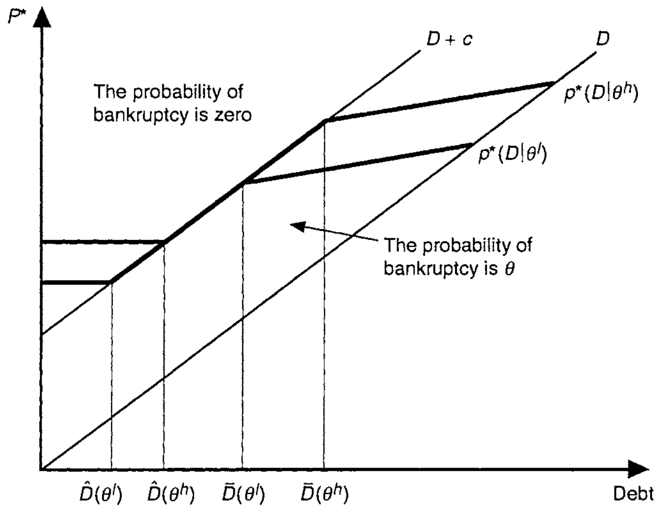
To understand equation (10), consider first the case where $D \leq p - c$. Then the probability of bankruptcy is zero, so the regulator's problem is to maximize $(V - p)^{\gamma/(1-\gamma)}(p - \theta c)$ subject to $D < p - c$. Solving for p yields $p^*(D \mid \theta) = (1 - \gamma)V + \gamma\theta c$. Using the definition of $\hat{D}(\theta)$ yields the first line in (10). When $D > \hat{D}(\theta)$, the constraint is binding, so $p^*(D \mid \theta) = D + c$. Second, consider the case where $D + c \leq p \leq D$. Then the probability of bankruptcy is θ, so the regulator's problem is

$$(V - p)^{\gamma/(1-\gamma)}(p - \theta c - \theta t(D - p + c))$$

subject to $p - c \leq D \leq p$. Ignoring the constraint, the solution for this problem yields the third line in (10). When $D \geq \bar{D}(\theta)$, the constraint is nonbinding. For $D < \bar{D}(\theta)$, the constraint is binding, so $p^*(D \mid \theta) = D + c$.

Figure 1 shows $p^*(D \mid \theta)$ as a function of the firm's debt level for the two possible firm types. There are several properties of $p^*(D \mid \theta)$ that are worth noting. First, $p^*(D \mid \theta)$ increases with the firm's type because the regulator sets it as a markup over the firm's expected operating costs, which in turn increase with θ. Second, $p^*(D \mid \theta)$ does not depend directly on the equity share, α (given his beliefs about θ, the regulator cares

FIGURE 1
THEGULATED PRICE UNDER FULL INFORMATION



about capital structure only to the extent that it affects the expected costs of bankruptcy), or on the firm's sunk cost, k (the regulator cannot commit to rates and therefore behaves opportunistically). Third, Figure 1 shows that for debt levels below $\hat{D}(\theta)$, $p^*(D \mid \theta)$ is sufficiently high to ensure that the firm never goes bankrupt, so in this range, $p^*(D \mid \theta)$ is independent of D. Once D reaches $\hat{D}(\theta)$, the regulator can no longer ignore it because then the firm would go bankrupt if the cost shock occurs. Since bankruptcy is socially costly, it is optimal for the regulator at this range to increase $p^*(D \mid \theta)$ at the same rate as the increase in D to ensure that the probability of bankruptcy remains zero. For debt levels above $\bar{D}(\theta)$, it is no longer optimal to avoid bankruptcy with certainty, since the marginal loss in consumer surplus from increasing $p^*(D \mid \theta)$ at the same rate as the increase in D exceeds the marginal gain from keeping the probability of bankruptcy at zero. Hence, from this point on, $p^*(D \mid \theta)$ increases by less than the increase in debt, leaving the firm susceptible to bankruptcy.

Substituting for $p^*(D \mid \theta)$ in (2) and rearranging terms, the likelihood of bankruptcy is zero if $D \leq \bar{D}(\theta)$, and θ if $D > \bar{D}(\theta)$. Hence, $\bar{D}(\theta)$ is the critical level of debt above which debt becomes risky (i.e., susceptible to the risk of default). In the next proposition, we study the properties of the critical debt levels, $\hat{D}(\theta)$, and $\bar{D}(\theta)$.

Proposition 1. (i) The critical debt level, $\hat{D}(\theta)$, is increasing in the probability of the cost shock, θ, and in the consumers' willingness to pay, V; decreasing in the cost shock, c, and in the welfare weight γ; and is independent of the bankruptcy cost, t. (ii) The critical debt level, $\bar{D}(\theta)$, above which debt becomes risky, is increasing and concave in θ, increasing in V and t; it is decreasing in c and γ. Consequently, the range of riskless debt levels becomes larger as θ, V, and t increase and as c and γ decrease.

At a first glance, it seems counterintuitive that an increase in the expected operating cost increases the range of riskless debt levels. Yet to compensate the firm for expected operating cost increases, the regulator sets the regulated price as a (weakly) increasing function of θ. This in turn allows the firm to issue more debt and still remain immune to bankruptcy.

Next consider the asymmetric-information case. Since the objective function of the regulator is linear in θ and b^R, the regulator's beliefs enter the problem only through θ^R, which is the posterior probability of a cost shock from the regulator's perspective. The regulator's equilibrium pricing strategy under asymmetric information is therefore $p^* \equiv p^*(D \mid \theta^R)$.

To see that $\bar{D}(\theta)$ is concave in θ, use the form of $\bar{D}(\theta)$ from equation (12), so that for any θ^h, θ^l, and $b^0 < 1$,

$$b^0\bar{D}(\theta^h) + (1 - b^0)\bar{D}(\theta^l) - \bar{D}(\theta^0) = \frac{-[t(\theta^h - \theta^l)^2 b^0(1 - b^0)(Vt + 2c)]}{[(2 + \theta^h t)(2 + \theta^l t)(2 + \theta^0 t)]} < 0.$$

4. The capital market equilibrium

■ Since the capital market is competitive, debtholders and new equityholders earn a net expected return equal to the risk-free interest rate, which without a loss of generality we normalize to zero. Assuming that investors correctly anticipate the regulator's equilibrium pricing strategy, their expectations about the likelihood of bankruptcy are represented by $L(D \mid \theta^I) \equiv L(p^*, D \mid \theta^I)$. The equilibrium market values of new equity and debt are therefore given by

$$E^*(p^*, \alpha, D \mid \theta^I) = \alpha(1 - L(D \mid \theta^I))[p^* - \theta c + L(D \mid \theta^I)c - D] \tag{13}$$

and

$$B^*(p^*, \alpha, D \mid \theta) = (1 - L(D \mid \theta^I))D + L(D \mid \theta^I)[p^* - c - t(D - p^* + c)]. \quad (14)$$

The right side of (13) represents the share of new equityholders in the expected profits of the firm net of debt payments conditional on the firm remaining solvent. The first term on the right side of (14) represents the expected return to debtholders in the event that the firm remains solvent. The second term represents the expected return to debtholders when the firm goes bankrupt, in which case they become the residual claimants and receive the firm's profits net of bankruptcy costs.

In equilibrium, the budget constraint of the firm must hold with equality. Substituting for $E^*(p^*, \alpha, D \mid \theta^I)$ and $B^*(p^*\ \alpha, D \mid \theta^I)$ in the firm's budget constraint given by equation (1) yields

$$\begin{aligned} k = {} & (1 - L(D \mid \theta^I)) \times [\alpha(p^* - \theta c + L(D \mid \theta^I)c - D) + D] \\ & + L(D \mid \theta^I) \times [p^* - c - t(D - p^* + c)]. \end{aligned} \quad (15)$$

Equation (15) is the condition for a competitive equilibrium in the capital market. This equation implicitly defines a unique equity participation of new equityholders, $\alpha^*(p^*, D \mid \theta^I)$, such that the project is fully financed:

$$\alpha^*(p^*, D \mid \theta^I) = \frac{k - D + L(D \mid \theta^I)(1 + t)(D - p^* + c)}{(1 - L(D \mid \theta^I))[p^* - \theta^I c + L(D \mid \theta^I)c - D]}. \quad (16)$$

Given k, (16) implies that the firm has only one degree of freedom when it chooses a pair (α, D). Consequently, the financial strategy of the firm is effectively reduced to a choice of a debt level, $D(\theta)$, with $\alpha(\theta)$ being determined by (16).

5. The equilibrium capital structure

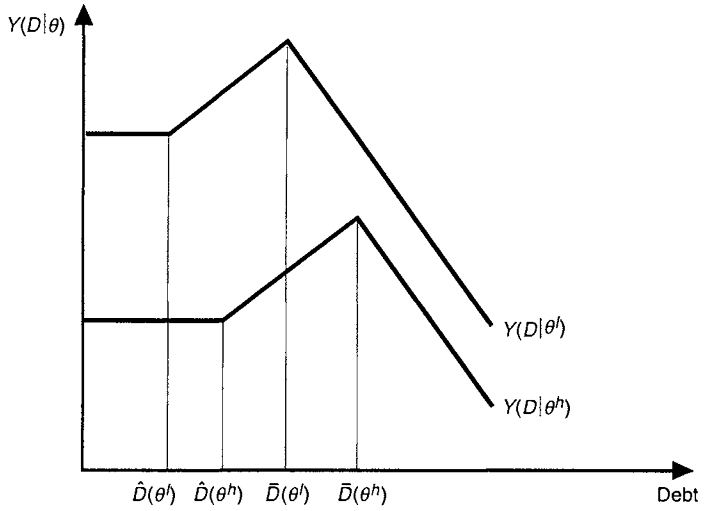
■ To solve for the equilibrium choice of capital structure, we substitute for $\alpha^*(p^*, D \mid \theta^I)$ into (5) and rearrange terms to express the expected payoff of the initial equityholders of a θ-type firm when the project is undertaken as a function of the face value of debt and the beliefs of outside investors and the regulator:

$$Y(D, \theta^I, \theta^R \mid \theta) = \begin{cases} [p^*(D \mid \theta^R) - \theta^I c - k] \times \dfrac{p^*(D \mid \theta^R) - \theta c - D}{p^*(D \mid \theta^R) - \theta^I c - D} & \text{if } D \le \overline{D}(\theta^R), \\ [p^*(D \mid \theta^R) - k - t\theta(D - p^*(D \mid \theta^R) + c)] \times \dfrac{1 - \theta}{1 - \theta^I} & \text{if } D > \overline{D}(\theta^R). \end{cases} \quad (17)$$

The expected payoff function is illustrated in Figure 2 for the two types of firms, assuming that the firm's type is common knowledge (i.e., $\theta^I = \theta^R = \theta$). The figure shows that under full information, the expected payoff of the firm is maximized at $\overline{D}(\theta)$, which is the largest debt level that is still riskless. The firm therefore wishes to issue as much riskless debt as possible. But since $\alpha \ge 0$, and $L(D \mid \theta) = 0$ for all $D \le \overline{D}(\theta)$, it follows from (15) that the firm can reach its debt target only if $k \ge \overline{D}(\theta)$. Hence, our model yields a "pecking order" theory of financing: the firm uses debt financing first until it reaches its debt target, and only then does it use equity financing to raise additional funds. Debt is used first because of its effect on the regulatory process.

Asymmetric information has an important implication for the regulated firm's financial strategy because it conveys information to regulators and investors. In the next proposition, we distinguish the effects of prices, beliefs, and capital structure on the initial equityholders' expected payoff function.

FIGURE 2
THE EXPECTED PAYOFF TO THE ORIGINAL OWNERS OF THE FIRM UNDER FULL INFORMATION



Proposition 2. (i) *The cost effect.* $Y(D, \theta^I, \theta^R | \theta)$ increases with p^*, which in turn increases (weakly) with θ^R, the probability that the regulator assigns to $C = c$. As a result, for sufficiently large debt levels, each type would like to convince the regulator that its type, θ, is high to induce him to set a high regulated price.

(ii) *The securities pricing effect.* $Y(D, \theta^I, \theta^R | \theta)$ decreases with θ^I, the probability that outside investors assign to $C = c$. Hence, each type would like to convince outside investors that its type, θ, is low.

(iii) *The leverage effect.* Fixing θ^I and θ^R, $Y(D, \theta^I, \theta^R | \theta)$ increases in D for all $\hat{D}(\theta) \leq D \leq \bar{D}(\theta)$ because of regulatory concern about bankruptcy.

In equilibrium, the firm chooses its financial strategy, $D(\theta)$, by balancing the three effects identified in Proposition 2. Since the cost and the securities pricing effects work in opposite directions, the firm faces countervailing incentives: it wishes to signal high cost to the regulator but low cost to the capital market. The presence of countervailing incentives implies that the cost of signalling information to one receiver in our model is not in the form of "burning money," as in Spence-style signalling models, but rather is due to the negative response of the other receiver.

The equilibrium financial strategy of the firm depends critically on the size of the project, k. This is because k imposes a restriction on the amount of debt that the firm can issue and therefore limits its ability to signal information. We need not consider very large projects, since when $k > \bar{D}(\theta^0) + (1 - \theta^0)c$, both types will choose to forgo the project in stage 1 of the game because undertaking it will yield their initial equityholders a negative expected payoff. We distinguish three types of projects that differ with respect to their size. If the project is small, there is no leverage effect. If the project is medium, the leverage effect dominates, leading to a separating equilibrium. Finally, if the project is large, countervailing incentives lead to a unique equilibrium that is pooling.

☐ **Small projects.** A project is small if its set-up cost, k, is less than $\hat{D}(\theta^l)$. As Figure 1 shows, the regulated price of both types in this case is independent of the firm's debt, so there is no leverage effect. Under full information, both types would therefore be indifferent about their debt-equity mix. Under asymmetric information, firms with a high likelihood of a cost shock (h-types) may wish to mimic firms with a low likelihood of a cost shock (l-types) if the latter issue equity, in order to make outside investors believe that their expected profits are higher than they really are and therefore cause their equity to be overpriced.[16] Likewise, l-types may wish to mimic h-types to make the regulator believe that the regulated price should be raised. This suggests that the equilibrium is separating only if l-types issue relatively little equity, so that the gain to h-types from mimicking them would be small, while h-types need to issue relatively high levels of equity to outsiders to ensure that l-types will face a significant equity-underpricing effect should they mimic h-types. We now establish necessary conditions for the existence of perfect Bayesian equilibria (PBE), and characterize them.

Proposition 3. Suppose that $k \leq \hat{D}(\theta^l)$ and let $Y(\theta) \equiv Y(D(\theta), \theta, \theta \mid \theta)$ be the expected payoff of a θ-type firm in a separating equilibrium. Then if $k \geq \gamma Y(\theta^h)/(1-\gamma)$, there exists a continuum of separating PBE in which $D^*(\theta^h) \neq D^*(\theta^l)$, where

$$D^*(\theta^h) \in [0, k - \gamma Y(\theta^h)/(1-\gamma)],$$

$$D^*(\theta^l) \in [\max\{0, k - \gamma Y(\theta^l)/(1-\gamma)\}, k],\ \alpha^*(\theta^h) \leq \gamma \leq \alpha^*(\theta^l),$$

$p^*(D(\theta) \mid \theta) \equiv p^*(\theta) = \hat{D}(\theta) + c$, and $Y(\theta) = \hat{D}(\theta) + (1-\theta)c - k$, $\theta \in \{\theta^l, \theta^h\}$. In addition, if $k \geq \gamma(1-\gamma)(V - \theta^0 c)$, there exists a pooling PBE in which $D^*(\theta^h) = D^*(\theta^l) = D^* \equiv k/(1-\gamma) - \gamma(V - \theta^0 c)$, $\alpha^* = \gamma$, and $p^* = \hat{D}(\theta^0) + c$. All equilibria are payoff-equivalent and give each type its full-information expected payoff.

Proposition 3 implies that when k is small (but not too small), the model admits both separating and pooling PBE. Since all equilibria are payoff-equivalent, both types of firms are indifferent among them, so the refinement of undefeated equilibrium has no bite (indeed, all equilibria are equally "reasonable"). To understand why k cannot be too small, note that l-types can always separate themselves; for example, when l-types finance the project entirely with debt, h-types have nothing to gain by mimicking them (there is no equity that can be overpriced), and at the same time h-types stand to lose the higher rates that they receive due to the cost effect. In contrast, h-types can separate themselves only if k is sufficiently large to enable h-types to issue at least a fraction γ of the firm's equity to outsiders to ensure that should l-types mimic them, the negative equity underpricing they will face will outweigh the positive cost effect.

Interestingly, although Proposition 3 confirms our intuition that $\alpha^*(\theta^h) \geq \alpha^*(\theta^l)$, it may nonetheless be the case that $D^*(\theta^h) > D^*(\theta^l)$ because h-type firms are less valuable than l-type firms, so receiving a larger fraction of their equity may not be enough to compensate investors, in which case debt with a higher face value may be also needed. Hence, while our model predicts a negative correlation between expected profits and outside equity, it does not predict a necessary correlation between expected profits and debt levels. In a pooling equilibrium, both types issue the same debt level that completely offsets the benefits and costs from separation for both types and, moreover, ensures each type its full information payoffs. A pooling equilibrium can exist only if k is sufficiently large to ensure the existence of such a debt level. Finally, note that when $\gamma Y(\theta^h)/(1-\gamma) \leq k < \gamma(1-\gamma)(V - \theta^0 c)$, the equilibrium must be separating (a pooling equilibrium does not exist), while when $k < \gamma Y(\theta^h)/(1-\gamma)$, there is no PBE in pure strategies.

In the absence of a leverage effect, our model becomes similar to the two-audience financial signalling model considered by Gertner, Gibbons, and Scharfstein (1988). The main result in their article (Propositions 1 and 2) states that the equilibrium is pooling if the *ex ante* expected profit of the firm is weakly greater under pooling than under separation, and separating if the reverse is true. Indeed, the *ex ante* profit of the firm

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[16] Unlike equity, the market value of debt is independent of the firm's type when $k \leq \hat{D}(\theta^l)$, since debt is riskless in this range, implying that the market value of debt equals its face value.

in the small-project case is the same under pooling and under separation, so their result implies ours. Although Gertner, Gibbons, and Scharfstein use the refinement concept of Farrell-Grossman-Perry or perfect sequential equilibrium (Grossman and Perry, 1986), whereas we use the refinement of undefeated equilibrium, the two refinements select the same equilibria for our small-projects case.[17] To see that the expected profits of the firm are indeed the same under pooling and separation, note that the *ex ante* profits of the firm under pooling are

$$b^0(\hat{D}(\theta^0) + (1 - \theta^h)c) + (1 - b^0)(\hat{D}(\theta^0) + (1 - \theta^l)c) = \hat{D}(\theta^0) + (1 - \theta^0)c,$$

whereas under separation they are

$$\begin{aligned} &b^0(\hat{D}(\theta^h) + (1 - \theta^h)c) + (1 - b^0)(\hat{D}(\theta^l) + (1 - \theta^l)c) \\ &\quad = b^0(1 - \gamma)(V - \theta^h c) + (1 - b^0)(1 - \gamma)(V - \theta^l c) \\ &\quad = (1 - \gamma)(V - \theta^0 c) = \hat{D}(\theta^0) + (1 - \theta^0)c, \end{aligned}$$

where the first and last equalities are implied by equations (11) and (12).

In contrast, the cases of medium and large projects, considered next, are substantially different from the model of Gertner, Gibbons, and Scharfstein (1988). This is because with medium and large projects, the leverage effect plays a crucial role in the firm's equilibrium financial strategy.

□ **Medium projects.** A project is of medium size if its set-up cost is such that $\hat{D}(\theta^l) < k \leq \hat{D}(\theta^h)$. If information were full, l-type firms could have exploited the leverage effect by issuing enough debt, whereas h-types could not have done so and are therefore indifferent to their capital structure. Under asymmetric information, l-types finance the project entirely with debt, exactly as they would have under full information, while h-types separate themselves by limiting the amount of debt that they issue and relying on equity financing instead.

Proposition 4. Suppose that $\hat{D}(\theta^l) < k \leq \hat{D}(\theta^h)$. Then, if $k \geq \hat{D}(\theta^h)Y(\theta^h)/Y(\theta^l)$, there exists a unique undefeated separating equilibrium in which

$$\begin{aligned} &D^*(\theta^h) \leq (kY(\theta^l) - \hat{D}(\theta^h)Y(\theta^h))(Y(\theta^l) - Y(\theta^h)), \\ &\alpha^*(\theta^h) \geq (\hat{D}(\theta^h) - k)/(\theta^h - \theta^l)c, \\ &p^*(\theta^h) = \hat{D}(\theta^h) + c, \end{aligned}$$

$D^*(\theta^l) = k$, $\alpha^*(\theta^l) = 0$, and $p^*(\theta^l) = k + c$, where $Y(\theta^h) = \hat{D}(\theta^h) + (1 - \theta^h)c - k$ and $Y(\theta^l) = (1 - \theta^l)c$ are the equilibrium expected payoffs. The expected payoffs of both types are equal to those that would obtain under full information.

Proposition 4 reveals that when the project is medium-sized, the model admits a unique undefeated equilibrium in which l-type firms fully exploit the leverage effect by using an all-debt financing, while h-types separate themselves by issuing enough equity to render mimicking by l-types unattractive. Unlike the small-project case, the equilibrium is now unique because the leverage effect implies that l-types are no longer indifferent among all separating equilibria. Thus, the undefeated equilibrium refinement eliminates all Pareto-dominated separating equilibria.

□ **Large projects.** A project is large if its set-up cost is such that $\hat{D}(\theta^h) < k \leq \overline{D}(\theta^0) + (1 - \theta^0)c$. In this case, the presence of countervailing incentives due to signalling to both regulators

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[17] The perfect sequential equilibrium refinement eliminates equilibria that are not immune to deviations with consistent interpretations. Interpretations are nonempty subsets of sender's types and they are consistent; if once they are believed, they induce the receivers to choose actions such that the sender's payoff is higher than his payoff in the putative equilibrium if and only if the sender's type is included in the interpretation in question.

and investors causes both types of firms to pursue in equilibrium the same financial strategy. Consequently, the capital structure of firms with high or low probabilities of a cost shock coincide in equilibrium.

Proposition 5. Suppose that $\hat{D}(\theta^h) < k \leq \overline{D}(\theta^0) + (1 - \theta^0)c$. Then, the model admits a unique undefeated equilibrium which is pooling. In this equilibrium, $D^* = \min\{k, \overline{D}(\theta^0)\}$, $\alpha^* = \max\{0, (k - \overline{D}(\theta^0))/(1 - \theta^0)c\}$, and $p^* = D^* + c$.

The intuition behind Proposition 5 is as follows. When the project is such that $\hat{D}(\theta^h) < k \leq \overline{D}(\theta^0)$, both types wish to finance it with as much debt as possible in order to exploit the leverage effect. The resulting regulated price is $p^* = D + c$. Since p^* does not depend on the firms' type, the regulator's beliefs do not matter. Similarly, the beliefs of debtholders do not matter, since p^* is high enough to ensure that debt is riskless (the firm can fully repay it even if the cost shock occurs). The beliefs of equityholders, however, do matter, since l-types are more profitable than h-types; consequently, both types will try to convince equityholders that their type is l in order to boost the market value of their equity. But since there are no countervailing incentives, signalling is costless, so l-types cannot separate themselves. Note that this result is *independent* of the specific refinement we use. The application of undefeated equilibrium, however, allows us to eliminate all Pareto-dominated pooling equilibria.

When $\overline{D}(\theta^0) < k \leq \overline{D}(\theta^0) + (1 - \theta^0)c$, the situation is more complex. In this case, the only candidate for an undefeated separating equilibrium is the Pareto–dominant separating equilibrium from the firm's perspective, because this equilibrium defeats all other separating equilibria. In this equilibrium (if it exists), either l-types or h-types reach their debt targets. However, the Pareto-dominant separating equilibrium is in turn defeated by the Pareto-dominant pooling equilibrium, in which $D^* = \min\{k, \overline{D}(\theta^0)\}$, since both types find the pooling equilibrium more attractive. Pooling dominates separation because the equity overpricing effect that h-types enjoy by pooling with l-types is sufficiently large to outweigh the negative cost effect that they face in equilibrium. For l-types the opposite is true: the positive cost effect that they enjoy under pooling is sufficiently large to outweigh the associated equity underpricing effect.

It should be noted that unlike in the case where $\hat{D}(\theta^h) < k \leq \overline{D}(\theta^0)$, now the nonexistence of separating equilibria does depend on the specific refinement we use.[18] Nevertheless, this result seems intuitive because all separating equilibria are Pareto dominated by pooling at $D^* = \min\{k, \overline{D}(\theta^0)\}$. The proof uses the fact that the critical debt function $\overline{D}(\theta)$ is concave to show that the Pareto-dominant pooling PBE defeats the Pareto-dominant separating PBE (i.e., both types are strictly better off in the former equilibrium). The concavity of the debt level follows from the form of the regulator's objective function and the regulator's choice of a pricing policy.

Finally, note that there is a substantial difference between the case where $k < \overline{D}(\theta^0)$ and the case where $k \geq \overline{D}(\theta^0)$. In the former, the firm uses debt financing on the margin, while in the latter it uses equity financing on the margin.

6. Properties of the equilibrium

■ Having fully characterized the equilibrium, we are now ready to examine its properties. First, substituting for the equilibrium debt level and regulated price into (2)

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[18] It is straightforward, however, to show that one can also eliminate all separating equilibria in this case by applying the refinement of perfect sequential equilibrium (Grossman and Perry, 1986). Given this refinement, separating equilibria can be eliminated by a deviation to $D^* = \min\{k, \overline{D}(\theta^0)\}$. Since this deviation benefits both types, it will have the consistent interpretation $\{\theta^l, \theta^h\}$ and will therefore upset the putative separating equilibrium.

reveals that the probability of bankruptcy in equilibrium is zero for both types of firms, regardless of the size of the project. Hence,

Proposition 6. In equilibrium, the regulated firm's debt is completely riskless; hence, the firm does not face the possibility of bankruptcy.

It should be emphasized that the firm's debt is riskless because of the leverage effect: the regulator responds to the firm's debt by setting a regulated price such that the firm can repay it with probability one. The result of Proposition 6 is consistent with the observation that bankruptcies have been very rare in the U.S. utility sector since the mid-1930s. It is similar to Spiegel (1994) but stands in contrast with Spiegel and Spulber (1994) and Spiegel (1996), because here and in Spiegel (1994), the regulator maximizes the product of consumer surplus and profits, which leads to prices based on average costs, whereas in Spiegel and Spulber (1994) and Spiegel (1996), the regulator maximizes the sum of consumer surplus and profits, which leads to marginal cost pricing. The latter has the feature that an increase in the regulated price benefits the firm not only on the margin, but also on its inframarginal units; consequently, the firm is more than compensated for the increase in its expected cost of bankruptcy and is therefore willing to issue risky debt.[19] With average cost pricing, there is no similar effect: once the firm is exposed to bankruptcy, it bears part of the associated costs, so debt levels beyond $\overline{D}(\theta)$ are not profitable to the firm.

Second, we examine the implication of asymmetric information for the capital structure of the firm. To this end, recall that the firm's debt target under full information is $\overline{D}(\theta)$. This debt target varies across firms based on their expected costs. Under asymmetric information, in contrast, the debt target of the firm depends on the prior beliefs of the regulator and outside investors rather than on the firm's true cost parameter, (i.e., it depends on θ^0 rather than on θ). This implies that when the project is large, there should not be a significant empirical correlation between the capital structure of the firm and its expected value. If, however, the project's size is small or medium, the model admits separating equilibria in which firms with high expected value (i.e., low expected costs) rely more heavily on debt financing (and may even use all-debt financing with medium-sized projects), whereas firms with low expected value (i.e., high expected costs) rely more heavily on equity financing.

When the project is smaller than the debt target under asymmetric information, $\overline{D}(\theta^0)$, the firm's capital structure is decoupled from cost and demand parameters (see Propositions 3–5). On the other hand, when the project is larger than $\overline{D}(\theta^0)$, cost and demand parameters affect capital structure. Thus, the size of the project relative to the debt target alters the effects of cost and demand parameters on the regulated price. In the large-projects case, both firms use a combination of debt and equity financing. In practice, regulated firms have substantial capital investments and generally employ a mix of debt and equity financing. Accordingly, we consider comparative statics for the large-projects case where k exceeds the debt target $\overline{D}(\theta^0)$, in which case $D^* = \overline{D}(\theta^0)$, $\alpha^* = (k - \overline{D}(\theta^0))/(1 - \theta^0)c$, and $p^* = \overline{D}(\theta^0) + c$.

Proposition 7. Suppose that $k > \overline{D}(\theta^0)$. Then, D^* is increasing in the prior probability θ^0, decreasing in the cost shock c, increasing in the bankruptcy cost t, increasing in the consumers' willingness to pay V, and decreasing in the welfare weight γ; and α^* is increasing in the size of the project k, decreasing in θ^0, increasing in c, decreasing in t, decreasing in V, and increasing in γ.

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[19] Note however that debt is risky because the regulator is unwilling to raise the regulated price enough to ensure that bankruptcy never happens. Nonetheless, with marginal cost pricing, the firm finds it optimal to issue a high level of debt to induce the regulator to increase prices, despite the fact that the increase in prices is not sufficient to prevent bankruptcy in all states of nature.

Proposition 7 implies that when k is large, debt and equity are substitutes in the sense that an increase in debt financing due to a change in an exogenous parameter leads to a decrease in equity financing and vice versa. The only exception is that an increase in k raises α^* without affecting D^*. This is because the debt target does not depend on the size of the project and since the firm uses equity financing on the margin.

Finally we examine the impact of changes in exogenous parameters on the equilibrium regulated price, p^*.

Proposition 8. Suppose that $k > \overline{D}(\theta^0)$. Then, p^* is increasing in the prior probability, θ^0, increasing in the bankruptcy cost t, increasing in the consumers' willingness to pay V, and decreasing in the welfare weight γ. The markup $p^* - c$ is decreasing in the cost shock.

7. Conclusion

■ The sequential game with asymmetric information between the firm, a regulator, and outside investors shows that regulated firms can affect their rates by properly choosing their capital structure. The regulator is concerned with the possibility that the firm will go bankrupt and incur a deadweight loss. This creates a leverage effect: when the firm issues debt, the regulator responds by increasing rates in order to reduce the likelihood of bankruptcy, enabling the firm to capture a larger share in the surplus it generates. Anticipating the regulator's response, the firm chooses its debt target by trading off higher rates induced by the leverage effect against the increase in expected bankruptcy costs.

Because the firm's costs are private information, capital structure can be used as a signalling device. When the beliefs of the regulator and outside investors are consistent (in the sense of the refinement of undefeated equilibria), the model admits only Pareto-undominated equilibria. These equilibria can be either pooling or separating, depending on the size of the firm's investment. When the size of the investment is relatively small, the model may admit both a continuum of separating equilibria and a pooling undefeated equilibrium, all of which are payoff-equivalent. In the separating equilibria, firms with low probability of a cost shock issue relatively little equity, while firms with a high probability of a cost shock rely more heavily on equity financing. In a pooling equilibrium, both types issue the same debt level that completely offsets the benefits and costs from separation for both types.

When the investment project is medium-sized, the model admits a unique separating undefeated equilibrium, in which firms with a low probability of a cost shock use all-debt financing, while firms with a high probability of a cost shock separate themselves by using enough equity financing. Finally, when investment is large, the model admits a unique undefeated equilibrium, which is pooling. This equilibrium is sustained by the fact that neither type of firm has an incentive to distinguish itself, as the potential gains for each type from revealing its identity to one receiver are outweighed by the loss associated with the negative response of the second receiver. Since the equilibrium financial strategy of the firm depends in this case on the prior beliefs of the regulator and outside investors rather than on the true cost parameter of the firm, the capital structure choice of the firm is decoupled from its private information about its value. Empirically, therefore, there need not be a correlation between capital structure and the expected value of the firm.

In addition to the regulatory leverage effect, firms have many reasons to issue debt, such as taxation, agency costs, and corporate control considerations.[20] Controlling

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[20] See Myers (1984) for a discussion of tax-based theories of capital structure and Harris and Raviv (1991) for a survey of theories based on agency costs and corporate control.

for these other effects, our analysis implies that regulated firms would be more leveraged than unregulated firms. This helps to explain the empirical finding of Bradley, Jarrell, and Kim (1984) that firms in regulated industries are among the most highly leveraged. The absence of bankruptcy in equilibrium explains why despite being so highly leveraged, regulated firms have hardly ever gone bankrupt under traditional rate regulation. Our model suggests that as the process of deregulation proceeds in the utility industries, regulated utilities will either have to lower their debt-equity ratios or face serious financial difficulties.

Appendix

■ The beliefs of receivers (outside investors and the regulator in the current model) are said to be inconsistent with the set of types T if

$$b \neq \frac{b^0 m(\theta^h)}{b^0 m(\theta^h) + (1 - b^0) m(\theta^l)}, \text{ for any } m\text{: } \{\theta^l, \theta^h\} \rightarrow [0, 1] \text{ satisfying}$$

$$m(\theta) = 1 \;\forall\; \theta \in T_1,\; m(\theta) = 0 \;\forall\; \theta \notin T,$$

where T_1 is the set of types who strictly prefer the alternative equilibrium to the proposed one. For a definition of undefeated equilibrium in the general case, the reader is referred to Mailath, Okuno-Fujiwara, and Postlewaite (1993).

Definition A1. An undefeated equilibrium is a PBE such that the following consistency requirement on the beliefs of outside investors and the regulator off the equilibrium path is satisfied:

Consider a proposed equilibrium, σ, and a capital structure (α', D'), that is not chosen in σ, but is chosen by at least one type of firm in an alternative equilibrium, σ'. Let T be the set of firm's types that choose (α', D') in σ'. If each member of T prefers σ' to the σ, with a strict preference for at least one member of T, then upon observing (α', D'), the posterior beliefs of outside investors and the regulator must be consistent with the set T in the following sense:

$$\theta^I = \theta^R = \begin{cases} \theta^h, & \text{if only type } h \text{ prefers } \sigma \text{ to } \sigma', \\ [\theta^0, \theta^h], & \text{if type } h \text{ strongly prefers } \sigma \text{ to } \sigma' \text{ and type } l \text{ weakly prefers it,} \\ \theta^0, & \text{if both types prefer } \sigma \text{ to } \sigma', \\ [\theta^l, \theta^0], & \text{if type } l \text{ strongly prefers } \sigma \text{ to } \sigma' \text{ and type } h \text{ weakly prefers it,} \\ \theta^l, & \text{if only type } l \text{ prefers } \sigma \text{ to } \sigma'. \end{cases} \tag{A1}$$

If the posterior beliefs of outside investors and the regulator satisfy condition (A1), then the proposed equilibrium is said to be *undefeated,* that is, no alternative equilibrium defeats it.

Derivation of the condition on t and c that ensures that the limited liability constraint on debtholders is never binding. First recall that the firm goes bankrupt only if the cost shock occurs. Hence, the payoff of debtholders in the event of bankruptcy is $Y_D = p^* - c - t(D - p^* + c)$, where p^* is given by the third line in equation (10). Differentiating this expression with respect to D reveals that $\partial Y_D / \partial D < 0$; consequently, it is sufficient to verify that $Y_D \geq 0$ at the highest debt level that the firm will ever issue. This debt level, denoted by $\tilde{D}(\theta)$, is implicitly defined by the equation $D = p^*$ (debt levels beyond this level lead to bankruptcy with probability one, and are therefore dominated strategies for the firm). Using the third line in (10) yields

$$\tilde{D}(\theta) \equiv \frac{((1 - \gamma)(V - \theta c) + c)(1 + \theta t)}{1 + (1 - \gamma)\theta t} - c(1 - \theta). \tag{A2}$$

The debtholders' payoff at this debt level as a function of t is

$$\tilde{Y}_D(t) = \tilde{D}(\theta) - c(1 - \theta). \tag{A3}$$

Now, $\partial^2 \tilde{Y}_D / \partial t^2 < 0$, indicating that $\tilde{Y}_D$ is concave in t. Together with the fact that $\tilde{Y}_D(0) = (1 - \gamma)V - c(1 - \gamma\theta) \geq 0$, where the inequality follows since $\gamma < \bar{\gamma} \leq (V - c)/(V - \theta c)$, this implies that $\tilde{Y}_D \geq 0$ for all $t < \bar{t}$, where $\bar{t}$ is the largest root of the equation $\tilde{Y}_D(t) = 0$. Specifically,

$$\tilde{t} \equiv \frac{A + \sqrt{A^2 + 4\theta c(1-\gamma)\tilde{Y}_D(0)}}{2\theta c(1-\gamma)}; \qquad A \equiv \theta \tilde{Y}_D(0) - c(1-\gamma\theta). \tag{A4}$$

Hence, $t < \tilde{t}$ is a sufficient condition for the payoff of debtholders to be nonnegative for all debt levels that are undominated strategies for the firm.

Proof of Proposition 3. Let $Y(\theta) \equiv Y(D^*(\theta), \theta, \theta \mid \theta)$ be the expected payoff of θ-types in a separating equilibrium, and let $Y(\theta' \mid \theta) \equiv Y(D^*(\theta'), \theta', \theta' \mid \theta)$ be the expected payoff of θ-types when they mimic the financial strategy of θ'-types. Incentive compatibility requires that in a separating equilibrium, $Y(\theta) \geq Y(\theta' \mid \theta)$, $\theta, \theta' \in \{\theta^l, \theta^h\}$. Using equation (17), this condition can be written as

$$\frac{c(\theta - \theta')}{(1-\gamma)(Y(\theta') + k - D^*(\theta'))}\left[\frac{\gamma Y(\theta')}{1-\gamma} + D^*(\theta') - k\right] \geq 0, \qquad \theta, \theta' \in \{\theta^l, \theta^h\}, \tag{A5}$$

where $Y(\theta') + k - D^*(\theta') \geq 0$, since $Y(\theta') > 0$ and $D^*(\theta') \leq k$. Noting that $\theta - \theta' > 0$ if $\theta = \theta^h$ and $\theta' = \theta^l$, and $\theta - \theta' < 0$ otherwise, it follows that in a separating equilibrium it must be the case that

$$\frac{\gamma Y(\theta^l)}{1-\gamma} + D^*(\theta^l) > k > \frac{\gamma Y(\theta^h)}{1-\gamma} + D^*(\theta^h). \tag{A6}$$

Since $Y(\theta^l) > 0$, the left inequality holds for any $D^*(\theta^l)$ sufficiently close to k; the lower bound on $D^*(\theta^l)$, defined in the proposition, is the lowest $D^*(\theta^l)$ that satisifies the left inequality. A necessary condition for the right inequality to hold is $k > \gamma Y(\theta^h)/(1-\gamma)$, because $D^*(\theta^h) \geq 0$. Hence, $k > \gamma Y(\theta^h)/(1-\gamma)$ is also a necessary condition for a separating PBE (when this inequality fails, there is no positive $D^*(\theta^h)$ that deters l-types from mimicking h-types). The upper bound on $D^*(\theta^h)$, defined in the proposition, is the largest $D^*(\theta^h)$ that satisifies the right side of (A6). Every nonnegative pair $(D^*(\theta^l), D^*(\theta^h))$ that satisifies (A6) can be supported as the debt-level choices in a separating PBE. One belief function that supports these debt levels as equilibrium outcomes is such $\theta^I = \theta^R = \theta^h$ if $D < D^*(\theta^l)$ or $D = D^*(\theta^h)$, and $\theta^I = \theta^R = \theta^l$ otherwise (there are other belief functions that support these equilibria). The equilibrium equity participation of outsiders is then determined by substituting for $D^*(\theta)$ in equation (16). Since $k \leq \hat{D}(\theta)$, the expected payoff of a θ-type firm is exactly as in the full-information case.

Next, let $Y(\theta^0 \mid \theta) \equiv Y(D^*, \theta^0, \theta^0 \mid \theta)$ be the expected payoff of θ-types in a pooling equilibrium (if it exists) in which both types issue a debt level D^*. Then $p^* = \hat{D}(\theta^0) + c$. A pooling PBE exists only if $Y(\theta^0 \mid \theta) \geq Y(\theta)$, $\theta \in \{\theta^l, \theta^h\}$. Using the first line of equation (17), this condition can be written as

$$\frac{c(\theta - \theta^0)}{(1-\gamma)((1-\gamma)(V - \theta^0 c) - D^*)}\left[\gamma(V - \theta^0 c) + D^* - \frac{k}{1-\gamma}\right] \geq 0, \qquad \theta \in \{\theta^l, \theta^h\}. \tag{A7}$$

Clearly, (A7) can hold for both types if and only if the expression in the square brackets vanishes. Hence, in a pooling PBE, $D^* = k/(1-\gamma) - \gamma(V - \theta^0 c)$. Substituting for D^* in equation (16) reveals that $\alpha^* = \gamma$. One belief function that supports D^* as the outcome of a pooling PBE is such that $\theta^I = \theta^R = \theta^0$ if $D < D^*$, $\theta^I = \theta^R = \theta^l$ if $D > D^*$, and $\theta^I = \theta^R = \theta^h$ otherwise (again, this belief function is not unique). Since (A7) must hold with equality, both types receive their separating equilibrium expected payoffs. Moreover, since all equilibria (pooling and separating) are payoff-equivalent, definition (A1) implies that all of them are undefeated. *Q.E.D.*

Proof of Proposition 4. First, suppose by way of negation that there exists an undefeated separating equilibrium in which $D^*(\theta^l) < k$. Incentive compatibility requires that in equilibrium, $Y(\theta^l) \geq Y(\theta^h \mid \theta^l)$ and $Y(\theta^h) \geq Y(\theta^l \mid \theta^h)$. Now consider a deviation by l-types to $D(\theta^l) = k$. From equation (17) it is easy to see that the deviation increases $Y(\theta^l)$ and leaves $Y(\theta^h \mid \theta^l)$ unaffected; hence, the first inequality continues to hold. Now, evaluated at $D(\theta^l) = k$, $Y(\theta^l \mid \theta^h) = (1 - \theta^h)c$. Since by assumption $k < \hat{D}(\theta^h) \equiv (1-\gamma)(V - \theta^h c) - (1 - \theta^h)c$ (see equation (11)), it follows that $(1-\theta^h)c < (1-\gamma)(V - \theta^h c) - k$. But the last expression equals $Y(\theta^h)$, so the second inequality continues to hold as well. Therefore, $D^*(\theta^l) = k$ can also be the outcome of a separating PBE. In the new equilibrium, though, $Y(\theta^l)$ is higher than before while $Y(\theta^h)$ is unchanged ($Y(\theta^h)$ does not depend on D), so the new equilibrium Pareto dominates the putative equilibrium. Hence, definition (A1) implies that in a separating undefeated equilibrium (if it exists), $D^*(\theta^l) = k$; this implies in turn that $\alpha^*(\theta^l) = 0$. The condition $Y(\theta^l) \geq Y(\theta^h \mid \theta^l)$ determines $D^*(\theta^h)$: using equation (17), this condition implies that $D^*(\theta^h) \leq (kY(\theta^l) - \hat{D}(\theta^h)Y(\theta^h))/(Y(\theta^l) - Y(\theta^h))$. Since $Y(\theta^l) > Y(\theta^h)$, there exists a positive $D^*(\theta^h)$ that satisifies this condition provided that $k > \hat{D}(\theta^h)Y(\theta^h)/Y(\theta^l)$. Substituting for $D^*(\theta^h)$ in equation (16) yields $\alpha^*(\theta^h)$. To show that a pair $(k, D^*(\theta^h)$, such that $0 \leq D^*(\theta^h) \leq (kY(\theta^l) - \hat{D}(\theta^h)Y(\theta^h))/(Y(\theta^l) - Y(\theta^h))$ can be supported as the debt-level choices in an undefeated equilibrium, we must find an appropriate belief function. One such belief function is such that $\theta^I = \theta^R = \theta^h$ if $D < k$, and $\theta^I = \theta^R = \theta^l$ if $D = k$ ($D > k$ is not feasible, since debt is riskless). Given this belief function, l-types can only lose by choosing $D < k$, while h-types lose if they choose $D = k$, and have nothing to gain be deviating to $D < k$ $(D \neq D^*(\theta^h))$.

Next we consider pooling equilibria. If $k < \hat{D}(\theta^p)$, then $D^* \leq \hat{D}(\theta^p)$ (recall that since debt is riskless, D cannot exceed k), so (A7) is a necessary condition for a pooling equilibrium. However, (A7) can hold only if $D^* = k/(1 - \gamma) - \gamma(V - \theta^p c)$, in which case $Y(\theta^p | \theta^l) = \hat{D}(\theta^l) + (1 - \theta^l)c - k$. But since by assumption $\hat{D}(\theta^l) < k$, $Y(\theta^p | \theta^l) < c(1 - \theta^l)$, which is the expected payoff of an l-type firm in the Pareto-dominant separating PBE in which $D^*(\theta^l) = k$. Moreover, we know from Proposition 3 that h-types are indifferent between pooling at $D^* = k/(1 - \gamma) - \gamma(V - \theta^p c)$ and separating. Hence, definition (A1) implies that the Pareto-dominant separating equilibrium defeats the putative pooling equilibrium.

If $k > \hat{D}(\theta^p)$, then D^* may exceed $\hat{D}(\theta^p)$, and in fact must exceed it, otherwise the pooling PBE will be defeated by the Pareto-dominant separating PBE in which $D^*(\theta^l) = k$. Therefore, equation (17) implies that $Y(\theta^p | \theta) = (1 - \theta)(D^* + c(1 - \theta^p) - k)/(1 - \theta^p)$, $\theta = \{\theta^l, \theta^h\}$. This expected payoff increases with D^*, so by definition (A1), the only candidate for an undefeated pooling equilibrium is such that $D^* = k$ (this equilibrium defeats all pooling PBE in which $D^* < k$). In equilibrium, the payoff of l-types remains $(1 - \theta^l)c$, while the payoff of h-types becomes $Y(\theta^p | \theta^h) = (1 - \theta^h)c$. But since by assumption $\hat{D}(\theta^h) > k$, $Y(\theta^p | \theta^h) < \hat{D}(\theta^h) + (1 - \theta^h)c - k = Y(\theta^h)$, so by definition (A1), the Pareto-dominant separating equilibrium defeats the putative pooling equilibrium. *Q.E.D.*

Proof of Proposition 5. We prove the proposition through a series of four lemmas.

Lemma 1. Suppose that $k \leq \bar{D}(\theta^p)$. Then there exists a unique undefeated equilibrium which is pooling. In this equilibrium, $D^* = k$, $\alpha^* = 0$, and $p^* = k + c$.

Proof. When $D^* = k$, the payoff of a θ-type firm is $Y(\theta^p | \theta) = (1 - \theta)c$. Since this is the highest payoff that each type can achieve, definition (A1) implies that this pooling equilibrium defeats all other PBE. One belief function that supports $D^* = k$ as an equilibrium outcome is such that $\theta^l = \theta^R = \theta^p$ if $D = k$ and $\theta^l = \theta^R = \theta^h$ if $D < k$ (since D is riskless, $D > k$ is not feasible). Finally, the equilibrium price is determined by equation (10). *Q.E.D.*

Lemma 2. Suppose that $\bar{D}(\theta^p) < k \leq \bar{D}(\theta^p) + (1 - \theta^p)c$. Then the model admits a unique Pareto-dominant pooling PBE. In this equilibrium, $D^* = \bar{D}(\theta^p)$.

Proof. First we show that $D^* > \hat{D}(\theta^p)$. To this end, recall from Proposition 3 that the model can admit only one pooling PBE in which $D^* < \hat{D}(\theta^p)$, and assume that the necessary condition for the existence of this PBE is satisfied (otherwise we are done). Now we shall show that both types are better off pooling at $\bar{D}(\theta^p)$ than pooling at $D^* < \hat{D}(\theta^p)$. By Proposition 3, the expected payoff of an h-type firm in the unique pooling PBE in which $D^* < \hat{D}(\theta^p)$ is $Y(D^*, \theta^p, \theta^p | \theta^h) = \hat{D}(\theta^h) + (1 - \theta^h)c - k$. On the other hand, equation (17) implies that the expected payoff of h-types when the firms pool at $\bar{D}(\theta^p)$ is

$$Y(\bar{D}(\theta^p), \theta^p, \theta^p | \theta^h) = [\bar{D}(\theta^p) + (1 - \theta^p)c - k] \times \frac{(1 - \theta^h)}{(1 - \theta^p)}. \tag{A8}$$

But since $\hat{D}(\theta^h) < \bar{D}(\theta^p) < k$,

$$\begin{aligned} Y(\bar{D}(\theta^p), \theta^p, \theta^p | \theta^h) &> \bar{D}(\theta^p) + (1 - \theta^h)c - k \\ &> \hat{D}(\theta^p) + (1 - \theta^h)c - k \\ &= Y(D^*, \theta^p, \theta^p | \theta^h). \end{aligned} \tag{A9}$$

That is, h-types are better off pooling at $\bar{D}(\theta^p)$. As for l-types, equation (17) implies that their payoff when $D^* < \hat{D}(\theta^p)$ is

$$Y(D^*, \theta^p, \theta^p | \theta^l) = [D^* + (1 - \theta^p)c - k] \times \frac{\hat{D}(\theta^p) + (1 - \theta^l)c - D^*}{\hat{D}(\theta^p) + (1 - \theta^p)c - D^*}. \tag{A10}$$

But since $D^* < \hat{D}(\theta^p) < \bar{D}(\theta^p)$ and $\theta^l < \theta^p$,

$$\begin{aligned} Y(D^*, \theta^p, \theta^p | \theta^l) &< [D^* + (1 - \theta^p)c - k] \times \frac{1 - \theta^l}{1 - \theta^p} \\ &< [\bar{D}(\theta^p) + (1 - \theta^p)c - k] \times \frac{1 - \theta^l}{1 - \theta^p} \\ &= Y(\bar{D}(\theta^p), \theta^p, \theta^p | \theta^l), \end{aligned} \tag{A11}$$

implying that l-types are also better off pooling at $\bar{D}(\theta^p)$.

Having shown that $D^* > \hat{D}(\theta^0)$, we next show that $D^* = \overline{D}(\theta^0)$. To this end, note from equation (17) that the expected payoff of a θ-type firm in pooling equilibria such that $D^* > \hat{D}(\theta^0)$ is

$$Y(D^*, \theta^0, \theta^0 \mid \theta) = \begin{cases} [D^* + (1 - \theta^0)c - k] \times \dfrac{1 - \theta}{1 - \theta^0} & \text{if } D^* \leq \overline{D}(\theta^0), \\ [\hat{D}(\theta^0) + (1 - \theta^0)c - k - (1 - \gamma)\theta t(V + \mathrm{c} - D^*)] \times \dfrac{1 - \theta}{1 - \theta^0} & \text{if } D^* > \overline{D}(\theta^0). \end{cases} \tag{A12}$$

This expression attains a unique maximum at $\overline{D}(\theta^0)$, so definition (A1) implies that the pooling equilibrium in which $D^* = \overline{D}(\theta^0)$ Pareto dominates all other pooling equilibria. One belief function that supports this pooling equilibrium is such that $\theta^I = \theta^R = \theta^0$ if $D \geq \hat{D}(\theta^0)$ and $\theta^I = \theta^R = \theta^h$ if $D < \hat{D}(\theta^0)$. Given these beliefs, the payoffs of both types are given by equation (A12), which is maximized at $\hat{D}(\theta^0)$. Hence no type will increase D to above $\hat{D}(\theta^0)$. When h-types deviate to $D < \hat{D}(\theta^0)$, their expected payoff becomes $\hat{D}(\theta^h) + (1 - \theta^h)c - k$, which by (A9) is less than their equilibrium expected payoff. Hence, h-types will not deviate. As for l-types, given the above belief function, their expected payoff when they deviate to $D < \hat{D}(\theta^0)$ becomes

$$Y(D, \theta^h, \theta^h \mid \theta^l) = \begin{cases} [\hat{D}(\theta^h) + (1 - \theta^h)c - k] \times \dfrac{\hat{D}(\theta^h) + (1 - \theta^l)c - D}{\hat{D}(\theta^h) + (1 - \theta^h)c - D} & \text{if } D \leq \hat{D}(\theta^h), \\ [D + (1 - \theta^h)c - k] \times \dfrac{1 - \theta^l}{1 - \theta^h} & \text{if } D > \hat{D}(\theta^h). \end{cases} \tag{A13}$$

This payoff increases with D, so whenever $D < \hat{D}(\theta^0)$,

$$Y(D, \theta^h, \theta^h \mid \theta^l) < [\overline{D}(\theta^0) + (1 - \theta^h)c - k] \times \frac{1 - \theta^l}{1 - \theta^h} < Y(\overline{D}(\theta^0), \theta^0, \theta^0 \mid \theta^l), \tag{A14}$$

implying that l-types will not deviate as well.

To prove existence, it only remains to verify that both types indeed have an incentive to undertake the project. A sufficient condition for this is $k \leq \overline{D}(\theta^0) + (1 - \theta^0)c$, because this condition guarantees that the initial equityholders of both types of firm receive a nonnegative expected payoff when they undertake the project. When this condition holds, the model admits a unique undefeated pooling equilibrium in which $D^* = \overline{D}(\theta^0)$. *Q.E.D.*

Lemma 3. Suppose that $k > \overline{D}(\theta^0)$. Then there does not exist a separating undefeated equilibrium in which $D^*(\theta^h) < \hat{D}(\theta^h)$ and $D^*(\theta^l) < \hat{D}(\theta^l)$.

Proof. Recall that when $D^*(\theta^h) < \hat{D}(\theta^h)$ and $D^*(\theta^l) < \hat{D}(\theta^l)$, all PBE (separating and pooling) are payoff equivalent. Lemma 2 (in particular (A9) and (A11)) shows that these equilibria are Pareto dominated by the pooling equilibrium in which $D^* = \overline{D}(\theta^0)$, and hence by definition (A1) they are defeated. *Q.E.D.*

Lemma 4. Suppose that $k > \overline{D}(\theta^0)$. Then there does not exist a separating undefeated equilibrium.

Proof. First we show that when $k > \overline{D}(\theta^0)$, there exists a unique candidate for a separating undefeated equilibrium. Then we show that this equilibrium is defeated by the pooling equilibrium in which $D^* = \overline{D}(\theta^0)$. To find a candidate for a separating equilibrium, recall that incentive compatibility requires that in a separating equilibrium, $Y(\theta') \geq Y(\theta \mid \theta')$, $\theta \in \{\theta^l, \theta^h\}$. Since $Y(\theta)$ attains a unique maximum at $\overline{D}(\theta)$ (see Figure 2), we can restrict attention without a serious loss of generality to separating equilibria in which $D^*(\theta^l) \leq \overline{D}(\theta^l)$ and $D^*(\theta^h) \leq \overline{D}(\theta^h)$. Moreover, by Lemma 3, it must be that in an undefeated separating equilibrium (if it exists), $D^*(\theta^h) > \hat{D}(\theta^h)$ and $D^*(\theta^l) > \hat{D}(\theta^l)$. Using equation (17), the incentive-compatibility condition can therefore be written as

$$Y(\theta') \geq Y(\theta) \frac{1 - \theta'}{1 - \theta}, \qquad \theta, \theta' \in \{\theta^l, \theta^h\}. \tag{A15}$$

This inequality implies that in a separating equilibrium,

$$Y(\theta^l) = Y(\theta^h) \frac{1 - \theta^l}{1 - \theta^h}. \tag{A16}$$

By equation (10), $p^* = D + c$ for $D \in [\hat{D}(\theta), \overline{D}(\theta)]$. Substituting for p^* in (17) reveals that $Y(\theta) = D^* + (1 - \theta)c - k$, so (A16) becomes

$$D^*(\theta^l) + (1 - \theta^l)c - k = \frac{(1 - \theta^l)(D^*(\theta^h) + (1 - \theta^h)c - k)}{1 - \theta^h}. \tag{A17}$$

Equation (A17) implies that in a separating equilibrium (if it exists),

$$D^*(\theta^h) = H(D^*(\theta^l)) \equiv \frac{D^*(\theta^l)(1 - \theta^h) + k(\theta^h - \theta^l)}{1 - \theta^l}. \tag{A18}$$

Moreover, since $Y(\theta^l)$ increases in D for all $D \leq \overline{D}(\theta^l)$, and since $Y(\theta^h)$ increases in D for all $D \leq \overline{D}(\theta^h)$, it must be the case that in an undefeated separating equilibrium either $D^*(\theta^l) = \overline{D}(\theta^l)$ or $D^*(\theta^h) = \overline{D}(\theta^h)$, otherwise the equilibrium can be defeated by a separating equilibrium in which both types issue more debt such that (A18) still holds. A necessary condition for an undefeated separating equilibrium in which $D^*(\theta^l) \leq \overline{D}(\theta^l)$ is $H(\overline{D}(\theta^l)) \leq \overline{D}(\theta^h)$ (otherwise there does not exist a pair $(D^*(\theta^l), H(D^*(\theta^l))$ that satisfies (A18)). Using (A18), this necessary condition can be written as

$$k \leq \frac{\overline{D}(\theta^h)(1 - \theta^l) - \overline{D}(\theta^l)(1 - \theta^h)}{\theta^h - \theta^l}. \tag{A19}$$

Similarly, a necessary condition for an undefeated separating equilibrium in which $D^*(\theta^h) \equiv H(D^*(\theta^l)) = \overline{D}(\theta^h)$ is $H^{-1}(\overline{D}(\theta^h)) \leq \overline{D}(\theta^l)$. Using (A18), this necessary condition can be written as

$$k \geq \frac{\overline{D}(\theta^h)(1 - \theta^l) - \overline{D}(\theta^l)(1 - \theta^h)}{\theta^h - \theta^l}. \tag{A20}$$

Since either (A19) or (A20) must hold, the model admits a (unique) Pareto-dominant separating PBE.

Next, we show that the pooling PBE in which $D^* = \overline{D}(\theta^p)$ defeats the Pareto-dominant separating equilibrium. The expected payoffs in the Pareto-dominant pooling PBE in which $D^* = \overline{D}(\theta^p)$ are

$$Y(\overline{D}(\theta^p), \theta^p, \theta^p | \theta) = \frac{(\overline{D}(\theta^p) + (1 - \theta^p)c - k)(1 - \theta)}{1 - \theta^p}, \qquad \theta \in \{\theta^h, \theta^l\}. \tag{A21}$$

On the other hand, the expected payoffs in the Pareto-dominant separating PBE are given by

$$Y(\theta) = D^*(\theta) + (1 - \theta)c - k, \qquad \theta \in \{\theta^h, \theta^l\}, \tag{A22}$$

where $D^*(\theta^h) = H(D^*(\theta^l))$. If $D^*(\theta^l) = \overline{D}(\theta^l)$, then a comparison of (A21) with (A22) reveals that a sufficient condition for the Pareto-dominant pooling PBE to defeat the Pareto-dominant separating PBE (i.e., both types are strictly better off in the former equilibrium) is

$$k < \frac{\overline{D}(\theta^p)(1 - \theta^l) - \overline{D}(\theta^l)(1 - \theta^p)}{\theta^p - \theta^l}. \tag{A23}$$

but (A23) is implied by (A19) and $\overline{D}(\theta)$ concave. Hence, the Pareto-dominant separating PBE is defeated. If on the other hand $D^*(\theta^h) \equiv H(D^*(\theta^l)) = \overline{D}(\theta^h)$, then a comparison of (A21) with (A22) reveals that the sufficient condition for the Pareto-dominant pooling PBE to defeat the Pareto-dominant separating PBE becomes

$$k > \frac{\overline{D}(\theta^h)(1 - \theta^p) - \overline{D}(\theta^p)(1 - \theta^h)}{\theta^h - \theta^p}. \tag{A24}$$

But (A24) is implied by (A20) and $\overline{D}(\theta)$ concave. Hence, the Pareto-dominant separating PBE is defeated. *Q.E.D.*

Lemmas 2–4 imply that when $\overline{D}(\theta^p) < k \leq \overline{D}(\theta^p) + (1 - \theta^p)c$, the model admits a unique undefeated equilibrium which is pooling. In this equilibrium, $D^* = \overline{D}(\theta^p)$, so by equations (16) and (10), $\alpha^* = \max\{0, (k - \overline{D}(\theta^p))/(1 - \theta^p)c\}$, and $p^* = D^* + c$. *Q.E.D.*

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CASE: UE 399
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 115

Company Response to:
Data Requests (DR)

June 22, 2022

OPUC Data Request 422

Total Rate Impact - Refer to Table 1 on PAC/1100, Meredith/15. Please reproduce this table to include the total rate impact of both UE 399 and UE 400 as filed.

Response to OPUC Data Request 422

Please refer to the table provided below which incorporates the impact of both proposed prices changes from the Company’s general rate case (GRC), Docket UE-399 and the Company’s 2023 transition adjustment mechanism (TAM), Docket UE-400:

Residential Schedule 4	14.3%
General Service	
Schedule 23/723 (0-30kW)	14.1%
Schedule 28/728 (31-200kW)	5.4%
Schedule 30/730 (201-999kW)	6.0%
Large General Service Schedules 47/747, 48/748 (≥1,000kW)	13.6%
Agricultural Pumping Service Schedule 41/741	18.3%
Lighting Schedules	0.2%
Overall	**12.2%**

CASE: UE 399
WITNESS: John L. Fox

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is John L. Fox. I am a Senior Financial Analyst employed in the Rates, Finance, and Audit (RFA) Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the changes in revenue requirement associated with Staff's opening position. Additionally, I provide background regarding specific issues I reviewed, and my analysis and recommendations.

Q. Did you prepare an exhibit for this docket?

A. Yes. In addition to my witness qualification statement, I prepared the following exhibits:

- Exhibit Staff/202, PacifiCorp Responses to Staff Data Requests referenced in my testimony.
- Exhibit Staff/203, PacifiCorp Confidential Responses to Staff Data Requests referenced in my testimony.
- Exhibit Staff/204, Staff Analysis UM 1964 PacifiCorp Deferred Accounting for TEC Program.
- Exhibit Staff/205, Staff Analysis UM 2134 PacifiCorp Deferral of Costs Related to Cedar Springs. II

- Exhibit Staff/206, Staff Analysis UM 2142 PacifiCorp Deferred Accounting for Cholla Unit 4 Property Tax Expense.
- Exhibit Staff/207, Staff Analysis Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain.
- Exhibit Staff/208, Staff Analysis UM 2186 Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (TB Flats).
- Exhibit Staff/209, Staff Analysis AWEC Application for PacifiCorp to Defer Fly Ash Revenues.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. What is the change in revenue requirement recommended by Staff?

A. Staff proposes to reduce the Company's requested General Rate Case revenue requirement increase from $84.4 million to $41.6 million.

Q. What areas of PacifiCorp's filing are you primarily responsible for reviewing?

A. I have primary responsibility for reviewing acquisition adjustments, amortization of environmental costs, escalation, income taxes, interest synchronization, taxes other than income, unbundling, and functionalization. To gain additional insight, I reviewed the Company's responses to Staff's Standard Data Requests (SDRs), issued approximately 48 additional data requests (DRs), and reviewed the Company's responses. I also reviewed the responses to pertinent requests issued by other parties in this case.

Q. Are you discussing all of the above issues in opening testimony?

A. No. I discuss only issues for which I am proposing revenue requirement adjustments and the general requirements for review of income taxes and utility plant.

Q. Are additional adjustments for these issues proposed by other Staff?

A. Yes. The Company's filing is complex, and a thorough review can involve multiple Staff looking at each general issue such as plant or labor-related compensation. In particular, individual Staff are reviewing additions to different categories of utility plant (e.g. production, transmission, distribution, etc.) and the effects of escalation on individual accounts.

Q. Please briefly summarize your conclusions regarding these issues.

A. I recommend corrections to the filed case regarding interest synchronization, the OPUC fee rate, and Wyoming Wind Tax. These corrections use the information provided in PacifiCorp's responses to Staff DRs.

I also recommend the Commission adopt three-year amortization of certain outstanding deferrals as included in the filed case, a correction to one of the deferrals therein, and propose, in addition, the Commission approve amortization of two additional deferrals not included in the filed case.

In addition, I recommend an increased provision for non-labor escalation based on the All-Urban CPI, removal of land from rate base which is not used and useful, and officer attestations for several projects projected to be completed prior to the rate effective date.

Q. Please summarize your proposed adjustments.

A. My proposed adjustments are summarized in the following table.

Adjustment - increase (decrease) in thousands	Revenue	Expense	Plant in Service
Issue 1, Interest Synchronization		$ -	
Issue 2, Deferral Amortization		4,555	
Issue 3, Escalation		2,806	
Issue 4, OPUC Fee Rate		686	
Issue 5, Wyoming Wind Tax		(44)	
Issue 6, Carbon and Cholla Land			(1,361)
Issue 7, Blanket Projects			
Issue 8, Attestations			
Total	$ -	$ 8,004	$ (1,361)

My recommendations may change based on further review and based on the testimonies offered by other parties.

OVERALL REVENUE REQUIREMENT

Q. Please provide background on how the Commission reviews a utility's general rate case filing?

A. The rates charged by a utility are based on the utility's "revenue requirement." To determine a utility's revenue requirement, the Commission determines for a specified test year: (1) the utility's forecasted gross revenues; (2) the utility's operating expenses to provide utility service; (3) the rate base on which a return should be earned; and, (4) the rate of return to be applied to the rate base.[1] Once a utility's revenue requirement is established, the Commission determines the rates the utility must charge different classes of customers to collect that revenue requirement, considering the different costs different classes of customers impose on the utility's system.[2]

Q. What is the revenue requirement increase proposed by PacifiCorp in filings currently before the Commission?

A. PacifiCorp proposes an overall increase of $154.4 million or 12.4 percent.[3] This overall increase includes a $70 million increase related to power costs (TAM) and an $84.4 general rate case (GRC) increase. The Company is also proposing a $50.5 million increase relating to excess power costs incurred in 2021.[4] But that value does not affect how the overall percentage change in rates in this UE 399 filing is calculated.

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[1] Order No. 01-787, pp. 5-6.

[2] Order No. 86-477 (1986 WL 1300169).

[3] See PAC/1001. $1,403,274,418 / 1,248,901,150 = 12.4 percent.

[4] See *In the Matter of PACIFICORP, dba PACIFIC POWER, 2021 Power Cost Adjustment Mechanism*, Docket No. UE 404, Filed 5/16/22.

Staff notes that the stated 6.8 percent GRC revenue increase[5] includes power costs in the divisor. Staff calculates the stand alone GRC revenue increase to be 8.8 percent as illustrated in the following summary of the Company's Exhibit 1001.

	TAM	GRC	Total
Adjusted Results (Test Year)	$ 288,535,772	$ 960,365,378	$ 1,248,901,150
Requested Revenue Increase	69,973,978	84,399,290	154,373,268
Results with Price Change	$ 358,509,750	$ 1,044,764,668	$ 1,403,274,418
Component Increase	*24.3%*	*8.8%*	*12.4%*
Requested Revenue Increase	$ 69,973,978	$ 84,399,290	$ 154,373,268
Adjusted Results (Test Year)	$ 1,248,901,150	$ 1,248,901,150	$ 1,248,901,150
*Increase as percent of overall revenue**	*5.6%*	*6.8%*	*12.4%*

**GRC increase as stated in Initial Filing - Exhibit A*

Q. Have the parties agreed to adjust any of the components of the overall $154 million increase?

A. Not currently.

Q. Please summarize Staff's adjustments to the GRC revenue requirement in this case.

A. Staff propose to reduce the Company's revenue requirement by an additional $42.8 million. The specific rate case topics, responsible Staff, and proposed changes in revenue requirement are summarized in the following table:

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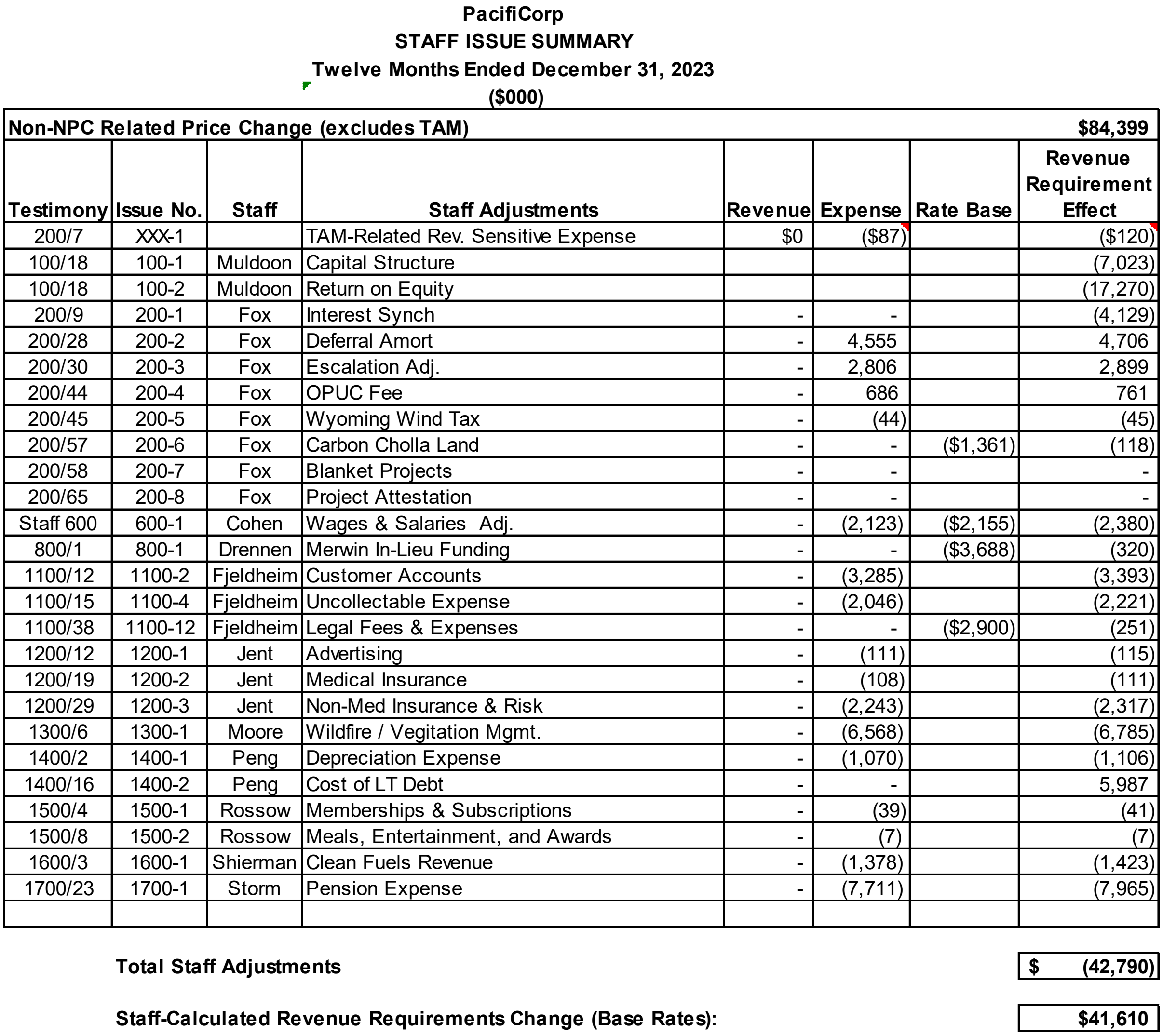
[5] See initial filing Exhibit A Summary of Requested Electric General Rate Increase.



PacifiCorp
STAFF ISSUE SUMMARY
Twelve Months Ended December 31, 2023
($000)

Non-NPC Related Price Change (excludes TAM)							**$84,399**
Testimony	**Issue No.**	**Staff**	**Staff Adjustments**	**Revenue**	**Expense**	**Rate Base**	**Revenue Requirement Effect**
200/7	XXX-1		TAM-Related Rev. Sensitive Expense	$0	($87)		($120)
100/18	100-1	Muldoon	Capital Structure				(7,023)
100/18	100-2	Muldoon	Return on Equity				(17,270)
200/9	200-1	Fox	Interest Synch	-	-		(4,129)
200/28	200-2	Fox	Deferral Amort	-	4,555		4,706
200/30	200-3	Fox	Escalation Adj.	-	2,806		2,899
200/44	200-4	Fox	OPUC Fee	-	686		761
200/45	200-5	Fox	Wyoming Wind Tax	-	(44)		(45)
200/57	200-6	Fox	Carbon Cholla Land	-	-	($1,361)	(118)
200/58	200-7	Fox	Blanket Projects	-	-		-
200/65	200-8	Fox	Project Attestation	-	-		-
Staff 600	600-1	Cohen	Wages & Salaries Adj.	-	(2,123)	($2,155)	(2,380)
800/1	800-1	Drennen	Merwin In-Lieu Funding	-	-	($3,688)	(320)
1100/12	1100-2	Fjeldheim	Customer Accounts	-	(3,285)		(3,393)
1100/15	1100-4	Fjeldheim	Uncollectable Expense	-	(2,046)		(2,221)
1100/38	1100-12	Fjeldheim	Legal Fees & Expenses	-	-	($2,900)	(251)
1200/12	1200-1	Jent	Advertising	-	(111)		(115)
1200/19	1200-2	Jent	Medical Insurance	-	(108)		(111)
1200/29	1200-3	Jent	Non-Med Insurance & Risk	-	(2,243)		(2,317)
1300/6	1300-1	Moore	Wildfire / Vegitation Mgmt.	-	(6,568)		(6,785)
1400/2	1400-1	Peng	Depreciation Expense	-	(1,070)		(1,106)
1400/16	1400-2	Peng	Cost of LT Debt	-	-		5,987
1500/4	1500-1	Rossow	Memberships & Subscriptions	-	(39)		(41)
1500/8	1500-2	Rossow	Meals, Entertainment, and Awards	-	(7)		(7)
1600/3	1600-1	Shierman	Clean Fuels Revenue	-	(1,378)		(1,423)
1700/23	1700-1	Storm	Pension Expense	-	(7,711)		(7,965)

Total Staff Adjustments	**$ (42,790)**
Staff-Calculated Revenue Requirements Change (Base Rates):	**$41,610**

Q. Please explain the TAM-related revenue sensitive cost adjustment.

A. Revenue sensitive costs include Uncollectibles, Franchise Fees, Resource Supplier Fees, and OPUC Fees. TAM-Related Revenue Sensitive Costs may only be adjusted during a general rate case. For TAM dockets that occur between rate cases the revenue sensitive costs do not change. In this case, PacifiCorp has forecasted the TAM price change to be an increase of

$69,973,978.[6] Staff's analysis of the Company's revenue sensitive factors is further discussed below.

Q. What does Staff recommend regarding the TAM adjustment for opening testimony?

A. Staff recommends delaying final adjustment[7] and truing up the TAM revenue sensitive adjustment once both the TAM revenues in UE 400 are determined and parties to UE 399 have settled the revenue sensitive factors in this docket.

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[6] PAC/1001, Cheung/3.

[7]. Staff's opening testimony adjusts for the effects of changes in the OPUC fee rate and Staff's proposed update for the uncollectable account rate.

ISSUE 1, INTEREST SYNCHRONIZATION

Q. Please explain the interest synchronization adjustment.

A. According to long-standing Commission policy, for ratemaking purposes, Staff routinely synchronizes interest expense to reflect changes in the regulated utility's cost of capital as initially filed in a general rate case. Accordingly, the interest synchronization adjustment depends on proposed adjustments to cost of capital (CoC) in this docket. Because interest expense on long-term debt is tax deductible, the proposed cost of long-term debt impacts income tax expense for ratemaking purposes.

Q. Please discuss Staff's review of interest expense in the Company's initial filing.

A. Staff's review noted an adjustment to the Company's initial filing may be necessary in addition to the customary rate case adjustments. In response to Staff DR, PacifiCorp agreed and states that correcting the interest expense calculation results in a reduction to revenue requirement of approximately $1.27 million.[8]

Q. What does Staff recommend?

A. Staff recommends the Commission adopt the Company's proposed adjustment.

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[8] OPUC 157.pdf

ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Q. What is an acquisition adjustment?

A. An acquisition adjustment describes the difference between the price an acquiring company pays to purchase a target company and the net original cost of the target utility company's assets. An acquisition adjustment is a premium paid for acquiring a company for more than its tangible assets or book value.[9]

Q. Please summarize the Company's filing.

A. PAC/1000, Cheung/34-35 discusses amortization of regulatory assets and liabilities.

PAC/1002, Cheung/3, shows that electric plant in service includes a net acquisition adjustment of $701 thousand.

PAC/1002, Cheung/242 provides the details regarding the amortization calculation.

Q. What is the Commission's standard for review?

A. Other Rate Base items require explicit Commission approval. Amounts for Other Rate Base items may include regulatory assets (Accounts 182, 186) and liabilities (Account 254) and acquisition adjustments (Accounts 114 and 115).

ORS 757.480 provides that approval is needed prior to disposal, mortgage or encumbrance of certain operative utility property, or consolidation with another public utility.

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[9] https://www.investopedia.com/termhj,.m,.ns/a/acquisition-adjustment.asp, accessed May 14, 2020.

Q. What is included in the definition of FERC Account 114?

A. Definition of Account 114 Electric plant acquisition adjustments.[10]

> This account shall include the difference between (1) the cost to the accounting utility of electric plant acquired as an operating unit or system by purchase, merger, consolidation, liquidation, or otherwise, and (2) the original cost, estimated, if not known, of such property, less the amount or amounts credited by the accounting utility at the time of acquisition to accumulated provisions for depreciation and amortization and contributions in aid of construction with respect to such property.

Q. Please discuss Staff's review of this account.

A. Staff review indicates that amortization expense decreased from $398,463 per month, system-wide, in the UE 374 case[11] to $6,279 per month, system-wide, in this case[12] and that the Company's adjustment reduces capitalized adjustments and accumulated amortization by $141 million dollars.[13]

The Company's response to Staff DR 280 indicates that the Craig/Hayden acquisition adjustments were fully amortized prior to the 2023 test year.[14] The Company provided details of the amortization expense adjustment in response to Staff DR 279.[15] These responses fully explain the

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[10] 18 CFR Part 101 - UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT, Balance Sheet Chart of Accounts.

[11] UE 374, PAC/1302, McCoy/232.

[12] PAC/1002, Cheung/242.

[13] Id.

[14] OPUC 280.pdf.

[15] OPUC 279.pdf, OPUC 279 Attach.xlsx.

rate base and amortization expense adjustments included by the Company in the case.

Q. Is Staff recommending further adjustment of these accounts?

A. No.

CONSOLIDATED DEFERRALS

Q. Please summarize the Company's filing.

A. The Company proposes to address six pending deferral dockets in its initial filing (Pac/100, Steward/14). On March 22, 2022, PacifiCorp filed a motion to consolidate Docket UE 399 with Dockets UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, and UM 2186, which was granted by the Administrative Law Judge (ALJ) on April 11, 2022. One of these, UM 2185, Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans, relates to pensions and is assigned to another analyst.[16] Regarding the other five, the Company proposes three-year amortization across the board as per the following testimony pages:

- UM 1964, Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program. (Cheung, 1000/34).
- UM 2134, Application to Defer Costs Relating to Cedar Springs II (Cheung, 1002/274).
- UM 2142, Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (Cheung, 1002/269).

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[16] UM 2185 is included in the earnings test discussion below.

- UM 2167, Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain (Cheung, 1000/34).
- UM 2186, Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120, which Staff notes is related to the TB Flats wind project (Cheung, 1002/274).

Q. Were additional deferrals consolidated into the case subsequent to the initial filing?

A. Yes. On April 11, 2022, the Administrative Law Judge (ALJ) ruled on pending motions to consolidate and added the following dockets to the list of dockets consolidated with UE 399 as the lead docket.

- UM 2063, Application for Deferred Accounting of Costs Associated with the COVID-19 Public Health Emergency.
- UM 2201, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues.

Q. Was there a motion to consolidate yet another deferral that was denied by the ALJ on the same date?

A. Yes. Consolidation of the following docket was denied.

- UM 2220, Application for Approval of Deferred Accounting for Operating Costs and Capital Investments Made to Implement PacifiCorp's Distribution System Plan.

Q. Returning now to the initial filing, please summarize the Company's amortization proposals.

A. For the five deferrals included in the initial filing[17], the Company proposes amortization of three years across the board, further discussed as issue 2 below.

Q. Please discuss Staff's overall approach to analyzing the Company's proposal.

A. The Commission typically considers deferral applications and related tariffs as separate public meeting (PM) agenda items supported by a Staff report (PM memo). The Commission has already approved deferrals for Dockets UM 2142 and 2063 for at least one twelve-month period and has yet to act upon the remaining consolidated dockets.

As the Commission and parties are familiar with deferral analysis and the PM memo format, Staff provides a similar analysis for each docket in Exhibits 204 to 209. The overall deferrals, amortization proposals, and application of an earnings test are discussed below.

Q. Please summarize Staff's recommendations regarding approval of the deferrals.

A. Staff recommends the Commission approve the deferral applications for UM 1964, UM 2134, UM 2167, UM 2186, and UM 2201.

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[17] Not including UM 2185 as discussed above. Staff notes that the UM 2185 deferral is fundamentally different as the Company proposes to amortize over the life of remaining plan participants not three years. PAC/200, Kobliha/31.

Q. How accurate are the various deferral amounts?

A. Regarding the five deferrals addressed in opening testimony, Staff has reviewed the Company's calculations and recommends the Commission approve the December 31, 2022, balances as prudent, subject to amortization, and the balances moved to the Modified Blended Treasury (MBT) rate, excepting the Cedar Springs deferral, UM 2142, for which Staff recommends a balance of $609 thousand rather than the $748 thousand proposed by the Company.[18]

Q. Why does Staff recommend a different amount for Cedar Springs?

A. Referring to PAC Exhibit 1002, Cheung/276, the "Dec 2020 Pre-Tax-Return" line divides the annual pre-tax return by 12. Based on the in-service date, Staff believes this ought to be 23 days rather than an entire month. Therefore, the deferral is overstated.

Q. What is the deferred amount Staff recommends to be amortized at this time for Docket UM 2063 (COVID-19)?

A. Staff recommends amortization amounts deferred 2020 and 2021 amounts of $17,010,221, a reduction of $376,593 to the Company's listed UM 2063 balance as of the end of 2021.

Q. What is the deferred amount Staff recommends to be amortized at this time for Docket UM 2201 Fly Ash?

A. Staff recommends the net annual revenue cited in the initial application, $3.1 million multiplied by 425/365 to account for a deferral period between

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[18] PAC/1002, Cheung/275.

November 2, 2021, and December 31, 2022.[19] As the deferral is proposed by the Alliance of Western Energy Consumers (AWEC) rather than PacifiCorp, Staff invites the Company to provide updated figures based on actual revenues in reply testimony.

Q. Please discuss Staff's conclusions regarding prudence of the deferred amounts.

A. Regarding Dockets UM 1964, 2134, 2142, 2167, and 2186, the economic transactions underlying the deferred amounts have been vetted in prior Commission dockets. Based on review of the filing in this case, Staff has not identified any additional information which would cause Staff to question the prudence of the deferred amounts.

Regarding UM 2201, Staff recommends the Commission find the return of excess fly ash revenues to customers to be prudent.

Regarding UM 2063, Staff finds reason to disallow some costs related to the Company's Arrearage Management Program (AMP).

Q. What is the total balance of UM 2063 as of December 2021?

A. The following table contains the Company's listed balance of UM 2063.

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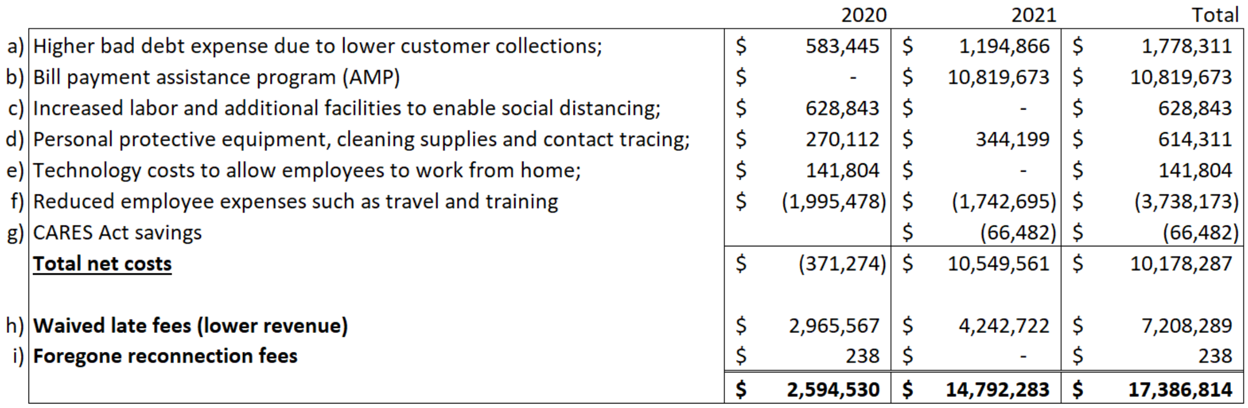
[19] See *In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS, Application for an Accounting Order* Requiring *PacifiCorp to Defer Fly Ash Revenues,* Docket No. UM 2201, Filed Nov 2, 2021, at 4.



		2020	2021	Total
a)	Higher bad debt expense due to lower customer collections;	$ 583,445	$ 1,194,866	$ 1,778,311
b)	Bill payment assistance program (AMP)	$ -	$ 10,819,673	$ 10,819,673
c)	Increased labor and additional facilities to enable social distancing;	$ 628,843	$ -	$ 628,843
d)	Personal protective equipment, cleaning supplies and contact tracing;	$ 270,112	$ 344,199	$ 614,311
e)	Technology costs to allow employees to work from home;	$ 141,804	$ -	$ 141,804
f)	Reduced employee expenses such as travel and training	$ (1,995,478)	$ (1,742,695)	$ (3,738,173)
g)	CARES Act savings		$ (66,482)	$ (66,482)
	Total net costs	$ (371,274)	$ 10,549,561	$ 10,178,287
h)	**Waived late fees (lower revenue)**	$ 2,965,567	$ 4,242,722	$ 7,208,289
i)	**Foregone reconnection fees**	$ 238	$ -	$ 238
		$ 2,594,530	**$ 14,792,283**	**$ 17,386,814**

Q. Why does Staff believe that some of the costs of the Company's AMP should not be deemed prudent?

A. Staff has concerns that there are some customers receiving AMP funds that are not receiving funds for truly residential purposes. Staff concern is rooted in the lack of effort the Company has made to ensure that high-usage residential customers receiving AMP funds are indeed residential customers.

Q. Why would customers under a residential schedule not actually be residential customers?

A. There are a variety of reasons why a household under a residential schedule may not truly be a residential customer. A residential customer meter may be used to power an at-home business or an energy-intensive agricultural crop and not be identified as a commercial customer. The Company's Oregon territory is largely in southern Oregon, where there have been notable problems with illegal agricultural operations.[20] Dr. Curtis Dlouhy brings up this

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[20] https://www.opb.org/article/2021/12/16/oregon-illegal-cannabis-farms-marijuana-grows-state-legislature-relief/.

same concern in his testimony when discussing the Company's proposed changes to the Residential Exchange Program.

Q. Why are you concerned that the Company's AMP funds are going to these sources?

A. Dr. Curtis Dlouhy asked what measures the Company has taken to ensure that AMP recipients consuming above 10,000 kWh on a bill are indeed residential customers in Staff DR 442. While it is possible for a residential household to consume this much electricity, the Company has also stated that it is unlikely in response to Staff DR 154. The Company goes on to say that these exceptionally high bills are likely due to large homes, faulty equipment, heated swimming pools, or indoor grow lights.[21]

Staff believes that an AMP recipient is unlikely to have exceptionally large homes or heated swimming pools, and thus believes that indoor grow lights could be a leading contributor to these high bills that receive AMP funds. However, Staff's concern would have been mitigated if the Company followed up with these high-usage customers to verify that they indeed should qualify for AMP funding and are not using it to subsidize any unsanctioned activities. In response to Staff DR 442, the Company states:

> The Company limits its Arrearage Management Program (AMP) participation to residential customers by reviewing an applicant's

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[21] Response to Staff DR 154.

revenue class at the time of issuing a grant – which is based on arrears without a differentiation for consumption.[22]

Put another way, the Company has made no efforts to follow up on these high-usage customers. Staff is concerned that AMP funds directed towards these exceptionally high bills subsidizes unsanctioned growing operations or other at-home businesses that may be better suited for a different rate schedule.

Q. How big are some of these bills and how many AMP recipients have experienced exceptionally high bills?

A. In response to Staff DR 427, it appears that the Company has provided AMP assistance to a customer that consumed 24,375 kWh on a single bill. In 2021, there were 255 bills with consumption over 10,000 kWh that received AMP assistance.[23]

Q. What do you recommend be done in response to this concern?

A. Staff recommends that any AMP funds directed towards bills of over 10,000 kWh be deemed imprudent based on the Company's inadequate measures to ensure that the customers are indeed residential, and that the electricity is not being directed towards unsanctioned growing operations. Although a 10,000-kWh bill threshold is exceptionally high for a residential customer and the same concern could exist for smaller bills, Staff chose this

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[22] Response to Staff DR 442.

[23] Response to Staff DR 427.

threshold to mitigate the probability that any AMP funds are improperly deemed imprudent.

Q. What is the effect of withholding recovery of AMP funds directed towards bills over 10,000 kWh?

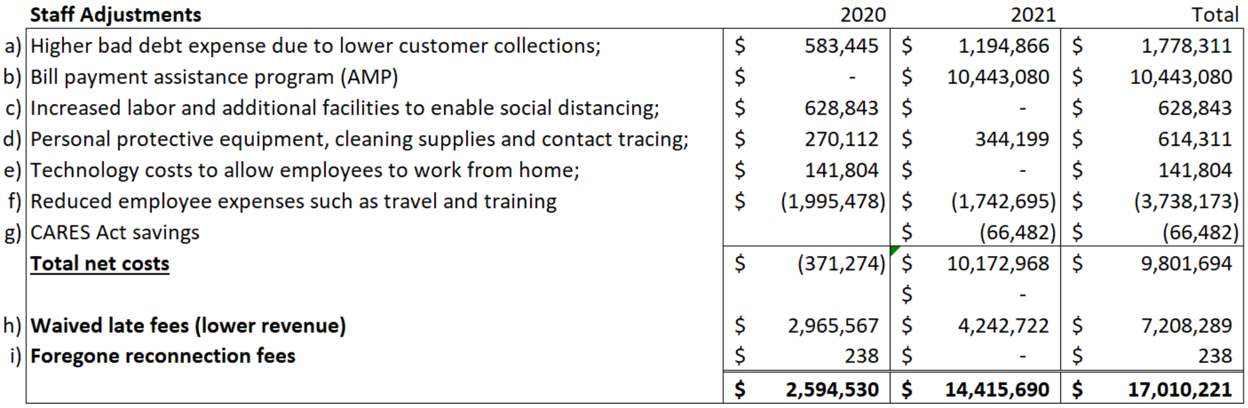
A. Using the Company's response to Staff DR 427[24], withholding these 255 bills results in a reduction of $376,593 to the UM 2063 balance.

Q. Does Staff have any other concerns about the prudence of UM 2063?

A. Not currently.

Q. What is the total value of the UM 2063 through 2021 after Staff's adjustment to the AMP?

A. The following table contains the balance of the UM 2063 after Staff's adjustment.



	Staff Adjustments	2020	2021	Total
a)	Higher bad debt expense due to lower customer collections;	$ 583,445	$ 1,194,866	$ 1,778,311
b)	Bill payment assistance program (AMP)	$ -	$ 10,443,080	$ 10,443,080
c)	Increased labor and additional facilities to enable social distancing;	$ 628,843	$ -	$ 628,843
d)	Personal protective equipment, cleaning supplies and contact tracing;	$ 270,112	$ 344,199	$ 614,311
e)	Technology costs to allow employees to work from home;	$ 141,804	$ -	$ 141,804
f)	Reduced employee expenses such as travel and training	$ (1,995,478)	$ (1,742,695)	$ (3,738,173)
g)	CARES Act savings		$ (66,482)	$ (66,482)
	Total net costs	$ (371,274)	$ 10,172,968	$ 9,801,694
			$ -	
h)	**Waived late fees (lower revenue)**	$ 2,965,567	$ 4,242,722	$ 7,208,289
i)	**Foregone reconnection fees**	$ 238	$ -	$ 238
		$ 2,594,530	**$ 14,415,690**	**$ 17,010,221**

Q. Please discuss the requirement for an earnings review prior to amortization.

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[24] Additional data regarding 2020 was provided in response to DR 530. Staff is reviewing this information and may propose additional adjustments in rebuttal testimony.

A. ORS 757.259(5) states that unless subject to an automatic adjustment clause, amounts deferred under ORS 757.259 shall be allowed in rates only to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates, and upon review of the utility's earnings at the time of application, to amortize the deferral. The earnings test need not be used to affect the amount to be recovered or returned to ratepayers. How the earnings test is applied is on a case-by-case basis to further the specific purpose of the deferral on consideration of relevant factors.[25]

The Commission may require that amortization of deferred amounts be subject to refund. The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility.

Q. Does Staff have all the information necessary to conduct an earnings review pursuant to ORS 757.259(5)?

A. Mostly. The deferrals Staff recommend for amortization involve years between 2017 and 2021 with the exception of the UM 2201 fly ash deferral which is for the period November 2, 2021, forward. The Company has filed its results of operations for the years 2017 through 2021. As the fly ash deferral involves a refund to customers, Staff recommends the parties agree not to wait for 2022

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[25] See *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision*, Docket No. UE 394, Order No. 22-129, at 44; *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL Mechanism for Recovery of Environmental Remediation Costs*, Docket No. 1635, Order No. 15-049, at 17; and *In the Matter of the Revised Tariff Sheets Filed by PORTLAND GENERAL ELECTRIC COMPANY to Implement the Provision of Order No. 91-1781*, Docket No. UE 82, Order No. 93-257, at 11.

results in favor of amortizing an estimated amount through December 31, 2022, in this case.

Q. Does Staff also recommend estimation and amortization of the UM 2063 COVID-19 deferrals for 2022?

A. No. Ongoing COVID deferrals are not as stable as fly ash revenues. Staff recommends amortization of the deferred COVID amounts for 2020 and 2021 in this case. Accordingly, Staff notes that additional proceedings in the UM 2063 docket will be necessary to resolved amounts deferred in 2022 and beyond.

Q. Please discuss Staff's proposed earnings thresholds for COVID-19 amounts deferred in 2020 and 2021.

A. Staff proposes the following earnings thresholds for the following elements identified and discussed in the testimony of Dr. Curtis Dlouhy:

- Category (a), UM 2114 Stipulation, Paragraph 25[26]: Authorized ROE (9.50 percent) less 50 basis points or nine percent.
- Category (b) through (f): Staff proposes full recovery of these amounts.

Q. Why does Staff propose authorized ROE less 50 basis points for item a?

A. The Commission has clarified that "the earnings test, coupled with deferral and amortization, is designed to ensure that utilities do not receive the extraordinary relief of retroactive rate making for added costs

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[26] See *In the Matter of Investigation into the Effects of the COVID-19 Pandemic on Utility Customers*, Docket UM 2114, Order No. 20-401, Appendix A at 19 (November 5, 2020).

when earnings exceed a reasonable rate of return."[27] What is a reasonable rate of return for purposes of the earnings review depends on the nature of the deferral.[28] Unlike the amounts at issue for deferral items (b) through (f) in the UM 2114 Stipulation, the amounts deferred for category (a) are simply changes in revenues and costs PacifiCorp experienced during the pandemic. PacifiCorp's experience in this regard was not unique and many business owners suffered the same impacts.

The shift to remote work arrangements and other measures to adjust business processes due to the COVID-19 pandemic were borne by all organizations in the economy. Although Staff concludes the amounts deferred for Item (a) are recoverable, Staff sees no reason PacifiCorp should be allowed to completely avoid the negative impacts of Covid-19 with an earnings test benchmark that would allow it to pass these negative impacts on to ratepayers, up to the point PacifiCorp earns its authorized rate of return. Staff notes this approach is consistent with the Commission's recent finding that the 2020 wildfires and 2021 ice storm were significant and unprecedented events and customers should not absorb all the risk associated with operations in challenging circumstances.[29]

In Staff's view, an earnings test threshold set at AROE minus 50 basis points is a reasonable benchmark that would allow PacifiCorp to amortize

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[27] See *In re Portland General* Electric *Co*., Docket No. UE 82, Order No. 93-257 (February 22, 1993).

[28] Id*.*

[29] Order No. 22-129 at 53.

deferred net costs categorized as Item (a) up to a rate of return that is reasonable for a period during which many people and business suffered negative economic consequences of a pandemic.

Q. Why does Staff propose full recovery for items (b) through (f)?

A. At the outset of the pandemic the Commission and stakeholders initiated an extensive public process to mitigate the effect of the COVID-19 pandemic on utility customers. In Staff's view, items (b) though (f) ought to be recovered in full as they are specific extraordinary measures agreed upon by the utilities and stakeholders and approved by the Commission to mitigate the pandemic impact.

Q. Please discuss Staff's proposed earnings thresholds for UM 1964, UM 2134, UM 2142, UM 2167, UM 2186, and UM 2201.

A. For 2021, Staff proposes the Company's UE 374 approved ROE of 9.5 percent with no further adjustment or sharing mechanism.

For 2017-2020, Staff proposes the Company's UE 263 approved ROE of 9.8 percent with no further adjustment or sharing mechanism.

Q. Please discuss Staff's review of PacifiCorp's earnings using the thresholds discussed above.

A. The following table summarizes the Company's earnings, after Type 1, adjustments[30], as reported annually in Docket No. RE 56.

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[30] Type 1 adjustments include: Normalizing for weather, stream-flows, and plant availability; incorporating significant rate making adjustments adopted in the most recent Oregon rate order if not reflected on the books (for example, advertising, memberships, payroll escalation, bonuses, and nonoperating expenses); and, removing entries relating to prior period activity, and including subsequent period transactions clearly related to the test period. Examples

	2017	2018	2019	2020	2021
Pacific Power					
Authorized ROE @ Dec 31	9.800%	9.800%	9.800%	9.800%	9.500%
Reported Results Docket No. RE 56:					
Unadjusted	12.233%	9.586%	10.005%	10.649%	5.551%
w/ Type 1 Adj.	10.016%	9.493%	9.613%	8.056%	5.600%
Type 1 variance from Authorized	0.216%	-0.307%	-0.187%	-1.744%	-3.900%

For 2020 and 2021, actual ROE, after Type 1 adjustments, is more than 50bp less than the Company's authorized ROE.

For 2018 through 2020, actual ROE, after Type 1 adjustments, is less than the Company's authorized ROE.

Accordingly, Staff concludes no sharing is necessary for 2018 through 2020. Furthermore, deferred amounts for 2017 only occurred in UM 1964 which is a balancing account, therefore no sharing is necessary for that year either even though PacifiCorp's earnings are above its authorized ROE.

Q. Please summarize Staff's recommendations regarding the consolidated deferrals.

A. Staff recommends the Commission approve the deferral applications for Docket Nos. UM 1964, UM 2134, UM 2167, UM 2186, and UM 2201.

As further discussed in Issue 2 below, Staff recommends amortization of these deferrals beginning January 1, 2023, along with deferrals previously approved by the Commission in Docket Nos. UM 2142 and 2063.

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include corrections of estimates or error, and removal of credits or charges associated with other periods. These earnings levels do not recognize the expenses associated with the deferrals so that if the Type ROE is less than authorized, then recognizing the expense and matching it with revenue will not cause the Type 1 ROE value to change.

Staff also recommends the Commission find the deferred amounts to be prudently incurred and that amortization of these amounts do not cause the Company to over earn in the deferral period.

ISSUE 2, DEFERRAL AMORTIZATION

Q. Please summarize the Company's proposed amortization of deferred amounts.

A. PacifiCorp proposes three-year amortization, beginning January 1, 2023, of the deferrals in Docket Nos. UM 1964, UM 2134, UM 2142, UM 2167, and UM 2186. As noted above, amounts deferred in Docket No. UM 1985 are related to pension expense and are further discussed by Staff witness Mr. Steve Storm.

The Company's annual amortization proposal, excluding UM 2185, is summarized in the following table.

Deferral Docket	Deferral Details	December 2022 Balance	Amortization Period	Annual Amortization	Interest Rate
UM 1964 Trans. Electrification	Cheung, 1002/245	$ 2,839,892	3 years	$ 974,165	1.82%
UM 2134 Cedar Springs 2	Cheung, 1002/275	$ 748,136	3 years	$ 256,632	1.82%
UM 2142 Cholla Taxes	Cheung, 1002/272	$ 639,589	3 years	$ 219,065	1.82%
UM 2167 Prior Mtn. REC's	Cheung, 1002/246	[redacted]	[redacted]	[redacted] [redacted]	[redacted]
UM 2186 TB Flats	Cheung, 1002/278	$17,900,662	3 years	$ 6,140,445	1.82%
Proposed Amortization				$ 7,465,401	

Q. Are these amounts proposed for amortization in base rates?

A. Yes. The amortized amounts flow through the base rate revenue requirement.

Q. What is Staff's recommendation regarding these deferrals and the two deferrals consolidated after the initial filing, Docket Nos. UM 2063 and UM 2201?

A. Absent the sizable rate changes that are likely given the multiple PacifiCorp filings before the OPUC, Staff would recommend amortization over a shorter period, two years beginning January 1, 2023. Given the substantive rate changes that are facing customers, Staff may support the PacifiCorp proposed three-year amortization period. Staff's annual amortization proposal, excluding UM 2185, is summarized in the following table:

Deferral Docket	December 2022 Balance	Amortization Period	Annual Amortization	Interest Rate
UM 1964 Trans. Electrification	$ 2,839,892	3 years	$ 974,165	1.82%
UM 2134 Cedar Springs 2	$ 609,342	3 years	$ 208,705	1.82%
UM 2142 Cholla Taxes	$ 639,589	3 years	$ 219,065	1.82%
UM 2167 Prior Mtn. REC's	$ [redacted]	[redacted]	[redacted] [redacted]	[redacted]
UM 2186 TB Flats	$ 17,900,662	3 years	$ 6,140,445	1.82%
UM 2063 COVID-19	$ 17,010,221	3 years	$ 5,826,155	1.82%
UM 2201 Fly Ash	$ (3,570,321)	3 years	$ (1,222,867)	1.82%
Proposed Amortization			$ 12,020,761	

Q. Does Staff recommend recovery in base rate tariffs?

A. No. Staff recommends recovery as separate rate adjustment schedule so recovery can be easily discontinued at the end of the three-year amortization period.

Q. Please discuss the requirement that deferrals not exceed three percent of revenue.

A. ORS 757.259(6) states that the overall average rate impact of the amortizations authorized under this section in any one year may not exceed three percent of the utility's gross revenues for the preceding calendar year. The three-year amortization period does not result in the three percent limit to come into effect.

ISSUE 3, ESCALATION

Q. Please provide a summary of the Commission's historical treatment of escalation and the latest available information.

A. The Commission has a long history of express reliance on the All-Urban CPI (CPI-U) in its determination of wages and salaries[31] and Staff uses it almost invariably to escalate costs in a general rate case. As the Commission has noted, "the All-Urban CPI measures price changes in a fixed market basket of goods and services in 200 categories, generally including housing, apparel, transportation, medical care, recreation, education, and others to urban consumers."[32] "Local economic conditions are represented in the All-Urban CPI, as the Bureau of Labor Statistics includes prices in Oregon when it conducts its survey."[33]

The most recent release of the All-Urban CPI was the June 2022 report, released May 18, 2022. According to Appendix A of this report, the percentage change for U.S. All-Urban CPI for 2021, 2022, and 2023 are 4.7 percent, 6.1 percent, and 2.6 percent, respectively.[34]

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[31] *See e.g., In the Matter of Portland General Electric Company Request for a General Rate Revision,* Docket No. UE 197, Order No. 09-020, p. (January 22, 2009) (Commission using All-Urban CPI to escalate wages and salaries); *In the Matter of Northwest Natural Request for a General Rate Revision*, Docket No. UG 132, Order No. 99-697, p. 37 (November 12, 1999) (Same).

[32] Northwest *Natural,* Docket No. UG 132, Order 99-697, p. 37, n10.

[33] Ibid*,* p. 38.

[34] Oregon Office of Economic Analysis, *Oregon Economic and Revenue Forecast*, June 2022, Appendix A, page 40.

Q. Regarding PacifiCorp specifically, what escalation methodology was approved in the Company's most recent rate case?

A. In UE 374, Staff recommended using the All-Urban CPI as published by the State of Oregon Office of Economic Analysis for year over year escalation of expenses rather than the escalation factors used by the company. PacifiCorp based its test-year level of expense for non-labor costs using inflation indices provided by IHS Markit (previously Global Insight).[35] Regarding methodology, the Commission noted:

> PacifiCorp's testimony explains that the company based its test-year level of expense using industry-specific inflation forecasts. The company provided testimony that the indices are prepared at the account level, based on FERC's Uniform System of Accounts for major electric utilities, based solely on electric utility costs for materials and services, which allows electric utilities to escalate very specific costs by appropriate measures.[36]

Further stating that,

> Staff did not address why use of the All-Urban CPI index was more appropriate than these industry-specific indices. Accordingly, we decline to adopt Staff's recommendation.[37]

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[35] See *In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision, Docket No. UE 374*, Order No. 20-473, Dec 18, 2020, at 110.

[36] Id. at 111.

[37] Id*.*

Q. What methodology is the Company using in this filing?

A. PacifiCorp states that it is using the same methodology consistent with UE 374 and prior rate case filings.[38]

Q. Are the escalation methods proposed in initial rate case filings prior to UE 374 relevant?

A. Not necessarily. The three most recent cases involved negotiated settlements that did not call out the basis for the escalation adjustment.[39] Accordingly, if the final rates in those cases reflect a consistent methodology that ought to be dispositive in misguided.

Q. Please summarize the Company's escalation calculations.

A. Exhibit PAC/1005 provides the IHS Markit Escalation Indices **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

These figures are carried forward to Adjustment 4.10, which applies the specific operations and maintenance escalation rates for the various ranges of FERC accounts (e.g. production, distribution, A&G, etc.).

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[38] PAC/1000, Cheung/22.

[39] See *In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision*, Docket No. UE 217, Order No.10-473, at 4; and *In the Matter of PACIFICORP, dba PACIFIC POWER Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493, Appendix A, at 14; and *In the Matter of PACIFICORP, dba PACIFIC POWER, ORDER Request for a General Rate Revision*, Docket No. UE 263, Order No. 13-474, Appendix A, at 18.

Q. Does Staff continue to advocate for using the CPI-U rates? If so, why?

A. Yes. First, the All-Urban CPI rates are more transparent and have a long history going back to the 1970s for CPI-U and roots back as far as 1919 when the Bureau of Labor Statistics began publishing price indexes.[40] Conversely, the IHS Markit indices are "proprietary and subject to copyright protection"[41] Staff recommends the use of information sources that are fully available to the public rather than opaque, privately controlled ones. The publicly available sources can be verified, but the proprietary sources cannot be analyzed and directly compared to the components of the widely used CPI rate.

Second, Staff supports having a consistent policy regarding escalation across the six investor-owned utilities. As noted above, the Commission has a long history of using the All-Urban CPI for escalation in general rate cases.

Q. Please discuss escalation adjustments in recent rate cases for other five Oregon investor owned utilities (IOU).

A. Avista Utilities current rates reflect application of the All-Urban CPI for several expense items.[42] Regarding Avista's currently pending rate case, escalation is part of a proposed black box settlement and the rate being used is, accordingly, indeterminate.[43]

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[40] *United* States *Consumer Price Index, History*, https://en.wikipedia.org/wiki/United_States_Consumer_Price_Index#CPI_for_all_urban_consumers_(CPI-U), accessed 5/20/22.

[41] PAC/1000, Cheung, 23.

[42] See *In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, Request for a General Rate Revision*, Docket No. UG 389, Order No. 20-468, at 5.

[43] See *Stipulating Parties' Second Settlement Stipulation Resolving All Remaining Issues,* Docket No. UG 433, Filed 3/18/2022, at 2-3.

Northwest Natural's current rates reflects compromises between the West Region CPI, as advocated by the Company, and the All-Urban CPI advocated by staff.[44] Regarding NW Natural's currently pending rate case, Staff notes that the recently filed stipulation in that case adjusts to the All-Urban CPI.[45]

Regarding the remaining three IOU,[46] current rates reflect O&M expense settlements which do not speak specifically to the CPI rate being used.[47]

Q. Has Staff estimated what the escalation would be using the U.S. All-Urban CPI?

A. Yes, the published rates are semi-annual and annual averages, Staff calculations yield 10.65 percent increase[48] over the same June 2021 to December 2023 time period used by the Company to apply the IHS market indexes. By replacing the escalation figures in the Company's model with 10.65 percent, Staff estimates that using CPI-U would increase the escalation adjustment by $2.8 million on an Oregon allocate basis.

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[44] See *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, Docket No. UG-388, Order No. 20-364, at 5, 9, and 11.

[45] See *Multi-Party Stipulation Regarding Revenue Requirement, Rate Spread And Certain Other Issues*, Docket No. UG-435, Filed 5/31/2022, at 3.

[46] Cascade Natural Gas, Idaho Power Company, and Portland General Electric Company.

[47] See *In the Matter of CASCADE NATURAL GAS CORPORATION, Request for a General Rate Revision,* Docket No. UG 390, Order No. 21-001, at 9; *In the Matter of IDAHO POWER COMPANY Request for a General Rate Revision*, Docket No. UE 233, Appendix A, at 15; and *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision, Docket No. UE 394*, Order No. 22-129, Appendix C, at 3.

[48] Using the published indices for 2021, 2023, and 2024, Staff estimates the December 2023 index to be 299.85 (296.7+303.0 divided by 2). Divided by the 2021 index, 299.85 / 271.0 = 10.65% increase.

Q. What does Staff recommend?

A. Staff recommends the Commission approve escalation in this case based on the higher CPI-U rate and approve an increase in expense of $2.8 million.

INCOME TAXES

Q. Please summarize the Company's filing related to income taxes.

A. Due to the detailed nature of the Company's filing, income tax calculations are embedded throughout. The following is a list of the most important sections of PacifiCorp testimony that include tax calculations:

- PAC/1000, Cheung/29-32: Narrative description of tax adjustments necessary to arrive at normalized results.
- PAC/1002, Cheung/7-8: Calculation of incremental tax on price change for requested rate of return, net to gross factor, and effective income tax rate as a percentage of net operating income.
- PAC/1002, Cheung/12: Summary of rate case parameters including tax rate assumptions.
- PAC/1002, Cheung/173-192 (tab 7): Tax adjustment work papers. The index on page 173 is particularly useful as it cross references to tax adjustments embedded in other work papers.
- PAC/1002, Cheung/190-192: Calculation of the Oregon Corporate Activity Tax (OCAT) and Metro Supportive Housing Services (MSHS) Tax which the Company proposes to move into base rates.

Q. What are the requirements of Oregon law regarding the inclusion of income taxes in utility rates?

A. Income taxes in utility rates are subject to the requirements of ORS 757.269.

> **757.269 Setting of rates based upon income taxes paid by utility; limitation on use of tax information; rules.** (1)

> When establishing schedules and rates under ORS 757.210 for an electricity or natural gas utility, the Public Utility Commission shall act to balance the interests of the customers of the utility and the utility's investors by setting fair, just and reasonable rates that include amounts for income taxes. Subject to subsections (2) and (3) of this section, amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operations of the utility.
>
> (2) During ratemaking proceedings conducted pursuant to ORS 757.210, the Public Utility Commission must ensure that the income taxes included in the electricity or natural gas utility's rates:
>
> (a) Include all expected current and deferred tax balances and tax credits made in providing regulated utility service to the utility's customers in this state;
>
> (b) Include only the current provision for deferred income taxes, accumulated deferred income taxes and other tax related items that are based on revenues, expenses and the rate base included in rates and on the same basis as included in rates;

> (c) Reflect all known changes to tax and accounting laws or policy that would affect the calculated taxes;
>
> (d) Are reduced by tax benefits generated by expenditures made in providing regulated utility service to the utility's customers in this state, regardless of whether the taxes are paid by the utility or an affiliated group;
>
> (e) Contain all adjustments necessary in order to ensure compliance with the normalization requirements of federal tax law; and
>
> (f) Reflect other considerations the commission deems relevant to protect the public interest.
>
> (3) During a ratemaking proceeding conducted under ORS 757.210 for an electricity or natural gas utility that pays taxes as part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon:
>
> (a) Whether the utility's affiliated group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation;
>
> (b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or

(c) Any other considerations the commission deems relevant to protect the public interest.

(4)(a) Because tax information of unregulated nonutility business in an electricity or natural gas utility’s affiliated group is commercially sensitive, and public disclosure of such information could provide a commercial advantage to other businesses, the Public Utility Commission may not use the tax information obtained under this section for any purpose other than those described in this section, in ORS 757.511 and as necessary for the implementation and administration of this section and ORS 757.511.

(b) The commission shall adopt rules to implement paragraph (a) of this subsection that:

(A) Identify all documents and tax information that an electricity or natural gas utility must file in its initial filing in a proceeding to change rates that include amounts for income taxes, recognizing that any party may object to providing such documents on the grounds that they are not relevant; and

(B) Determine the procedures under which intervenors in such proceedings may obtain and use documents and tax information to fully participate in the proceeding.

> (5) As used in this section, "affiliated group" means a group of corporations of which the public utility is a member and that files a consolidated federal income tax return.
> [2011 c.137 §1]

Q. Please summarize Staff's review of income taxes in this case.

A. Overall, Staff concludes that the Company's provision for tax appears to be correctly calculated for rate making purposes. Staff issued several data requests and analyzed the Company's responses.[49] Staff's examination and discovery included confirming the federal and state tax rates, flow through tax benefits, calculation of current and deferred income tax expense, application of tax credits, and the ongoing ratemaking treatment of excess deferred income taxes (EDIT) as approved in prior Commission orders.

Q. Are you proposing adjustments with respect to income taxes?

A. Staff does not propose adjustments to the methodology of calculating taxes in the filing, however, Staff does suggest that the Oregon Corporate Activity Tax (OCAT) and Metro Supportive Housing Services (MSHS) taxes be moved from the Income Taxes – State line item in the filing to the Taxes Other Than Income line in future filings. The Company states that it is agreeable to this change.[50]

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[49] Staff DR 324-333.

[50] OPUC 332.pdf.

TAXES OTHER THAN INCOME

Q. Please provide a summary of the Commission's historical treatment of taxes other than income.

A. The category "taxes other than income" (Other Taxes) typically includes franchise fees, the regulatory fee imposed by the OPUC, property taxes, payroll taxes and other miscellaneous taxes or fees (e.g., the Oregon Dept. of Energy (ODOE) energy supplier assessment (ESA)), incurred by the energy utility. Payroll taxes are included as a component of wages and salaries, which is discussed in a separate section of Staff's testimony.

Franchise fees, along with business or occupation taxes, licenses, and similar exactions or costs, are allowed as operating expenses for ratemaking purposes on the condition these costs do not exceed three percent of gross revenues for a gas utility.[51] For simplicity, these costs are referred to collectively as franchise fees.

The OPUC fee and ODOE assessment are also included in operating expenses for ratemaking purposes. In rate cases, franchise fees and the OPUC fee are a function of the fee rate multiplied by gross revenues and are called revenue sensitive costs. Additionally, these revenue sensitive fees are included in the conversion factor used to determine the revenue requirement.

The ODOE ESA is an annual assessment based on both the Company's annual business revenues and ODOE's revenue need. This means the ODOE

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[51] See OAR 860-022-0040(1). Fees that exceed three percent must be charged to the customers within the *jurisdiction* assessing the fee. (OAR 860-022-0040(6)).

ESA can vary from year-to-year based on the ODOE assessment dollar amount, year-to-year variations in the Company's gross revenues, and the relative percentage of the Company's annual revenues when compared to the combined annual revenues of all Oregon power suppliers.

Property taxes related to property that is not yet used and useful may not be included in customer rates of a gas or electric utility.[52] Hence, these property taxes are excluded from the Test Year operating expenses. Property taxes related to property that is used and useful are included in Test Year operating expense and are usually forecasted for ratemaking purposes based on historical property tax information.

Q. Please discuss Staff's overall recommendations regarding taxes other than income.

A. *Franchise Fees*

The Company had adjusted to the three-year averaging methodology approved by the Commission in the UE 374 case (Cheung, 1000/22). Staff recommends approval of amounts included in the initial filing.

Property Taxes

Staff issued several DR based on review of confidential Exhibit 1003.[53]

Based on review of the Company's responses, Staff has no issues with application of the existing methodology and recommends approval of amounts included in the initial filing.

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[52] See ORS 757.*355*(1).

[53] Staff DR 309(a) through (e).

OPUC Fee

Staff recommends an adjustment as elaborated in the discussion of Issue 4 below.

ODE Energy Supplier Assessment (ESA)

The Company had adjusted to the three-year averaging methodology approved by the Commission in the UE 374 case (Cheung, 1000/22). Staff recommends approval of amounts included in the initial filing.

Wyoming Wind Generation Tax

Staff recommends an adjustment as elaborated in the discussion of Issue 5 below.

Oregon Corporate Activity Tax (OCAT) and
Metro Supportive Housing Services (MSHS) Tax

See discussion under Income Taxes above.

Other Taxes

The unadjusted filing includes several miscellaneous taxes that comprise less than one percent of the total. Based on review of the particulars, Staff recommends approval of amounts included in the initial filing.

ISSUE 4, OPUC FEE RATE

Q. What is the currently effective OPUC fee rate?

A. The current OPUC fee rate has increased to 0.430 percent.[54]

Q. Please summarize the OPUC fee rate in the Company's filing.

A. The Company's initial filing cites OPUC rates of 3.50 percent and 3.75 percent in its calculation of revenue sensitive factors and adjustment work papers, respectively.[55]

The Company states that this was an oversight and as discussed in the direct testimony of Company witness, Sherona L. Cheung, Exhibit PAC/1000/Cheung/22, lines 3-4, the Public Utility Fee reflected in the revenue requirement calculation in this general rate case (GRC) will be updated to the recently approved rate of 0.43 percent in the Company's Reply filing. [56]

Q. What does Staff recommend?

A. Rather than waiting for the Company's reply testimony, Staff has included the 0.430 percent rate in the Staff revenue requirement model. This results in an increase in expense of $686 thousand dollars compared to the Company's initial filing.

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[54] OPUC fee set to 0.43 percent for 2022. See *In the Matter of The Imposition of Annual Regulatory Fees upon Public Utilities Operating within the State of Oregon*, Docket No. UM 1012, Order No. 22-062 (Feb 24, 2022).

[55] PAC/1002, Cheung/8 and PAC/1002, Cheung/102.

[56] OPUC 306.pdf.

ISSUE 5, WYOMING WIND TAX

Q. Please summarize the Company's filing regarding this tax.

A. This tax is discussed in testimony at PAC/1000, Cheung/31 and Company's calculation of the expected $2.3 million test year amount is presented at PAC/1002, Cheung/187.

Q. Please discuss Staff's review.

A. Wyoming grants a tax holiday for the first three years after a plant is placed into service. The Foote Creek repowering will not be taxable until 2024 which is beyond the test year. The Company offers phased in MWh production figures for the other repowered projects beginning in December 2023.

In response to Staff DR 308, the Company states that the Ekola Flats and TB Flats I/TB Flats II facilities were placed in service on a circuit-by-circuit basis, with each circuit comprised of multiple turbines. This was not fully reflected in the Company's initial filing and results in a downward adjustment in tax expense of $44 thousand.[57] This is accompanied by revised calculations.[58]

Q. What does Staff recommend?

A. Staff recommends the Commission accept the Company's revised calculation provided to Staff in response to DR 308.

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[57] OPUC 308 Redacted.pdf.

[58] OPUC 308 CONF Attach.xlsx.

EMISSIONS CONTROL INVESTMENT ADJUSTMENT

Q. Please summarize the Company's filing.

A. Adjustment 8.11 Emission Control Investment Adjustment (Cheung, 1000/36-37 and Cheung, 1002/262-265) decreases administrative and general expense by ($1.7) million and decreases rate base by ($1.0) million (Cheung, 1002/196).

The adjustment work papers further state, "This adjustment removes 10 percent of the net book value of the Hunter U1 Clean Air – PM & NOX LNB Clean Air equipment projects and reduces return on Jim Bridger Unit 3 & 4 SCR projects to authorized return equal to long-term debt cost as ordered in UE 374, Order No. 20-473.[59]

Q. Please discuss Staff's review of this adjustment.

A. The adjustment includes full details regarding calculation of the adjustment. For Hunter Clean Air Equipment, ten percent of the Dec 2022 net book value and related depreciation are removed. For the Jim Bridger Unit 3 & 4 SCR, the entire pre-tax return on the Dec 2022 net book value is removed and replaced with cost of long-term debt only. As this adjustment is recorded as a reduction in A&G expense which then flows through the revenue requirement, the pre-tax return calculation is appropriate.

Q. What does Staff recommend?

A. Staff concludes that the adjustment is in accordance with the prior order and recommends the Commission accept this adjustment as filed.

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[59] PAC/1002, Cheung/262, Order No. 20-473 at 59, 81.

UTILITY PLANT

Q. What is the Company's requested increase in utility plant?

A. The Company's filing includes the following figures for total electric plant in service:[60]

- System-wide: $31.318 billion on June 30, 2021, increasing to $32.579 billion on December 31, 2022.
- Oregon allocated: $8.567 billion on June 30, 2021, increasing to $8.853 billion on December 31, 2022. Oregon's allocated share of the system-wide totals is 27.4 percent and 27.2 percent, respectively.

Q. Please discuss the Company's overall methodology for developing utility plant estimates.

A. PacifiCorp states that it has included capital additions to plant in-service through December 31, 2022, rather than through the end of the forecast Test Period and the rate effective period, which would be December 31, 2023. This treatment is consistent with the Company's 2010, 2012, 2013, and 2021 Rate Cases.[61]

The following table summarizes the Company's adjustments to electric plant in service to arrive at December 2022 balances in the filed case:

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[60] PAC/1002, Cheung/38.

[61] PAC/1000, Cheung/12.

	(millions)
Oregon Allocated June 30, 2021	$ 8,567
Adjustments:	
8.2 Trapper Mine Rate Base	2
8.3 Jim Bridger Mine Rate Base	10
8.4 Pro Forma Plant Additions	389
8.9 Remove Rolling Hills	(51)
8.11 Emissions Control Investment Adjustment	(1)
8.12 Transmission Project Adjustment	(0)
8.17 Remove Labor Day Wildfire Restoration	(64)
Oregon Allocated December 31, 2022	$ 8,853

Regarding Adjustment 8.4, the Company states that to reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be used and useful by December 31, 2022.[62]

Regarding Adjustment 8.17, the Company states that the adjustment removes the capital additions from the Base Period 12 months ended June 2021 for the Labor Day Wildfire Restoration capital projects.[63]

The Rolling Hills, Trapper, and Jim Bridger adjustments are similar to those made in prior cases.

Q. Turning now to Staff's review, please discuss the Commission's standard for prudence.

A. The purpose of a prudence review has been succinctly stated by the Commission in prior rate cases. For example, in a 2012 order, the Commission stated:

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[62] PAC/1002, Cheung/206.
[63] PAC/1002, Cheung/289.

> *[W]e take this opportunity to clarify the prudence standard in ratemaking. Parties have raised questions about how the Commission applies the prudence standard, particularly with regard to the relevance of the decision-making process that a utility uses to make an investment.*
>
> *The prudence standard is traditionally used to address the proper valuation of utility investment in rate base. Any investment found to be unreasonable is deemed imprudent and subject to partial or full disallowance. An example of a modem articulation of the prudence standard is as follows:*
>
> *A prudence review must determine whether the company's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company's managers. The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to*

> *determine how reasonable people would have performed the task that confronted the company.*
>
> *Although the Oregon courts have not expressly discussed the applicability of the prudence standard in this state, this Commission has long used the standard when examining utility investments. Through various orders, the Commission has confirmed that prudence of an investment is measured from the point of time of the utility's actions and decisions without the advantage of hindsight, that the standard does not require optimal results, and the review uses an objective standard of reasonableness.* [64]

Q. Please discuss provisions of Oregon's "used and useful" standard.

A. The "used and useful" standard requires the property to be placed into service prior to the effective date of the rates (ORS 757.355).[65, 66] The law applies to all utility plant including plant placed into service before the rate effective date and prior additions to rate base that are no longer used in providing utility service to customers.

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[64] See *In the Matter of PacifiCorp* Request *for a General Rate Revision,* Docket No. UE 246, Order No. 12-493 at 25 (Dec. 20, 2012).

[65] ORS 757.355 prohibits the inclusion of "property not presently used for providing utility service to the customer."

[66] *Pacific Power and Light,* Docket No. UE 210, Order No. 10-022, pp. 14-15 *("ORS 757.355 prohibits a* public *utility from collecting in* customer *rates the costs of any property not presently used for providing utility service to those customers" … "Given this evidence, and despite the parties' contentions about specific rate base adjustments, it is clear that the Stipulation will allow Pacific Power to collect in* rates *only the costs of property presently providing service to customers in conformance with ORS 757.355. We therefore deny ICNU's objection on this point.")*.

Q. Please discuss the symmetry between the UE 374 and UE 399 filings.

A. The following relationships are useful when comparing electric plant in service projected in the two rate cases.

- UE 374 base year July 2018 to June 2019.
- UE 399 base year July 2020 to June 2021.
- UE 374 18-month projection July 2019 to December 2020.
- UE 399 18-month projection July 2020 to December 2022.

As each case is projecting 18 months of additions in the same fashion, Staff would expect the nature and amount of projects within each FERC category to be somewhat similar.

Q. Please summarize Staff's analysis of the overall increase in electric plant in service (EPIS).

A. Staff has prepared the following display to facilitate further analysis of the overall increase in electric plant in service.

Oregon Allocated (billions)

	UE 374 Final	*Estimated * Dec-20 UE 374 Factors*	June 2021	2020 ROO 2021 Proforma **	2021 ROO w/Type 1 Adj.	UE 399 Dec 2022
Steam Production Plant	$ 1.785	$ 1.776	$ 1.795	$ 1.837	$ 1.853	$ 1.811
Hydraulic Production Plant	0.291	0.293	0.292	0.302	0.302	0.322
Other Production Plant	1.109	1.225	1.399	1.429	1.359	1.380
Transmission Plant	1.957	1.985	2.017	2.091	2.090	2.097
Distribution Plant	2.260	2.271	2.365	2.311	2.366	2.484
General Plant	0.426	0.397	0.407	0.428	0.430	0.455
Intangible Plant	0.265	0.300	0.292	0.286	0.299	0.304
Electric Plant in Service	$ 8.095	$ 8.245	$ 8.567	$ 8.684	$ 8.699	$ 8.853
6 month increase from UE 374			5.8%			
18 month increase from June 21						3.3%
24 month increase from UE 374						9.4%

* Year-end system balances reported on FERC Form 1 (Docket No. RE 68)
Multiplied by Oregon's UE 374 final share for each FERC Acct.
UE 374 case and FERC filing are both as of Dec 2020.
** Includes Type 1, 2, and 3 adjustments. Estimated AMA plant for 2021.

Q. Please discuss the overall increase in Utility Plant and compare to the increases reported in Company's results of operations.

A. The requested Oregon allocated plant in this case is $758 million more than was approved in the UE 374 case. As the base year in this case is July 2020 through June 2021, there is a six-month overlap with the prior case.

Staff notes that EPIS reported in results of operations (ROO) reflects a 13-month AMA (average of monthly averages) method. However, 2021 additions projected in the 2020 ROO are 99.8 percent of the actual additions reported in the 2021 ROO which increases Staff's confidence in the quality of the Company's projections. Staff does note that allocation factors vary (e.g. the SG factor is 26.9469 and 26.0703 in the 2021 ROO and UE 399 filing, respectively) therefore drilling down into the detail variances between the filings can be problematic.

Q. Please summarize the net increase by plant category from UE 374 to UE 399.

A. The following display summarizes the net increase from December 2020 (UE 374) to December 2022 (UE 399) by FERC plant category:

	Proposed Increase	%
Steam Production Plant	$ 0.025	1.4%
Hydraulic Production Plant	0.030	10.4%
Other Production Plant	0.271	24.5%
Transmission Plant	0.140	7.1%
Distribution Plant	0.224	9.9%
General Plant	0.029	6.7%
Intangible Plant	0.039	14.6%
Electric Plant in Service	$ 0.758	9.4%

Q. What are Staff's further observations regarding this $758 million increase?

A. 84 percent of the $758 million increase in Oregon allocated gross plant since the UE 374 order occurs in other production plant, transmission, and distribution.

The other production plant increase is largely explained by various wind projects now being fully online. In response to Staff DR, PacifiCorp refers to its various compliance filings for details.[67] Staff notes this is strong evidence as the particulars have been vetted in the respective dockets cited.

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[67] OPUC 413.pdf, specifically 413 a) "For actual in-service information for the Ekola Flats wind project, please refer to the Company's compliance filing for Docket UE-374, filed January 7, 2021. For the actual in-service information for the Pryor Mountain and Foote Creek wind

Regarding transmission projects, Staff notes that the two headline projects in testimony account for less than ten percent of the overall increase.[68] Referring to PAC/1002, Cheung/228, there are many other projects comprising the remaining 90 percent, which Staff investigated using a sampling approach further discussed below.

Distribution is situs allocated. Projected Oregon distribution additions (18 months) are \$137.1 million and \$159.6 million for UE 374 and UE 399, respectively, which is a 16 percent increase. However, as further discussed in Issue 7 below, the proportion resulting from non-specific "blanket" projects has significantly increased compared to UE 374.

Q. Please discuss Staff's overall approach to review electric plant in service.

A. Staff reviewed the Company's testimony regarding plant additions and the related rate base adjustment work papers (PAC/1002, Cheung/194-290).

Staff then reviewed other information filed with the Commission such as IRP filings (Docket No. LC 77), annual construction budgets (Docket No. RE 43), and annual results of operations (Docket No. RE 56).

Following those reviews, Staff conducted discovery regarding the figures presented in the initial filing, narrative descriptions for projects under

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projects, please refer to the Company's compliance filing for Docket UE-374, filed April 5, 2021. For details on TB Flats wind project, please refer to the direct testimony of Company witness, Timothy J. Hemstreet, Exhibit PAC/500/Hemstreet/2-7."

[68] PAC/600, Vail/7, Goshen-Sugarmill-Rigby \$23.2m and Jordanelle-Midway \$21.9m, system-wide. Oregon allocation is \$45.1 x 26.0703% = \$11.75m. 11.75/140 = 8% of the overall increase.

$10 million[69], plant removals and retirements, capitalized interest and overhead, spare parts, and specific questions regarding how plant additions are being projected in the various FERC categories.[70]

Q. Did Staff modify its approach based on the Commission's direction in Order No. 20-473?

A. Yes. The Commission directed that, generally, a sampling approach ought to be used when requesting detailed project documentation.[71] Accordingly, when requesting detail regarding transmission project change orders and one-line diagrams, Staff used a stratified approach of requesting details for projects over $3 million and a sample of the remaining projects under that amount.

Q. Did Staff request that level of documentation for other FERC categories?

A. Not in this case. In Staff's view, review of testimony, additional narrative descriptions for projects under $10 million, and other data responses provide adequate evidence at this stage of the proceeding. However, Staff may issue additional detailed data requests as necessary in response to the testimony of intervening parties and the Company's reply testimony.

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[69] Narrative descriptions for projects over $10 million are in the initial filing at PAC/1002, Cheung/234-238.

[70] Steam, hydro, other production plant, transmission, distribution, general, intangible.

[71] Order No. 20-473 at 42.

Q. Regarding the portions of electric plant in service you have reviewed, what are your findings regarding prudence?

A. No evidence has come to my attention indicating that the Company's proposed plant additions are imprudent. However, other Staff witnesses are reviewing specific portions of the filing (e.g. wind projects, IT projects, wildfire restoration, etc.) and may propose prudence adjustments in their respective testimonies.

Q. Based on the evidence you have examined, are you proposing adjustments to utility plant?

A. Yes. My proposed adjustments are discussed in Issues 6, 7, and 8 below and generally pertain to removal of land not being used to provide utility service, increased dollar amounts for "blanket" projects compared to the prior case, and Staff's proposal for attestations regarding certain projects prior to the rate effective date.

ISSUE 6, CARBON AND CHOLLA LAND

Q. Please discuss Staff's findings.

A. The Company's response to Staff DR 411 indicates that there is $94 thousand and $1.267 million of land, system-wide, at the Carbon and Cholla plants, respectively, proposed to be included in rate base.[72]

Q. Did the Company provide an explanation of the larger Cholla amount?

A. Yes. The Company states that it cannot dispose of the property until after full plant retirement, demolition, and reclamation. Furthermore, only the retired Cholla plant assets were included in Oregon's buy-down so the land piece was not included and remains in rate base for this GRC.[73]

Q. What are the requirements of ORS 757.355?

A. Specifically, ORS 757.355(1) requires that "a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer."

Q. What adjustment does Staff propose?

A. As the plants are closed and no longer providing service to Oregon customers, these amounts, totaling $355 thousand Oregon allocated, must be removed.[74]

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[72] OPUC 411.pdf and OPUC 411-1 Attach.xlsx.

[73] *Id.* Staff DR 411(c).

[74] System wide amounts x 26.070 percent SG allocation factor.

ISSUE 7, BLANKET PROJECTS

Q. Please elaborate Staff's concerns regarding blanket projects.

A. Staff notes that the 18-month amounts projected for many blanket projects appear to significantly exceed amounts projected in the Company's prior case.

For example, just looking at the projects labeled as "PP" or "Pacific Power", the projections are $241 million Oregon allocated in this case compared to $78 million in UE 374, a 300% increase. Details by FERC category as follows:

Hydraulic Production Plant

	July19 to Dec20 Plant Adds
Hydro Plant Additions - UE 374	
PP Other Hydro Dam Safety East	$ 1,263,838
PP Hydro West	5,987,500
PP Hydro Relicensing East	2,016,840
PP Hydro Impl On-Proj West	3,128,470
PP Hydro East	2,472,302
	14,868,950
	26.0226%
Oregon Allocated	$ 3,869,287

		July21 to Dec22 Plant Adds
Hydro Plant Additions - UE 399		
PP Other Hydro Dam Safety West	$	2,811,412
PP Other Hydro Dam Safety JA		2,186,344
PP Other Hydro Dam Safety East		1,140,601
PP Hydro West		17,546,469
PP Hydro Plant JA		3,341,354
PP Hydro Impl On-Proj West		7,034,218
PP Hydro East		10,267,241
		44,327,639
		26.0703%
Oregon Allocated	$	11,556,348

Other Production Plant

		July19 to Dec20 Plant Adds
Other Plant Additions - UE 374		
PP Wind Production	$	3,151,679
		26.0226%
Oregon Allocated	$	820,149

		July21 to Dec22 Plant Adds
Other Plant Additions - UE 399		
PP Wind Production	$	6,891,562
PP Eagle Mitigation		2,136,539
		9,028,101
		26.0703%
Oregon Allocated	$	2,353,653

Transmission Plant

		July19 to Dec20 Plant Adds
Transmission Plant Additions - UE 374		
PP Trans		$ 13,327,202
PP Trans New Connect		27,715,083
		41,042,285
		26.0226%
	Oregon Allocated	$ 10,680,270

		July21 to Dec22 Plant Adds
Transmission Plant Additions - UE 399		
Pacific Power Transmission Wildfire Mitigation Projects		$ 14,942,038
Pacific Power Transmission Replacements		29,346,318
Pacific Power Transmission New Connects		1,731,815
Pacific Power Transmission Line Reliability Linescope projects		1,484,798
Pacific Power Sub-Trans/Major Sub System Upgrades		14,383,367
Pacific Power Spare Transmission 230-69kV Transformer Purchase		2,360,613
Pacific Power Spare Transmission 115-69kV Transformer Purchase		1,713,625
		65,962,574
		26.0703%
	Oregon Allocated	$ 17,196,641

Distribution Plant

	July19 to Dec20 Plant Adds
Distribution Plant Additions - UE 374	
PP Distribution OR	$ 36,385,682
PP Dist New Connect OR	13,012,503
TMP OR Distribution Major Projects - PP	3,719,625
	$ 53,117,810

	July21 to Dec22 Plant Adds
Distribution Plant Additions - UE 399	
PP Distribution OR	$ 81,479,359
PP Dist New Connect OR	72,121,946
OR Distribution Major Projects	18,464,660
	$ 172,065,966

1 *General Plant*

	July19 to Dec20 Plant Adds
General Plant Additions - UE 374	
PP Structures OR	$ 1,656,220
PP Hydro Vehicles	1,019,130
PP Hydro General Plant	1,621,095
PP Com Plant OR	4,771,763
	9,068,207
Oregon Allocated	$ 7,115,038

	July21 to Dec22 Plant Adds
General Plant Additions - UE 399	
PP Vehicles OR	$ 9,416,788
PP Structures OR	2,062,095
PP IT Business Requested Hardware Equip	1,225,195
PP Hydro Vehicles	4,496,952
PP Hydro General Plant	3,605,449
PP General Plant OR	1,394,270
PP Core IT and TOM Hardware Equipment	30,784,123
PP Com Plant OR	8,902,871
PP Com Main Grid - East	2,496,505
	64,384,247
Oregon Allocated	$ 33,237,114

Intangible Plant

	July19 to Dec20 Plant Adds
Intangible Plant Additions	
PP-IT	$ 8,878,450
	27.2153%
Oregon Allocated	$ 2,416,297

	July21 to Dec22 Plant Adds
Intangible Plant Additions - UE 399	
PP IT Business Requested Software	$ 3,142,416
PP Core IT and TOM Software	14,233,137
	17,375,553
	27.1731%
Oregon Allocated	$ 4,721,476

Q. Did Staff conduct discovery regarding the "PP" and "Pacific Power" blanket projects?

A. Yes. Specifically, Staff requested, "Please explain the projection methodology and provide all work papers underlying the following blanket projects" for each FERC category.

Q. How did the Company respond?

A. The Company provided narrative explanations of the nature and purpose of expenditures in each blanket project.[75] Regarding the underlying work papers,

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[75] OPUC 412.pdf, OPUC 413.pdf, OPUC 414 1st SUPP - subpart (a)(c) ONLY.pdf, OPUC 415.pdf, OPUC 417.pdf, and OPUC 418.pdf.

the Company provided spreadsheets disaggregating the amount projected by month, nothing more.[76]

Q. Are there other blanket projects other than those “PP” and “Pacific Power”?

A. Yes. However, they become increasingly difficult to compare from one case to another. Staff provides the details above only to illustrate that this case appears to include significantly higher projected amounts and that the Company did not provide reasonable details regarding how those higher amounts were derived despite being asked for “all work papers”.

Q. What does Staff recommend?

A. In Staff’s view, these blanket projects may be over projected. Staff recommends attestations, further discussed below, to ensure the amounts projected are in service at the rate effective date.

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[76] OPUC 412-2 Attach.xlsx, OPUC 414-2 Attach.xlsx, OPUC 415 Attach.xlsx, OPUC 417 Attach.xlsx, and OPUC 418 Attach.xlsx.

ISSUE 8, ATTESTATIONS

Q. Please discuss the provision of officer attestations for certain projects in the Company's previous rate case.

A. In Order No. 20-473, the Commission required PacifiCorp to provide attestations for non-wind, non-transmission plant in excess of $1 million on an Oregon-allocated basis, put in service after the hearing.[77]

The Commission also directed PacifiCorp to provide attestations for pro-forma transmission projects in excess of $1 million on an Oregon-allocated basis and also required attestation for Klamath hydroelectric investments.[78]

Q. Does Staff recommend a similar approach in this case?

A. Yes. In this case, Staff recommends attestations for discrete projects in excess of $1 million on an Oregon-allocated basis, put in service after the hearing before the rate effective date, prior to inclusion in rates.

Staff notes that PacifiCorp argued for a $5 million threshold in the UE 374 case.[79] Staff notes that the Company lists a number of pro-forma projects under $5 million[80], providing attestations for those projects placed in service after the hearing date will limit the number of projects to a reasonable number.

Q. Does Staff recommend attestations for certain non-discrete projects?

A. Yes. At a minimum, Staff recommends officer attestations for "PP" and "Pacific Power" blanket projects discussed above, in the event those projects

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[77] Order No. 20-473 at 32-33.
[78] Id.
[79] Id.
[80] PAC/1002, Cheung/225-232.

are less than the amount projected in the filed case, Staff recommends that rate base be reduced to the actual amount spent prior to the rate effective date.

UNBUNDLING AND FUNCTIONALIZATION

Q. Please summarize the Company's filing.

A. The Company's proposed unbundling and functionalization methodology is presented in testimony PAC/1100, Meredith/1-17 and Exhibits PAC/1102-1105.

The Company states that rate base balances, revenues and expenses were either assigned or allocated to unbundled categories in accordance with Oregon Administrative Rules (OAR) 860-038-0200 and states that the functionalization procedures in this case are consistent with those approved in Order 01-787 and implemented in Advice No. 01-020.[81]

Q. Please discuss the OAR requirements.

A. The Commission's rules regarding unbundling and functionalization are within the OAR regarding direct access, Division 38. Specifically, OAR 860-038-0200. This rule identifies specific functional categories which must be separately identified, allocation methodologies, and requires direct assignment of costs whenever possible.

The unbundled functional categories presented in Exhibits PAC/1102-1105 are in accordance with those delineated in OAR 860-038-200(1).

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[81] PAC/1100, Meredith/4.

Q. Please summarize the unbundled functionalized revenues in this case compared to the UE 374 compliance filing.

A. Unbundled functionalized revenues in this case are presented in Exhibit PAC/1103, Meredith/1. The final UE 374 figures were provided in the Company's compliance filing in that case.[82] Staff summarizes as follows:

Function	UE 374 Marginal Cost Study Compliance Filing			UE 399 Marginal Cost Study Exhibit 1107 Filed			UE 374 to UE 399 Variance
Production	$	680,376	51.98%	$	698,716	55.95%	3.97%
Transmission		232,681	17.78%		133,281	10.67%	-7.11%
Distribution		294,690	22.51%		319,434	25.58%	3.06%
Distribution-Lighting		3,416	0.26%		2,548	0.20%	-0.06%
Franchise Fees		32,917	2.51%		29,219	2.34%	-0.18%
Distribution Total							0.00%
Ancillary		24,877	1.90%		23,848	1.91%	0.01%
Customer Billing		8,536	0.65%		14,720	1.18%	0.53%
Customer Metering		22,190	1.70%		18,059	1.45%	-0.25%
Customer Other		9,201	0.70%		9,077	0.73%	0.02%
	$	1,308,885	100.00%	$	1,248,901	100.00%	0.00%

Q. Please discuss the increased proportions for production and distribution revenue and the nearly offsetting reduction in transmission revenue.

A. Staff was initially quite concerned about this outcome but upon further review and comparison of the underlying models the revenue figures appear to be correctly calculated.

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[82] OR GRC MC Study Dec 2021 - ORDER.xlsm, 1403_Pg1_FuncResults.

Q. Please elaborate.

A. The $1.249 billion total revenue being unbundled and functionalized is the total adjusted results before the requested price increase as presented elsewhere in the filing.[83]

OAR 860-038-200(9)(d), specifically, requires that “required revenues must be calculated for each unbundling category using the traditional revenue requirement calculation methodology (recovery of costs plus a return on investment). For reporting purposes, revenues must be assigned to the appropriate category per the underlying tariff for which they were collected. Common revenues that cannot be directly assigned must be functionalized using the Net Plant allocation factor”.

As net operating revenue consists only of return on rate base, most of the change in unbundled functionalized results is proportionate to the change in the relative shares of rate base. From that point, the remainder of the change is due to application of the specific methodologies elaborated in the Company’s testimony.[84]

Q. What proportion of the Company’s business is the sum of the production, transmission, and distribution functions?

A. Production, transmission, and distribution are 97 percent of rate base and operating expenses.

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[83] PAC/1001, Cheung/1.

[84] PAC/1100, Meredith/1-17 and Exhibits PAC/1102-1105.

Q. Is there a significant change in other revenues influencing the functionalized revenue requirement?

A. Yes. Other operating revenues directly allocable to the transmission function increased from $33.5 million to $74.4 million which is primarily due to increased OATT revenues. Staff notes this increase reduces the amount of base tariff revenues necessary to fund the transmission function and significantly contributes to the 7.11 percent decrease in proportional revenues noted above.

Q. Overall, do the Company's unbundling and functionalization calculations comport with the requirements of OAR 860-038-0200?

A. Yes.

Q. Are the Company's unbundling and functionalization methodologies the same as the prior rate case?

A. Based on Staff's review of the underlying work papers, yes.

Q. Is Staff proposing an adjustment at this time?

A. No. However, Staff's recommendations may change based on the testimonies offered by other parties.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

June 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME: John L. Fox

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Financial Analyst
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: I hold a Bachelor of Science degree in Business Administration / Accounting from the University of Oregon (1989). I also completed the Certificate in Public Management program at Willamette University (2010).

I have been licensed as a Certified Public Accountant in Oregon since 1991. Maintaining active status has required a minimum of 80 hours continuing professional education every two years.

EXPERIENCE: From 1989 to 1999 I was in general practice with several CPA firms in Southern Oregon and the Mid-Willamette Valley. My tax experience includes individuals, trusts and estates, qualified retirement plans, and extensive corporate, partnership, and LLC work. Accounting experience during this time includes client write up, compilation and review, and significant audit and attest work.

I have been employed in the executive branch of Oregon state government since 1999. My experience prior to joining the Commission staff includes 3 years as a cost accountant, 11 years as a senior budget analyst, and 4 years in an oversight role as a budget team lead.

I have extensive experience in capital construction and financing, complex cost modeling, rate development, fiscal projections, expenditure analysis, and cost control for programs with biennial revenues between $100 million and $300 million.

PRIOR DOCKETS: I have provided testimony as a Staff witness in the following OPUC proceedings; UE 333, UE 335, UE 374, UE 390, UE 391, UE 392, UE 394, UG 344, UG 347, UG 366, UG 388, UG 389, UG 390, UG 435, UM 1992, UM 2004, UM 2026.

CASE: UE 399
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support Of Opening Testimony

June 22, 2022

OPUC Data Request 154

Residential Exchange Credit - Please provide a narrative description discussing why the Company suspects that a residential customer's monthly usage would exceed 10,000 kWh in a single month (e.g., heated swimming pool, plant lights, heating, cooling, etc.).

Response to OPUC Data Request 154

PacifiCorp objects to this data request to the extent it calls for speculation. Subject to and without waiving the foregoing objection, the Company states as follows:

Energy usage for a residential customer in excess of 10,000 kilowatt-hours (kWh) in a month is very uncommon. While customers with this high of usage exist, they are few and are outliers to the preponderance of the data. The Company believes that the most likely reason that a customer would have this much usage is that the customer has a very large home. Other reasons could include faulty equipment, indoor grow lights, and heated swimming pools.

OPUC Data Request 157

Interest Synchronization - Regarding the file OR GRC JAM Dec 2023 Test Period.xlsm, Report tab, Calculation of Taxable Income, cell N1461:

(a) Please explain why dividing interest expense by the total rate base in Exhibit 1001 ($84,048,729 / $4,199,121,534 = 2.002%) does not agree with the weighted cost of debt (2.09%) as stated in Exhibit 1002/12.

(b) In the event the Company proposes to correct the amount of interest later in this case, please provide the anticipated adjustment details in the same format as OR GRC JAM Dec 2023 Test Period.xlsm, Adj. Summary tab. This is an ongoing request.

Response to OPUC Data Request 157

(a) The interest stated in Exhibit PAC/1002/12 should equal total rate base in Exhibit PAC/1001 times weighted cost of debt. The variance observed is a formulaic error. The Company will correct the amount of interest in its Reply Testimony filing to ensure interest expense reflected in the case reflects a level that equals total rate base multiplied by the weighted cost of debt.

(b) Please refer to Attachment OPUC 157 which provides a copy of work paper "OR GRC JAM Dec 2023 Test Period.xlsm" that reflects the interest expense correction described in the Company's response to subpart (a) above. Correcting the interest expense calculation results in a reduction to revenue requirement of approximately $1.27 million.

OPUC Data Request 279

Electric Plant Acquisition Adjustments - Please provide all work papers underlying calculation of the system wide and Oregon test year amounts for FERC Accounts 114, 115, and 406.

Response to OPUC Data Request 279

Please refer to attachment OPUC 279.

		Total Company			Oregon Allocated				
		FERC 406	FERC 114	FERC 115	FERC 406	FERC 114	FERC 115	**Notes:**	**Exhibit Reference**
Total in the Oregon JAM (Unadjusted)									
	SG	6,496,204	144,704,699	(137,980,477)	1,693,583	37,725,010	(35,971,982)	1,2	Exhibit PAC/1002/Cheung/
	UT	301,635	11,763,784	(3,612,186)	-	-	-	1,2	Exhibit PAC/1002/Cheung/
		6,797,839	**156,468,483**	**(141,592,663)**	**1,693,583**	**37,725,010**	**(35,971,982)**		Exhibit PAC/1002/Cheung/
Adjustment:									
Regulatory Asset & Liability Amortization									
	SG	(4,706,208)	(141,186,243)	137,153,218	(1,226,925)	(36,807,736)	35,756,313	3	Exhibit PAC/1002/Cheung/
	UT	-	-	-	-	-	-		Exhibit PAC/1002/Cheung/
		(4,706,208)	**(141,186,243)**	**137,153,218**	**(1,226,925)**	**(36,807,736)**	**35,756,313**		Exhibit PAC/1002/Cheung/
Total in the Oregon JAM (Normalized Test Period)									
	SG	1,789,996	3,518,456	(827,259)	466,658	917,274	(215,669)		Exhibit PAC/1002/Cheung/
	UT	301,635	11,763,784	(3,612,186)	-	-	-		Exhibit PAC/1002/Cheung/
		2,091,631	**15,282,240**	**(4,439,445)**	**466,658**	**917,274**	**(215,669)**		Exhibit PAC/1002/Cheung/

Notes:

1. Unadjusted balances are supported by "B-Tab" report workpapers that was supplemented on 4/4/2022.

2. SG Factor 26.070%.

2. Please refer to confidential work papers provided with the direct testimony of Ms. Sherona L. Cheung - "8.6 - Regulatory Assets & Liabilties Amortization_CONF" for details supporting the calculation of

OPUC Data Request 280

Electric Plant Acquisition Adjustments - Regarding Exhibit 1002/38-39 Staff notes that the SG (system generation) allocated amounts in Accounts 114 and 115 appear to have been reduced by the embedded cost differentials appearing on Exhibit 1002/292 which is not commensurate with how these amounts were calculated in the UE 374 case.

(a) Please provide a detailed explanation of why such an adjustment is occurring in this case.

(b) Please confirm which case, UE 399 or UE 374, is the correct treatment.

Response to OPUC Data Request 280

(a) The FERC 114 and 115 amounts on Exhibit PAC/1002/38-39 are the total electric plant acquisition adjustments balances. The amounts shown on Exhibit PAC/1002/ 292 for FERC account 114 and 115, reflect only the portion of unadjusted acquisition adjustment costs for the Craig/Hayden acquisitions, which is the subset of electric plant acquisition adjustment balance that is eligible to be included in the embedded cost differential (ECD) calculation. This is the same treatment used in the UE 374 case.

(b) While the methodology is consistent in both UE 374 and UE 399, both cases should have applied the fully normalized balances, rather than the unadjusted balance, of the Craig/Hayden acquisition adjustment in its ECD calculation. For UE 399 the normalized amounts should be zero, as the Craig/Hayden acquisition adjustments are fully amortized prior to the beginning of the Test Period. Correcting for this would reduce the embedded cost adjustment by $11,452. This has no impact to the overall revenue requirement in this filing because the ECD is capped at $11,000,000, per the 2020 Protocol agreement.

OPUC Data Request 306

Taxes Other Than Income - Regarding page 4.7.1 (Cheung, 1002/102):

(a) Please explain why the PUC rate of 0.375 percent does not agree to the 0.350 percent revenue sensitive factor on page 1.6 (Cheung, 1002/8).

(b) Please explain why the calculated PUC Fee Expense adjustment of ($227,655) does not appear to flow through to the revenue requirement.

Response to OPUC Data Request 306

(a) The Public Utility Commission (PUC) rate on page 1.6 in Exhibit PAC/1002/Cheung/8 should match that reflected in Exhibit PAC/1002/Cheung/102, so the mismatch was an oversight. As discussed in the direct testimony of Company witness, Sherona L. Cheung, Exhibit PAC/1000/Cheung/22, lines 3-4, the Public Utility Fee reflected in the revenue requirement calculation in this general rate case (GRC) will be updated to the recently approved rate of 0.43 percent in the Company's Reply filing. This update will need to be reflected on both referenced pages.

(b) The calculated adjustment of ($227,655) is flowed through to the revenue requirement through the Jurisdictional Allocation Model (JAM) on the "Adjustments" tab, in cell N1017. A copy of the JAM is provided with the non-confidential work paper supporting by Ms. Cheung's direct testimony.

OPUC Data Request 308

Taxes Other Than Income - Regarding page 7.6.1 (Cheung, 1002/187):

(a) For the wind plants with tax beginning dates in 2023, please explain if this date is the same for all turbines in each respective plant.

   i. If not please, provide a list of turbines and dates they become taxable.

(b) For the plants referenced in footnote (a) [2023 and 2024 tax effective dates], please provide the expected taxable annual Mwh production for each plant when it becomes fully taxable.

Confidential Response to OPUC Data Request 308

(a) Cedar Springs: All of the turbines for Cedar Springs were placed in service on December 4, 2020, therefore, the Wyoming Wind Tax begins on December 4, 2023. Projected production for December 2023 is forecast to be [redacted] megawatt-hours (MWh). Pro-rated based on days subject to tax (28 days ÷ 31 days), results in [redacted].

Ekola Flats and TB Flats I / TB Flats II were placed in service on a circuit-by-circuit basis, with each circuit comprised of multiple turbines. Please refer Confidential Attachment OPUC 308 which provides the dates the production for the turbines on each circuit become taxable. The tax calculated in Adjustment 7.6 assumes all turbines for these projects were placed in service on the same date. Please refer to Confidential Attachment OPUC 308 which recalculates the tax on a circuit-by-circuit basis, resulting in an Oregon-allocated reduction of $44,001.

(b) Please refer to the confidential table provided below for the estimated annual MWh generation for the applicable projects:

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 309

CONFIDENTIAL REQUEST - Property Taxes

Regarding Exhibit 1003:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Response to OPUC Data Request 309

(a) The principal factors that contribute to changes in assessed values are changes to plant in service balances, net operating income levels and the capitalization rates used by each state. Significant recent property additions include the Pryor Mountain wind facility (MT), the TB Flats and Ekola Flats wind facilities (WY) and the repowering of the Foote Creek wind project (WY). Wyoming exempts from property tax all pollution control investments. California, Idaho, Montana, Utah, Washington and Wyoming exempt from property tax intangible assets such as software and licenses.

(b) The Company annually capitalizes property taxes for any capital project under construction as of each year's January 1 property tax assessment date if the project has a cumulative capital spend of at least $5 million at that date. Column k for 2023 does not include capitalized property tax amounts for Idaho, Montana and Washington because the projects under construction in those states as of December 31, 2022, are expected to be below the $5 million capitalization threshold used by the Company.

(c) The amount of property tax capitalized for each state is not a function of an allocation process but is instead based on the state in which the property under construction is physically located.

(d) The amount of property tax capitalized in 2023 is expected to exceed the amount capitalized in 2021 because the estimated construction work in progress (CWIP) balance at December 31, 2022, is expected to be significantly higher than the CWIP balance at December 31, 2020.

(e) Assessed values only represent the assets physically located in a jurisdiction. Some assets are located in other jurisdictions and provide benefits to the entire system such as, generation and transmission assets. Regulatory principles match costs with benefits. Property taxes are a cost that is borne by the system and is therefore appropriate to be allocated using a system allocation factor.

Property taxes are system allocated based on gross plant and allocated on a Gross Plant System (GPS) allocation factor. The use of the GPS allocation factor to allocate property taxes was approved by the Oregon Public Utility Commission (OPUC) in Docket No. UM-1050, Order No. 20-024, Entered January 23, 2020. Please refer to Order No. 20-024, Appendix B page 11, line 230.

OPUC Data Request 332

Income Taxes - Regarding the General Rate Case Results (Cheung, 1001/2):

(a) Please confirm that the $10,593,846 State Income Taxes figure in column (1) includes the OCAT and MSHS taxes being moved into base rates.

(b) Please explain the Company's plans for reporting the OCAT and MSHS taxes in the Jurisdictional Allocation Model (JAM) on a forward looking basis and whether the Company has considered reporting them as Taxes Other Than Income.

Response to OPUC Data Request 332

(a) Confirmed.

(b) The Company is agreeable to recording the Oregon Corporate Activity Tax (OCAT) and Metro Supportive Housing Services (MSHS) as taxes other than income tax in the jurisdictional allocation model (JAM) as it will result in the proper state tax deductibility of these taxes as well as the application of the proper gross-up factor.

OPUC Data Request 405

Utility Plant - Regarding the Company's 2020 Results of Operations (Docket No. RE 56(9), Adjustment 8.5, Major Plant Addition Detail - January 2021 - December 2021 (pages 8.5.6 and 8.5.7):

(a) Please cross-reference all projects to the plant additions projected in the UE 399 case (Adjustment 8.4, Cheung, 1002/225-232).

(b) Please provide a detailed narrative description of each project over $1 million similar to those provided in testimony starting on Cheung, 1002/234.

(c) Please provide the actual in-service date and final cost for each project which has been completed. This is an ongoing request.

(d) For those projects not yet completed, please provide the currently anticipated in-service date and expected final cost.

Response to OPUC Data Request 405

The Company objects to this request as overly broad, outside the scope of this proceeding, requesting the unduly burdensome development of information or preparation of study, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

The Company's 2023 general rate case (GRC), Docket UE-399, is not based on the Company's 2020 Results of Operations (ROO).

OPUC Data Request 411

Utility Plant - Regarding Steam Production Plant:

(a) Please provide the total plant, on a system-wide basis, by FERC Account, for each generating plant as of December 31, 2020, June 30, 2021, December 31, 2021, and projected as of December 31, 2022.

(b) Please explain whether unclassified plant is included in the STEAM-ELECTRIC GENERATING PLANT STATISTICS, 2020 FERC Form 1 pages 403-402.4.

(c) Staff notes that that Cholla land of $1,266,851 was reported in the 2020 FERC Form 1 plant balance:

  i. Please indicate if this amount has been removed from the request in this case.
  ii. If not, please provide the rationale for continuing to include this land in rate base.

(d) Regarding page 8.4.19 (Cheung, 1002/225), Staff notes that project under $1 million are 75% of the total. Please provide a list of projects therein between $500k and $1 million and a detailed narrative description of each project.

Response to OPUC Data Request 411

(a) Please refer to Attachment 411-1 which provides steam production plant costs on a system-wide basis, as reported in FERC Account 101 (Electric Plant-In Service) as of June 30, 2021 and December 31, 2020 and December 31, 2021. The Company does not prepare test period data at the plant account level. The projected plant as of December 31, 2022 is available on a plant function/factor basis only, details for which are provided in the Company's Exhibit PAC/1002/Cheung/209-224.

(b) The Company does not report FERC Account 106 (Completed Construction Not Classified) in its annual Federal Energy Regulatory Commission (FERC) Form 1, generation pages 402 through 403, lines 13 through 16.

(c) With regard to Cholla land, please refer to the Company's responses to subpart i. and ii. below:

  i. The Cholla land amount has not been removed from this general rate case (GRC).

    ii. The Company cannot dispose of the property until after full plant retirement, demolition and reclamation. Furthermore, only the retired Cholla plant assets were included in Oregon's buy-down so the land piece was not included and remains in rate base for this GRC.

(d) Please refer to Attachment OPUC 411-2.

OPUC Data Request 412

Utility Plant - Regarding Hydraulic Production Plant:

(a) Please provide the total plant, on a system-wide basis, by FERC Account, for each generating plant as of December 31, 2020, June 30, 2021, December 31, 2021, and projected as of December 31, 2022.

(b) Regarding page 8.4.20 (Cheung, 1002/226):

  i. Please explain the significance and use of the SG-P and SG-U factors listed. Staff notes the 2020 Protocol Factors (Cheung, 1002/294) shows a combined SG factor.

  ii. Please explain the projection methodology and provide all work papers underlying the following blanket projects.

    1. PP Hydro West
    2. PP Hydro East
    3. PP Hydro Impl On-Proj West
    4. PP Hydro Plant JA
    5. PP Other Hydro Dam Safety West
    6. PP Other Hydro Dam Safety JA
    7. PP Other Hydro Dam Safety East

(c) Staff notes that overall hydro plant increased by 10% compared to UE 374. This is a significant investment. Please explain the overarching needs and Company policies driving this level of investment.

Response to OPUC Data Request 412

(a) Please refer to Attachment 412-1 which provides hydraulic production plant costs on a system-wide basis, as reported in FERC Account 101 (Electric Plant-In Service) as of December 31, 2020, June 30, 2021, and December 31, 2021. The Company does not prepare test period data at the plant level as of December 31, 2022, but rather it is prepared on a function/allocation factor basis. All of the listed plants would be included in the same FERC Account Plant Function (Hydro) and allocation factor in all periods.

(b) The projection methodology is described below for each project and underlying support is provided in Attachment OPUC 412-2:

  i. The factor percentages for system generation-Pacific (SG-P) and system generation-Utah (SG-U) are the same as the system generation (SG) allocation factor. For allocation and embedded cost differential calculation purposes, the Company needs a way to identify westside and eastside hydro production plant. The SG-P allocation factor is for hydro plant on the westside, and the SG-U allocation factor is for hydro plant on the eastside.

ii. The hydro 'blanket' projects on page 8.4.20 are numerous projects categorized into the categories below. Only the two jurisdictional allocated (JA) designated projects are blankets, as described below:

1. "PP Hydro West" - Pacific Power hydro west includes investments in operating facilities on the Lewis River in Washington, the North Umpqua River and Rogue River in Oregon and the Klamath River which runs through Oregon and California. There are numerous projects in this category that include projects such as programmable logic controllers (PLC), automation of the Lemolo dam, generator step-up unit (GSU) replacements, cottage repairs at the Merwin village to provide safe housing, replacement of draft tube doors, trash rakes to remove debris from the intakes, and fish screens.

2. "PP Hydro East" - Pacific Power hydro east includes numerous investments in operating facilities in Utah and Idaho. There are various projects that include replacements of exciters and governors at Grace Units 3 through 5, governor replacements at Oneida Units 1 through 3, Grace Unit 3 and Unit 5 pivot valve replacement, Paris plant decommissioning, Grace plant protective relay replacements, and coating of the Cutler flowline.

3. "PP Hydro Impl On-Proj West" - Pacific Power hydro implementation west includes various investments in operating facilities as required per Federal Energy Regulatory Commission (FERC) licenses for hydro projects on the Lewis River in Washington, the North Umpqua River and Rogue River in Oregon and the Klamath River which runs through Oregon and California. These projects include renovations at the Cougar Campground, upstream and downstream fish passage facilities on the Lewis River, fishing access modifications on the Lewis River to comply with the Americans with Disabilities Act (ADA), and projects at the Prospect facility for wildlife crossings, and flowline replacement.

4. "PP Hydro Plant JA" - Hydro plant JA includes blanket projects that provide a means of allocating capital funds for unplanned equipment failures, supervisory control and data acquisition (SCADA) replacements, and surveillance camera replacements. These funds are

designated as “JA” instead of east or west since these funds will be allocated across all of the Company’s hydro fleet.

5. “PP Other Hydro Dam Safety West” and “PP Other Hydro Dam Safety East” - Pacific Power Other Hydro Dam Safety East and West includes various dam safety investments at the Company’s operating plants that are required for compliance with FERC dam safety obligations. Annual dam safety inspections are required under 18 Code of Federal Regulations (CFR) Part 12D and the FERC’s Division of Dam Safety and Inspections (D2SI). The projects include improvements to address Probable Maximum Flood (PMF) passage at dams and spillways and seismic remediation for dams on the Lewis River and Soda Springs plant, Lifton plant outlet gate rehabilitation, Lemolo 1 spillway improvements, and Yale Main Dam In-Situ Instrumentation.

6. “PP Other Hydro Dam Safety JA” - Pacific Power Other Dam Safety JA is a blanket project that provide a means of allocating capital funds for unplanned or emergency dam safety projects. These funds will be used for compliance with FERC dam safety inspections and initiatives. The “JA” designation is used instead of east or west since these funds will be allocated across the Company’s hydro fleet.

7. Please refer to the Company’s response to subpart (b) ii. 5. above.

(c) PacifiCorp hydro operations plant additions are driven primarily by the need to maintain compliance with FERC dam safety and license implementation obligations as well as compliance with local, state, and federal regulations that govern facility operations, maintenance of water levels and flow continuity, employee safety, environmental stewardship and preventative maintenance to ensure PacifiCorp’s hydro plants continue to reliably deliver clean energy. The average age of PacifiCorp’s hydro plants, which is 90 years old, also drives an ongoing need for capital additions for necessary upgrade and refurbishment projects.

OPUC Data Request 413

Utility Plant - Regarding Other Production Plant:

(a) Please provide the total plant, on a system-wide basis, by FERC Account, for each generating plant as of December 31, 2020, June 30, 2021, December 31, 2021, and projected as of December 31, 2022.

(b) Regarding the Company's 2020 Results of Operations (Docket No. RE 56(9), Adjustment 8.5, Major Plant Addition Detail - January 2021 - December 2021 (pages 8.5.6), Staff notes that "New Wind Generation" of $773,629,892 system-wide was listed. Please disaggregate this amount by plant and provide the final or estimated final total cost of each and the actual or estimated in-service date.

(c) Please explain the projection methodology and provide all work papers underlying the following blanket projects:

   i. PP Wind Production
   ii. PP Eagle Mitigation

(d) Regarding the overall allocation of Other Production Plant, please explain what is included in the situs plant allocated to Oregon which increased from $74,986 to $390,301 in this case.

(e) Regarding page 8.4.21 (Cheung, 1002/227):

   i. Please explain the projection methodology and provide all work papers underlying the following blanket projects.

      1. PP Wind Production
      2. PP Eagle Mitigation

   ii. Please explain how the $54,196,091 incremental additions for TB Flats are reflected in the deferred capital figures on page 8.14.15 (Cheung, 1002/279).
   iii. Please explain the significance and use of the SG-W factor listed. Staff notes the 2020 Protocol Factors (Cheung, 1002/294) shows a combined SG factor.
   iv. Please explain what "Seasonal SSGCT" means and why those projects are segregated from the other projects less than $1 million.

(f) Regarding PAC/500, Hemstreet/7, please provide all work papers underlying the stated variance in the final cost of the TB Flats wind project.

Response to OPUC Data Request 413

(a) Please refer to Attachment 413-1 which provides other production plant costs on a system-wide basis, as reported in FERC Account 101 (Electric Plant-In Service) as of June 30, 2021 and December 31, 2020 and December 31, 2021.

(b) Please refer to Confidential Attachment OPUC 413-2 which provides the disaggregation of the referenced $773.6 million by plant. For actual in-service information for the Ekola Flats wind project, please refer to the Company's compliance filing for Docket UE-374, filed January 7, 2021. For the actual in-service information for the Pryor Mountain and Foote Creek wind projects, please refer to the Company's compliance filing for Docket UE-374, filed April 5, 2021. For details on TB Flats wind project, please refer to the direct testimony of Company witness, Timothy J. Hemstreet, Exhibit PAC/500/Hemstreet/2-7.

(c) Please refer to the descriptions below which outline projection methodologies:

   i. "PP Wind Production" – Pacific Power wind production includes blanket projects that provide the means of allocating capital funds across the company's wind fleet for small tools, road and bank stabilization, electrical components, facility/office repairs, and wind Supervisory Control and Data Acquisition (SCADA) hardware and software, and vehicles for wind operations personnel. During the test period, these blankets were used to repair wind operations and maintenance (O&M) buildings, replace lighting fixtures, purchase or replace snow equipment, and vehicles for operations personnel for the Energy Vision 2020 (EV2020) projects.

   ii. "PP Eagle Mitigation" – Pacific Power eagle mitigation includes blanket projects that provide the means of allocating capital funds for wildlife technicians and environmental permitting and compliance for the entire wind fleet. These includes investments for vehicles for the wind wildlife technicians for avian monitoring, monitoring equipment, and freezers for avian carcasses.

(d) The situs plant is capital additions related to the Black Cap Solar project.

(e) Please refer to the Company's responses to subparts i. through iv. below:

   i. Please refer to the Company's response to subpart (c) above.

ii. The Company assumes that reference to "page 8.14.15" was intended to be a reference to page 8.14.5 of Cheung, Exhibit PAC/1002/279. Based on the foregoing assumption, the Company responds as follows:

    Please refer to Attachment OPUC 413-3.

iii. The allocation percentage is the same as the system generation (SG) allocation factor. The Company needed a way to identify the wind plant in the other production plant function. The system generation-wind (SG-W) designation was assigned to wind plant locations to make it easier to identify the amount of wind plant.

iv. The factor percentage for allocation is the same as the SG allocation factor. The Seasonal System Generation – Combustion Turbine, (SSGCT) allocation factor was part of the Revised Protocol allocation and is no longer used to allocate costs. The Company needed a way to identify gas peaker plants and continues to use the SSGCT designation to easily identify the gas peaker plants in the other production plant function. The resources in this category are the Gadsby Peaker units and the West Valley Peaker units.

(f) Please refer to Confidential Attachment OPUC 413-4.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 414

Utility Plant - Regarding Transmission Plant:

(a) Regarding the project benefits stated on Pac/600, Vail/8, please disaggregate and provide a separate narrative explanation regarding how each of the stated items specifically benefits Oregon customers. Please provide separate responses for each project and cross reference to the remainder of Mr. Vail's testimony as appropriate. If the Oregon benefits can be quantified please provide data.

   i. Increased load serving capability,
   ii. enhanced reliability,
   iii. conformance with NERC Reliability Standards,
   iv. improved transfer capability within the existing system,
   v. relief of existing congestion,
   vi. And interconnection and integration of new wind resources into PacifiCorp's transmission system.

(b) Regarding the OATT transmission charges discussed on Pac/600, Vail/8, please provide the expected annual incremental OATT revenue associated with each project and explain how the incremental revenues credits are reflected in this case.

(c) Regarding page 8.4.22 (Cheung, 1002/228) please identify which of the listed projects are blanket projects and explain the projection methodology and provide all underlying work papers.

1st Supplemental Response to OPUC Data Request 414

Further to the Company's response to OPUC Data Request 414 dated May 4, 2022, which provided the Company's response to subpart (b), the Company now provides this supplemental response to provide its responses to subparts (a) and (c):

(a) These projects increase transmission capacity, enhance overall system reliability and provide for conformance with North American Electric Reliability Corporation (NERC) Reliability Standards, which benefits all customers, including Oregon customers. As PacifiCorp has an extremely large, expansive transmission system stretching across multiple states, it is difficult, if not impossible to segregate benefits and the information requested on a state-by-state basis. The new lines will support the integration of new renewable resources if such requests are received.

1. The Jordanelle to Midway 138 kilovolt (kV) transmission line project has provided additional load serving capability by providing a third 138 kV source to transmission network customers. Prior to completion of the project, certain conditions would have caused voltage collapse and voltages below the accepted limits. The project mitigated this risk, providing enhanced reliability to transmission network customers as well as the capability to add load without increased risk of voltage collapse and service disruption to customers.

2. The Sugarmill to Rigby line supports the interconnection of Q0255 a new 151.8 megawatt (MW) renewable resource. The project also resolved system issues where certain conditions would have caused line overloads and voltages below the accepted limits.

(c) Please see Attachment OPUC 414-1 and OPUC 414-2 file regarding project methodologies and work papers on blanket project listed on page 8.4.22 (Cheung, 1002/228).

OPUC Data Request 414

Utility Plant - Regarding Transmission Plant:

(a) Regarding the project benefits stated on Pac/600, Vail/8, please disaggregate and provide a separate narrative explanation regarding how each of the stated items specifically benefits Oregon customers. Please provide separate responses for each project and cross reference to the remainder of Mr. Vail's testimony as appropriate. If the Oregon benefits can be quantified please provide data.

  i. Increased load serving capability,
  ii. enhanced reliability,
  iii. conformance with NERC Reliability Standards,
  iv. improved transfer capability within the existing system,
  v. relief of existing congestion,
  vi. And interconnection and integration of new wind resources into PacifiCorp's transmission system.

(b) Regarding the OATT transmission charges discussed on Pac/600, Vail/8, please provide the expected annual incremental OATT revenue associated with each project and explain how the incremental revenues credits are reflected in this case.

(c) Regarding page 8.4.22 (Cheung, 1002/228) please identify which of the listed projects are blanket projects and explain the projection methodology and provide all underlying work papers.

Response to OPUC Data Request 414

The Company is providing a response to subpart (b) only in this data request response. The Company's responses to subpart (a) and (c) will be provided in a supplemental response shortly.

(b) Open Access Transmission Tariff (OATT) revenue cannot be isolated on a plant or project-specific basis. As new transmission capital plant is placed in-service, the total transmission capital balance will be reported in FERC Form 1, and the Company will capture the balance as a rate base component in the annual transmission revenue requirement (ATRR) formula. There is not a one-to-one relationship between transmission revenues and individual projects that is calculated. Please refer to the direct testimony of Company witness, Exhibit PAC/600, Vail/8, for a detailed description on how the rate is calculated and applied.

OPUC Data Request 415

Utility Plant - Regarding Distribution Plant Additions, pages 8.4.23 and 8.4.24 (Cheung, 1002/229/230):

(a) Please explain the projection methodology and provide all work papers underlying the following blanket projects:

  i. PP Distribution OR
  ii. PP Dist New Connect OR
  iii. OR Distribution Major Projects

Response to OPUC Data Request 415

Please refer to the methodologies below and Attachment OPUC 415 for the supporting work papers.

i. "PP Distribution OR" includes blanket projects that provide the means of allocating capital funds to replace, rebuild, upgrade, and improve distribution lines and substations. Projection methodologies include replacement and upgrade plans based on asset inspection results, historical analysis of replacement and failure spend rates, analysis of system loading measures identifying and prioritizing areas for system improvement, identifying unit replacement quantities applying a forecasted cost per unit spend based on historical analysis.

ii. "PP Dist New Connect OR" includes blanket projects that provide the means of allocating capital funds to build and upgrade distribution lines for the purpose of connecting new residential, commercial, industrial, irrigation, and street lighting loads. Projection methodologies include utilizing load forecasting models based on the last trends from the preceding history to predict growth rates each planning cycle and then forecast quantities and costs associated to new load additions by customer class.

iii. "OR Distribution Major Projects" includes blanket projects that provides the means of allocating capital funds for improvements and reinforcements needed on distribution facilities in Oregon that are 69 kilovolt (kV) and below. These projects support general load growth, as determined by area planners through studies and analysis. The area planning group falls within the Transmission group of PacifiCorp which is why these projects are differentiated from the projects included in the blanket project classifications as described in the Company's responses to subparts i. and ii. above.

OPUC Data Request 417

Utility Plant - Regarding General Plant Additions, page 8.4.25 (Cheung, 1002/231):

(a) Please explain the projection methodology and provide all work papers underlying the following blanket projects:

i. PP Core IT and TOM Hardware Equipment
ii. PP Vehicles OR
iii. PP Com Plant OR
iv. PP Hydro Vehicles
v. PP Hydro General Plant
vi. PP Structures OR
vii. PP General Plant OR
viii. PP IT Business Requested Hardware Equipment

Response to OPUC Data Request 417

(a) Please refer to the descriptions below which outline projection methodologies and Attachment OPUC 417 which provides the supporting work papers used to derive plant additions for listed blanket projects:

i. "PP Core IT and TOM Hardware Equipment" represents PacifiCorp's investment program which provides a means to allocate capital funds to hardware purchases necessary to support the Company's existing applications, infrastructure, and for Large Scale Technology Obsolescence Management (TOM). The hardware investments are conducted to add capacity or improve software functionality and capabilities while the large scale TOM seek to address system obsolescence and to add capacity to support server computing and storage. The projection methodology includes historical analysis of hardware spend and technology refresh cycles of five to seven years.

ii. "PP Vehicles OR" includes blanket projects that provide the means of allocating capital funds to add, replace, or rebuild vehicles. Projection methodologies include replacement and upgrade plans based on vehicle inspection and repair results, historical analysis of replacement and failure rates, industry lifecycle replacement recommendations by vehicle class as reviewed and proposed by our Transportation department.

iii. "PP Com Plant OR" provides the means of allocating capital funds for the purchase of telecommunication equipment including replacement or functional upgrades of mobile, microwave/fiber, or other communication equipment. The projection methodology includes a detailed analysis of business requirements and replacement lifecycle based on the expectancy for telecommunication hardware.

iv. "PP Hydro Vehicles" includes blanket projects that provide the means of allocating capital funds to add, replace, or rebuild vehicles. Projection methodologies include replacement and upgrade plans based on vehicle inspection and repair results, historical analysis of replacement, mileage, failure rates, and industry lifecycle replacement recommendations by vehicle class as reviewed and proposed by the Company's transportation department.

v. "PP Hydro General Plant" incudes blanket capital projects related to the Company's hydro facilities. Projects include office furniture and equipment, stores equipment, small tools, communication equipment, power operated equipment to maintain facilities and repairs to the Company's facilities.

vi. "PP Structures OR" includes blanket projects that provide the means of allocating capital funds to replace or upgrade Company facility structures. Projection methodologies include replacement and upgrade plans based on facility inspection and repair results, historical analysis of replacement and failure rates of various assets at the Company facilities in Oregon, plan replacement schedules for lifecycle expectancy of facility assets.

vii. "PP General Plant OR" includes blanket projects that provide the means of allocating capital funds to add, replace, or upgrade Company tools and equipment. Projection methodologies include replacement and upgrade plans based on facility inspection and repair results, historical analysis of replacement and failure rates of various tools used across the Company locations in Oregon, plan replacement schedules for lifecycle expectancy of tool and equipment asset, analysis, and review of new tools for improving work processes.

viii. "PP IT Business Requested Hardware Equipment" includes activities related to new or improved IT hardware purchases required to support business operations which are approved as individual projects, for various locations. The projection methodology includes a detailed analysis of business requirements and replacement lifecycle based on the expectancy for hardware.

OPUC Data Request 418

Utility Plant - Regarding Intangible Plant Additions, page 8.4.26 (Cheung, 1002/232):

(a) Please explain the projection methodology and provide all work papers underlying the following blanket project:

    i. PP Core IT and TOM Software

Response to OPUC Data Request 418

Please refer to the Company's response to OPUC Data Request 383, specifically Attachment OPUC 383. The projection methodology includes historical analysis of software spend related to Core IT and Large Scale Technology Obsolescence Management (TOMs).

Please refer to Attachment OPUC 418 which provides underlying support for this project.

OPUC Data Request 427

Arrearage Management Program - Refer to the Company's response to OPUC Data Request 151. Please reproduce this data request with added columns that state the kWh consumed in each month and the size of the bill in that month. That is, for each residential customers that consumed more than 5,000 kWh in a single month in 2021, please provide:

(a) The nine-digit zip code for the customer,

(b) The month(s) in which the customer's consumption exceeded 5,000 kWh,

(c) Whether the customer received bill assistance through the Company's Arrearage Management Plan (AMP),

(d) The billed kWh in that month, and

(e) The dollar value of the bill for that month.

Response to OPUC Data Request 427

Please refer to Attachment OPUC 427.

Note: some slight variances exist in the data provided in Attachment OPUC 427 when compared to the Company's response to OPUC Data Request 151 due, in part, to billing adjustments and on-going changes with the Arrearage Management Program (AMP).

OPUC Data Request 442

Arrearage Management Program - Refer to the Company's response to Staff DR 427. Please discussed any efforts the Company has made to confirm that the customers who consumed more than 10,000 kWh on a bill and enrolled in the Arrearage Management Program were indeed residential customers.

Response to OPUC Data Request 442

The Company limits Arrearage Management Program (AMP) participation to residential customers by reviewing an applicant's revenue class at the time of issuing a grant -- which is based on arrears without a differentiation for consumption.

Jun 2022 - Other Economic Indicators

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP (Bil of 2012 $),												
Chain Weight (in billions of $)	19,032.7	18,384.7	19,427.3	20,006.5	20,567.6	21,119.0	21,626.6	22,118.1	22,610.6	23,110.2	23,588.9	24,060.4
% Ch	2.3	(3.4)	5.7	3.0	2.8	2.7	2.4	2.3	2.2	2.2	2.1	2.0
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2012=100	112.3	113.7	118.5	125.2	128.9	132.0	135.1	138.0	140.9	144.0	147.1	150.3
% Ch	1.8	1.3	4.2	5.7	2.9	2.4	2.3	2.2	2.1	2.2	2.2	2.2
Personal Consumption Deflator,												
Chain Weight U.S., 2012=100	109.9	111.2	115.5	122.2	125.3	127.8	130.3	132.8	135.3	138.0	140.8	143.6
% Ch	1.5	1.2	3.9	5.8	2.5	2.0	2.0	1.9	1.9	2.0	2.0	2.0
CPI, Urban Consumers,												
1982-84=100												
West Region	270.3	275.1	287.5	308.5	319.5	327.7	335.3	342.9	350.9	359.9	369.3	379.1
% Ch	2.7	1.7	4.5	7.3	3.6	2.6	2.3	2.2	2.3	2.6	2.6	2.7
U.S.	255.6	258.8	271.0	289.4	296.7	303.0	308.9	314.3	320.6	327.5	334.7	342.1
% Ch	1.8	1.2	4.7	6.8	2.6	2.1	1.9	1.7	2.0	2.2	2.2	2.2
Oregon Average Wage												
Rate (Thous $)	57.4	62.6	67.1	70.8	73.9	77.1	80.2	83.3	86.5	89.9	93.4	97.1
% Ch	3.8	9.2	7.1	5.6	4.4	4.2	4.0	3.9	3.9	3.9	3.9	3.9
U.S. Average Wage												
Wage Rate (Thous $)	61.8	66.4	70.7	74.2	77.7	81.1	84.5	87.9	91.3	94.8	98.4	102.1
% Ch	3.4	7.5	6.4	5.0	4.7	4.4	4.2	4.0	3.9	3.8	3.8	3.8
Housing Indicators												
FHFA Oregon Housing Price Index												
1991 Q1=100	436.6	472.8	559.4	627.6	658.7	688.5	720.8	756.3	794.9	834.8	876.4	920.1
% Ch	4.8	8.3	18.3	12.2	5.0	4.5	4.7	4.9	5.1	5.0	5.0	5.0
FHFA National Housing Price Index												
1991 Q1=100	270.0	291.2	340.1	386.8	408.8	421.4	431.0	437.7	443.6	450.5	459.5	469.5
% Ch	5.1	7.9	16.8	13.7	5.7	3.1	2.3	1.6	1.3	1.6	2.0	2.2
Housing Starts												
Oregon (Thous)	20.7	18.1	20.2	19.8	21.1	21.8	22.0	22.3	22.5	22.6	22.7	22.7
% Ch	5.7	(12.7)	12.1	(2.5)	6.9	3.3	0.8	1.5	0.7	0.7	0.2	(0.0)
U.S. (Millions)	1.3	1.4	1.6	1.6	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.4
% Ch	3.6	8.1	14.9	0.9	(6.8)	(1.2)	0.4	(2.8)	(2.3)	(0.9)	(0.9)	(1.9)
Other Indicators												
Unemployment Rate (%)												
Oregon	3.7	7.6	5.2	3.7	3.6	3.8	4.0	4.1	4.1	4.1	4.1	4.1
Point Change	(0.3)	3.9	(2.4)	(1.5)	(0.1)	0.2	0.2	0.1	0.0	0.0	0.0	0.0
U.S.	3.7	8.1	5.4	3.6	3.6	3.8	4.1	4.3	4.4	4.4	4.3	4.3
Point Change	(0.2)	4.4	(2.7)	(1.8)	0.0	0.2	0.3	0.2	0.1	(0.0)	(0.0)	(0.0)
Industrial Production Index												
U.S, 2012 = 100	102.3	95.0	100.1	105.9	109.2	111.8	114.2	116.1	117.8	119.5	121.2	122.8
% Ch	(0.8)	(7.2)	5.4	5.8	3.1	2.4	2.1	1.7	1.5	1.4	1.4	1.3
Prime Rate (Percent)	5.3	3.5	3.3	4.1	6.0	6.1	5.8	5.8	5.7	5.7	5.7	5.7
% Ch	7.7	(32.9)	(8.3)	27.3	44.5	2.1	(5.7)	(0.0)	(0.0)	(0.0)	(0.0)	0.0
Population (Millions)												
Oregon	4.21	4.24	4.27	4.30	4.33	4.36	4.40	4.43	4.47	4.51	4.54	4.58
% Ch	0.9	0.7	0.5	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
U.S.	330.4	331.5	332.0	333.1	334.7	336.4	338.1	340.0	341.8	343.6	345.5	347.3
% Ch	0.5	0.3	0.1	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Timber Harvest (Mil Bd Ft)												
Oregon	3,541.3	3,377.5	3,664.9	3,653.0	3,509.0	3,553.1	3,624.7	3,697.7	3,767.5	3,781.5	3,780.2	3,779.0
% Ch	(12.9)	(4.6)	8.5	(0.3)	(3.9)	1.3	2.0	2.0	1.9	0.4	(0.0)	(0.0)

CASE: UE 399
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Confidential Exhibits in Support Of Opening Testimony

June 22, 2022

CASE: UE 399
WITNESS: John Fox and Eric Shierman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Staff Analysis

UM 1964
PACIFICORP DEFERRED ACCOUNTING FOR TEC PROGRAM

June 22, 2022

STAFF RECOMMENDATION:

Staff recommends that the Public Utility Commission of Oregon (Commission) approve Pacific Power's (PacifiCorp or Company) application for an order authorizing the company to establish and maintain a balancing account to record the deferral of program costs and revenues related to PacifiCorp's Transportation Electrification Program beginning July 17, 2018.

DISCUSSION:

Issue

Whether the Commission should authorize PacifiCorp's use of deferred accounting for program costs and revenues related to PacifiCorp's Transportation Electrification Program.

Applicable Rule or Law

Beginning with the date of the Application, the Commission may approve the deferral of identifiable utility expenses or revenues, the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes for the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers. ORS 757.259(2)(e) and (4). Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts deferred are allowed in rates to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. ORS 757.259(4); OAR 860-027-0300(9). The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility. ORS 757.259(5).

Analysis

Background
In Docket No. UM 1810, Order No. 18-075, as amended by Order No. 19-087, the Commission approved a stipulation authorizing PacifiCorp to undertake three pilot programs designed to accelerate transportation electrification: an Outreach and Education Pilot, a Demonstration and Development Pilot, and a Public Charging Pilot.

On December 28, 2021, the Commission approved PacifiCorp's Advice No. 21-022 revising Schedule 290 and creating Schedule 291 to adjust and implement rates for Public Purpose, Energy Efficiency and Transportation Electrification funds pursuant to HB 3141 and HB 2165, for service rendered on and after January 1, 2022.

PacifiCorp's Filings
The Company has filed the following deferral applications in this docket:

- UM 1964 initial application – filed 7/27/18,

- UM 1964(1) supplemental application – filed 3/20/20,
- UM 1964(2) supplemental application – filed 3/24/20,
- UM 1964(3) supplemental application – filed 3/23/21, and
- UM 1964(4) supplemental application – filed 3/23/22.

Proposed Accounting

PacifiCorp will record deferred TE Program expense amounts by crediting FERC Account 906, Customer Service and Informational Expenses, and debiting the TE Program balancing account, in FERC Account 182.3, Other Regulatory Assets.[1]

PacifiCorp also proposed that the deferral balance would be reduced monthly by the amount collected under Schedule 95 recovering TE Program costs. In addition, revenues from public charging stations and monetized credits from the Oregon Clean Fuels Program related to the TE Program will be credited to the proposed TE Program balancing account.[2]

Staff notes that Schedule 95 was originally approved by the Commission in 2016 for a funding a proposed Irrigation Load Control Program Pilot and is no longer in effect.[3]

In its most recent deferral application, the Company states the following:

> PacifiCorp proposes to continue maintaining a balancing account to record the costs related to its TE Program, the collection of cost recovery through Schedule 291, the collection of revenues from public charging stations established under the TE Program, the receipt of monetized credits from the Oregon Clean Fuels Program, and related interest.[4]

Estimated Deferrals in Authorization Period

In its most recent deferral application, the Company states the following:

> Through December 31, 2021, PacifiCorp has deferred $2,600,000 (including interest) for program-related activity including public charging capital spend and operations and maintenance offset by charging station revenue, outreach and education capital spend and operations and maintenance, demonstration capital spend and operations and maintenance and other miscellaneous costs. PacifiCorp expects to defer approximately $65,000 in 2022.[5]

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[1] Initial application at 5.

[2] *Id.*

[3] See *PACIFICORP. Schedule 95, Pilot Program Cost Adjustment*, Docket No. ADV 279, approved May 3, 2016.

[4] UM 1964(4) at 4.

[5] *Id.* The application also states that *"As agreed to by stipulating parties and approved by the Commission in docket UM 1810, Order No. 18-075, as modified by Order No. 19-087, the budget is capped at $4.64 million during the three-year pilot period."*

Staff notes that the accumulated deferred amounts and proposed amortization schedule are presented in testimony and that the December 31, 2021, balance presented therein is $2,660,557.[6]

Effective January 1, 2022, as noted above, transportation electrification costs are being collected on Schedule 291. Therefore, no additional amounts are being deferred after 2021.[7]

Interest Accrued

Amounts deferred include interest at the Company's authorized ROR through December 31, 2022 and the Modified Blended Treasury (MBT) rate thereafter.[8]

Information Related to Proposed Amortization

- Earnings Review – The earnings review required under ORS 757.259 is discussed in Staff's UE 399 opening testimony.
- Prudence Review – The scope of amounts deferred are pursuant to the stipulated agreement in Order No. 18-075. Staff is not aware of any subsequent information which would cause Staff to question the prudence of amounts deferred.
- Sharing – Staff does not propose a sharing mechanism for the deferred amounts.
- Rate Spread/Design – Not applicable as the Company is proposing amortization in base rates.

Discussion

For the reasons stated above, Staff recommends the Commission approve the Company's application.

Conclusion

For the reasons stated above, Staff recommends the Commission approve the Company's application.

PROPOSED COMMISSION GRC ACTION:

Approve PacifiCorp's use of deferred accounting for program costs and revenues related to PacifiCorp's Transportation Electrification Program from July 17, 2018 through December 31, 2021.

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[6] Page 8.6.4 (Cheung, 1002/245).

[7] *Id.*

[8] *Id.*

CASE: UE 399
WITNESS: John Fox

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Staff Analysis

UM 2134
PACIFICORP DEFERRAL OF COSTS RELATING TO CEDAR SPRINGS II

June 22, 2022

STAFF RECOMMENDATION:

Staff recommends that the Public Utility Commission of Oregon (Commission) approve Pacific Power's (PacifiCorp or Company) application to defer the revenue requirement associated with the Cedar Springs wind project effective December 10 through December 31, 2020.

DISCUSSION:

Issue

Whether the Commission should for an order authorizing the Company to defer the revenue requirement associated with the Cedar Springs II wind resource and associated transmission (Cedar Springs II), which was placed into service on December 8, 2020.

Applicable Rule or Law

Beginning with the date of the Application, the Commission may approve the deferral of identifiable utility expenses or revenues, the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes for the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers. ORS 757.259(2)(e) and (4). Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts deferred are allowed in rates to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. ORS 757.259(4); OAR 860-027-0300(9). The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility. ORS 757.259(5).

The Company also cites Oregon's Renewable Portfolio Standards (ORS 469A), the Commission's *Investigation of Automatic Adjustment Clause Pursuant to SB 838* (Order No. 07-572, Docket No. UM 1330) and *Investigation of the Scope of the Commission's Authority to Defer Capital Costs* (Order No. 20-147, Docket No. UM 1909) as part of the statutory and regulatory framework underlying this particular deferral request.[1]

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[1] Application at 2.

Analysis

Background

As noted in the application, Cedar Springs 2 was included in the Company's 2020 rate case filing.[2] The Commission subsequently ordered the capital cost of the project to be included in base rates effective January 1, 2021.[3]

PacifiCorp's Filings

The Company's deferral filing occurred on December 10, 2020, stating that the Cedar Springs II wind resource and associated transmission (Cedar Springs II), was placed into service on December 8, 2020.[4]

In this case, the Company's amortization proposal is summarized at Cheung, 1000/38-39 and detailed calculation are included in the Company's adjustment 8.14 (Cheung, 1002/274-283).

Proposed Accounting

PacifiCorp proposes to account for the revenue requirement of Cedar Springs II by recording the deferral in Account 182.3 (Regulatory Assets).[5]

Estimated Deferrals in Authorization Period

The Company's deferral filing estimated that approximately $0.8 million plus interest may be deferred as the revenue requirement of Cedar Springs II between December 10, 2020, and ending on December 31, 2020.[6]

The Company's rate case filing reports a total deferred amount of $647,365, without gross up, which includes return on investment, O&M expense, depreciation, and property taxes.[7]

Interest Accrued

Amounts deferred include interest at the Company's authorized ROR through December 31, 2022, and the Modified Blended Treasury (MBT) rate thereafter.[8]

Information Related to Proposed Amortization

- Earnings Review – The earnings review required under ORS 757.259 is discussed in Staff's UE 399 opening testimony.
- Prudence Review – As discussed above the deferred amounts are reasonable. The project itself was determined to be prudent in the UE 374 rate case.

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[2] Application at 4.

[3] See *In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 50.

[4] Application at 1.

[5] Application at 5.

[6] Application at 5.

[7] Adjustment 8.14.2 (Cheung, 1002/276).

[8] Adjustment 8.14.1 (Cheung, 1002/275).

- Sharing – Staff does not propose a sharing mechanism for the deferred amounts.
- Rate Spread/Design – Not applicable as the Company is proposing amortization in base rates.

Discussion

Staff has reviewed the Company's work papers and finds the amounts and methodology to be reasonable, with the exception that the return on capital appears to include an entire month.[9] Staff recommends this amount be calculated based on the 22 day period elapsed between the deferral filing and the end of December 2020 which Staff calculates will decrease the deferred amount from $647,365 to $511,073.

Conclusion

For the reasons stated above, Staff recommends the Commission approve the Company's application subject to a reduction in the deferred amount to $511 thousand.

PROPOSED COMMISSION GRC ACTION:

Approve PacifiCorp's application to defer the revenue requirement associated with the Cedar Springs wind project effective December 10 through December 31, 2020, subject to the revised methodology proposed by Staff.

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[9] See Adjustment 8.14.2. The calculated return on an Oregon allocated basis, is $7,966,308 annually / 12 = $663,859.

CASE: UE 399
WITNESS: John Fox

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 206

Staff Analysis

UM 2142
PACIFICORP DEFERRED ACCOUNTING FOR CHOLLA UNIT 4 PROPERTY TAX EXPENSE

June 22, 2022

STAFF RECOMMENDATION:

Not Applicable - no reauthorization of the deferral application is pending. Amortization of the previously approved deferral is discussed in Staff's opening testimony.

REFERENCE INFORMATION:

Background
In Order No. 20-473, the Commission declined to include property tax expenses related to closure of the Cholla Generating Station, known to be non-recurring, in base rates, but stated that it will allow the Company to defer the assessed property tax costs assigned to Cholla Unit 4 through the closure process.[1]

In Order No. 21-044, the Commission approved PacifiCorp's previous application in the UM 2142 docket requesting deferral of Cholla Unit 4-Related Property Tax Expense for the 12-month period beginning January 1, 2021.

PacifiCorp's Rate Case Filing
The Company's amortization proposal is summarized at Cheung, 1000/37-38 and detailed calculations are included in the Company's adjustment 8.13 (Cheung, 1002/272-273).

Proposed Accounting
PacifiCorp records deferred amounts to FERC Account 182.3, Other Regulatory Assets.

Estimated Deferrals in Authorization Period
In Order No. 21-044 the Commission approved deferral of PacifiCorp's full Cholla Unit 4-related property tax expense beginning on January 1, 2021, for later inclusion in rates.

The Company's rate case filing shows a total of $624,180 was deferred before interest charges.[2] The accumulated balance including interest as of December 31, 2022, is estimated to be $639,589.

Interest Accrued
This account accrues interest at the Modified Blended Treasury (MBT) rate (i.e., blended Treasury rate plus 100 basis points).[3]

Information Related to Proposed Amortization

- Earnings Review – The earnings review required under ORS 757.259 is discussed in Staff's UE 399 opening testimony.

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[1] See *In re PacifiCorp*, OPUC Docket No. UE 374, Order No. 20-473 at 97 (Dec 18, 2020).
[2] Adjustment 8.13.14 (Cheung, 1002/273).
[3] *Id*.

- Prudence Review – The Commission's UE 374 order states: "we will allow the company to defer the assessed property tax costs assigned to Cholla Unit 4 through the closure process". As the amount of taxes assessed is an objectively verifiable figure, no further prudence review is necessary.
- Sharing – Staff does not propose a sharing mechanism for the deferred amounts.
- Rate Spread/Design – Not applicable as the Company is proposing amortization in base rates.

CASE: UE 399
WITNESS: John Fox and Madison Bolton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 207

Staff Analysis

UM 2167
Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain

June 22, 2022

STAFF RECOMMENDATION:

Staff recommends that the Public Utility Commission of Oregon (Commission) approve Pacific Power's (PacifiCorp or Company) application for an order authorizing the Company to defer the revenues associated with the renewable energy credits (RECs) from the Pryor Mountain Wind Facility for the period May 1, 2021 through April 30, 2022.

DISCUSSION:

Issue

Whether the Commission should authorize PacifiCorp's application for an order authorizing the Company to defer the revenues associated with the renewable energy credits (RECs) from the Pryor Mountain Wind Facility.

Applicable Rule or Law

Beginning with the date of the Application, the Commission may approve the deferral of identifiable utility expenses or revenues, the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes for the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers. ORS 757.259(2)(e) and (4). Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts deferred are allowed in rates to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. ORS 757.259(4); OAR 860-027-0300(9). The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility. ORS 757.259(5).

Analysis

Background
As stated in the Company's application, Pryor Mountain is a 240 megawatt wind facility located in Carbon County, Montana. In 2019, PacifiCorp purchased the development rights for the Pryor Mountain wind facility and contracted with Vitesse, LLC (Vitesse) to purchase all the RECs associated with the project under Oregon's schedule 272.[1]

The history and policy implications of this arrangement have been litigated in Docket No. UE 374 and further elaborated in Docket No. UM 2163 and need not be repeated here.[2]

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[1] Application at 2.
[2] See Order Nos. 20-473 at 50 and 131, 20-190 at 9, and 21-146 at 3.

PacifiCorp's Filing
The Company states that the Pryor Mountain project was placed in service on April 1, 2021, and PacifiCorp filed on April 5, 2021, to recover the costs of the project and pass on the net power cost benefits to customers. Under the Schedule 272 agreement with Vitesse, PacifiCorp supplies and retires on behalf of Vitesse, all of the RECs generated by the resource for which PacifiCorp receives certain revenue.[3]

The Company also states that it is the revenue from these purchases that PacifiCorp is seeking to defer for the benefit of PacifiCorp's customers.[4]

In this case, the Company's amortization proposal is summarized at Cheung, 1000/34-35 and detailed calculation are included in the Company's adjustment 8.6 (Cheung, 1002/241-251).

Proposed Accounting
Beginning on the date that the Pryor Mountain Wind Facility was placed in service, PacifiCorp proposes to account for the revenue by recording the deferral in FERC Account 254 (Other Regulatory Liabilities).

Estimated Deferrals in Authorization Period
PacifiCorp estimated in its deferral application that approximately **[Begin Confidential]** [redacted] **[End Confidential]** plus interest may be deferred as revenue between May 1, 2021, and ending on April 30, 2022.[5]

The Company's work papers in this case show **[Begin Confidential]** [redacted] **[End Confidential]** before interest, during this period and an additional **[Begin Confidential]** [redacted] **[End Confidential]** expected to be deferred through December 2022.[6]

Interest Accrued
Amounts deferred include interest at the Company's authorized ROR through December 31, 2022, and the Modified Blended Treasury (MBT) rate thereafter.[7]

Information Related to Proposed Amortization

- Earnings Review – The earnings review required under ORS 757.259 is discussed in Staff's UE 399 opening testimony.
- Prudence Review – Staff finds that the Company's deferral of these amounts for the benefit of customers is prudent.
- Sharing – Staff does not propose a sharing mechanism for the deferred amounts.

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[3] Application at 3.
[4] *Id.*
[5] *Id.*
[6] Adjustment 8.6.5_CONF (Cheung, 1002/246).
[7] Adjustment 8.6.5_REDACTED (Cheung, 1002/246).

- Rate Spread/Design – Not applicable as the Company is proposing amortization in base rates.

Conclusion

For the reasons stated above, Staff recommends the Commission approve the Company’s application.

PROPOSED COMMISSION GRC ACTION:

Approve PacifiCorp's application to defer the revenues associated with the RECs from the Pryor Mountain Wind Facility for the period May 1, 2021 through April 30, 2022.

CASE: UE 399
WITNESS: John Fox and Rose Anderson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 208

Staff Analysis

UM 2186
Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120
(TB Flats)

June 22, 2022

STAFF RECOMMENDATION:

Staff recommends that the Public Utility Commission of Oregon (Commission) approve Pacific Power's (PacifiCorp or Company) application for an order authorizing the Company to defer the revenue requirement associated with the remaining portion of the TB Flats wind facility for the 12 months beginning July 27, 2021.

DISCUSSION:

Issue

Whether the Commission should authorize PacifiCorp's application for an order authorizing the Company to defer the revenues associated with the renewable energy credits (RECs) from the Pryor Mountain Wind Facility.

Applicable Rule or Law

Beginning with the date of the Application, the Commission may approve the deferral of identifiable utility expenses or revenues, the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes for the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers. ORS 757.259(2)(e) and (4). Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts deferred are allowed in rates to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. ORS 757.259(4); OAR 860-027-0300(9). The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility. ORS 757.259(5).

Analysis

Background
As stated in the Company's application, TB Flats is a nominal 500 MW resource consisting of 132 wind turbine generators with a total nameplate capacity of 503.2 MW. By December 21, 2020, 35 wind turbine generators were placed in service and included in customer rates on January 1, 2021. The remaining 97 wind turbine generators were fully placed into service, producing power, and connected to transmission facilities on July 26, 2021.[1]

PacifiCorp's Filing
The Company states that the requested deferral is for the costs and benefits of the 97 remaining wind turbine generators at the TB Flats wind facility that are not yet included in customer rates.[2]

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[1] Application at 4.
[2] *Id.*

The Company further states that TB Flats is currently in commercial operation and is used and useful, but the costs and benefits associated with the resource are not currently reflected in rates. The Commission has examined the TB Flats wind project as part of PacifiCorp's most recent general rate case and determined that it was "prudent and in the public interest".[3] However, since all of the remaining wind turbine generators were not be in service by June 30, 2021, PacifiCorp conferred with the parties to the general rate case. After those discussions PacifiCorp determined it was necessary to file a RAC. This deferral accounts for the costs and benefits of the TB Flats project until it is recovered through rates at the conclusion of the RAC proceeding.[4]

In this case, the TB Flats project in general is discussed in Exhibit 500. The total project cost is noted to be approximately $15.8 million higher overall on a total-company basis when compared to the 2021 rate case (Cheung, 1000/9).

Company's amortization proposal is summarized at Cheung, 1000/38-39 and detailed calculations are included in the Company's adjustment 8.14 (Cheung, 1002/274-283).

Proposed Accounting
Beginning on July 27, 2021, PacifiCorp proposes to account for the revenue requirement and NPC and PTC benefits of TB Flats by recording the deferral in Account 182.3 (Regulatory Assets).

Estimated Deferrals in Authorization Period
PacifiCorp estimated that approximately $12.4 million plus interest may be deferred for the revenue requirement and NPC and PTC Benefits of TB Flats for the 12 months beginning July 27, 2021.[5]

The Company's work papers in this case show $10,132,814 before interest, during this period and an additional $6,920,512 expected to be deferred through December 2022.[6]

Interest Accrued
Amounts deferred include interest at the Company's authorized ROR through December 31, 2022, and the Modified Blended Treasury (MBT) rate thereafter.[7]

Information Related to Proposed Amortization

- Earnings Review – The earnings review required under ORS 757.259 is discussed in Staff's UE 399 opening testimony.

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[3] See Docket No. UE 374, Order No. 20-473 at 50.

[4] Staff notes that the RAC filing did not occur and that the prudence review and amortization terms are proposed in this case.

[5] Application at 5.

[6] Adjustment 8.14.4 (Cheung, 1002/278).

[7] *Id.*

- Prudence Review – Staff is not aware of any subsequent information which would cause Staff to question the prudence of amounts deferred.
- Sharing – Staff does not propose a sharing mechanism for the deferred amounts.
- Rate Spread/Design – Not applicable as the Company is proposing amortization in base rates.

Conclusion

For the reasons stated above, Staff recommends the Commission approve the Company's application.

PROPOSED COMMISSION GRC ACTION:

Approve PacifiCorp's application authorizing the Company to defer the revenue requirement associated with the remaining portion of the TB Flats wind facility for the 12 months beginning July 27, 2021.

CASE: UE 399
WITNESS: John Fox and Ryan Bain

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 209

Staff Analysis

UM 2201
AWEC APPLICATION FOR PACIFICORP TO DEFER FLY ASH REVENUES

June 22, 2022

STAFF RECOMMENDATION:

Staff recommends that the Public Utility Commission of Oregon (Commission) approve the Alliance of Western Energy Consumers' (AWEC) application for an order requiring PacifiCorp to defer fly ash revenues effective for the 12-month period beginning November 2, 2021.

DISCUSSION:

Issue

Whether the Commission should authorize AWEC's application for an order requiring PacifiCorp to defer fly ash revenues.

Applicable Rule or Law

Beginning with the date of the Application, the Commission may approve the deferral of identifiable utility expenses or revenues, the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes for the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers. ORS 757.259(2)(e) and (4). Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts deferred are allowed in rates to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. ORS 757.259(4); OAR 860-027-0300(9). The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility. ORS 757.259(5).

Analysis

Background
As stated in the AWEC's application, Fly ash is a byproduct of the combustion of coal and used in construction to develop concrete, bricks, and other building supply products. "PacifiCorp produces fly-ash mainly from the Jim Bridger plant, with small amounts being sold from Naughton, Craig, and previously, Cholla."[1]Fly ash revenue, including an Oregon allocation of the revenue associated with Jim Bridger, is included Oregon's 2020 rate base.[2] Subsequent to the conclusion of PacifiCorp's 2020 general rate case, Docket No. UE 374, PacifiCorp entered into a new, more lucrative third-party contract to sell fly ash. As a result, PacifiCorp's revenues from fly ash sales have increased substantially on a system basis, resulting in an increase to the amount allocated to Oregon.[3]

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[1] Docket No. UE 390, Order No. 21-379, at 34 (Nov. 1, 2021).
[2] *Id.*
[3] Application at 3.

Furthermore, AWEC states that in October 2020, Rocky Mountain Power, a business unit of PacifiCorp with service territory throughout Utah, Wyoming, and Idaho, entered into a new fly ash sales agreement from the Jim Bridger coal plant. Based on this new contract, PacifiCorp has recognized a material increase to the revenues generated from fly ash sales in 2021 relative to the amounts included in the Company's Oregon 2020 rate base in UE 374.[4]

AWEC's Deferral Filing
AWEC's application requests deferred accounting treatment for Oregon-allocated revenue generated from PacifiCorp's increased fly ash sales so those revenues can eventually be passed back to customers through later ratemaking treatment as deemed appropriate by the Commission.[5]

PacifiCorp's Rate Case Filing
In this case, PacifiCorp increases fly ash revenue to $15,364,905 system-wide and $4,005,631 Oregon allocated in Adjustment 3.5 (Cheung, 1002/65).

Proposed Accounting
Beginning on July 27, 2021, PacifiCorp proposes to account for the revenue requirement and NPC and PTC benefits of TB Flats by recording the deferral in Account 182.3 (Regulatory Assets).

Estimated Deferrals in Authorization Period
AWEC estimates the amount of fly ash sales revenue projected in PacifiCorp's Oregon 2020 base rates was $4,256,000 on a system basis, with $1,107,523 allocated to Oregon. However, PacifiCorp's fly ash sales are expected to increase to $15,761,142 on a system basis in 2021, with $4,173,799 allocated to Oregon, an increase of 377 percent.[6]

Interest Accrued
Amounts deferred should include interest at the Company's authorized ROR through December 31, 2022, and the Modified Blended Treasury (MBT) rate thereafter.

Information Related to Proposed Amortization

- Earnings Review – The earnings review required under ORS 757.259 is discussed in Staff's UE 399 opening testimony.
- Prudence Review – Staff finds that AWEC's proposed deferral of these amounts for the benefit of customers is prudent.
- Sharing – Staff does not propose a sharing mechanism for the deferred amounts.
- Rate Spread/Design – Staff proposed to use the same rate spread and rate design as the other deferrals in the GRC.

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[4] Order No. 21-379, at 34.
[5] Application at 3.
[6] *Id.*

Conclusion

Staff supports AWEC's deferral and notes that the amount deferred from November 2021 through December 2022 (14 months) should be approximately $3.6 million.

PROPOSED COMMISSION GRC ACTION:

Approve AWEC's application for an order requiring PacifiCorp to defer fly ash revenues.

CASE: UE 399
WITNESS: Rose Anderson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Rose Anderson. I am a Senior Economist employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. I discuss Staff's position on the request for inclusion in rates of the remainder of the TB Flats wind project. Additionally, I discuss PacifiCorp's (the Company) request for updated depreciation dates and Exit Orders for certain coal plants and the methodology to remove coal from Oregon rates.

My recommendations may change based on further review and based on the testimonies offered by other parties.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/302, consisting of a confidential discovery response from PacifiCorp.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: TB FLATS COST INCREASE

Q. Please describe the TB Flats cost increase.

A. I investigated the TB Flats cost increase reported by PacifiCorp in this Rate Case of [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] of total TB Flats project costs approved by the Commission in the most recent Rate Case. In total, final costs for TB Flats were [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] as compared to the [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] approved in the most recent Rate Case.

Q. For context, please summarize the Commission's findings on TB Flats in PacifiCorp's most recent Rate Case.

A. In Docket No. UE 374, the Commission found the Company's investment in TB Flats to be prudent and determined that the cost of the plant as presented in that Rate Case should be allowed into customer rates. The Commission conditioned the inclusion in rates on the plant being placed in service by June 30, 2021.[1] The Commission included discussion of ratepayer protections around the construction and operation of the plant, including protection of production tax credit (PTC) value through achieving a timely Commercial Online Date (COD), protection of PTC and capacity factor value through the stipulation in the 2020 transition adjustment mechanism (TAM) to

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[1] *In the Matter of PacifiCorp, Request for General Rate Revision*, Docket UE 374 Order No.20-473. Page 52 (December 18, 2020).

hold these constant for five years, and protection of net power cost benefits through potential future TAM proceedings.[2]

When PacifiCorp became aware the plant would not be placed in service by June 30, 2021, a process was initiated to ensure that only costs associated with turbines operational before December 20, 2020, would be included in rates until PacifiCorp requested cost recovery of the remaining revenue requirement in a separate request.[3]

Q. Please summarize PacifiCorp's explanation for the cost increase at TB Flats.

A. PacifiCorp provided a description of the supply chain issues and construction delays that resulted in the cost overrun in Opening Testimony.[4] Staff has reviewed the items responsible for the cost increase through discovery. These items included [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]. [5]

Q. What is Staff's finding regarding the additional capital at TB Flats requested for inclusion in rate base?

A. Staff finds that the COVID pandemic and associated supply chain disruptions and construction delays at TB Flats were outside the control of the Company.

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[2] Order No. 20-473. Page 53.
[3] PAC/500, Hemstreet/2.
[4] PAC/500, Hemstreet/4-7.
[5] PacifiCorp's Confidential Response to Staff DR 497.

In addition, a [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] cost overrun is well within the 11.1 percent margin of error reported by PacifiCorp in Docket No. UE 374 and evaluated by Staff in Opening Testimony in that docket.[6] PacifiCorp's analysis showed that, unless costs increased by 11.1 percent, the plant would have net benefits to customers.

Further, in the 2017 IRP, the Commission acknowledged the EV 2020 projects with the condition that:

> customers do not bear the risk of construction cost overruns, delays or other factors that impact PTC value, or project costs and expected capacity factors that are less favorable than the assumptions presented in the IRP.

Given that the costs of the actual wind resources selected in the RFP were [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] lower than the proxy Wyoming wind resources acknowledged in the 2017 IRP, Staff finds that the projects are not subject to cost overruns that exceed the estimates from the IRP. Indeed, the projects are significantly less expensive than those acknowledged with conditions in the 2017 IRP.

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[6] Docket No. UE 374. Staff/800, Storm/31.

ISSUE 2: COAL DEPRECIATION CHANGES AND EXIT ORDERS

Q. **Please discuss PacifiCorp's proposal regarding coal unit depreciation dates and Exit Orders in the 2022 Rate Case.**

A. Regarding depreciation dates, PacifiCorp has proposed to accelerate the depreciation of Colstrip units three and four from 2027 to 2025 because the 2021 IRP analysis showed that 2025 is an optimal retirement date for the Colstrip plant. In addition, in response to IRP analysis and recent retirement announcements from plant owners, PacifiCorp has also proposed to decelerate the depreciation of Craig 2 from 2026 to 2028, Hayden 1 from 2023 to 2028, and Hayden 2 from 2023 to 2027. PacifiCorp's share of each unit in MW is provided in Table 1 for reference.

TABLE 1. PACIFICORP SHARE OF COAL UNIT CAPACITY

Unit	Capacity
Craig 2	79 MW
Hayden 1	44 MW
Hayden 2	33 MW
Colstrip 3	74 MW
Colstrip 4	74 MW

Regarding Exit Orders, PacifiCorp has requested the Commission take action to clarify its intentions regarding the Jim Bridger Unit 1 Exit Order issued in Order No. 20-473.[7] PacifiCorp requests the Commission modify the

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[7] Order No. 20-473 at 12.

Exit Order for Jim Bridger 1 to specify that it only applies to coal-fueled operations at Jim Bridger 1. The Company asserts that this will allow gas-fueled operations at Jim Bridger 1 to be included in Oregon rates.

Q. Is the economic analysis of coal retirement dates from the 2021 IRP sufficient to determine that these depreciation dates are reasonable for these units?

A. Yes. The 2021 IRP analysis included consideration of economic coal retirements, and represents the best knowledge that is currently available on the optimal retirement dates for these units. Aligning depreciation dates with these expected retirement dates is reasonable and fair to customers who will pay for the resources during the same timeframe that they are creating benefits to the system. The deceleration of depreciation for the Hayden and Craig units will help offset the rate impacts of accelerating Colstrip 3 and 4 depreciation to facilitate an exit from these units in 2025.

Regarding the depreciation date extension requests for Craig 2 and Hayden 1 and 2, the rate impacts of any potential future acceleration of the exit dates for these units would be moderate. For example, if the entire remaining "Future Accruals" for depreciation at these units had to be collected over only one year in 2023, it would equal about $13.5 million on an Oregon-allocated basis. That is about 1.3 percent of Oregon-allocated revenue requirement.[8]

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[8] Analysis using data from PAC/1002, Cheung/168-169.

Q. Is the economic analysis of Jim Bridger 1 gas conversion from the 2021 IRP sufficient to determine that a modified Exit Order is appropriate?

A. Yes. The 2021 IRP analysis showed net benefits from the avoided costs of coal fuel and emissions reduction technology resulting from the gas conversion. The conversion of the units is also expected to reduce greenhouse gas emissions and associated risks.[9] Gas conversion at Jim Bridger Unit 1 will allow PacifiCorp to keep approximately 354 MW of dispatchable capacity on its system. SB 1547 requires Oregon to remove the benefits and costs of coal fueled generation from utility rates by 2030. Once the units are converted to gas, they will no longer be subject to the SB 1547 requirements for coal units. The Exit Order for Jim Bridger 1 should be modified to specify that the Exit Order only applies to Jim Bridger 1 as a coal fueled resource.

Q. Does Staff have any concerns about a modified Exit Order?

A. Yes. Oregon's current Exit Date for Jim Bridger 1 is December 31, 2023. Staff is concerned that if Jim Bridger 1 is not converted to gas by December 31, 2023, coal-fueled operations at Jim Bridger 1 could continue beyond the Exit Date for that unit. Therefore, the Exit Order could technically become effective on that date, and Oregon could technically be required to exit the unit. This would bring into question Oregon's ability to include a gas-converted Bridger 1 in rates in the future.

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[9] PacifiCorp's 2021 Integrated Resource Plan. Page 270.

Q. What remedy does Staff suggest to limit the risk of a delay in the gas conversion at Jim Bridger 1?

A. Staff recommends that the Commission direct PacifiCorp in this General Rate Case to file a notification with the Commission as soon as the Company becomes aware that coal-fueled operations at Jim Bridger 1 are expected to continue past December 31, 2023. The notification should occur before September 31, 2023, to provide the Commission adequate time to respond. The notification should request a change to the Exit Order for Jim Bridger 1 that resolves the issue identified by Staff above. For example, the Exit Date for Jim Bridger 1 could be extended until after the expected, delayed in-service date of the gas-converted unit.

Q. Please summarize your position regarding depreciation end dates and Exit Orders in this General Rate Case.

A. I support each of PacifiCorp's recommendations regarding coal unit depreciation end dates and Exit Orders in this Rate Case. PacifiCorp's Table 2 summarizing their recommendations is reproduced here:

Coal Plant/Unit	Oregon Depreciable Life[27]	Oregon Exit Orders[28]	2021 IRP Retirement[29]
Colstrip 3-4	2027	2027	2025
Craig 2	2026	2026	2028
Hayden 1	2023	N/A	2028
Hayden 2	2023	N/A	2027
Jim Bridger 1	2023	2023	Convert to Gas
Jim Bridger 2	2025	N/A	Convert to Gas

ISSUE 3: REMOVING COAL FROM RATES

Q. What does PacifiCorp recommend regarding the removal of the costs of coal plants from Oregon rates at the time of retirement or Oregon's exit from a given coal unit?

A. PacifiCorp recommends that the removal of coal plants from rates be addressed as a part of the discussion of decommissioning and coal removal in Docket No. UM 2183.

Q. Does Staff agree that Docket No. UM 2183 is an appropriate place to decide on a methodology to remove coal from Oregon rates?

A. Yes. If the depreciation extension for Craig 1 and 2 is granted in this Rate Case, this should provide enough time to discuss the best method of removing coal from Oregon rates before the expected retirement of Colstrip in 2025. If the depreciation extension is not granted for Craig 1 and 2, PacifiCorp should remove the depreciation and other costs associated with Craig 1 and 2 from base rates and add them to a separate tariff rider that can be updated and set to zero upon the depreciation end date.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 300
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

June 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME: Rose Anderson

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Resources and Planning Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: Master of Science, Agriculture and Resource Economics, University of California Davis, Davis, CA

Bachelor of Arts, International Political Economy
University of Puget Sound, Tacoma, WA

EXPERIENCE: I have been employed at the Public Utility Commission of Oregon since September of 2016. My position is Senior Economist in the Energy Resources and Planning Division. I perform economic and policy analysis, including analysis of net present value revenue requirement and load forecasts, in Rate Cases and planning dockets. I have participated in OPUC rate cases including UE 319, UG 325, and UG 344, and OPUC power cost dockets including UE 320, UE 323, UE 333, and UE 335. Prior to working for the PUC I was a Research Associate at McCullough Research for two years. My responsibilities included economic analysis of energy markets and utilities.

CASE: UE 399
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

June 22, 2022

STAFF ELECTRONIC EXHIBIT 302

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 22-044.

CASE: UE 399
WITNESS: RYAN BAIN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Dr. Ryan Bain. PhD. I am a Senior Economist employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. My testimony analyzes and reviews PacifiCorp (Company) load forecast and resulting sales and transportation revenue forecasts, sales for resale revenues including wheeling, and renewable energy credits (RECs) revenues. My recommendations may change based on further review and based on the testimonies offered by other parties.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. LOAD AND REVENUE FORECAST

Q. Please summarize the Company's load forecasting methodology.

A. PacifiCorp utilizes autoregressive time-series models for its customer count and demand forecasts, with one customer count model utilizing differencing as well. Like many other utilities, the Company breaks down its residential sales forecast into two components of load that are forecasted separately: sales-per-customer (UPC) and number of customers. These components are multiplied to obtain the load. Economic and weather variables are used as explanatory variables in model forecasts for most sufficiently populated schedules. Schedules with few customers employ simple smoothing techniques to predict both load and customer counts in future periods, with additional input from the Company's regional business managers.

Q. What is an autoregressive time-series model?

A. An autoregressive time-series model is a type of regression analysis that can remove some trends and seasonality in a data series such that the differences between modeled values and historical actuals can be assumed to have been generated by one unpredictable random process across the entire time series. This allows the modeler reasonable assurance that the model is using all available information and that it is appropriate to use for near-term forecasts. Autoregression allows the model to use past values of the dependent variable to forecast future values.

The Company employs differencing as well in the case of the residential customer count model. Differencing the residential count data allows the model to examine the change in the dependent variable, as opposed to the level of the dependent variable, such that the model exhibits certain well-behaved properties.

Q. Does Staff support the use of an autoregressive model for forecasting load?

A. Yes. Autoregressive models are used by all Oregon regulated utilities. Autoregressive models are appropriate for short-term forecasting of electricity usage because they can inform the model with information from previous time periods and control for certain statistical problems. Staff generally recommends models with autoregressive components for shorter-term forecasts because of their relative balance between complexity and simplicity.

Q. Why is the residential count model differenced?

A. The main difference between a differenced model and a standard ordinary least squares (OLS) model is that the differenced model allows the modeler to eliminate some effects of trend, such as population growth in the case of the residential count model, which can cause the model's error to grow over time. A model with growing error variance over time is said to demonstrate non-stationarity, violating one of the principal assumptions that make an OLS model reliable for forecasting.

Q. What is non-stationarity and how does differencing solve the issue?

A. Non-stationarity can be several things, but in general it means that the predicted variable does not have constant statistical properties over time. For example, in variables that increase over time, such as population, the average value would not remain constant. Regression models attempt to identify constant relationships between variables to predict future values; if the relationship of two variables does not remain constant because of a trend, then the result of the regression could be spurious.

Q. What is the autoregressive part of the load and customer count models?

A. The autoregressive part of the model defines how much information from previous years is significant in the estimation of the current year. The autoregressive term in a yearly model is the number of previous years, or lags, of the estimated variable that are included. So, if last year's value was indicative of this year's value, but the value from two years ago was not, then the autoregressive component of the model would include a single lag.

PacifiCorp inspects several metrics when deciding on a model's specification, including auto-correlation functions, Durbin-Watson statistics, and Mean-Average-Percent-Error (MAPE).

Q. Describe the Company's primary explanatory variables for residential sales per customer forecasts.

A. The Company uses weather as the primary explanatory variable for UPC forecasts. Weather is broken down into heating degree days (XHeat) and cooling days (XCool). PacifiCorp uses a 20 year period from 2001 through 2020 of weather data to calculate normal weather. The Company also uses a Statistically Adjusted End-Use (SAE) variable to adjust their sales-per-customer model. This variable incorporates PAC's customer survey data on equipment shares and saturation levels among customers to capture efficiency trends.

Staff supports the Company's decision to utilize this SAE component as it increases the model's adjusted-R^2 while reducing the associated Akaike Information Criterion, suggesting a meaningful improvement in the model's fit.

Q. Describe the Company's primary explanatory variable for customer count forecasts.

A. PacifiCorp uses IHS Markit's forecasts of population and households as explanatory variables in the residential and commercial customer counts. The industrial, street lighting, and irrigation count models demonstrate low variability over time, and thus are modeled using simple moving average or exponential smoothing models.

Q. Please explain the methodology used to develop the forecasts for large industrial customers?

A. In response to Staff DR 474, the Company stated that large industrial customers are forecast individually by the regional business managers (RBM) responsible for each account. RBMs use input from large industrial customers regarding future operational plans and historical load to produce individual industrial customer forecasts that are subsequently incorporated into the Company's load forecast.

Q. To what extent do the large industrial customer forecasts contribute to the forecasted decrease in industrial customer sales for Oregon?

A. In response to Staff DR 475, the Company stated that the individual customer forecasts are not contributing to the forecasted 12.9 percent decline in industrial Oregon sales, as the forecast for these customers are the same in both the previous general rate case (GRC), Docket UE 374, and the current GRC.

Q. Has there been a meaningful change in the methodology used to produce large industrial forecasts since the previous rate case?

A. No. The Company informed Staff in response to DR 475 that the methodology as well as the results of the large industrial individual customer forecasts is unchanged from the Company's previous GRC.

Q. Has the Company proposed any changes in load forecast methodology from the previous general rate case UE 374?

A. Yes. The load forecast for this docket and the 2023 TAM (Docket UE 400) includes the Company's expectations for building electrification as reflected in the SAE model described above.

Q. Please summarize the Company's load forecasting results.

A. The Company has forecast roughly 14 million MWhs total for Oregon usage in the test year filed in the Company's opening testimony. This is a roughly 1.6 percent increase from the Company's previous GRC. See inset table below for a breakdown of MWh sales between the previous and current GRC across customer classes.

Oregon Sales Comparison (MWh)			
Class	**Previous GRC**	**Current GRC**	**% Change**
Residential	5,671,134	5,780,833	1.9%
Commercial	5,996,343	6,321,549	5.4%
Industrial	1,682,735	1,465,509	-12.9%
Irrigation	333,381	333,716	0.1%
Lighting	32,935	35,996	9.3%
Total	**13,716,528**	**13,937,602**	**1.6%**

Q. How did Staff review the Company's forecast?

A. Staff reviewed the workpapers for accuracy and load forecast overall for reasonableness. On initial review, Staff finds the Company's methodology, formulation, calculations, and revised data inputs to be accurate and the forecast to be reasonable.

Q. How does the resulting revenue forecast compare to UE 374?

A. In UE 374 the total revenue collected under proposed rates was approximately $1.046 billion, while the total revenue collected in this case is approximately $1.045 billion under proposed rates, a decrease of approximately 0.1%.

Q. Does Staff recommend any adjustments?

A. No. Staff does not recommend any adjustment.

Q. Do you have other remarks?

A. Yes. Staff's recommendations in this testimony could change after review of testimonies offered by other parties and further analysis.

ISSUE 2. ENERGY EFFICIENCY

Q. Does the Company plan to reduce demand through energy efficiency programs?

A. Yes, the Company plans to reduce demand from 2021 through 2040 by 4,290 MW through energy efficiency programs, as well as incorporating 2,448 MW of direct load control programs, as outlined in the Company's 2021 IRP.

Q. What will these programs contribute in the near-term when the rates in this proceeding are likely in effect?

A. These programs will provide 603 MW of reduced demand from efficiency programs and 549 MW of demand response between 2021 and 2024 per the Company.

Q. Does Staff recommend any adjustments?

A. No. Staff does not recommend any adjustment.

Q. Do you have other remarks?

A. Yes. Staff's recommendations in this testimony could change after review of testimonies offered by other parties and further analysis.

ISSUE 3. SALES FOR RESALE, WHEELING & REC REVENUES

Q. Does the company include an adjustment for Sales for Resale in Net Power Costs?

A. Yes. FERC Account 447 contains the Oregon allocated adjustment for Total Sales for Resale of $40,563,155.

Q. What are total and Oregon allocated wheeling revenues in this matter?

A. Total wheeling revenues are $31,704,405 with $8,265,447 allocated to Oregon.

Q. What are the Company's total and Oregon allocated REC revenues?

A. The Company's total REC revenues sum to $6,294,757 with $1,641,065 allocated to Oregon.

Q. How many of the Company's Oregon allocated RECs are RPS ineligible?

A. There have been no RPS ineligible RECs sold or allocated to the Oregon property sales balancing account over the last five years per the Company's response to Staff DR 525.

Q. How does the Company decide whether to bank or sell RECs?

A. One hundred percent of Oregon's allocation of Oregon eligible RPS compliant RECs not used to comply with a RPS in a calendar year are banked for future compliance year needs, per Company response to Staff DR 527.

Q. How does the Company define "banked" when discussing banked RECs?

A. Per the Company's response to Staff DR 526, "ORS 469A.005 (2) – "Banked renewable energy certificate" means a bundled or unbundled renewable energy certificate that is not used by an electric utility or electricity service supplier to comply with a renewable portfolio standard in a calendar year, and that is carried forward for the purpose of compliance with a renewable portfolio standard in a subsequent year”.

Q. What are the Company’s total and Oregon allocated Fly Ash revenue adjustments?

A. The Company’s total Fly Ash revenues sum to $3,177,631 with $828,419 allocated to Oregon.

Q. Does Staff recommend any adjustments?

A. No. Staff does not recommend any adjustment.

Q. Do you have other remarks?

A. Yes. Staff’s recommendations may change based on further review and based on the testimonies offered by other parties.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: RYAN BAIN

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

June 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME:	Ryan Bain
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Utility Strategy and Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Ph.D., Economics (2020) Washington State University
	B.S., Economics (2009) Texas A&M University
EXPERIENCE:	Prior to joining the Oregon Public Utility Commission as a Senior Analyst in the Utility Strategy and Integration Division, I was employed as an economist with a forensic economics consultancy in the Dallas / Fort Worth area. My peer reviewed published research involves understanding information impacts on national and local agricultural commodity markets, and I have presented research on testing the accuracy of various forecasting methods in the case of agricultural commodities before a meeting of economic professionals.

CASE: UE 399
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Madison Bolton. I am a utility analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe and recommend whether to approve the Company's proposed voluntary renewable energy tariff (VRET) in Schedule 273, Accelerated Commitment Tariff (ACT). My recommendations may change based on further review and based on the testimonies offered by other parties.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/502, consisting of 6 pages. This exhibit contains PacifiCorp responses to Staff data requests and a table summarizing Staff's requests in order to support the VRET proposal.

ISSUE 1, VOLUNTARY RENEWABLE ENERGY TARIFF

Q. Please provide background on the Commission's historical treatment of VRETs.

A. In 2014, with the passage of House Bill (HB) 4126, the legislature directed the Public Utility Commission of Oregon (PUC) to study the potential impacts of electric utilities offering VRETs to nonresidential customers. The study aimed at determining, "whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide voluntary renewable energy tariffs to non-residential customers."[1] At the completion of the study, the Commission outlined nine conditions in Order No. 16-251 for VRET programs.[2] The Commission revised the conditions when investigating Portland General Electric Company's (PGE) proposed VRET in Order No. 21-091.[3] In that order, which addressed both PGE's and PacifiCorp's VRET, the Commission's Condition 4, limits PacifiCorp's VRET program size to 175 average megawatts (aMW).

Q. Please describe the Company's VRET proposal.

A. PacifiCorp's VRET is proposed in Schedule 273, Accelerated Commitment Tariff (ACT). The program offers nonresidential customers a pathway to accelerated decarbonization with new renewable energy resources. The Company would execute a PPA, providing participating customers with the

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[1] House Bill 4126, Oregon Laws 2014, Ch. 100, Section 3(3).

[2] *In the Matter of Public Utility Commission of Oregon, Voluntary Renewable Energy Tariff for Nonresidential Customers,* Docket No. UM 1690, Order No. 16-251 (Jul. 5, 2016).

[3] *In the Matter of Portland General Electric Company, Investigation into Proposed Green Tariff,* Docket No. UM 1953, Order No. 21-091 (Mar. 29, 2021); Order No. 21-096 (Mar. 30, 2021), correcting Order No. 21-091.

bundled renewable energy and renewable energy certificates (RECs), while the participant pays a supplemental rider representing all the costs of the program in addition to their current cost-of-service (COS) rate schedule. The participant receives a credit reflecting the system value of the energy and capacity provided by the renewable energy resource.

Q. How does the program design prevent cost shifting to non-participants?

A. The program design requires the participant to pay all the costs associated with the bundled renewable energy they receive, the administrative costs to operate the program, a subscriber mismatch fee recovering costs for the entire length of the power purchase agreement (PPA) over the participant's contract term, and a risk adjustment to the contracted MWh delivered to the participant. These charges ensure participants are paying for the entire cost associated with the program and the resource. Additionally, the participant must continue paying their COS schedule rates, allowing for continued recovery of system costs.

Q. How does PacifiCorp propose to handle the revenues from the subscriber mismatch fee?

A. The subscriber mismatch fee is structured to collect revenue from the participant over the PPA contract term to account for costs over the entire length of the PPA. For example, if participants subscribe to the program for a duration shorter than the PPA, the Company will collect revenues equal to, "the net present value of the above market costs for the full term of the contract, spread across the years to which the participants have subscribed."[4] In the case of a utility-owned VRET resource, the term would be the life of the facility since there is no PPA contract.

Q. Does Staff have concerns about how PacifiCorp proposes to handle the revenues from the subscriber mismatch fee?

A. Yes. Staff followed up on the Company's proposed treatment in OPUC DR 318. Staff asked PacifiCorp how it plans to treat the revenues from the subscriber mismatch fee. The Company's response states that the excess revenue would be recorded in a regulatory liability, accruing interest at the authorized rate of return for deferred accounts.[5] Staff has concerns that, if the renewable resource is utility-owned, this fee would act as accelerated cost recovery for PacifiCorp without any reduction in overall costs to participants. Staff does not currently support the subscriber mismatch fee as it applies to PacifiCorp-owned resources.

Q. What is Staff's recommendation on PacifiCorp-owned VRET resources?

A. Staff does not support Company-owned resources in the VRET until PacifiCorp submits specific accounting methodologies and safeguards to protect the competitive market. Staff recognizes that the testimony of Erik Anderson addresses this concern, and that the Company is not asking for approval of a utility-owned resource at this time.[6] Additionally, Staff agrees that PacifiCorp

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[4] PAC/800, Anderson/13
[5] Staff/502, Bolton/4
[6] PAC/800, Anderson/23, at line 1.

should submit a filing detailing the accounting methods prior to any consideration for a Company-owned resource.

Q. Please elaborate on the credit the participant receives for energy and capacity benefits of the resource.

A. The additional renewable resource brings energy and capacity to the PacifiCorp generation system that can be valued based on PacifiCorp's integrated resource plan (IRP). The credit is calculated based on the difference in total system cost between a scenario that includes the resource and, a least-cost, least-risk scenario that does not contain the VRET resource. Since non-participants also benefit from the energy and capacity of the VRET resource, the resulting credit is paid by non-participants to the participant through a fixed offset to the participant's cost of the resource. Staff notes that ongoing changes in the Pacific Northwest's energy industry are an important consideration in capacity and credit evaluation. Evolving issues like load growth, coal generation retirement, and decarbonization signal a need to evaluate capacity more precisely, as demonstrated in the history of the Commission's General Capacity Investigation in Docket No. UM 2011. It is important to highlight that the outcome of UM 2011 could require utilities' capacity and energy evaluation methodologies to evolve, which could impact the relevance of PacifiCorp's IRP used in this VRET.

Q. What questions did Staff have about PacifiCorp's energy and capacity credit calculation?

A. In OPUC DR 317, Staff inquired whether the energy and capacity credit could exceed the PPA price and result in a net reduction in energy costs for the VRET participants. Staff views this as an unfair price risk to non-participants because they would be essentially entering into a lengthy fixed price contract that is not based on resource need. The Company's response noted that a scenario resulting in a net reduction in energy costs for a participant is unlikely, but that the customer credit will be limited to not exceed the participant's total costs.[7] Staff would support this approach if the Company explicitly states in the tariff that there is a price floor to not allow the credit to exceed the participant's total costs. Staff's concern may also be mitigated if a floating calculation mechanism is proposed that does not lock non-participants into a fixed price for the energy and capacity credit.

Q. Please elaborate on the risk adjustment mentioned on page 3 of your testimony and whether Staff supports this approach.

A. In response to Staff DR 315, the Company provided additional detail on how the risk adjustment is calculated. The risk adjustment addresses the issue of paying a fixed price for a fixed quantity of renewable energy, while that energy generation is a variable factor. In an example of a solar resource, the Company explains that the participant would receive a delivery guarantee of 90 percent of the subscribed energy volume. The resource owner would be liable for damages if the delivered volume falls below 90 percent. However, the participant would pay for 100 percent of the incremental costs of the full

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[7] Staff/502, Bolton/3

contracted volume, helping to mitigate generator variability risk to non-participating customers. Additionally, the Company states that any RECs generated above the guaranteed delivery volume would be passed through to non-participants, further mitigating risk to those customers.[8] Staff initially supports this approach because it provides additional safeguards against volumetric and price risks for non-participating customers.

Q. Does the Company's procurement process align with the Commission's Competitive Bidding Rules (CBRs)?

A. The Competitive Bidding Rules set forth in OAR Chapter 860, Division 089, include specific requirements for electric companies' request for proposals (RFP) and resource selection when a resource acquisition is subject to the rules. Section 0010 of the rules states that an electric company may request a waiver of some or all of the rules, which the Commission may grant for good cause shown. In OPUC DR 314, the Company's response states there are no current plans to release a program-specific RFP that would require Commission review and approval. The Company plans to use results from the 2022 All Source Request for Proposals, approved to issue under Docket UM 2193, to determine potential resources for the VRET to match resources not chosen to the final shortlist with VRET customers. The Company states that this is compliant with the competitive bidding rules, and PacifiCorp will request waivers on a case-by-case basis if required in any future circumstances.[9]

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[8] Staff/502, Bolton/2

[9] Staff/502, Bolton/2

Q. Does the Company have an estimate of potential load size and number of customers interested in a VRET?

A. Yes. The Company's response to OPUC DR 319 notes that ten customers have expressed interest in a VRET program, with a total load of about 282,000 MWh or 32.2 aMW.[10] This estimate is within the Commission's overall size cap of 175 aMW for a PacifiCorp VRET.

Q. Is PacifiCorp's VRET similar to PGE's VRET that has already been approved by the Commission?

A. PacifiCorp's VRET proposal is largely consistent with the key components of PGE's Green Energy Affinity Rider (GEAR).PacifiCorp's ACT has similar attributes protecting against cost shifting and negative impacts to the Direct Access market that the Commission referenced in Order No. 21-091, such as a long-term subscription commitment, a bill credit floor preventing customers from saving money relative to COS rates, and exposure to COS rate changes for participating customers.[11] PacifiCorp's evaluation of the energy and capacity credit based on their approved IRP and the structure of the risk adjustment fee are similar to what was approved for PGE in phase 1 of the GEAR program. Because many of these key features are akin to what has already been approved for PGE, Staff does not currently oppose the core design of PacifiCorp's VRET.

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[10] Staff/502, Bolton/5

[11] Order No. 21-091, at 11.

Q. Does Staff have any additional recommendations for the VRET proposal?

A. Yes. Staff believes that something similar to PGE's customer-supplied option (CSO) in the GEAR should be considered for PacifiCorp's VRET program. A customer-supplied option allows large qualifying customers the choice to identify and procure the resource independently of the electric company to meet their specific goals and needs. Anecdotally, Staff believes that the CSO option provides additional value to potentially interested customers. Staff requests that PacifiCorp add a customer-supplied option within its VRET proposal and provide a methodology regarding such an option in the Company's reply testimony.

Q. Does Staff recommend approval of PacifiCorp's VRET proposal?

A. Not at this time. While Staff does not oppose the majority of the VRET design, further information on the subscriber mismatch fee for Company-owned VRET resources is required, as it raises issues around the fairness of cost recovery while participants do not see an increased benefit. Staff also has requested that the Schedule 273 tariff includes mention of a price floor in the energy and capacity credit calculation or propose a floating mechanism instead of a fixed credit. Lastly, Staff requests that the Company consider how a CSO would work in this VRET and provide details in PacifiCorp's reply testimony. Staff's requests in order to support PacifiCorp's VRET proposal are summarized in Exhibit Staff/502, Bolton/6.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

June 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME:	Madison Bolton
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Utility Strategy & Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	B.A. Carroll College, Helena, Montana Major: Biology, 2017 M.ENV. University of Colorado, Boulder, Colorado Specialization: Renewable and Sustainable Energy, 2020
EXPERIENCE:	Since September 2021, I have been employed by the Oregon Public Utility Commission. I currently hold the position of Utility Analyst 2 in the Utility Strategy and Integration Division From 2019 to 2020 I worked as a graduate research analyst at E Source where I conducted research for utility clientele on large non-residential energy consumers. Additionally, in 2020 I assisted Camus Energy in researching the feasibility of electric grid management software

CASE: UE 399
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support Of Opening Testimony: OPUC Data Requests and Staff's Requests in Order to Support

June 22, 2022

UE 399 / PacifiCorp April 21, 2022 OPUC Data Request 314

OPUC Data Request 314
VRET - Regarding PAC/800 Anderson/2, 17-19, please clarify whether the Company will be adhering to the RFP guidelines in the Commission's Competitive Bidding Rules (CBRs) in OAR 860-89, will PAC request a blanket waiver of the CBRs and propose an alternative RFP method, or will PAC seek waivers on a case-by-case basis.

Response to OPUC Data Request 314
Pacific Power plans to leverage the results from the 2022 All Source Request for Proposals (RFP) to provide potential resources for the Accelerated Commitment Tariff program, as such the Company plans to comply with the Public Utility Commission of Oregon's (OPUC) Competitive Bidding Rules. The Company has no plans to release a program specific RFP at this point. Should alternative circumstances develop where a waiver would be necessary, the Company will seek that waiver from the OPUC on a case-by-case basis.

UE 399 / PacifiCorp April 21, 2022 OPUC Data Request 315

OPUC Data Request 315
VRET - Regarding the risk adjustment fee referenced in PAC/800 Anderson/8, 15-16, please explain how the risk adjustment is calculated and what factors will determine the amount of the risk adjustment fee.

Response to OPUC Data Request 315
The first risk factor is variability in generator output, as the participating customer will pay a fixed price for a fixed quantity of bundled renewable energy. To mitigate risks associated with variability in generator output, participating customers will only be able to subscribe to guaranteed annual delivery volumes agreed to by the resource's owner and specified in the renewable resource contract. For solar resources, a 90 percent delivery guarantee is typical, and the renewable resource contract would include damages, paid by the resource's owner, if actual volumes fell below the guaranteed level. However, all incremental costs from the full contracted volumes, as calculated using the portfolio analysis tools used to produce the Company's Integrated Resource Plan and evaluate bids submitted in response to a Request For Proposals, will be collected from the participating customer. Using solar as an example, 100 percent of the incremental costs would be collected over the 90 percent of the renewable resource output being subscribed by the customer, resulting in a higher rate that captures a portion of the risk.

A comparable calculation would be used to account for differences between the term of the renewable resource contract and the term agreed to by the participating customer. 100 percent of the incremental costs over the term of the renewable resource contract would be collected during the period subscribed by the customer. The Company (on behalf of other customers) would not assume any portion of the incremental costs would be paid by future participants.

While the subscribed output is capped at the guaranteed delivery volume, Renewable Energy Credits (RECs) associated with deliveries in excess of the guaranteed level would be allocated to non-participating customers in Oregon. Similarly, RECs associated with all deliveries after the conclusion of the subscribing customer's agreed upon term would be allocated to non-participating customers in Oregon. These remaining RECs could help mitigate a portion of the risk to non-participating customers.

In the past, the expected energy and capacity benefits have been modeled assuming restricted wholesale sales, or a lower market price forecast. Both of these assumptions result in lower energy benefits. The Company has not yet determined how these or other factors might be applied to mitigate the risks associated with incremental resource procurement.

UE 399 / PacifiCorp April 21, 2022 OPUC Data Request 317

OPUC Data Request 317
VRET - Please explain whether the energy and capacity credit can exceed the PPA price and whether PAC's VRET program can result in a net reduction in energy costs for participants.

Response to OPUC Data Request 317
No, the proposed Accelerated Commitment Tariff (ACT) program can not result in a net reduction in energy costs for a participant. The ACT program participant will pay cost of service (COS) rates plus all ACT program administrative costs as well as the power purchase agreement (PPA) price. In the unlikely scenario where the addition of a resource would provide benefits to the system in excess of the PPA plus administrative costs of ACT participation, and yet was still not selected as a system resource, PacifiCorp would limit the customer credit to not exceed the total costs.

UE 399 / PacifiCorp April 21, 2022 OPUC Data Request 318

OPUC Data Request 318
VRET - Please explain how the Company treats the revenues collected via the subscriber mismatch fee. Where will these funds be held? Do the fee revenues earn interest?

Response to OPUC Data Request 318
The subscriber mismatch fee is designed to pre-collect all costs associated with a resource over the duration of the power purchase agreement. The collection of revenue from the participant in excess of the current obligation will be recorded in a regulatory liability and will accrue interest at the Public Utility Commission of Oregon authorized rate for deferred accounts. The interest potential will be taken into consideration when establishing the amount of the subscriber mismatch fee.

UE 399 / PacifiCorp April 21, 2022 OPUC Data Request 319

OPUC Data Request 319
VRET - Please provide the estimated load size and number of the customers who have informally expressed interest in the ACT program.

Response to OPUC Data Request 319
To date, PacifiCorp has had 10 customers express interest in participation in a voluntary renewable energy tariff style program. The total load for those participants is 282,000 megawatt-hours.

Table 1. Staff’s Requests in Order to Support

Subscriber Mismatch Fee	Provide an explanation or alternative methodology for how to prevent accelerated cost recovery of a utility-owned resource without the participant receiving additional benefit
Energy and Capacity Credit Floor or Floating Calculation	In the Schedule 273 tariff, directly mention an energy and capacity credit floor designed to prevent the credit from exceeding a participant’s total costs. Staff may also be amenable to an alternative method using a floating credit calculation so as not to lock non-participants into a fixed price.
Customer Supplied Option	Please provide methodology detailing how PacifiCorp would implement a customer supplied option into the VRET.

CASE: UE 399
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Heather Cohen. I am a Senior Utility Analyst employed in the Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/601.

Q. Did you prepare other supporting exhibits?

A. Yes. I prepared the following exhibits:

- Staff/602, PAC's Non-Confidential responses to Staff DRs relied on in this testimony; and
- Staff/603, Staff's Wage and Salary model (Confidential Electronic spreadsheet).

Q. What is the purpose of your testimony?

A. I provide background, analysis, and recommendations regarding the Company's Test Year expense for wages, salary, incentives, and full-time equivalents (FTE). I also address the Company's Test Year expense for customer services, sales expenses, promotional items and director's fees.

My recommendations may change based on further review and based on the testimonies offered by other parties.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. WAGES, SALARY, AND FTE

Q. Please provide a summary of the Commission's historical method for determining the amount to include in a utility's revenue requirement for wages, salaries, incentives, and overtime expense.

A. The Commission's historical methodology has many components. The Commission determines the appropriate level of wages and salaries for employees in the Test Year using its three-year wage and salary (W&S) model to estimate union and non-union payroll levels for energy utilities.[1,2] The model determines an appropriate level of Test Year expense and capital investment for wages and salaries by escalating the Company's base year wages and salaries by annual changes to the All-Urban CPI (for non-union) or negotiated increases (for union) and applying a sharing mechanism between the wages and salaries determined by the W&S model and the wages and salaries proposed by the utility.

To determine the appropriate amount to include in revenue requirement for incentives paid to employees, the Commission's policy is to disallow 100 percent of officers' bonuses because they are typically based on increased earnings, which benefits shareholders.[3] It is also Commission policy to

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[1] *In the Matter of Northwest Natural*, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999), In the Manner of PacifiCorp, Docket No. UE 374, Order No. 20-473 at 102 (December 18, 2020).

[2] *See Pacific Power & Light*, UE 116, Order No. 01-787 at 40; *In the Matter of Northwest Natura*l, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999); *In the Matter of PGE*, Docket No. UE 102, Order No. 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, Docket No. UE 88, Order No. 95-322 at 10 (March 29, 1995).

[3] See Order No. 99-033 at 62; and *In the Matter of the Application of US West*, Docket No. UT 125, Order No. 97-171 at 74-76 (May 19, 1997).

disallow 75 percent of performance-based bonuses because they are generally focused on increased earnings and therefore bring more benefit to shareholders. The Commission disallows 50 percent of merit-based bonuses because they equally benefit shareholders and ratepayers. Union bonuses are treated in the same manner as non-union bonuses.[4]

Finally, the Commission determines the appropriate ratio of expense and capital to apply to the total forecasted compensation and applies it to determine what compensation expense that is included in Test Year expense and what compensation is included in rate base.

Q. Please explain how Staff used the Three-Year W&S model to arrive at its recommendation for wage and salary levels for the Test Year.

A. As a starting point for determining non-union wages for each employee class, the W&S model uses the utility's actual wage, salary, and overtime levels as they existed three years prior to the Test Year.[5] For example, a 2023 Test Year would require a Base Year of 2020. From there, the Base Year wages and salaries are adjusted by a year-over-year escalation of expenses using the All-Urban CPI for each of the three subsequent years to establish a forecast of Test Year wage and salary levels.[6]

The model calculates the average salary based on the Company’s actual Base Year calendar payroll (2020), divided by the actual Base Year FTE (2020), then escalates the average by the annual changes to the All-Urban CPI

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[4] See Order No. 20-473 at 97; Order No. 99-697 at 44-45; Order No. 99-033 at 62.

[5] See Order No. 99-697 at 43.

[6] Ibid.

for 2021, 2022, and 2023. Once the escalated amount is determined, it is compared to the Company's Test Year figures.[7] At this point the sharing principle is applied, wherein Staff adjusts its forecasted amount to allow the Company to share 50/50 the lesser of the difference between the model forecast and the amount the Company has included in its Test Year or a 10 percent band around Staff's projection.[8]

For non-union wages, the W&S model incorporates actual market-based data by using historic wages and adjusting for inflation using the All-Urban CPI index.[9] The Commission has consistently validated the All-Urban CPI to adjust historic wages and salaries as "adjusting payroll levels by changes in inflation provides employees the same real level of compensation as in the base year and provides an incentive to companies to minimize labor costs."[10] Further, the methodology of equally dividing between ratepayers and shareholders the difference between the utility's Test Year forecast and the forecast obtained by the model allows for some adjustments to reflect changes in market conditions without allowing unchecked escalation.[11]

For union wages, the W&S model again starts with actual wages three years before the Test Year. Rather than escalating the wages using All-Urban CPI, wages are escalated using negotiated wage increases as set forth in union contracts, and Staff's final adjustment incorporates any sharing

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[7] Ibid.

[8] Ibid.

[9] Ibid.

[10] Ibid.

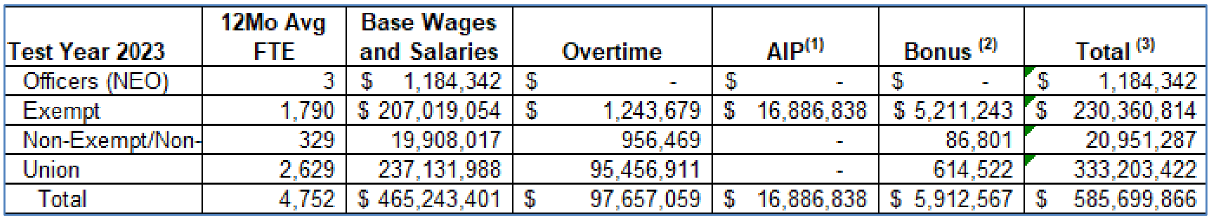
[11] Order No. 95-322 at 10.

between the Company's Test Year forecast and the forecast obtained under the W&S model.[12] In Order 20-473 (2020) in PacifiCorp's general rate case, the Commission rejected Staff's proposed 50/50 sharing between Staff's Test Year determination of expense for union wages and salaries and the Company's projection. The Commission concluded that the arms-length nature of the negotiations regarding wages was sufficient protection for ratepayers.[13]

Q. Please summarize the Company's proposal for wages, salaries, incentives and overtime expense in this case.

A. The Company's 2023 Test Year includes $465 million in wages and salaries (base pay), $22.8 million in incentive compensation, and $97.7 million in overtime (Total Company).[14] The Oregon allocation factor is 28.7 percent with a O&M/Capital split of 64.8/35.2.[15]

FIGURE 1: INCENTIVES IN TEST YEAR[16]



Test Year 2023	12Mo Avg FTE	Base Wages and Salaries	Overtime	AIP(1)	Bonus (2)	Total (3)
Officers (NEO)	3	$ 1,184,342	$ -	$ -	$ -	$ 1,184,342
Exempt	1,790	$ 207,019,054	$ 1,243,679	$ 16,886,838	$ 5,211,243	$ 230,360,814
Non-Exempt/Non-	329	19,908,017	956,469	-	86,801	20,951,287
Union	2,629	237,131,988	95,456,911	-	614,522	333,203,422
Total	4,752	$ 465,243,401	$ 97,657,059	$ 16,886,838	$ 5,912,567	$ 585,699,866

The Company states it has removed all Named Executive Officers' (NEO) incentives and 50 percent of non-NEO incentives.[17] Staff calculates the total

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[12] See Order No. 99-697 at 43.
[13] Order No. 20-473 at 94.
[14] Staff/602 PAC response to Staff DR 92.
[15] Staff/602, PAC response to Staff DR 93.
[16] Staff/602, PAC response to Staff DR 92.
[17] PAC/1000, Cheung/18.

officer incentives capitalized in plant since 2010 to be approximately $1.1 million.[18]

Q. What adjustments did the Company make to its actual 2020 Base Year salaries and wages to forecast the 2023 Test Year?

A. PacifiCorp's labor projection is two-fold. First, the Company testifies it uses actual June 2021 total labor expense escalated to reflect wage increases during the base period.[19] Second, these annualized June 2021 labor expenses were escalated prospectively by labor group to December 2023 based on expected increases in 2022 and 2023 for non-union and exempt employees' wages.[20] For union employees, the Company uses nine collective bargaining agreements across six unions of various sizes to estimate increases.[21] To project its Test Year, the Company escalates its actual June 2021 Officer/Exempt salaries by [redacted] [redacted]

[redacted] .[22] These June 2021 expenses are then escalated to the Test Year by increasing Officer/Exempt [redacted] [23]

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[18] Staff/602, PAC response to Staff DR 313 and 313 1st Supplemental.

[19] PAC/1000/Cheung/18.

[20] PAC Confidential Workpaper Cheung 4.2 Wages and Employee Benefits Adjustment.CONF.xls tab 4.2.1.

[21] PAC/1000/Cheung/18.

[22] PAC Confidential Workpaper Cheung 4.2 Wages and Employee Benefits Adjustment.CONF.xls tab 4.2.3-4.2.5 CONF

[23] Ibid.

Union salaries have a variety of increases and are captured in Figure 2 below.[24]

FIGURE 2: LABOR ESCALATION

[redacted]

[redacted]

Wages, Salaries, Overtime & FTE

Q. What is Staff's recommendation for Test Year wages and salaries including overtime?

A. Staff, consistent with the W&S model, starts with a Base Year (2020) that is three years prior to the Test Year, and escalates to the Test Year using All-Urban CPI (CPI) rates, which are 4.7 percent for 2021, 6.8 percent for 2022, and 2.6 percent for 2023.[25] Staff escalates union salaries and wages in for

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[24] Ibid.

[25] Oregon Economic & Revenue Forecast June 2022, Volume XLII, No. 2, Table A.4, page 40, https://www.oregon.gov/das/OEA/Documents/appendixa.pdf

union employees by applying a rate of 2.8 percent for 2021, 2.5 percent for 2022 and 2.6 percent for 2023.[26] Because the number of unions impacted and the timing of raises was so varied, Staff used a weighted average based on FTE to determine the union increase. As a check on the weighted average computation, Staff escalated Union salaries using the weighted average and totals for Annualized and Proforma Labor and came within five thousand dollars from the Proforma Labor Test Year total for the nine unions (Staff's projection was higher).[27]

Staff then applied the sharing principle to its and the Company's projected 2023 Test Year amounts. The sharing principle, which allows the Company to share 50/50 the lesser of the difference between the Company's and Staff's calculated projections, or a 10 percent band around Staff's calculated projection, makes a reduction to Staff's projection. Because of the high inflation via the CPI, Staff's projection for Exempt, Non-Exempt and Union base salaries is slightly higher than the Company's, with one exception: Officer salaries. After applying the Oregon allocation rate as well as the O&M/Rate Base split, Staff has a small adjustment to Officer salaries of approximately $3 thousand O&M and $2 thousand rate base.[28]

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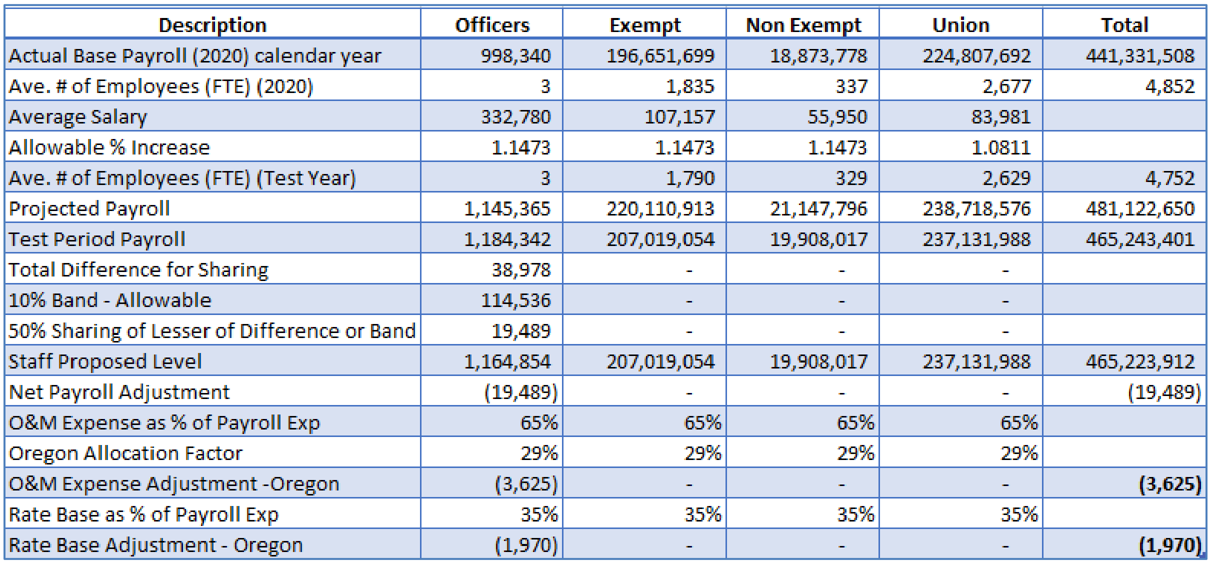
[26] See Staff electronic work paper UE 399 Exhibit 603 Wage and Salary Model CONF, tab Union increases yearly, Attach OPUC 094 Staff.

[27] See Staff electronic work paper UE 399 Exhibit 603 Wage and Salary Model CONF, tab check.

[28] Ibid.

FIGURE 3: W&S MODEL ADJUSTMENTS



Description	Officers	Exempt	Non Exempt	Union	Total
Actual Base Payroll (2020) calendar year	998,340	196,651,699	18,873,778	224,807,692	441,331,508
Ave. # of Employees (FTE) (2020)	3	1,835	337	2,677	4,852
Average Salary	332,780	107,157	55,950	83,981	
Allowable % Increase	1.1473	1.1473	1.1473	1.0811	
Ave. # of Employees (FTE) (Test Year)	3	1,790	329	2,629	4,752
Projected Payroll	1,145,365	220,110,913	21,147,796	238,718,576	481,122,650
Test Period Payroll	1,184,342	207,019,054	19,908,017	237,131,988	465,243,401
Total Difference for Sharing	38,978	-	-	-	
10% Band - Allowable	114,536	-	-	-	
50% Sharing of Lesser of Difference or Band	19,489	-	-	-	
Staff Proposed Level	1,164,854	207,019,054	19,908,017	237,131,988	465,223,912
Net Payroll Adjustment	(19,489)	-	-	-	(19,489)
O&M Expense as % of Payroll Exp	65%	65%	65%	65%	
Oregon Allocation Factor	29%	29%	29%	29%	
O&M Expense Adjustment -Oregon	(3,625)	-	-	-	**(3,625)**
Rate Base as % of Payroll Exp	35%	35%	35%	35%	
Rate Base Adjustment - Oregon	(1,970)	-	-	-	**(1,970)**

Q. Does Staff have an adjustment for Overtime?

A. The Company's Test Year (Total Company) included $1.2 million in Exempt overtime, $956 thousand in Non-Exempt overtime and $95 million in Union overtime. After inflating Non-Union levels by the All-Urban CPI and Union levels by projected Union increases, Staff's projected overtime amount is approximately $8 million lower than the Company's, as shown below.[29]

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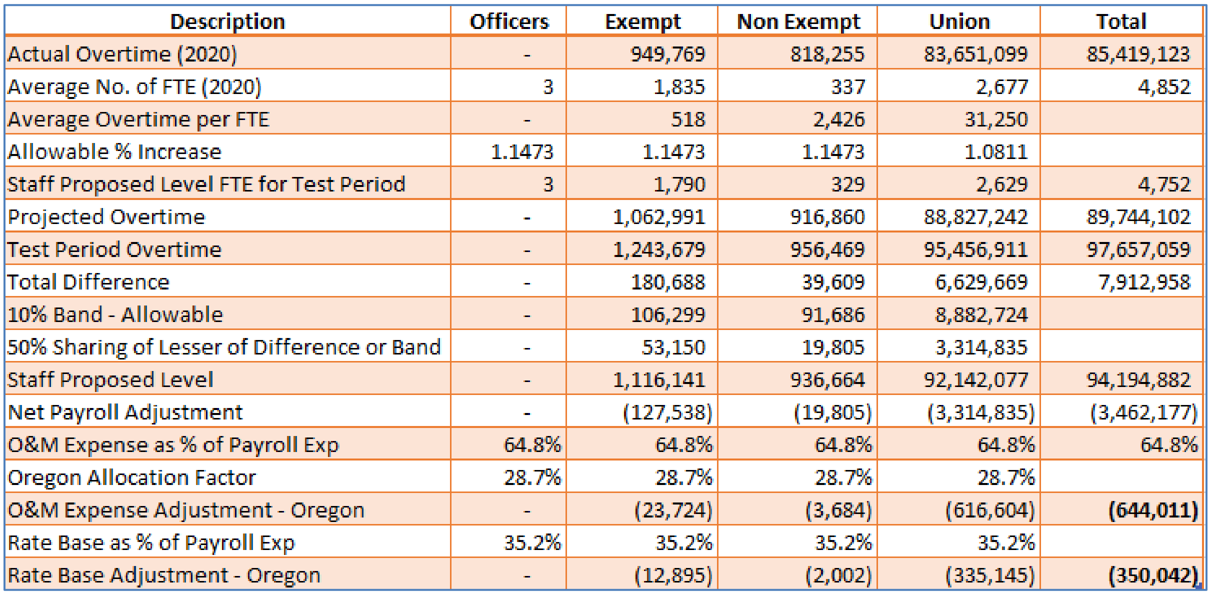
[29] See Staff electronic work paper UE 399 Exhibit 603 Wage and Salary Model CONF, tab 3-year OT.

FIGURE 4: OVERTIME ADJUSTMENT



Description	Officers	Exempt	Non Exempt	Union	Total
Actual Overtime (2020)	-	949,769	818,255	83,651,099	85,419,123
Average No. of FTE (2020)	3	1,835	337	2,677	4,852
Average Overtime per FTE	-	518	2,426	31,250	
Allowable % Increase	1.1473	1.1473	1.1473	1.0811	
Staff Proposed Level FTE for Test Period	3	1,790	329	2,629	4,752
Projected Overtime	-	1,062,991	916,860	88,827,242	89,744,102
Test Period Overtime	-	1,243,679	956,469	95,456,911	97,657,059
Total Difference	-	180,688	39,609	6,629,669	7,912,958
10% Band - Allowable	-	106,299	91,686	8,882,724	
50% Sharing of Lesser of Difference or Band	-	53,150	19,805	3,314,835	
Staff Proposed Level	-	1,116,141	936,664	92,142,077	94,194,882
Net Payroll Adjustment	-	(127,538)	(19,805)	(3,314,835)	(3,462,177)
O&M Expense as % of Payroll Exp	64.8%	64.8%	64.8%	64.8%	64.8%
Oregon Allocation Factor	28.7%	28.7%	28.7%	28.7%	
O&M Expense Adjustment - Oregon	-	(23,724)	(3,684)	(616,604)	**(644,011)**
Rate Base as % of Payroll Exp	35.2%	35.2%	35.2%	35.2%	
Rate Base Adjustment - Oregon	-	(12,895)	(2,002)	(335,145)	**(350,042)**

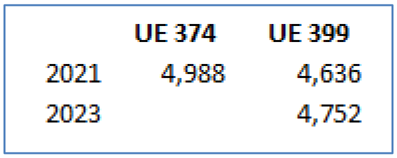
After adjusting for the Oregon allocation factor of 28.7 percent, Staff has the following adjustments:

- Exempt: $24 thousand O&M and $13 thousand Rate Base;
- Non-Exempt: $3 thousand O&M and $2 thousand Rate Base; and
- Union: $616 thousand O&M and $335 thousand Rate Base.[30]

Q. Does Staff have an adjustment for FTE?

A. Staff does not have an adjustment for FTE. The Company's FTE count is currently three percent lower than it was in its last rate case (UE 374).[31]

FIGURE 5: FTES 2021 AND TEST YEAR



	UE 374	UE 399
2021	4,988	4,636
2023		4,752

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[30] See Staff electronic work paper UE 399 Exhibit 603 Wage and Salary Model CONF, tab 3-year OT.

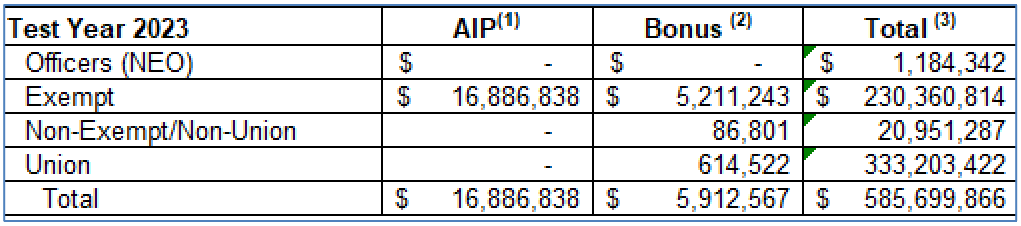
[31] Staff/602, PAC response to Staff DR 92 (UE 374, UE 399).

Incentives

Q. What does the Company propose for employee incentives?

A. As noted earlier, PacifiCorp claims to have removed all of named executive incentives and half of non-executive incentives.[32] However, Staff observes that approximately $6 million in bonuses (separate from the Annual Incentive Plan or AIP) for Exempt, Non-Exempt and Union remains unadjusted.

FIGURE 6: INCENTIVES FROM DR 92



Test Year 2023	AIP(1)	Bonus (2)	Total (3)
Officers (NEO)	$ -	$ -	$ 1,184,342
Exempt	$ 16,886,838	$ 5,211,243	$ 230,360,814
Non-Exempt/Non-Union	-	86,801	20,951,287
Union	-	614,522	333,203,422
Total	$ 16,886,838	$ 5,912,567	$ 585,699,866

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[32] PAC Confidential Workpaper Cheung 4.2.1 Wages and Employee Benefits Adjustment.CONF.xls.

As illustrated below, the Company's incentive adjustment was made to the Test Year AIP amount of [redacted] excluding the bonus amount of $5.9 million.

FIGURE 7: PAC INCENTIVE ADJUSTMENT

[redacted]

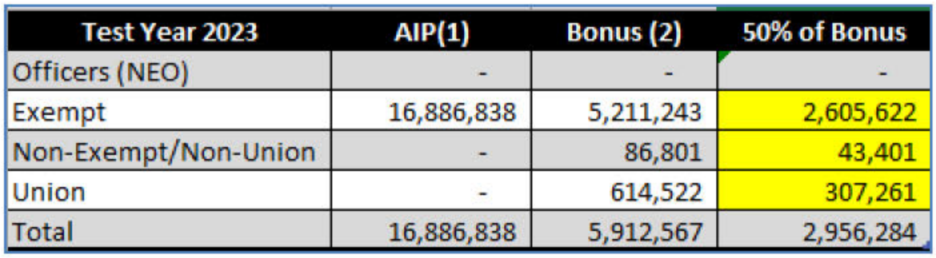
[redacted]

[redacted]

Q. What does Staff recommend regarding the bonuses in the Test Year?

A. Because the Commission does not distinguish between bonuses and AIP, Staff has included the $5.9 million bonus in the adjustment. Staff proposes reducing the Exempt bonus by half or $2.6 million along with the Non-Exempt and Union bonuses by half or $43 thousand and $307 thousand, respectively.

FIGURE 8: BONUS ADJUSTMENT

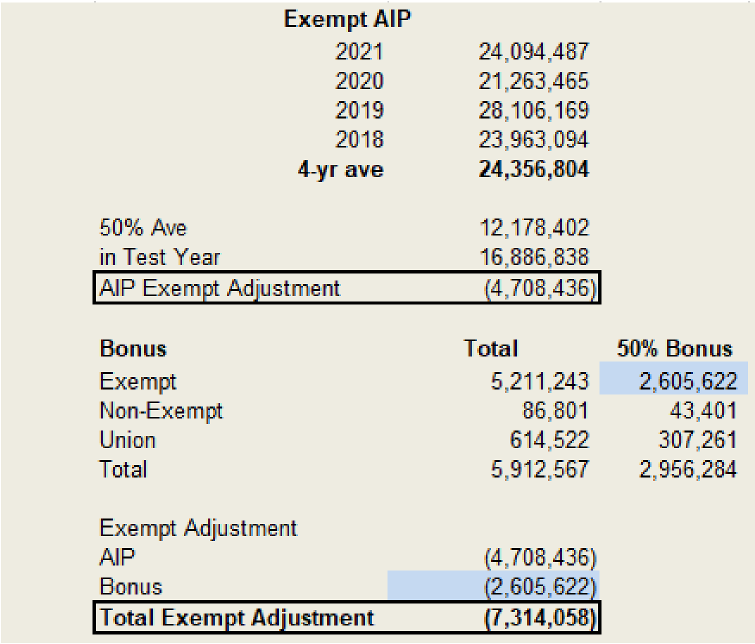


Test Year 2023	AIP(1)	Bonus (2)	50% of Bonus
Officers (NEO)	-	-	-
Exempt	16,886,838	5,211,243	2,605,622
Non-Exempt/Non-Union	-	86,801	43,401
Union	-	614,522	307,261
Total	16,886,838	5,912,567	2,956,284

Q. What does Staff recommend regarding the AIP amounts in the Test Year?

A. While the Company has reduced its AIP projected expense ($35 million) for Exempt by approximately half ($16.9 million) for inclusion in the Test Year, Staff observes that the projected Test Year amount of AIP for the Exempt category seems to be inflated at [redacted] as compared to the average of the past four years of $24 million, half of which would be $12 million. Because the Company has already made a reduction to $16 million in the Test Year, Staff reduces that amount by $4.7 million to bring the total amount of Exempt AIP to $12 million, consistent with the four-year average AIP average from 2018-2021. As previously mentioned, Staff has also reduced the Exempt bonus by $2.6 million (or half), which makes the total adjustment to the Exempt category $7.3 million as noted below.

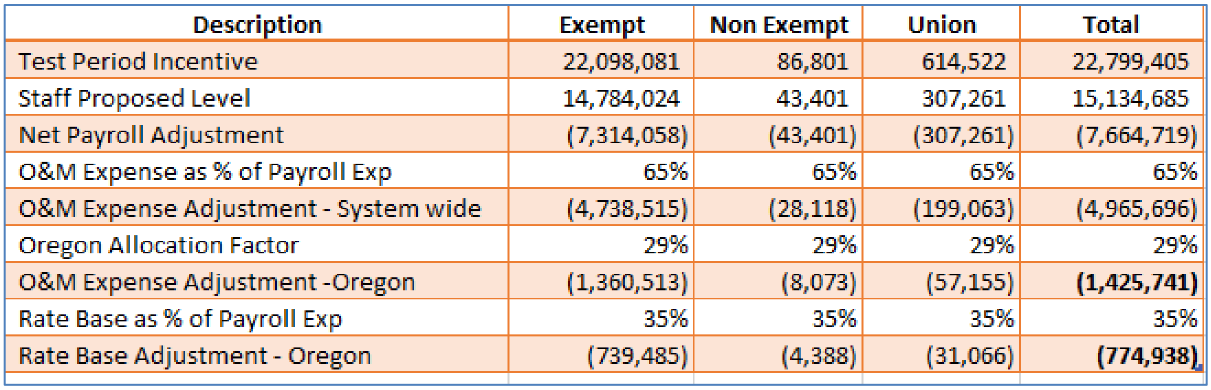
FIGURE 9: AIP AND BONUSES IN THE TEST YEAR



Exempt AIP		
2021	24,094,487	
2020	21,263,465	
2019	28,106,169	
2018	23,963,094	
4-yr ave	**24,356,804**	
50% Ave	12,178,402	
in Test Year	16,886,838	
AIP Exempt Adjustment	(4,708,436)	
Bonus	**Total**	**50% Bonus**
Exempt	5,211,243	2,605,622
Non-Exempt	86,801	43,401
Union	614,522	307,261
Total	5,912,567	2,956,284
Exempt Adjustment		
AIP	(4,708,436)	
Bonus	(2,605,622)	
Total Exempt Adjustment	**(7,314,058)**	

After the Oregon Allocation and O&M/Rate Base splits have been applied, the incentives adjustment is $1.4 million O&M and $775 thousand Rate Base.[33]

FIGURE 10: INCENTIVES ADJUSTMENT



Description	Exempt	Non Exempt	Union	Total
Test Period Incentive	22,098,081	86,801	614,522	22,799,405
Staff Proposed Level	14,784,024	43,401	307,261	15,134,685
Net Payroll Adjustment	(7,314,058)	(43,401)	(307,261)	(7,664,719)
O&M Expense as % of Payroll Exp	65%	65%	65%	65%
O&M Expense Adjustment - System wide	(4,738,515)	(28,118)	(199,063)	(4,965,696)
Oregon Allocation Factor	29%	29%	29%	29%
O&M Expense Adjustment -Oregon	(1,360,513)	(8,073)	(57,155)	**(1,425,741)**
Rate Base as % of Payroll Exp	35%	35%	35%	35%
Rate Base Adjustment - Oregon	(739,485)	(4,388)	(31,066)	**(774,938)**

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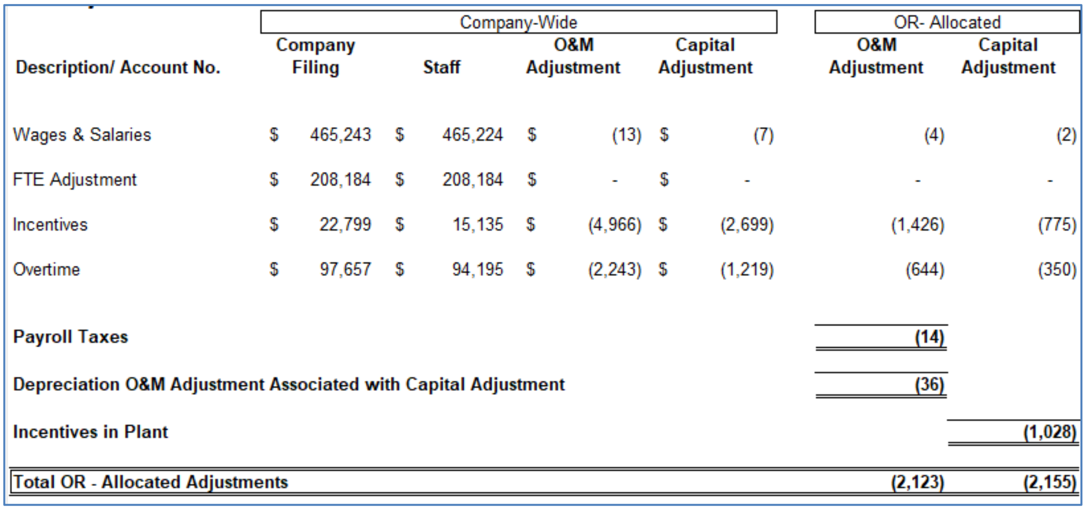
[33] See Staff electronic work paper UE 399 Exhibit 603 Wage and Salary Model CONF, tab 3-year W&S.

Q. Please summarize all of Staff's adjustments to Salaries, Wages, Overtime, and Incentives.

A. Staff has the following adjustments:

- Wages and Salary: $3 thousand O&M and $2 thousand Rate Base;
- Incentives: $1.4 million O&M and $775 thousand Rate Base;
- Overtime: $644 thousand O&M and $350 thousand Rate Base;
- Capitalized incentives (since 2010): $1 million Rate Base; and
- Small adjustments for payroll ($14 thousand) and depreciation ($36 thousand).

FIGURE 11: LABOR ADJUSTMENTS



Description/ Account No.	Company-Wide				OR- Allocated	
	Company Filing	Staff	O&M Adjustment	Capital Adjustment	O&M Adjustment	Capital Adjustment
Wages & Salaries	$ 465,243	$ 465,224	$ (13)	$ (7)	(4)	(2)
FTE Adjustment	$ 208,184	$ 208,184	$ -	$ -	-	-
Incentives	$ 22,799	$ 15,135	$ (4,966)	$ (2,699)	(1,426)	(775)
Overtime	$ 97,657	$ 94,195	$ (2,243)	$ (1,219)	(644)	(350)
Payroll Taxes					**(14)**	
Depreciation O&M Adjustment Associated with Capital Adjustment					**(36)**	
Incentives in Plant						**(1,028)**
Total OR - Allocated Adjustments					**(2,123)**	**(2,155)**

ISSUE 2. CUSTOMER SERVICE, SALES & ADMINISTRATIVE, AND GENERAL EXPENSES

Q. Please describe the activities and expenses associated with Customer Service, Sales and Administrative and General Expenses.

A. Customer Service expense consists of FERC accounts 907, 908, and 910 (excluding 909 Informational and Instructional Advertising Expenses, which was analyzed separately). These expenses are for Supervision, Customer Assistance, and Miscellaneous Customer Service. FERC accounts 911-917 are typically comprised of other Advertising, Promotional Activities, Demonstration and Selling, and Miscellaneous Sales expenses. FERC accounts 920-931 are Administrative and General accounts consisting of general salaries, office supplies, regulatory expenses and filing fees, rents, and duplicate charges accounts.

Q. Does the Commission Staff have a standard for how these expenses are treated for ratemaking purposes?

A. Yes. Sales and marketing (including advertising) expenses are prohibited from being posted in customer account or customer service expenses in keeping with Order No. 99-033. Sales and Marketing Costs must demonstrate reasonableness and consumer benefits to be present in rates.[34]

Staff reviews expenses per appropriate use per FERC account. Staff also reviews transaction-level data to ensure expenses relate to activities such as responding to customer requests, inquiries, and safety concerns, resolving

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[34] Order No. 99-033 at 63.

customer complaints, extending service to new customers, and providing information about safety and service issues.

Q. How did Staff perform its analysis of the Company's Customer Service and Sales Expense?

A. After reviewing historical trends and Company's adjustments, Staff reviewed the Company's transactional data in its DR 57 and submitted multiple DRs inquiring about expense. Staff then reviewed the Company's adjustments within the included FERC accounts. Adjustments were made for the following purposes:

- Removal and reallocation of certain expenses from miscellaneous general expenses, the largest of which ($348 thousand) was related to the reallocation of overhead for office supplies;
- Wages and Salary, adjusted per the discussion in the previous section;
- Removal of PUC fees in Revenue Sensitive Items and plant depreciation, and O&M related to Rolling Hills wind resources;
- Removal of 25 percent of membership fees and 50 percent of meals and entertainment as per Commission precedent; and
- Finally, the escalation of non-labor O&M expense by Global Insight Factors as shown below.[35]

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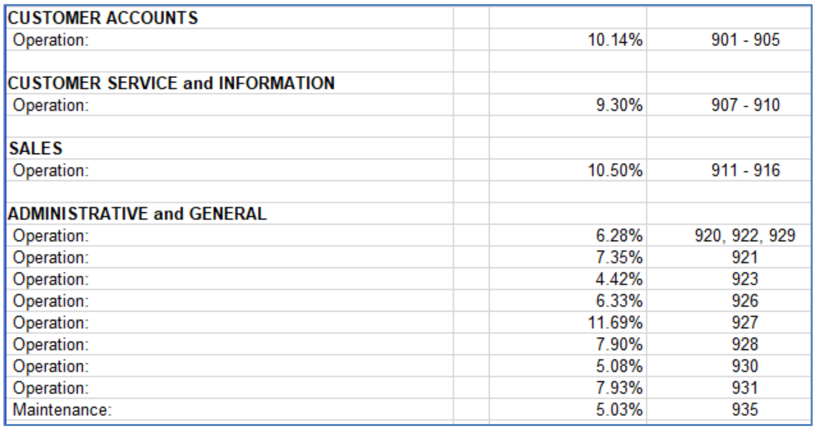
[35] PAC Non-Confidential Workpapers O&M 4.1-4.10.

FIGURE 12: PAC ESCALATION, GLOBAL INSIGHT FACTORS



CUSTOMER ACCOUNTS		
Operation:	10.14%	901 - 905
CUSTOMER SERVICE and INFORMATION		
Operation:	9.30%	907 - 910
SALES		
Operation:	10.50%	911 - 916
ADMINISTRATIVE and GENERAL		
Operation:	6.28%	920, 922, 929
Operation:	7.35%	921
Operation:	4.42%	923
Operation:	6.33%	926
Operation:	11.69%	927
Operation:	7.90%	928
Operation:	5.08%	930
Operation:	7.93%	931
Maintenance:	5.03%	935

Q. Please describe the Company's expenses in the Base Year (July 2020 – June 2021) and historically.

A. Non-labor expenses in Customer Service and Assistance Accounts 907 and 908 are concentrated on items such as cell phone expenses and miscellaneous contracts. The largest expense is associated with the Oregon Clean Fuel Program Amortization and is discussed further in Staff/1600/Shierman. Miscellaneous Customer Service Account 910 includes expenses for vehicle and mobile plant depreciation along with dues and licenses and safety equipment.[36] Office Supplies and Expense (Account 921) includes telephone, software licenses and equipment charges. This account contains a $1.5 million expense (Oregon allocated) for miscellaneous materials which is attributed to the Cholla closure amortization.[37] This amount has been offset by the Deferred Income Tax

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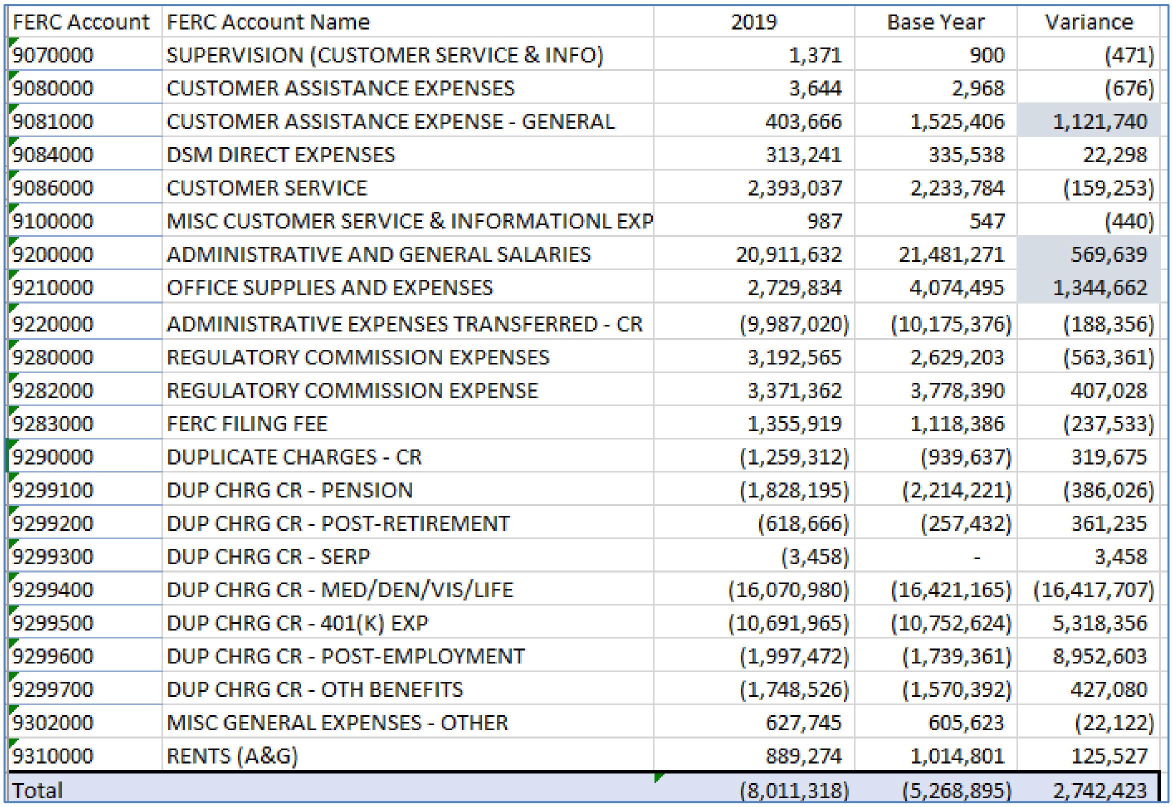
[36] Staff/602, PAC response to Staff DR 142 (electronic spreadsheet).

[37] Ibid.

(DIT) expense according to the Company.[38] There is also an increase in severance in the Administrative and General Salary (Account 920) category ($732 thousand) also attributed to the Cholla closure but this has been removed as part of the Company's Wages and Employee Benefits Adjustment.[39] The rest of the Company's expenses were related to FERC filing fees, PUC fees and a multitude of transfers within the Duplicate Charges accounts. Below, this is shown to be typical year-to-year.

FIGURE 13: FERC 907-931, 2019 & BASE YEAR



FERC Account	FERC Account Name	2019	Base Year	Variance
9070000	SUPERVISION (CUSTOMER SERVICE & INFO)	1,371	900	(471)
9080000	CUSTOMER ASSISTANCE EXPENSES	3,644	2,968	(676)
9081000	CUSTOMER ASSISTANCE EXPENSE - GENERAL	403,666	1,525,406	1,121,740
9084000	DSM DIRECT EXPENSES	313,241	335,538	22,298
9086000	CUSTOMER SERVICE	2,393,037	2,233,784	(159,253)
9100000	MISC CUSTOMER SERVICE & INFORMATIONL EXP	987	547	(440)
9200000	ADMINISTRATIVE AND GENERAL SALARIES	20,911,632	21,481,271	569,639
9210000	OFFICE SUPPLIES AND EXPENSES	2,729,834	4,074,495	1,344,662
9220000	ADMINISTRATIVE EXPENSES TRANSFERRED - CR	(9,987,020)	(10,175,376)	(188,356)
9280000	REGULATORY COMMISSION EXPENSES	3,192,565	2,629,203	(563,361)
9282000	REGULATORY COMMISSION EXPENSE	3,371,362	3,778,390	407,028
9283000	FERC FILING FEE	1,355,919	1,118,386	(237,533)
9290000	DUPLICATE CHARGES - CR	(1,259,312)	(939,637)	319,675
9299100	DUP CHRG CR - PENSION	(1,828,195)	(2,214,221)	(386,026)
9299200	DUP CHRG CR - POST-RETIREMENT	(618,666)	(257,432)	361,235
9299300	DUP CHRG CR - SERP	(3,458)	-	3,458
9299400	DUP CHRG CR - MED/DEN/VIS/LIFE	(16,070,980)	(16,421,165)	(16,417,707)
9299500	DUP CHRG CR - 401(K) EXP	(10,691,965)	(10,752,624)	5,318,356
9299600	DUP CHRG CR - POST-EMPLOYMENT	(1,997,472)	(1,739,361)	8,952,603
9299700	DUP CHRG CR - OTH BENEFITS	(1,748,526)	(1,570,392)	427,080
9302000	MISC GENERAL EXPENSES - OTHER	627,745	605,623	(22,122)
9310000	RENTS (A&G)	889,274	1,014,801	125,527
Total		(8,011,318)	(5,268,895)	2,742,423

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[38] Staff/602, PAC response to Staff DR 419.

[39] Staff/602, PAC response to Staff DR 420, PAC Confidential Workpaper Cheung 4.2 Wages and Employee Benefits Adjustment.CONF.xls tab 4.2.2.

Q. Has the Company included any expenses related to Demonstration and Selling Expenses (FERC Accounts 912-916), typically known as Sales Expenses?

A. The Company did not include expenses related to these accounts.

Q. Does Staff have any adjustments to Customer Service and Administrative and General accounts?

A. Staff has no adjustments to propose in these accounts. However, as noted in my opening statement, Staff's recommendations could change after review of testimony offered by other parties.

ISSUE 3. PROMOTIONAL ACTIVITY AND EXPENSES

Q. What are promotional activities?

A. OAR 860-026-0010 defines promotional activities as actions by a utility or its affiliates meant to increase its service use by present and prospective customers or induce consumers to use its service rather than a competitive provider's.

Q. What are promotional concessions?

A. OAR 860-026-0015 defines promotional concessions as any offers by a utility or its affiliate to any person meant to promote the utility's service or install an appliance or equipment for use of the utility's service. It could include financing, acquiring or building property, or providing free or discounted equipment or appliances. It excludes making repairs, inspecting or adjustments to appliances or equipment, providing new demonstration products for testing, or providing light bulbs or outdoor lighting services. Providing rebates, low interest loans, and other considerations for Commission-approved energy efficiency programs is also excluded. A promotional concession must be approved by the Commission.

Q. Has the Company filed its promotional concessions request with the Commission?

A. No. PacifiCorp does not engage in promotional activities in Oregon and has not filed a request with the Commission for promotional concessions.[40]

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[40] Staff/602, PAC response to Staff DR 141.

ISSUE 4. DIRECTORS FEES AND EXPENSES

Q. Does the Company incur Directors fees or expenses?

A. Based on the Company's response to SDR 062, the Company does not incur Directors fees and expenses. The Company provided an excerpt (Part III, Item 10) from their 2020 SEC (Part III, Item 10) 10-K filing. "Director Compensation: PacifiCorp's directors do not receive additional compensation for service as directors of PacifiCorp."

Q. What is the Commission's historical treatment of Directors fees and expenses in a general rate case?

A. Pursuant to OAR 860-027-0016, Directors fees and expenses that are paid to members of the broad of directors who are also paid as officers of a regulated utility are 100 percent disallowed.

Q. Please describe Staff's analysis of this issue.

A. Staff reviewed base year expenditure details from the Company's response to SDR 057 and the contents of the SDR 062 response and did not identify any Directors fees/expenses included in the rate filing.[41]

Q. Does Staff recommend an adjustment?

A. Staff proposes no adjustment for this issue.

Q. Does this conclude your testimony?

A. Yes.

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[41] Staff/602, PAC response to DR 514.

CASE: UE 399
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement

June 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME: Heather Cohen

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE., Suite 100
Salem, OR. 97301

EDUCATION: Bachelor of Arts, Political Science
Fordham University, New York, NY

Master of Public Policy
American University, Washington, DC.

EXPERIENCE: I have been employed as a Senior Financial Analyst by the Oregon Public Utility Commission since January 2020 in the Energy, Rates and Finance Division. I currently perform a range of financial analysis duties related to natural gas, electric and water utilities, with a focus on operations and maintenance. I have worked on the following general rate and power cost dockets: UG 388, UG 389, UG 390, UG 433, UG 435, UE 374, UE 390, UE 391, and UE 394.

I have ten years of professional level budget and fiscal analysis experience. I was previously employed as a Budget Analyst with the Oregon Department of Education (ODE), where I was the lead analyst for the Early Learning Division (ELD) which includes the federal $97M Child Care Development Fund (CCDF) and $37M Preschool Promise program. Prior to ODE, I was a Senior Financial Analyst for the state of Texas's Department of Family and Protective Services and Health and Human Services. Before that, I was a Project Manager for the University of Southern California where I directed data collection and analysis, staffing and deliverables for a $1.2M federal grant related to the provision of mental health services in Los Angeles County. Prior to USC, I was a Senior Budget Analyst for the City of New York responsible for the $1B expense budget of the Administration for Children's Services (ACS).

CASE: UE 399
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Exhibits in Support
Of Opening Testimony

June 22, 2022

PAC’s Response to Staff Data Request 92
Is
Filed in Electronic Format

Standard Data Request - OPUC 093

Wage and Salary Data: For the Test Year, please provide the breakout between O&M and rate base for all labor expense expressed as percentages. If applicable, please also provide the breakout for all labor expense between Total Company and Oregon expressed as a percentage.

Response to Standard Data Request – OPUC 093

All labor and benefit expenses are combined before applying the test year capitalization percentage as well as before being allocated to jurisdictions. As a result, these costs are not directly available on an Oregon-allocated basis on an individual account-by-account basis. However, these costs can be calculated using the Oregon allocation of total utility labor in the test year. Please also refer to Exhibit PAC/1002, Adjustment 4.2, submitted by Company witness, Sherona L. Cheung.

Description	Percentage
Total Labor and Benefits	100.0000 %
Capitalized and Non-Utility Portion	35.2136 %
Utility Portion (O&M)	64.7864 %
Oregon Allocated Portion	28.7118 %

OPUC Data Request 141

Promotional Activities, FERC accounts 901-935 and Wages, Salaries and Incentives - Does the Company engage in any Promotional Activities in the state of Oregon?

(a) If so, please identify all references to Promotional Activities in Company work papers and testimony.

(b) Please identify each promotional item the Company conducted in Oregon and describe the benefits produced and available to customers.

Response to OPUC Data Request 141

No. PacifiCorp does not engage in Promotional Activities in the state of Oregon (per Oregon Administrative Rules (OAR) 860-026-0010).

PAC’s Response to Staff Data Request 142
Is
Filed in Electronic Format

OPUC Data Request 313

Annual Incentive Plan (AIP). Long Term Incentive Plan (LTIP) - Please provide the dollar and percentage loading amount of Officer and Executive Incentives capitalized in Plant Costs by year for the time period 2010 through 2021. Please explain how the amount of Officer and Executive incentives capitalized in plant costs is consistent with Commission practices with regards to the amount included in rates and Commission orders issued.

1st Supplemental Response to OPUC Data Request 313

Further to the Company's response to OPUC Data Request 313 dated April 21, 2022, the Company provides the following supplemental response to provide the requested information for calendar year 2021:

PacifiCorp continues to object to this data request on the grounds that it is overly broad, unduly burdensome, seeks information that is outside the scope of this proceeding, and is not reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving the foregoing objections, PacifiCorp responds as follows:

Please refer to the table below for the amount of Annual Incentive Plan (AIP) awards for PacifiCorp's named executive officers (NEO), capitalized to FERC Account 107 (Construction Work In Progress (CWIP)) for calendar year 2021. The Company cannot specifically state the amount of NEO incentive in CWIP that was placed in service to electric plant in-service (EPIS) for any year, or the amount allocated to Oregon. The amounts below are estimates of the NEO incentives in electric plant allocated to Oregon. The Company is unable to estimate the depreciated value of these amounts and therefore cannot provide the net amount included in rate base allocated to Oregon.

Calendar Year	**PacifiCorp NEO, Capitalized AIP**	**Oregon's Allocated share [1]**
2021	$ 316,452	$ 88,581

1. Oregon's Allocated share is extrapolated using an unadjusted gross electric plant in service percentage calculated as: Oregon's gross EPIS balance divided by Total Company gross EPIS balance. Gross EPIS balances are sourced from the Company's annual results of operations (ROO) filings.

OPUC Data Request 313

Annual Incentive Plan (AIP). Long Term Incentive Plan (LTIP) - Please provide the dollar and percentage loading amount of Officer and Executive Incentives capitalized in Plant Costs by year for the time period 2010 through 2021. Please explain how the amount of Officer and Executive incentives capitalized in plant costs is consistent with Commission practices with regards to the amount included in rates and Commission orders issued.

Response to OPUC Data Request 313

PacifiCorp objects to this data request on the grounds that it is overly broad, unduly burdensome, seeks information that is outside the scope of this proceeding, and is not reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving the foregoing objections, PacifiCorp responds as follows:

Please refer to the table below for the amount of Annual Incentive Plan (AIP) awards for PacifiCorp's named executive officers (NEO), capitalized to FERC Account 107 (Construction Work In Progress (CWIP)). The Company cannot specifically state the amount of NEO incentive in CWIP that was placed in service to electric plant in-service (EPIS) for any year, or the amount allocated to Oregon. The amounts below are estimates of the NEO incentives in electric plant allocated to Oregon. The Company is unable to estimate the depreciated value of these amounts and therefore cannot provide the net amount included in rate base allocated to Oregon.

Calendar Year	PacifiCorp NEO, Capitalized AIP	Oregon's Allocated share [1]
2010	$ 249,099	$ 69,045
2011	$ 261,666	$ 72,537
2012	$ 286,916	$ 78,405
2013	$ 325,271	$ 86,961
2014	$ 256,971	$ 69,236
2015	$ 256,415	$ 69,430
2016	$ 271,205	$ 75,137
2017	$ 410,100	$ 111,165
2018	$ 295,922	$ 80,898
2019	$ 397,773	$ 109,557
2020	$ 416,671	$ 117,263
2021	Not available [2]	Not available [2]

Notes:

1. Oregon's Allocated share is extrapolated using an unadjusted gross electric plant in service percentage calculated as: Oregon's gross EPIS balance divided by Total Company gross EPIS balance. Gross EPIS balances are sourced from the Company's annual results of operations (ROO) filings.

2. Calendar year 2021 allocation is not yet available for inclusion in the above table until sometime after the Company's 2021 ROO is filed with the Public Utility Commission of Oregon (OPUC) on or about April 30, 2022.

OPUC Data Request 419

Miscellaneous Materials and Supplies, Severance Pay - Company's response to DR 142 details a $1.5 million expense for Cholla closure miscellaneous materials and supplies amortization.

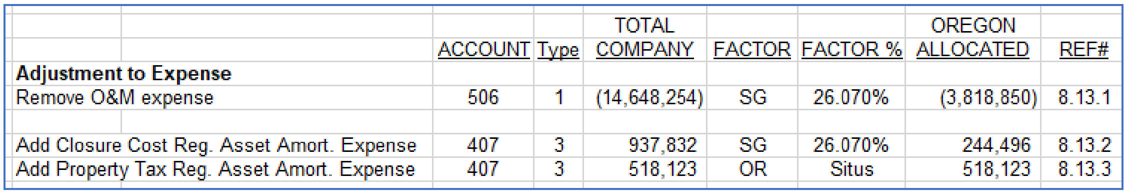
(a) What is the reason for this expense?

(b) How does it relate to Adjustment 8.13 Cholla Unit 4 Retirement costs?

(c) If Adjustment 8.13 is related, how does FERC account 921 factor in when these adjustments are to Accounts 506 and 407.

Sum of Oregon Allocated $			
FERC Account	**Account Number Name**	**Text**	**Total**
⊟9210000	**⊟Miscellaneous Materials & Supplies**	Cholla Closure M&S RA OR Amort	1,546,794
Grand Total			**1,546,794**

Figure 1: DR 142



	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense							
Remove O&M expense	506	1	(14,648,254)	SG	26.070%	(3,818,850)	8.13.1
Add Closure Cost Reg. Asset Amort. Expense	407	3	937,832	SG	26.070%	244,496	8.13.2
Add Property Tax Reg. Asset Amort. Expense	407	3	518,123	OR	Situs	518,123	8.13.3

Figure 2: 8.13 Cholla Unit Retirement

Response to OPUC Data Request 419

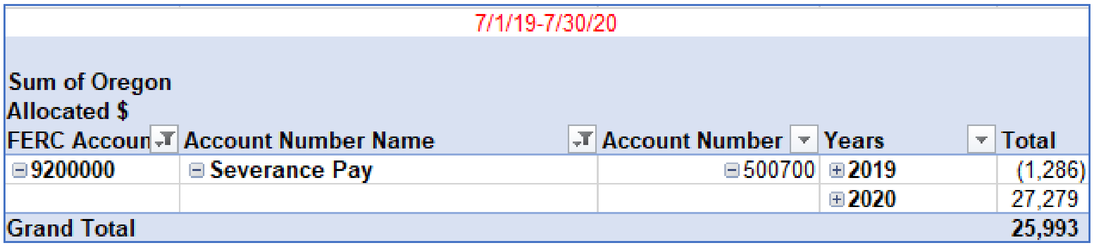
a.) The $1.5 million is the buy-down of the Cholla materials and supplies closure costs using Tax Cut and Jobs Act funds. The $1.5 million M&S item is offset by Deferred Income Tax (DIT) Expense and nets to zero in the base data for this general rate case.

b.) The $1.5 million is not being adjusted in Adjustment 8.13, as the amount nets against a corresponding balance in DIT Expenses to zero, as per subpart a above.

c.) Please refer to subpart b above.

OPUC Data Request 420

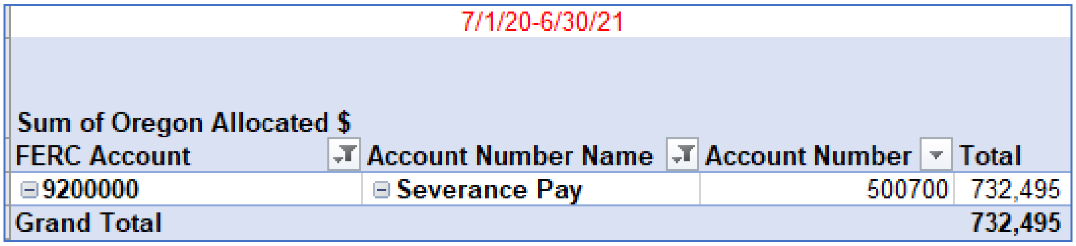
Miscellaneous Materials and Supplies, Severance Pay - The Company's Base Year Severance expenses (account 500700) increased from $25 thousand to $732 thousand from 2019-2020 to base year according to DR 142 (see below). Please give an explanation for this increase.



7/1/19-7/30/20

Sum of Oregon Allocated $

FERC Accoun	Account Number Name	Account Number	Years	Total
9200000	Severance Pay	500700	2019	(1,286)
			2020	27,279
Grand Total				25,993



7/1/20-6/30/21

Sum of Oregon Allocated $

FERC Account	Account Number Name	Account Number	Total
9200000	Severance Pay	500700	732,495
Grand Total			732,495

Response to OPUC Data Request 420

The source of the above screen prints from the Company's response to OPUC Data Request 142, which represents actual data on an Oregon allocated basis for the two respective periods 12 months ended June 2020, and June 2021.

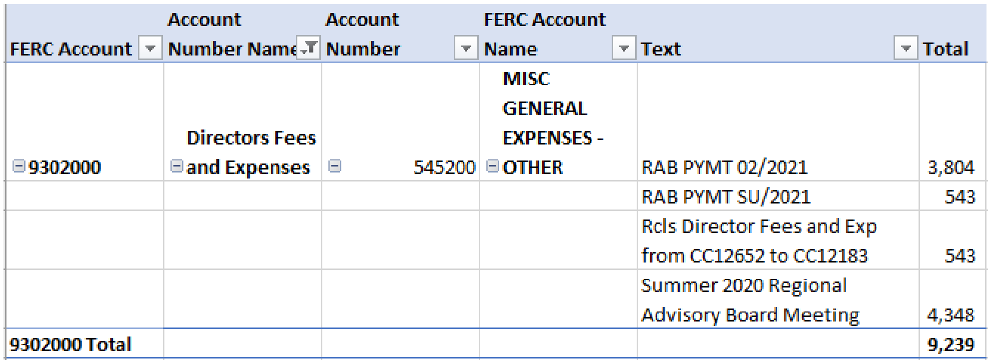
The major driver for the increase is severance expense related to the Cholla Unit 4 plant closure. The Company removes Cholla Unit 4 related severance costs out of its Wages & Employee Benefits adjustment, on Page 4.2 in Exhibit PAC/1002/Cheung) calculation for test year amounts.

The Company responds with the following reconciliation to the above request:

Source	12 ME June 2020	12 ME June 2021
Attach OPUC 142 FERC 920, Oregon Allocated	$ 25,993	$ 732,495
Removed in Exhibit PAC/1002, Pages 4.2.2, 4.2.6, line Severance	0	(702,610)
Net amount in Oregon Filing, FERC 920, Oregon Allocated	$ 25,993	$ 29,885

OPUC Data Request 514

Directors Fees, DR 57 - In response to DR 62 and in its 10-k, the Company states that Directors receive no direct compensation from PacifiCorp and therefore Directors fees are not included in the Test Year. However, Company's response to DR 57 contains $9,239 in Account Number Name Directors Fees and Expenses (FERC Account 9302). Please explain what these amounts are and how they differ from Directors Fees.



FERC Account	Account Number Name	Account Number	FERC Account Name	Text	Total
9302000	Directors Fees and Expenses	545200	MISC GENERAL EXPENSES - OTHER	RAB PYMT 02/2021	3,804
				RAB PYMT SU/2021	543
				Rcls Director Fees and Exp from CC12652 to CC12183	543
				Summer 2020 Regional Advisory Board Meeting	4,348
9302000 Total					**9,239**

Response to OPUC Data Request 514

The Company assumes that the reference to "DR 57" is intended to be a reference to the Company's response to Standard Data Request – OPUC 057. The Company further assumes that the reference to "DR 62" is intended to be a reference to the Company's response to Standard Data Request – OPUC 062. Based on the foregoing assumptions, the Company responds as follows:

The term "Directors" used in the Company's Securities and Exchange Commission (SEC) Form 10-K filing, is not the same as the term used in the description of general ledger (G/L) account 545200 (Director Fees and Expenses).

In the Company's SEC Form 10-K filing, Item 11 (Executive Compensation) refers to Directors as members of PacifiCorp's Board of Directors. Directors are elected based on individual responsibilities, experience in the energy industry and functional expertise. As of December 31, 2021, William J. Fehrman (Chair, Board of Directors and Chief Executive Officer (CEO), PacifiCorp) received no direct compensation from PacifiCorp.

The fees recorded to (G/L) account 545200 (Director Fees and Expenses) relate to External Affairs Regional Advisory Board (RAB) meeting fees and not fees for PacifiCorp's Board of Directors.

STAFF EXHIBIT 603
IS CONFIDENTIAL AND FILED IN
ELECTRONIC FORMAT

PROTECTIVE ORDER 22-044

CASE: UE 399
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Curtis Dlouhy. I am an economist employed in the Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. My testimony addresses the Company's marginal cost study, rate spread and rate design. I also note that I am continuing to investigate an issue related to dynamic interstate allocation factors brought up by AWEC in UE 400.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

- Exhibit Staff/701, which contains my witness qualification statement.
- Exhibit Staff/702, which contains non-confidential PacifiCorp responses to Staff data requests.

Many of the data requests in Exhibit Staff/702 refer to attachments containing data. These attachments are filed electronically with my supporting workpapers if they were used in my analysis in any way.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: MARGINAL COST STUDY

Q. Please describe the marginal cost study and how it is used to set rates.

A. A marginal cost study – which is often also referred to as the long-run incremental cost study – is a way for a utility to estimate the additional costs to serve one additional unit of electricity or add one additional customer to the system. Marginal costs can reflect serving these units only for a period as short as a year or for a longer time-period, perhaps as long as 15 to twenty years. In a marginal cost study, costs are broken down into various separate components, which are broadly speaking demand- (kW capacity), energy- (kwh), and customer-related marginal costs. The Oregon PUC has over a 20-year history of using marginal cost studies in their current form to inform the design of retail rates, in part by comparing average rates to marginal costs, as well as the spread of the revenue requirement among the various classes of customers.[1]

Once marginal costs for all these subcategories of the overall expense are determined, we can calculate the total revenue generated if the Company were to charge its customers prices equal to the estimated marginal cost. The Company presents the results of its marginal cost study in Exhibit PAC/1106.

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[1] *In the Matter of the Investigation of Methods for Estimating Marginal Cost of Service for Electric Utilities*, Docket UM 827, Order No. 98-374 (September 11, 1998).

Q. What issues do you address regarding the Company's marginal cost study?

A. I find that the Company's marginal cost study incorrectly relies on resources that it has no intention of adding to its system to calculate the two subcomponents of the marginal cost of generation – the marginal cost of energy and the marginal cost of capacity – which results in estimated marginal costs that do not reflect reality or potentially Oregon statutes governing the use of resources that operate on carbon-emitting fuels.

Further, I find that the design of the Company's marginal cost study falls short in two key ways. First, it does not properly account for changes in the true marginal cost that results from moving into a market that increasingly relies on renewable resources. Second, the Company appears to have assumed that some costs are customer charges that Staff thinks would be more appropriately reclassified, such as billing, metering, and communications.

Q. How do you address your concern that the Company's marginal cost study does not reflect reality?

A. To address the first part, I revise the Company's marginal cost of generation without relying on the hypothetical costs of a new natural-gas fired Single-Cycle Combustion Turbine (SCCT) and Combined-Cycle Combustion Turbine (CCCT). In their place, I calculate the marginal costs of energy and capacity using a combination of solar, wind, and storage resources that the Company plans to add to its system through 2030 based on the preferred portfolio the Company submitted in its most recent IRP.

Q. Why do you believe that the current marginal cost study framework does not work well in a renewable-heavy environment?

A. The increased cost-effectiveness of renewable resources and mandates to decarbonize the energy sector have made new fossil fuel-based electricity projects essentially either uneconomic or impermissible. While addressing the capacity and energy costs of this transition can be addressed somewhat easily in the current marginal cost framework, the current framework is not set up to address the intermittency of these resources. In theory, this intermittency requires utilities to not only add more resources, but also add a mix of resources that is more nuanced than the traditional problem of just adding another dispatchable plant.

Q. How do you recommend that this intermittency problem be addressed in a marginal cost study?

A. The current marginal cost study is not adequate to address the intermittency of renewable resources sans storage. In the future, I suggest that the marginal cost study integrate information from the Company's loss of load probability studies into its marginal cost study to create some form of marginal cost of risk reduction. My suggestion is beyond the scope of this rate case and is better addressed in other dockets, perhaps as an extension to the existing UM 2011 capacity valuation docket or as a new docket. I only bring up this concern to demonstrate that the marginal cost study's current framework wherein SCCT and CCCT plants are used as a proxy for the marginal cost of energy and capacity is inadequate.

Q. How does the Company use SCCT and CCCT plants to create its marginal cost study?

A. As I previously mentioned, the marginal cost of generation is broken down into the marginal cost of energy and the marginal cost of capacity. Disentangling these two subcomponents is tricky, as most generating resources both provide energy and capacity – that is they contribute to the Company's ability to meet its peak load. Traditionally, utilities assume that the marginal cost of capacity is derived from the avoided cost to build and operate an SCCT plant, as those plants have been the least-cost method to meet peak load. The avoided cost of energy is then assumed to be the difference between the avoided costs to own and operate a CCCT plant and an SCCT plant, with the intuition that a CCCT is has both a capacity and energy contribution. Therefore, the additional cost incurred to build a CCCT plant over a SCCT plant can be interpreted as the marginal energy cost. This is a common practice that is also outlined in PacifiCorp's opening testimony.[2]

Q. What is the problem with using SCCT and CCCT plants to estimate the marginal cost of energy and capacity?

A. As I stated above, the Company has no intentions to add these plants in the near term or long term. This can be seen in the Company's response to Staff DR 128,[3] where the Company states:

> No natural gas fired generation was selected as an expansion resource in PacifiCorp's 2021 Integrated Resource Plan (IRP). There are existing natural gas fired

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[2] PAC/1100, Meredith/7.

[3] Staff/702, Dlouhy/2.

> plants which continue operation through end of resource life, however, no new natural gas fired plants are selected to be built.

The marginal cost study is meant to reflect the costs of meeting future electricity needs given the circumstances and constraints facing the company. Continuing to use resources in a marginal cost study that are not reflective of the resources that will actually be added to the system runs counter to this goal.

Q. Given that the Company does not plan on adding any natural gas resources to its system, what changes do you recommend be made to the Company's marginal cost study?

A. Put simply, I recommend that the Company calculate its marginal cost of generation and its two subcomponents based on the resources it actually plans to add in the future.

Q. In the Company's most recent IRP, it appears that the Company intends to add a wide array of resources between now and 2040. Which resources do you recommend be used in the Company's marginal cost study?

A. I recommend the use of solar resources, wind resources, and any battery or storage components, given these are the resources the utility intends to add to its system to meet future load requirements.

Q. Do you have data on which of these resources the Company plans to add to its system and the expected costs of these resources?

A. Yes. In response to DR 127, the Company generally referred Staff to Docket LC 77, its most recent Integrated Resource Plan (IRP) and provided the confidential Plexos portfolio data it submitted in its 2021 IRP.[4] This data contains an annual breakdown of the portfolio projects the Company intends to add to its system, the type of resource, the nameplate capacity of the project, the expected generation of the project, and the project costs. For projects solar plus storage projects, the data even separate the estimated cost of the storage component from the generating component.

In my modifications to the Company's marginal cost study, I use these data to construct an alternate estimate of the marginal cost of energy and the marginal cost of capacity without using the estimates derived from the hypothetical SCCT and CCCT plants.

Q. How do you use this data to replace the hypothetical SCCT and CCCT plants?

A. As much as the data allow, I try to separate the capacity costs from the energy costs of the generating resources the Company currently plans to add through 2030. According to the data, the Company will almost exclusively add wind and solar plus storage projects.

I undertake a similar exercise to the Company's netting of costs between the SCCT and CCCT plant with the solar plus storage projects. In this case, I

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[4] Staff/702, Dlouhy/1.

assume that the cost of the storage component has a purely capacity value, whereas the cost of the full project has a mixed capacity and energy value. In other words, I use the costs of the battery to proxy for an SCCT plant and the cost of the full solar plus storage project to proxy for a CCCT plant.

If the Company planned on adding any wind plus storage projects to its system, I would go through the same exercise. However, the Company's response to Staff DR 127 indicates that it only intends to add standalone wind to its system through 2030.

Fortunately, data exist in Docket UM 2011 that can be used to separate the capacity contribution of wind from its energy contribution, and which was provided to Staff in response to a data request in this docket. As can be seen in response to the response to Staff DR 397, the Company's proxy wind resource has an effective load-carrying capacity (ELCC) of 15.2 percent.[5] This indicates that 15.2 percent of the total cost of a new wind project can be thought of as a marginal contribution to capacity needs while the rest of the project addresses energy needs. I apply the ELCC of wind resources to the cost data derived from the Company's response to Staff DR 127 to derive its marginal cost of capacity. Whatever is left over is assumed to feed into the marginal cost of energy.

Once I have the costs of capacity and energy of the Company's solar plus storage and wind additions through 2030, I take the weighted average of the costs of all of its projects, where the costs are weighted by the nameplate

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[5] Staff/702, Dlouhy/5.

capacity of the project. I then feed these newly calculated costs into the Company's existing marginal cost model to generate a new marginal cost of energy and capacity.

Q. What steps do you make to ensure that the marginal cost study properly integrates wind and solar resources?

A. The main structure of the Company's filed marginal cost study remains almost entirely unchanged. The only parts that I change are the Avoided Cost tab where the Company calculates the avoided costs of an SCCT and a CCCT plant.

I first create two new worksheets in the Company's filed marginal cost study. The first replaces the SCCT and CCCT with average avoided costs of solar plus storage and the battery attached to a solar plus storage project, respectively. The second replaces the SCCT and CCCT with the avoided cost of a new wind plant and the avoided cost of a new wind plant that is scaled back by the Company's filed ELCC, respectively. I then modify the Avoided Cost worksheet that the Company uses to flow through these calculations to the rest of the Company's filed marginal cost study to take the weighted average of values contained in the two new worksheets I created. The avoided costs in this modified worksheet are weighted by the capacity of the added resources as evidenced by PacifiCorp's IRP.

Q. Do you make any other changes to make sure that a battery constitutes an apples-to-apples comparison to a SCCT plant when calculating the marginal cost of capacity?

A. Yes. When constructing my revisions to the marginal cost study using batteries as a capacity resource, I noted that the most batteries that are planned to be installed are expected to have a four-hour duration while a SCCT plant may operate longer than four hours while meeting capacity. As such, replacing 100 MW of SCCT plants may require more than 100 MW of four-hour batteries. I issued a set of data requests to the Company to confirm if they believe the same as well. Based on the Company's response to Staff DR 426, the Company believes that approximately 121.3 MW of four-hour battery storage would be needed to replace 100 MW of SCCT plants.[6] As such, I scale up my avoided cost of batteries by 1.213 to reflect this ratio.

Q. What is the mix of solar plus storage and wind that you use for the marginal cost study?

A. Based on the Company's IRP portfolio, approximately 55 percent of the added generating resources that I select for my marginal cost study are wind while the remaining 45 percent are solar plus storage installations.

Q. How does the marginal cost study change once you implement these changes?

A. Table 1 contains a comparison of the Company's marginal costs of energy and capacity with my updated estimates. Overall, marginal costs decrease. This

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[6] Staff/702, Dlouhy/8.

means that the total revenue at marginal cost is significantly lower than the Company's total revenue requirement. I will discuss this in greater depth later in my testimony, but a valid interpretation of this is to say that the Company's move away from its inverted-block rate design is justified on a marginal cost basis.

Table 1: PacifiCorp and Staff's 20-Year Marginal Cost Estimates

	Company	Staff
MC Capacity ($/kW)	93.29	68.89
MC Capacity (Mills/kWh)	15.11	21.77
MC Energy (Mills/kWh)	35.32	31.81

This change is largely driven by a reduction in the marginal cost of capacity when it is discussed on a dollars per kilowatt basis but an increase in marginal cost of capacity when discussed on a dollars per kWh basis. My edits also result in a small decrease in the marginal cost of energy. Together, these changes are intuitive given the role that wind anecdotally plays in an energy portfolio. Recently, wind has become an attractive resource for its generation capabilities, but it is not particularly dispatchable without storage and has a much lower capacity factor than a natural gas turbine. Therefore, one would expect that the costs of a wind project allocated to capacity would be lower than the costs allocated to energy when discussing it on a power basis, i.e., dollars per kilowatt, but perhaps higher when augmented by the amount of energy that is actually being generated, i.e., mills per kWh.

Q. Regarding your second point, why do you believe that some items are incorrectly assumed to be customer charges?

A. As previously discussed, I believe that the Company has incorrectly allocated some of its costs to customer charges, such as billing, metering, and communication. Although these items may have had a clean interpretation as a purely customer-related cost in the past, the electricity market has changed, meaning that a lot of these expenses serve dual purposes. Billing systems that once only had to track electricity usage now have to track time-of-day or seasonal rates. Meters must be upgraded to allow the Company to integrate in time-of-use, demand response, and electric vehicle (EV) functions. To further these new and more nuanced rate designs that are only made possible by upgraded metering and billing systems, the Company's communication to its customers will likely be geared towards alerting its customers to these changes and how customers can change their behavior in a way to better align with the intended effects of these changes. As such, many of these costs are not purely customer costs, but also serve other purposes in the Company's system.

Q. What other purposes would be served by added costs to billing systems, metering, and communication related to the functions you described above?

A. The added costs of upgrades to each of these systems also have clear distribution, energy, and demand functions. The proliferation of EVs will likely require added investment to the distribution network and will necessarily increase the need for energy. Smart meters can be used to institute time-of-use or demand response rates that can affect peak demand. As previously discussed, the communication costs needed to fully realize the benefits of these programs can also be interpreted as being properly spread to distribution, energy, and demand functions as well. Therefore, the company's costs attached to these items should be allocated between customer, distribution, energy, and demand functions.

Q. Given that your revisions to the marginal cost study decrease the revenue requirement at marginal cost, and your concern about the misclassification of customer-related costs, do you have any other recommended changes to the Company's rate case?

A. Yes. In light of my revisions to the marginal cost study and my concern about customer-related costs, I recommend some changes to the Company's proposed rate spread in this case. These changes will be discussed in the next section of my testimony. I also further scrutinize the Company's customer-related costs that it uses to support its residential basic charge in my rate design section.

ISSUE 2: RATE SPREAD

Q. Please summarize the Company's proposal on rate spread.

A. The Company proposes an average percent of margin of 12.51 percent in this rate case. The proposed breakdown of the percent of margin can be seen in Table 2, which was compiled from the Company's Unbundled Revenue Requirement Allocation contained in Exhibit PAC/1107. It is worth noting that these differ from the changes to net rates presented in Exhibit PAC/1100, Meredith/15, which include adders from various other schedules.

Table 2: Proposed Changes to Base Rates

Customer Class	Schedule(s)		$ Change	% Of margin increase
Total			**$154,929**	**12.51%**
Residential	4	(sec)	$106,304	17.80%
General Service	23	(sec)	$18,470	14.88%
		(pri)	$113	34.03%
General Service	28	(sec)	$8,097	5.01%
		(pri)	($150)	-7.26%
General Service	30	(sec)	$3,515	4.04%
		(pri)	$213	2.95%
Large Power Service	48	(sec)	$1,913	4.67%
		(pri)	$4,890	5.09%
		(trn)	$5,266	6.03%
Irrigation	41	(sec)	$6,879	23.56%
Lighting	15, 51, 53, 54		($582)	-11.29%

Q. Please discuss whether you agree with the Company's proposal for rate spread.

A. I disagree with the Company's proposed rate spread for base rates for a few reasons:

1. Although the Company's net rates result in an increase or no change to all customer schedules, its base rate proposal does not. I find this inappropriate to decrease base rates for certain customer classes when base rates are rising overall, especially when the proposed rate changes are so large when combined with the Company's filed Transitions Adjustment Mechanism (TAM).
2. The Company's decision to limit the rate increase to a particular customer class to twice the overall rate increase is larger than the Commission has adopted in the past, especially when there are larger rate increases. I find it inappropriate to allow such an uneven spread when the total proposed rate increase between the TAM and the rate case is more than 12 percent.[7]
3. For reasons described in the previous section of my testimony, I do not have confidence in the Company's methods in its marginal cost study and believe that the added percent of margin is more appropriately calculated using my results.

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[7] Staff/702, Dlouhy/7.

Q. Based on your criticism, what do you propose to do for rate spread?

A. I propose that base rates be spread more evenly across customer classes while still preserving some movement towards parity. To do so, I propose the following criteria to modify the Company's rate spread proposal for base rates:

1. No customer class or schedule experiences a base rate decrease. Any customer that was listed as receiving a base rate decrease in the Company's filed Exhibit 1107 will instead be given a 0 percent increase in rates to preserve some movement towards parity.
2. The base rate increase for any individual schedule and customer class shall be no larger than 25 percent larger than the average increase in base rates.
3. Any costs that need to be reallocated as a result of my first two changes will be allocated to schedules unaffected by the previous two changes. Costs will be allocated proportionally to their forecasted usage by schedule. If reallocation results in any schedule receiving more than 25 percent larger than average increase in base rates, the excess costs will be reallocated to the remaining schedules that were not affected by my first two changes.

Additionally, I recommend using my revisions to the marginal cost study to calculate any changes to rate spread. In practice, the end results are very similar whether my revisions or the Company's filed marginal cost study is used.

Q. Why do you believe that it is improper for a customer class or schedule to see a rate decrease in this rate case?

A. The Commission has not supported raising rates for certain customers, while reducing rates for others, absent compelling evidence that immediate action is needed.[8] It is appropriate to apply the same principle here. Given the large increase in rates between the TAM and the rate case, rate shock is a real concern for all customer classes. As such, the burden from the rate increase should be spread across all customer classes to some degree.

Q. The Company uses the Rate Mitigation Adjustment (RMA) to limit agricultural customers to double the average rate increase and residential customers to 1.4 times the average increase.[9] Do you believe this is appropriate?

A. No. As discussed previously, the burden should be spread among customer classes. In a rate case where the average proposed rate increase is 6.6 percent, I do not believe that a 13.2 percent increase for a single customer class and a 9.1 percent increase to the largest customer class constitute an equitable rate spread. This does not even take into account the TAM, which would create a total rate increase of 12.2 percent when combined with this rate case as filed.[10]

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[8] *In the Matter of Avista Corporation, Request for General Rate Revision*, Docket UG 284, Order No. 15-054 (February 23, 2015).

[9] PAC/1100, Meredith/16.

[10] Staff/702, Dlouhy/7.

Q. Has Staff recommended similar caps on the increase in rates?

A. Yes. In UG 435, Staff recommends putting in place a cap equal to 1.05 times the final overall incremental margin increase to commercial customers, with a smaller cap on residential schedules.[11] Compared to UG 435, my recommendation more aggressively moves rates towards costs.

Q. What is the effect of your proposed changes on base rates?

A. Table 3 contains my proposed changes to base rates.

Table 3: Staff Proposed Base Rate Spread

Customer Class	Schedule(s)		$ Change	% Of Margin Change
Total			**$154,929**	**12.51%**
Residential	4	(sec)	$93,386	15.64%
General Service	23	(sec)	$19,410	15.64%
		(pri)	$52	15.64%
General Service	28	(sec)	$11,613	7.18%
		(pri)	$0	0.00%
General Service	30	(sec)	$5,794	6.66%
		(pri)	$396	5.47%
Large Power Service	48	(sec)	$2,993	7.30%
		(pri)	$8,001	8.33%
		(trn)	$8,718	9.98%
Irrigation	41	(sec)	$4,566	15.64%
Lighting	15, 51, 53, 54		$0	0.00%

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[11] See *In the Matter of Northwest Natural*, Docket, UG 435, Exhibit Staff/1300, Scala/44.

Q. Do you make any other changes to the Company's net rate spread in this case?

A. Yes. The Company's proposed Rate Mitigation Adjustment (RMA) schedule was initially constructed to add costs to customer classes that received a decrease to base rates to ensure that those customer classes experienced flat rates. With my changes to base rates, the Company's RMA would add costs to these customer classes, resulting in an increase to their rates which were instead meant to be flat. I modify the PacifiCorp-proposed RMA to be spread among the customer classes and schedules that received a rate increase to bring each customer class's overall change in net rates to within 125 percent of the overall average change proposed in the Company's filing.

In effect, this caps the rate increase to a single customer class at no more than 8.25 percent in this docket. While the total rate increase is likely to change over the course of this docket, I recommend retaining this rule of thumb to cap the overall rate increase to mitigate rate shock.

Q. What is the effect of your proposed changes on net rates?

A. Table 4 contains the effect of my recommended changes on net rate spread. To maintain movement towards parity, I recommend maintaining the 0 percent increase to lighting schedules and only recommend small increases to general service schedules.

Table 4: Staff's Proposed Net Rate Spread

Schedule	Company Proposed	Staff Proposed
Residential Schedule 4	9.1%	7.7%
General Service		
Schedule 23/723 (0-30kW)	9.5%	8.2%
Schedule 28/728 (31-200kW)	0.0%	2.4%
Schedule 30/730 (201-999kW)	0.0%	3.0%
Large General Service Schedules 47/747, 48/748 (>1000kW)	5.9%	7.9%
Agricultural Pumping Service Schedule 41/741	13.2%	8.1%
Lighting Schedule	0.0%	0.0%
Overall	**6.6%**	**6.6%**

ISSUE 3: RESIDENTIAL RATE DESIGN

Q. Please summarize the Company's new proposals on rate design.

A. The Company proposes two notable changes to its rate design in this general rate case:

- An increase to the single-family basic charge for residential customers from $9.50 to $12.00 while leaving the multi-family basic charge at $8.00.[12]
- The removal of the inverted block rate structure that will be replaced by a seasonal, flat rate structure for residential customers.[13]

Q. Are there any other rate design issues that you will address in this testimony?

A. Yes. As part of the Company's proposal to move to a flat rate structure, the Company proposes to change the Schedule 98 Regional Power Act credit from a two-block structure with a lower credit provided to customers using more than 1000 kWh a month to a flat rate structure.[14]

Q. Please summarize Staff's position on the changes outlined above.

A. Although Staff disagrees with some of the Company's evidence on cost causation, Staff supports the Company's proposal to increase the single-family basic charge from $9.50 to $12.00 while leaving the multi-family basic charge unchanged. Staff objects to the Company's choice to classify some assets as

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[12] PAC/1100, Meredith/19.
[13] *Id*.
[14] PAC/1101, Meredith/18.

customer assets rather than volumetric but still finds a sufficient cost basis to raise the single-family basic charge.

Staff also supports the Company’s proposal to adopt a flat rate design. As the Company has pointed out, an inverted block tier rate design is no longer supportable given the relationship of long-run marginal costs to average costs. That is, current marginal cost estimates are lower than the prices proposed for flat rates, and do not support an inverted rate. I also provide evidence from the Company’s marginal cost study to support the transition away from this rate design.

Much like past rate cases, Staff generally supports the Company’s choice to create a seasonal rate structure as that move is cost-based. However, Staff is continuing to investigate the Company’s choice of its seasonal rate differential.

Despite Staff support for the Company’s move towards a seasonal flat rate design for residential customers, Staff opposes the Company’s proposal to remove the inverted tiered rate structure for residential customers in Schedule 98. Staff believes that removing the 1000 kwh first tier poses significant equity issues, as electricity use appears to be correlated with household income. As an alternative to maintaining the 1000 kwh first tier on Schedule 98, Staff instead recommends distributing the refund from Schedule 98 to residential customers on a per-customer basis instead of a per-kwh basis.

Q. What reasons are given by the Company to justify an increase in the single-family basic charge from $9.50 to $12.00?

A. The Company states that raising the single-family residential basic service rate to $12.00 more fairly apportions cost between fixed and volumetric charges. In particular, the Company notes that its monthly marginal cost per residential customer is approximately $28.85 per customer. The Company's calculation of this is contained in PAC/1111.

The Company then goes on to compare its residential basic charges to the basic charges of other Oregon electric utilities and notes that it is among the lowest. This can be seen in Table 2 on PAC/1100, Meredith/21.

Q. Do you agree with the Company's method to calculate its marginal cost per customer?

A. No. I find that the Company's choice to include some items in its marginal cost per customer do not cleanly have a purely "per customer" interpretation, but also have a volumetric interpretation. Including these factors in the basic charge justification improperly allocates costs between functions.

Q. Why do you believe that some items included in the Company's calculations have a volumetric interpretation?

A. As the electricity industry evolves, utilities and government agencies are increasingly giving customers incentives to adopt higher efficiency, lower carbon, and renewable equipment. Examples of these include demand response, energy efficiency investment, electric vehicles, and at home solar panels.

These items do not necessarily change the customer count or the customer's location, but they can have massive implications for the net energy a customer consumes, when the energy is consumed, and what equipment is needed to accommodate these new technologies. Using the example of electric vehicles, one would expect that there may be a large influx of demand in the evening at a particular substation if a critical mass of residential customers in that area were to purchase an electric vehicle. Therefore, the costs to upgrade the system do not necessarily map perfectly onto an individual customer, but rather the volume of electricity consumed by the customer. A similar thought experiment could be conducted with the other examples I gave in the previous paragraph. Further, rate design can affect a customer's choice as to when car charging occurs, or other electric usage occurs.

Q. What items do you believe are wrongly included in the Company's marginal cost per customer calculation?

A. Transformers and their associated O&M costs are one example of something that has a volumetric interpretation in an era of customer-focused electrical investments. Given that transformers cannot handle an infinitely large energy flow, it would follow that they would need to be updated based not just on the addition of a new customer at the substation level, but also based on the mass adoption of some new technology that changes the volume of energy flowing in or out of a transformer.

Customer costs should reflect a minimum amount of electricity provided designed such that it meets safety requirements. The appliance and equipment choices of a consumer, such as an electric car or electric heated spa or lighting for plants, are choices in the use of electricity and so are capacity and energy related. Further, if the facilities needed for handling such things as handling customer car charging were treated as a customer cost, since electric vehicle ownership tends to be income related, such a rate design would be inequitable for lower income customers.

Q. Would this dual classification of transformers as both a volumetric and a customer cost alter the Company's estimated marginal cost of a residential customer enough to recommend against a $12.00 single-family basic charge?

A. No. Even if the cost of a transformer were entirely volumetric, the Company's estimated monthly marginal cost per customer would be approximately $21.73 based on PAC/1111. When broken down between single-family and multi-family, the Company's estimates become $23.00 and $15.99, respectively. On this basis, the Company's proposed changes to the single-family basic charge are still justified and bring the costs closer to parity.

Although I recommend no change on a cost basis, I bring up this thought exercise as a way to encourage the Commission and Company to think carefully about how to classify assets in an electricity market that increasingly relies on decarbonization and demand side measures.

Q. Do you think that the Company's comparison of basic charges on PAC/1100, Meredith/21 is a fair comparison?

A. No. Table 2 on the above-referenced page seems to indicate that PacifiCorp has an abnormally low basic charge for Oregon. In making this comparison, the Company pulls in municipal utilities, co-ops, and investor-owned utilities in Oregon. Of these, I believe it is most correct to compare the Company's rates only to the rates of other Oregon investor-owned utilities, namely Idaho Power and Portland General Electric as they serve 75 percent of all Oregonians.

Further, while a chart showing basic charges in effect for various utilities providing electric service in Oregon is useful from an informational perspective, it provides no evidence with respect to cost of service. The Oregon PUC has a long history of basing rates on the cost of service. Showing other utility basic charge values may show standard industry practices, but it does not imply a customer would move from PacifiCorp territory to a different utility merely as a way to escape a few dollars a month in a customer charge. PacifiCorp did not make a competitive argument. PacifiCorp made a standard practice argument. But again, no analysis of the customer cost of other utilities was provided.

PacifiCorp's Table 2 shows that the Company's proposed basic charge would be the highest basic change of the three Oregon investor-owned electric utilities. On this basis, it would appear that the Company's proposed rate puts it out of line with other PUC-regulated utilities.

Q. Given this concern, do you support the Company's proposed change to its basic charge?

A. Yes. Although I object to the comparison that the Company draws to non-investor-owned utilities, I still support the Company's proposed change. I find that the difference between Portland General Electric's and PGE's single-family basic charges, $11.00 vs $12.00, to be acceptable. Further, both utilities offer a multi-family basic charge of $8.00. Lower-income households have a higher propensity to live in multi-family housing units, so keeping the multi-family basic charge at the same rate has positive equity implications.

Q. What reasons are given by the Company to support the move away from the inverted block tier rate design it has previously employed?

A. In its opening testimony, the Company says that the inverted block rate structure was once considered an effective tool to incentivize energy efficiency by making the cost of consuming electricity higher after a certain level.[15] The Company goes on to say that in an evolving energy market, this rate design is no longer appropriate as it is no longer economically justified and provides perverse incentives.

In particular, the Company states that the tiered structure creates perverse incentives by rewarding customers who heat their home using non-electric sources and dissuading electric vehicle adoption, which runs counter to the movement to decarbonize the energy sector.[16]

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[15] PAC/1100, Meredith/22.

[16] PAC/1100, Meredith/23-24.

Further, the Company notes that the rates are no longer economically justified in that the tiered structure does not address the timing of electricity consumption. In particular, the Company points out that the cost of providing service varies during different seasons and different hours of the day, a nuance that is not captured by the current tiered rate design.[17]

Q. Do you agree with the Company's assertions?

A. Somewhat. I disagree with the Company's claim that the inverted block rates create a disincentive for electrification from the standpoint that a time-of-day rate is a better way of addressing that issue. That is to say, if we want to promote transportation electrification, a better cost basis for doing so is a time-of day rate.

On the topic of whether the shift away from inverted block rates is economically justified, one can look to the marginal cost study. If the revenue requirement at marginal cost is higher than the total revenue requirement, it would suggest that the marginal cost of generating unit is increasing, thus providing justification for the inverted block rates.

Using both the Company's filed marginal cost study and my edits to the Company's study, I do not find this to be the case when comparing the revenue requirement at marginal cost to the volumetric revenue requirement in both the rate case and TAM. Therefore, I also support the Company's claim that the inverted block rates are no longer economically justified.

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[17] PAC/1100, Meredith/24-25.

Q. The Company has a time-of-day rate pilot program in Schedule 6. What is the current enrollment in this program?

A. According to the Company's response to Staff DR 533, the Company has enrolled only 112 customers in the time-of-day pilot compared to the 25,000 customers that the Company agreed to allow to participate following its last general rate case, UE 374.[18] As previously stated, I believe expanding this pilot program to be a more effective incentive for EV adoption than a flat rate.

Q. How does actual residential revenue requirement from volumetric charges compare to residential revenue requirement at marginal cost?

A. Using my edits to the marginal cost study, I find that the revenue requirement at marginal cost for residential customers is approximately $553 million. The Company's proposed net residential revenue requirement are approximately $672 million, its added proposed revenue requirement to residential customers in the TAM is approximately $32 million, and the expected revenue from the basic charges is $72 million. All told, this means that the Company's revenue requirement from volumetric charges totals approximate $632 million, which is well above the revenue requirement at marginal cost. It is worth pointing out that the revenue requirement at marginal cost does not substantially change if the Company's filed marginal cost study is used in place of my edits.

As stated previously, this implies that the marginal cost is below the average cost. However, this analysis alone is not adequate enough to say that a flat rate is preferable to a time-of-day rate mentioned earlier, but rather that a

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[18] Staff/702, Dlouhy/13.

flat rate is preferable to the current, inverted-block rates. I want to qualify these results by pointing out that this is not a perfect comparison, as the average cost has embedded into it the costs of previous vintages of equipment while the marginal cost contains current dollars.

Q. Do you support the Company's move to a seasonal rate design?

A. I support the Company's choice to impose a seasonal rate. As the Company touched on in its argument against inverted block rates, the cost to provide electricity varies by season. Staff supports designing rates to reflect that.

However, Staff is investigating whether the Company's choice of summer-winter differential is economically justified.

Q. What is the Company's summer-winter differential and how is it calculated?

A. As discussed in the Company's opening testimony, it proposes a rate of 10.335 cents per kWh during the winter months of October through May and a rate of 12.264 cents per kWh for the months of June through October, which is a differential of approximately 1.9 cents per kWh.[19] The Company chose its differential by finding the average market price over these two time intervals according to the most recent monthly price curve of the Mid-Columbia (Mid-C) trading hub.[20]

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[19] PAC/1100, Meredith/26.

[20] PAC/1100, Meredith/26-27.

Q. What concerns do you have with the way the Company calculated its summer-winter differential?

A. I have two primary concerns. First, although the market price can be an informative measure, calculating the summer-winter differential based on the market rate for wholesale electricity does not necessarily capture all of the differences in costs to the Company. For example, capacity costs are also a consideration as well as the class of service coincidental and non-coincidental load factors. Second, even if using the market price is a worthy proxy for the electricity cost differential between seasons, the Company's choice to use only the Mid-C trading hub does not capture the Company's cost of transacting in the open market. And with respect to capacity costs, reviewing PacifiCorp's Loss of Load Probability (LOLP) analysis submitted in UM 2011 would be informative in designing a seasonal rate.

Q. What is the LOLP analysis?

A. LOLP is the probability that a system demand will exceed capacity in a given period. As part of the UM 2011 docket, the Company submitted its simulated LOLP for every hour of the year under both its preferred portfolio and committed resources in 2024, 2028, 2032, 2036, and 2040. The Company provided the results of this analysis in response to Staff DR No. 397.[21]

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[21] Staff/702, Dlouhy/5.

Q. What have you done to investigate the Company's seasonal differences in costs?

A. I issued a series of data requests to the Company asking whether the Company uses its LOLP modeling to inform its summer-winter rate differential and how the Company suggests it be used for rate setting purposes. The Company stated that it has not used its LOLP results to inform its rate setting and has not conducted analysis for its time-of-use or seasonal pricing.[22]

Q. Have you conducted any analysis on the Company's LOLP results to inform your recommendation on the Company's seasonal rate design?

A. Yes. The Company provided the results of its LOLP analysis in UM 2011 in its response to Staff DR 397.[23] I examined the Company's LOLP for its preferred 2024 portfolio and looked at which parts of the year have the highest LOLP. While this does not necessarily answer the question about the Company's operation cost in each season, it does inform which seasons are dictating future Company investment, and thus future added costs.

Figure 1 shows the maximum daily LOLP under the Company's 2024 preferred portfolio. It can be clearly seen that the Company's designated summer months contain the majority of the Company's load loss risk. This is suggestive that the Company's summer load is the driving force of its investment decisions.

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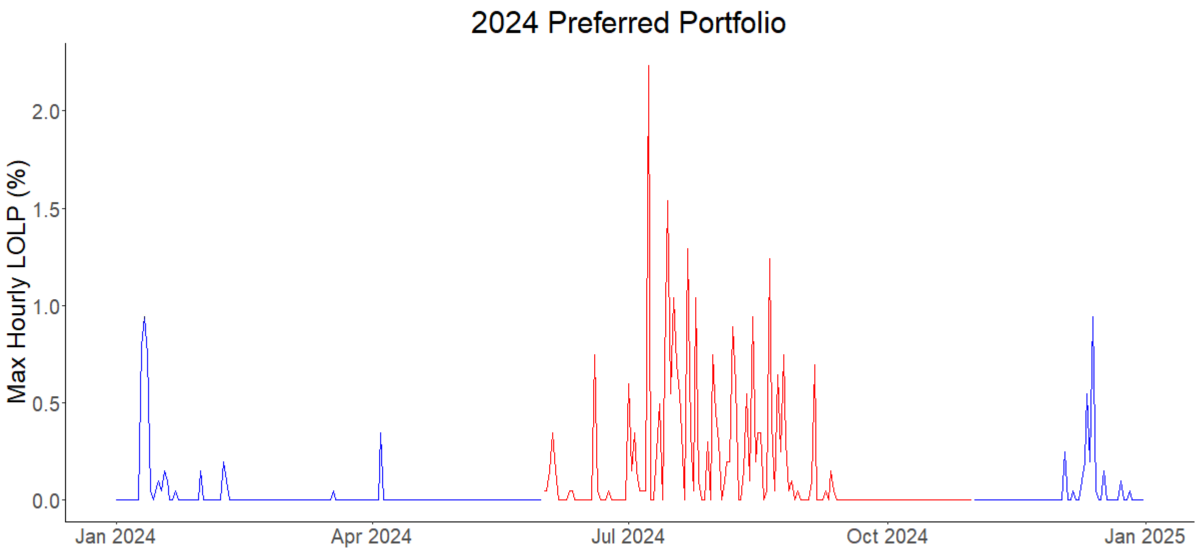
[22] Staff/702, Dlouhy/4-6.

[23] Staff/702, Dlouhy/5.

Figure 1: Loss of Load Probability



Red indicates PAC-proposed summer months

Q. How do you suggest that the Commission incorporate the information from Figure 1 into a summer-winter differential rate design?

A. At this time, I do not have a recommendation on how to transfer the LOLP study into a summer-winter rate differential. While the above figure is indicative that the Company's risks of load loss are highest in the summer, the question of how to allocate the costs of investment between days, months, or even seasons is more nuanced and requires a deeper investigation. For the time being, I am comfortable with the Company's proposal to structure its seasonal rates based on prevailing market prices in this proceeding. However, I do object to the Company's choice to structure its summer-winter rate differential on the prices at a single hub.

Q. Regarding your second concern, why is the use of only the Mid-C market price inadequate measure of the Company's seasonal cost differential to buy wholesale electricity?

A. The Company buys wholesale electricity from a variety of hubs that all presumably charge different prices, but the Company only relies on the Mid-C price to set its summer-winter differential. If one assumes that prices at every hub move in exactly the same way, then this would not be a problem. However, it is obvious that such an assumption vastly oversimplifies wholesale electricity market transactions.

As such, it would be naïve to expect that the market prices at one hub fully determine the Company's true cost to operate in wholesale electricity markets.

Q. What do you recommend that the Company use to proxy for its wholesale electricity market costs?

A. In place of just the Mid-C price, I recommend that the summer-winter differential be based off of a weighted average of the seasonal market prices the Company faces for all of its off-system purchases. In this, the weight given to each price would be proportional to the quantity of electricity the Company buys from the hub in each season.

Q. Have you calculated this price?

A. Yes. The Company provided all transactions of electricity purchased from hubs and other entities in the market 2016-2021 in response to Staff Data

Requests 501 and 502.[24] I find that the Company faced a weighted average market price for wholesale electricity of 4.06 cents per kWh for the summer months and 2.63 cents per kWh for the winter months over this period. Confidential Table 5 contains the seasonal volume of sales for each hub, the seasonal average market price for each hub, and the seasonal weighted average market price faced by the Company.

Confidential Table 5: Volume and Average Price 2016-2021

[BEGIN CONFIDENTIAL]

[redacted]

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[24] Staff/702, Dlouhy/11-12.

[END CONFIDENTIAL]

Q. Based on your calculated prices, what do you recommend the Company use for its summer winter differential?

A. I find that the summer-winter differential should be 1.43 cents per kWh.

Q. What is the Company's proposal regarding Schedule 98?

A. The Company proposes that the Schedule 98 be modified to a flat 0.914 cents per kWh credit for all usage by customers under Schedules 4, 5 and 6.[25] Schedules 4, 5, and 6 primarily serve residential customers. This is a departure from the Company's previous Schedule 98 structure for Schedules 4 and 5 that provided a credit of 1.142 cents per kWh for the first 1,000 kWh of usage and a credit of 0.208 cents per kWh for all electricity consumed above 1,000 kWh.

Q. Please give a brief description of history of Schedule 98 and why the rate credit exists.

A. The full name of Schedule 98 is the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act. One of the main provisions of this act is the Residential Exchange Program (REP). Under the REP, the residential exchange is how the benefit of the low-cost federal system is shared with residential and small-farm customers of investor-owned utilities. Currently those benefits are established through a settlement BPA adopted that resolves such sharing of benefits through September 30, 2028.

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[25] PAC/1100, Meredith/26.

Q. Please give a brief description of how the Schedule 98 credit was previously structured.

A. Beginning in 2011, Schedule 98 applied only to the first 1,000 kWh of usage by qualifying customers. In Docket No. ADV 1310, which was meant to set the Schedule 98 rate beginning on October 1, 2021, the Company initially proposed a flat per kWh credit of 0.914 cent much like it proposes in this docket. At the October 7, 2021, Public Meeting, the Commission adopted Staff's recommendation to suspend and investigate this matter, which would later be docketed in UE 397.[26] Ultimately, the Company and Staff agreed on the two-tiered per kWh rate credit with a rate effective date of January 1, 2021, and agreed that this matter could be taken up in the next Company's rate case which is now this docket UE 399.[27]

Q. What issues did Staff identify in UE 397 that warranted the initial recommendation to suspend and investigate?

A. In the ADV 1310 Staff report for the September 21, 2021 Public Meeting, adopted in Commission Order No. 21-315, Staff noted that the REP is arguably better allocated on a per-customer basis than a per kWh basis, and removing the 1000 kWh cap on the credit as the Company proposed moves the rate design further away from a per-customer credit.[28] In that report, Staff noted

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[26] *In the Matter of PacifiCorp Schedule 98 Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act*, Docket UE 397, Order No. 21-315 (September 23, 2021).

[27] See Docket UE 397, Order No. 21-471 (December 20, 2021).

[28] See the Staff report: Docket UE 397, Order No. 21-315, Appendix A.

that this presents equality issues in that customers who consume more electricity reap larger benefits from the REP.[29]

Q. Does an uncapped per-kWh rate present any other issues as well?

A. Yes. Eliminating the cap on the per-kWh REP credit presents clear equity issues that run counter to the State of Oregon's equity goals that are exemplified in 2021's House Bill (HB) 2475. An uncapped per-kWh rate incentivizes electricity consumption, which disproportionately benefits those who consumer greater quantities of electricity. As the Company points out in Table 5 on PAC/1100, Meredith/28, electricity usage appears to be correlated with income level.[30] Therefore, removing the cap would shift the credits away customers that the Oregon government has made moves to protect in other settings. Further, having the credit based on usage gives an illusion that there are additional benefits available if a customer uses more electricity. This is not the case. Residential exchange benefits are at fixed dollar values for the investor-owned utilities, by year, through September 30, 2028.

Q. Do you have any other concerns with a flat rate design for the REP?

A. Yes. I have concerns that the Company has not done enough due diligence to ensure that its large consumers under the residential rate schedule are truly residential customers.

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[29] Id.
[30] PAC/1100, Meredith/28.

Q. Why do you have this concern?

A. I issued Staff DR 442 to enquire about any efforts that the Company has made to verify that customers consuming above 10,000 kWh on a single bill are indeed residential customers. When issuing this request, my concern was that residential customers may be using their residential utility service to power an at-home business or, for example, an unsanctioned, energy-intensive growing operations and that the Arrearage Management Program created as a COVID-19 relief was improperly funding it. The Company gave the following response:

> The Company limits its Arrearage Management Program (AMP) participation to residential customers by reviewing an applicant's revenue class at the time of issuing a grant – which is based on arrears without a differentiation for consumption.[31]

Q. How could the Company's response to a DR about the AMP present concerns about the REP?

A. The Company's response implies that it does not do any sort of due diligence to make sure that its large residential customers are consuming electricity for residential purposes. The Company's response to Staff DR 427 indicates that some it has given AMP assistance to customers with bills well over 20,000 kWh.[32] Even the most affluent households struggle to consume that much electricity in a single month, meaning that it is likely that this energy is being used for non-residential ends, meaning that the AMP assistance is inappropriate.

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[31] Staff/702, Dlouhy/10.

[32] Staff/702, Dlouhy/9.

A flat per-kWh REP credit – which is meant as a refund for *residential* customers – misallocates funds in the same way as described above for the AMP. Large residential customers will reap disproportionate benefits from a flat rate, and the Company's response to Staff DR No. 132 indicates that it often sees residential bills in excess of 30,000 kWh. Allowing the REP to function as a flat rate not only presents equity concerns outlined above, but also could potentially subsidize customers for non-residential use, such as off-the-books and energy-intensive growing operations.

Q. Can you quantify the rate impact of adopting the Company's proposal to flatten the per kWh REP?

A. Yes. In Staff DR 131, I ask that the Company provide a bill comparison between the Company's current two-tiered REP bill discount, the Company's proposed bill discount, and a per kWh discount limited only to the first 1,000 kWh of usage.[33] The results show that relative to the two-tiered structure approved in UE 397, removing the 1,000-kWh cap and flattening the rate increases the bills for all consumers that consume 1,200 kWh or less. The Company's response also shows that approximately 75 percent of all residential bills are less than 1,200 kWh, meaning that the Company's proposed Schedule 98 adjustments not only harm demographics that are more likely to be lower-income households, but also a large majority of PacifiCorp's residential customers. Conversely, reimposing a cap at 1,000 kWh benefits

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[33] Staff/702, Dlouhy/3.

residential customers that consume 1,200 kWh or less. The results of this data request are summarized in Table 6 below.

Table 6: Bill Effects of Schedule 98 Changes

Monthly kWh	Bill Frequency	Cumulative Frequency	Present Bill Est.	1000 kWh Cap % Difference	PAC Proposed % Difference
0	1.0%	1.0%	$13.22	**0.00%**	**0.00%**
200	6.9%	7.8%	$34.72	**-0.40%**	**1.30%**
400	13.7%	21.6%	$56.22	**-0.48%**	**1.62%**
600	17.0%	38.6%	$77.72	**-0.53%**	**1.76%**
800	15.3%	53.9%	$99.22	**-0.54%**	**1.84%**
1000	12.2%	66.1%	$120.72	**-0.56%**	**1.89%**
1200	9.2%	75.2%	$144.08	**-0.18%**	**0.60%**
1400	6.7%	81.9%	$167.46	**0.09%**	**-0.33%**
1600	4.8%	86.8%	$190.82	**0.30%**	**-1.02%**
1800	3.5%	90.2%	$214.20	**0.46%**	**-1.57%**
2000	2.5%	92.8%	$237.56	**0.59%**	**-2.01%**
2200	1.8%	94.6%	$260.93	**0.70%**	**-2.37%**
2400	1.3%	95.9%	$284.30	**0.78%**	**-2.68%**
2600	1.0%	96.9%	$307.66	**0.86%**	**-2.93%**
2800	0.7%	97.6%	$331.04	**0.92%**	**-3.15%**
3000	0.5%	98.1%	$354.40	**0.98%**	**-3.34%**

Q. Based on this analysis, what do you propose be done to ensure that any changes to the REP credits benefit low-income consumers and the majority of Oregonians?

A. I propose that the Company reimpose the 1,000-kWh cap on the REP credits. In effect, this increases the per-kWh credit to 1.210 cents per kWh based on the Company's estimates included in response to DR 131 and spreads the benefits more evenly across customers regardless of energy consumption.

Q. Is there another concern about moving to a flat residential exchange credit?

A. A flat residential exchange credit increases rate instability for residential consumers. The credit is based on dividing the fixed dollars available under the residential exchange settlement and forecasted qualifying load. When sales differ from forecast, either too much or too little benefits were provided to qualifying customers. That would mean rate adjustments to take that into account. Capping the benefit to the first 1000 kWh of monthly usage reduces this risk as this usage is more stable than total usage given how weather affects usage.

Q. Your recommendation seems to run counter to the Company's broad goal to flatten rates in its move to flat, seasonal rates. Is there another way that the REP credit could be spread evenly among customers without creating block-inverted rates?

A. Yes. As an alternative to reimposing a 1,000-kWh cap, I recommend designing the REP on a per-customer basis than a per-kWh basis. This would eliminate Staff's concerns that the benefits of the REP are accruing to higher-usage and higher-income customers, as well as the message that the residential exchange benefits can grow larger which is inconsistent with the residential exchange settlement.

Q. How large would a per-customer credit be in Schedule 98?

A. I estimate that a per-customer REP credit would be $8.62 per bill.

Q. How did you calculate this per-customer credit?

A. Based on the Company's filed rate design workpapers in this docket, the Company expects to receive approximately $55,378,000 from BPA through the REP net of employee discounts. The Company's marginal cost study workpapers indicate that it expects an average of 535,059 customers in 2023, or 6,420,708 bills per year. Therefore, a per-customer REP credit can be easily estimated by dividing the total net REP revenue by the total estimated bills in a calendar year.

Q. Are there any other equity-related reasons that a per-customer REP credit should be considered?

A. Yes. The estimated per-customer REP credit of $8.62 per bill would entirely offset the basic charge of $8 for multi-family households and mostly offset the proposed $12 basic charge for single family households. This constitutes significant bill relief for a class of customers that the State of Oregon has made moves to protect through HB 2475 and other related initiatives.

ISSUE 4: DYNAMIC INTERSTATE ALLOCATION FACTORS

Q. Why are you continuing to investigate the Company's dynamic interstate allocation factors?

A. In UE 400, AWEC noted it believed that the Company's interstate allocation factors are inconsistent with the 2020 Protocol due to the Company's treatment of Utah Schedule 34.[34] Ultimately, AWEC proposes changes to the Company's System Energy (SE) and System Generation (SG) factors based on the inclusion of Utah Customer load.[35] I expect that AWEC will propose the same adjustments in this proceeding.

Given that parties' opening testimony was filed in UE 400 on May 25, 2022, I have not had adequate time to conduct a full investigation and form a recommendation on this issue. However, I plan to address the issue in the next round of testimony.

Q. Does this conclude your testimony?

A. Yes.

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[34] See *In the Matter of PacifiCorp, dba Pacific Power, Transition Adjustment Mechanism*, Docket, UE 400, Exhibit AWEC/100, Mullins/4.

[35] See *In the Matter of PacifiCorp, dba Pacific Power, Transition Adjustment Mechanism*, Docket, UE 400, Exhibit AWEC/100, Mullins/9.

CASE: UE 399
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualification

June 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME: Curtis Dlouhy

EMPLOYER: Public Utility Commission of Oregon

TITLE: Economist, Strategy and Integration Division

ADDRESS: 201 High St. SE, Ste. 100
Salem, OR 97301-3612

EDUCATION: PhD, Economics
University of Oregon,
Eugene, OR

Master of Science, Economics
University of Oregon,
Eugene, OR

Bachelor of Arts, Economics & Math
Nebraska Wesleyan
University, Lincoln, NE

EXPERIENCE: I have been employed by the Oregon Public Utility Commission (OPUC) in the Strategy and Integration Division since April 2022 and had previously worked in the Rates, Finance, and Audit Division since June 2020. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues. I have provided analysis and expert testimony in various contested cases including UG 388, UG 389, UG 390, UE 374, UE 390, UE 391, UE 394, UG 433, UG 435, UE 399 (ongoing), UE 400 (ongoing), and UE 402 (ongoing).

Prior to working for the Commission, I was employed by the University of Oregon as a graduate employee where I taught classes in Intermediate Microeconomics, Industrial Organization, and Antitrust Economics. My PhD dissertation won an award from the Transportation and Public Utility Working Group and covered topics in fossil fuel markets ranging from coal mine closure, dispatchable electricity choices under carbon taxes and coal transport via railroad. While completing my PhD, I provided economic analysis for the Graduate Teaching Fellows Federation as a member of its contract bargaining team.

CASE: UE 399
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Non-Confidential Responses to Staff Data Requests.

June 22, 2022

OPUC Data Request 127

Marginal Cost Study - What are the type of generation resources the Company plans to add, by year, through 2036. For each resource type, provide the nameplate MW, AMW and expected availability rate and installed construction cost.

Response to OPUC Data Request 127

Please refer to PacifiCorp's 2021 Integrated Resource Plan (IRP) which is publicly available and can be accessed by utilizing the following website link:

Integrated Resource Plan (pacificorp.com)

Please refer to Confidential Attachment OPUC 127, specifically the tabs referenced below. Total nameplate resource additions to PacifiCorp's system, by resource category, over the IRP's 20-year study horizon, are provided on tab "Portfolio Summary". Location specific nameplate resource additions are provided on tab "Plexos Portfolio". Installed construction cost for any newly built resources are provided on tab "Portfolio Data" and by filtering column D ("Category") and deselecting any category with "Micro" in the name. Then, filter column R ("Build Cost") to remove any zero or blank value cells to provide the resource build cost in nominal dollars in the year the resource is selected. Note: expected availability rate, average megawatts (aMW) and outage rates are not reported out of the PLEXOS model.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 128

Marginal Cost Study - In your response to number #5 above did the Company list any natural gas fired generation? If yes, please describe why those resources are advisable given Oregon's statutes in force.

Response to OPUC Data Request 128

The Company assumes that the reference to "number #5 above" is intended to be a reference to OPUC Data Request 127. Based on the foregoing assumption, the Company responds as follows:

No natural gas fired generation was selected as an expansion resource in PacifiCorp's 2021 Integrated Resource Plan (IRP). There are existing natural gas fired plants which continue operation through end of resource life, however, no new natural gas fired plants are selected to be built.

OPUC Data Request 131

Schedule 98 - Please provide a bill comparison, using kWh usage by increments of 200 kWh, from 0 kWh of use to 30,000 kWh of use under a discount limiting it available only to the first 1000 kWh of use; the current tiered discount and the Company's proposal.

Response to OPUC Data Request 131

Please refer to Attachment OPUC 131.

UE 399 / PacifiCorp
April 29, 2022
OPUC Data Request 396

OPUC Data Request 396

Seasonal Rate Design - Please provide a narrative description about how and to what extent PacifiCorp's Loss of Load Probability (LOLP) modelling/results influenced the Company's proposed seasonal rate design in this rate case.

Response to OPUC Data Request 396

PacifiCorp's loss of load probability (LOLP) modelling/results were not used in the development of the Company's proposed seasonal rate design in this general rate case (GRC).

UE 399 / PacifiCorp
April 29, 2022
OPUC Data Request 397

OPUC Data Request 397

Seasonal Rate Design - Please provide the results of the Company's most recent LOLP modelling and those, if different, used in docket UM 2011.

Response to OPUC Data Request 397

The Company's most recent loss of load probability (LOLP) results were prepared for Docket UM-2011 and previously provided to parties on January 25, 2022. Please refer to Attachment OPUC 397-1 and Confidential Attachment OPUC 397-2.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 399 / PacifiCorp
April 29, 2022
OPUC Data Request 398

OPUC Data Request 398

Seasonal Rate Design - Please describe the calculations and provide an example for how the Company would recommend for utilizing LOLP results for time-of-day and seasonal pricing.

Response to OPUC Data Request 398

The Company has not prepared the requested analysis.

OPUC Data Request 422

Total Rate Impact - Refer to Table 1 on PAC/1100, Meredith/15. Please reproduce this table to include the total rate impact of both UE 399 and UE 400 as filed.

Response to OPUC Data Request 422

Please refer to the table provided below which incorporates the impact of both proposed prices changes from the Company's general rate case (GRC), Docket UE-399 and the Company's 2023 transition adjustment mechanism (TAM), Docket UE-400:

Residential Schedule 4	14.3%
General Service	
Schedule 23/723 (0-30kW)	14.1%
Schedule 28/728 (31-200kW)	5.4%
Schedule 30/730 (201-999kW)	6.0%
Large General Service Schedules 47/747, 48/748 (≥1,000kW)	13.6%
Agricultural Pumping Service Schedule 41/741	18.3%
Lighting Schedules	0.2%
Overall	**12.2%**

OPUC Data Request 426

> **Marginal Cost Study -** Using this estimate derived in #5 above, and assuming you had a battery storage unit of 100 MW of capacity, with a four-hour duration limit, how many units of 100 MW battery storage, would provide equivalent peak load coverage as is expected from a 100 SCCT?

Response to OPUC Data Request 426

The Company assumes that the reference to "#5 above" is intended to be a reference to OPUC Data Request 425. Based on the foregoing assumption, the Company responds as follows:

PacifiCorp's 2021 Integrated Resource Plan (IRP), Volume II, Appendix K (Capacity Contribution) identified a capacity contribution for four-hour duration battery storage of 74 percent in the summer, and 90 percent in the winter. The weighted annual result that accounts for the relative frequency of events in the summer and winter is 77 percent, or 77 megawatts (MW) per 100 MW of four-hour battery nameplate.

The "Frame SCCT" in the 2021 IRP was modeled with a forced outage rate (FOR) of 6.6 percent. It's availability during peak hours and capacity contribution are thus approximately 93.4 percent, or 93.4 MW per 100 MW of simple-cycle combustion turbine (SCCT) nameplate. This value is not impacted by the expected frequency of events, for example the analysis referenced in OPUC Data Request 425.

93.4 MW / 77 MW = 1.213 MW, therefore, approximately 121.3 MW (nameplate) of four-hour battery storage would be required to equate to a 100 MW SCCT. Note: the capacity contribution of storage resources will vary over time and is impacted by the penetration of energy-limited resources (both storage and demand response) in the Company's portfolio, as well as the penetration of variable energy resources like wind and solar. In addition, energy storage resources are expected to provide frequent energy cost savings as a result of charging and discharging and the provision of operating reserves, likely on a daily basis, which would help defray a portion of their fixed costs. While both a battery and a SCCT would provide energy cost savings, the savings for a battery would likely be higher.

OPUC Data Request 427

Arrearage Management Program - Refer to the Company's response to OPUC Data Request 151. Please reproduce this data request with added columns that state the kWh consumed in each month and the size of the bill in that month. That is, for each residential customers that consumed more than 5,000 kWh in a single month in 2021, please provide:

(a) The nine-digit zip code for the customer,

(b) The month(s) in which the customer's consumption exceeded 5,000 kWh,

(c) Whether the customer received bill assistance through the Company's Arrearage Management Plan (AMP),

(d) The billed kWh in that month, and

(e) The dollar value of the bill for that month.

Response to OPUC Data Request 427

Please refer to Attachment OPUC 427.

Note: some slight variances exist in the data provided in Attachment OPUC 427 when compared to the Company's response to OPUC Data Request 151 due, in part, to billing adjustments and on-going changes with the Arrearage Management Program (AMP).

UE 399 / PacifiCorp
May 13, 2022
OPUC Data Request 442

OPUC Data Request 442

Arrearage Management Program - Refer to the Company's response to Staff DR 427. Please discussed any efforts the Company has made to confirm that the customers who consumed more than 10,000 kWh on a bill and enrolled in the Arrearage Management Program were indeed residential customers.

Response to OPUC Data Request 442

The Company limits Arrearage Management Program (AMP) participation to residential customers by reviewing an applicant's revenue class at the time of issuing a grant -- which is based on arrears without a differentiation for consumption.

UE 399 / PacifiCorp
May 31, 2022
OPUC Data Request 501

OPUC Data Request 501

Seasonal Rate Design - For each month 2016-2021, please provide the monthly volume of purchases for all the trading hubs that the Company buys or sells wholesale power in both dollars and MWh.

Response to OPUC Data Request 501

Please refer to Confidential Attachment OPUC 501 which provides information on all power physical transactions (sales and purchases) that were settled during each of calendar years 2016 through 2021.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 399 / PacifiCorp
May 31, 2022
OPUC Data Request 502

OPUC Data Request 502

Seasonal Rate Design - For each month 2016-2021, please provide the monthly volume of sales for all the trading hubs that the Company buys or sells wholesale power in both dollars and MWh.

Response to OPUC Data Request 502

Please refer to the Company's response to OPUC Data Request 501.

OPUC Data Request 533

Time of Use Pilot - Please list the number of currently enrolled customers in the Company's Time of Use pilot in Schedule 6.

Response to OPUC Data Request 533

As of April 30, 2022, there were 112 active customers participating in the Company's residential time of use (TOU) pilot (Schedule 6).

CASE: UE 399
WITNESS: TED DRENNAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Ted Drennan. I am an Energy Policy Analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. I am recommending an overall rate base adjustment of $14,144,756 system-wide and $3,688 Oregon-allocated to the Company's filing. This adjustment is to correct the Company's inclusion of funds for aquatic habitat restoration projects that will not be undertaken. My recommendations may change based on further review and based on the testimonies offered by other parties.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/802, consisting of the Company's responses to Staff data request Nos. 228-229, 400, and 1st supplemental response to data request 229, consisting of five pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. MERWIN DOWNSTREAM IN-LIEU REQUEST

Q. Please briefly explain the Company's request related to Merwin Downstream In-Lieu request.

A. In the Company's filing was a request for $14,144,756 for funding that would be used for "aquatic habitat restoration projects in-lieu of constructing fish passage into and out of Merwin Reservoir."[1] According to the filing this was to be "in-service Dec-22."[2] The Company included the funding for what they consider capital additions under "Pro forma plant additions and retirements."[3]

The Lewis River Settlement Agreement allowed for the potential of improving offsite aquatic habitat "in-lieu of" building fish passage for the Merwin reservoir.[4] The National Marine Fisheries Service and the US Fish and Wildlife Services (Services) initially selected the habitat enhancement in lieu of fish passage in December 2020.[5]

Q. Please explain why these costs should be excluded from PacifiCorp's request.

A. While the Services initially selected the habitat enhancement with a preliminary decision issued in April 2019. In December 2021 the Services withdrew their preliminary decision supporting the "in-lieu of" funding. The Services now prescribed anadromous fish passage into Merwin Reservoir instead of the "in-lieu of" funding. This will now require PacifiCorp construct two new facilities

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[1] See PAC/1002 Cheung/234
[2] ibid
[3] See PAC/1000 Cheung/33-34 lines 19-2
[4] See Exhibit Staff/802, Response to Staff Data Request No. 228
[5] ibid

facilitating up- and down-stream passage.[6] That is, PacifiCorp will no longer be constructing the aquatic habitat in-lieu of the fish passages as this does not meet the Services requirements.

Q. Why were the costs of the environmental enhancements included in this rate case if the Company no longer plans to construct them?

A. The Company indicated that it included the costs of the project in error. The Company agreed to remove the funds in its July 2022 Reply Filing in this proceeding.[7] Construction now required by the Services for the fish passages at Merwin Reservoir, will not be completed until June of 2026, and 2028[8], meaning that the new project will not be used and useful be the rate effective date of this general rate case and the Company will need to seek recovery through a future filing.

Q. What is the impact of Staff's adjustment?

A. The removal of the environmental enhancement project results in a rate base reduction of $14,144,756 system-wide and $3,688 Oregon-allocated for the Company's test year.

Q. Does this conclude your testimony?

A. Yes.

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[6] See Exhibit Staff/802, Response to Staff Data Request No. 229
[7] See Exhibit Staff/802, 1st Supplemental Response to Staff Data Request No. 229
[8] See Exhibit Staff/802, Response to Staff Data Request No. 400

CASE: UE 399
WITNESS: TED DRENNAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualification Statement

June 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME: Ted Drennan

EMPLOYER: Public Utility Commission of Oregon

TITLE: Energy Policy Analyst
Strategy and Integration

ADDRESS: 201 High St. SE Ste. 100
Salem, OR 97301-3612

EDUCATION: Bachelor of Science, Economics, University of Wyoming
Graduate Studies, Regulatory Economics, University of Wyoming

EXPERIENCE: I have over twenty years of experience in utility regulatory and economic evaluations. Currently I am employed at the Oregon Public Utility Commission (Commission), since November of 2021. Job responsibilities include working on Resource Adequacy (UM 2143) and Interconnection Modernization (UM 2111) in addition to other work. Earlier experience at the Commission included working on long-term planning.

Prior work experience includes long-term planning at Portland General Electric (PGE), PacifiCorp, and NW Natural. While at PacifiCorp I managed the public input process for the 2015 IRP. I also filed testimony as an expert witness in UM 1600 addressing QF issues.

At PGE, responsibilities included work in long-term planning, the 2013 and 2019 IRPs, as well as procurement. I managed PGE's renewable RFP (UM 1613), and worked on the capacity and energy RFP (UM 1535). Rate case work for UE 180 included analysis of cost recovery related to the Trojan Nuclear Plant decommissioning, O&M costs, power costs, and A&G expenses. I presented testimony as an expert witness for issues regarding costs of plant outage (UM 1234), Qualifying Facilities (UM 1129), partial requirements tariff (Joint testimony with OPUC Staff UE 158). Tariff work at PGE included developing tariffs dealing with partial-requirements customers (Schedule 75/76R), Standard rates for QFs (Schedule 201), Experimental time-of-use pricing (Schedule 87).

Other experienced includes consulting with work analysis of municipalization of electric system in California, impact of 2000 California market dysfunction on electric pricing the Pacific Northwest, planning issues for Louisiana Electric Power Authority, and a cost-of-service study for a water utility.

I have also presented testimony as an expert witness before the Iowa Utilities Board on a variety of telecommunications issues.

CASE: UE 399
WITNESS: TED DRENNAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Company Response to:
Data Requests (DR)

June 22, 2022

OPUC Data Request 228

Merwin Downstream In-Lieu - Testimony submitted in UE 374 (PAC/900, Hemstreet/4, lines 7-10) state:

> The Merwin Fish Collection and Sorting Facility project was required by the Lewis River Settlement Agreement and the Federal Energy Regulatory Commission (FERC) licenses issued to the Company for the Merwin, Yale and Swift No. 1 Hydroelectric Projects.

Please explain the request of ‘in-lieu’ funding and the relationship to the Merwin fish collector system costs included in UE 374.

Response to OPUC Data Request 228

The Lewis River Settlement Agreement and the Federal Energy Regulatory Commission (FERC) licenses provide the Company the opportunity to explore the value of offsite aquatic habitat to anadromous fish versus (i.e., in lieu of) providing fish passage into Merwin and Yale Reservoirs. Consistent with the preliminary determination issued in April 2019, on December 1, 2020, and December 2, 2020, the National Marine Fisheries Service and the United States (U.S.) Fish and Wildlife Service (the “Services”), under section 18 of the Federal Power Act, selected habitat enhancement in lieu of fish passage for Merwin Reservoir. This action supported “in-lieu” funding rather than the construction of fish passage into and out of Merwin Reservoir (also known as Lake Merwin). The Company therefore included “in-lieu” funding in this general rate case (GRC), Docket UE-399.

In the Company’s prior GRC, Docket UE-374, PacifiCorp sought cost recovery for the Merwin Fish Collection and Sorting Facility, which was placed in service in December 2013. The Merwin Fish Collection and Sorting Facility currently provides upstream passage for anadromous fish from Merwin Dam to habitat areas within and upstream of Swift Reservoir. Its costs are unrelated to the “in-lieu” funding determination by the Services and the costs for “in-lieu” funding included in this GRC, Docket UE-399.

OPUC Data Request 229

Merwin Downstream In-Lieu - Please provide the underlying details of the "in lieu" fund, in your response and demonstrate how these funds meet with the requirements of the Lewis Settlement Agreement (LSA) dated November 30, 2004 (LSA) for each of the following items:

(a) The determination by NOAA Fisheries and USFWS on the need for In Lieu Fund as required by Section 7.6 of the LSA;

(b) When fund was established;

(c) Annual balances; and

(d) Allocation of funds and underlying details.

Response to OPUC Data Request 229

(a) Pursuant to Section 4.1.9 of the Lewis River Settlement Agreement, the National Marine Fisheries Service and United States (U.S.) Fish and Wildlife Service (the "Services") were required to review new information regarding the appropriateness of reintroduction of anadromous fish into Merwin and Yale Reservoirs. PacifiCorp funded the collection of new scientific information developed independently by the U.S. Geological Survey and University of Washington in coordination with the Lewis River Aquatic Coordination Committee established by the Lewis River Settlement Agreement. Based on this new information, the Services determined on a preliminary basis in April 2019 that it was not appropriate to reintroduce anadromous fish into Merwin Reservoir given the substantial benefits to these populations that would be realized with off-site habitat enhancements as compared to benefits that would be obtained from fish passage. The Services issued preliminary section 18 of the Federal Power Act fishway determinations on the appropriateness of habitat enhancement in-lieu of fish passage into Merwin Reservoir in December 2020 reflecting this finding. However, in December 2021, the Services withdrew their preliminary determination supporting "in-lieu" funding and prescribed anadromous fish passage into Merwin Reservoir. The Services now require the construction of two new facilities to facilitate upstream and downstream fish passage from Merwin Reservoir.

(b) The fund has not been established.

(c) Please refer to the Company's response to subpart (b) above.

(d) No funds have been allocated.

OPUC Data Request 229

Merwin Downstream In-Lieu - Please provide the underlying details of the "in lieu" fund, in your response and demonstrate how these funds meet with the requirements of the Lewis Settlement Agreement (LSA) dated November 30, 2004 (LSA) for each of the followin1st g items:

(a) The determination by NOAA Fisheries and USFWS on the need for In Lieu Fund as required by Section 7.6 of the LSA;

(b) When fund was established;

(c) Annual balances; and

(d) Allocation of funds and underlying details.

1st Supplemental Response to OPUC Data Request 229

Further to the Company's response to OPUC Data Request 229 dated April 11, 2022, and the telephone conference held between representatives of the Public Utility Commission of Oregon (OPUC) staff and the Company on April 14, 2022, the Company responds as follows:

The Company's initial filing included "in-lieu" funding, however, with the National Marine Fisheries Service and United States (U.S.) Fish and Wildlife Service (FWS) now requiring the construction of two new facilities to facilitate upstream and downstream fish passage from the Merwin Reservoir, the "in-lieu" funding will be removed. PacifiCorp will make this update in its July 2022 Reply Filing in this proceeding.

OPUC Data Request 400

Merwin Downstream In-Lieu - In PacifiCorp's 1st Supplemental Response to OPUC Data Request 229 PacifiCorp it states:

> The Company's initial filing included "in-lieu" funding, however, with the National Marine Fisheries Service and United States (U.S.) Fish and Wildlife Service (FWS) now requiring the construction of two new facilities to facilitate upstream and downstream fish passage from the Merwin Reservoir, the "in-lieu" funding will be removed.

Regarding this change in approach, please provide the following information related to the downstream fish passage:

(a) What are the Company plans as to when these facilities will be added? Please explain.

(b) What are the estimated costs of the facilities to be added?

(c) When does the Company anticipate the costs of these facilities will be requested to be included in rates?

Response to OPUC Data Request 400

(a) The Company plans to complete the Merwin downstream fish collection and bypass facility by June 26, 2028 (instead of providing "in-lieu" funding). The Company is also required to complete a fish collection and transport facility to provide downstream passage from Yale reservoir to the lower Lewis River by June 26, 2026. The Company is also required to install upstream fish collection and transport facilities to provide fish passage from Merwin and Yale reservoirs by June 26, 2026, although "in-lieu" funding associated with these facilities was not included in this general rate case (GRC) proceeding.

(b) The Company has not completed estimates of the costs of these facilities.

(c) The Company anticipates requesting that the cost of the additional Lewis River fish passage facilities be included in rates in a future GRC proceeding, but the timing of such case has not been determined.

CASE: UE 399
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Moya Enright. I am a Senior Economist employed in the Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/901.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe Staff's analysis of the Company's Fuel Stock forecast, non-labor Generation Expense forecast, and proposed changes to its TAM and PCAM filings. I have made multiple recommendations, and no adjustments to the Company's revenue requirement. My recommendations, along with other Staff recommendations, may change based on further review and based on the testimonies offered by other parties.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: FUEL STOCK

Q. What is Fuel Stock?

A. Fuel Stock is included in rate base and represents a stock of fuel typically stored at a generating plant to ensure a reliable fuel supply is always available to operate the plant. Fuel Stock complements the expense forecasted in the Company's Transition Adjustment Mechanism (TAM) for fuel requirements that may be delivered at differing times and locations during the year. Fuel Stock differs from the Company's TAM fuel because instead of being a pass-through cost, the Company earns a return on its Fuel Stock.

The Company's fuel stock inventory is valued at the lower of weighted average cost or net realizable value, and PacifiCorp does not expect to update its forecast of fuel stock costs during this filing.[1]

Q. What Fuel Stock value has the Company claimed in this general rate case?

A. The Company is requesting to include $172.3 million, total-Company, of fuel stock in rate base, or $43.2 million Oregon-allocated,[2] a value which reflects coal fuel stock balances exclusively.[3]

Q. How does the Company determine its required Fuel Stock?

A. The Company follows its "Coal Inventory Policies and Procedures," which also detail the policies, procedures, and practices developed by PacifiCorp for the management of coal stockpile levels at PacifiCorp's thermal generating stations.

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[1] See Exhibit Staff/902, Enright/1-2, PAC's response to Staff DR 231.
[2] See Exhibit Staff/902, Enright/1-2, PAC's response to Staff DR 231.
[3] See Exhibit Staff/902, Enright/7, PAC's response to Staff DR 234.

PacifiCorp asserts that it **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

PacifiCorp's Coal Inventory Policies and Procedures **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[4]

Q. Please summarize the Commission's historical treatment of non-fuel materials and supplies in rate base.

A. The Commission typically authorizes utilities to include fuel stock in rate base. In previous rate cases, Staff have used a range of historical data to perform trend analysis. In general, Staff recommends a three-year historical average for non-labor expenses as the basis for making adjustment recommendations. For plants nearing end of life, fuel stock management should change to take into account the cost of having unused fuel remaining at the plant.

Q. Please describe Staff's analysis of this issue in this filing.

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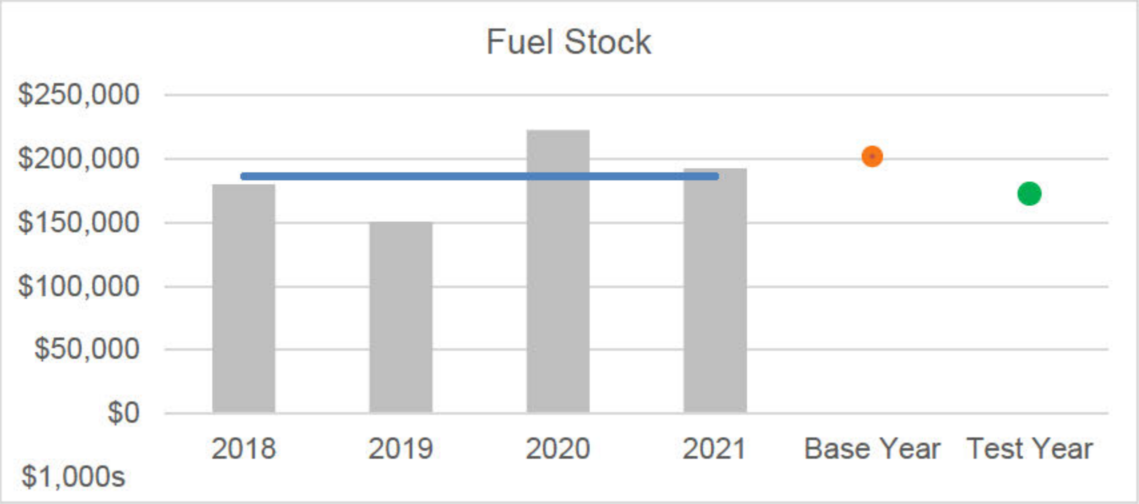
[4] See Exhibit/1002, Enright/3-4, Attachment A to PAC response to Staff DR 232.

A. In addition to investigating the policies driving the Company's fuel stock needs described above, Staff consulted the Company's annual FERC Form 1 reports for the most recent four years and performed a three-year trend analysis of the available data. The Figure 1 displays Fuel Stock for the years 2018 to 2021.[5]

Figure 1 - Historic vs forecasted Fuel Stock



In the Company's most recent GRC, the declines in fuel stock were attributed to the planned retirement of Cholla Unit 4 in December of 2020 and the elimination of all coal fuel inventory for the unit.[6]

Q. Has Staff observed any other details regarding the Company's fuel stock?

A. Yes. Staff happened upon an error in the Company's direct testimony, where in its opening testimony PAC stated that "fuel stock levels for the 13-month average year ending December 2023 are projected to be *lower* than the year ended June 2021 levels due to an *increase* in the amount of coal stockpiled."

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[5] See Exhibit/903, Enright/1-6, relevant pages from PacifiCorp's FERC Form 1, 2019 and 2021.

[6] Docket No. UE 374, Staff/300, Fjeldheim/21.

Noting the peculiar phrasing, Staff queried this issue and found that the text had been intended to read "fuel stock levels for the 13-month average year ending December 2023 are projected to be *lower* than the year ended June 2021 levels due to a *decrease* in the amount of coal stockpiled".[7] The clarification provided by PacifiCorp is reasonable and resolves Staff's concerns.

Q. Does Staff have any adjustments or recommendations regarding the Company's Fuel Stock forecast?

A. Yes. Staff has a recommendation but no adjustment. The Company is due to retire multiple coal plants over the coming ten years, and the Company's fuel stock retirement can be expected to fall in line with this change.

Staff recommends that during the 12 months prior to its next General Rate Case (GRC) filing, the Company be required to update its Coal Inventory Policies and Procedures so that forward-looking data will be available for the forecasting of fuel stock for years in which a decommissioning may occur, or already have occurred.

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[7] See Exhibit/902, Enright/5-6, PAC response to Staff DR 233.

ISSUE 2: GENERATION EXPENSES (NON-LABOR)

Q. Describe PAC's proposal for generation expenses (non-labor).

A. Generation non-labor operations and maintenance (O&M) expense reflects the non-labor costs required to perform corrective and preventative maintenance on generation assets, site and equipment management, and health and safety measures. This includes costs reflected in FERC Accounts 500 through 557.

In this filing, PAC forecasts $276.4 million in non-labor generation expenses in the test year. The Company does not expect to update its non-labor generation expense in this filing.[8]

Q. Describe Staff's analysis of non-labor Generation expense.

A. Staff reviewed Company testimony and work papers, as well as historical expenses for calendar years 2019, 2020, and the base year. Excluding FERC Accounts 501, 503, 547, and 555, which include mainly Net Power Cost related expenses,[9] PacifiCorp's request represents a 21.2 percent reduction on the base year, and 15.3 percent reduction when compared with calendar years 2019 and 2020.

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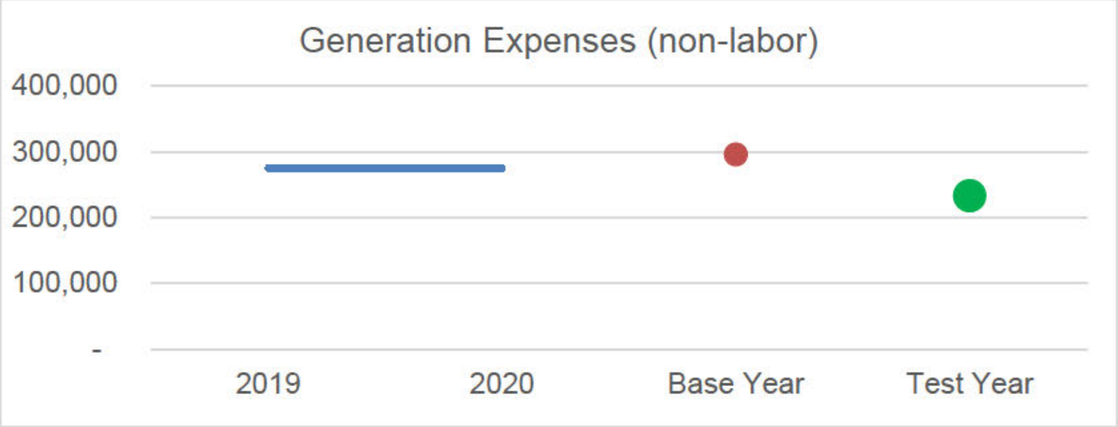
[8] See Exhibit Staff/902, Enright/1-2, PAC's response to Staff DR 231.

[9] Costs recorded in FERC accounts 501, 503, 547, and 555 include fuel related, fuel, purchased power, and steam related costs. See Exhibit Staff/902, Enright/8-10, Attachment to PAC's first supplemental response to Staff DR 236.

Figure 2 - Historic vs Forecasted non-labor Generation Expenses



Q. What is Staff's recommendation regarding PAC's generation expenses (non-labor)?

A. Staff finds PAC's test year expense to be below historical norms, suggesting PAC is prudently forecasting costs in this area. Therefore, Staff does not recommend any adjustment to the Company's Test Year expense.

ISSUE 3: PROPOSED CHANGES TO PACIFICORP'S TAM

Q. What changes has PacifiCorp proposed for its TAM?

A. PacifiCorp is proposing to make three changes to its Transition Adjustment Mechanism (TAM or Forecast):

1. The updating of certain inputs during the rate year;
2. The use of a new forecast for its hydro generation forecast; and
3. The implementation of changes to the TAM Guidelines.

Q. Please explain the first proposed change, which would allow PacifiCorp to update certain inputs to the TAM during the rate year.

A. PacifiCorp is asking for permission to update three inputs to the TAM forecast on March 1 (during the rate year), and to have those changes go into effect on April 1 of the rate year. The specific inputs that PacifiCorp would like to update are the latest official forward price curve, the latest short-term purchases and sales, and the most recent hydrologic forecast for the Test Year.

PacifiCorp intends for the rate year update to allow for more recent information to be reflected in rates, including the Company's latest transactions relating to resource adequacy for the summer period under the Western Power Pool's (WPP) Western Resource Adequacy Program (WRAP), and updated WRAP information for the winter period.

Q. What is Staff's position on this issue?

A. Staff notes that the filing date of March 1 is beneficial not only because of the WRAP timelines detailed by the Company, but also because forward market prices in Spring are typically far closer to actual market prices than forward prices from fall. The reason for this is that power producers across the Northwest will have updated data about the hydro year, and forward market prices will have incorporated known information about whether a “dry year” or “wet year.” PacifiCorp’s filing has heavily stressed the risks that it faces and its changing risk appetite, so Staff finds the rate year update to be a good opportunity to reduce the Company’s risk and improve the NPC forecast, without major alterations to the structure of the Company’s TAM and PCAM.

One major concern for Staff is that the introduction of a rate year update will increase Staff and intervenors’ workload on a permanent basis, which is reflected in Staff’s recommendation below.

Q. What is Staff’s recommendation?

A. Staff recommends that the Commission allow PacifiCorp to introduce a rate year update filing as described in its direct testimony. PacifiCorp’s proposal to add updates, essentially a new filing, that will add administrative burdens and costs to all interested parties, including Staff. Therefore, Staff recommends the Commission limit this update to changes to those described in its direct testimony, with all other inputs fixed to streamline the review process.

Q. Please explain the second proposed change relating to the Company’s hydro generation forecast.

A. PacifiCorp would like to switch to using hydro generation forecasts specific to the rate year for its assets on the Lewis River, instead of the normalized hydro generation that it currently uses.

If allowed, PacifiCorp would use the same sources of hydro data for its forecast as Idaho Power currently uses, namely, data from the Northwest River Forecast Center and from the National Oceanic and Atmospheric Administration, in its indicative, final updates to the TAM.[10] The Company's proposed rate year update would combine this data with a stream forecast from the United States Department of Agriculture and a seasonal hydro forecast created by Upstream Tech (its current hydro contractor).

Q. What is Staff's position on this issue?

A. Staff agrees with PacifiCorp's expectation that this change would increase the accuracy of hydro generation in the TAM. As such, the Company would be "providing a more accurate NPC forecast."[11]

However, Staff is somewhat concerned about how PacifiCorp's proposal will be put into action. In direct testimony, the Company has provided some specific plans regarding what data would be used in each update, but also some more general plans, such as "PacifiCorp will use the Seasonal Outlooks for Temperature and Precipitation … for December if it's warranted." Staff would like to see PacifiCorp address these specifics in further detail in its reply testimony in this case. Generally speaking, it should not be up to PacifiCorp as to whether there is an update or not. The updates should be required as a matter of course of action. The parties can meet and decide whether or not

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[10] PAC/400, Wilding/7.

[11] PAC/400, Wilding/6-7.

they can agree on whether they support continuing with the current power cost estimates given the changes in hydroelectric availability.

Q. What is Staff's recommendation?

A. Staff recommends that the Commission allow the proposed change in the 2024 TAM, subject to review by parties to the 2024 and 2025 TAM and final approval for future use by the Commission. The review would include a workshop held between the Company, Staff, and Intervenors in mid-March 2024, prior to the 2025 TAM filing and after the mid-year update, coupled with testimony from parties during the course of the 2025 TAM the proceeding. The benefits of Staff's proposal include that it:

1. Provides PacifiCorp the opportunity to test the proposed timelines for TAM and rate year updates, and the gathering of the numerous data streams it intends to use;
2. Allows PAC and parties the opportunity to provide input on what data is "warranted" to be used for the month of December in the final TAM update;
3. Allows Staff and interveners to review the new hydro forecast, in its various proposed iterations/combinations; and
4. Allows PAC and parties to ensure that any learnings are incorporated into the TAM Guidelines.

Q. Please explain the third proposed change, which involves several proposed changes to PacifiCorp's TAM guidelines

A. Each proposed change, and Staff's position on the change is listed in the table below.

Location	**Summary of change proposed by PAC**	**Staff position**
PAC/401, Wilding/1, Part A	Addition of FERC account details.	Staff supports this change
PAC/401, Wilding/2, Part B, Item 1	PAC to provide a pre-filing notice of substantial changes to the methodologies used to forecast NPC, at least 30 days prior to the Initial Filing.	Staff supports this change
PAC/401, Wilding/2, Part B, Item 2	PAC to include the variable costs and dispatch benefits of new resources not eligible for inclusion in the Renewable Adjustment Clause in its NPC.	Staff supports this change
PAC/401, Wilding/3, Part B, Item 7	PAC to provide an Aurora a license and all inputs to Commission Staff and intervenors for the TAM.	Staff supports this change
PAC/401, Wilding/3, Part B, Item 8	PAC to conduct one Aurora model run per intervenor during future TAM proceedings.	Staff supports this change
PAC/401, Wilding/3, Part B, Item 11	PAC to provide testimony regarding the prudence of new Coal Supply Agreements.	Staff supports this change
PAC/401, Wilding/3, Part B, Item 12	PAC to provide workpapers to support depreciable lives of Bridger Coal Company assets.	Staff supports this change
PAC/401, Wilding/3, Part B, Item 13	PAC to provide data relating to wholesale trades.	Staff supports this change

PAC/401, Wilding/4, Part B, Item 14	PAC to provide certain data on its wind fleet.	Staff supports this change
PAC/401, Wilding/4, Part B, Item 15	PAC to provide a sample calculation of Schedule 296 within 30 days of filing.	Staff supports this change
PAC/401, Wilding/4, Part C, Item 1.b.v	New hydro forecast data to be included in the TAM rebuttal update.	Staff supports this change on a trial basis, subject to review in 2024 and 2025 TAMs.
PAC/401, Wilding/5, Part D, Item 1.a.iv	New hydro forecast data to be included in the TAM final update.	Staff supports this change on a trial basis, subject to review in 2024 and 2025 TAMs.
PAC/401, Wilding/5, Part D, Item 1.d	PAC to provide attestations confirming inclusion of executed contracts in forecast, and confirming expectations of QF online dates.	Staff supports this change
PAC/401, Wilding/6-7, Part D, Item 4	Details procedure for dealing with challenges to final TAM updates.	Staff supports this change
PAC/401, Wilding/7-8, Part E	Provides for rate year update.	Staff supports this change

Q. Does Staff propose any additions to the TAM guidelines?

A. Yes. Staff's proposed changes are listed in the table below.

Staff edit #	Location	Summary of change proposed by PAC
#1	PAC/401, Wilding/3, Part B, Item 6	In any TAM proceeding, the Company has a continuing obligation to provide notice of any correction or omission promptly after the discovery of the error or new information. In addition, the Company will file a summary of all identified corrections or omissions to the components included in the Initial Filing ~~15 business days before Staff and Intervenor Direct Testimony is due.~~ within 5 business days of the correction or omission being identified by the Company. The Company will file corrected versions of any associated testimony, forecasts, workpapers, documents, and/or data responses within 10 business days of the correction or omission being identified.
#2	TAM Workpapers and Supporting Documents, Part A, Item 3	As soon as practical after filing, delivered on an as-ready basis, but no later than 15 days after the Initial Filing, the Company will deliver to the Parties… q) Workpapers and all supporting documents underlying each of the Company's models or adjustments, either existing or newly proposed.

Q. Please explain why Staff's first proposed change, Staff edit #1, is needed?

A. Under the current setup, the Company may be aware of errors or emissions in its Initial Filing for two or three months, but it under no obligation to share this knowledge with Staff or intervenors until 15 business days prior to Staff and Intervener Opening Testimony coming due.

In the most recent two TAM filings, Dockets Nos. UE 390 and UE 400,[12] PacifiCorp has notified Staff and Interveners of its errors and omissions exactly 15 <u>*calendar*</u> days prior to the filing of Staff and Intervenor Opening Testimony. This process is sub-optimal for the following reasons:

- It has led to Staff and Interveners spending working hours analyzing values which the Company is already aware are incorrect.
- It has led to issues that could have reasonably been dealt with in the Opening Testimony of Staff and Interveners being carried forward into future rounds of testimony.
- Although notably, in each of the past two years, the Company has not complied with the existing TAM guidelines given that it has filed its notice 15 calendar days rather than 15 business days prior to Staff and Intervener opening testimony, the existing timeline does not allow for discovery to be carried out prior to opening testimony, nor does it require the Company to provide a revised forecast or revised values to parties.

Q. Please explain why Staff's second proposed change, Staff edit #2, is needed?

A. Under the current setup, Staff and Interveners are required to issue Data Requests to the Company requesting even the most basic data and models underlying the Company's forecasts and testimony. This is a completely unnecessary obstacle, as it is clearly necessary for parties to have access

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[12] Exhibit Staff/904, Enright/1-2, copies of PacifiCorp's List of Corrections or Omissions filed in Docket Nos. UE 390 and UE 400.

to this data to complete their analysis, and the Company has the data to hand at the time of filing. Staff is interested in reducing the administrative burdens that exist in the TAM and improving the value of the analysis brought to the filing by Staff and Interveners, so expects this change to bring value to PacifiCorp's customers.

Q. What changes has PacifiCorp proposed for its PCAM?

A. PacifiCorp is proposing to three changes to its Power Cost Adjustment Mechanism (PCAM or True-up):

1. Reduce the upper deadband from $30 million to $15 million;
2. Change the earnings test; and
3. Allow PAC to recover costs outside of the established deadbands, sharing bands, and earnings test.

Q. Why is PacifiCorp requesting changes to its PCAM?

A. PacifiCorp has a duty to its shareholders to maximize returns. It has been under-recovering NPC in recent years. In this rate case, PacifiCorp is proposing to reduce its risks by including later updates and specific hydrological forecasts as discussed above as well as narrowing the deadband, making it symmetric and allowing for different treatment of extraordinary events. While these proposals reduce PacifiCorp's risk, in reality, as will be discussed further in this section, the PCAM is currently under-assigning "normal business risk" to PacifiCorp, to the detriment of ratepayers.

Q. Please provide some background on the establishment of the PCAM.

A. PacifiCorp’s PCAM was established through the utility’s 2012 general rate case. PacifiCorp’s PCAM was designed to be identical to the PCAM adopted several years earlier for PGE,[13] and founded on the general principles that the Commission believed should form the basis of a well-designed PCAM:[14]

1. Any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility;
2. There should be no adjustments if the utility's overall earnings are reasonable;
3. The PCAM's application should result in revenue neutrality;
4. The PCAM should operate in the long-term to balance the interests of the utility shareholder and ratepayer; and implicitly;
5. The PCAM should provide an incentive to the utility to manage its costs effectively.[15]

Q. Has the Commission’s original decision regarding the PCAM ever been reviewed?

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[13] Originally adopted in Docket Nos. UE 180, UE 181, UE 184, Order No. 07-015 at 26-27 (Jan 12, 2007), with deadbands revised to a dollar value by a stipulation between the parties to Docket No. UE 215, Order 10-478 (Dec 17, 2010)

[14] In the Matter of PacifiCorp, Request for General Rate Revision, Docket UE 246, Order No.12-493 (December 20, 2012) (established PCAM). “We base our adopted power cost deadband on Pacific Power's authorized rate base, rather than on the utility's net power costs. Although Pacific Power's rate base is slightly larger than PGE's we find these amounts to be reasonable for use in the PCAM.” And “In determining an appropriate power cost deadband, we look to the size of the utility's rate base and to the utility's authorized ROE.”

[15] Docket UE 246, Order No. 12-493 at page 13, citing “Docket Nos. UE 180, UE 181, UE 184, Order No. 07-015 at 26-27 (Jan 12, 2007).”

A. Yes. The theory behind the Commission's PCAM design has been revisited on multiple occasions, however the dollar value of the Company's deadbands has not been updated.

For instance, when establishing PAC's PCAM in 2012, the Commission expressed its contentment with the PCAM design, stating that "after reviewing the factual record and the parties' arguments in this proceeding, we conclude that our reasoning used to establish a PCAM for PGE remains sound and applies equally with respect to establishing a PCAM for Pacific Power."

The Commission reviewed the PCAM once again in PacifiCorp's 2020 GRC filing, declining to make changes proposed by PacifiCorp. In its Order, the Commission highlighted that with the existing power cost recovery and policy in place for almost a decade, in recent years PacifiCorp's TAM and PCAM proceedings had stabilized with fewer contested issues. The Commission then highlighted the multitude of modelling changes being undertaken by PacifiCorp that would directly affect its power cost filings. This includes the use of new TAM and IRP models, and changes to the MSP framework that may affect the intrastate allocation of power costs based on load.[16] Given the success of the mechanism to date, the significant change on the horizon, and the inability of PacifiCorp to demonstrate "a fundamental change in the risk balance between customers and the company, the Commission indicated its unwillingness to entertain a redesign of the system prior to 2024, and supported the current "well-designed PCAM that complies

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[16] Order No. 20-473, pg 130.

with the principles we summarized" as "the most prudent way to accomplish proper recovery."[17,18]

Q. Is the PCAM working as intended?

A. Yes. The PCAM was designed to "exclude normal variation from triggering the mechanism,"[19] and over the past nine years it has been working as intended, including the 2021 PCAM, which is discussed below.

Q. PacifiCorp argues that the deadbands should be changed. Does Staff believe that the deadbands are too wide?

A. No. Staff believes the opposite. The PCAM was designed so that the utility "will absorb some normal variation of power costs,"[20] and through the years, the Commission has opined that "the ability to absorb power cost increases depends on a utility's total rate base."[21]

PacifiCorp's deadbands of $15 and $30 million were set in 2012,[22,23] and were based on the Company's forecasted 2013 test year rate base of $3.253 billion. In the ten years since, the Company's rate base had grown to $4.554 billion. Essentially, by the Commission's own standards, the

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[17] Order No. 20-473 at f2.

[18] Order No. 12-495 at 1b.

[19] Order No. 07-015, at 25.

[20] Order No. 07-015, at 26.

[21] Order No. 07-015, at 27.

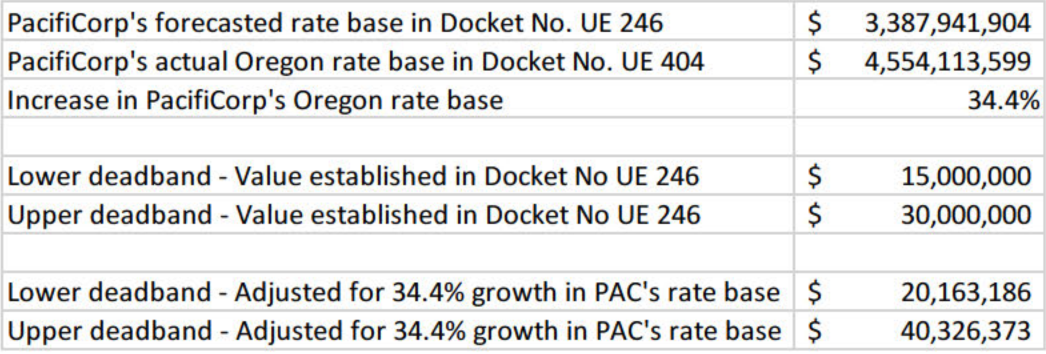
[22] In 2012, considering the similar sizes of PAC and PGE's rate base in Oregon, the Commission decided that both utilities should have identical asymmetrical deadbands, and the same other parameters (earnings test, earnings review etc.).

[23] The original PGE PCAM deadbands were established as a function of rate base. Edits were made to PGE's deadbands in 2010 whereby the deadband was set as a static number. This replaced the original deadbands, calculated as a lower deadband of 75 basis points ROE below the base level of NVPC included in rates, to an upper deadband of 150 basis points ROE above.

Company's "ability to absorb power cost increases" has grown by a whopping 34.4 percent, but the deadbands have remained static.

Figure 3 illustrates how the Company's deadbands might have increased between the 2013 and 2023 test years, had the Commission adopted a deadband that increased with along with rate base.

Figure 3 - Calculation of deadbands adjusted for 34.4 percent growth in rate base



PacifiCorp's forecasted rate base in Docket No. UE 246	$	3,387,941,904
PacifiCorp's actual Oregon rate base in Docket No. UE 404	$	4,554,113,599
Increase in PacifiCorp's Oregon rate base		34.4%
Lower deadband - Value established in Docket No UE 246	$	15,000,000
Upper deadband - Value established in Docket No UE 246	$	30,000,000
Lower deadband - Adjusted for 34.4% growth in PAC's rate base	$	20,163,186
Upper deadband - Adjusted for 34.4% growth in PAC's rate base	$	40,326,373

Q. What other factors are you considering in the deadbands?

A. Staff is considering two offsetting factors. The following discussion has the perspective that deadbands should capture some percentage of total power cost outcomes as being normal business risk. From that perspective, the update proposals PacifiCorp has proposed and Staff supports as a change, or also as a trial, should tend to narrow the difference between actual power cost and projected power costs. This means the variance should be reduced and so the deadbands could be reduced from a statistics perspective disregarding the changes in the financial ability of PacifiCorp to withstand power cost hits and benefits because PacifiCorp has a much larger earnings base. On the other hand, recent large increases in natural gas prices may give rise to larger variances in wholesale market prices and corresponding changes in power costs. From this perspective, larger deadbands may be justified.

When weighing all the considerations: larger financial heft, updates and changes in market prices, as well as going to symmetric deadbands, I conclude that symmetric deadbands of +/- $30 million seems reasonable. This also corresponds to roughly 30 basis points ROE as 100 basis points is worth $30 million.[24]

Q. Why is Staff supporting symmetrical deadbands instead of asymmetrical deadbands?

A. Staff finds the Company's argument, that the distribution of power costs has changed as the market has added lots of renewable resources and the generation mix has changed, compelling. However, Staff notes that the Company has not provided any tangible evidence to this effect.

In the absence of consensus between the parties on this issue in Opening Testimony, Staff recommends that the Company provide evidence to support its assertions. This could be provided in the form of multiple iterations of power cost forecasting runs and/or Monte Carlo simulations, using different assumptions on gas prices and plant availability. Such analysis would be very informative as it would provide parties and the Commission actual data on current and past power cost distributions, allowing the group to observe whether a change has in fact taken place.

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[24] Exhibit Staff/905, Enright/1, Staff calculation.

Q. Does Staff have any other comments regarding the proposed move to symmetrical deadbands?

A. Yes. Staff believes that if large excursions in power costs are able to be removed from power costs and treated as separate deferrals (as proposed by the Company in this filing) the distribution of cost recovery would be significantly affected. For example, some of the right (high costs) tail observations would be removed from the "no deferral" alternative such that an asymmetric deadband would restore balance in the right and left sides of the distribution. Therefore, if a deferral of high-cost excursions is allowed by the Commission, the Commission should consider retaining asymmetric dead bands.

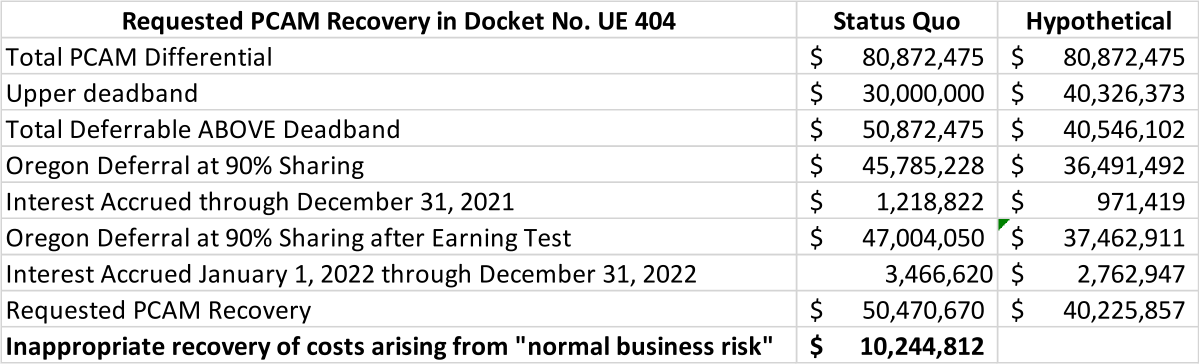
Q. Has the PCAM been triggered for the first time in Docket No. UE 404, the 2021 PCAM?

A. Yes. This is true. Because the Company's deadbands have not been revised in line with growth in the Company's rate base, customers are now on the line to compensate PacifiCorp for its ability to absorb normal business risk – through both base rates, and through the PCAM adjustment proposed in Docket No. UE 404.

This is a provision allowed for under the PCAM and so is working as envisioned. However, this is a very unfortunate situation from a customer perspective. Customers are already facing record inflation and potential rate shock in the 2023 year following the substantial increases forecasted in PacifiCorp's GRC and TAM filings. These same customers will also be required to pay up to supplement PacifiCorp's shareholder's 2021 income for what should be considered "normal variation" under the principles set out by the Commission when establishing the PCAM ten years ago.

Staff's calculations in the table below demonstrate how customers stand to supplement PacifiCorp's 2021 income by approximately $10.244 million through 2023 rates, as a result of the outdated deadbands.[25]

Figure 4 - Hypothetical cost recovery in Docket No UE 404 if deadbands had been appropriately updated



Requested PCAM Recovery in Docket No. UE 404	Status Quo	Hypothetical
Total PCAM Differential	$ 80,872,475	$ 80,872,475
Upper deadband	$ 30,000,000	$ 40,326,373
Total Deferrable ABOVE Deadband	$ 50,872,475	$ 40,546,102
Oregon Deferral at 90% Sharing	$ 45,785,228	$ 36,491,492
Interest Accrued through December 31, 2021	$ 1,218,822	$ 971,419
Oregon Deferral at 90% Sharing after Earning Test	$ 47,004,050	$ 37,462,911
Interest Accrued January 1, 2022 through December 31, 2022	3,466,620	$ 2,762,947
Requested PCAM Recovery	$ 50,470,670	$ 40,225,857
Inappropriate recovery of costs arising from "normal business risk"	**$ 10,244,812**	

Q. PacifiCorp has described this issue in its 2020 GRC filing, where it asserts that it finds itself at a terrible disadvantage because of the current PCAM construct. What is Staff's opinion on this?

A. PacifiCorp's narrative in the current filing includes statements such as that the "PCAM does not fully mitigate the power cost risk for PacifiCorp," putting it at a supposed disadvantage in comparison to a proxy group of utilities,[26] and completely disregarding the fact that the PCAM was *designed* to not fully mitigate the power cost risk to the Company, and, in contrast, to incent it to manage its costs.

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[25] Docket No. UE 404, PAC/100, Painter/4.

[26] PAC/300, Bulkley/55.

PacifiCorp also dedicates a considerable amount of testimony to the argument that changes to its resource mix, changes to state policies relating to emissions, the introduction of the EIM market, and even climate change have changed the business risk that it faces, driving a need to "rebalance the risk between the Company and customers by allowing PacifiCorp a better opportunity to recover the significant deviations from forecast NPC."[27]

Staff does not find that discussion compelling. The various risks and woes referred to by PacifiCorp are merely the business risk of operating as a utility in 2022. With a rate base of $4.554 billion, the Company also has a significantly higher capacity to absorb variations in power costs.

In addition, PacifiCorp's narrative attempts to distract from the clear message sent by the Commission in its 2020 filing. That the effect of model changes in the TAM and IRP, and changes to the MSP protocol, should be seen before an overhaul of the PCAM may be considered.

Finally, PacifiCorp's narrative assumes that the TAM filing will not be improved by the many modelling changes that it has proposed in the 2023 TAM, which alone (excluding the unmeasured effects of the switch to the AURORA model) drive a $159.2 million forecasted increase in NVPC in 2023.[28] By ignoring the Company's move to modelling NVPC with Aurora, and the many "enhancements" to its model in recent years and the current year, the Company implies that the destruction of the ratepayer protections that exist in

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[27] PAC/400, Wilding/23.

[28] Docket No UE 400, Staff/100, Enright/4.

the PCAM are preferential to resolving the recognized failings of its TAM forecast.[29]

Q. What is Staff's recommendation?

A. PacifiCorp recommended three changes to its PCAM:

1. Reduce the upper deadband from $30 million to $15 million;
2. Change the earnings test; and
3. Allow PAC to recover costs outside of the established deadbands, sharing bands, and earnings test.

With respect to recommendation #1, Staff supports going to a symmetric deadband, but with the deadbands +/- $30 million. With respect to recommendation #2, Staff does not support changing the earnings test. With respect to the recommendation #3, Staff supports the use of deferred accounting for extreme unforeseen events, rather than monthly deviations from the forecast.

Q. Does Staff have any further recommendations regarding the Company's PCAM filing?

A. Yes. As was recently established in Docket No. UE 390, there has been a persistent error in PacifiCorp's forecasting of QF costs. This remains an open issue in this year's TAM filing, as the Company has not yet provided

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[29] *"PacifiCorp may be able to make targeted forecast adjustments to remedy specific issues with its under-recovery. The TAM is an annual filing and PacifiCorp has an annual opportunity to improve its forecast … PacifiCorp did not address the feasibility of reducing this component of its forecast and it is something that may be considered in the TAM. With PacifiCorp's upcoming transition to a new power forecast model (AURORA) there may be other options for improving PacifiCorp's forecast that will emerge once the parties begin training with the model."* Order No. 20-473, pg 130.

the data and analysis required by Commission Order No. 21-379, to explain the errors in its forecast.

Nevertheless, Staff has gathered the necessary data to complete this analysis through Data Requests (DR) in this filing. Figure 5 below summarizes the Company's forecasted QF costs and actual QF costs since 2009, highlighting how the Company has **[BEGIN CONFIDENTIAL]** [redacted]

Confidential Figure 5 - QF forecasts vs actuals

[redacted]

[END CONFIDENTIAL][30]

Unfortunately, because QF costs are generally higher than self-generation and market purchases, there is a significant incentive for the

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[30] Exhibit Staff/902, Enright/11-13. PAC response and attachments to Data Request 248.

Company to over forecast QF costs in the TAM, as it has frequently done over the past decade.[31] QF costs represent 19.4 percent of the Company's Net Variable Power Costs (NVPC), or $327 million in 2023,[32] so the Company's incentive to mis-forecast, and the risk to customers, is high.

Staff recommends that QF costs be recovered as a pass-through of NVPC in the PCAM proceeding, beginning with the 2022 PCAM filed next year.

Q. How would Staff's recommendation work in practice?

A. Staff proposes adjusting the treatment of QFs in PAC's TAM and PCAM filings by introducing the following pass-through mechanism.

Staff's proposed methodology would work as follows:

- In the TAM, TAC would forecast QF costs using a four-year moving average of historical QF generation while also including new QFs with CODs in the test year.
- In the PCAM, PAC's actual QF costs would be compared to the forecasted costs, and the resulting surplus or deficit would be passed through as either a charge or a refund to customers based on the day-ahead Mid-C power price for replacement power, or the difference between the Mid-C price and the QF contract price in the event of surplus generation. The price for the Mid-C would include a weighting of the light load and heavy load hours by the respective hours in the day until a better method is identified.

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[31] Order No. 21-379 at 4d.

[32] Docket No UE 400, PAC/102, Wilding/3 & 6.

Staff believes forecasting QF generation using a historical four-year average will limit over or under forecasting, while the pass-through mechanism will address additional forms of risk associated with market prices for QF replacement power and generation surplus that are not currently mitigated by the existing track and true-up mechanism for new QFs.

Q. Did Staff engage with the Company, or any other Oregon utility, regarding this issue?

A. Yes. Staff issued a DR in PacifiCorp's 2023 TAM filing,[33] and also engaged with Portland General Electric (PGE) in Docket No. UE 402 regarding the same issue.

Q. Please describe Staff's communication with PacifiCorp on this issue?

A. Staff's DR to PAC in Docket No UE 402 asked, "how PacifiCorp would value the difference between its QF expenses (forecasted in the Company's TAM) and its actual QF expenses (in the Company's true-up filing), if PacifiCorp was required by the Oregon Public Utilities Commission to recover its QF costs through a pass-through mechanism?" Unfortunately, PacifiCorp failed to provide a useful response to Staff's DR.

Q. Please describe Staff's communication with PGE on this issue?

A. Staff had a far more fruitful engagement with PGE in Docket No. UE 402. This is described by Staff witness Madison Bolton in Staff's opening testimony in Docket No. UE 402, which will be published on June 23, 2022.

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[33] Docket No. UE 402.

Q. Why is Staff's approach the most reasonable approach for recovering costs associated with QFs?

A. A pass-through mechanism is the most reasonable approach for the following reasons:

1) Because Oregon-regulated electric utilities are required to buy power from QFs at rates established by the Commission, a pass-through approach appropriately absolves the Company of any price or volumetric risk associated with its QF purchases.
2) Staff's proposed approach represents a significant improvement on the current process, which has incentivized the Company to over forecast its QF costs over the past decade.
3) The forecasting of QF costs in the TAM has been a contentious issue for many years, and has required significant input from Staff, parties, and the Commission in each year. By removing the incentive to over-forecast costs, and by establishing a set procedure for calculating the forecast and pass-through payments, Staff's proposed approach will ultimately benefit consumers by reducing the workload of intervening parties in each docket.

Q. Will Staff recommend that PGE adopt a similar mechanism in its Annual Power Cost Update Mechanism (APCU) filing?

A. Yes. On June 23, 2022, Staff witness Madison Bolton will make identical[34] recommendations in Staff's opening testimony in Docket No. UE 402.

Q. What is the overall effect of Staff's recommendations for the TAM and PCAM?

A. Staff's recommendations regarding the TAM are aimed at improving the Company's forecast. Staff supports the Company's use of forecasted hydro data for the rate year, and the introduction of a rate year increase which would incorporate new contracts signed by the Company and market prices informed by rate year hydrological conditions. Staff expects that both changes will contribute to a more accurate TAM forecast from 2023 onward.

Staff's proposal for the three proposed changes to the PCAM structure and risk limits is a counter-recommendation that the PCAM deadbands be reset to ensure that customers are being adequately protected from the risk of power cost variances.

Finally, Staff recommends that QF costs become a pass through, so as to remove any forecasting error relating to these costs in the TAM and remove the incentive for PacifiCorp to over-forecast such costs. QF costs represent almost 20 percent of the Company's TAM costs, so their switch to a pass-

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[34] Staff's recommendations are identical with the exception of the historical period used to inform the forecast. In the PGE case, Staff has recommended a three-year historic period for forecasting QF costs in the APCU, to remain consistent with the use of three years of historical data in the majority of PGE's forecasting models. In PAC's case, Staff is recommending a four-year historic period for forecasting QF costs in the TAM, to remain consistent with the use of four years of historical data in the majority of PAC's forecasting models.

through should remove a significant portion of the risk of the TAM and PCAM construct.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualifications Statement

June 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME: Moya Enright

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: Energy Risk Professional Certification, 2021.
Global Association of Risk Professionals.

M.Sc. Political Science, 2015.
University of Amsterdam.

M.Sc. Investment, Treasury and Banking, 2011.
Dublin City University.

B.A. International Business and Languages, 2008.
Dublin City University through a joint curriculum with
École Supérieure de Commerce de Montpellier.

EXPERIENCE: Senior Utility and Energy Analyst at OPUC since January 2019.

Energy Trader for Meridian Energy from 2015 to 2019. Meridian Energy is a power generator and retailer operating both in New Zealand and Australia.

Trading and Operations Analyst at Tynagh Energy from 2011 to 2013. Tynagh Energy is an independent power producer operating in the Republic of Ireland.

Senior Electricity Market Controller at EirGrid from 2008 to 2011. EirGrid is the Irish electricity Transmission System Operator. It operates the Single Electricity Market for the Republic of Ireland and Northern Ireland.

Accounts Assistant roles from 2004 to 2008, including Audit Intern at KPMG in Northern Ireland.

CASE: UE 399
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support
Of Opening Testimony

June 22, 2022

UE 399 / PacifiCorp
April 19, 2022
OPUC Data Request 231

OPUC Data Request 231

Fuel Stock - Regarding the Company's fuel stock:

(a) Please provide a narrative explanation of the purpose of fuel stock.

(b) Please provide a narrative explanation of how existing fuel stock is valued in the Company's filing.

(c) If fuel stock is not valued at the lower of average cost or net realizable value in this filing, please explain why not.

(d) If the calculation of fuel stock as included in the Company's filing differs from the calculation of fuel stock recorded on the Company's FERC Form 1 filing, please provide a narrative explanation of this difference.

(e) Please specify the value of fuel stock that the Company's is requesting recovery for in this filing in US dollars. Include a reference to where this value is reflected in the Company's work papers, and indicate whether and when this value will be updated during the course of this filing.

Response to OPUC Data Request 231

(a) The primary purpose of coal fuel stock is to provide an economic and reliable supply of fuel to the Company's generating stations, and coal inventories are regularly reviewed to ensure inventory levels are appropriate. These reviews consider the following: potential supply or transportation disruptions, coal quality, coal market conditions, known geologic and/or reserve concerns, potential labor disruptions, new environmental laws and regulations, uncertainties in weather, carrying costs, etc.

(b) Coal fuel inventory is valued at the weighted average cost of delivered coal.

(c) Per Company policy, the fuel stock inventory is valued at the lower of weighted average cost or net realizable value.

(d) The coal fuel inventory included in the Company's filing is calculated the same as in the Company's Federal Energy Regulatory Commission (FERC) Form 1 filings.

(e) Please refer to the direct testimony of Company witness, Sherona L. Cheung, specifically Exhibit PAC/1002/Cheung/39, line 2077. The Company is requesting to include $172.3 million, total-Company, of fuel stock in rate base, or $43.2 million Oregon-allocated. The Company does not currently anticipate that this value will be updated during the course of this general rate case (GRC) filing.

UE 399 / PacifiCorp
April 19, 2022
OPUC Data Request 232

OPUC Data Request 232

Fuel Stock - Please provide a narrative explanation of how Company determines the most efficient and effective inventory levels for fuel stock. In addition to this response, please provide the following information:

(a) References to any relevant internal policies in response to the question above.

(b) A copy of any relevant internal policies with this response.

(c) Indicate whether the optimal inventory levels depend on the price of the fuel. If yes, please provide an explanation of this.

(d) Explain how the Company accounts for potential supply disruptions when planning its fuel stock.

Response to OPUC Data Request 232

(a) Please refer to Confidential Attachment OPUC 232, specifically page 7.

(b) Please refer to Confidential Attachment OPUC 232.

(c) Please refer to Confidential Attachment OPUC 232, specifically page 5. While the price of fuel is not a primary factor in determining plant inventory levels, PacifiCorp's policies and procedures do not preclude the Company from prudently purchasing coal when coal prices are low.

(d) Potential supply or transportation disruptions are considered when the Company determines the most efficient and effective inventory levels for fuel stock. Please refer to Confidential Attachment OPUC 232, specifically page 7 which provides an explanation of the methodology used to determine fuel stock inventory levels.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Staff Exhibit “Confidential attachment to PacifiCorp's response to Staff DR 232” is filed in electronic format

UE 399 / PacifiCorp
April 19, 2022
OPUC Data Request 233

OPUC Data Request 233

Fuel Stock - Exhibit PAC/1002, Cheung/284, page 8.15 states that "fuel stock levels for the 13 month average year ending December 2023 are projected to be lower than the year ended June 2021 levels due to an increase in the amount of coal stockpiled."

(a) Please explain how a larger coal stockpile will lead to lower fuel stock levels in the test year.

(b) Please provide data to illustrate the Company's response to subpart (a), including but not limited to:

i. Fuel stock levels for the 13 month average year ending December 2023, specifying the unit of measurement.

ii. Fuel stock levels for the year ended June 2021, using the same unit of measurement as in subpart (i).

iii. Amount of coal stockpiled in the 13 month average year ending December 2023, specifying the unit of measurement.

iv. Amount of coal stockpiles in the year ended June 2021, using the same unit of measurement as in subpart (i).

Response to OPUC Data Request 233

(a) Referencing the direct testimony of Company witness, Sherona, L Cheung, specifically Exhibit PAC/1002, Cheung/284, page 8.15 the Company states as follows:

The referenced statement above was in error and should have read:

"fuel stock levels for the 13 month average year ending December 2023 are projected to be lower than the year ended June 2021 levels due to a **decrease** in the amount of coal stockpiled".

(b) Please refer to the Company's responses to subparts i. through iv. below:

i. Please refer to Exhibit PAC/1002/Cheung/39, page 2.27, line 2077. Specific coal fuel stock balance detail, by plant, supporting total fuel stock balances reflected in the section referenced above are provided in Exhibit PAC/1022/Cheung/285, page 8.15.1.

UE 399 / PacifiCorp
April 19, 2022
OPUC Data Request 233

ii. Please refer to the Company’s response to subpart (b) i. above.

iii. Please refer to the Company’s response to subpart (b) i. above.

iv. Please refer to the Company’s response to subpart (b) i. above.

UE 399 / PacifiCorp
April 19, 2022
OPUC Data Request 234

OPUC Data Request 234

Fuel Stock - For each year from 2018 through 2023, please provide the Company's forecasted fuel stock as of December 31, broken down as follows:

(a) Total value of fuel stock in US dollars.

(b) Total value of each type of fuel stock shown separately in US dollars.

(c) Total volume of each type of fuel stock shown separately, specifying the unit of measure (e.g. gallons or other).

(d) Total value of each type of fuel stock assigned to/stored in proximity to each of the Company's plan/generators in US dollars, listing each plant/generator separately.

(e) Total volume of each type of fuel stock assigned to/stored in proximity to each of the Company's plan/generators, specifying the unit of measure (e.g. gallons or other), listing each plant/generator separately.

Response to OPUC Data Request 234

The Company assumes that the references to "Company's plan/generators" is intended to be a reference to the Company's plant/generators. Based on the foregoing assumption, the Company responds as follows:

(a) The Company only forecasts coal fuel stock balances. Please refer to Attachment OPUC 234 which provides the actual fuel stock balances for years 2018, 2019, 2020, and 2021, and the forecasted fuel stock balances for years 2022 and 2023.

(b) Please refer to the Company's response to subpart (a) above.

(c) Balances are in United States (U.S.) Dollars, and volumes are in tons.

(d) Please refer to Attachment OPUC 234.

(e) Please refer to Attachment OPUC 234.

UE 399 / PacifiCorp
April 19, 2022
OPUC Data Request 236

OPUC Data Request 236

Non-labor Generation Expenses - Regarding the Company's non-labor generation expenses:

(a) Please provide a narrative explanation of what specific expenses are included in the Company's non-labor generation expenses.

(b) Please specify the value of non-labor generation expenses that the Company's is requesting recovery for in this filing in US dollars. Include a reference to where this value is reflected in the Company's work papers and indicate whether and when this value will be updated during the course of this filing.

(c) Please provide a breakdown showing the specific expenses included in the Company's non-labor generation expenses in the test year, and the value of each.

(d) Please provide a narrative explanation of how non-labor generation expenses are forecasted in the Company's filing.

Response to OPUC Data Request 236

(a) Non-labor generation expenses included in the Company's general rate case (GRC) filing include amounts recorded to FERC Account 500 through FERC Account 557, as defined in the Code of Federal Regulations (CFR), Title 18, Chapter I, Subchapter C, Part 101. The referenced section of the CFR is publicly available and can be accessed by utilizing the following website link:

https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101.

(b) Please refer to the Company's response to Standard Data Request – OPUC 058, specifically Attachment OPUC 058-2 which outlines the test year balances associated with non-labor generation expense accounts, including net power costs (NPC), included in the Company's direct testimony in this GRC proceeding. At present time, the Company is unaware of any updates to non-labor generation expense for this filing.

(c) Please refer to the Company's response to subpart (b) above.

(d) Please refer to the direct testimony of Company witness, Sherona L. Cheung, Exhibit PAC/1000/Cheung/6-8 which provides an explanation of how test period revenues and expenses were determined in this GRC.

UE 399 / PacifiCorp
May 13, 2022
OPUC Data Request 236 - 1st Supplemental

OPUC Data Request 236

Non-labor Generation Expenses - Regarding the Company's non-labor generation expenses:

(a) Please provide a narrative explanation of what specific expenses are included in the Company's non-labor generation expenses.

(b) Please specify the value of non-labor generation expenses that the Company's is requesting recovery for in this filing in US dollars. Include a reference to where this value is reflected in the Company's work papers and indicate whether and when this value will be updated during the course of this filing.

(c) Please provide a breakdown showing the specific expenses included in the Company's non-labor generation expenses in the test year, and the value of each.

(d) Please provide a narrative explanation of how non-labor generation expenses are forecasted in the Company's filing.

1st Supplemental Response to OPUC Data Request 236

Further to the Company's response to OPUC Data Request 236 dated April 19, 2022, the Company provides the following supplemental information at the request of Public Utility Commission of Oregon (OPUC) Staff:

Please refer to Attachment OPUC 236 1st Supplemental which provides non-labor generation expenses excluding net power costs (NPC) calculated based on balances previously provided with the Company's response to Standard Data Request - OPUC 058, specifically Attachment OPUC 058-2-1st Supplemental, and NPC balances available in the Jurisdictional Allocation Model (JAM) provided at the same time of the Company's direct testimony in this general rate case (GRC).

Staff Exhibit "Attachment to PacifiCorp's first supplemental response to Staff DR 236" is filed in electronic format

UE 399 / PacifiCorp
April 12, 2022
OPUC Data Request 248

OPUC Data Request 248

> **Proposed Change in Power Cost Rate Mechanism -** Please provide a copy of the Company's responses to Staff DRs 32, 33, 34, and 35 in Docket No. UE 400, including any attachments.

Response to OPUC Data Request 248

> The Company will provide copies of the Company's responses to OPUC Data Request 32 through OPUC Data Request 35 submitted in the Company's Oregon 2023 transition adjustment mechanism (TAM) proceeding, Docket UE-400, as soon as the responses become available.

UE 399 / PacifiCorp
April 26, 2022
OPUC Data Request 248 – 1st Supplemental

OPUC Data Request 248

> **Proposed Change in Power Cost Rate Mechanism -** Please provide a copy of the Company's responses to Staff DRs 32, 33, 34, and 35 in Docket No. UE 400, including any attachments.

1st Supplemental Response to OPUC Data Request 248

PacifiCorp objects to this request as requesting information outside the record in this proceeding and not reasonably calculated to lead to the discovery of admissible information. Without waiving the foregoing objection, PacifiCorp responds as follows:

Further to the Company's response to OPUC Data Request 248 dated April 12, 2022, the Company provides the following supplemental response:

Please refer to Attachment OPUC 248-1 1st Supplemental and Confidential Attachment 248-2 1st Supplemental.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Staff Exhibit “Attachments to PacifiCorp's response to Staff DR 248” is filed in electronic format

CASE: UE 399
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 903

PacifiCorp FERC 1
Forms 2019 & 2020
(relevant pages)

June 22, 2022

THIS FILING IS	
Item 1: ☒ An Initial (Original) Submission	OR ☐ Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
PacifiCorp	**End of** 2019/Q4

FERC FORM No.1/3-Q (REV. 02-04)

Name of Respondent	This Report Is:	Date of Report *(Mo, Da, Yr)*	Year/Period of Report
PacifiCorp	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2019/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	28,843,430,112	28,425,063,446
3	Construction Work in Progress (107)	200-201	2,002,448,524	1,194,168,876
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		30,845,878,636	29,619,232,322
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	10,870,776,722	11,032,877,405
6	Net Utility Plant (Enter Total of line 4 less 5)		19,975,101,914	18,586,354,917
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120 2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		19,975,101,914	18,586,354,917
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		13,320,639	13,578,986
19	(Less) Accum. Prov. for Depr. and Amort. (122)		3,196,879	3,149,894
20	Investments in Associated Companies (123)		69,928	69,928
21	Investment in Subsidiary Companies (123.1)	224-225	201,902,001	183,401,017
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		102,845,814	95,479,061
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		36,427,872	14,919,564
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		2,278,492	2,565,604
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		353,647,867	306,864,266
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		10,421,766	20,006,166
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		11,969,487	49,330,121
39	Notes Receivable (141)		2,405,884	5,068,150
40	Customer Accounts Receivable (142)		420,564,473	426,619,902
41	Other Accounts Receivable (143)		30,462,387	48,930,705
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		7,644,908	7,691,154
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		795,724	628,710
45	Fuel Stock (151)	227	150,404,985	179,588,705
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	244,022,924	237,694,431
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) / /	End of 2019/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		62,585,511	48,020,660
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		924,623	1,128,478
61	Accrued Utility Revenues (173)		244,728,000	229,061,000
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		13,451,134	27,458,631
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		2,278,492	2,565,604
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,182,813,498	1,263,278,901
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		33,683,227	29,412,802
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,119,161,023	1,107,326,144
73	Prelim. Survey and Investigation Charges (Electric) (183)		576,164	477,354
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		-14,358	26,188
78	Miscellaneous Deferred Debits (186)	233	114,194,930	83,176,009
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		3,971,176	4,554,871
82	Accumulated Deferred Income Taxes (190)	234	783,561,636	824,459,612
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,055,133,798	2,049,432,980
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		23,566,697,077	22,205,931,064

THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company) PacifiCorp	Year/Period of Report End of: 2021/ Q4

FERC FORM NO. 1 (REV. 02-04)

Name of Respondent: PacifiCorp	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/13/2022	Year/Period of Report End of: 2021/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	32,293,100,959	30,752,136,973
3	Construction Work in Progress (107)	200	1,131,734,692	1,539,838,861
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		33,424,835,651	32,291,975,834
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	11,632,340,710	10,874,594,134
6	Net Utility Plant (Enter Total of line 4 less 5)		21,792,494,941	21,417,381,700
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		21,792,494,941	21,417,381,700
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		21,197,450	12,333,949
19	(Less) Accum. Prov. for Depr. and Amort. (122)		3,221,891	3,224,650
20	Investments in Associated Companies (123)		69,928	69,928
21	Investment in Subsidiary Companies (123.1)	224	115,816,829	137,091,815
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		118,042,168	106,378,001
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		106,001,549	35,358,662
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		19,559,679	6,372,711
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		377,465,712	294,380,416
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		1,470,795	11,310,312
36	Special Deposits (132-134)			69,648
37	Working Fund (135)			
38	Temporary Cash Investments (136)		151,097,351	52,513
39	Notes Receivable (141)		1,361,714	1,374,246
40	Customer Accounts Receivable (142)		479,505,475	472,567,933
41	Other Accounts Receivable (143)		49,554,169	39,312,444

42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		17,701,164	17,084,938
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		(a)55,652,195	(b)28,457,757
45	Fuel Stock (151)	227	192,078,435	222,141,625
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	281,877,967	260,235,105
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228		
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		81,560,111	80,191,819
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		1,965	
60	Rents Receivable (172)		1,181,610	1,184,888
61	Accrued Utility Revenues (173)		263,654,000	253,806,000
62	Miscellaneous Current and Accrued Assets (174)			11,101,465
63	Derivative Instrument Assets (175)		95,643,511	33,026,440
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		19,559,679	6,372,711
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		1,617,378,455	1,391,374,546
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		42,678,915	37,670,714
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	1,278,010,867	1,296,157,597
73	Prelim. Survey and Investigation Charges (Electric) (183)		9,534,716	1,673,810
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	107,087,451	101,368,220
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		2,836,085	3,388,709
82	Accumulated Deferred Income Taxes (190)	234	701,421,321	777,003,313
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		2,141,569,355	2,217,262,363
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		25,928,908,463	25,320,399,025

CASE: UE 399
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 904

PacifiCorp's letter of corrections and omissions Docket Nos. UE 390 & UE 400

June 22, 2022

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

May 25, 2021

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

RE: UE 390—2022 Transition Adjustment Mechanism
Pacific Power's List of Corrections or Omissions

PacifiCorp d/b/a Pacific Power provides for filing a summary of all identified corrections or omissions to net power costs since the company's April 1, 2021 initial filing in this docket. This submission is made pursuant to Section A(4) of the Transition Adjustment Mechanism (TAM) Guidelines, adopted by the Commission in Order No. 09-274.

Corrections:

The historical GHG benefits related to EIM participation were overstated as a result of having cost components excluded in the benefit calculation. As the GHG benefit forecast is based on historical actuals, this caused an overstatement of the EIM forecast in the Company's direct filing. This will increase net power costs by $381,982 on a total-company basis.

Transacted volumes for January 2020 through June 2020 were not considered in the market capacity calculation (the 48-month window was left at January 2016 through December 2019), resulting in incorrect market capacity limits in the direct filing study. This correction has not yet been quantified but will be quantified in PacifiCorp's reply testimony.

The allocation of the Reasonable Energy Price Adjustment, where the total-company net power cost amount is to be replaced by a situs-assigned amount, was incorrectly included on a situs basis, rather than a system-allocated basis. Correcting for this allocation will result in a net increase in net power costs by $1,529,092.

Please direct informal correspondence and questions regarding this filing to Cathie Allen at (503) 813-5934.

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

May 10, 2022

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

RE: UE 400—2023 Transition Adjustment Mechanism
PacifiCorp's List of Corrections or Omissions

PacifiCorp d/b/a Pacific Power provides for filing a summary of all identified corrections or omissions to net power costs since the company's March 1, 2022 initial filing in this docket. This submission is made pursuant to Section A(4) of the Transition Adjustment Mechanism (TAM) Guidelines, adopted by the Commission in Order No. 09-274.

Corrections:

PacifiCorp identified an error on the UT Solar Adjustment tab in the Net Power Cost report that did not capture the full solar generation of certain resources. This will decrease net power costs by $11.04 million on a total-company basis.

The Company has also identified a correction to the Aurora input for the regulating reserve requirement values. This is a technical correction that is limited to the modeling input, but does not impact the proposed methodology discussed in PacifiCorp's direct testimony. This correction will be quantified in PacifiCorp's reply testimony.

Please direct informal correspondence and questions regarding this filing to Cathie Allen at (503) 813-5934.

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

CASE: UE 399
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 905

Staff calculation

June 22, 2022

Filed Case

	% Capital	Cost	Weighted Cost
Long Term Debt	47.740%	4.380%	2.091%
Preferred Stock	0.010%	6.750%	0.001%
Common Equity	52.250%	9.800%	5.121%
Total	100.000%		7.212%

Rate Base (000's)	$	4,199,122
Net Operating Revenue (000's)	$	302,848

-100 bp ROE

	% Capital	Cost	Weighted Cost
Long Term Debt	47.740%	4.380%	2.091%
Preferred Stock	0.010%	6.750%	0.001%
Common Equity	52.250%	8.800%	4.598%
Total	100.000%		6.690%

Rate Base (000's)	$	4,199,122
Net Operating Revenue (000's)	$	280,908
Decrease (000$)	$	(21,940)
Net to Gross Factor		1.371
Revenue Requirement (000's)	$	(30,080)

CASE: UE 399
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Bret Farrell. I am a Utility and Energy Analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1001

Q. Did you prepare any other exhibits?

A. Yes. I prepared Exhibit Staff/1002 which contains responses to Staff Data Requests, as well as tariffs pertaining to PacifiCorp's low-income bill assistance programs in California and Washington

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address lighting, and low-income issues in PacifiCorp's filing. My recommendations may change based on further review and based on the testimonies offered by other parties.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. LIGHTING

Q. What are the Company's current street and area lighting schedules?

A. The company has four main street and area lighting schedules: Schedule 15 (Outdoor Area Lighting Service), Schedule 51 (Street Lighting Service, Company-Owned System), Schedule 53 (Street Lighting Service, Consumer-Owned System), and Schedule 54 (Recreational Field Lighting).

Q. Please summarize how the Company's current street and area lighting schedules are structured.

A. In the Company's previous rate case (UE 374) the structure of the lighting schedules was updated to be based on the level of lighting service that the Company is providing, rather than on technology (i.e., bulb) type.[1] The level of lighting service was updated to be based on ranges of LED-equivalent lumens. Under this current design, a LED, a mercury vapor, and a high-pressure sodium vapor lamp that provide the same level of light would have the same price.

Q. What was the Company's reasoning for the proposed updates in UE 374?

A. The Company offered two reasons for the proposed change. First, basing prices on service level better aligns the Company's incentives towards providing the provision of lighting at the lowest possible cost. The company stated that LED has emerged as the dominant lighting technology and is the

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[1] In the Matter of PacifiCorp Request for General Rate Revision, Docket UE 374, Order No. 20-473 (December 18, 2020).

most efficient way to light a space, but that the present structure of PacifiCorp's rates disincentivizes the Company from converting lights to LED. If the Company replaces an older light with LED, its revenue decreases to reflect the lower-priced LED lamp. The Company argued that basing the price for Company-owned lights on level of service will provide the Company with an incentive to transition its fleet of lights to the most efficient technology available.[2]

Second, the Company's former prices for Company-owned lighting service were difficult to understand. Simplifying them to specific ranges of light levels makes it easier for customers to understand. The Stipulating Parties in UE 374 agreed that PacifiCorp's Street and area lighting tariffs should be re-designed to be based upon the level of service described in the Company's initial filing.[3]

Q. Is the Company proposing any changes to the structure of street and are lighting schedules in this filing?

A. No, The Company has made no proposal to change the overall structure of the street and area lighting schedules. The only changes to the schedules are reflected in the update to the sales and customer forecasts and the proposed update to rates.

Q. What methodology does the Company use for the lighting sales forecast?

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[2] Docket UE 374, PAC/1400, Meredith/73

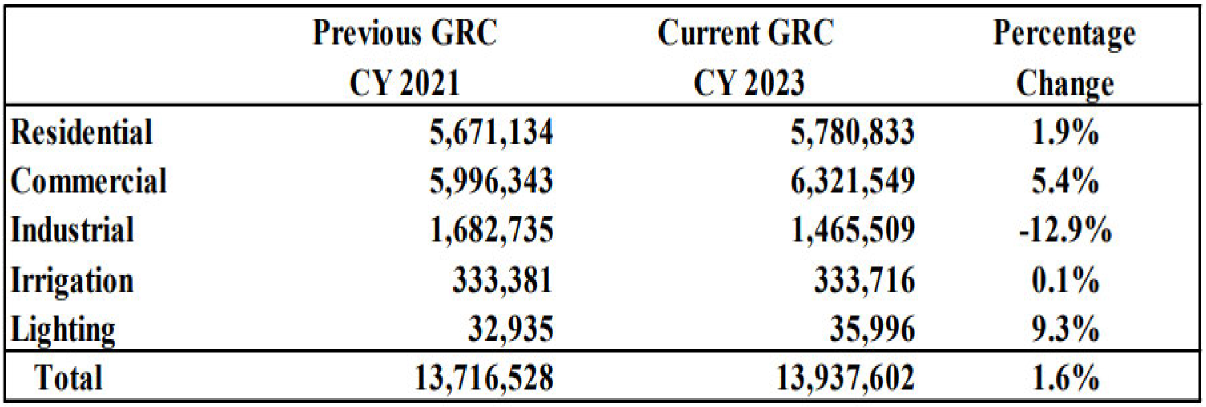
[3] Docket UE 374, PAC/1400, Meredith/73

A. Monthly sales for lighting are forecast using regression analysis techniques based on historical sales volumes and a light-emitting lighting adoption curve. The lighting forecast uses the historical data period of April 2006 through February 2021.[4] The Company states that for lighting classes, the customer forecasts are relatively static and developed using time series or regression models without any economic drivers.[5]

Q. Please describe the results of the Company's Oregon lighting sales forecast.

A. The Company forecasts 35,996 MWh in the test year (2023) for lighting schedules which is an increase of 9.3 percent from the base year (2021). This is the largest forecasted increase among the Company's five major forecasted customer categories. Table 1 (See Below) shows the comparison between the Oregon base year (2021) usage and the forecasted usage in the test year (2023) for the Company's five major customer classes.

Table 1



	Previous GRC CY 2021	Current GRC CY 2023	Percentage Change
Residential	5,671,134	5,780,833	1.9%
Commercial	5,996,343	6,321,549	5.4%
Industrial	1,682,735	1,465,509	-12.9%
Irrigation	333,381	333,716	0.1%
Lighting	32,935	35,996	9.3%
Total	13,716,528	13,937,602	1.6%

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[4] UE 399, PAC/900, Elder/8

[5] UE 399, PAC/900, Elder/6

Q. What is the underlying cause of the forecasted increase in lighting sales in Oregon?

A. In the Company's previous rate case, Docket UE 374, PacifiCorp incorporated a light emitting diode (LED) lighting adoption curve for its street lighting forecast. This curve was meant to factor into the lighting forecast the adoption of LED light bulbs among street lighting customers and capture the fact that LED light bulbs would use less energy that older technologies.[6] The Company informed Staff that the increase in the lighting forecasts in this docket is a result of slower adoption of LED bulbs among street lighting customers than the Company had initially anticipated in Docket UE 374.

Q. What is the Company's proposal for rates for street and area lighting schedules?

A. The Company proposes a base change to the rates of street and area lighting schedules of -11.5 percent in conjunction with increasing the rate mitigation adjustment (RMA) to hold these customers at a zero net price change[7]. Table 2 (See below) shows the base and net effect of rate change on each customer class, including lighting.

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[6] UE 374, PAC/700, Link/114

[7] UE 399, PAC/1100, Meredith/18

Table 2

Effect of rate change on each customer class:	Base Change	Net Change[1]
• Residential:	12.6%	9.1%
• Small General Service (Schedule 23):	10.3%	9.5%
• General Service 31-200 kW (Schedule 28):	-0.8%	0.0%
• General Service 201-999 kW (Schedule 30):	-2.4%	0.0%
• Large General Service >= 1,000 kW (Schedule 48):	-1.9%	5.9%
• Agriculture Pumping Service (Schedule 41):	19.1%	13.2%
• Street lighting:	-11.5%	0.0%
• Total	6.8%	6.6%

Q. What is the Company's reasoning for this rate proposal?

A. In response to Staff DR 470, the Company stated that per the unbundled revenue requirement allocation presented in Exhibit PAC/1107, Schedule 15 and Schedule 51 required an 8.85 percent decrease, Schedule 53 required a 26.31 percent decrease, and Schedule 54 required a 22.49 percent decrease. In light of this result, the Company proposed no net price change for these rate schedules[8].

Q. To what extent do these rates reflect cost of service?

A. The results of the Company's marginal cost of service study, which are shown, in part, in PacifiCorp's unbundled revenue requirement allocation, *(*Exhibit PAC/1107*)* indicate that to bring street and area lighting customers to rate parity, Schedules 15, 53, and 54 would require a reduction in rates. In other words, based on the latest lighting forecast and use-per-customer inputs, these

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[8] Staff/1001, Farrell/3, Company response to Staff DR 470.

schedules are paying above their actual cost of service[9]. In the Company's previous rate case (UE 374) the Company proposed a net decrease for street and area lighting customers in an attempt to have each customer category more closely reflect the cost of service for those rate schedules. Ultimately, in Commission Order No. 20-473, lighting customers received a zero net price change. In this docket, the Company has proposed to hold street and area lighting customers at a zero net price change again in an attempt to have these rate schedules more closely reflect their actual cost of service.

Q. Does Staff recommend any adjustments?

A. Please refer to Staff witness Dr. Curtis Dlouhy testimony as he is addressing rate spread and rate design.

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[9] Staff/1001, Farrell/3, Company response to Staff DR 470.

ISSUE 2. LOW-INCOME ISSUES

Q. Please briefly describe Staff's analysis related to low-income issues.

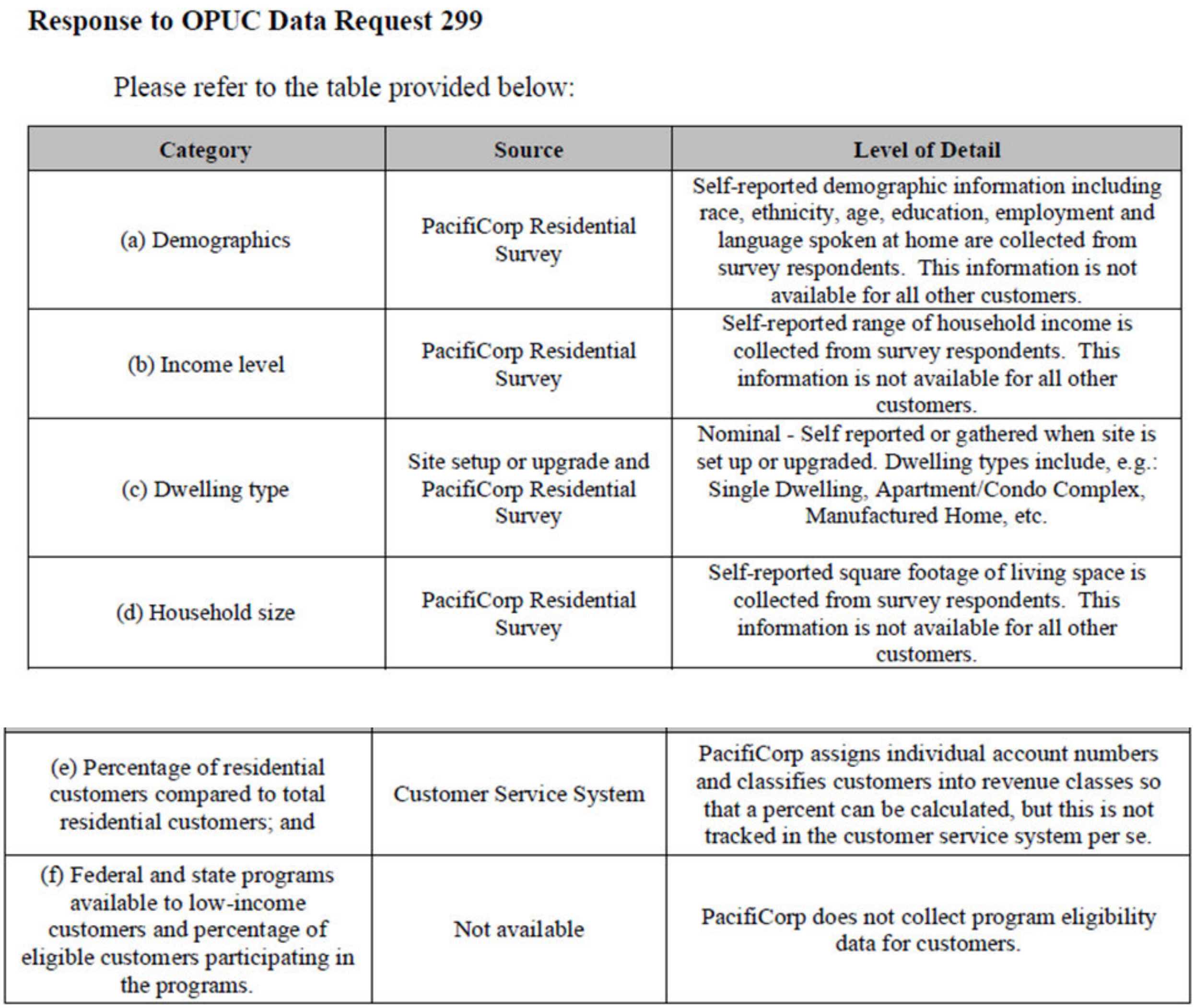
A. Staff conducted a general review of the availability and performance of the Company's existing income-eligible programs and services. More specifically, Staff reviewed the Company's testimony and other publicly available information describing PacifiCorp's:

- Existing low-income programs;
- Arrearage Management Program;
- Energy Affordability Act implementation efforts; and
- Proposed changes impacting low-income customers in this filing.

Staff also issued a number of data requests to the Company in an effort to further assess the cost effectiveness and qualitative benefits associated with these programs and initiatives.

Q. Please describe PacifiCorp's current data collection practices relative to low-income customers.

A. In response to Staff DR 299, the Company provided the following table which gives an overview of their data collection practices relating to low-income customers. The Company highlights metrics around demographics, income level, dwelling type, household size, percentage of low-income residential customers compared to total residential customers, and federal and state programs available to low-income customers and corresponding participation levels.



Response to OPUC Data Request 299

Please refer to the table provided below:

Category	Source	Level of Detail
(a) Demographics	PacifiCorp Residential Survey	Self-reported demographic information including race, ethnicity, age, education, employment and language spoken at home are collected from survey respondents. This information is not available for all other customers.
(b) Income level	PacifiCorp Residential Survey	Self-reported range of household income is collected from survey respondents. This information is not available for all other customers.
(c) Dwelling type	Site setup or upgrade and PacifiCorp Residential Survey	Nominal - Self reported or gathered when site is set up or upgraded. Dwelling types include, e.g.: Single Dwelling, Apartment/Condo Complex, Manufactured Home, etc.
(d) Household size	PacifiCorp Residential Survey	Self-reported square footage of living space is collected from survey respondents. This information is not available for all other customers.
(e) Percentage of residential customers compared to total residential customers; and	Customer Service System	PacifiCorp assigns individual account numbers and classifies customers into revenue classes so that a percent can be calculated, but this is not tracked in the customer service system per se.
(f) Federal and state programs available to low-income customers and percentage of eligible customers participating in the programs.	Not available	PacifiCorp does not collect program eligibility data for customers.

Q. Please provide additional information about the Company's 2019 customer survey.

A. In response to Staff DR 479, the Company stated that an active link to an online survey platform was distributed to all PacifiCorp customers with an active online account that had elected to receive non-billing related correspondence. All invited customers were sent a unique survey URL that allowed the customer to re-start a partially completed survey. Survey invitation emails included text in Spanish directing Spanish-speaking customers to click on a variation of the URL, which brought up the survey in Spanish. All customers had the ability to choose between English and Spanish to participate in the language most comfortable to them. The survey was distributed to 339,011 Oregon customer email accounts.

Data was collected by a third-party vendor (MDC Research) on a web-based platform. All survey data was collected on MDC's servers, and only anonymous results were shared with PacifiCorp for analysis. To maximize participation and increase the representation of the sample, a total of three emails were sent (one invitation and two reminders). The survey was open and available to customers for four weeks. Survey invitation and reminder emails were sent through PacifiCorp's email vendor. This maximized the response rate and mitigated the risk of non-response bias, as customers are not exposed to an unfamiliar email sender which could increase the likelihood of email landing in "spam" or customers choosing not to click the survey link.

Q. Please describe PacifiCorp's existing low-income programs.

A. PacifiCorp has a variety of programs which provide assistance to low-income customers through different channels. The Company works with Oregon Housing and Community Services (OHCS) to help administer the federally funded Low Income Home Energy Assistance Program (LIHEAP) which helps low-income households with heating costs. The Company also works with Community Action Agencies and Oregon Housing and Community Services (OHCS) to administer funds for the Oregon Energy Assistance Program

(OEAP) which also provides energy assistance funding to Oregon households at or below 60 percent of the state median income.

Additionally, under 1999's Senate Bill (SB) 1149, as amended, PacifiCorp and Portland General Electric (PGE) were directed to collect a public purpose charge (PPC) from their customers on their monthly bills to help fund energy conservation in schools, low-income weatherization and housing, and renewable energy projects.[10] Lastly, in response to the COVID-19 pandemic, with Order No. 20-401, issued in Docket UM 2114 the Commission adopted a stipulation under which the energy utilities agreed to establish an Arrearage Management Program (AMP) to identify and manage residential customer arrearages associated with the COVID-19 pandemic to proactively assist residential customers prior to resuming disconnections.

Q. Is PacifiCorp proposing any changes to its existing low-income programs in its initial filing?

A. No. PacifiCorp has not proposed any changes to its existing low-income programs. Low-income issues are being addressed in Docket UM 2211 and future filings as discussed later on in my testimony.

Q. Please describe PacifiCorp's Arrearage Management Program.

A. PacifiCorp's Bill Assistance Program provided two Arrearage Management options to residential customers whose accounts were past due at the time of enrollment. The total authorized funding for these two options was roughly $12.7 million. Those two options are as follows:

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[10] SB 1149 is codified, with further amendments, in ORS 757.612.

1. Extended Payment Match – Designed for qualified customers who require long-term payment arrangements on past due balances. Participating customers will receive a monthly payment match up to $1,000. The customer must enroll in an extended payment plan and may elect to use a portion of the match as a down payment on the payment plan. The Company will match customer payments until the $1,000 maximum is met, 12 months have elapsed, the arrearage is paid in full, or the customer is disconnected for nonpayment, whichever occurs first.
2. Instant Grant – A one-time grant up to $500 to provide customers who need assistance to pay off the arrearage, reconnect service, or set up an extended payment plan.

Q. Please discuss the performance of the Company's Arrearage Management Program.

A. As of February 2022, PacifiCorp expended $11.2 million in AMP funds and committed an additional $1.1 million to customers. The Company has a total of 25,597 AMP participants or 4.7 percent of all residential customers[11]. The following table shows the difference in expended funds and AMP participants between PacifiCorp's two arrearage management options.

Table 1

	Funds Expended	**AMP Participants**
Instant Grant	$ 8,635,217	21,142
Extended Match	$ 2,591,927	4,455

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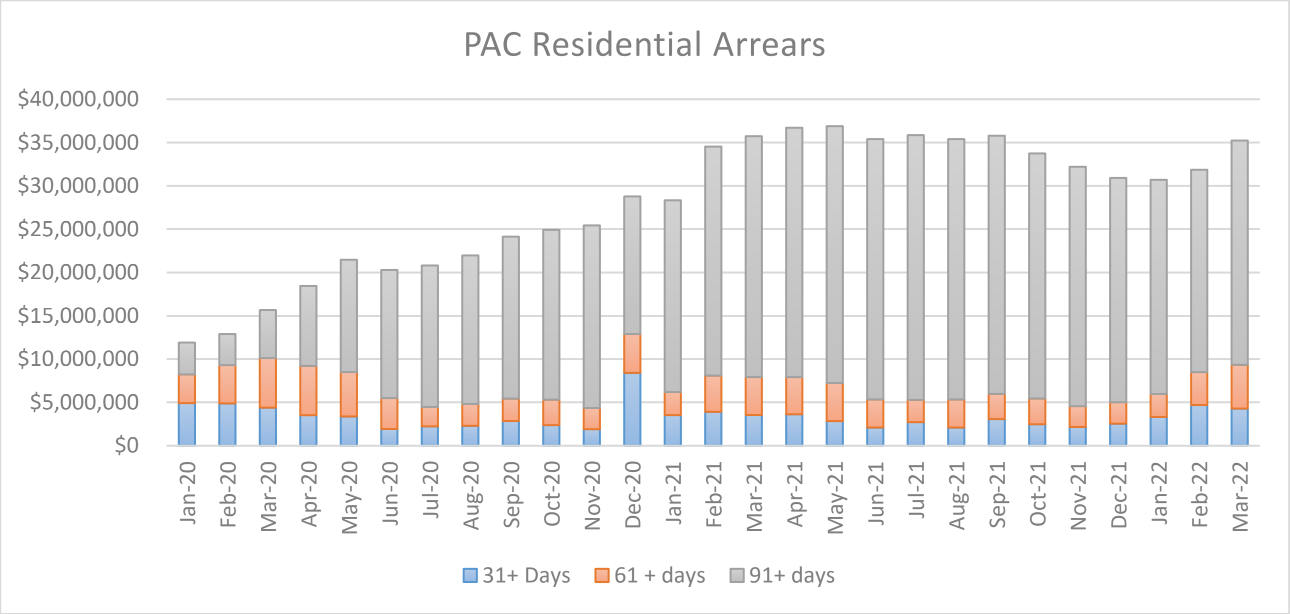
[11] RE 189, PacifiCorp's COVID-19 Credit and Collections Report for February 2022.

As of March 2022, PacifiCorp's total residential arrearage balance was $35.2 million, with a total of 86,476 residential customers in arrears[12]. Since their peak in May 2021, PacifiCorp's residential arrears have come down roughly $1.65 million (-4.5 percent). Table 2 shows PacifiCorp's residential arrears balance, segmented by delinquency basket, from January 2020 to March 2022.

Table 2



Residential customers in arrears have come down 9,326 (-9.7 percent) since their peak in May 2020. Table 3 shows PacifiCorp's the count of residential customers in arrears, segmented by delinquency basket, from January 2020 to March 2022.

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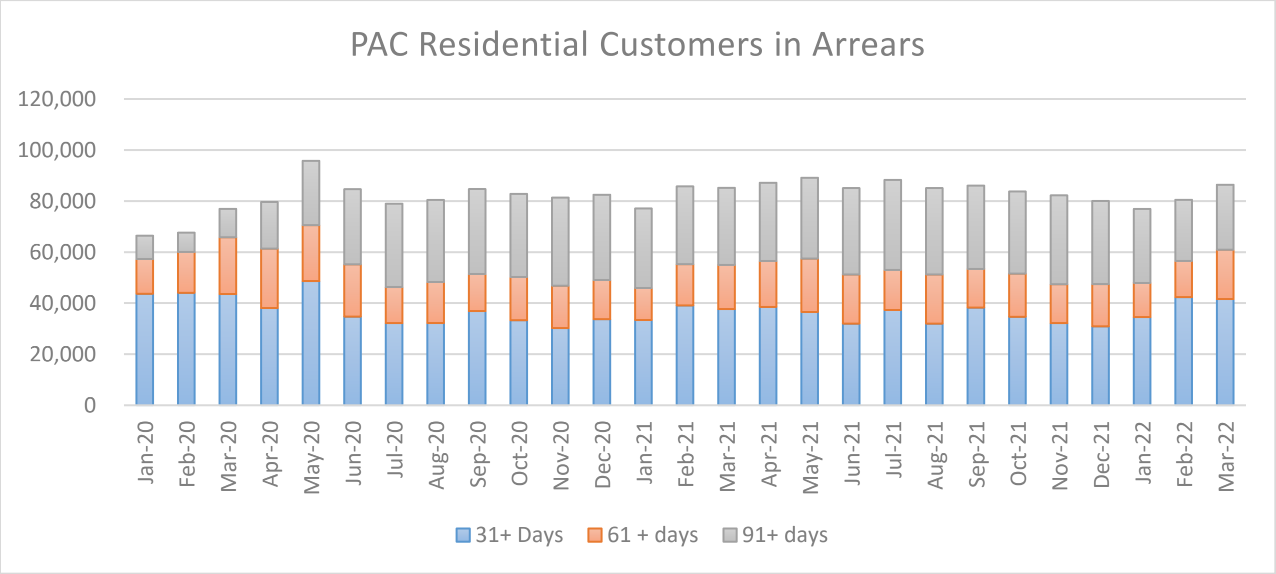
[12] RE 189, PacifiCorp's COVID-19 Credit and Collections Report for March 2022.

Table 3



Q. Is PacifiCorp in the process of developing any additional low-income programs?

A. Yes. In response to the enactment of the Energy Affordability Act, Oregon House Bill (HB) 2475 , PacifiCorp has begun developing an interim low-income bill discount program in coordination with Staff and stakeholders.

Q. Please describe HB 2475.

A. HB 2475 was signed into law in 2021, creating new provisions and amending ORS 756.010, 757.072, and 757.230 to include definitions for “environmental justice” and “environmental justice communities” in ORS governing the Commission and utilities it regulates. Section 2 of the Act amends ORS 757.230 to allow consideration of differential energy burdens on low-income customers and other economic, social equity, or environmental justice factors that affect affordability for certain classes of utility customers in rate design. Section 3 of the act provides intervenor funding agreements for organizations that represent low-income residential customers and residential customers of environmental justice communities. Section 7 of the Act allows the Commission to address the mitigation of energy burdens through bill reduction measures, including, but not limited to, demand response or weatherization.

Q. Does PacifiCorp have income qualified discount programs in other states?

A. Yes, the Company has income-qualified discount programs in both California and Washington. In California, qualifying residential customers, who self-certify their income, can receive a 20 percent discount on Pacific Power bills through the California Alternate Rates for Energy (CARE) program[13]. The program was established in 1989 by the California legislature and is funded through a surcharge on non-CARE customers' monthly bills. In Washington, qualifying residential customer receive a discount based on the qualification level for which the customer was certified. There are three levels of discount in the Washington program based on the federal poverty levels[14]:

- <u>0-75% of Federal Poverty Level (FPL)</u>: 70% of net bill
- <u>76-100% of Federal Poverty Level (FPL)</u>: 35% of net bill
- <u>101 -200% of Federal Poverty Level (FPL) or 80% of Area Median Income (AMI), whichever is greater:</u> 15% of net bill

Q. What is the Company's rationale for not including HB 2475 implementation proposals in the initial UE 399 filing?

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[13] Staff/1002, Farrell/6-8, PAC California Schedule No. DL-6 CARE tariff

[14] Staff/1002, Farrell/9-10, PAC's Washington Schedule 17: Low Income Bill Assistance Program Residential Service Optional for Qualifying Customers

A. In response to Staff DR 302, PacifiCorp stated that the Company did not include a low-income bill assistance program proposal in this general rate case application because it hopes a program can be implemented sooner than the effective date for this rate case[15]

Q. Please describe the current status of the Company's HB 2475 low-income bill discount program implementation in Oregon.

A. As of writing this testimony, Staff is continuing to work with PacifiCorp and UM 2211 Stakeholders on an interim differential rate design that will be launched later this year.

Q. Please outline any issues in this filing that may impact low-income customers or programs.

A. Staff has identified three potential issues presented by the Company in this filing that may disproportionately impact low-income customers.

- Proposed residential rate increase;
- Flattening the residential rate design;
- Flattening the Regional Power Act Credit; and
- Proposed seasonal rates where winter prices are lower than summer prices.

One of the objectives in Docket UM 2211 and across each of the utilities' HB 2475 program implementations is to help alleviate energy burden for low-income customers in Oregon. In this filing, the Company is seeking a net

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[15] Staff/1002, Farrell/2, Company response to DR 302

increase of residential customers of 9.1 percent[16]. If this increase were to be adopted, it would significantly offset any low-income discount proposed by the Company and further reduce the impact on energy burden in Oregon. Staff believes that it important to consider that in considering rate spread and rate design because as residential energy rates increase it will be important to reevaluate the energy burden of low-income households. Also of concern are the other increases PacifiCorp is asking for in other dockets relating to power costs[17]. When these dockets are taken into account, the increase to residential customers, especially those using less than average, is above 20 percent.

In addition to the overall impact of a rate increase on low-income customers, PacifiCorp is also proposing to replace the inverted block energy charge structure with seasonal rates where winter prices are lower than summer prices. The Company is also proposing to eliminate the blocking in the residential exchange credit. The merits of these pricing proposals are discussed in the testimony of Staff witness Dr. Curtis Dlouhy.

Q. Is the Company proposing to increase the multifamily basic charge?

A. No. Even though the Company states that the basic charge is well above costs, the Company is not proposing to increase the multifamily basic charge and low-income users are more likely to be in multifamily housing relative to higher-income customers. In his testimony, Dr. Dlouhy further discusses the

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[16] Docket No UE 399, PAC/1100, Meredith/15

[17] In the matter of PacifiCorp, dba Pacific Power, 2023 Transition Adjustment Mechanism, Docket No. UE 400

Company's method to quantify the difference between the fixed customer costs and the basic charge.

Q. Does the Company state the potential bill impacts across income levels for these proposed changes?

A. Analysis provided by the Company show that the bill impact, including the proposed changes from the currently filed transition adjustment mechanism (TAM), on average was very similar for different income levels. Company witness Robert Meredith provided Table 4[18] which shows the average monthly bill change and percent bill change if the proposed increase in the basic charge and the move from inclining block tiered rates to seasonal rates were adopted.

Table 4

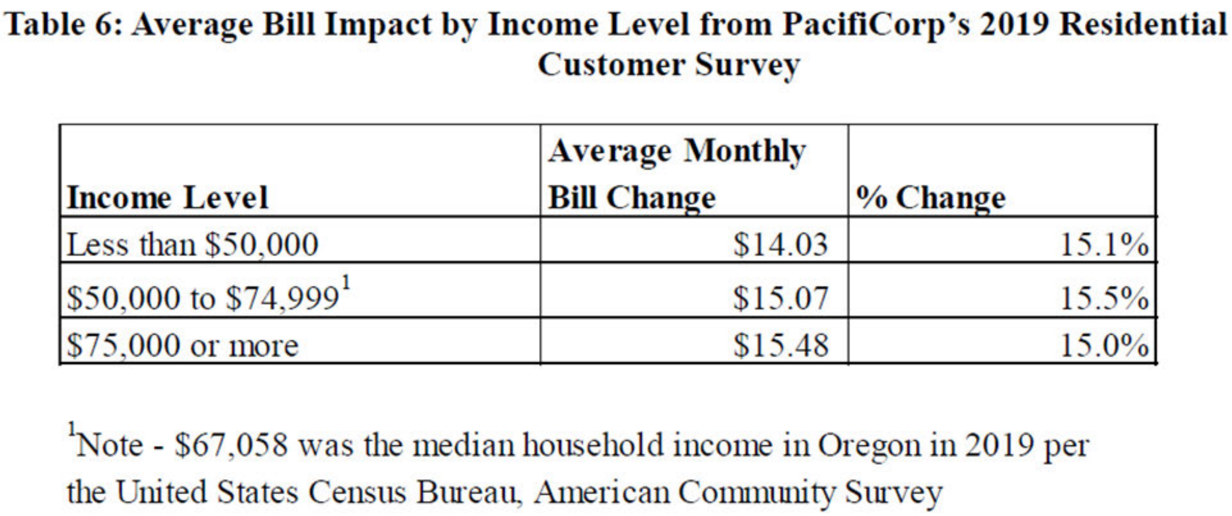

Table 6: Average Bill Impact by Income Level from PacifiCorp's 2019 Residential Customer Survey

Income Level	Average Monthly Bill Change	% Change
Less than $50,000	$14.03	15.1%
$50,000 to $74,999[1]	$15.07	15.5%
$75,000 or more	$15.48	15.0%

[1] Note - $67,058 was the median household income in Oregon in 2019 per the United States Census Bureau, American Community Survey

Q. Has Staff made any findings regarding the direct impacts of PacifiCorp's proposals regarding moving to seasonal rates and other changes on low-income customers?

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[18] Docket No. UE 399, PAC/1100, Meredith/29

A. Not at this time. During the course of Staff's analysis, Staff asked the Company for further detail on the rate impacts of these proposals; however, the responses provided did not expand beyond information provided in PacifiCorp's initial filing or what Staff could deduce independently. Staff asked the Company to provide information regarding low-income usage rates in PacifiCorp's service territory.[19] Generally, the Company indicates that average usage is less for lower income customers.[20] Based on this, Staff is concerned the proposals to flatten energy rates may have disparate impacts for low-income customers. Relative to the seasonal rates, Staff is continuing to investigate whether or not low-income customers experience disproportionate challenges with adjusting seasonal usage.

Q. Does Staff recommend any adjustments?

A. Please refer to Staff witness Dr. Curtis Dlouhy testimony for rate spread and rate design recommendations in Exhibit Staff/700. In his testimony, Dr. Dlouhy generally supports the Company's proposals to keep the multi-family basic charge at $8.00 and to replace the block-inverted rates with flat, seasonal rates. However, Dr. Dlouhy does propose a narrower seasonal rate differential than the Company and a change to Schedule 98 that is likely to benefit low-income customers.

Q. Does this conclude your testimony?

A. Yes.

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[19] Staff/1002, Farrell/1 and Farrell/4, PAC Response to OPUC DRs 300 and 477.

[20] Staff/1002, Farrell/5, PAC Response to OPUC DR 478.

CASE: UE 399
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualification Statement

June 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME:	Bret Farrell
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Strategy Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	BA Economics, Illinois State University, Normal, IL MS Applied Economics, Illinois State University, Normal, IL
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since April 2019. I initially began work at the Commission in the Universal Service and Regulatory Analysis Division and later transitioned to the Strategy Integration Division upon its inception. My work prior to the Commission included working as a graduate research assistant at Illinois State University's Institute for Corruption Studies.

CASE: UE 399
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Exhibits in Support of Opening Testimony

June 22, 2022

UE 399 / PacifiCorp
April 20, 2022
OPUC Data Request 300

OPUC Data Request 300

Low-income considerations - Please describe and provide supporting work papers or documentation regarding the following measures for low-income customers compared to the residential class as a whole:

(a) Average monthly kWh usage;

(b) Average monthly bill amount;

(c) Average past due balance;

*If the Company is unable to respond to the DR for low-income customers, please provide the information using the aggregated data from zip codes where the average median income is less than the State median income as a proxy for "low-income customers"

Response to OPUC Data Request 300

Please refer to the table provided below:

	Non Low Income [A]	Low Income	Total
(a) Average monthly kWh usage	986	956	984
(b) Average monthly bill amount	$109.07	$105.31	$108.83
(c) Average past due balance [B]	$115.07	$161.50	$117.94

Note A: Low Income defined as Energy Assistance Program recipients, from select energy assistance providers in the past 12 months.

Note B: Average past due is defined as current debt over 30 days as extracted on April 12, 2022.

UE 399 / PacifiCorp
April 20, 2022
OPUC Data Request 302

OPUC Data Request 302

> **Low-income considerations** - Please describe the Company's position and rationale in not including HB 2475 implementation proposals in the initial UE 399 filing.

Response to OPUC Data Request 302

> As discussed in the direct testimony of Company witness, Robert M. Meredith, Exhibit PAC/1100, page 30, lines 4 through 6, "The Company did not include a low-income bill assistance program proposal in this general rate case application because it hopes a program can be implemented sooner than the effective date for this rate case".

UE 399 / PacifiCorp
May 20, 2022
OPUC Data Request 470

OPUC Data Request 470

> **Lighting Schedules -** Please explain in greater detail the company's reasoning for proposing a net zero revenue change (zero net price change) for lighting schedules.

Response to OPUC Data Request 470

> Per the Company's unbundled revenue requirement allocation presented on Exhibit PAC/1107, Schedule 15 and Schedule 51 required an 8.85 percent decrease, Schedule 53 required a 26.31 percent decrease, and Schedule 54 required a 22.49 percent decrease. In light of this result, the Company proposed no net price change for these rate schedules.

UE 399 / PacifiCorp
May 20, 2022
OPUC Data Request 477

OPUC Data Request 477

> **Low-income considerations** - Please utilize the proxy defined by Staff for low-income customers and resubmit the response.

Response to OPUC Data Request 477

The Company assumes that the request to "resubmit the response" is intended to be related to the Company's response to OPUC Data Request 300. Based on the foregoing assumption, the Company responds as follows:

Please refer to the table provided below which utilizes the proxy defined by the Public Utility Commission of Oregon (OPUC) staff for low-income customers. Information provided based on aggregated census data from zip codes where the average median income is less than the State median income as a proxy for "low-income customers". Note: PacifiCorp's response to OPUC Data Request 300 utilized "Energy assistance program recipients from select energy assistance providers" to identify the low-income customer cohort as energy assistance program (EAP) recipients are income qualified -with Low Income Home Energy Assistance Program (LIHEAP) and Oregon Energy Assistance Program (OEAP) recipients generally reporting an income of up to 60 percent State Median Income (SMI).

	Non-Low Income	Low Income	Total
(a) Average monthly kWh usage	889	1,008	974
(b) Average monthly bill amount	$99.60	$111.27	$107.98
(c) Average past due balance [A]	$84.56	$125.97	$114.31

Note A: Average past due is defined as current debt over 30 days as extracted on April 12, 2022.

UE 399 / PacifiCorp
May 20, 2022
OPUC Data Request 478

OPUC Data Request 478

Low-income considerations - Please discuss the Company's understanding regarding usage differences between customers with income levels less than $50,000 as shown in Table 5 (PAC/1100, Meredith/28, Table 5) compared to the low-income customer usage provided in the Company's original response to OPUC 300.

Response to OPUC Data Request 478

Both tables referenced indicate that average usage is less for lower income customers.

Schedule No. DL-6

RESIDENTIAL SERVICE
CALIFORNIA ALTERNATIVE RATES FOR ENERGY (CARE)
OPTIONAL FOR QUALIFYING CUSTOMERS

APPLICABILITY

Applicable to residential low income households in single-family dwellings and as specified further under special conditions of this Schedule, and Residential Service Schedule No. D, and for multiple dwelling units in which each of the single-family dwellings receive service directly from the utility through separate meters, and to multi-family accommodations which are separately submetered.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic and Energy Charges.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94 and the applicable adjustment schedules that are a part of this tariff. Applicable adjustment schedules are specified in Schedule X-90.

	Distrib.	**FERC Trans.**	**Calif. Trans.**	**Generation**	**Gener. Franch.**	**CARE Adj.**	**Total Rate**
Basic Charge	$8.12					($1.62)	$6.50
Energy Charge:							
All Baseline kWh	5.762¢	0.539¢	0.521¢	3.014¢	0.073¢	(1.982¢)	7.927¢
All Non-Baseline kWh	7.478¢	0.539¢	0.521¢	3.359¢	0.073¢	(2.394¢)	9.576¢

Adjustments:

The above Total Rate includes the CARE Adjustment which is equal to twenty percent (20%) of the Residential Service Schedule No. D charges. The CARE Adjustment of twenty percent (20%) will also be applied to the adjustment schedules applicable to this tariff and specified in Schedule X-90. Customers taking service under this rate schedule are not subject to the California Alternative Rates for Energy Surcharge in Schedule S-100.

Minimum Charge:

The monthly Minimum Charge shall be the Basic Charge. A higher minimum may be required under contract to cover special conditions.

SPECIAL CONDITIONS

1. Service under this schedule is subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

(Continued)

Issued by

Advice Letter No.	663-E	Etta Lockey Name	Date Filed	October 15, 2021
Decision No.		VP, Regulation Title	Effective	January 1, 2022

Resolution No. ________

SCHEDULE NO. DL-6

RESIDENTIAL SERVICE
CALIFORNIA ALTERNATIVE RATES FOR ENERGY (CARE)
OPTIONAL FOR QUALIFYING CUSTOMERS
(Continued)

SPECIAL CONDITIONS (Continued)

2. A Low-Income Household where the total gross income from all sources is less than shown on the table below based on the number of persons in the household. Total gross income shall include income from all sources, both taxable and nontaxable.

These income limits are effective from June 1, 2022 to May 31, 2023

No. of Persons In Household	Total Gross Income Annually
1-2	$36,620
3	46,060
4	55,500
5	64,940
6	74,380
7	83,820
8	93,260

For Households with more than eight persons add $9,440 annually for each additional person residing in the household.

3. An application is required for each request of service under this schedule. An eligible applicant will be placed on this schedule within one billing cycle of the receipt of their application. Renewal of a customer's eligibility declaration will be required every two years and may be required randomly at the utility's discretion. Submetered tenants of master metered customers (Schedule DS-8) will be required to reestablish eligibility on an annual basis. Customers are only eligible to receive service under this rate at one residential location at any one time.

4. It is the customer's responsibility to notify the utility if there is a change in eligibility status. Master meter customers (Schedule DS-8) with submetered tenants are responsible for notifying the utility when enrolled tenants move. Master meter customers will not be held responsible should a submetered tenant misrepresent his eligibility to the utility. However, if a master meter customer has a good reason to suspect that the tenant is not eligible, the master meter customer should, but is not required to, so advise the utility.

5. Customers may be rebilled for periods of ineligibility under the applicable rate schedule.

6. Price discounts or billing credits which may be available under other rate schedules or tariffs may not be used in conjunction with the Low Income Schedule No. DL-6.

7. The Basic Residential use baseline allowance as defined in Residential Service Schedule D will apply unless baseline allowances available for electric space heating are qualified and elected. The standard medical baseline quantities for the use of a Life Support device as defined under the special conditions of Residential Service Schedule No. D shall be applicable under this Schedule.

Issued by

Advice Letter No. 683-E
Matthew McVee
Name
Date Filed April 28, 2022

Decision No. 21-10-023
VP, Regulation
Title
Effective June 1, 2022

Resolution No.

SCHEDULE NO. DL-6

RESIDENTIAL SERVICE
CALIFORNIA ALTERNATIVE RATES FOR ENERGY (CARE)
OPTIONAL FOR QUALIFYING CUSTOMERS
(Continued)

CONTINUING SERVICE

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a customer from minimum monthly charges.

RULES AND REGULATIONS

Service under this schedule is subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

		Issued by		
Advice Letter No.	603-E	Etta Lockey Name	Date Filed	February 26, 2020
Decision No.		VP, Regulation Title	Effective	February 6, 2020

Resolution No.

PACIFIC POWER
A DIVISION OF PACIFICORP

WN U-76

Second Revision of Sheet No. 17.1
Canceling First Revision of Sheet No. 17.1

Schedule 17
LOW INCOME BILL ASSISTANCE PROGRAM—RESIDENTIAL SERVICE OPTIONAL FOR QUALIFYING CUSTOMERS

AVAILABLE:
In all territory served by Company in the State of Washington.

APPLICABLE:
To residential Customers only for all single-phase electric requirements when all service is supplied at one point of delivery. For three-phase residential service see Schedule 18.

MONTHLY BILLING:
The Monthly Billing shall be the sum of the Basic and Energy Charges and the Low Income Energy Credit. All Monthly Billings shall be adjusted in accordance with Schedule 80.

Basic Charge: $7.75

Energy Charge:

Base Rate	
7.224¢	per kWh for the first 600 kWh
10.146¢	per kWh for all additional kWh

LOW INCOME ENERGY CREDIT:
The credit amount shall be based on the qualification level for which the customer was certified.

0-75% of Federal Poverty Level(FPL):
70% of net bill

76-100% of Federal Poverty Level(FPL):
35% of net bill

101 -200% of Federal Poverty Level (FPL) or 80% of Area Median Income (AMI), whichever is greater
15% of net bill

MINIMUM CHARGE:
The monthly minimum charge shall be the Basic Charge. A higher minimum may be required under contract to cover special conditions.

(continued)

Issued: January 21, 2022
Docket No. UE-210532
Effective: February 1, 2022

Issued By PacifiCorp d/b/a Pacific Power & Light Company

By: ____________________ Matthew McVee **Title:** Vice President, Regulation

PACIFIC POWER
A DIVISION OF PACIFICORP

WN U-76

First Revision of Sheet No. 17.2
Canceling Original Sheet No. 17.2

Schedule 17
LOW INCOME BILL ASSISTANCE PROGRAM—RESIDENTIAL SERVICE OPTIONAL FOR QUALIFYING CUSTOMERS

SPECIAL CONDITIONS:

1. To qualify, a Customer's household income does not exceed the higher of eighty percent of area median income (AMI) or 200 percent of the Federal Poverty Level.
2. Qualifying Customers will be placed into one of three qualifying levels. Program is available to all income qualified households.
3. Non-profit agencies will administer the program. They will determine if a customer qualifies for the program and assign them to one of the three income bands. The Company will authorize these agencies to certify customer eligibility for the Program.

CONTINUING SERVICE:
Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Customer from monthly minimum charges.

RULES AND REGULATIONS:
Service under this schedule is subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

Issued: July 2, 2021
Advice No. 21-04

Effective: August 1, 2021

Issued By PacifiCorp d/b/a Pacific Power & Light Company

By: Etta Lockey

Title: Vice President, Regulation

CASE: UE 399
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Brian Fjeldheim. I am a Senior Financial Analyst employed in the Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. I present Staff's analysis and recommendations regarding the rate treatment of transmission and distribution - operations and maintenance (O&M) expenses, customer accounts expenses (non-labor), uncollectible accounts, gains on sales of utility property, non-fuel materials and supplies, miscellaneous deferred debits, working capital, miscellaneous rate base, customer advances for construction, cyber security, information technology (IT) costs, and legal expenses and fees.

A. Yes. I prepared the following exhibit:

Exhibit Staff/1102 – Responses to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. For the recommendations provided in your testimony, are they your final recommendations or could they be revised?

A. My recommendations could change as a result of reviewing testimony submitted by other parties as well as Company responses to data requests that are forthcoming.

ISSUE 1. TRANSMISSION AND DISTRIBUTION - OPERATIONS AND MAINTENANCE (O&M) EXPENSES

Q. Please describe Staff's review process for O&M-related expenses.

A. Staff reviews the Company's base year and historical expenditure data for prudence and appropriate recording using FERC's uniform system of accounts (USOA). Transmission O&M expenditures are recorded in FERC accounts 560 – 574, and distribution O&M expenses are recorded in FERC accounts 580 – 598. Staff excluded FERC account 593 – Maintenance of Overhead Lines here as a significant portion of these expenses entail vegetation management, which is addressed by Mitch Moore in Staff/1300.

Q. Please summarize PacifiCorp's proposed O&M expenses for the Test Year.

A. Based on PacifiCorp's 2023 JAM model and response to Staff SDR 058(b), the Company seeks to recover $62.4 million, an increase of $3.5 million over the Base Year.

Q. Please describe the adjustments PacifiCorp proposed for O&M expenses.

A. PacifiCorp uses an escalation factor for non-labor expenses from the Base Year through the Test Year using utility industry information provided by HIS Markit (previously Global Insight).[1] The Company's escalation is not uniform and varies by FERC account.[2] In addition to the escalation

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[1] See PAC/1000, Cheung/7 at 16-20.

[2] See PacifiCorp Confidential Workpaper 4.10 O&M Escalation.

increases, PacifiCorp also specifies specific adjustments to individual FERC accounts based on anticipated Test Year needs that are not contemplated in the Base Year expenditure data.[3]

Q. Has PacifiCorp established that the requested Test Year costs are appropriate, just, and reasonable for customers?

A. No. Staff and parties have not yet received fully accurate data in the Company's responses to Standard Data Requests (SDR) 057 and 058(b). SDR 057 requires a utility to provide detailed non-labor Base Year expenditure data. SDR 058(b) requires a utility to provide non-labor summary expenditure data by FERC account for the Base Year, the two preceding years, and the Test Year request. The Base Year expenditure data for FERC accounts 560 – 574 and 580 – 598 provided in PacifiCorp's responses to SDRs 057 and 058(b) do not match one another and do not tie-out. The Company needs to resolve the discrepancy between the SDR 057 and SDR 058(b) non-labor data sets.

In the interim, Staff used a ratio of the difference between SDR 057 data and SDR 058(b) data by individual FERC account as a proxy to analyze the change in expenditures from the Base Year to the Test Year. In the event the Company fails to supplement its responses with the correct data, Staff will issue additional Data Requests (DRs) pertaining to the discrepancy between SDR 057 and 058 FERC account totals as well as base its recommendations using conservative assumptions to both protect customers from potentially

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[3] See PacifiCorp Workpapers 4.1 Miscellaneous General Expenses & Revenues; 4.4 Remove Non-Recurring Entries; 4.6 Generation Overhaul Expense; 4.10 O&M Expense Escalation; and 4.11 Vegetation & Wildfire Management O&M.

being charged excess costs as well as provide incentives for the Company to fully and completely comply with SDR requirements.

Q. Please describe Staff's analysis of PacifiCorp's proposed O&M expenses.

A. As just discussed above, Staff and Parties have not been provided with complete and adequate information as required by SDRs 057 and 058(b). Specifically, because the Base Year summary data for SDR 058(b) does not match the SDR 057 data, Staff is unable to compare the Test Year request to Base Year and historical period expenses to determine whether the request is reasonable. For example, per the Company's response to SDR 057, Base Year non-labor expenses for FERC 560–598 (excluding FERC 593) total $55.4 million. However, in the Company's response to SDR 058(b), Base Year non-labor expenses for the same FERC accounts totaled $58.8 million, a difference of $3.48 million. There should no difference between the SDR 057 and SDR 058(b) Base Year responses. This inconsistency between SDR 057 and 058(b) non-labor data hampers Staff's ability to calculate a precise adjustment for the Test Year request. Staff also notes that PacifiCorp submitted a revision to SDR 058 on April 6 to adjust labor expenses out of FERC account 926.

As a starting point, Staff compiled summary information for the O&M FERC accounts using the Jurisdictional Allocation Model (JAM) file provided with the application and the JAM files from PacifiCorp's annual Report of

Operation submission.[4] Staff analyzed the summary data then compared the Test Year against prior year averages as well as an escalation of the Base Year using the All-Urban Consumer Price Index (CPI-U).

Q. Please summarize Staff's recommended approach to escalation for these accounts.

A. Other than for wages and salaries, except where a publicly-available index is demonstrated to be a superior index, it is Staff policy to use the CPI-U as published by the State of Oregon Office of Economic Analysis (OEA) for year over year escalation of expenses. The CPI-U measures price changes in a fixed market basket of goods and services in 200 categories, generally including housing, apparel, transportation, medical care, recreation, education, and others to urban consumers.[5] It is publicly available information and is not designated proprietary. The most recent release of the CPI-U was the June 2022 report, released May 18, 2022. According to Appendix A of OEA's report, the percentage change for CPI-U for 2020-2021, 2021-2022, and 2022-2023 is 4.7 percent, 6.8 percent, and 2.6 percent, respectively. Because PacifiCorp used a Base Year ending June 30, 2021, Staff used half of the 2020-2021 rate (4.7 percent/2) in the escalation model. Staff then used the full increase for the subsequent two years (6.8 and 2.6 percent).

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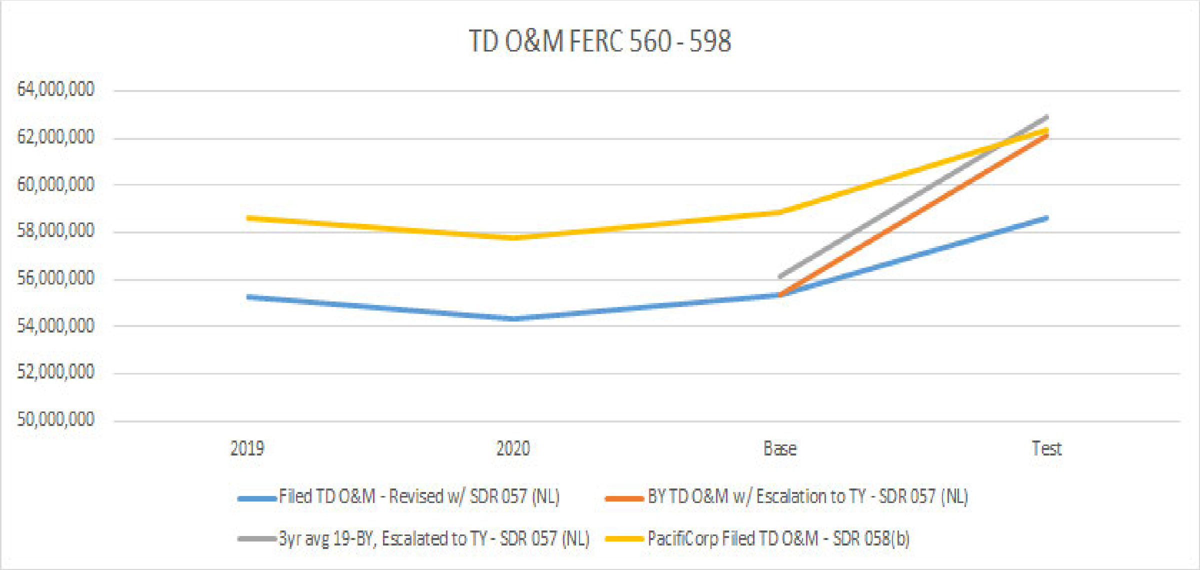
[4] PacifiCorp RE 56, years 2016-2018.

[5] In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149, UE 116, Order 01-787 at 40 n10 (September 7, 2001); In the Matter of Northwest Natural, UG 132, Order No. 99-697 at 43 (November 12, 1999).

As shown in Figure 1, Staff calculated four possible transmission and distribution O&M escalation outcomes using the Company's filed Base Year, a Staff calculated Base Year adjusted for SDR 057,[6] and a three-year average (2019–2021) Base Year adjusted for SDR 057.

Figure 1



Q. Does Staff have any adjustments to the Company's proposed O&M Expenses?

A. Given, in part, the concerns expressed above, and reviewing the three-year CPI-U escalated average, Staff recommends no adjustment in the Company's non-labor Test Year O&M expenses for FERC accounts 560–598 (excluding FERC 593). The Company appears to be appropriately managing this area of costs given the somewhat conflicting data received to date. This recommendation is subject to change, pending responses to future Staff DRs

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[6] Staff used a ratio of the difference in non-labor data supplied in PacifiCorp's response to Staff SDRs 057 and 058(b) to create a proxy Base Year for FERC accounts 560-598.

related to specific FERC accounts and supplemental information that Staff expects to be provided by PacifiCorp in response to SDRs 057 and 058(b) and Staff DR 375.

ISSUE 2. CUSTOMER ACCOUNTS EXPENSES (NON-LABOR)

Q. Please describe customer accounting and customer service expenses.

A. Customer accounting expense is recorded in FERC accounts 901, 902, 903, 904, and 905. These accounts track expenses related to Supervision, Meter Reading, Customer Records and Collection, Uncollectibles, as well as Miscellaneous Customer Accounts. FERC account 904 – Uncollectible Accounts, is analyzed separately in Issue 3 of this testimony.

Q. Does the Commission Staff have a standard for how Customer Account Expenses and Customer Service expenses are treated for ratemaking purposes?

A. Sales and marketing (including advertising) expenses are prohibited from being posted in customer accounts or customer service expenses in keeping with Order No. 99-033.[7] Staff reviews expenses per appropriate use per FERC account. Staff also reviews transaction-level data to ensure expenses relate to activities such as responding to customer requests, inquiries and safety concerns, resolving customer complaints, extending service to new customers, and providing information about safety and service issues.

Q. Please describe the Company's customer account expenses in the Base Year.

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[7] *In the Matter of Portland General Electric Company*, Docket UE 102, Order No. 99-033 (January 28, 1999).

A. For Customer Account expenses (FERC accounts 901–903 and 905), the Company reported a Base Year Oregon allocated non-labor total of $5.96 million and is requesting a Test Year non-labor amount of $7.17 million.[8] Customer account expenses increased 9.9 percent from Base to Test Year.[9] It is also important to note that residential and commercial customer counts increased 1.0 percent and 1.5 percent, respectively, while industrial customers declined 1.3 percent from 2020 to 2021.[10]

Q. How did Staff perform its analysis of the Company's customer accounting and customer expense?

A. First, Staff reviewed the Company's adjustments, which included the removal of advertising expenses, and then applied a series of CPI-U escalation factors to recent historical years expenditure data to derive the CPI-U escalation growth for Test Year customer accounts. PacifiCorp used IHS Markit Escalation Indices (Fourth Quarter 2021 forecast) with a release date of January 25, 2022.[11] It is worth noting that Staff proposes to use the CPI-U as published by the State of Oregon Office of Economic Analysis (OEA) for year–over–year escalation of expenses, given the historic use of this index, the need for consistency across utilities, and public release of the CPI-U. The most recent release of the CPI–U was the June 2022 report

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[8] PAC response to SDR 058(b), excluding FERC 904.

[9] See PAC/1100 Cheung Workpapers OR GRC JAM Dec 2023 Test Period.

[10] PacifiCorp 2020 and 2021 Annual Results of Operations, page 3.1.3, filed in Docket RE 56.

[11] See PAC Exhibit/1005, Cheung/1.

released May 18, 2022. The percentage change in the CPI–U for 2021, 2022, and 2023 is 4.7 percent, 6.8 percent, and 2.6 percent, respectively. In light of recent economic turmoil and significantly elevated inflation running throughout the U.S. economy and the global supply chain, Staff feels the May 2022 CPI–U publication is a better barometer of inflation than an earlier indicator published in January 2022.

Staff is awaiting further details from the Company regarding the discrepancy between non-labor data presented in the Company's responses to SDR 057 and 058(b). Once the Company resolves this discrepancy, Staff will use the escalation methodology previously described to calculate reasonably escalated Test Year expenses for FERC accounts 901-905 (excluding 904 – Uncollectible Accounts)[12] and then compare the escalated Base Year to the Company's proposed Test Year expense for these FERC accounts.

Q. Did Staff find any issue with customer accounting expense in the Company's application?

A. After adjusting the SDR 058(b) data with a proxy factor to bring the Base Year non-labor expense into alignment with SDR 057 non-labor expenditure date for FERC accounts 901-903 and 905, based on a comparison of escalated three-year average adjusted historical costs compared to the filed Test Year request, Staff recommends a $3.285 million reduction to FERC accounts 901-905 (excluding 904).[13]

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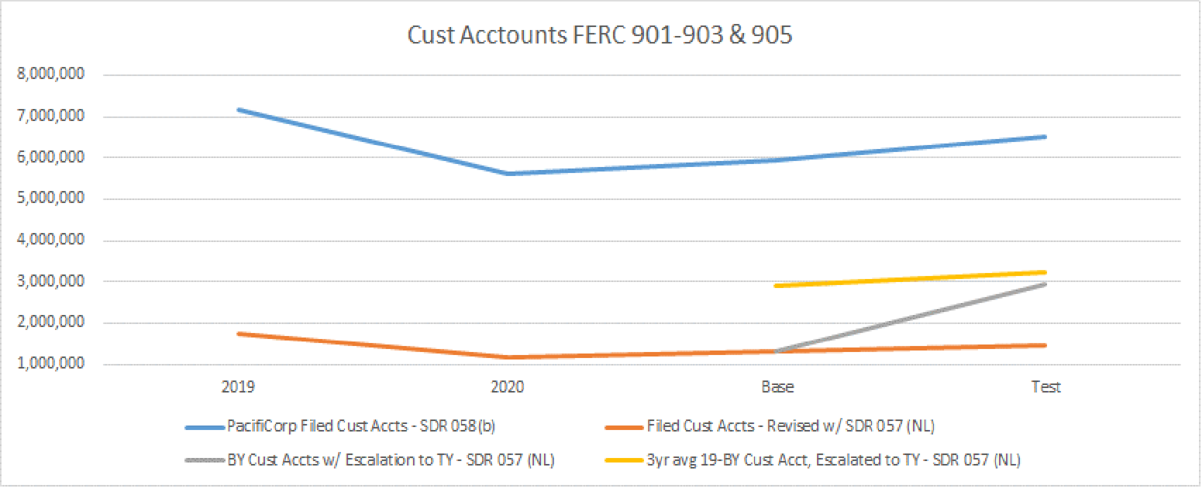
[12] See Staff Electronic Workpapers, excel file "UE 399 Staff Exhibit 1100 Issue 1 TD O&M and Cust Accts v3 Fjeldheim 6.8.22".

[13] Ibid.

Figure 2



Besides using the CPI-U in place of IHS Markit escalation factors, Staff also excluded labor from this review. Staff addresses all labor expenses as a separate issue in Staff/600, Cohen. As previously mentioned, there is pending discovery for non-labor expenses data provided in the SDRs 057 and 058(b) responses necessary to complete this analysis.

Q. Please summarize Staff's recommendations and adjustments.

A. Staff recommends a $3.285 million reduction to Customer Accounts, with a final numerical adjustment possible, pending data responses expected in a later round of testimony.

ISSUE 3. UNCOLLECTIBLE ACCOUNTS

Q. Please provide a summary of the Commission's historical treatment of uncollectible expense.

A. The amount included in a utility's Revenue Requirement for uncollectible expense is revenue sensitive because it depends on the amount of forecasted revenue. The amount of uncollectible expense included in the Revenue Requirement is a function of the test year revenue and the uncollectible rate.

The uncollectible rate is based on an average of the net-write offs, i.e., the uncollectible amounts that were written off the books, for the three years preceding test year divided by the average of the revenues for those same years. The uncollectible rate that is derived from this three-year average methodology is then multiplied by the forecast of test year revenue to determine the test year uncollectible expense for a utility's Revenue Requirement.[14] In addition, Commission Staff reviews other materials to determine the reasonableness of the rate and level of expense produced by the three-year model.

Q. Please provide a summary of the Company's filed proposal and Staff's analysis of the issue.

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[14] *See, e.g.*, *In the Matter of Avista Corporation*, UG 246, Order No. 14-015 at 3 (January 21, 2014); and *In the Matter of Avista Corporation*, UG 186, Order No. 09-422, Appendix A at 4 (October 26, 2009) (adopting stipulations for Avista general rate increase with uncollectible expense in revenue requirement based on three-year average); *but see In the Matter of Idaho Power Company*, UE 167, Order No. 05-871 (January 28, 2005) (adopting stipulation for Idaho Power Company general rate increase with uncollectible expense based on four-year average); and *In the Matter of Cascade Natural Gas Corporation*, UG 287, Order No. 15-412 (December 28, 2015) (adopting stipulation for Cascade Natural Gas general rate increase with uncollectible expense based on three-year average, removing an anomalous year).

A. The Company adjusts its actual June 2021 uncollectible accounts expense to the December 2023 pro forma period by applying the unadjusted uncollectible rate (unadjusted uncollectible accounts expense/unadjusted general business revenues) to the normalized level of general business revenues.[15] While the Company is using the correct methodology, the amount for 2021 is pending the Company's filing of its Oregon Results of Operation and 2021 FERC Form 1.[16] Staff's analysis of this issue will be updated in later testimony after fully reviewing the 2021 data.

Q. What is Staff's recommendation?

A. The Company's proposed Test Year uncollectible rate of 0.500 percent is significantly higher when compared to historical data and other regulated Oregon utilities. It does not seem reasonable to Staff to utilize uncollectible account data from a time period that includes a once in a century global pandemic in the proposed Test Year.[17] Instead, Staff recommends the Company use the uncollectible rate of 0.336 percent established in the Company's previous rate case that predates the onset of Covid-19.[18]

Staff's recommendation is based upon the Company's implementation of a temporary arrearage management plan (AMP) for COVID-19 in the Base Year

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[15] See PAC/1000, Cheung/21 at 17-23; and PAC/1002, Cheung/102.

[16] PAC filed the OR Supplement to the FERC Form 1 May 26, 2022.

[17] In NW Natural's most recent rate case filed in Docket No. UG 435, Staff, Intervenors, and the Company agreed to use the Company's uncollectible account factor from the prior rate case filing (Docket No. UG 388), thereby excluding the impact of a once in a century global pandemic on uncollectible account data in the Test Year.

[18] Commission Docket No. UE 374.

that is anticipated to ramp down in the Test Year;[19] the Commission's approval of the Company's application to defer COVID-19 costs, including customer arrearages, uncollected late payment and disconnection fees, and bad debt expenses;[20] continuing improvement in Oregon's employment outlook;[21] and current efforts by the Commission to develop new low income (LI) and low-middle income (LMI) rates that may affect the Test Year period.

Staff's recommended uncollectible rate of 0.336 percent results in a $2.046 million reduction to uncollectible expense.

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[19] Docket No. UM 2114, Order Nos 20-401 and 21-483; and the Company's Schedule 11 Residential Bill Assistance Program in Docket No. ADV 1247, approved by the Commission at the March 23, 2021, regular public meeting.

[20] PacifiCorp's deferral request for costs associated with COVID-19 in Docket No. UM 2063, Order Nos 20-375, 22-090, and 22-139.

[21] State of Oregon Employment Department – Oregon Economic Indicators (May 2022), accessed here: https://www.qualityinfo.org/.

ISSUE 4. GAINS ON SALES OF UTILITY PROPERTY

Q. Please discuss Staff's review of PacifiCorp's gains on sales of utility property.

A. Staff reviewed PacifiCorp's recent history of property sales filings before the OPUC and sent Staff data requests.

Q. How has the Commission treated PacifiCorp property sales in previous filings?

A. The Company maintains a property sales balancing account that "flows through" any net gains (or losses) to customers resulting from the sale of utility property. Sales of property of $1 million or more are contingent upon receiving Commission approval prior to a sale closing.[22]

PacifiCorp is recording the gains and losses from property sales in FERC account 421. This treatment is necessary to prevent double counting of utility gains and losses. Double counting would occur if gains and losses were included in customer base rates, while at the same time including them in a "rate tracker" mechanism that annually flows gains and losses to customers.

Q. How did Staff confirm this accounting treatment?

A. In response to Staff DR 343, the Company confirmed that any gains and losses from property sales are passed through to customers via Schedule 96, Property Sales and Balancing Account.[23]

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[22] ORS 757.480(1)(a).

[23] Company response to Staff DR 343.

Q. Should Oregon-allocated gains or losses from property sales be passed through to customers?

A. Yes. PacifiCorp demonstrated that net gains and losses are being flowed through to customers in Schedule 96.[24] Staff agrees with the Company that there should not be an adjustment in this rate case. Because there is a dedicated schedule that captures the effects of property sales outside of base rates, an adjustment in this filing would result in double counting the financial effects of property sales.

Q. Does Staff recommend any adjustment(s) to PacifiCorp Test Year expenditures to account for gains on property sales?

A. No. Since the Company's last general rate case in Docket UE 374, PacifiCorp continued to record any gains and losses related to the sales of utility property in a balancing account and is recovering them via Schedule 96, rather than through an ongoing balancing account method. Staff proposes no adjustment on this issue.

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[24] Company response to Staff DR 344.

ISSUE 5. NON-FUEL MATERIALS AND SUPPLIES

Q. Please discuss how the Company records non-fuel materials and supplies.

A. The Company utilizes FERC accounts 154 – Plant materials and operating supplies to record the bulk of their materials and supplies balances. The Company also records a small offsetting liability balance in FERC 253 – Other deferred credits for working capital deposits, which are excluded from this issue and are addressed elsewhere in Staff testimony.

Q. Please provide a summary of the Company's proposed rate treatment for this issue.

A. The Company reported $83.2 million in the Base Year and the adjusted Test Year is $81.8 million for Oregon allocated non-fuel materials and supplies, a decline of $1.4 million. The reduction to non-fuel materials and supplies continues to be attributed to the Cholla Unit 4 retirement and the subsequent removal of Cholla materials and supplies balances.[25] No other significant factors were noted by Staff.

Q. Please summarize the Commission's historical treatment of non-fuel materials and supplies in rate base.

A. The Commission typically authorizes utilities to include an allowance for non-fuel materials and supplies in rate base.[26]

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[25] Exhibit PAC/1002, Cheung/39 at 2092.

[26] In the last four rate cases for Avista Utilities, the Commission adopted stipulations that allowed materials and supplies into rate base. See: *In the Matter of Avista Corporation*, UG 246, Order No. 14-015 at 3; In the Matter of Avista Corporation, UG 284, Order No. 15-109 at 3 (April 9, 2015); In the In the Matter of Avista Corporation, UG 288, Order No. 16-076 at App. A, page 3

Q. Did Staff issue data request(s) to PacifiCorp concerning non-fuel materials and supplies inventory?

A. Yes. Staff issued DR 345 requesting additional information concerning why the Test Year is projected to decline.

Q. Did Staff review any other materials in this filing?

A. Yes. Staff reviewed the Company's response to SDR 084, Exhibit PAC/1002, Cheung/258-259; Cheung - Non Conf WPs, Excel work paper "OR GRC JAM Dec 2023 Test Period", tab "Report", rows 2017 – 2101; Cheung - Non Conf WPs, Excel work paper "8.13 – Cholla Unit 4 Retirement"; Cheung - Non Conf WPs, Excel file "B-Tabs, B13 – Materials and Supplies", and the Company's 2017–2021 Oregon annual results of operations (ROO) filed in Docket No. RE 056.

Q. Please describe Staff's analysis of this issue.

A. Staff compared a three-year rolling average against available data and noted steadily increasing balances in FERC account 154 from 2017 to June 30, 2021. See Figure 3.

(February 29, 2016); and In the Matter of Avista Corporation, UG 325, Order No. 17-344 at 3 (September 13, 2017).

Figure 3

	2017	2018	2019	2020	BY		TY
FERC 154 actuals	66,844	70,632	75,165	79,631	83,784		
3 yr avg. - rolling	70,880	70,880	70,880	75,143	76,750	76,750	76,750
Test Year							81,791

Staff was unable to identify in the Company's filing an explanation as to why materials and supply balances steadily increased in each of the last five years. From the Base Year to the Test Year, the projected balance declined from $83.2 million to $81.8 million, a $1.4 million reduction. Per notes included in Exhibit PAC/1002, Cheung/258, the Test Year decline is due to the retirement of Cholla Unit 4 in December of 2020 and the subsequent removal of materials and supplies associated with plant operations at this location on a going forward basis.[27]

Q. Does Staff have any concerns with the Company's Test Year balance?

A. In general, no.

Q. Does Staff recommend an adjustment for this issue?

A. No adjustment is recommended at this time.

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[27] PacifiCorp response to Staff DR 345 corroborates the decommissioning of Cholla 4 as the driver of this decline.

ISSUE 6. MISCELLANEOUS DEFERRED DEBITS

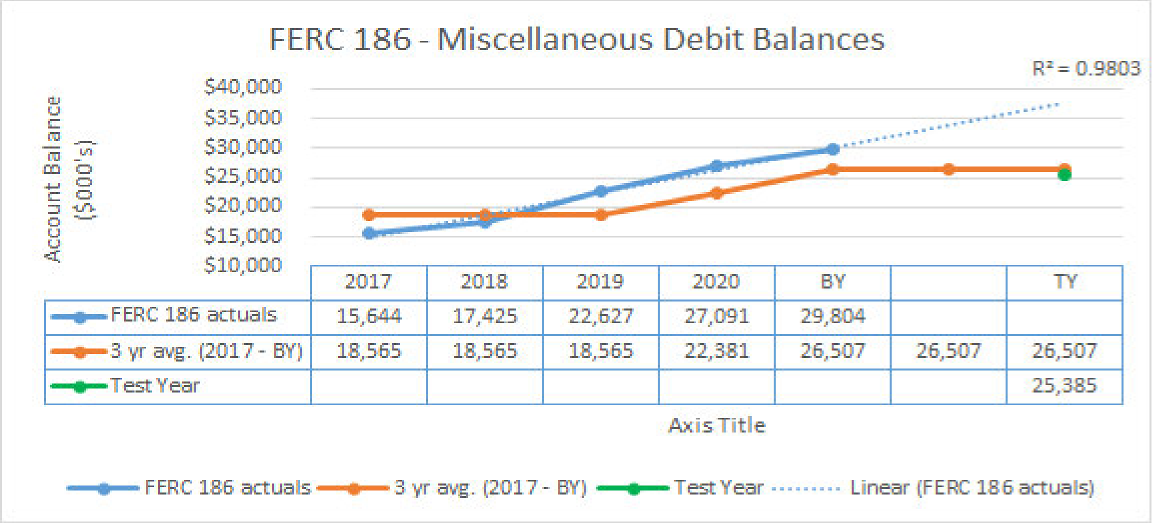
Q. What are miscellaneous deferred debits and how are they treated?

A. The Company uses FERC account 186 – Miscellaneous deferred debits to book items such as miscellaneous work in progress, maintenance prepayments, prepaid transportation and transportation reservation fees, purchased emission reduction credits and emission reduction credit impairments, and any other unusual or extraordinary expenses not included in any other accounts that are in the process of being amortized.

Q. Please describe Staff's analysis of this issue.

A. Staff reviewed Base Year and Test Year data provided in Exhibit PAC/1002, Cheung/40 at 2124-2133; Cheung - Non Conf WPs, Excel workpaper "OR GRC JAM Dec 2023 Test Period", tab "Report", rows 2244 – 2253; and Excel file "B-Tabs, B11 – Deferred Debits". Staff also reviewed four years of historical data in the Company's 2017–2021 Oregon ROO filed in Docket No. RE 056. Staff compared a three-year rolling average against available data and noted steadily increasing balances in FERC account 186 from 2017 to June 30, 2021.

Figure 4



	2017	2018	2019	2020	BY		TY
FERC 186 actuals	15,644	17,425	22,627	27,091	29,804		
3 yr avg. (2017 - BY)	18,565	18,565	18,565	22,381	26,507	26,507	26,507
Test Year							25,385

Q. Does Staff have any concerns with the Company's Test Year balance?

A. In general, no. The Company's Test Year account balance clearly trails the three-year rolling average.

Q. Does Staff recommend an adjustment for this issue?

A. No adjustment is recommended at this time.

ISSUE 7. WORKING CAPITAL

Q. What is cash working capital?

A. Cash working capital is the amount of cash needed on-hand by a public utility to pay its day-to-day operating expenses, for the time period during which the utility has provided electric service to its customers and has not yet received payment for that service. If, on average, the time difference between providing service and collecting the associated revenue exceeds the time difference between providing service and paying the associated expenses, the utility experiences a “net revenue receipt lag.” This requires funding a working cash balance. A utility experiencing a “net revenue receipt lag” requires working cash in its revenue requirement. A cash working capital allowance describes a permissible net addition to rate base to reflect borrowed or investor-supplied working cash.[28]

Q. Did the Company provide documentation to support their Test Year working capital needs?

A. Yes. PAC/100, Cheung/32 at 14-21, and Exhibit PAC/1002, Cheung/198 and 375 address the Company’s cash working capital needs. Additionally, PacifiCorp provided their 2015 lead/lag study and Cheung - Non Conf WPs, Excel workpaper “OR GRC JAM Dec 2023 Test Period”, tab “Report”, rows 2255 – 2260. According to the Company rate case filing, Oregon allocated Test Year cash working capital will decline by $108,000 (rounded) from the filed Base Year, dropping from $8.61 million to $8.50 million. This decrease is

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[28] PacifiCorp 2015 Lead/Lag Study, Tab 1 – Introduction – OR 2015, pg. 1

driven by a slight decline of $11.4 million in the Company's total calculated average daily cost of service in the Test Year; and, is attributed to a significant decline in Test Year Federal and State income taxes that is partially offset by a large increase in total O&M expenses.[29] The Company continues to use the 2015 Lead/Lag Study and the lag days remain unchanged at 3.45 days.[30]

Q. Does Staff have any concerns with the Company's lead/lag study?

A. The financial data utilized in the lead/lag study was from 2015 and is seven years out of date. Otherwise, Staff's review of the Company's lead/lag study calculations did not reveal any errors in the calculations performed.

Q. Besides cash working capital, does the Company identify any other working capital needs?

A. Yes. In in addition to cash working capital, the Company identifies several other areas of working capital recorded in FERC accounts 143 – Other accounts receivable; 230 – Asset retirement obligations; 232 – Accounts payable; 253 – Other deferred credits; and 254 – Other regulatory liabilities.[31] For the Test Year, Oregon allocated other working capital will decline from $5.38 million to $4.84 million, a $540 thousand decrease. This decline is primarily driven by an increased miscellaneous deferred credit recorded in

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[29] Cheung – Non Conf WPs, Excel file "OR GRC Jam Dec 2023 Test Period", tab "Report", rows 135-137.

[30] Docket No. UE 399, Exhibit PAC/1002, Cheung/199 and Excel file "OR GRC Jam Dec 2023 Test Period", tab "CWC", row 22.

[31] Cheung - Non Conf WPs, Excel workpaper "OR GRC JAM Dec 2023 Test Period", tab "Report", rows 2262 – 2278.

FERC account 253.3 totaling negative $2.33 million in the Test Year compared to negative $1.79 million in the Base Year.

Q. What is the total change in the Company Test Year working capital?

A. In aggregate, total Company working capital will decline $2.8 million from the Base Year to the Test Year, with the Oregon allocated CWC declining $648 thousand to $13.3 million.

Q. Did Staff perform any additional analysis on other working capital?

A. Yes. Staff performed a comparison of a rolling three-year average of FERC accounts 131, 135, 141, 143, 232, 253, and 254 using the Company's response to SDR 058 and the Base Year and Test year data provided in Cheung - Non Conf WPs, Excel workpaper "OR GRC JAM Dec 2023 Test Period", tab "Report", rows 2253 – 2278.

Q. Does Staff recommend an adjustment to working capital?

A. No dollar adjustment is recommended at this time. Due to the relatively old age of the 2015 Lead/Lag Study submitted in the current and prior rate case, Staff recommends the Company be required by the Commission to file an updated Lead/Lag Study with its next general rate case filing.

ISSUE 8. MISCELLANEOUS RATE BASE

Q. Which FERC account(s) does the Company use to record miscellaneous rate base?

A. Based on information provided in Cheung – Non Conf WPs, B - tabs, Excel file “B15 - Miscellaneous Rate Base”, the Company is recording Test Year miscellaneous rate base transactions in the following FERC accounts:

114 - Electric plant acquisition adjustments, 115 - Accumulated provision for amortization of electric plant acquisition adjustments (Major only), 128 - Other special funds (Major only), 165 – Prepayments, and 253 – Other deferred credits.

Q. Does the Company use any other FERC accounts to record miscellaneous rate base?

A. Yes. In Cheung – Non Conf WPs, Excel file “8.15 - Miscellaneous Rate Base”, tab “8.15.1”, the Company also uses FERC accounts 151 – Fuel stock (Majors only), 186 - Miscellaneous deferred debits, 228.1-4 – Accumulated provision for 1) property insurance; 2) injuries and damages; 3) pensions and benefits; and 4) miscellaneous operations, and 254 – Other regulatory liabilities. Staff addresses FERC accounts 151,186, and 228.1-4 elsewhere in testimony and is excluded from discussion here. FERC account 254 primarily addresses Oregon deferred taxes and post-retirement benefits, which are being investigated by other Staff and are not included here.

Q. Please describe Staff’s analysis of this issue.

A. Staff analyzed three years of historical actuals data,[32] with a focus on PacifiCorp's Excel workpaper "OR GRC JAM Dec 2023 Test Period", tab "Report", rows 2136-2140 & 2142-2146 & 2226-2232 & 2303-2306 & 2335-2344. Due to the Company's use of expenditure data for the 12 months prior to June 30, 2021, certain components of various FERC accounts were skewed in the Company's Base Year and Test Year dollar amounts compared to the prior two years. For example, prepaid property taxes were $0 in the Base Year and Test Year. However, the average property tax prepayment for 2017-2018 was approximately $1.48 million. Prepayments are primarily a payment timing issue, and the Company made adjustments elsewhere to the Test Year to reflect their projected property tax expense.[33]

Staff noted, in aggregate, the various asset components for "Miscellaneous Rate Base" appear reasonable. The liability components of FERC account 228.3 – Accumulated provision for pension liability saw a significant decline of $20.2 million in the Test Year. However, pension costs and liabilities are a separate issue being reviewed by other Staff and are not contemplated in this analysis.

Q. Does Staff propose an adjustment to any of the FERC accounts contemplated in "Miscellaneous Rate Base"?

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[32] 2017 - 2020 data obtained via the Company's ROO filings in Docket No. RE 56; Excel files "B15 - Miscellaneous Rate Base" provided actuals thru June 30, 2021. The Company response to SDR 057 and "OR GRC JAM Dec 2021 Test Period", tab "Report", columns I – N provide additional details for the Base Year and the Test Year.

[33] See Company electronic workpapers "7 – Tax", and Excel file "OR GRC JAM Dec 2023 Test Period", tab "Report", columns I – N, row 1260, and Cheung – Non Conf WPs, Excel file "7.2 - Property Tax Expense".

A. Staff proposes no adjustment at this time.

ISSUE 9. CUSTOMER ADVANCES FOR CONSTRUCTION

Q. What is a customer advance payment for construction (CAC)?

A. This occurs when a utility customer advances a cash payment to a utility to be used in the construction of utility facilities on a customer's behalf. These advances are refundable to the customer and are usually governed by contract provisions associated with the advance.[34] The utility records the receipt of cash (an asset) and records an offsetting entry in customer advances for construction (a liability). CAC is recorded in FERC account 252. Once an asset is constructed and placed in service, revenues from the newly constructed facility are paid to the customer, thereby refunding the construction advance back to the customer. As the construction advance is repaid, the balance in the customer advance account is reduced and a like dollar amount is recorded in the revenues account.

Q. What purpose does CAC serve?

A. CAC is a means of financing construction of utility facilities/plant to serve a dedicated customer(s) need/load. This can benefit a utility by reducing financing costs for a capital project while increasing revenues with the plant addition. Ratepayers can benefit by avoiding paying increased rates associated with financing and construction costs associated with plant that will benefit the customer(s) that provide CAC funds to the utility.

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[34] Financial Accounting Institute – Glossary of Utility Finance and Accounting Terms, accessed here: http://financialaccounting.com/glossary.pdf

Q. What analysis did Staff perform?

A. Staff reviewed PacifiCorp's Base Year and Test Year data contained in PacifiCorp's Excel workpaper "OR GRC JAM Dec 2023 Test Period", and PacifiCorp's electronic workpaper Cheung Non Conf WPs, Excel file "B-Tabs", tab "B20 - Customer Advances BY". Because CAC represents a voluntary process whereby a customer can advance funds of varying amounts at any time for use in plant or facility construction, trend analysis of past, current, and projected customer advances for construction advance balances becomes problematic in that the past may not be predictive of future projects and account balances.

That said, Staff used a rolling three-year average, beginning with 2019 thru the Base Year, to test the relative "reasonableness" of the Company's Test Year projection. Staff's calculated Oregon allocated rolling three-year average is negative $24.5 million and the Company's Oregon allocated Test Year projection is negative $23.0 million. The Company's projection differs from Staff's three-year average calculation by $1.4 million and is within one standard deviation of the three-year mean.[35] Please see Figure 5.

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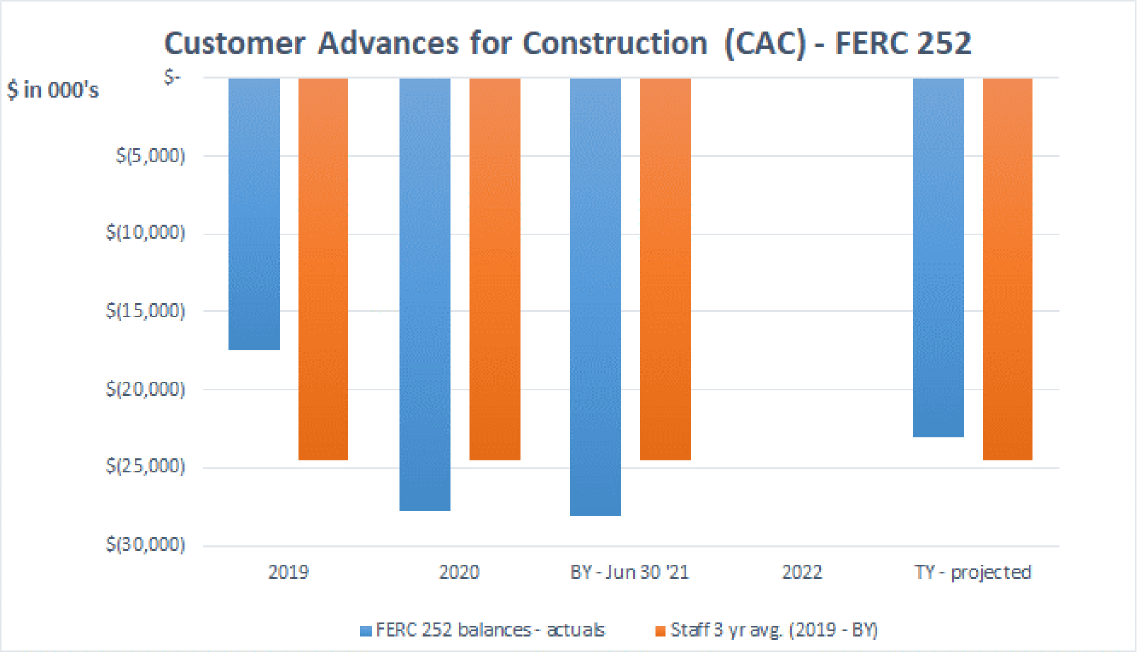
[35] Staff used a sample population assumption for the standard deviation calculation. There are more than three years of data for CAC, Staff's use of a three average is effectively a sample of the larger population size. Staff's calculated sample standard deviation (n-1) is $6.049 million.

Figure 5



Q. Does Staff propose adjusting the Company's Test Year CAC?

A. No. Staff proposes no adjustment at this time.

ISSUE 10. CYBER SECURITY

Q. Did the Company discuss the topic of cybersecurity addressed in this rate case filing?

A. No. Cybersecurity was not specifically identified in the rate case filing. To Staff's knowledge, there is no specific mention of IT or cybersecurity capital projects or ongoing operating expenses in the Company's rate request. However, Staff has an active interest in this issue and submitted several DRs to the Company.[36]

Q. Does Staff have any specific concerns related to this issue?

A. Staff is not aware of any pressing concerns at this time. This case is an opportunity for Staff to investigate and better understand elements of the Company's cybersecurity posture and to identify what resources the Company is committing to protect their physical and digital infrastructure as well as ratepayers personal data, which will help inform Staff assessment of necessity and prudence of such investments in the future.

Q. What analysis did Staff perform?

A. Staff reviewed SDR 057 for evidence of information technology (IT) and cybersecurity expenditures in the Base Year and issued DRs 380 - 384.

Q. Do expenses recorded in FERC accounts 569.1 and 569.2 include cybersecurity expenses?

A. Pursuant to the definitions and instructions provided in the Code of Federal Regulations (CFR), Title 18, Chapter I, Subchapter C, Part 101 – Uniform

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[36] Staff DRs 375-379.

System of Accounts (USOA), there is no specific FERC account dedicated to cyber security expenditures. As such, proper recording of cybersecurity expenses by regulated utilities is somewhat subjective, within the usual scope of FERC accounts. Staff also issued DRs 377 and 378 requesting additional data regarding historical and projected Test Year cyber security spending.

Table 1 – Cybersecurity Plant and Expense History[37]

Year	*Company Cybersecurity - Expense*	*Oregon Allocation*	*$ Change Year-to-Year*	*% Change Year-to-Year*
2017	*$2,409,964*	*$653,266*	*-*	*-*
2018	*$4,012,869*	*$1,097,016*	*$443,750*	*67.9%*
2019	*$4,287,278*	*$1,180,832*	*$83,816*	*7.6%*
2020	*$4,187,166*	*$1,178,391*	*($2,441)*	*-0.2%*
2021	*$4,927,372*	*$1,379,260*	*$200,869*	*17.0%*

Year	*Company Cybersecurity - Capital*	*Oregon Allocation*	*$ Change Year-to-Year*	*% Change Year-to-Year*
2017	*$75,345*	*$20,473*	*-*	*-*
2018	*$1,786,899*	*$480,265*	*$459,792*	*2245.8%*
2019	*$634,635*	*$172,295*	*($307,970)*	*-64.1%*
2020	*$918,736*	*$249,649*	*$77,354*	*44.9%*
2021	*$1,175,416*	*$317,259*	*$67,610*	*27.1%*

Q. How much does the Company spend annually on cybersecurity?

A. Based on the Company's response to Staff DR 377, the Company spent an average of $1.1 million a year for cybersecurity expenses and an average of $248 thousand a year in cybersecurity equipment/additional plant during the 2017–2021 period.

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[37] PacifiCorp Response to Staff DR 377.

Q. Does Staff recommend an adjustment for cybersecurity spending in this filing?

A. No.

ISSUE 11. INFORMATION TECHNOLOGY (IT) COSTS

Q. Please summarize PacifiCorp's "IT Projects" included in this rate filing.

A. In PacifiCorp's response to Staff DR 383, the Company identified 11 individual IT projects exceeding $1.0 million, and consist of $15.8 million in combined IT software and hardware capital additions. Additionally, there was an additional $1.9 million blanket amount for IT project additions costing less than $1.0 million. Based on PacifiCorp's response to Staff DR 383, there were no IT acquisitions solely assigned to Oregon, all IT additions in this filing occurred on a Company basis and were allocated amongst the various operational jurisdictions of PacifiCorp. Oregon's allocation share for IT projects is 27.215 percent.

Q. Did the Company provide any written testimony in the initial filing concerning significant IT projects or procurements?

A. Generally, no. The Company provided a limited reference to the "AMI – IT Comm Network" IT project in PAC/1002, Cheung/237. There were also IT projects added to Test Year plant noted in the Company's non-confidential Excel workpaper "8.4 – Pro Forma Plant Additions and Retirements" for intangible plant additions.

Q. How did Staff review and analyze IT Projects?

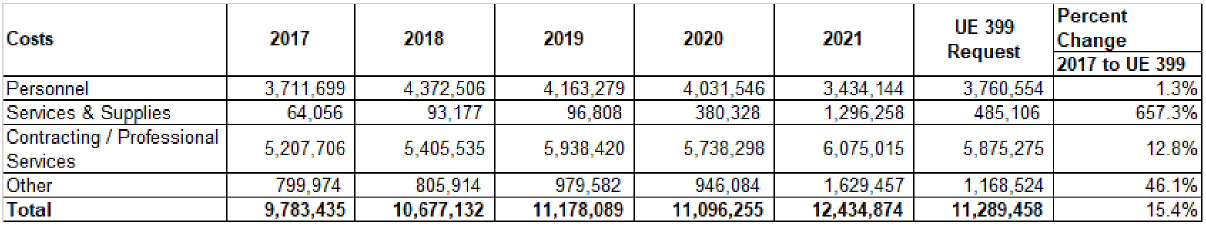
A. Staff first reviewed Base Year expenditures in the Company's response to Staff SDR 057 for reasonableness and prudence. Staff also reviewed the IT project descriptions and justification narratives provided in the Company's response to

DR 383 and reviewed the Company's general procurement policy and procedures overview.[38]

Q. Please provide an overview of the Company's overall IT spending.

A. Oregon's allocated IT plant spending has steadily increased over the past five years, growing 15.4 percent from the $9.8 million spent in 2017 to the $11.3 million Test Year requested amount. Staff noted the significant spike in the beginning in 2020 for services and supplies expense. This increase is generally in line with the onset of the COVID-19 pandemic and the Test Year request appears to be in-line with the pandemic tapering off.

<u>Table 2 - PacifiCorp IT Expenditures</u>[39]



Costs	**2017**	**2018**	**2019**	**2020**	**2021**	**UE 399 Request**	**Percent Change 2017 to UE 399**
Personnel	3,711,699	4,372,506	4,163,279	4,031,546	3,434,144	3,760,554	1.3%
Services & Supplies	64,056	93,177	96,808	380,328	1,296,258	485,106	657.3%
Contracting / Professional Services	5,207,706	5,405,535	5,938,420	5,738,298	6,075,015	5,875,275	12.8%
Other	799,974	805,914	979,582	946,084	1,629,457	1,168,524	46.1%
Total	**9,783,435**	**10,677,132**	**11,178,089**	**11,096,255**	**12,434,874**	**11,289,458**	15.4%

Q. Does Staff recommend an adjustment to IT spending?

A. No. Staff did not identify any expenditures or IT capital additions that were excessive or imprudent.

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[38] PAC response to Staff DR 384.

[39] PAC response to Staff DR 380, Excel file attachment "OPUC 380 Attach".

ISSUE 12. LEGAL EXPENSES AND FEES

Q. Please summarize why legal expenses are of interest to Staff.

A. The Company has been named in at least two separate lawsuits related to several of the 2020 Labor Day fires in Oregon. Additionally, significant outlays for legal expenses and fees could be considered a proxy for imprudent or reckless behavior on the part of the Company.

Q Does Staff have any concerns regarding PacifiCorp's legal expenses and fees?

A. Yes. In the Company's response to Staff SDR 057, several of the Excel files pertaining to transmission and distribution FERC accounts were designated confidential. During Staff's review of FERC accounts 560, 566, 570, 571, 588, 592, 593, and 594, Staff noted that all expenditure descriptions and dollar amounts associated with legal expenses and fees were redacted and zeroed out of the Excel data files. The Company has not elaborated as to why this information needed to be redacted from the SDR 057 response. Staff subsequently issued DRs 349 and 350 requesting detailed descriptions and expenditure data for the Company's legal expenses, on a system basis and an Oregon allocated basis.

In the Base Year, PacifiCorp booked $42 thousand in net expenses to the income statement FERC account 426.5 – Other deductions, $2.1 million to various FERC 500 series accounts for transmission and distribution O&M expenses, and $8.8 million to various FERC 900 series A&G accounts. Staff notes there were also numerous expenditures entries that were later reversed out, resulting is a net $0 expense. Based on PacifiCorp's response to Staff DR 339(c), these reversing accounting entries occur when the Company transfers operating expenses associated with capital projects from an operating expense FERC account to a capital/plant FERC account. On this basis, it appears that PacifiCorp also capitalized $82 thousand associated with FERC 400 series accounts, $6.5 million for FERC 500 series accounts, and $14.8 million for FERC 900 series accounts.[40] Of the suspected capitalized legal fees and expenses, 420 transaction entries totaling negative $2.9 million lack a description for the individual expenditures.

Q. What does Staff recommend?

A. Due to a lack of supporting information and transaction details, Staff recommends a $2.9 million reduction to Test Year plant.

Q. Does this conclude your testimony?

A. Yes.

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[40] PAC response to Staff DR 349, Excel file attachment "OPUC 349 Attach".

CASE: UE 399
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualifications Statement

June 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME:	Brian Fjeldheim
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Science, Business Accountancy Regis University, Denver, CO Bachelor of Science, Aviation Technology Metropolitan State College of Denver, Denver, CO

EXPERIENCE:

I have been employed as a Senior Financial Analyst by the Oregon Public Utility Commission since May of 2018 in the Rates, Finance, and Audit Division. I currently perform a range of financial analysis duties related to natural gas and electric utilities, with a focus on rate case, operational audit, and annual Purchased Gas Adjustment (PGA) filings. I have participated in utility general rate cases and power cost filings in the following dockets: Cascade Natural Gas – UG 347, Avista Utilities – UG 366, NW Natural – UG 388, PacifiCorp – UE 374, Avista Utilities – UG 389, Cascade Natural Gas – UG 390, PacifiCorp – UE 390, PGE – UE 391, PGE – UE 394, Avista Utilities – UG 433, NW Natural – UG 435, PacifiCorp – UE 399, PacifiCorp – UE 400, and PGE – UE 402.

I have nine years of professional level financial analysis and accounting experience. I was previously employed as a Budget and Fiscal Analyst with the Oregon Department of Justice (DOJ), where I was responsible for the budget build and ongoing budget execution of four legal divisions with 165 staff members and a biennial budget of $75 million. Prior to DOJ, I was employed as a Senior Budget Analyst with the Oregon Department of Administrative Services (DAS) and was responsible for the budget build, ongoing budget execution and cash flow analysis for the state data center with a biennial budget of $165 million. Prior to DAS, I worked as a Financial Analyst for the Insurance Division of the Department of Consumer and Business Services (DCBS), where I performed financial analysis and solvency surveillance of nine Oregon insurers with annual revenues of $1.4 billion and assets of $1.1 billion.

CASE: UE 399
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1102 –

PacifiCorp Responses to Staff Data Requests

Exhibits in Support
Of Opening Testimony

June 22, 2022

Docket No: UE 399

UE 399 / PacifiCorp
April 06, 2022
Standard Data Request – OPUC 058 - 1st Supplemental

Standard Data Request – OPUC 058

Please provide a separate table in Excel for each subpart:

(a) For all FERC Accounts, please provide all of the information in the format as shown in Attachment 58 A or B2. If the requested information is not relevant to the Company's operations, please enter "N/A" in the appropriate cell.

(b) Please provide the same information requested in a. above except exclude Labor Expense, from all entries.

1st Supplemental Response to Standard Data Request – OPUC 058

Further to the Company's response to Standard Data Request - OPUC 058 dated March 1, 2022, the Company provides the following supplemental information responsive to subpart (b):

Referencing Attachment OPUC 058-2, the Company now provides Attachment OPUC 058-2 1st Supplemental which removes labor expense from FERC Account 926 for all periods. Please also refer to the Company's response to OPUC Data Request 189.

Sent – March 1, 2022
Response to OPUC 058

(a) Please refer to Attachment OPUC 058-1 which provides a summary of all FERC accounts on a total-company and Oregon-allocated basis for calendar years 2019 and 2020, the Base Year, and the Test Year.

(b) Based on the December 10, 2021 joint discussion held on Zoom between representatives of the Company and Public Utility Commission of Oregon (OPUC) staff regarding this Standard Data Request – OPUC 058 in the prior Oregon general rate case (GRC), docket UE 374, the Company submits this response to Standard Data Request – OPUC 058 in this current GRC in compliance with the December 10, 2021 joint discussion as follows:

Please refer to Attachment OPUC 058-2 which provides a summary of non-labor operations and maintenance expenses (FERC Account 500 through FERC Account 935) on a total-company and Oregon-allocated basis for calendar years 2019 and 2020, the Base Year, and the Test Year.

UE 399 / PacifiCorp
April 06, 2022
Standard Data Request – OPUC 058 - 1st Supplemental

The Company is unable to provide the requested information for the balance sheet accounts as the detailed records are not available for the entirety of the assets' lives.

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 336

OPUC Data Request 336

Operations and Maintenance (O&M) Expenses - Regarding PacifiCorp's Excel work paper "OR GRC JAM Dec 2021 Test Period", tab "Report", rows 2195-2221, columns J and N, please explain:

(a) Please explain the $238 thousand increase in Test Year FERC 561 compared to the Base Year.

(b) Please explain the $3.021 million increase in Test Year FERC 565NPC compared to the Base Year.

(c) Please explain the $1.192 million decrease in Test Year FERC 566 compared to the Base Year.

(d) Please explain the $608 thousand increase in Test Year FERC 571 compared to the Base Year.

(e) Please explain the $375 thousand increase in Test Year FERC 587 compared to the Base Year.

(f) Please explain the $26.292 million increase in Test Year FERC 593 compared to the Base Year. In the explanation, please describe the primary factors driving the Test Year increase.

(g) Please explain the $482 thousand increase in Test Year FERC 594 compared to the Base Year.

(h) Please explain the $375 thousand increase in Test Year FERC 587 compared to the Base Year.

Response to OPUC Data Request 336

For additional information on the each of the increases and decreases referenced, please refer to the direct testimony of Company witness, Sherona L. Cheung, PAC/1000, Exhibit PAC/1002 – Oregon Results of Operations – December 2023, and the Company's associated revenue requirement adjustment work papers provided at the time of filing.

(a) Please refer to Attachment OPUC 336.

(b) Please refer to Attachment OPUC 336. FERC 565NPC reflects exclusively net power costs (NPC) amounts for which recovery is not being requested in this general rate case. Please refer to the Company's 2023 Transition Adjustment Mechanism, docket UE 400, for details on NPC.

(c) Please refer to Attachment OPUC 336.

(d) Please refer to Attachment OPUC 336.

(e) Please refer to Attachment OPUC 336.

(f) Please refer to Attachment OPUC 336. The primary driver is the increase for the projected Wildfire operations and maintenance distribution expenses. Also, please refer to Ms. Cheung's direct testimony, Exhibit PAC/1000 pages 11 and 23, and the direct testimony of Company witness, Allen Berreth, Exhibit PAC/700.

(g) Please refer to Attachment OPUC 336.

(h) This is a duplicate request. Please refer to the Company's response to subpart (e) above.

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 337

OPUC Data Request 337

Customer Accounts - Regarding PacifiCorp's response to Staff Standard Data Request 057, Excel file "Attach OPUC 057 FERC 901":

(a) Please explain why Utah and Wyoming profit center metering expenses totaling $13,788.83 are apportioned to Oregon customers.

(b) Please explain why most of the Utah and Wyoming profit center entries are negative/reversed out of FERC 901.

Response to OPUC Data Request 337

(a) Cost allocation is made in accordance with the 2020 Inter-Jurisdictional Allocation Methodology (2020 Protocol). Cost allocation is not dictated by profit center, but rather the nature of the expense. Expenses that are initiated by employees reporting into any specific profit center, can result in expenses that are considered system costs for allocation purposes under the 2020 Protocol, so long as the expenses meet the criteria as agreed upon in the 2020 Protocol. Costs recorded in FERC Account 901, regardless of initiating profit center, if they pertain to total system customer related expenses, would be system allocated to all states. Costs that are directly caused by any specific state, would subsequently be situs assigned to that state. For details on the allocation methodology, please refer to the Company's response to OPUC Data Request 187, specifically Attachment OPUC 187, which provides an extract from the 2020 Protocol, specifically Appendix B.

(b) Regardless of profit centers, credits in FERC Account 901, primarily represent accrual reversals, corrections or amounts moving to capital. Accrual reversals are identified as "AC" document types found in the 5xxxxx series of accounts. The capital surcharge accounts in the 690xxx series, show movement of capital amounts to FERC Account 107 (Construction Work In Progress).

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 338

OPUC Data Request 338

Customer Accounts - Regarding PacifiCorp's response to Staff Standard Data Request 057, Excel file "Attach OPUC 057 FERC 902":

(a) Please explain why 3,449 line entries with Allocation Codes "OR" and "CN" totaling $244,075.79 lack Supplier Numbers and Supplier Names.

(b) Please provide the missing supplier information for these transactions. If this information is not readily available, please explain why this information cannot be provided.

Response to OPUC Data Request 338

(a) The amount of $244,075.79 represents Oregon's allocated share of costs that do not have a supplier number and/or supplier name. These lines pertain to fuel card transactions, accruals, refund checks, material overhead assessments, purchase-card/credit card transactions and amounts transferred to capital projects. Only transactions which are vendor invoices will have a "Supplier Number" and "Supplier Name".

(b) This information is not available as previously noted in the above response. Any vendor information used by a company issued credit card is maintained in separate modules outside the SAP accounting system.

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 339

OPUC Data Request 339

Customer Accounts - Regarding PacifiCorp's response to Staff Standard Data Request 057, Excel file "Attach OPUC 057 FERC 903":

(a) Please explain why 11,648 line entries with Allocation Codes "OR" and "CN" totaling negative $4,385,862.14 lack Supplier Numbers and Supplier Names.

(b) Please provide the missing supplier information for these transactions. If this information is not readily available, please explain why this information cannot be provided.

(c) Please explain why the "OR" and "CN" entries net to a negative total.

Response to OPUC Data Request 339

(a) The $4.4 million represents Oregon's allocated share of costs that do not have a supplier number and/or supplier name. These lines pertain to fuel card transactions, accruals, refund checks, material overhead assessments, surcharges and purchase-card/credit card transactions and amounts transferred to capital projects. Only transactions which are vendor invoices will have a "Supplier Number" and "Supplier Name".

(b) This information is not available as noted in the Company's response to subpart (a) above. Any vendor information used by a company issued credit card is maintained in separate modules outside the SAP accounting system. Accruals, surcharges and/or assessments do not directly pertain to suppliers and therefore is not available.

(c) The credits represent amounts moving costs to capital projects.

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 340

OPUC Data Request 340

Uncollectible Accounts - For each calendar years 2016 through 2021, please provide on a total company and Oregon-allocated basis:

(a) The total actual net write-off related to uncollectible customer accounts, the related general business revenues, and the uncollectible rate.

(b) Energy assistance applied to customer's accounts (e.g., LIEAP and other public funds, outside agency funds, internal company funds of shareholder/customer voluntary funds, other, etc.).

(c) Total amount of funds received for energy assistance. Please include the FERC account number(s), account title, account description, and GL account for which said funds were recorded to.

(d) Total non-payment disconnections.

(e) The calendar year FERC account 904 uncollectible expense.

(f) The amount that was turned over to a collection agency.

(g) The amount eventually recovered by PacifiCorp through use of a collection agency.

(h) The collection agencies fees charged to and paid by PacifiCorp, and average percent of recoveries paid as fees.

Response to OPUC Data Request 340

(a) Please refer to Attachment OPUC 340-1 for total-company and Oregon-allocated net write-off related to uncollectible customer accounts, retail revenues and uncollectible rates. Note: calendar year 2021 information will be provided after the December 31, 2021 Oregon Results of Operations (ROO) has been filed with the Public Utility Commission of Oregon (OPUC) in early May 2022.

(b) Energy assistance received from all sources and applied on customer's accounts on total-company and Oregon-allocated bases from 2016 through 2021 is provided in the table below:

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 340

Calendar Year	Total Company	Oregon
2016	$ 24,013,605	$ 13,164,805
2017	$ 24,295,744	$ 13,790,385
2018	$ 25,331,367	$ 13,456,519
2019	$ 26,175,382	$ 13,884,805
2020	$ 30,012,050	$ 13,853,993
2021	$ 37,028,418	$ 19,408,852

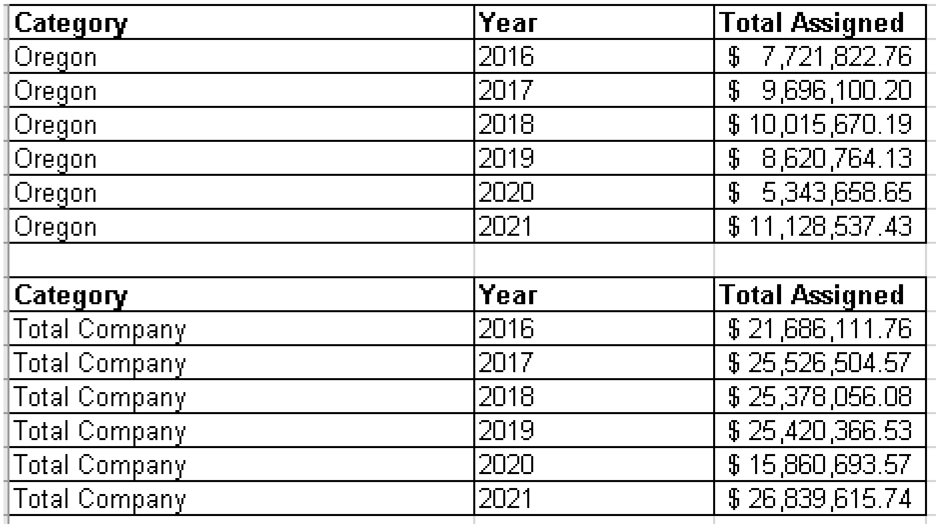
(c) Please refer to Attachment OPUC 340-2.

(d) Total non-payment disconnections is provided in the table below:

Year	Oregon	Total PacifiCorp
2016	8,904	27,368
2017	6,812	22,941
2018	16,015	31,845
2019	20,671	33,448
2020	4,602]	9,560
2021	2,015	6,313

(e) Please refer to the Company's response to subpart (a) above for inclusion of calendar year 2016-2021 FERC Account 904 uncollectible expense.

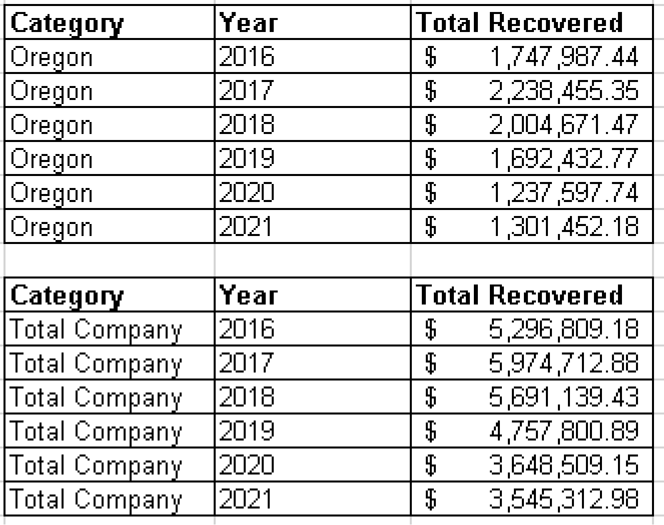
(f) The amount assigned to collection agencies is provided below:



Category	Year	Total Assigned
Oregon	2016	$ 7,721,822.76
Oregon	2017	$ 9,696,100.20
Oregon	2018	$ 10,015,670.19
Oregon	2019	$ 8,620,764.13
Oregon	2020	$ 5,343,658.65
Oregon	2021	$ 11,128,537.43

Category	Year	Total Assigned
Total Company	2016	$ 21,686,111.76
Total Company	2017	$ 25,526,504.57
Total Company	2018	$ 25,378,056.08
Total Company	2019	$ 25,420,366.53
Total Company	2020	$ 15,860,693.57
Total Company	2021	$ 26,839,615.74

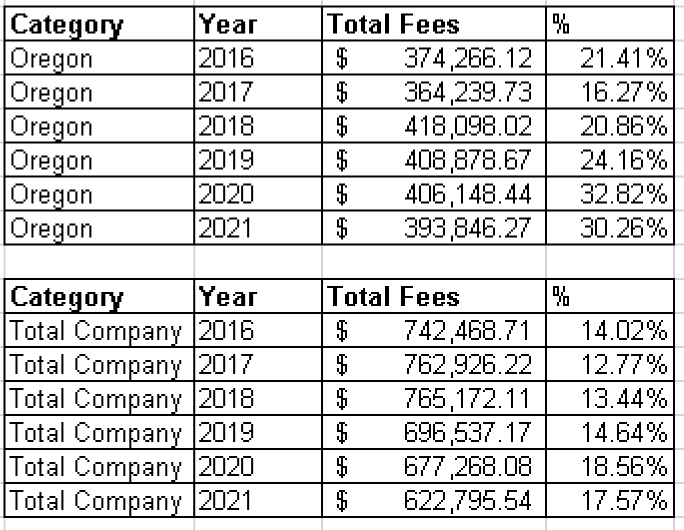
(g) The amount eventually recovered by PacifiCorp through the use of a collection agency is provided below. The dollars assigned in 2015 through 2019 are still actively being worked and collected. Collection efforts will cease once the statute of limitations has been met. The recoveries mentioned below are reported in the year they were assigned to a collection agency:



Category	Year	Total Recovered
Oregon	2016	$ 1,747,987.44
Oregon	2017	$ 2,238,455.35
Oregon	2018	$ 2,004,671.47
Oregon	2019	$ 1,692,432.77
Oregon	2020	$ 1,237,597.74
Oregon	2021	$ 1,301,452.18

Category	Year	Total Recovered
Total Company	2016	$ 5,296,809.18
Total Company	2017	$ 5,974,712.88
Total Company	2018	$ 5,691,139.43
Total Company	2019	$ 4,757,800.89
Total Company	2020	$ 3,648,509.15
Total Company	2021	$ 3,545,312.98

(h) The collection agencies fees charged to and paid by PacifiCorp, and average percent of recoveries paid as fees are provided below. All of the recoveries that a collection agency collects for PacifiCorp will be associated with a collection agency fee, unless the customer comes back online with PacifiCorp or the debt is paid in full within 15 days of assignment to a collection agency:



Category	Year	Total Fees	%
Oregon	2016	$ 374,266.12	21.41%
Oregon	2017	$ 364,239.73	16.27%
Oregon	2018	$ 418,098.02	20.86%
Oregon	2019	$ 408,878.67	24.16%
Oregon	2020	$ 406,148.44	32.82%
Oregon	2021	$ 393,846.27	30.26%

Category	Year	Total Fees	%
Total Company	2016	$ 742,468.71	14.02%
Total Company	2017	$ 762,926.22	12.77%
Total Company	2018	$ 765,172.11	13.44%
Total Company	2019	$ 696,537.17	14.64%
Total Company	2020	$ 677,268.08	18.56%
Total Company	2021	$ 622,795.54	17.57%

UE 399 / PacifiCorp
May 6, 2022
OPUC Data Request 340 – 1st Supplemental

OPUC Data Request 340

Uncollectible Accounts - For each calendar years 2016 through 2021, please provide on a total company and Oregon-allocated basis:

(a) The total actual net write-off related to uncollectible customer accounts, the related general business revenues, and the uncollectible rate.

(b) Energy assistance applied to customer's accounts (e.g., LIEAP and other public funds, outside agency funds, internal company funds of shareholder/customer voluntary funds, other, etc.).

(c) Total amount of funds received for energy assistance. Please include the FERC account number(s), account title, account description, and GL account for which said funds were recorded to.

(d) Total non-payment disconnections.

(e) The calendar year FERC account 904 uncollectible expense.

(f) The amount that was turned over to a collection agency.

(g) The amount eventually recovered by PacifiCorp through use of a collection agency.

(h) The collection agencies fees charged to and paid by PacifiCorp, and average percent of recoveries paid as fees.

1st Supplemental Response to OPUC Data Request 340

Further to the Company's response to OPUC Data Request 340 dated April 28, 2022, the Company provides the following additional information responsive to subpart (a):

(a) Please refer to Attachment OPUC 340 1st Supplemental which provides total-company and Oregon-allocated net write-off related to uncollectible customer accounts, retail revenues and uncollectible rates for calendar year 2021.

OR - UE 374
OPUC 340

Attachment OPUC 340-1

Net write-off, related revenue and uncollectible rates
CY 2016 - CY 2021

Calendar	Net Write-off		Related Revenue		Uncollectible Rate	
Year	Oregon	Total PacifiCorp(2)	Oregon	Total PacifiCorp(3)	Oregon	Total PacifiCorp
2021(1)						
2020	$ 6,654,067	$ 18,138,836	$ 1,293,711,531	$ 4,939,332,097	0.5143%	0.3672%
2019	$ 4,634,594	$ 13,068,251	$ 1,270,397,389	$ 4,697,555,109	0.3648%	0.2782%
2018	$ 4,586,107	$ 11,655,692	$ 1,284,977,555	$ 4,656,340,714	0.3569%	0.2503%
2017	$ 6,281,056	$ 15,424,209	$ 1,317,990,019	$ 4,851,077,383	0.4766%	0.3180%
2016	$ 3,985,042	$ 12,228,903	$ 1,268,559,437	$ 4,866,606,600	0.3141%	0.2513%
2015	$ 3,799,403	$ 10,227,550	$ 1,265,741,623	$ 4,810,600,630	0.3002%	0.2126%

Notes

(1) This data is not yet available and will be provided after the December 31, 2021 Oregon Results of Operations have been filed.

(2) As taken from PacifiCorp's FERC Form No. 1, Page 320-323, Line 162, Account 904 Uncollectible Accounts.

(3) As taken from PacifiCorp's FERC Form No. 1, Page 300, Line 10, Total Sales of Electricity for retail customers.

OR - UE 399
OPUC 340, 1st Supp

Attachment OPUC 340 -1, 1st Supplemental

Net write-off, related revenue and uncollectible rates
CY 2016 - CY 2021

Calendar	Net Write-off			Related Revenue			Uncollectible Rate	
Year	Oregon	Total PacifiCorp[2]		Oregon	Total PacifiCorp[3]		Oregon	Total PacifiCorp
2021[1]	$ 5,508,659	$ 12,679,848		$ 1,251,099,183	$ 4,844,638,943		0.4403%	0.2617%

Notes
(1) Calendar year 2021 is being provided as part of Attachment OPUC 340 -1, 1st Supplemental
(2) As taken from PacifiCorp's FERC Form No. 1, Page 320-323, Line 162, Account 904 Uncollectible Accounts.
(3) As taken from PacifiCorp's FERC Form No. 1, Page 300, Line 10, Total Sales of Electricity for retail customers.

OR - UE 399
OPUC 340-2

Attachment - OPUC 340-2

Total Amount of Funds received for energy assistance.

	Project HELP		CSS Project HELP		CSS OR Low Income Assistance		Donations (1)			
	GL Acct: 215427		GL Acct: 215428		GL Acct: 215429		GL Acct: 553100			
	FERC Acct: 232		FERC Acct: 232		FERC Acct: 232		FERC Acct: 426.1		TOTAL	
	Oregon	Total PacifiCorp	Oregon	Total PacifiCorp	Oregon	Total PacifiCorp	Oregon	Total PacifiCorp	Oregon	Total PacifiCorp
2016	71,928	128,839	19,553	74,054	8,011,912	8,011,912	120,162	195,293	8,223,554	8,410,098
2017	73,473	143,216	20,286	77,795	8,110,957	8,110,957	188,143	171,100	8,392,859	8,503,068
2018	76,374	140,422	21,868	80,262	8,249,870	8,249,870	85,361	249,241	8,433,474	8,719,796
2019	84,862	150,058	21,515	78,799	8,322,076	8,322,076	158,710	356,412	8,587,165	8,907,346
2020	110,974	199,283	25,137	90,726	8,232,976	8,232,976	149,781	351,781	8,518,868	8,874,766
2021	132,543	203,947	25,137	90,729	8,413,337	8,413,337	146,055	348,056	8,717,072	9,056,069

Note 1: Donations are not included in the Company's Regulatory Results or the current general rate case. The Oregon amount represents donations made to Oregon agencies and not an allocation of donations to Oregon results.

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 341

OPUC Data Request 341

Uncollectible Accounts - Please describe PacifiCorp's policy regarding uncollectible accounts. In addition to describing the Company's general policy, please include specific responses to (a – d) below.

(a) What determines that an account is uncollectible?

(b) What attempts are made to recover the funds?

(c) What is the procedure for determining when delinquent accounts are disconnected?

(d) Provide any benchmarking comparing PacifiCorp's uncollectible rate to the electric industry.

Response to OPUC Data Request 341

(a) An account is deemed uncollectible and placed with a third-party collection agency once it has closed and the final bill due date has passed.

(b) Accounts are placed with a third-party collection agency for collection efforts. The Company's third-party agencies utilize outbound calls and letters to make contact with customers to collect payment and/or establish payment arrangements.

(c) An active account with an unpaid balance of $50 or greater from a previous month's billing statement may enter the active collections process. The account may be at risk of disconnection when a customer has not made payment and/or payment arrangements following the due date of the past due notice, final notice, and 48-hour door hanger notification. Currently, accounts that have not made a payment in the last 60 days and are greater than two months in arrears are prioritized for disconnection. This prioritization is subject to change.

(d) PacifiCorp does not have any data responsive to this request.

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 342

OPUC Data Request 342

Uncollectible Accounts - Please direct Staff to all testimony, work papers and responses which describe or reference uncollectibles. This request is ongoing for the 2022 calendar year.

Response to OPUC Data Request 342

PacifiCorp objects to this request as duplicative, overly broad, unduly burdensome, requesting the development of information that is easily and readily available to staff, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

The Company is making a good faith effort to identify all specific references in testimony and data requests regarding the subject of uncollectibles. As such, the Company responds as follows:

Please refer to the following:

(a) The direct testimony of Company witness, Sherona L. Cheung, Exhibit PAC/1000/Cheung/21.

(b) Ms. Cheung’s direct testimony, Exhibit PAC/1002/Cheung/101-103.

(c) The Company’s revenue requirement non-confidential work paper submitted at the time of filing for adjustment 4.7, Revenue-Sensitive & uncollectible Accounts.

(d) OR GRC JAM Dec23 Test Period model, adjustment tab, excel column N.

(e) OR GRC JAM Dec23 Test Period model, adjustment summary tab, excel column P.

(f) The direct testimony of Company witness, Robert M. Meredith, Exhibit PAC/1108/Meredith/66.

(g) The Company’s response to OPUC Data Request 340.

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 343

OPUC Data Request 343

Property - Has the Company sold any utility property since the rate effective date from the previous rate case in Docket No. UE 374? If yes, please provide:

(a) The date(s) of the sales transaction,

(b) The location of the property sold,

(c) A description of the property sold,

(d) The dollar amount of any gain/loss from the sale,

(e) The FERC account in which the sale proceeds and gain/loss were recorded, and

(f) The Company's internal account(s) in which the sale and any gain/loss were recorded.

Response to OPUC Data Request 343

Please refer to Attachment OPUC 343. Note: Oregon's share of gains and losses from the disposition of property are recorded in a balancing account and amortized back to Oregon customers through Schedule 96, Property Sales Balancing Account.

OR - UE 399
OPUC 343

Attachment OPUC 343

PacifiCorp
Asset Sales Booked to Account 554000 and 554100
Activity for OR Data Request UE 399 / GRC / OPUC 336-350 - #343
For CY2021 through Q1 of CY2022
[Sales only - excludes retirement of Leasehold Improvements]

Gain on Sale of Assets (Account 554000) + Gain on Sale of Future Use Assets (Account 554410)

Transaction Description	Location	FERC 101 Sub Acct	Date	Sales Price	Book Value	Net Gain/(Loss)	Gain - FERC Acct. 421.1
Easement on Terminal-Camp Williams 345kV Land to UDOT	UT	350	02/25/21	70,500.00	3,898.19	49,072.15	554000
Easement on Terminal-Taylorsville 46kV Land to Salt Lake Cty/Jordan Valley Water Conservancy Dist/ UDOT	UT	350	02/25/21	139,808.88	30.82	102,988.33	554000
Easement on Camp Williams-Spanish Fork 345kV Transmission Land to Spanish Fork City	UT	350	03/22/21	16,000.00	675.58	11,291.02	554000
Easements on Camp Williams-Spanish Fork 345 kV Transmission Land to Lehi City	UT	350	06/16/21	34,990.57	3,440.15	22,988.21	554000
Easements on Terminal-Camp Williams 345kV Transmission Land to West Valley City	UT	350	06/17/21	208,389.85	-	151,836.68	554000
Easements on Camp Williams - Four Corners 345kV Transmission Land to Kern River	UT	350	06/17/21	104,218.67	2,292.87	74,265.01	554000
Sale of Camp Williams-Spanish Fork 345 kV Transmission Land to Spanish Fork City	UT	350	06/17/21	115,000.00	11,001.11	75,775.50	554000
Sale of Camp Williams-90 s 345 kV Transmission Land to Draper City	UT	350	06/16/21	314,813.00	620.81	228,926.20	554000
Sale of portion of Bend Tech Ops Land to City of Bend	OR	350	06/18/21	4,000.00	1,050.39	2,119.50	554000
Sale of portion of Skypark Distribution Sub to Utah Transit Authority	UT	350	06/18/21	903.90	342.05	561.85	554000
Easement on Ben Lomond-Terminal East Transmission Lands to Clearfield City	UT	350	07/21/21	145,203.88	145.72	105,692.04	554000
Easement on Camp Williams-Mona #1 Transmission Land to City of Saratoga Springs	UT	350	07/21/21	53,150.00	7.25	38,720.78	554000
Sale of Portion of Hunter Plant Lands to Emery County	UT	310	09/29/21	20,367.34	16,121.56	3,093.55	554000
Sale of Portion of Hunter Plant Lands to Emery County	UT	310	09/29/21	11,320.66	8,960.75	1,719.47	554000
Easement on Terminal-Camp Williams 345kV Transmission Land to Williamsburg Holdings/West Valley City	UT	350	11/23/21	77,451.96	521.45	56,052.98	554000
Easement on Terminal-Camp Williams 345kV Transmission Land to Williamsburg Holdings/West Valley City	UT	350	11/23/21	99,548.04	-	72,532.53	554000
Easement on Camp Williams - 90th South Transmission Land to Trivew Apartments	UT	350	11/23/21	199,484.96	484.09	144,995.69	554000
Easement on Camp Williams - 90th South Transmission Land to Trivew Apartments	UT	350	11/23/21	1,215.04	2.88	883.20	554000
Easement on Terminal - Ninety South 345kV Land to City of Taylorsville	UT	350	12/14/21	2,692.90	10.01	1,954.80	554000
Easement on Terminal - Ninety South 138kV Land to City of Taylorsville	UT	350	12/14/21	8,007.10	206.78	5,683.46	554000
Sale of Lone Pine Sub Transmission Land to City of Medford	OR	350	03/14/22	108,828.45	2,288.56	77,626.92	554000
Sale of New Lone Pine Sub Transmission Land to City of Medford	OR	350	03/14/22	25,319.04	95.64	18,378.24	554000
Easement on Terminal - Ninety South 345kV Transmission land to City of Murray	UT	350	03/14/22	25,500.00	673.19	18,089.27	554000
Sale of Terminal-Camp Williams 345 kV Land to West Jordan City (with Retained Easement)	UT	350	03/29/22	226,598.91	2,694.21	163,141.07	554000
Sale of Terminal-Camp Williams 345 kV Land to West Jordan City (with Retained Easement)	UT	350	03/29/22	244,735.84	4,095.31	175,335.11	554000
				2,258,048.99	**59,659.37**	**1,603,723.56**	

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 344

OPUC Data Request 344

Property - From calendar year 2019 to the present, for any plant not located in Oregon but included in Oregon rates as a result of PacifiCorp's multi-state allocation procedures, please provide a listing of all property sales, including:

(a) A description of the property,
(b) The location of the property sold,
(c) The date of sale,
(d) The sale price,
(e) Net book value at time of sale, and
(f) The net gain/loss.

Response to OPUC Data Request 344

Please refer to Attachment OPUC 344. Note: Oregon's share of gains and losses from the disposition of property are recorded in a balancing account and amortized back to Oregon customers through Schedule 96, Property Sales Balancing Account. The Company reviews the property gains/losses each Results of Operations and makes an adjustment in 4.1 Miscellaneous Expense & Revenue to reallocate gains and losses on property sales to reflect the appropriate allocation.

PacifiCorp
Asset Sales Booked to Account 554000
Activity for OR Data Request UE 399 / GRC / OPUC 336-350 - #344
For CY2019 through Q1 of CY2022
[Sales only - excludes retirement of Leasehold Improvements]

Gain on Sale of Assets (Account 554000) + Gain on Sale of Future Use Assets (Account 554410)

Transaction Description	Location	FERC 101 Sub Acct	Date	Sales Price	Net Book Value	Net Gain/(Loss)	Gain - FERC Acct. 421.1
Easement Grant of 90 South - Hale 138 kV Line to Living Planet Aquarium	UT	35010	01/31/19	30,500.00	73.74	22,584.56	554000
Sale of Terminal-Camp Williams 345 kV Line Land to West Valley City	UT	35010	02/22/19	3,789.79	1,182.09	1,935.62	554000
Sale of Terminal-Camp Williams 345 kV Line Land to West Valley City	UT	35010	02/22/19	8,694.21	1,304.46	5,485.21	554000
Sale of Naughton-Ben Lomond #2 230kV Line Land to Wolf Creek Water & Sewer	UT	35010	03/21/19	14,662.50	217.82	10,721.88	554000
Sale of Terminal-Camp Williams 345 kV Line Land to IOP, LLC	UT	35010	03/21/19	50,690.50	239.23	37,448.56	554000
Sale of Terminal-Camp Williams 345 kV Line Land to IOP, LLC	UT	35010	03/21/19	17,209.50	93.92	12,704.41	554000
Easement Grant on Camp Williams - Spanish Fork 345 kV Line to Lehi City	UT	35010	04/23/19	106,100.00	7,896.71	72,893.55	554000
Easement Grant on Terminal-Camp Williams 345 kV Line Land to Riverton Ranch, LLC	UT	35010	05/30/19	28,000.00	240.82	20,525.11	554000
Easement on Dave Johnston Steam Land to Black Hills Gas Distribution, LLC	WY	31010	06/27/19	50,108.97	14.96	37,039.46	554000
Easement on Dave Johnston Steam Land to Black Hills Gas Distribution, LLC	WY	31010	06/27/19	11,736.24	36.20	8,651.00	554000
Easement on Purgatory Flat Sub Land to Dixie Escalante REA	UT	35010	07/23/19	10,552.00	8,645.81	1,409.44	554000
Sale of Olmsted Land to City of Orem	UT	35010	07/26/19	216,050.99	108.23	159,667.86	554000
Easement on Camp Williams-90 South Land to Syringa	UT	35010	08/29/19	6,101.39	0.04	4,511.33	554000
Easement on Camp Williams-90 South Land to Syringa	UT	35010	08/29/19	4,860.20	0.03	3,593.60	554000
Easement on Camp Williams-90 South Land to Syringa	UT	35010	08/29/19	5,619.41	0.04	4,154.96	554000
Easement on Camp Williams-90 South Land to Syringa	UT	35010	08/29/19	326.63	0.03	241.49	554000
Easement on Camp Williams-90 South Land to Syringa	UT	35010	08/29/19	862.29	0.03	637.55	554000
Easement on Camp Williams-90 South Land to Syringa	UT	35010	08/29/19	12,230.08	-	9,042.91	554000
Easement on Terminal-Camp Williams Land to UDOT - Mountain View Corridor Group 3	UT	35010	08/29/19	12,383.00	-	9,155.98	554000
Easement on Camp Williams - Four Corners Land to Sunrise LLC/Saratoga Springs	UT	35010	08/29/19	26,000.00	110.66	19,142.55	554000
Easement on Dave Johnston Steam Land to Cedar Springs Transmission - preliminary - to be trued up upon final surveys	WY	31010	09/27/19	77,500.00	1,143.84	56,457.67	554000
Easement on Terminal-Camp Williams 345kv Land to Bluffdale City, UT	UT	35010	10/30/19	160,000.00	620.93	117,844.72	554000
Easement on Terminal-Camp Williams 345kv Land to Bluffdale City, UT	UT	35010	10/30/19	160,000.00	498.21	117,935.55	554000
Easement on Terminal-Camp Williams 345kv Land to Bluffdale City, UT	UT	35010	10/30/19	1,700.00	12.85	1,247.48	554000
Easement on Camp Williams - 90 South #1&2 345kv DC Land to Bluffdale City, UT	UT	35010	12/11/19	10,300.00	48.13	7,580.22	554000
Easement on Terminal-Camp Williams 345kv Land to UDOT Group 8 (Dominion Energy UT (Questar) and Magna Water District)	UT	35010	12/23/19	41,200.00	3,165.43	28,122.72	554000
Land Sale with Retained Easement on Camp Williams - Spanish Fork 345 kV St L Land to Clearwing LC	UT	35010	12/23/19	22,308.17	1,788.80	15,172.00	554000
Easement Grant of Oquirrh Sub Land to Jordan Valley Water Conservancy District	UT	35010	01/29/20	53,200.00	278.71	39,129.95	554000
Easement Grant on Naughton-Ben Lomond No 1 230kV Line to Dominion Energy UT	UT	35010	05/15/20	12,700.00	345.96	9,102.44	554000
Easement Grant on 90 S - Hale 138kV Line land to Draper City	UT	35010	05/27/20	39,138.29	35.72	28,810.73	554000
Easement Grant on Camp Williams-90 S #1 & 2 345kV Line to Draper City	UT	35010	05/27/20	71,130.44	69.44	52,357.67	554000
Sale of Huntington Office Land to 15 N Main, Huntington, LLC	UT	60010	06/23/20	11,074.43	10,859.59	161.68	554000
Sale of Huntington Office Land to 15 N Main, Huntington, LLC	UT	60010	06/23/20	21,484.40	21,067.61	313.65	554000

Transaction Description	Location	FERC 101 Sub Acct	Date	Sales Price	Net Book Value	Net Gain/(Loss)	Gain - FERC Acct. 421.1
Sale of easement on Terminal-Camp Williams 345kV Land to UDOT - MVC Grp 9	UT	35010	07/20/20	29,502.50	4,501.23	18,420.91	554000
Survey Adjustment on Easement on Dave Johnston Steam Land to Black Hills Gas Distribution, LLC	WY	31010	07/22/20	359.80	0.11	265.02	554000
Sale of Glenrock Wind land to ONEOK	WY	34010	07/27/20	164,060.00	1,048.64	120,106.61	554000
Easement Grant on Camp Williams - 90 South #1 & 2 345kV Land to Brixton Partners (Hotel Investments)	UT	35010	08/24/20	7,575.95	22.62	5,565.28	554000
Easement Grant on Camp Williams - 90 South #1 & 2 345kV Land to Brixton Partners (Hotel Investments)	UT	35010	08/24/20	38,424.05	134.57	28,211.65	554000
Sale of Terminal-Camp Williams 345kV Land with Retained Easement to West Jordan City for CW Land	UT	35010	08/31/20	58,753.87	-	43,289.80	554000
Easement Grant of Terminal-Camp Williams 345kV Land with Retained Easement to West Jordan City for CW Land	UT	35010	08/31/20	8,992.69	-	6,625.80	554000
Sale of Camp Williams-Spanish Fork 345 kV Land to Springville City	UT	35010	08/31/20	684,154.00	45,176.95	470,797.65	554000
Easement Grant on Camp Williams-Spanish Fork 345kV Line to Spanish Fork City	UT	35010	11/xx/2020	25,000.00	657.77	17,935.33	554000
Easement on Terminal-Camp Williams 345kV Land to UDOT	UT	35010	02/25/21	70,500.00	3,898.19	49,072.15	554000
Easement on Terminal-Taylorsville 46kV Land to Salt Lake Cty/Jordan Valley Water Conservancy Dist/ UDOT	UT	35010	02/25/21	139,808.88	30.82	102,988.33	554000
Easement on Camp Williams-Spanish Fork 345kV Transmission Land to Spanish Fork City	UT	35010	03/22/21	16,000.00	675.58	11,291.02	554000
Easements on Camp Williams-Spanish Fork 345 kV Transmission Land to Lehi City	UT	35010	06/16/21	34,990.57	3,440.15	22,988.21	554000
Easements on Terminal-Camp Williams 345kV Transmission Land to West Valley City	UT	35010	06/17/21	208,389.85	-	151,836.68	554000
Easements on Camp Williams - Four Corners 345kV Transmission Land to Kern River	UT	35010	06/17/21	104,218.67	2,292.87	74,265.01	554000
Sale of Camp Williams-Spanish Fork 345 kV Transmission Land to Spanish Fork City	UT	35010	06/17/21	115,000.00	11,001.11	75,775.50	554000
Sale of Camp Williams-90 s 345 kV Transmission Land to Draper City	UT	35010	06/16/21	314,813.00	620.81	228,926.20	554000
Easement on Ben Lomond-Terminal East Transmission Lands to Clearfield City	UT	35010	07/21/21	145,203.88	145.72	105,692.04	554000
Easement on Camp Williams-Mona #1 Transmission Land to City of Saratoga Springs	UT	35010	07/21/21	53,150.00	7.25	38,720.78	554000
Sale of Portion of Hunter Plant Lands to Emery County	UT	31010	09/29/21	20,367.34	16,121.56	3,093.55	554000
Sale of Portion of Hunter Plant Lands to Emery County	UT	31010	09/29/21	11,320.66	8,960.75	1,719.47	554000
Easement on Terminal-Camp Williams 345kV Transmission Land to Williamsburg Holdings/West Valley City	UT	35010	11/23/21	77,451.96	521.45	56,052.98	554000
Easement on Terminal-Camp Williams 345kV Transmission Land to Williamsburg Holdings/West Valley City	UT	35010	11/23/21	99,548.04	-	72,532.53	554000
Easement on Camp Williams - 90th South Transmission Land to Trivew Apartments	UT	35010	11/23/21	199,484.96	484.09	144,995.69	554000
Easement on Camp Williams - 90th South Transmission Land to Trivew Apartments	UT	35010	11/23/21	1,215.04	2.88	883.20	554000
Easement on Terminal - Ninety South 345kV Land to City of Taylorsville	UT	35010	12/14/21	2,692.90	10.01	1,954.80	554000
Easement on Terminal - Ninety South 138kV Land to City of Taylorsville	UT	35010	12/14/21	8,007.10	206.78	5,683.46	554000
Easement on Terminal - Ninety South 345kV Transmission land to City of Murray	UT	35010	03/14/22	25,500.00	673.19	18,089.27	554000
Sale of Terminal-Camp Williams 345 kV Land to West Jordan City (with Retained Easement)	UT	35010	03/29/22	226,598.91	2,694.21	163,141.07	554000
Sale of Terminal-Camp Williams 345 kV Land to West Jordan City (with Retained Easement)	UT	35010	03/29/22	244,735.84	4,095.31	175,335.11	554000
				4,434,033.89	**167,524.66**	**3,132,038.63**	

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 345

OPUC Data Request 345

Materials and Supplies (non-fuel) - Regarding PacifiCorp's calculation for "Total Materials and Supplies" contained in Excel workpaper "OR GRC JAM Dec 2023 Test Period", tab "Report", rows 2198-2224, columns J and N, please provide:

(a) A brief narrative describing why Oregon Allocated Materials and Supplies expenses are projected to decline $1.393 million from Base Year to the Test Year.

(b) The supporting workpaper(s), to include intact formulas, for Oregon allocated Base Year and Test Year expense calculations. Please note: Staff reviewed the pertinent data contained in Tab "Variables" and "UTCR", 2020 Protocol Year End Factors and 2020 Protocol 13-month Average Factors.

Response to OPUC Data Request 345

(a) The $1.393 million Oregon-allocated decrease is due to the Cholla materials and supplies balance being removed in Adjustment 8.13 in Exhibit PAC/1002.

(b) Please refer to Attachment OPUC 345 for the total-company and Oregon-allocated amounts included in the "Total Materials and Supplies" amounts on row 2224 on the report tab in the "OR GRC JAM Dec 2023 Test Period".

Oregon General Rate Case - December 2023

Primary Account		Secondary Account		Alloc	Total	Factor %	Oregon Allocated
1541000	PLNT M&S STK CNTRL	0	MATERIAL CONTROL ADJUST	SO	(147,998)	27.173%	(40,216)
1541000	PLNT M&S STK CNTRL	1510	JIM BRIDGER STORE ROOM	SG	24,928,628	26.070%	6,498,979
1541000	PLNT M&S STK CNTRL	1515	DAVE JOHNSTON STORE ROOM	SG	18,285,577	26.070%	4,767,113
1541000	PLNT M&S STK CNTRL	1520	WYODAK STORE ROOM	SG	6,681,662	26.070%	1,741,932
1541000	PLNT M&S STK CNTRL	1525	GADSBY STORE ROOM	SG	4,423,957	26.070%	1,153,341
1541000	PLNT M&S STK CNTRL	1530	CARBON STORE ROOM	SG	1,457	26.070%	380
1541000	PLNT M&S STK CNTRL	1535	NAUGHTON STORE ROOM	SG	13,493,054	26.070%	3,517,685
1541000	PLNT M&S STK CNTRL	1540	HUNTINGTON STORE ROOM	SG	18,984,092	26.070%	4,949,218
1541000	PLNT M&S STK CNTRL	1545	HUNTER STORE ROOM	SG	26,671,409	26.070%	6,953,328
1541000	PLNT M&S STK CNTRL	1550	BLUNDELL STORE ROOM	SG	1,084,469	26.070%	282,725
1541000	PLNT M&S STK CNTRL	1565	CURRANT CREEK PLANT	SG	4,017,899	26.070%	1,047,480
1541000	PLNT M&S STK CNTRL	1570	LAKESIDE PLANT	SG	6,502,092	26.070%	1,695,118
1541000	PLNT M&S STK CNTRL	1580	CHEHALIS PLANT	SG	3,681,544	26.070%	959,791
1541000	PLNT M&S STK CNTRL	1675	HYDRO EAST - UTAH	SG	6,915	26.070%	1,803
1541000	PLNT M&S STK CNTRL	1680	HYDRO EAST - IDAHO	SG	2,899	26.070%	756
1541000	PLNT M&S STK CNTRL	1700	LEANING JUNIPER STOREROOM	SG	235,277	26.070%	61,338
1541000	PLNT M&S STK CNTRL	1705	GOODNOE HILLS WIND	SG	128,653	26.070%	33,540
1541000	PLNT M&S STK CNTRL	1715	MARENGO WIND	SG	366,850	26.070%	95,639
1541000	PLNT M&S STK CNTRL	1720	Foote Creek	SG	3,776	26.070%	985
1541000	PLNT M&S STK CNTRL	1725	Glenrock/Rolling Hills	SG	990,215	26.070%	258,152
1541000	PLNT M&S STK CNTRL	1730	Seven Mile Hill	SG	611,604	26.070%	159,447
1541000	PLNT M&S STK CNTRL	1735	Ekola Flats	SG	5,396	26.070%	1,407
1541000	PLNT M&S STK CNTRL	1740	High Plains/McFadden	SG	451,838	26.070%	117,796
1541000	PLNT M&S STK CNTRL	1745	Dunlap Wind Project	SG	573,073	26.070%	149,402
1541000	PLNT M&S STK CNTRL	1750	TB Flats 1 & 2	SG	4,442	26.070%	1,158
1541000	PLNT M&S STK CNTRL	1760	Cedar Springs II	SG	38,113	26.070%	9,936
1541000	PLNT M&S STK CNTRL	1765	Pryor Mountain	SG	4,460	26.070%	1,163
1541000	PLNT M&S STK CNTRL	2005	CASPER STORE ROOM	WYP	567,699	0.000%	-
1541000	PLNT M&S STK CNTRL	2010	BUFFALO STORE ROOM	WYP	152,992	0.000%	-
1541000	PLNT M&S STK CNTRL	2015	DOUGLAS STORE ROOM	WYP	238,389	0.000%	-
1541000	PLNT M&S STK CNTRL	2020	CODY STORE ROOM	WYP	681,095	0.000%	-
1541000	PLNT M&S STK CNTRL	2030	WORLAND STORE ROOM	WYP	727,226	0.000%	-
1541000	PLNT M&S STK CNTRL	2035	RIVERTON STORE ROOM	WYP	482,900	0.000%	-
1541000	PLNT M&S STK CNTRL	2040	EVANSTON STORE ROOM	WYU	814,839	0.000%	-
1541000	PLNT M&S STK CNTRL	2045	KEMMERER STORE ROOM	WYU	10,904	0.000%	-
1541000	PLNT M&S STK CNTRL	2050	PINEDALE STORE ROOM	WYU	619,889	0.000%	-
1541000	PLNT M&S STK CNTRL	2060	ROCK SPRINGS STORE ROOM	WYP	1,423,681	0.000%	-
1541000	PLNT M&S STK CNTRL	2065	RAWLINS STORE ROOM	WYP	511,258	0.000%	-
1541000	PLNT M&S STK CNTRL	2070	LARAMIE STORE ROOM	WYP	498,639	0.000%	-
1541000	PLNT M&S STK CNTRL	2075	REXBERG STORE ROOM	IDU	1,700,205	0.000%	-
1541000	PLNT M&S STK CNTRL	2085	SHELLY STORE ROOM	IDU	825,865	0.000%	-
1541000	PLNT M&S STK CNTRL	2090	PRESTON STORE ROOM	IDU	79,534	0.000%	-
1541000	PLNT M&S STK CNTRL	2095	LAVA HOT SPRINGS STORE ROOM	IDU	151,888	0.000%	-
1541000	PLNT M&S STK CNTRL	2100	MONTPELIER STORE ROOM	IDU	254,112	0.000%	-
1541000	PLNT M&S STK CNTRL	2110	BRIDGERLAND STORE ROOM	UT	493,022	0.000%	-
1541000	PLNT M&S STK CNTRL	2205	TREMONTON STORE ROOM	UT	397,675	0.000%	-
1541000	PLNT M&S STK CNTRL	2210	OGDEN STORE ROOM	UT	1,612,219	0.000%	-
1541000	PLNT M&S STK CNTRL	2215	LAYTON STORE ROOM	UT	1,137,708	0.000%	-
1541000	PLNT M&S STK CNTRL	2220	SALT LAKE METRO STORE ROOM	UT	9,329,521	0.000%	-
1541000	PLNT M&S STK CNTRL	2230	JORDAN VALLEY STORE ROOM	UT	1,035,996	0.000%	-
1541000	PLNT M&S STK CNTRL	2235	PARK CITY STORE ROOM	UT	1,462,208	0.000%	-
1541000	PLNT M&S STK CNTRL	2240	TOOELE STORE ROOM	UT	566,929	0.000%	-
1541000	PLNT M&S STK CNTRL	2245	WASATCH RESTORATION CENTER	UT	691,052	0.000%	-
1541000	PLNT M&S STK CNTRL	2400	PLNT M&S STK CNTRL EAGLE MOUNTAIN	UT	361,597	0.000%	-
1541000	PLNT M&S STK CNTRL	2405	AMERICAN FORK STORE ROOM	UT	1,795,662	0.000%	-
1541000	PLNT M&S STK CNTRL	2410	SANTAQUIN STORE ROOM	UT	565,290	0.000%	-
1541000	PLNT M&S STK CNTRL	2415	DELTA STORE ROOM	UT	528,454	0.000%	-
1541000	PLNT M&S STK CNTRL	2420	VERNAL STORE ROOM	UT	743,836	0.000%	-
1541000	PLNT M&S STK CNTRL	2425	PRICE STORE ROOM	UT	688,285	0.000%	-
1541000	PLNT M&S STK CNTRL	2430	MOAB STORE ROOM	UT	865,661	0.000%	-
1541000	PLNT M&S STK CNTRL	2435	BLANDING STORE ROOM	UT	100,083	0.000%	-

Primary Account		Secondary Account		Alloc	Total	Factor %	Oregon Allocated
1541000	PLNT M&S STK CNTRL	2445	RICHFIELD STORE ROOM	UT	124,067	0.000%	-
1541000	PLNT M&S STK CNTRL	2450	CEDAR CITY STORE ROOM	UT	1,400,929	0.000%	-
1541000	PLNT M&S STK CNTRL	2455	MILFORD STORE ROOM	UT	351,748	0.000%	-
1541000	PLNT M&S STK CNTRL	2460	WASHINGTON STORE ROOM	UT	615,409	0.000%	-
1541000	PLNT M&S STK CNTRL	2620	WALLA WALLA STORE ROOM	WA	2,264,459	0.000%	-
1541000	PLNT M&S STK CNTRL	2630	YAKIMA STORE ROOM	WA	391,582	0.000%	-
1541000	PLNT M&S STK CNTRL	2635	ENTERPRISE STORE ROOM	OR	232,963	100.000%	232,963
1541000	PLNT M&S STK CNTRL	2640	PENDLETON STORE ROOM	OR	961,724	100.000%	961,724
1541000	PLNT M&S STK CNTRL	2650	HOOD RIVER STORE ROOM	OR	522,501	100.000%	522,501
1541000	PLNT M&S STK CNTRL	2655	PORTLAND METRO - STORE ROOM	OR	12,977,890	100.000%	12,977,890
1541000	PLNT M&S STK CNTRL	2660	ASTORIA STORE ROOM	OR	1,310,682	100.000%	1,310,682
1541000	PLNT M&S STK CNTRL	2665	MADRAS STORE ROOM	OR	100,156	100.000%	100,156
1541000	PLNT M&S STK CNTRL	2675	BEND STORE ROOM	OR	2,047,963	100.000%	2,047,963
1541000	PLNT M&S STK CNTRL	2805	ALBANY STORE ROOM	OR	248,685	100.000%	248,685
1541000	PLNT M&S STK CNTRL	2810	LINCOLN CITY STORE ROOM	OR	219,047	100.000%	219,047
1541000	PLNT M&S STK CNTRL	2830	ROSEBURG STORE ROOM	OR	3,572,114	100.000%	3,572,114
1541000	PLNT M&S STK CNTRL	2835	COOS BAY STORE ROOM	OR	956,915	100.000%	956,915
1541000	PLNT M&S STK CNTRL	2840	GRANTS PASS STORE ROOM	OR	1,388,481	100.000%	1,388,481
1541000	PLNT M&S STK CNTRL	2845	MEDFORD STORE ROOM	OR	932,617	100.000%	932,617
1541000	PLNT M&S STK CNTRL	2850	KLAMATH FALLS STORE ROOM	OR	3,226,858	100.000%	3,226,858
1541000	PLNT M&S STK CNTRL	2855	LAKEVIEW STORE ROOM	OR	128,210	100.000%	128,210
1541000	PLNT M&S STK CNTRL	2860	ALTURAS STORE ROOM	CA	108,410	0.000%	-
1541000	PLNT M&S STK CNTRL	2865	MT SHASTA STORE ROOM	CA	268,428	0.000%	-
1541000	PLNT M&S STK CNTRL	2870	YREKA STORE ROOM	CA	1,605,400	0.000%	-
1541000	PLNT M&S STK CNTRL	2875	CRESENT CITY STORE ROOM	CA	591,934	0.000%	-
1541000	PLNT M&S STK CNTRL	5005	TREMONTON STORE ROOM	SO	145,727	27.173%	39,599
1541000	PLNT M&S STK CNTRL	5110	MATERIAL PACKAGING CENTER - WEST	OR	99	100.000%	99
1541000	PLNT M&S STK CNTRL	5115	DEMC - SLC	SNPD	149,629	26.473%	39,611
1541000	PLNT M&S STK CNTRL	5120	DEMC - MEDFORD	OR	63,911	100.000%	63,911
1541000	PLNT M&S STK CNTRL	5125	DEMC - OREGON	OR	10,332,501	100.000%	10,332,501
1541000	PLNT M&S STK CNTRL	5130	MEDFORD HUB	OR	9,873,134	100.000%	9,873,134
1541000	PLNT M&S STK CNTRL	5135	YAKIMA HUB	WA	8,274,879	0.000%	-
1541000	PLNT M&S STK CNTRL	5140	PRESTON HUB	IDU	3,709,623	0.000%	-
1541000	PLNT M&S STK CNTRL	5150	RICHFIELD HUB	UT	4,586,063	0.000%	-
1541000	PLNT M&S STK CNTRL	5155	CASPER HUB	WYP	6,248,067	0.000%	-
1541000	PLNT M&S STK CNTRL	5160	SALT LAKE METRO HUB	UT	30,718,186	0.000%	-
1541000	PLNT M&S STK CNTRL	5200	UTAH TRANSPORTATION BUILDING	SNPD	16,480	26.473%	4,363
1541000	PLNT M&S STK CNTRL	5300	METER TEST WAREHOUSE	UT	2,592	0.000%	-
1541000 Total					274,817,727		83,599,415
1541500	OTHER M&S	0	M&S GLENROCK COAL MINE	SE	197,586	25.068%	49,531
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SE	(197,586)	25.068%	(49,531)
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SO	137,495	27.173%	37,362
1541500 Total					137,495		37,362
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SG	2,154,409	26.070%	561,662
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SO	(1,379,634)	27.173%	(374,889)
1541900 Total					774,775		186,773
1549900	CR-OBSOL&SURPL INV	102930	SB Asset # 120930	SO	(27,435)	27.173%	(7,455)
1549900	CR-OBSOL&SURPL INV	120930	INVENTORY RESERVE POWER SUPPLY	SG	(915,402)	26.070%	(238,648)
1549900	CR-OBSOL&SURPL INV	120930	INVENTORY RESERVE POWER SUPPLY	SO	(12,404)	27.173%	(3,370)
1549900	CR-OBSOL&SURPL INV	120932	Inventory Reserve - RMP (T&D)	SNPD	(894,463)	26.473%	(236,788)
1549900	CR-OBSOL&SURPL INV	120933	Inventory Reserve - PP (T&D)	SNPD	(580,429)	26.473%	(153,655)
1549900 Total					(2,430,133)		(639,916)
2531800	WCD-PROVO-PLNT M&S	289922	OTH DEF CR - WCD - PROVO - PLANT M&S	SG	(273,000)	26.070%	(71,172)
2531800 Total					(273,000)		(71,172)
			Base Year Amounts		**273,026,865**		**83,112,462**
			Removal of Cholla Balance, Exhibit/PAC 1002, Adjustment 8.13		(5,341,897)	26.070%	(1,392,651)
			Test Year Amounts		**267,684,968**		**81,719,811**

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OPUC Data Request 346

Prepayments - Regarding PacifiCorp's calculation for "Prepayments" contained in Excel workpaper "OR GRC JAM Dec 2023 Test Period", tab "Report", rows 2226-2232, columns J and N:

(a) Please provide a brief narrative describing why this expenditure category is unchanged at $11.130 million from the Base Year to the Test Year.

(b) Please describe how the OR allocated June 2021 Base Year amount in the current filing increased $2.325 million from the Company's prior rate case filing in Docket No. UE 374 (UE 374 OR allocated December 2021 Test Year amount was $8.805 million).

Response to OPUC Data Request 346

(a) The balance is unchanged from the Base Year to the Test Year because the Company has not identified any known and measurable changes that are expected in the balance in FERC Account 165 (Prepayments), in the time between the end of the Base Year and into the Test Year. This treatment is consistent with the Company's approach in the prior general rate case (GRC), Docket No. UE 374.

(b) The increase noted above in FERC Account 165 (Prepayments) is largely due to three main drivers or three unamortized repaid balances or categories:

1. An increase in the prepaid unamortized balance of the Public Utility Commission of Oregon annual fee to PacifiCorp. Approximately $1 million on a total-company basis and $1 million on an Oregon-allocated basis.

2. An increase of prepaid operations and maintenance fixed service agreement or long-term service agreement balances associated with wind plants. Approximately $1.6 million on a total-company basis, and $412,000 on an Oregon-allocated basis.

3. An increase in prepaid hardware and software agreement balances over the prior GRC base period. Approximately $3.2 million on a total-company basis, and $862,000 on an Oregon-allocated basis.

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OPUC Data Request 347

Miscellaneous Deferred Debits - Regarding expenditures that are recorded as “Miscellaneous Deferred Debits” contained in Excel workpaper “OR GRC JAM Dec 2023 Test Period”, tab “Report”, rows 2244-2253, columns J and N, please provide:

(a) A list of the types of expenditures recorded in this account.

(b) A breakout of the total dollar amount for each type of expenditure within this account.

(c) Supporting documentation for the Test Year projection dollar amount.

Response to OPUC Data Request 347

(a) Please refer to Exhibit PAC 1002, specifically B-tab report B11 – Deferred Debits, for the items included in the June 2021 Year End balance.

(b) Please refer to the Company’s response to subpart (a) above.

(c) Please refer to Exhibit PAC 1002, specifically the Misc. Rate Base Adjustment 8.15 for details of the $(16.9) million adjustment made to FERC 186M that is included in the Test Year amount.

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OPUC Data Request 348

Customer Advances for Construction - Regarding expenditures that are recorded as "Customer Advances for Construction" contained in Excel workpaper "OR GRC JAM Dec 2023 Test Period", tab "Report", rows 2327-2333, columns J and N, please provide:

(a) A brief narrative explaining why the Test Year projection for these line items declined $5.089 million from the Base Year.

(b) A list of the customers that advanced funds for construction and dollar amounts contributed.

Response to OPUC Data Request 348

(a) The source in the Company's filing showing the $5.089 million decrease in Customer Advances for Construction balances from the Base Year to the Test Year is Exhibit PAC/1002, Page 8.5, the 'Customer Advances for Construction' regulatory adjustment. As explained in the direct testimony of Company witness, Sherona L. Cheung, Exhibit PAC/1000, page 34, line 8, the adjustment is necessary to correct the Base Year balances for transactions recorded to a corporate cost center rather than a state-specific location. This adjustment is necessary to properly assign the customer advance balances to the correct state for the base period 12 months ended June 2021. The total-company customer advances for construction balance remains the same from the Base Year to the Test Year as there were not any known or measurable changes identified at of the time of filing.

(b) Please refer to Attachment OPUC 348.

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Attachment OPUC 348

PacifiCorp
Oregon General Rate Case, Test Year 2023
Payments Received, Uncompleted Projects
Situs Oregon
at 6/30/2021

CSS Agreement #	SAP Customer #	Amount
00090364001006	10001566	$ (9,726)
00399794001039	10005345	(48,559)
00399794215001	10005826	(63,675)
01739991018001	10006614	(1,923)
01750565001003	10006620	(3,483)
03212898001006	10006661	(3,928)
03212898001007	10006664	(10,095)
04712782001001	10006664	(7,722)
04804250001001	10006822	(4,892)
04885379005004	10007086	(1,480)
04885379089002	10007095	(2,872)
04885379089003	10007173	(2,325)
05586722003001		(1,917)
05891164001004		(6,906)
05891164002001		(4,424)
06771670004001		(30,364)
06771670004002		(7,473)
07422919001002		(6,298)
08263368001118		(4,276)
08263368001120		(6,743)
08263368293001		(4,666)
08263368294001		(1,398)
08676626001004		(3,504)
09924350004002		(600)
09940981690003		(8,370)
09940981690004		(6,210)
10345065001001		(5,310)
11237825001001		(29,423)
11389695001051		(55,615)
11989104001005		(5,372)
12163341005001		(10,687)
13331341002003		(5,190)
15619591002002		(5,018)
15740312005002		(34,909)
15740312005003		(55,351)
18390734001003		(4,256)
18426088326005		(3,187)
18811345093001		(119,417)
22999561001006		(5,851)
23886943007002		(22,589)
23938850001001		(4,117)
24700939005001		(1,148)

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Attachment OPUC 348

CSS Agreement #	SAP Customer #	Amount
25623728001002		(2,467)
25910813001003		(88,721)
25982726001005		(4,998)
26274011004001		(8,182)
26390329004007		(2,043)
27562041003001		(7,792)
28295751001273		(5,128)
28300231011057		(11,610)
28300231011059		(17,307)
28300231011060		(6,889)
28409641002002		(3,779)
28543073014158		(5,279)
28543073023157		(2,489)
28543073023170		(48,425)
28543073023175		(8,967)
28643721003001		(8,881)
29011511001005		(115)
29194831048012		(20,234)
29891804003005		(2,606)
30137381005003		(12,162)
30262065002001		(2,906)
30511478015001		(4,528)
31160571001046		(7,157)
31244100001002		(4,119)
31304888001002		(2,014)
31770971003001		(4,017)
31932495001002		(5,853)
31974881001003		(594)
32076311003003		(3,480)
32492204001018		(6,796)
32517241003001		(6,730)
32535861004001		(7,305)
32639413001004		(28,163)
32683555002001		(63,190)
32848271011001		(4,415)
33283251001005		(2,865)
34027073001017		(2,261)
34607617001005		(3,260)
34638090002001		(5,735)
34749972001001		(4,211)
35361831001004		(4,117)
35365401001005		(6,861)
35523750001026		(1,966)
35681871001005		(5,129)
35989480001003		(4,437)
36568071002001		(1,831)
37094821002002		(7,281)
37551221004005		(6,106)
37635361004001		(3,296)
37750171006001		(4,101)
38201544003001		(4,309)

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Attachment OPUC 348

CSS Agreement #	SAP Customer #	Amount
38730931005084		(2,249)
38730931005085		(1,738)
39053001001003		(896)
39518104001001		(24,997)
39623431051004		(4,284)
39623431117010		(18,322)
40225589001002		(4,814)
41479930001002		(10,652)
42633216002001		(4,195)
44007079002001		(51,025)
45411886001001		(4,756)
46819479001002		(5,372)
48695998002001		(3,547)
48924942002001		(2,519)
49375827001004		(12,698)
49759595001002		(32,789)
50620953001006		(600)
50712134001002		(3,902)
50922245001003		(1,972)
51773265003001		(3,151)
51848889001001		(17,529)
51945239001001		(5,639)
52459772001004		(6,278)
52700162001001		(14,401)
52870139001007		(2,765)
57392655001003		(3,404)
57612082002035		(30,757)
57612082621001		(30,101)
58231883001004		(39)
60168170001002		(8,521)
60277050002001		(16,398)
61118122002001		(12,165)
61344372002001		(688)
61370799001003		157
61540626001005		(11,100)
63573725002001		(2,074)
63612013002001		(8,152)
63972165007001		(15,172)
65193795001007		(3,364)
66913442001001		(1,032)
67392102007001		(1,070)
67943092001001		(3,896)
68252122054001		(7,576)
69188525001003		(5,806)
69299250013002		(9,467)
71307461001003		(8,590)
71620205001002		(925)
71771068002002		(4,110)
72525675001005		(6,188)
72735167001005		(5,827)
73608391001007		(17,637)

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CSS Agreement #	SAP Customer #	Amount
73660968001001		(8,391)
74445233006001		(4,492)
76086300001001		(4,733)
76509378001001		(12,207)
76542607001004		(7,546)
76914546001004		(1,421)
77858632001011		(924)
78646624008006		(392)
80044935001003		(1,713)
80775761001002		(1,419)
80850752001002		600
80850752001003		(6,208)
81076890001001		600
81076890001004		(5,179)
82980658001003		(5,302)
84066155001002		(8,241)
84450161001002		(3,506)
84450161001002		(1,912)
84579041001003		(2,325)
88237226001001		(13,129)
88670472002005		(35,372)
89118185004001		(13,017)
89712330007005		(4,920)
91214084002002		(3,010)
91899666002001		(4,724)
95055020001069		(610)
95123683001001		(2,778)
95432831001001		(8,942)
95776705001005		(839)
97141158001001		(5,113)
98355816003001		(7,459)
99343090006001		(23,174)
99572053001001		(26,156)
	10001566	(17,816)
	10005345	(19,507)
	10005826	(22,460)
	10006614	(4,266)
	10006620	(5,643)
	10006661	(80,155)
	10006664	(31,395)
	10006664	(64,789)
	10006822	(10,408)
	10007086	(9,040)
	10007095	(7,106)
	10007173	(10,000)
Total		$ (2,069,907)

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 349

OPUC Data Request 349

Legal Expenses and Fees - Please identify all legal expenses included in the current rate filing, to include:

(a) FERC account,

(b) Profit Center number,

(c) Profit Center name,

(d) A description of the expense,

(e) The Company dollar amount, and

(f) The OR allocated dollar amount.

Response to OPUC Data Request 349

Please refer to Attachment OPUC 349.

Staff Exhibit

“Relevant attachment to PacifiCorp’s response to Staff DR 349”

is

filed in electronic format

UE 399 / PacifiCorp
May 2, 2022
OPUC Data Request 350

OPUC Data Request 350

Legal Expenses and Fees - Please provide a breakout of the legal expenses in the current filing, to include:

(a) Type of litigation (e.g. general counsel, property damage, liability, criminal defense).

(b) Specific cases/dockets where legal expenses exceeded $100 thousand.

(c) The jurisdiction of the court and why that jurisdiction applied.

(d) The dollar amounts, by litigation type, on a Company and OR allocated basis.

(e) The dollar amounts by attorney fees, fines, court fees, settlements, and adverse judgements.

(f) The dollar amount for legal fees apportioned to Oregon as part of the Company's MSP process.

Response to OPUC Data Request 350

PacifiCorp objects to this request as overly broad, unduly burdensome, requesting the development of information and preparation of a study, and not reasonably calculated to the discovery of admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

(a) Please refer to Attachment OPUC 350.

(b) Please refer to the table below which provides a list of specific cases or dockets where legal expenses exceeded $100,000 on an Oregon-allocated basis.

Case/Docket	Legal Expense (Oregon-Allocated)
Marriott Condemnation	$111,988.76

(c) PacifiCorp assumes this question refers to subpart (b), which is a condemnation action in the state of Utah for land rights related to transmission build. Based on the foregoing assumption, the Company responds as follows:

The land is located in Utah, therefore, Utah courts have jurisdiction.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

(d) Please refer to Attachment OPUC 350.

(e) Please refer to Attachment OPUC 350 which delineates Legal Fees (Attorney Fees), Expert Witness Fees, and other costs (Legal costs).

(f) The Company is unclear on what this question refers to. Assuming this question is requesting the allocation factors for various FERC Accounts, the Company responds as follows:

Those allocation factors for various FERC Accounts are provided in Appendix B of the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol).

OR - UE 399
OPUC 350

Attachment OPUC 350

Matter Type	Account Name	Total Company ($)	Oregon Allocated $
Administrative	Legal Consulting Services - Legal Costs	(0)	0
	Legal Consulting Services - Legal Fees	190,452	51,636
Administrative Total		**190,452**	**51,636**
BANKRUPTCY	Legal Consulting Services - Legal Costs	22,364	6,047
	Legal Consulting Services - Legal Fees	297,880	79,808
BANKRUPTCY Total		**320,244**	**85,855**
CLAIMS & DISPUTES	Legal Consulting Services - Legal Costs	51,800	11,744
	Legal Consulting Services - Legal Fees	171,797	19,322
	Legal Consulting Svc-Expert Witness Fees	1,071,490	290,872
CLAIMS & DISPUTES Total		**1,295,087**	**321,938**
Compliance	Legal Consulting Services - Legal Fees	62,204	16,903
Compliance Total		**62,204**	**16,903**
Contracts & Agreements	Legal Consulting Services - Legal Costs	2,137	557
	Legal Consulting Services - Legal Fees	66,734	17,398
Contracts & Agreements Total		**68,871**	**17,955**
Corporate or Finance	Legal Consulting Services - Legal Costs	-	-
	Legal Consulting Services - Legal Fees	(48,183)	(10,525)
Corporate or Finance Total		**(48,183)**	**(10,525)**
Expense Accrual	Legal Consulting Services - Legal Fees	1,925,860	523,315
Expense Accrual Total		**1,925,860**	**523,315**
Federal Regulatory	Legal Consulting Services - Legal Costs	928	231
	Legal Consulting Services - Legal Fees	1,486,682	411,099
Federal Regulatory Total		**1,487,610**	**411,330**
INSURANCE	Legal Consulting Services - Legal Costs	(766)	(1,115)
	Legal Consulting Services - Legal Fees	(211,322)	(56,763)
INSURANCE Total		**(212,088)**	**(57,878)**
Litigation	Legal Consulting Services - Legal Costs	78,065	16,683
	Legal Consulting Services - Legal Fees	2,968,486	793,692
	Legal Consulting Svc-Expert Witness Fees	450	122
Litigation Total		**3,047,001**	**810,497**
OPERATIONS	Legal Consulting Services - Legal Costs	(194,250)	(50,778)
	Legal Consulting Services - Legal Fees	1,295,766	248,092
	Legal Consulting Svc-Expert Witness Fees	5,161	0
OPERATIONS Total		**1,106,678**	**197,315**
Other Expenses	Legal Consulting Services - Legal Costs	1,706	445
	Legal Consulting Services - Legal Fees	21,874	5,703
Other Expenses Total		**23,580**	**6,148**
Outside Services Employed	Legal Consulting Services - Legal Fees	2,984	811
Outside Services Employed Total		**2,984**	**811**
Property	Legal Consulting Services - Legal Costs	14,199	4,228
	Legal Consulting Services - Legal Fees	227,348	64,516
	Legal Consulting Svc-Expert Witness Fees	5,198	1,413
Property Total		**246,745**	**70,156**
State Regulatory	Legal Consulting Services - Legal Costs	24,565	2,801
	Legal Consulting Services - Legal Fees	4,397,834	1,877,877
	Legal Consulting Svc-Expert Witness Fees	16,010	4,174
State Regulatory Total		**4,438,408**	**1,884,852**
Grand Total		**13,955,457**	**4,330,307**

UE 399 / PacifiCorp
April 29, 2022
OPUC Data Request 375

OPUC Data Request 375

Cyber Security - Regarding PacifiCorp's cybersecurity policies and procedures, please provide:

(a) A narrative overview describing how the Company secures their corporate and customer data as well as their digital infrastructure.

(b) A narrative description of the primary measures the Company is taking to improve and strengthen cybersecurity.

Response to OPUC Data Request 375

(a) PacifiCorp takes a "defense-in-depth" approach to protecting company data and systems that serve our customers. This includes rigorous, mandatory, and enforceable reliability regulations; close coordination among industry and government partners at all levels; and efforts to prepare, respond, and recover should an incident impact the energy grid. PacifiCorp's policies and procedures draw from internationally recognized standards and apply such in a comprehensive management framework across every aspect of our business.

(b) A Company executive is responsible for an organization that drives the Company's overall cybersecurity practices. The program operates under a fundamental principle of continuous improvement that challenges existing practices against emerging threats to identify areas of improvement. Active engagement and information sharing with government partners enables a collaborative approach in classified settings with the goal to further protect critical infrastructure. This approach drives a continuous threat-informed resiliency approach against modern day cyber risks.

UE 399 / PacifiCorp
April 29, 2022
OPUC Data Request 376

OPUC Data Request 376

Cyber Security - Has PacifiCorp had a cybersecurity audit performed by a federal or state agency in the past five years? If yes, please provide a summary of the most recent cybersecurity audit findings.

Response to OPUC Data Request 376

No.

UE 399 / PacifiCorp
May 2, 2022
OPUC Data Request 377

OPUC Data Request 377

Cyber Security - On an annual basis, for each of the years 2017 through 2021, how much did PacifiCorp spend on cybersecurity on an OR allocated basis? Please indicate which expenditures were recorded as expenses and which were recorded as capital additions/rate base.

Response to OPUC Data Request 377

Please refer to the tables below for estimated costs pertaining to expense and capital additions for cybersecurity, including the Oregon allocation:

Year	Cybersecurity - Expense	Oregon Allocation
2017	$2,409,964	$653,266
2018	$4,012,869	$1,097,016
2019	$4,287,278	$1,180,832
2020	$4,187,166	$1,178,391
2021	$4,927,372	$1,379,260

Year	Cybersecurity - Capital	Oregon Allocation
2017	$75,345	$20,473
2018	$1,786,899	$480,265
2019	$634,635	$172,295
2020	$918,736	$249,649
2021	$1,175,416	$317,259

UE 399 / PacifiCorp
May 9, 2022
OPUC Data Request 378

OPUC Data Request 378

Cyber Security - Does the current rate case include cybersecurity investments/expenditures? If yes, please provide:

(a) A description of the expenditures with sufficient detail to discern the nature of the expense (e.g. firewall equipment, virus scanning software, system penetration testing).

(b) The total dollar amount,

(c) The OR allocated dollar amount,

(d) A brief synopsis of how these expenditures will improve/strengthen the Company's cybersecurity posture, and

(e) All references in the rate case filing, to include supporting exhibits and Company responses to data requests addressing this issue.

Response to OPUC Data Request 378

(a) Please refer to Attachment OPUC 378 which provides a description of the Company's cybersecurity investments/expenditures.

(b) Total company assets placed in-service for cybersecurity, since the last general rate case (GRC), Docket UE 374, which became effective January 1, 2021 through the end of the base period in the current GRC proceeding, is $23,297. Total company expense for the 12 months ended June 2021 was $4,862,548.

(c) The corresponding Oregon-allocated capital reported in the Company's response to subpart (b) above is $6,466. Oregon-allocated expense for the 12 months ended June 2021 was $1,364,808.

(d) Please refer to the Company's response to subpart (a) above.

(e) The cybersecurity capital dollars are included in the base period data ended June 30, 2021. They are included in the unadjusted General Plant Electric Plant In-Service (EPIS) figure in Exhibit PAC/1002/Cheung/37, line 1916, and the unadjusted Intangible Plant EPIS figure in Exhibit PAC/1002/Cheung/38, line 1964. The cybersecurity expense dollars are included in the base period ended June 30, 2021. They are included in unadjusted operations and maintenance (O&M) expense in Exhibit 1002/Cheung/25, line 950.

OR - UE 399
OPUC 378

Attachment OPUC 378

OPUC 378(a)	Project Definition	Project Description	Blanket	WBS Element	WBS Description	AUC#
Replacing old switches at NTO SOC with new equipment before problems arise allow for more efficient up time for customer support. - CISCO 48-Port POE Switch and CISCO 24-Port POE Switch	CITS/2019/C/117	NTO Security Switch TOM	No	CITS/2019/C/117/CAP	NTO Security Switch TOM cap	60607946
This project will engage professional services (RFP will be created for Professional Services) to implement QRadar. A couple new servers be integrated into our existing SEIM and ElasticSearch systems to collect system logs/events. These logs/events will then be analyzed and monitored by the new QRadar and ElasticSearch cybersecurity systems. - QRadar SW was purchased as part of IBM ESSO.	CITS/2019/C/119	Q Radar Implementation	No	CITS/2019/C/119/SW	Q Radar Implementation Software	60612086
These servers will be used as mobile servers for currently deployed security forwarder equipment in the generation plants. This will allow the security dept. to quickly deploy the servers where needed if a currently deployment server malfunctions. - USC c220 MS SSF Computer Servers	CITS/2020/C/183	Security Eng TOM-Phase 2	No	CITS/2020/C/183/CAP	Security Eng TOM-Phase 2 HW	60630439
We are purchasing this security camera equipment to use at different sites, like Service Centers and Substations. This equipment is part of a mobile unit that we can use a any site temporary and move from site to site, depending on the security threat.	CITS/2020/C/199	New Mobile SpotterRF Equipment	No	CITS/2020/C/199/CAP	New Mobile SpotterRF Cap	60650448
Will help the functionality of Station 1 and help with monitoring of cameras in the Security Operations Center. SOC System Cameleon Monitor Wall Server. Server shall be rack mounted in the Security Main Equipment Room and operate one (1) up to three (4) wall mount display monitors.	CITS/2021/C/004	NTO SOC Station 1 Upgrade	No	CITS/2021/C/004/CAP	NTO SOC Station 1 Upgrade Capital	60652377
This server provides security event log forwarding for generation, providing means of capturing, storing, forwarding and searching security events to deter, prevent and detect malicious cyber activity within control networks. It was explored to directly push logs to the SIEM from field devices. However, this was deemed less desirable given the reliability and stability of the forwarding process. By replacing the forwarder, this allows breaks in network connectivity to be mitigated, variability in log volume to be regulated and noisy or overwhelming log data to be dropped as needed. The lack of an forwarder would introduce compliance risk for log retention, log review and security monitoring.	CITS/2021/C/006	Plant Log Forwarder DJohston Plant	No	CITS/2021/C/006/DJ	Plant Log Forwarder DJohston Plant	60652841
This server provides security event log forwarding for generation, providing means of capturing, storing, forwarding and searching security events to deter, prevent and detect malicious cyber activity within control networks. It was explored to directly push logs to the SIEM from field devices. However, this was deemed less desirable given the reliability and stability of the forwarding process. By replacing the forwarder, this allows breaks in network connectivity to be mitigated, variability in log volume to be regulated and noisy or overwhelming log data to be dropped as needed. The lack of an forwarder would introduce compliance risk for log retention, log review and security monitoring.	CITS/2021/C/008	Plant Log Forwarder Huntington	No	CITS/2021/C/008/HNTG	Plant Log Forwarder Huntington	60653135

UE 399 / PacifiCorp
April 29, 2022
OPUC Data Request 379

OPUC Data Request 379

Cyber Security - In the past five years, has the Company:

(a) Suffered a data breach? If yes, please provide a narrative of the breach event, the monetary impact to the Company, and the number of customers affected.

(b) Suffered any damage to digital or physical systems due to an external cyber intrusion? If yes, please provide a narrative description for each occurrence, to include steps taken to mitigate the damage and prevent future attacks.

(c) Suffered any adverse effects to Company operational control (OC) systems?

(d) Received notification from NERC of a critical infrastructure protection (CIP) plan violation related to cybersecurity? If yes, please provide:

    i. The date of each infraction,
    ii. A description of the violation,
    iii. A description of the action taken against the Company (e.g. advisory, sanction), and
    iv. The dollar amount for each fine or sanction (if any).

Response to OPUC Data Request 379

(a) No.

(b) No.

(c) No.

(d) No.

UE 399 / PacifiCorp
May 9, 2022
OPUC Data Request 380

OPUC Data Request 380

Information Technology Expenditures - Please provide PacifiCorp's OR allocated IT cost information in the following MS Excel table format:

Costs	**2017**	**2018**	**2019**	**2020**	**2021**	**UE 399 Request**	**Percent Change 2017 to UE 399**
Personnel							
Services & Supplies							
Contracting / Professional Services							
Other							
Total							

Response to OPUC Data Request 380

Please refer to Attachment OPUC 380 which provides Oregon's allocated share of unadjusted information technology (IT) costs for the requested historical years. The general rate case (GRC), Docket UE 399 amounts reflect escalated test year amounts.

OR - UE 399
OPUC 380

Attachment OPUC 380

Costs	**2017**	**2018**	**2019**	**2020**	**2021**	**UE 399 Request**	**Percent Change**
							2017 to UE 399
Personnel	3,711,699	4,372,506	4,163,279	4,031,546	3,434,144	3,760,554	1.3%
Services & Supplies	64,056	93,177	96,808	380,328	1,296,258	485,106	657.3%
Contracting / Professional Services	5,207,706	5,405,535	5,938,420	5,738,298	6,075,015	5,875,275	12.8%
Other	799,974	805,914	979,582	946,084	1,629,457	1,168,524	46.1%
Total	**9,783,435**	**10,677,132**	**11,178,089**	**11,096,255**	**12,434,874**	**11,289,458**	15.4%

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 381

OPUC Data Request 381

Information Technology Expenditures - Please provide PacifiCorp's FTE count for IT staff in the following MS Excel table format:

	2017	**2018**	**2019**	**2020**	**2021**	**UE 399 Request**	**Percent Change 2017 to UE 399**	
FTE								

Response to OPUC Data Request 381

Please refer to Attachment OPUC 381 for requested full-time equivalent (FTE) information based on 12-month average FTE for each calendar year.

OR - UE 399
OPUC 381

Attachment OPUC 381

	2017	**2018**	**2019**	**2020**	**2021**	**UE 399 Request**	**Percent Change** **2017 to UE 399**
FTE	221.7	224.5	232.8	246.2	221.3	238.3	7.5%

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 382

OPUC Data Request 382

Information Technology Expenditures - For each of the component FTE included in PacifiCorp's response to the previous DR:

(a) Please list the current job-title (i.e. Database Administrator 2, etc.).

(b) Please provide the time in-service at the Company.

Response to OPUC Data Request 382

The Company assumes that the reference to "the previous DR" is intended to be a reference to OPUC Data Request 381. Based on the foregoing assumption, the Company responds as follows:

(a) Please refer to Attachment OPUC 382 which provides titles for employees in the Information Technology/Chief Information Officer and Security groups at December 31, of 2017 through 2021 and June 2021.

(b) Please refer to Attachment OPUC 382 which provides time-in-service for employees in the IT/CIO and Security groups at December 31, of 2017 through 2021 and June 2021.

Staff Exhibit

“Relevant attachment to PacifiCorp’s response to Staff DR 382”

is

filed in electronic format

Docket No: UE 399

UE 399 / PacifiCorp
May 2, 2022
OPUC Data Request 383

OPUC Data Request 383

Information Technology Expenditures - Does the current rate filing include new IT projects, IT system upgrades, and/or incremental IT rate base additions? If yes, please provide:

(a) A breakout of expenditures by project, to include the total Company dollar amount, the Oregon allocated dollar amount, and the FERC account.

(b) A brief narrative describing why each project is needed and how ratepayers will benefit.

Response to OPUC Data Request 383

Please refer to Attachment OPUC 383.

OR - UE 399
OPUC 383

Attachment OPUC 383

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
Intangible Plant Additions

	383 A			**383 A**	**383 A**	**383 A**	
Project Description	**FERC Account**	**Factor**	**Inservice Date**	**July21 to Dec22 Plant Adds**	**OREGON FACTOR**	**Oregon Allocated Additions**	**Proposed Updated Overview**
PP Core IT and TOM Software	303	SO	various	14,233,137	27.215%	3,873,593	The PP Core IT and TOM Software project represents PacifiCorp's investment program in software for the Company's existing applications, software needed to support PacifiCorp's infrastructure, and software related to Large Scale Technology Obsolescence Management (TOMs). The software investments are conducted to add capacity or improve software functionality and capabilities while the Large scale TOMs seek to address system obsolescence.
Maximo Phase 1A	303	SO	Jun-22	10,486,213	27.215%	2,853,856	Maximo is a world-class enterprise asset management software. With an average system age of 17 years, 80 percent of the core asset and work management systems at the BHE companies are beyond end-of-life. Modernizing enterprise asset management capabilities will lower or eliminate the costs and complexities associated with outdated systems. System integration will allow us to better serve our customers while adhering to compliance timelines through reduced costs, increased security and simplified processes across the business. Implementing a standardized tool for asset and work management across BHE will enable standardized processes, universal visibility and master data integrity – including data driven reporting, analysis and decision making – positioning us to be a more agile organization, improve the employee experience and better serve our customers. Maximo Phase 1A rollout for PacifiCorp is scheduled for in-service in Q2 2022 and will focus on substation operations, including preventative maintenance scheduling and field inspection results collection.
CX Engagement	303	SO		9,248,663	27.215%	2,517,053	This project includes the deployment of the Customer Experience Engagement systems. This project aims to implement CX Sales Cloud, a customer relationship management application for Regional Business Managers (RBM's) supporting large customers and replace existing Salesforce solution. This project will provides Sales, Functional, Reporting and Custom integration capabilities to RBM's. With this project, regional business managers will also be able to receive notifications on outages at large customer sites for impacted customers.
Monarch PAC6 Upgrade and HW TOM	303	SO	Nov-21	6,554,759	27.215%	1,783,898	This project includes direct hardware purchases including server, network and workstation hardware to support Data Center Consolidation and future system deployments. PacifiCorp's existing hardware infrastructure is at the end of life thus investment is needed to expand infrastructure to support anticipated increase in data load driven by future grid operation growth and emerging requirements for additional generation, transmission lines, substations, and distribution equipment. The hardware will be sized in the project for the growth for the next five years.
Mapping Sys Consolidation	303	SO	Jan-22	3,672,800	27.215%	999,564	The project intends to consolidate PacifiCorp's mapping systems to reduce data redundancy, provide a single system of record for operational assets and serve as the asset inventory source for PacifiCorp's planned Work Asset Management system. The consolidation of the mapping system will also provide operational benefits by reducing manpower required to map information in two disparate systems using different formats. The existing process creates inefficiencies and increases the risk of error and inconsistencies.
CX Communications	303	SO		3,436,541	27.215%	935,265	This project includes the deployment of the Customer Experience Communication systems including the Eloqua, Responsys and Infinity software modules. These tools will provide PacifiCorp with expanded capabilities for rate payer outreach through email and SMS communications including the ability to provide real-time communications on outages and service restoration.
SunNet iTOA (Compass Repl)	303	SO	Dec-21	3,182,959	27.215%	866,252	This project is to replace PacifiCorp's current Outage Management tool COMPASS (coordinated outage management planning and scheduling system) which the provider retired in May 2021. The Outage Management tool is critical to the conduct of PacifiCorp's business as it directly relates to PacifiCorp's ability to remain compliant with North American Electric Reliability Corporation (NERC) standards, participate in the Energy Imbalance Market (EIM), and manage safety regulations. This effort will replicate and add functionality to the replacement tool Sun-Net iTOA (iTOA). Expanded functionality includes switch writing, distribution clearance tracking, and distribution outage scheduling. The iTOA solution will also add efficiencies for compliance reporting.
PP IT Business Requested Software	302	SO	various	3,142,416	27.215%	855,218	This project includes activities related to new or improved software required to support business operations which are approved as individual projects, for various locations.
UII RVN Replacement	303	SO	Jun-22	1,713,600	27.215%	466,362	PacifiCorp's Revenue (RVN) system is a legacy system which provides monthly and annual variance analysis for revenue, kWh and number of customers. This project is to implement expanded capabilities of the UIPlanner Customer Revenue Model (CRM) to include revenue accounting for actual results, and is intended to be used as the book of record for kWh and number of customers. The replacement of the RVN system is necessary as the system relies upon obsolete technology causing difficulty with system maintenance and creates limitations in adjusting for regulatory tariff requirements. Replacement of the RVN system will allow greater functionality for reporting in today's business environment, create synergies with PacifiCorp's upgraded systems and technologies. Replacement will also increase data integrity, improve database maintenance, and mitigate risk of errors of reliance on a legacy access database.
ARCOS Callout Crew Availability System	303	SO	Aug-21	1,268,568	27.215%	345,245	The Callout and Crew Availability System Replacement project includes funding for the extended use of PacifiCorp's Callout and Crew Availability system which is the system utilized by the Transmission and Distribution departments to obtain trouble responders and crews to work system outages. The system provides ability to track employee's work time (hours) and real-time availability.
Replace IAM-Scheduling/Tagging Power	303	SO	Sep-21	1,024,559	27.215%	278,837	This project includes the development of a tool to help automate PacifiCorp's bidding, scheduling and tagging process which is a critical to the reliable operation of the electric grid. The project seeks to improve the integration of bidding, scheduling and tagging by creating more automation and flexibility in order to more fully optimize bids and transfer the least cost hourly dispatch. The current tools require more manual changes in information requirements creating risk of error and resulting in slower response to market conditions. The project is designed to provide more automation to help manage the interactive system balancing requirements as well as to meet the CAISO's hour-ahead scheduling, bidding and tagging requirements which is expected to provide the lowest cost result for net power costs the benefit of which is passed along to customers.
Projects Less Than	303	OR	Various	-	0.000%	-	
Projects Less Than	303	SO	Various	7,030,432	27.215%	1,913,354	
				64,994,648		17,688,497	

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 384

OPUC Data Request 384

Information Technology Expenditures - Does the Company have a formal acquisition policy or procurement procedure for IT and OT projects? If yes:

(a) Please provide a copy of the current policy/procedure(s).

(b) Please provide a narrative description of Avista's process(es) for acquiring IT and OT resources.

(c) Please describe how the IT and OT procurement process enhances cybersecurity, IT, and OT system resilience.

Response to OPUC Data Request 384

The Company assumes that the reference to "Avista" is in error and that this request is intended to request information related to PacifiCorp. Based on the foregoing assumption, the Company responds as follows:

PacifiCorp does not have a policy or procurement procedure specifically for information technology and operational technology projects, however, please refer to Attachment OPUC 384 which provides the Company's general procurement policy and procurement procedures overview documents.

Staff Exhibit

“Relevant attachment to PacifiCorp’s response to Staff DR 384”

is

filed in electronic format

CASE: UE 399
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Julie Jent. I am a Utility Analyst employed in the Telecom/Universal Services and Regulatory Analysis Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review several categories of PacifiCorp's Company's (PAC, PacifiCorp, or Company) Test Year expense, including expenses for advertising, promotional activities and concessions, current medical and health insurance, non-medical insurance, and Directors and Officers (D&O) Insurance.

Q. Did you prepare any other exhibits for this docket?

A. Yes. PacifiCorp's non-confidential responses to select data requests can be found in Exhibit Staff/1202 and PacifiCorp's confidential responses to select data requests can be found in Exhibit Staff/1203. Staff's workpapers can be found in Staff Exhibit/1204.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Staff's recommendations to the Oregon allocated amounts are as follows: Issue 1 (Advertising Expenses) – an adjustment of $111,483; Issue 2 (Promotional Activities and Concessions) – no adjustment; Issue 3 (Current Medical and Health Insurance) – an adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**; Issue 4 (Insurance and Risk (Non-Medical)) – an adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**; Issue 5 (D&O Insurance) – no adjustment. My recommendations may change based on further review and based on the testimonies offered by other parties.

ISSUE 1, ADVERTISING EXPENSES

Q. Does the Commission have a standard means of determining how advertising and promotional expenses are treated?

A. Yes. OAR 860-026-0022 sets out how advertising expenses should be addressed in a rate case. This rule defines advertising expenses as, "expenses for communications which inform, influence, and/or educate customers."[1] A key difference between an "advertising expense" and a "promotional activity" is that advertising expenses are specifically described as communicating a message to customers and chargeable to FERC Account 909, while promotional activities are meant to promote the utility's product to a wider audience and chargeable to FERC Accounts 911, 912, 913, or 916.[2] Utility advertising expenses are grouped into five categories:

Category "A" – Energy efficiency or conservation advertising expenses that do not relate to a Commission approved program, utility service advertising expenses, and utility information advertising expenses;

Category "B" – Legally mandated advertising expenses;

Category "C" – Institutional advertising expenses, promotional advertising expenses and any other advertising expenses not fitting into Category "A," "B," or "D";

Category "D" – Political advertising expenses and non-utility; and

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[1] OAR 860-026-0022 (1)(a).

[2] OAR 860-026-0010.

Category “E” – Energy efficiency or conservation advertising expenses that related to a Commission-approved program.[3]

OAR 860-026-0022(3) specifies that for ratemaking purposes:

- Category "A" expenses are presumed to be just and reasonable to the extent that expenses are twelve and one-half hundredths of 1 percent (0.125 percent) or less of the gross retail operating revenues determined in the rate proceeding.
- Category "B" expenses are presumed to be just and reasonable.
- Category “C” expenses can be included in rates, but the utility shall carry the burden of showing that any advertising expenses in this category are just and reasonable.
- Category "D" expenses are presumed to be not just and reasonable.
- Category "E" expenses may be capitalized and are subject to a prudence review.

Q. Please describe the Company’s request for advertising.

A. The Company proposes to include $1,698,010 in its 2023 Pro Forma Test Year (TY) for advertising in FERC Accounts 909 (Informational Advertising) and 930.1 (General Advertising). This includes $1,423,498 in Category A, $163,029 in Category B, $67,178 in Category C, and $44,305 in unclassified advertising expenses for their Oregon allocated totals.[4] The percentage change from the Base Year (BY) to the TY for the System and for Oregon

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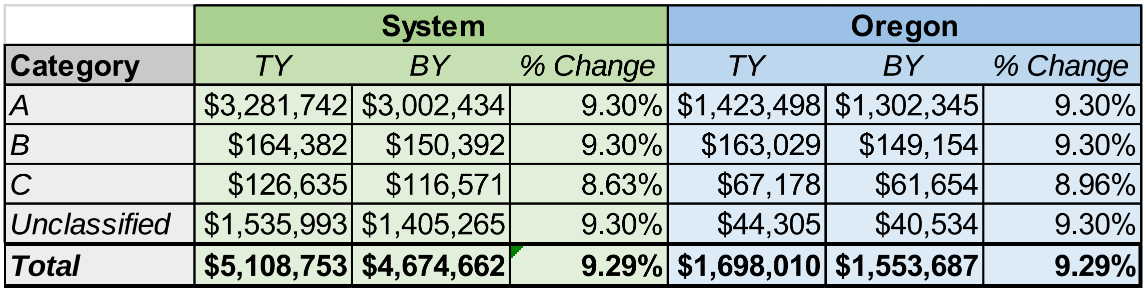
[3] OAR 860-026-0022(2).

[4] *See* Staff/1202, PAC Response to DR 359 (pdf) and DR 359 Attach (electronic spreadsheet). This response also includes previous data mentioned in Responses to SDR 104 and DR 176.

differ slightly (by approximately $200) as shown in Figure 1 for Category C. Staff is attempting to find out whether this is an error in their own calculation or in that of PacifiCorp's.

FIGURE 1: ADVERTISING CATEGORY CHANGES FROM BY TO TY[5]



	System			Oregon		
Category	*TY*	*BY*	*% Change*	*TY*	*BY*	*% Change*
A	$3,281,742	$3,002,434	9.30%	$1,423,498	$1,302,345	9.30%
B	$164,382	$150,392	9.30%	$163,029	$149,154	9.30%
C	$126,635	$116,571	8.63%	$67,178	$61,654	8.96%
Unclassified	$1,535,993	$1,405,265	9.30%	$44,305	$40,534	9.30%
Total	**$5,108,753**	**$4,674,662**	**9.29%**	**$1,698,010**	**$1,553,687**	**9.29%**

TY amounts were forecasted taking the BY (July 2020-June 2021) total Company data, removing miscellaneous expenses that should have been charged to non-regulated accounts, using one of the three Oregon allocated percentages (27.173 (SO), 30.990 (CN), or 100 (OR)), escalating labor data using contracted and expected increases and escalating non-labor data using industry specific inflation indices provided by the IHS Markit.[6] The escalation factors used are shown in Figure 2.

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[5] *See* UE 399, Staff/1204, Staff electronic work paper Exhibit 1204 Non-Confidential Figures for an excel page dedicated to each figure with the sources listed and calculations intact. In some cases, Staff recreated or modified a DR response to create the figures you see in this exhibit.

[6] Confidential Exhibit PAC/1005 Cheung/1 – IHS Markit Escalation Indices. *See also* Staff/1202, PAC Response to DR 187 (pdf) and PAC Response to DR 364 (pdf).

FIGURE 2: EXHIBIT PAC 1005 CONFIDENTIAL ESCALATION FACTORS[7]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Please describe your analysis of the Company's adjustments.

A. The Company detailed advertising adjustments in its work paper, which is summarized by Figure 3 below.[8] These adjustments were used in conjunction with escalation factors to arrive at a TY request.

FIGURE 3: PAC ADVERTISING ADJUSTMENTS

FERC Account	Description	System Adjustment	Factor Percentage	OR Adjustment
903	Customer Records-Blue Sky	$ (14,359)	Situs	$ (14,359)
909	Blue Sky	$ 4,970	30.99%	$ 1,540
	Add Situs Allocation (OR)	$ 45,719	Situs	$ 45,719
	Giving Campagin	$ (420)	30.99%	$ (130)
	Remove system allocation	$ (78,541)	30.99%	$ (24,340)
	Add Situs Allocation (CA)	$ 19,017	Situs	
	Add Situs Allocation (ID)	$ 1,052	Situs	
	Add Situs Allocation (UT)	$ 11,080	Situs	
	Add Situs Allocation (WA)	$ 10,746	Situs	
	Add Situs Allocation (WY)	$ -	Situs	
929	Duplicate Charge	$ 317	27.17%	$ 86
Total		**$ (420)**		**$ 8,516**

Staff reviewed the Total Company's advertising adjustments, which consisted of the reallocation of advertising expenses (Blue Sky) from

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[7] *See* UE 399, Staff/1204, Staff electronic work paper Exhibit 1204 Confidential Figures for an excel page dedicated to each figure with the sources listed and calculations intact.

[8] PAC/1002, Cheung Workpapers 4.1 Misc Gen Expense & Revenue (electronic spreadsheet).

customer expense Accounts 903 and 929 into Advertising Account 909, as per Commission policy as well as adding situs allocations.[9]

Q. Did Staff go beyond reviewing the adjustments?

A. Yes. In addition to the review of adjustments and transaction-level detail of the BY advertising expenses, Staff reviewed copies of advertisements in various formats.[10] Staff issued additional data requests (DRs), which included DR Nos. 141-142, 176-188, and 359-366, responses to some of which are included in Staff Exhibit 1202.

Q. Please describe your analysis of the Company's proposed advertising expenses in Category A.

A. In Category A, the Company requests $1,423,498 in the TY.[11] The expenses included in the filing do not exceed the set limit provided in OAR 860-026-0022(3)(a). Staff reviewed the BY transaction-level data and determined the expenses were properly attributed to Category A, "utility service and utility information advertising." The bulk of spending in this area was on awareness advertising and outreach of energy efficiency, safety, and service information. From BY to TY, Category A increased 9.3 percent from $1,302,345 and Staff has no adjustment since the increase is a result of PAC using the escalation described in Figure 2.

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[9] Order 99-033 at 63.

[10] *See* Staff/1202, PAC Response to DR 177 (pdf) and 178 (pdf).

[11] *See* Staff/1202, PAC Response to SDR 104-1 Attach (electronic spreadsheet) and DR 176-1 (electronic spreadsheet).

Q. Please describe your analysis of the Company's proposed advertising expenses in Category B.

A. In Category B, or "legally mandated" advertising, the Company requests $163,029.[12] Staff reviewed the Category B "legally mandated" advertising expenses, which mostly consisted of direct mailings. Category B saw a 9.3 percent increase from a BY total of $149,154 and Staff has no adjustment.

Q. Please describe your analysis of the Company's proposed advertising expenses in Category C.

A. Category C includes two sub-types of advertising: 1. Institutional Advertising, "the primary purpose of which is not to convey information, but to enhance the credibility, reputation, character, or image of an entity or institution," and 2. Promotional Advertising Expenses, "the primary purpose of which is to communicate with respect to an energy or large telecommunications utility's promotional activities or promotional concessions, as defined in OARs 860-026-0010 ("Promotional Activity" Defined) and 860-026-0015 ("Promotional Concession" Defined).[13] None of PAC's Category C expenses are related to Promotional Advertising Expenses so they all Category C advertising falls under Institutional Advertising.

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[12] *See* Staff/1202, PAC Response to SDR 104 (pdf) SDR 104-1 Attach (electronic spreadsheet).

[13] OAR 860-026-0022(1)(c) and OAR 860-026-0022(1)(f).

In Category "C", the Company requested $67,178, which is assigned to both FERC Account 909 and 930.1.[14] The expenses are primarily job recruitment advertising expenses and informational expenses related to the Blue Sky Program.[15] Category C increased 8.96 percent, from $61,654 (BY) to $67,178 (TY), most of this change is due to the reallocation of Blue Sky advertising expenses from customer accounts.

Despite Category C expenses being attributed to Blue Sky in its accounting data and in its original response to DR 104,[16] the Company seems to contradict itself by stating that "[t]he following programs (Blue Sky and Demand-Side Management Programs) do not include advertising in the TY. Funds for these programs are collected through a separate tariff and not part of base rates."[17] In addition, they stated, "[r]evenue and expenses related to the Blue Sky program are not included in PacifiCorp's general rate case (GRC)."[18] The burden of proof is on the Company to prove that the Category C expenses are just and reasonable. The Company did not fully include information requested in Standard Data Request (SDR) 104 and subsequent DRs 360-362, which asked for details such as a justification for inclusion into rates.[19] The ten largest expenses for Category C in FERC Accounts 909 and 930.1 are shown in Figure 4 to demonstrate the types of

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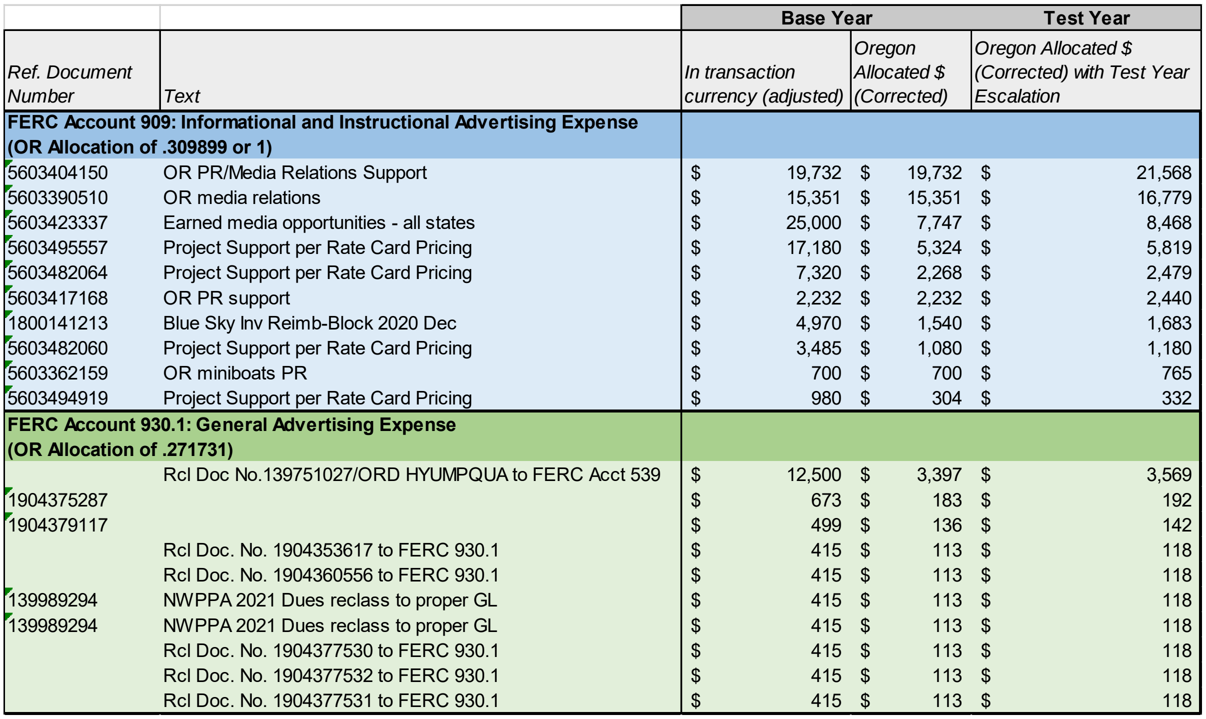
[14] *See* Staff/1202, PAC Response to DR Request 361 (pdf).
[15] *See* Staff/1202, PAC Response to DR 360 (pdf).
[16] *See* Staff/1202, PAC Response to DR 104 (pdf).
[17] *See* Staff/1202, PAC Response to DR 362 (pdf).
[18] *See* Staff/1202, PAC Response to DR 180 (pdf).
[19] *See* Staff/1202, PAC Response to DR 360 (pdf), DR 361 (pdf), 362 (pdf).

expenses included in this category. Staff recommends removing Category C expenses, which total $67,178 for the TY.

FIGURE 4: EXAMPLES OF CATEGORY C ADVERTISING EXPENSES IN OREGON[20]



		Base Year		Test Year
Ref. Document Number	*Text*	*In transaction currency (adjusted)*	*Oregon Allocated $ (Corrected)*	*Oregon Allocated $ (Corrected) with Test Year Escalation*
FERC Account 909: Informational and Instructional Advertising Expense (OR Allocation of .309899 or 1)				
5603404150	OR PR/Media Relations Support	$ 19,732	$ 19,732	$ 21,568
5603390510	OR media relations	$ 15,351	$ 15,351	$ 16,779
5603423337	Earned media opportunities - all states	$ 25,000	$ 7,747	$ 8,468
5603495557	Project Support per Rate Card Pricing	$ 17,180	$ 5,324	$ 5,819
5603482064	Project Support per Rate Card Pricing	$ 7,320	$ 2,268	$ 2,479
5603417168	OR PR support	$ 2,232	$ 2,232	$ 2,440
1800141213	Blue Sky Inv Reimb-Block 2020 Dec	$ 4,970	$ 1,540	$ 1,683
5603482060	Project Support per Rate Card Pricing	$ 3,485	$ 1,080	$ 1,180
5603362159	OR miniboats PR	$ 700	$ 700	$ 765
5603494919	Project Support per Rate Card Pricing	$ 980	$ 304	$ 332
FERC Account 930.1: General Advertising Expense (OR Allocation of .271731)				
	Rcl Doc No.139751027/ORD HYUMPQUA to FERC Acct 539	$ 12,500	$ 3,397	$ 3,569
1904375287		$ 673	$ 183	$ 192
1904379117		$ 499	$ 136	$ 142
	Rcl Doc. No. 1904353617 to FERC 930.1	$ 415	$ 113	$ 118
	Rcl Doc. No. 1904360556 to FERC 930.1	$ 415	$ 113	$ 118
139989294	NWPPA 2021 Dues reclass to proper GL	$ 415	$ 113	$ 118
139989294	NWPPA 2021 Dues reclass to proper GL	$ 415	$ 113	$ 118
	Rcl Doc. No. 1904377530 to FERC 930.1	$ 415	$ 113	$ 118
	Rcl Doc. No. 1904377532 to FERC 930.1	$ 415	$ 113	$ 118
	Rcl Doc. No. 1904377531 to FERC 930.1	$ 415	$ 113	$ 118

Q. Please describe your analysis of the Company's proposed unclassified advertising expenses in FERC Account 909.

A. These unclassified advertising expenses total $44,305 on an Oregon-allocated basis. Staff found that the unclassified (n/a) advertising costs are either: 1. Partially assigned to Oregon despite providing direct benefits for states other than Oregon; or, 2. Are expenses that do not fall under the allowable definitions of advertising expenses (in FERC 909 or others). Staff

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[20] *See* Staff/1202, PAC Response to DR 176-1 Attach (electronic spreadsheet).

has included the ten largest examples that are demonstrative of these costs in Figure 5. Staff recommends removing these unclassified advertising expenses, which total $44,305 for the TY.

FIGURE 5: EXAMPLES OF UNCLASSIFIED ADVERTISING EXPENSES IN OREGON[21]

Expense Description	Sum of Oregon Allocated $ (Corrected) with Test Year Escalation
Jun-2021 Accrual THE 3THIRDS GROUP INC	$ 15,759
CA wildfire safety	$ 5,243
Project Support per Rate Card Pricing	$ 4,135
UT wildfire safety	$ 3,176
WA wildfire safety	$ 2,823
HR/Payroll Document	$ 1,601
RMP Outage Mailing	$ 1,600
RMP-Winter/Contact Info Postcard + Mailing	$ 1,484
CA wildfire safety/preparedness	$ 1,198
UT wildfire safety and preparedness	$ 933

Q. What is your overall recommendation regarding advertising expenses?

A. Staff recommends removing Category C advertising expenses as well as unclassified expenses, resulting in an adjustment of $111,483 to the TY Oregon allocated amount of $1,692,735. This TY total includes Categories A-C and unclassified advertising expenses. This would arrive at a TY amount of $1,586,527.

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[21] *Ibid*. *See also*, Staff/1203, PAC Confidential Responses to DR 142 provides line-item details for FERC Account 901 through FERC Account 935 on a total Company and Oregon allocated basis for each of the 12 months which ended June 30, 2020 and June 30, 2021 (electronic spreadsheet 909).

ISSUE 2, PROMOTIONAL ACTIVITY AND EXPENSES

Q. What are promotional activities and concessions?

A. A promotional activity or concession is intended to promote the use of the utility's product or service among present or prospective customers.

ORS 860-026-0010 defines promotional activity as:

> [A]ction by an energy or large telecommunications utility or its affiliate with the objective of increasing or preventing a decrease in the quantity of the energy or large telecommunications utility's service used by present and prospective customers; inducing any person to use an energy utility's service rather than a competing form of energy[.]

OAR 860-026-0015 defines promotional concession as:

> [A]ny consideration offered or granted by an energy or large telecommunications utility or its affiliates to any person with the object, express or implied, of inducing such person to select or use the service or additional service of such utility, or to select or install any appliance of equipment designed to use such utility service.

Examples of promotional concessions include rebates, provision of free goods or services, or providing financing for a natural gas appliance at a lower-than-market interest rate.[22] Utilities are required to file a description of all promotional concession expenses with the Commission before making them.[23] Utilities are also required to file, concurrently with their annual report, a report detailing the previous year's promotional activities and concessions and a statement of the benefits achieved from each.[24]

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[22] OAR 860-026-0015(2).

[23] OAR 860-026-0025(1).

[24] OAR 860-026-0035(1).

Q. What are the standards for reviewing promotional activities and concessions?

A. Promotional activities and concessions should benefit both the utility and its customers. ORS 860-026-0020 provides the following direction for promotional activities and concessions:

> All promotional activities and concessions shall be just and reasonable, prudent as a business practice, economically feasible and compensatory, and reasonably beneficial both to the energy or large telecommunications utility and its customers. The cost of promotional activities and concessions must not be so large as to impose an undue burden on the energy or large telecommunications utility's customers in general and must be recoverable through related sales stimulation within a reasonable time.[25]

Q. Has the Company filed its promotional concessions request with the Commission?

A. No, PacifiCorp does not engage in promotional activities in Oregon and has not filed a request with the Commission for promotional concessions.[26]

Q. Does Staff propose an adjustment to promotional activities and concessions?

A. No adjustment is needed or recommended as there were no promotional activities or concessions included in this GRC. In addition, those Category C expenses included in Issue 1 fall under Institutional advertising and not Promotional advertising.

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[25] OAR 860-026-0020.

[26] *See* Staff/1202, PAC Response to DR 185 (pdf) and DR 188 (pdf).

ISSUE 3, CURRENT MEDICAL AND HEALTH INSURANCE

Q. Please summarize the Company's proposed Test Year expenses for health insurance and workers compensation benefits.

A. Staff performed a four-year trend analysis for the health coverages for which PacifiCorp provided data in response to SDRs 064-067. Staff submitted additional DRs (142-146, 189-193, 351-353, and 366). Figure 6 illustrates the Company's medical benefit costs for the Base Year (BY), the preceding two years, and the Test Year (TY) amounts.

FIGURE 6: HEALTH INSURANCE BENEFITS OVER TIME FOR OREGON[27]

	CY 2023	CY 2021	CY 2020	CY 2019	CY 2018
Medical	$11,395,468	$10,377,600	$10,175,387	$10,398,532	$10,716,805
Dental	$808,448	$664,007	$600,256	$693,884	$770,248
Vision	$97,792	$47,940	$53,318	$67,846	$72,571
Total	$12,301,709	$11,089,548	$10,828,961	$11,160,263	$11,559,624

The Company used internal planning targets for TY medical, dental and vision benefits, resulting in a TY System total of $66.1 million and an Oregon allocated amount of 12.3 million.[28] The amounts are after employer/employee sharing and include no increase in employees beyond BY levels. Planning targets for medical, dental, and vision are not detailed beyond the escalation rates listed in Confidential Exhibit PAC/1005.

Q. What is the historical treatment of the issue?

A. Staff generally analyzes medical benefits by performing the following:

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[27] *See* Staff/1202, PAC Response to DR 366 Attach (electronic spreadsheet), and PAC Supplemental Response to DR 366 (electronic spreadsheet).

[28] *Ibid.*

1. Reviewing the Company's policies for overall reasonableness;
2. Reviewing the historical trend of benefits costs and taking into account factors that might distort the trend;
3. Comparing the Company's actual historical benefits costs with its budgeted historical costs;
4. Comparing the Company's cost trend against national data,
5. Comparing the premium sharing percentages of the Company to national averages; and,
6. Coordinating with the Staff responsible for FTE to make sure that the FTE adjustment incorporates the medical benefits cost per FTE.

Q. Please describe an overview of the analysis performed by Staff.

A. First, the Company's projected TY health insurance expense for Oregon is $12.3 million (an 11 percent increase) over the BY ($11.1 million). Health care coverage usually runs on a calendar year (CY) basis, so BY expense data is likely skewed lower than actual 2021 CY since Q3 and Q4 expenses tend to trend higher than Q1 and Q2 expenses.

Second, PAC's premium contribution sharing is aligned with the average from Kaiser Family Foundation's 2021 Survey (83/17 for single employees).[29] PACs sharing is **[BEGIN CONFIDENTIAL]** [redacted]

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[29] Kaiser Family Foundation (KFF) 2021 annual Employer Health Benefits Survey available at 2021 Employer Health Benefits Survey | KFF.

[redacted] **[END CONFIDENTIAL]**.[30]

Third, Staff also looked at Pricewaterhouse Cooper's (PwC) Health Research Institute (HRI) Annual Medical Cost Trend: Behind the Numbers Reports for 2021 and 2022.[31] In general, the current and ongoing COVID-19 pandemic likely skewed recent years' medical care costs and continues to weigh on projected 2022 medical cost growth. PwC projected medical cost trends to be 6.5 percent in 2022, down from 7 percent in 2021. This is comparable to the December 2023 escalation used by PAC, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This is still well above economic growth and general inflation and contributes to increases in medical insurance from BY to TY.

Q. Did Staff find any issues with the proposed Test Year expenses for medical, dental, or vision?

A. Yes. Staff finds that the TY totals for vision and dental insurance (which are based on internal targets) are notably higher than estimates for inflation and the expected increases in vision related expenses. This is not in line with the following facts **[BEGIN CONFIDENTIAL]** [redacted]

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[30] *See* Staff/1203, PAC Response to SDR 65 (pdf). PAC Response to SDR 65 is non-confidential but it could be used to infer confidential information and is therefore included in Staff/1203 as confidential.

[31] PwC HRI Medical cost trend: Behind the numbers 2021 available at https://www.pwc.com/us/en/industries/health-industries/library/assets/hri-behind-the-numbers-2021.pdf. PwC HRI Medical cost trend: Behind the numbers 2022 available at https://www.pwc.com/us/en/industries/health-industries/library/behind-the-numbers.html.

[redacted] **[END CONFIDENTIAL]** and 3. Take-up rates across employers are not expected to have a dramatic uptick moving forward according to the Kaiser Family Foundation. The share of eligible workers surveyed by Kaiser taking up benefits in offering firms was 77 percent for 2021, similar to the take-up rate for 2016 (79 percent).[33] This stability in dental and vision insurance is demonstrated in Figure 7.

FIGURE 7: STABILITY OF DENTAL AND VISION[34]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. What does Staff recommend?

A. Staff recommends escalating June 2021 data to December 2023 by the Global Insight Factors and Percentage shown in Figure 8 (which are used by the Company and in line with health reports referenced above).

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[32] The adjustment is described in PAC CONF workpaper 4.2.7 but it does not include information related to the internal planning targets for Dental and Vision.

[33] Kaiser Family Foundation (KFF) 2021 annual Employer Health Benefits Survey available at 2021 Employer Health Benefits Survey | KFF (Figure 3.1; Page 59).

[34] *See* Staff/1203, PAC Response to SDR 64 (electronic spreadsheet).

FIGURE 8: CONFIDENTIAL ESCALATION FACTORS FOR FERC 926[35]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Current requests for dental and vision are based on actuarial projections/internal planning targets, which contribute to the large increase from the BY to the TY for dental and vision. The adjustment calculation shown in Figure 9 results in an adjustment to the Oregon allocated amount of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

FIGURE 9: ADJUSTMENTS TO DENTAL AND VISION

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Please state Staff's proposed adjustment.

A. Staff proposes an adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to Oregon allocated health coverage expenses. This would

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[35] Confidential Exhibit PAC/1005.

bring the TY request of $12.3 million, down to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which is more in line with national health inflation trends addressed on Jent/17.

ISSUE 4, INSURANCE AND RISK (NON-MEDICAL)

Q. Please explain what types of insurance were reviewed.

A. In addition to medical insurance, which was addressed in Issue 3, Staff reviewed documents relating to property insurance, liability insurance, workers' compensation insurance, and other risk management insurance (in SDRs 063-075). Staff requested additional information in DRs 142, 351-358, and 367-374. This issue encompasses FERC Account 924 (Property Insurance) and 925 (Injuries and Damages).

Q. Please summarize the Company's proposed Test Year expenses for non-health insurance coverages.

A. The Company used ten years of property loss/damages and three years of injuries and damages data for the Test Year (TY) estimate. The Company escalated property loss/damages using the CPI-U but did not escalate injuries and damages.[36] For Oregon, the Company's projected non-health insurance expense is $23.8 million in the TY, a 53.97 percent reduction from the Base Year (BY) total of $51.6 million; this is illustrated in Figure 10.

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[36] *See* Staff/1202, PAC Response to SDR 68 Attach (electronic spreadsheet) and PAC Response to DR 353 Attach (electronic spreadsheet). *See also* PAC/1000 Cheung/19-21 and Cheung workpapers, 4.5 – Insurance Expense.

FIGURE 10: SYSTEM AND OREGON ALLOCATED NON-HEALTH INSURANCE EXPENSES

	System			Oregon		
Cost	*Test Year 2023*	*Base Year 2021*	*Change from BY to TY*	*Test Year 2023*	*Base Year 2021*	*Change from BY to TY*
Property Insurance Premiums	$ 3,612,548	$ 4,371,510	-17.36%	$981,641	$1,187,874	-17.36%
Property – Uninsured Losses	$16,064,875	$ 11,665,617	37.71%	$11,847,293	$7,448,035	59.07%
Liability Insurance Premiums	$29,399,334	$ 8,607,251	241.56%	$7,988,705	$2,338,855	241.56%
Liability – Uninsured Losses	$ 5,257,146	$144,478,090	-96.36%	$2,600,101	$40,340,442	-93.55%
Workers' Compensation Premiums	$ 1,236,449	$ 1,156,797	6.89%	$355,006	$332,137	6.89%
Total	**$55,570,351**	**$170,279,266**	**-67.37%**	**$23,772,746**	**$51,647,343**	**-53.97%**

Q. What is the Commission's treatment of insurance expenses in a general rate case?

A. Commission order 09-020 (UE 197) sets forth the following principles:

- *D&O Insurance*: Eliminate 50 percent.
- *Premiums*: Remove any costs that are attributed to nonoperating and nonregulated operations. Apply the utility allocation percentage to overall policy premiums. And examine market increases/decreases from websites such as marketscout.com to verify any proposed increases.
- *Uninsured Losses*: Staff examines a utility's actual uninsured losses related to automobile liability, general liability, and workers' compensation over the previous five-year period. For each year of losses, the losses are escalated using the CPI-U, to obtain equivalent year losses. Staff will

then calculate the five-year average of the losses, escalate the average to the TY and compare to the Company's TY amount.[37]

In addition, in the 2010 Rate Case, the Commission authorized the Company to establish monthly accruals and associated reserve balances for self-insurance which started on April 1, 2011. [38] Staff reviews premiums and uninsured losses separately in the rest of this issue.

Q. What is your analysis of total premiums?

A. Total premiums (excluding workers' compensation) in Oregon increased 154 percent from the BY to the TY (going from 3.5 million to 9.0 million). Two types of premiums (property and liability) are analyzed further below.

Q. What is your analysis of property premiums and adjustments?

A. Consistent with the treatment from the 2010 Rate Case, the Company used a 10-year average of the most recent property damages for the self-insurance reserve accrual. Oregon allocated property premiums were $1.2 million for the 12 months ended June 2021 and were adjusted to $981,461 for the TY.

Q. What is your analysis of liability premiums and adjustments?

A. Staff noted liability insurance premiums effectively quadrupled from the BY to the TY. Oregon allocated liability insurance premiums were $2.3 million for the 12 months ended June 2021 and will increase to $8.0 million in the Test Period. The increase in renewed liability insurance premiums effective

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[37] In UE 197, the Commission adopted this principal to set uninsured losses at an escalated five-year average adjusted for inflation. In the Matter of Portland General Electric Company, Request for General Rate Revision, Docket UE 197, (Order 09-020 at 20) January 22, 2009.

[38] PAC/1000 Cheung/19 and 4.5.5 Work Papers.

August 15, 2021, is attributable to wildfire risk and other factors outside PacifiCorp's control.[39] For the past several years, P&C premium growth traditionally grew at a faster pace than the all-urban consumer price index (CPI-U) inflation rate (the CPI-U is generally Staff's primary escalation metric). Because insurance is generally a competitively priced market, PAC is treated as a sophisticated insurance customer that can (and should) evaluate "like" coverages for the best price point vis-à-vis reliability/quality of the insurer and the policy coverage offered. In addition, because of some policy coverage changes in one (or more) of the historical periods, it is difficult to do year-to-year comparisons of premium pricing to risk coverages.

Q. What is your analysis of total uninsured losses?

A. Total Uninsured Losses (both property and liability) in Oregon declined 69.77 percent from the BY to the TY (going from 47.8 million to 14.4 million). Property and liability uninsured losses are broken down into separate questions below.

Q. What is your analysis of Property Uninsured Losses and Adjustments?

A. The amount for property-uninsured losses increased from $7.4 million in the BY to $11.8 million in the TY. The Insurance Expense Adjustment work paper includes the support for the two items which make up the additional $4.4 million for property and Staff finds an issue with the second part of the adjustment. One part of the Insurance Adjustment recalculates the historical 10-year

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[39] *Ibid.*

average Oregon-allocated property damage amount using the most recent 10-year time-period and results in a $2.3 million increase.

Another piece of the Insurance Adjustment includes amortizing the June 2021 Oregon property reserve balance. The Company proposes that the steep debit position of $20.9 million should be amortized over 10 years, which results in a $2.1 million increase to the TY.[40] Staff disagrees and proposes instead to remove the $2.1 million increase. PAC failed to properly estimate uninsured loss reserves for several years and Staff does not believe the current estimate is accurate. Staff recommends the Company engage an independent third-party actuary to vet PacifiCorp's projected future self-uninsured loss recovery projection methodology as well as the actual dollar deficiency.

Q. What is your analysis of liability uninsured losses and adjustments?

A. For liability, there was a decline of 93.55 percent from the BY to the TY (from 40.3 million to 2.6 million), this decline was due to the large total of uninsured losses for the company in 2020 and 2021 highlighted in red below in Figure 11. There was $136 million recorded in the last half of calendar year 2020, but this was adjusted out for the TY request.

However, the Net Base Year Expense amount on page 4.5.1 of $139 million (which includes general ledger (G/L) Accounts 545050 and 549302) was removed by PacifiCorp through an adjustment and that total

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[40] PAC/1000 Cheung/20-21; PAC attributed this to the underpaying of Oregon customers over the years.

includes the $136 million accrual.[41] In addition, PacifiCorp did not include any of the accrued claims for litigation/damages from the 2020 wildfires or any capital additions from the restoration efforts in this general rate case (GRC).[42] As noted in the testimony, PacifiCorp may seek recovery of these costs in a future proceeding.[43]

FIGURE 11: SYSTEM AND OREGON ALLOCATED NON-HEALTH INSURANCE EXPENSES IN PREVIOUS BASE YEARS

	System				Oregon			
Cost	*2023*	***2021***	***2020***	*2019*	*2023*	***2021***	***2020***	*2019*
Property Insurance Premiums	$ 3,612,548	$ 4,371,510	$4,494,291	$4,737,084	$981,641	$1,187,874	$1,264,824	$1,304,721
Property – Uninsured Losses	$16,064,875	$ 11,665,617	$11,869,459	$10,192,677	$11,847,293	$7,448,035	$6,649,341	$6,450,779
Liability Insurance Premiums	$29,399,334	$ 8,607,251	$7,633,162	$4,648,313	$7,988,705	$2,338,855	$2,148,193	$1,280,271
Liability – Uninsured Losses	$ 5,257,146	**$144,478,090**	**$141,812,794**	$3,448,356	$2,600,101	**$40,340,442**	**$41,422,153**	$2,287,227
Workers' Compensation Premiums	$ 1,236,449	$ 1,156,797	$1,108,299	$1,439,724	$355,006	$332,137	$318,790	$407,691
Total	$55,570,351	**$170,279,266**	**$166,918,005**	$24,466,154	$23,772,746	**$51,647,343**	**$51,803,302**	$11,730,689

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[41] *See* Staff/1203, PAC Response to DR 369 (pdf) and also refer to Exhibit PAC/1002 – Oregon Results of Operations – December 2023, specifically the Insurance Expense Adjustment workpaper (Adjustment 4.5) for the adjustments that were made to FERC Account 925.

[42] Wildfire Mitigation is covered in depth in both Moore/1300 and Storm/1700. In Docket No. RE 68, PAC filed a supplemental application on 4/30/2021. "PacifiCorp has accrued $136 million as its best estimate of the potential losses net of expected insurance recoveries associated with the 2020 Wildfires that are considered probable of being incurred. These accruals include estimated losses for fire suppression costs, property damage, personal injury damages and loss of life damages. It is reasonably possible that PacifiCorp will incur additional losses beyond the amounts accrued; however, PacifiCorp is currently unable to estimate the range of possible additional losses that could be incurred due to the number of properties and parties involved and the lack of specific claims for all potential claimants. To the extent losses beyond the amounts accrued are incurred, additional insurance coverage is expected to be available to cover at least a portion of the losses."

[43] *See* Staff/1203, PAC Response to DR 368 (pdf). *See also* Exhibit PAC/1000, Cheung/40 for details on this adjustment.

In opening testimony, PAC states that the Oregon-allocated monthly accrual for third-party liability losses was established based on an annual average of historical insurance claim payments from April 2005 to December 2009."[44] However, this seems to have been updated in the Company's workpaper and adjusted to reflect injuries and damages in the three years from 2019 to 2021.

Q. Did PacifiCorp file an application for deferred accounting related to wildfire damage and restoration costs (which may fall under the $136 million mentioned above)?

A. Yes. In Docket No. UM 2116, PacifiCorp filed an application on September 14, 2020, and submitted a supplemental application on October 4, 2021. This means there is approximately a three-week gap between the end of the first 12-month period and the beginning of the next twelve-month period, where costs incurred relevant to the deferral in that window will not be recoverable. Both applications were approved as indicated in Order Nos. 22-140 and 22-154.[45]

Q. Please note the issues that Staff discovered.

A. Regarding non-health insurance coverages, Staff noted three concerns:

First, Staff finds it unusual that the Company is cutting back on its TY insurance premiums at the same time it is significantly increasing its projected retained loss risk. A more prudent business decision (and customer protection)

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[44] PAC/1000 Cheung/20.

[45] PacifiCorp's Application for Authorization to Defer Costs and Lost Revenues Associated with the Wildfire Emergency, Page 3.

would be to hold the line or possibly even increase the insured loss coverage via an insurance provider(s), especially considering PacifiCorp's recent loss history and the potentially sizable self-insurance shortage balance. The slight decline in the TY property loss insurance premiums will have minimal customer rate impact, whereas Oregon's significantly increased risk retention places the burden on customers to cover any uninsured losses (in the form of future rate hikes) if the Company has another bad loss year. Staff does not believe that the minimal rate relief from lower insurance premium costs is worth the risk exposure to customers, especially given PAC experienced significant uninsured losses the past couple of years.

Second, the Company proposes amortizing the debit of $20.9 million for property reserve over ten years. Staff recommends removing this $2.1 million from the TY.

And third, any potential bonus or credit for non-liability coverage does not appear to be considered in the TY insurance premium. PacifiCorp states, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The Company further states for the TY that, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[46] Staff sees no provision for a credit or bonus in PacifiCorp workpapers Cheung - Non Conf WPs, Excel file

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[46] Staff/1203, PAC Response to SDR 71 Attach (electronic spreadsheet).

"4.5 - Insurance Expense", however PAC does state that policy holder credits in the Base Year are carried forward to the Test Year.[47] Based on the Company receiving **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, Staff proposes adjusting the Company's TY premiums calculation **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. On an Oregon allocated basis, this adjustment would **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[48]

Q. What is Staff's recommendation?

A. First, Staff recommends that the Company take reasonable steps to insuring more of its risks as time goes on, thereby ensuring coverage, even if this means a modest increase in rates to accommodate higher insurance premiums. Second, Staff recommends removing the $2,093,761 to address the issue of the ten-year amortization. Third, Staff recommends removing **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. What is Staff's overall recommended adjustment?

A. Staff recommends adjusting the Oregon-Allocated TY amount of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

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[47] Staff/1202, PAC Response to SDR 71

[48] *See* Staff/1203, PAC Response to SDR 071 (pdf) and SDR 071 Confidential Attach (electronic spreadsheet).

ISSUE 5, DIRECTORS AND OFFICERS (D&O) INSURANCE

Q. What is D&O insurance?

A. Directors and Officers insurance is liability insurance payable to the directors and officers of a company, or to the organization itself, as reimbursement for losses or advancement of defense costs in the event an insured suffers such a loss as a result of a legal action brought for alleged wrongful acts in their capacity as directors and officers.

Q. Does the Company purchase D&O insurance coverage?

A. Per the Company’s response to SDR 074, the Company no longer purchases D&O insurance coverage at the PacifiCorp level and there are no D&O insurance expenses included in this rate case. This is consistent with the Company’s responses to DRs issued in the Commission’s most recent operational audit of PacifiCorp.

Q. What is the Commission’s treatment of D&O insurance expenses in a general rate case?

A. It is Staff practice to dis-allow 50 percent of D&O insurance premiums, as this coverage often inures to the benefit of shareholders.

Q. Does Staff recommend an adjustment?

A. Staff proposes no adjustment for this issue.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualifications Statement

June 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME:	Julie Jent
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst 2 USRA
ADDRESS:	201 High Street SE, Suite 100 Salem, OR. 97301
EDUCATION:	I have a Bachelor of Science from Berea College in Political Science where I concentrated on economics and the regions of Eastern Europe and Southeastern Asia. I also hold a Masters of Integral Economic Development Policy specializing in the public sector and econometrics.
EXPERIENCE:	I have been employed as a Junior Financial Analyst by the Oregon Public Utility Commission since June 2021 in the Telecommunications and Water division. Within telecom, I work with colleagues and telecom companies on issues relating to OUSF funding and the transition to a new cost model. Within energy, I currently perform a range of financial analysis duties related to natural gas, electric, and water utilities, with a focus on operations and maintenance. However, UG 435 is my first general rate case docket. I was previously employed as an Analyst with the Executive Office of the President (EOP), where I worked as part of a team on education funding. Prior to EOP, I was an Economic Consultant for the U.S. Conference of Catholic Bishops.

CASE: UE 399
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1202

Exhibits in Support
Of Opening Testimony

June 22, 2022

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 359

OPUC Data Request 359

Advertising - Please explain and reconcile the discrepancies demonstrated in the table below. Then, state the correct system and Oregon allocated total for each of the advertising categories as well as the total system and Oregon allocated amounts.

	System					OR Allocated			
	A	B	C	Total		A	B	C	Total
DR 104 Attachment 1	3,002,434	150,392	116,571	**3,269,397**		1,423,498	163,029	67,178	**1,653,705**
DR 104 Attachment 1 (only those charged to FERC 909-others in FERC 930)	3,002,434	150,392	98,096	3,250,923		1,423,498	163,029	61,903	1,648,430
DR 176 Attachment 1	3,281,742	164,382	126,635	**3,572,760**		1,423,498	163,029	67,178	**1,653,705**
DR 58 Attachment 1 (only account 909)				**5,018,601**					**1,656,622**
DR 58 Attachment 1 (only account 930)				149,022					(1,181,559)

Response to OPUC Data Request 359

The following explanation may help in understanding the observed variances between the Company's previously provided data responses:

Standard Data Request - OPUC 104, specifically Attachment OPUC 104-1 includes summary amounts for category A, B, and C advertising expenses in FERC Account 909 and FERC Account 930.1. The attachment excludes (1) summary amounts for FERC Account 930.2, (2) total company amounts not allocated to Oregon, and (3) does not provide a total company test period amount for the data in the attachment, only an Oregon allocated test period amount.

OPUC Data Request 176, specifically Attachment OPUC 176-1 includes line-item detail for FERC Account 909 and FERC Account 930.1 and excludes non-advertising adjustments made elsewhere in the filing to those same FERC Accounts.

Standard Data Request – OPUC 058, specifically Attachment OPUC 058-1 includes a summary by FERC Account (including FERC Account 909 and FERC Account 930) in which summary amounts include all line-item transactions and all regulatory adjustments to FERC Account 909 and FERC Account 930 on both a base and test period basis.

Please refer to Attachment OPUC 359 for the requested reconciliation. No discrepancies were identified to any of the previously filed attachments during the preparation of the reconciliation.

Attachment to PAC Response to Staff DR 359 is filed in electronic format only.

OPUC Data Request 187

Advertising and Promotions - Explain why the Oregon allocation factor varies in column U of SDR 57 FERC 909.

Response to OPUC Data Request 187

Referencing the Company's response to Standard Data Request – OPUC 057, column U shows the Oregon allocation percentage for the allocation factor in column S. Costs in FERC Account 909 are either direct assigned to a jurisdiction or allocated on the Customer Number (CN) allocation factor in accordance with the 2020 Inter-Jurisdictional Allocation Methodology (2020 Protocol). Please refer to the Attachment OPUC 187, which provides an extract from the 2020 Protocol, specifically Appendix B, page 3.

The allocation percentage varies in column U because it is determined by the allocation code in column S. The line-item detail rows with 0.000 percent in column U are direct assigned to a jurisdiction other than Oregon and the allocation code in column S is not "OR" or "CN". Oregon customers are not assigned any portion these costs. The line-item detail rows with 100.000 percent in column U are direct assigned to Oregon and the allocation code in column S is "OR". Oregon customers bear 100 percent of these costs in rates. The line-item detail rows with 30.990 percent have an allocation code of "CN" in column S. These are system costs of which Oregon's share is allocated to Oregon customers. Oregon customers see approximately 30.990 percent of these amounts in rates.

OPUC Data Request 364

Advertising - Provide details on how the Oregon allocation factors are chosen and used for calculations involving account 909 and 930.1 as it relates to advertising expenses. For example, why is 30.99 percent and 100 percent both used for account 909 and 27.173 percent used for account 930.1?

Response to OPUC Data Request 364

Please refer to the Company's response to OPUC Data Request 187 regarding the allocation factors used for FERC Account 909.

Costs in FERC Account 930.1 can be direct assigned to a jurisdiction or allocated using the Customer Number (CN) allocation factor or allocated on the System Energy (SE) allocation factor or allocated on the System Generation (SG) allocation factor, or the System Overhead (SO) allocation factor in accordance with the 2020 Inter-Jurisdictional Allocation Methodology (2020 Protocol).
Please refer to the Company's response to OPUC Data Request 187, specifically Attachment OPUC 187, which provides an extract from the 2020 Protocol, specifically Appendix B, page 3.

The allocation percentage varies because it is determined by the allocation factor. The allocation percentage of 27.173 in FERC Account 930.1 is Oregon's portion of the SO allocation factor. These are system costs of which Oregon's share is allocated to Oregon customers. Oregon customers see approximately 27.173 percent of these amounts in rates. The 27.173 percent is not seen in FERC Account 909 because the SO allocation factor is not a factor that is used in FERC Account 909. Again, refer to the Company's response to OPUC Data Request 187, specifically Attachment OPUC 187, which provides an extract from the 2020 Protocol, specifically Appendix B, page 3 that shows which allocation factors can be used for the different FERC Accounts.

UE 399 / PacifiCorp
April 13, 2022
OPUC Data Request 177

OPUC Data Request 177

Advertising and Promotions - Please provide a copy of the advertising media produced for customers referenced in OPUC 104-1 Attachment. For purposes of this request, the term "copy" means:

(a) For printed advertising, a hard copy or pdf of the material;

(b) For a radio broadcast, a hard copy or pdf of the radio script;

(c) For a television broadcast, a link to a video of the advertisement on a webpage accessible by Staff, a DVD, or in a file format viewable on a modern Windows operating system;

(d) For an online advertisement, an Adobe PDF of any webpages created; and

(e) For other items not listed above, including but not limited to billboards, banners, displays, hats, mugs, and pens, – a hard copy picture or digital picture that provides an accurate depiction of the item.

Response to OPUC Data Request 177

Please refer to the links provided below for advertising and customer communications copies from the Company's response to Standard Data Request – OPUC 104, specifically Attachment OPUC 104-1:
http://pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/July_2020_Connect_OR.pdf

http://pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/October_Connect_Newsletter_OR.pdf

http://pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/Connect_Newsletter_Feb2021_OR.pdf

http://pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/May_Connect_Newsletter_OR_2021.pdf

http://pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/OR_Assistance_Plus_Onsert.pdf

http://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PAC-Helping_Customers_2.0_Postcard_PP_RES_ENG.pdf https://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_HelpingCustomers_Res_Email.pdf

http://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/Helping_Customers_Res_Letter_OR.pdf

http://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_HelpingBizCustomers_Letter.OR.pdf

http://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_HelpingBizCustomers_Email_v2.pdf

http://pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/PP_OR_ResidentialPricing_Insert.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/19-pcpp-3005-WildfireSafety.mp3

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/Wildfire_Safety_Oregon.png

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/Wildfire_Safety_Display.png

http://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/WidfireSafetyAd_PP_OR_GrantsPass.pdf

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/reliable-digital.pdf

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/go-anywhere-social.png

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PCPP151319W_PPMedfordYMCA_RBM.mp4

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PCPP150619W_PPCorvallisAvid_RBM.mp4

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_Assurance_Simple_Things.mp3 https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_EV_GoAnywhere.mp3

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PAC-20082_PP_Assurance_Clean_Renewable_Radio_Script.pdf

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/community-digital.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PAC_ASSURANCE_RADIO_30_Baking_PP.mp3

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PAC_ASSURANCE_RADIO_30_GuitarPractice_PP_V2.mp3

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/eim-digital.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PAC_ASSURANCE_RADIO_30_ScienceProject_PP.mp3

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/Assurance_Dream_Social.png

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/Assurance_Reliaibilty_Social.png

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/Assurance_Reliability_15_YouCanCountonUs.mp4

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PAC_ASSURANCE_RADIO_30_Resilience_PP.mp 3

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/Assurance_Resilience_Social.png

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/sustainable-digital.pdf https://youtu.be/yCvqMjiVk0k

http://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/OR_Irrigation_TOU_Gen_Letter.pdf

http://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_Feb_Outage_ThankYou_Ad.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_Community_Outage_ThankYou_Social.png

https://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_Outage_Email.pdf

https://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_Outage_Postcard.pdf

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/2021_OR_Labeling_Insert_RES.pdf

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/2021_OR_Labeling_Insert_SM_BIZ.pdf

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/2021_OR_Labeling_Insert_LG_BIZ.pdf

https://poweringgreatness.com/the-power-of-partnerships/

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/Welcome_Aboard_OR_RES.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/Welcome_Aboard_OR_BUS.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/Direct_Access_2021_Letter.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/Direct_Access_2021_Booklet.pdf

http://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_OR_EmailSeries_1.pdf http://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_OR_EmailSeries_2.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_OR_EmailSeries_3.pdf

https://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/EmailNurture_Wk1_Social.png

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/EmailNurture_Wk2_Social.png

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/EmailNurture_Wk3_Social.png

https://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_LineWorkerAppreciation_Letter.pdf

http://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/2020_LineworkerPrint_PP.pdf

http://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/League%20of%20Oregon_Cities%20Conference_Ad.pdf

http://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_NAYA_Ad_FNL.pdf

https://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_KlamathFalls_Print_OR_2020.pdf

http://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_Albany_Chamber_Ad.pdf

http://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/AFP_Philanthropy_Award_Ad.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_Santiam_Resource_Guide_Ad.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_Santiam_Resource_Guide_Ad.pdf https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_Santiam_Resource_Guide_Ad.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_Santiam_Resource_Guide_Ad.pdf

https://pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/Inactive_Credit_Letter.pdf

OPUC Data Request 178

Advertising and Promotions - Provide a copy of the following advertising media produced for customers. Please refer to the question above for the description of what a copy is.

Posting Date	Ref. Document Number	Supplier	Text	Order	Account Number Name	FERC Account	In transaction currency	Oregon Allocated $
9/28/2020	5603390623	150859	OR Brand Media -Education/Safety	250027	Informational Advertising Services	9090000	55,807.00	55,807.00
11/29/2020	5603417043	150859	OR brand media	250027	Informational Advertising Services	9090000	41,921.00	41,921.00
3/23/2021	5603468424	150859	OR Assurance/Community/repowering	250027	Informational Advertising Services	9090000	40,552.00	40,552.00
4/27/2021	5603482055	150859	Media Planning, Buying and Optimization	250027	Informational Advertising Services	9090000	37,181.00	37,181.00
6/1/2021	5603495636	150859	Media Planning, Buying and Optimization	344489	Informational Advertising Services	9090000	36,866.00	36,866.00
4/27/2021	5603482053	150859	Brand Journalism / Community Activation	239088	Informational Advertising Services	9090000	33,985.00	33,985.00
6/28/2021	5603508547	150859	OR Clean Fuels/Summer Travel	344489	Informational Advertising Services	9090000	28,650.00	28,650.00
7/29/2020	5603365427	150859	DSM Marketing - TV - OR SB838	406484	Informational Advertising Services	9090000	28,237.00	28,237.00
6/1/2021	5603495490	150859	Media Planning, Buying and Optimization	250027	Informational Advertising Services	9090000	27,083.00	27,083.00
5/10/2021	5603486823	119075	Large Quantity Printing	235441	Legally Mandated Advertising Services	9090000	26,766.00	26,766.00
10/29/2020	5603405314	150859	DSM Marketing - Radio - OR SB838	406482	Informational Advertising Services	9090000	26,610.00	26,610.00
8/25/2020	5603376644	150859	OR Brand Media - reliabliity/service/education	250027	Informational Advertising Services	9090000	25,943.00	25,943.00
7/29/2020	5603365427	150859	DSM Marketing - Outdoor - OR SB838	406483	Informational Advertising Services	9090000	25,174.00	25,174.00
9/30/2020	31210356		WBS CREG/2017/D/STP/EVECI		Informational Advertising Services	9090000	77,795.00	24,108.62

Response to OPUC Data Request 178

Please refer to the website links provided below to advertisements produced for customers associated with the requested line items. Note: Six of these rows are ***not*** included in the Company's Oregon general rate case (GRC), Docket UE-399 because they are part of separate tariffs or orders for Schedule 297 (Energy Efficiency) and the Oregon Clean Fuels Program (Order 18-376).

Items included in Docket UE-399

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/reliable-digital.pdf

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/go-anywhere-social.png

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PCPP151319W_PPMedfordYMCA_RBM.mp4

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PCPP150619W_PPCorvallisAvid_RBM.mp4

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_Assurance_Simple_Things.mp3 https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PP_EV_GoAnywhere.mp3

https://www.pacificorp.com/content/dam/pcorp/communications- advertising/en/pacificpower/PAC-20082_PP_Assurance_Clean_Renewable_Radio_Script.pdf

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my- account/bill-inserts/community-digital.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PAC_ASSURANCE_RADIO_30_Baking_PP.mp3

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PAC_ASSURANCE_RADIO_30_GuitarPractice_PP_V2.mp3

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my- account/bill-inserts/eim-digital.pdf

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PAC_ASSURANCE_RADIO_30_ScienceProject_P P.mp3

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my- account/bill-inserts/Assurance_Dream_Social.png

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my- account/bill-inserts/Assurance_Reliaibilty_Social.png

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/Assurance_Reliability_15_YouCanCountonUs.mp4

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/PAC_ASSURANCE_RADIO_30_Resilience_PP.mp 3

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my- account/bill-inserts/Assurance_Resilience_Social.png

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my- account/bill-inserts/sustainable-digital.pdf https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my- account/bill-inserts/2021_OR_Labeling_Insert_RES.pdf

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my- account/bill-inserts/2021_OR_Labeling_Insert_SM_BIZ.pdf

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificpower/my- account/bill-inserts/2021_OR_Labeling_Insert_LG_BIZ.pdf

https://poweringgreatness.com/the-power-of-partnerships/

Items Not Included in Docket UE-399

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/Oregon_Better_Summer.mp4

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/17PCPPOR6005_OregonThrive.mp3

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/OR_Wattsmart_Transit.jpg

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/Oregon_EV_Awareness_Radio_ENG.mp3

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/OR_EV_Digital_Ad.png

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/OR_EV_Social_1.png

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/en/pacificpower/OR_EV_Social_2.png

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/es/Oregon_EV_Awareness_Radio_SPA_V2.mp3

https://www.pacificorp.com/content/dam/pcorp/communications-advertising/es/OR_EV_Social_Spanish.png

https://poweringgreatness.com/ev-summer-travel/

Attachment 1 to PAC Response to Staff SDR 104 is filed in electronic format only.

Attachment 1 to PAC Response to Staff DR 176 is filed in electronic format only.

UE 399 / PacifiCorp
March 1, 2022
OPUC Data Request – OPUC 104

Standard Data Request – OPUC 104

Advertising and Marketing Expense: For the questions below related to advertising expense, please see the definitions and descriptions in OAR 860-026-0022. For questions related to promotional activities or concessions, please see OAR 860-026-0015 & 0020.

(a) Please identify the Category A advertising expense included in the Test Year; including references to the appropriate testimony and / or exhibit pages;

(b) Please provide a work paper that shows the calculation of the Category A limit provided in OAR 860-026-0022 (3) (a);

(c) If the Test Year Category A advertising expense exceeds the OAR 860 026-0022 (3) (a) limit, please provide support for including the additional expense in rates;

(d) Please identify the Category B advertising expense included in the Test Year; including references to the appropriate testimony and / or exhibit pages;

(e) For any Category C advertising expense included in the Test Year revenue requirement that is associated with a promotional activity or a promotional concession program, please provide a summary table that includes:

  i. A description of the activity or program, and justification for inclusion into rates;

  ii. A breakout of the related expense by labor & non-labor; and

  iii. The FERC and internal utility account to which the expense will be booked and include references to appropriate exhibit pages.

(f) Please identify any other budgeted advertising expense for the test year that will NOT be included in base rates, including below-the-line or nonutility expense, or advertising expense expected to be collected through a tariff. Please include how the expense is allocated between the categories identified in OAR 860-026-0022(2). Please describe the activities and associated expense (broken out by labor & non-labor) associated with marketing research and sales activities (include fuel switching and retention of customers) that is included in the test year. Please include references to the testimony and exhibits, and to which FERC and internal utility accounts this expense is booked.

UE 399 / PacifiCorp
March 1, 2022
OPUC Data Request – OPUC 104

Response to Standard Data Request – OPUC 104

(a) Total Category A advertising expense included in the test year is $1,423,498. Please refer to Attachment OPUC 104-1 for details by Federal Energy Regulatory Commission Account.

(b) Please refer to Attachment OPUC 104-1.

(c) The Category A advertising expenses included in the filing does not exceed the set limit provided in Oregon Administrative Rules (OAR) 860-026-0022(3)(a).

(d) Please refer to Attachment OPUC 104-1.

(e) There are no Category C advertising expenses that are associated with a promotional activity or a promotional concession program.

(f) The following programs did include advertising during Test Year. Funds for these programs are collected through a separate tariff and not part of base rates.

Blue Sky: This program is a self-sustained voluntary program that does not impact revenue requirement. The costs of the program are paid for entirely by program participants. As all revenue collected for the program is directed towards the program, the Company does not profit financially from the program. The Company does not have budgeted advertising expenditures for this program.

Demand-Side Management programs: Please refer to Attachment OPUC 104-2 for details on the annual budget for advertising as outlined in the Company's funding agreement with the Energy Trust of Oregon related to PacifiCorp's Schedule 297, Energy Conservation Charge. The Company does not have additional detail beyond what is included in the agreement.

OPUC Data Request 361

Advertising - 860-026-0022 (2)(c) describes Category C expenses as "Institutional advertising expenses, promotional advertising expenses and any other advertising expenses not fitting into Category "A," "B," or "D"." See response to SDR 104 (e), which states, "There are no Category C advertising expenses that are associated with a promotional activity or a promotional concession program".

(a) Reconcile and explain the statement above and the fact that Category C expenses are estimated to be $67,178 for Oregon.

(b) Resubmit a response that answers SDR 104 (e) and all of its subcomponents.

Response to OPUC Data Request 361

(a) There are $67,178 of expenses per Oregon Administrative Rules (OAR) 860-026-0022 (2) considered in Category C, Institutional advertising expenses and other advertising expenses not fitting into Category "A," "B," or "D." However, there are no Category C expenses that are considered Promotional Activities or Promotional Concessions (OAR 860-026-0010, 860-026-0015, 860-026-0025 and 860-026-0035).

(b) Please refer to the Company's response to subpart (a) above.

OPUC Data Request 360

Advertising - For advertising expenses that are assigned to FERC 930.1 rather than 909, describe why that decision was made.

(a) Provide a breakdown of how the expenses that are assigned to FERC 930.1 fit within the labor and materials and expenses subcategories of 930.1. This would include which expenses are considered labor and their total value as well as which expenses are considered materials and expenses and their total value.

Response to OPUC Data Request 360

Most advertising expenses are assigned to FERC Account 909. There are only a few transactions that are assigned to FERC Account 930.1, which are primarily job recruitment advertising expenses.

(a) There are no labor costs in the base year assigned to FERC Account 930.1. Advertising material expenses in the base year total is $18,475 on a total company basis, and $5,020 on an Oregon allocated basis. Please refer to the Company's response to Standard Data Request – OPUC 104, specifically Attachment OPUC 104 -1.

OPUC Data Request 362

> **Advertising -** Please explain why in response to SDR 104 (f) it is stated, "The following programs did include advertising during Test Year [Blue Sky and Demand-Side Management Programs]," yet under the Blue Sky description it is stated, "The Company does not have budgeted advertising expenditures for this program."

Response to OPUC Data Request 362

The Company's response to Standard Data Request – OPUC 104 subpart (f) mistakenly omitted the word "not". The response to Standard Data Request - OPUC 104 subpart (f) should read:

"The following programs do *not* include advertising during the Test Year. Funds for these programs are collected through a separate tariff and not part of base rates."

The Company does not budget advertising expenditures at the level of detail requested.

OPUC Data Request 180

Advertising and Promotions - Please both:

(a) Provide transaction level accounting detail for revenues and expenses of the "Blue Sky" program since its inception; provide in excel format.

(b) Describe the Blue Sky Program in narrative format similar to DR 104 Response.

(c) State its connection to the purpose of advertising expenses expressed in statute.

Response to OPUC Data Request 180

PacifiCorp objects to this data request as it is outside the scope of this proceeding and thus, not relevant. As such, the request is not reasonably calculated to lead to the discovery of admissible evidence. Revenue and expenses related to the Blue Sky program are not included in PacifiCorp's general rate case (GRC).
Furthermore, PacifiCorp objects to subpart (a) of the data request to the extent the request is overly broad and it would be unduly burdensome to produce the information requested. The Blue Sky Program has been in existence for 20 years.

UE 399 / PacifiCorp
April 6, 2022
OPUC Data Request 185

OPUC Data Request 185

Advertising and Promotions - Is PacifiCorp required to submit a promotional report to the PUC? If so, submit detailed expenses for the items in this report in an excel document.

Response to OPUC Data Request 185

No, PacifiCorp did not engage in Promotional Activities or Promotional Concessions in the state of Oregon in 2021 (per Oregon Administrative Rules (OAR) 860-026-0010, 860-026-0015, 860-026-0025 and 860-026-0035).

OPUC Data Request 188

Advertising and Promotions - Please provide:

(a) A list of expenditures for promotional activities and concessions charged to accounts during the test year; and

(b) A description of all programs related to sales promotion included in the test year.

Response to OPUC Data Request 188

PacifiCorp does not engage in Promotional Activities or Promotional Concessions in the state of Oregon (per Oregon Administrative Rules (OAR) 860-026-0010 and 860-026-0015).

PAC Response to Staff DR 366 is filed in electronic format only.

Supplemental to PAC Response to Staff DR 366 is filed in electronic format only.

Attachment to PAC Response to Staff SDR 68 is filed in electronic format only.

Attachment to PAC Response to Staff DR 353 is filed in electronic format only.

CASE: UE 399
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1203

Exhibits in Support
Of Opening Testimony

June 22, 2022

Attachment FERC 909 to PAC Response to Staff DR 142 is filed in electronic format only.

Standard Data Request – OPUC 065

[redacted]

Response to Standard Data Request – OPUC 065

[redacted]

[redacted]

PAC Response to Staff SDR 64 is filed in electronic format only.

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 369

OPUC Data Request 369

CONFIDENTIAL REQUEST - [BEGIN CONFIDENTIAL] [redacted]

[redacted]

[END CONFIDENTIAL]

Response to OPUC Data Request 369

[redacted]

[redacted]

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 368

OPUC Data Request 368

CONFIDENTIAL REQUEST - [redacted]

[redacted]

[redacted] PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 368

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

Response to OPUC Data Request 368

[redacted]

[redacted]

Standard Data Request – OPUC 071

[redacted]

Response to Standard Data Request – OPUC 071

[redacted]

[redacted]

[redacted]

Attachment to PAC Response to Staff SDR 71 is filed in electronic format only.

CASE: UE 399
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1204

Exhibits in Support
Of Opening Testimony

June 22, 2022

Staff Electronic Work Paper titled Non-Confidential Figures is filed in electronic format only.

Staff Electronic Workpaper titled Confidential Figures is filed in electronic format only.

CASE: UE 399
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Rates Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1301.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Company's capital investments for wildfire mitigation and expenses for wildfire mitigation and vegetation management. My recommendations may change based on further review and based on the testimonies offered by other parties.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/1302, containing Company responses to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, WILDFIRE MITIGATION CAPITAL INVESTMENT

Q. Please describe PacifiCorp's proposal regarding wildfire mitigation.

A. PacifiCorp provided a list of the discrete capital construction projects related to wildfire mitigation to be placed into service by December 31, 2022.[1] The total forecasted cost of these projects is $34.9 million for both situs and Oregon-allocated system projects.[2] The projects include: 41 miles of distribution line rebuilds to install insulated covered conductor; system hardening activities to replace electro-mechanical relays with modern microprocessor relays to protect distribution lines in Fire High Consequence Areas (FHCA); and replacement of fuses, lightning arrestors and other equipment throughout the FHCA.[3]

The Company also identifies an additional $1.7 million capital investment in tools, software, and hardware to better track weather information and improve risk forecasting. The Company has not included this additional amount in this general rate case, but states it will track them in its Wildfire Protection Plan (WPP) deferral request, docketed as UM 2221 (filed in Docket No. 2207, and approved by the Commission in Order No. 22-131 at its April 21, 2022, Public Meeting).

Q. Please describe Staff review of PacifiCorp's proposal.

A. Staff reviewed the Company's opening testimony and its WPP. Staff also issued several data requests regarding the proposed capital and expense

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[1] Exhibit Staff/1302, Moore/1 - Company response to Staff DR No. 465.

[2] Exhibit Staff/1302, Moore/2 - Company response to Staff DR No. 466.

[3] *See* Docket No. UE 399 PAC/700, Berreth/7.

projects and reviewed them to ensure they were consistent with the Company's WPP, as well as previous Commission Orders. Specifically, the WPP identifies investment strategies and programs to mitigate wildfire risk; identifies protocols for the de-energization of power lines; preservation of communications infrastructure; describes outreach efforts to regional, state, and municipal entities, as well as affected communities.

Q. What does Staff conclude about the Company's Wildfire Mitigation costs?

A. Staff concludes the proposed capital investment is consistent with the proposals identified in Commission Order No. 22-131. Staff does not recommend any adjustment. However, staff does recommend that the Commission require the Company to provide certification that the capital projects are complete and in-service by the rate effective date.

Additionally, Staff believes the Commission should be aware of PacifiCorp's planned capital expenditures for 2023-2025. For 2023 the Company forecasts $45.1 million in wildfire mitigation investment; for 2024 $81.6 million; and for 2025 $81.3 million.[4] Staff also notes and reiterates the Staff recommendation addressing the WPP, that PacifiCorp provide risk-based cost/benefit analysis to support its capital investment in wildfire mitigation for its 2023 WPP.[5] Staff plans to address these expenditures in the Company's next rate case.

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[4] Exhibit Staff/1302, Moore/2 – Company response to Staff DR No. 466

[5] *See* Docket No. UM 2207 – Staff Report, April 14, 2022 pgs. 5 & 12.

ISSUE 2, VEGETATION MANAGEMENT AND WILDFIRE MITIGATION EXPENSE

Q. Please describe the Company's proposal regarding vegetation management and wildfire mitigation expense.

A. PacifiCorp is requesting a total of $70.8 million in vegetation management and wildfire mitigation expense.[6] For wildfire mitigation (non-vegetation management) incremental expense in 2023, PacifiCorp forecasts approximately $4.2 million for various activities. The majority of this expense involves annual asset inspections in the FHCA; transition from a 10-year to a 5-year detailed inspection in the FHCA; development of dynamic risk assessment and risk management; stakeholder and community engagement; and Wildfire Mitigation Plan (WPP) monitoring.[7] To contextualize these numbers, PacifiCorp reported spending approximately $5.1 million on wildfire mitigation expense in 2020 and $1.1 million on wildfire mitigation expense in 2021. The total Test Year forecast amount represents a nearly 60 percent increase in the Test Year over the Base Year expense of $44.4 million.[8]

PacifiCorp explains in its opening testimony that part of the driver for increased vegetation management expense is that the Company is transitioning from a four-year pruning and trimming cycle to a three-year cycle to address the growing risk of wildfires in Oregon.[9] Additionally, PacifiCorp

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[6] See Exhibit Staff/1302, Moore/3 - Company response to Staff DR 467

[7] See UE 399 PAC/700, Berreth/17.

[8] Ibid.

[9] See UE 399 PAC/700, Berreth/22

plans to use increased minimum clearance distances for distribution cycle work completed in the FHCA. Moreover, the Company plans to complete annual pole cleaning on poles located in the FHCA. Finally, the Company cites general inflation and an increase in base labor costs and increased labor premiums to attract additional travel crews to the area.[10]

Q. Please describe Staff's review of the Company's vegetation management and wildfire mitigation expense.

A. Staff reviewed the Company's opening testimony and line item transactions of base year expenses for this category, as well as the responses to additional data requests. Staff finds that the Company's expenditures in the test year are consistent with the outlined objectives in the previous general rate case UE 374 and with the objectives stated in its WPP.

Staff also reviewed and compared total Company and Oregon-allocated and situs expenses for the Test Year, Base Year, and the two years prior (2019 and 2020) to the Base Year. Test Year expenditures are forecast to be 80 percent of total company expense for this category. In the Base Year, wildfire mitigation and vegetation management expense was 75 percent of total company expense, and 66 percent of total company expense in 2019. Therefore, costs in Oregon are increasing at a significantly higher rate than in the Company's other states.

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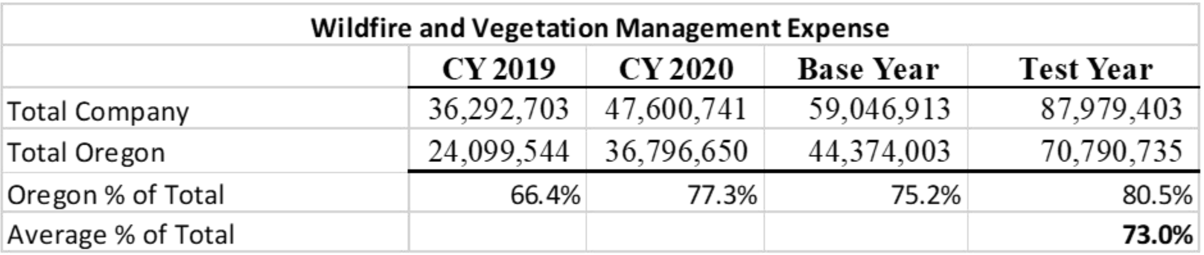
[10] See UE 399 PAC/700, Berreth/24



Wildfire and Vegetation Management Expense				
	CY 2019	CY 2020	Base Year	Test Year
Total Company	36,292,703	47,600,741	59,046,913	87,979,403
Total Oregon	24,099,544	36,796,650	44,374,003	70,790,735
Oregon % of Total	66.4%	77.3%	75.2%	80.5%
Average % of Total				**73.0%**

Wildfire risk is also increasing in the other PacifiCorp jurisdictions of California, Washington, Idaho, Utah and Colorado.[11]

Q. Does Staff recommend any adjustment to wildfire mitigation and vegetation management expense?

A. Yes. Staff recommends an adjustment of ($6.5 million) in expense for a total Test Year expense of $64.2 million. This amount represents 73 percent of total company Test Year expense, which reflects the average Oregon portion of total company expense for the Base Year and 2019-2020. (See above Table). Because the Company does not provide a basis for Oregon costs to be increasing at a faster rate than its costs in its other jurisdictions, with similar elevated wildfire risk, Staff finds it reasonable to expect that the relative cost increase would be similar in Oregon as in other jurisdictions.

Q. Does this conclude your testimony?

A. Yes.

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[11] https://hazards.fema.gov/nri/wildfire

CASE: UE 399
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

Witness Qualifications Statement

June 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME: Mitchell Moore

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem Oregon 97301-3612

EDUCATION: Bachelor of Arts, Journalism and Political Science
University of Hawaii at Manoa (1992)

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since 2009, with my current position being a Senior Utility Analyst in the utility program’s Energy Rates, Finance and Audit division. I have provided expert witness testimony on a number of general rate case dockets, including: UE 294, UE 319, UE 335, UG 288, UG 305, UG 325, UG 344, UG 347, UG 366, and UG 388.

My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints.

Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant design engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

CASE: UE 399
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support
Of Opening Testimony

June 22, 2022

OPUC Data Request 465

Wildfire mitigation and vegetation management - Referencing PAC/700, Berreth/7, Table 1: Please provide an itemized list of individual capital projects through 2022 associated with wildfire mitigation that PacifiCorp proposes to include in this case. Please identify the location, description of work, and actual or expected in-service date for each project.

Response to OPUC Data Request 465

Please refer to Attachment OPUC 465. Each tab describes a group of capital projects that are either completed or forecast for completion by December 31, 2022.

OPUC Data Request 466

Wildfire mitigation and vegetation management - Please provide the costs projected for Wildfire Mitigation and Vegetation Management for the years 2022, 2023, 2024 and 2025. Please provide a breakdown between capital and expense, between Vegetation Management versus Wildfire Mitigation, and amounts situs versus Oregon-allocated.

Response to OPUC Data Request 466

The capital amounts below reflect projects projected to be placed in service during the respective year. Capital situs includes all PacifiCorp values for distribution within the boundaries of Oregon. The transmission values provided represent spend within the boundaries of Oregon. Costs provided in the table below reflect Oregon's share of these costs.

The expense values provided represent the spend associated with the wildfire mitigation plan (WMP) and vegetation management, as such the transmission values provided represent spend within the boundaries of Oregon. Costs provided in the table below reflect Oregon's share of these costs.

Table 1 : Vegetation Management

	2022		2023		2024		2025	
	Situs/ Dist.	**OR. Alloc. / System.**	**Situs/ Dist.**	**OR. Alloc. /System.**	**Situs/ Dist.**	**OR. Alloc. /System.**	**Situs/ Dist.**	**OR. Alloc. /System.**
Capital	$0	$0	$0	$0	$0	$0	$0	$0
Expense	$48.7m	$1.3m	$49.0m	$1.4m	$52.5m	$1.5m	$54.0m	$1.7m

Table 2 : Wildfire Mitigation

	2022		2023		2024		2025	
	Situs/ Dist.	**OR. Alloc. /System.**	**Situs/ Dist.**	**OR. Alloc. /System.**	**Situs/ Dist.**	**OR. Alloc. /System.**	**Situs/ Dist.**	**OR. Alloc. / System.**
Capital	$27.9m	$7.0m	$44.6m	0.5m	$80.9m	0.7m	$80.6m	0.7m
Expense	$19.8m	$0.1m	$19.5m	$0.2m	$20.2m	$0.3m	$20.9m	$0.3m

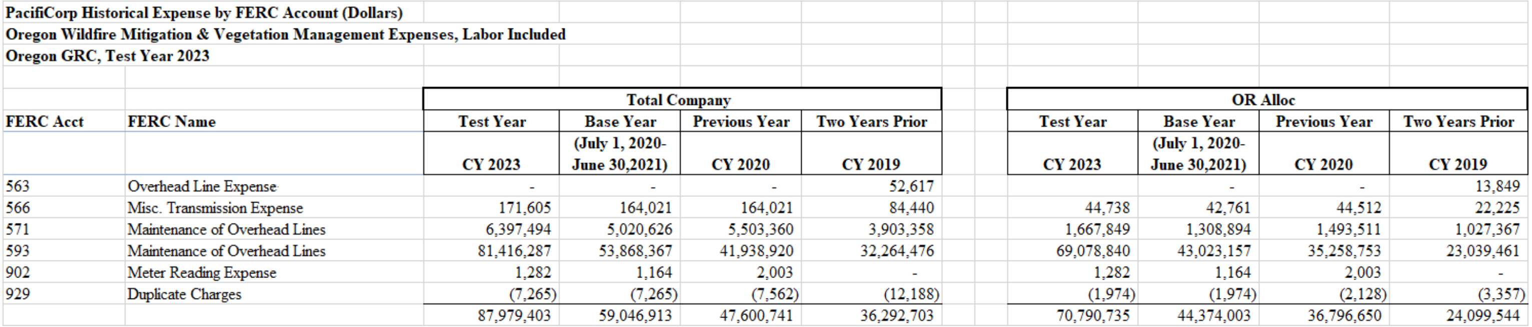
OPUC Data Request 467

Wildfire mitigation and vegetation management - Referencing the Company's response to Standard Data Request Nos. 57 and 58: Please supplement this response by resubmitting the complete responses for only vegetation management and wildfire mitigation expense.

Response to OPUC Data Request 467

Please refer to Attachment OPUC 467-1 which provides wildfire mitigation and vegetation management expenses in Oregon in the format of Standard Data Request - OPUC 057.

Please refer to Attachment OPUC 467-2 which provides wildfire mitigation and vegetation management expenses in Oregon in the format of Standard Data Request - OPUC 058. A labor-excluded breakout of any specific sub-category, like wildfire mitigation and vegetation management, of expenses is not available.



PacifiCorp Historical Expense by FERC Account (Dollars)
Oregon Wildfire Mitigation & Vegetation Management Expenses, Labor Included
Oregon GRC, Test Year 2023

		Total Company				OR Alloc			
FERC Acct	**FERC Name**	**Test Year**	**Base Year**	**Previous Year**	**Two Years Prior**	**Test Year**	**Base Year**	**Previous Year**	**Two Years Prior**
		CY 2023	**(July 1, 2020-June 30,2021)**	**CY 2020**	**CY 2019**	**CY 2023**	**(July 1, 2020-June 30,2021)**	**CY 2020**	**CY 2019**
563	Overhead Line Expense	-	-	-	52,617		-	-	13,849
566	Misc. Transmission Expense	171,605	164,021	164,021	84,440	44,738	42,761	44,512	22,225
571	Maintenance of Overhead Lines	6,397,494	5,020,626	5,503,360	3,903,358	1,667,849	1,308,894	1,493,511	1,027,367
593	Maintenance of Overhead Lines	81,416,287	53,868,367	41,938,920	32,264,476	69,078,840	43,023,157	35,258,753	23,039,461
902	Meter Reading Expense	1,282	1,164	2,003	-	1,282	1,164	2,003	-
929	Duplicate Charges	(7,265)	(7,265)	(7,562)	(12,188)	(1,974)	(1,974)	(2,128)	(3,357)
		87,979,403	59,046,913	47,600,741	36,292,703	70,790,735	44,374,003	36,796,650	24,099,544

CASE: UE 399
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1400

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Ming Peng. I am a Utility Analyst employed in the Energy Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1401.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss my review of several components (listed below for issues 1-8) of PacifiCorp's revenue requirement in UE 399.

My recommendations may change based on further review and based on the testimonies offered by other parties.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/1402, consisting of Staff workpapers and PAC data responses.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: DEPRECIATION EXPENSE

Q. Please summarize your recommendation for PAC's Depreciation Expense.

A. For **coal power** plant, on a total-company basis, I recommend lowering the depreciation rate from 6.87 percent to 6.81 percent by reducing the net salvage value by $7.95 million, from $314.5 million to $306.5 million, and consequently reducing the coal power depreciation expense by $4.1 million from the PAC-requested $456.07 million to $451.96 million each year, as of the 2023 test year.

For **non-coal** depreciable plants, Staff's review is based on the detailed depreciation parameters that have been authorized by OPUC in Order No. 20-470, Docket No. UM 1968.

Q. What is depreciation?

A. Depreciation is defined by the National Association of Regulatory Utility Commissioners (NARUC) in relevant part as follows:

> As applied to the depreciable plant of utilities, the term depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that are known to be in current operation, against which the company is not protected by insurance, and the effect of which can be forecast with reasonable accuracy. Among the causes to be considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirement of public authorities.[1]

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[1] NARUC, *Public Utility Depreciation Practices*, p.318 (1996).

The statement above defines depreciation from a valuation perspective. From an accounting perspective, depreciation is the allocation of the cost of fixed assets less net salvage to accounting periods, which is a capital recovery concept. From a ratemaking perspective, both the valuation (rate base) and accounting (capital recovery) concepts of deprecation are important.

Q. Do Oregon statutes address utility depreciation rates?

A. Yes. ORS 757.140(1), states in relevant part:

> Every public utility shall carry a proper and adequate depreciation account. The public utility commission shall ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility. The rates shall be such as will provide the amounts required over and above the expenses of maintenance, to keep such property in a state of efficiency corresponding to the progress of the industry.

Q. How are utility property depreciation rates determined?

A. To develop depreciation rates, it is necessary to estimate: (1) the combination of survivor curve[2]-service life (Curve-Life) of utility property, and (2) the net salvage[3] (Gross Salvage – Cost of Removal) ratio. Based on these two fundamental depreciation parameters (and other required elements, such as

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[2] "Survivor curves" are curves that show the number of units or cost of a given group which is surviving in service at given ages. The survivor curves were developed by the Engineering Research Institute of Iowa State University. These curves are frequently referred to as "Iowa Curves."

[3] Net Salvage is the gross salvage of the property retired less the cost of removal. This will be negative, if the cost of removal exceeds the gross salvage.

asset value, asset remaining life, and depreciation method) the depreciation rates are derived.

Q. Why do we need to use authorized depreciation rate results for the revenue requirement calculation?

A. To compute the revenue requirement (RR), which is measured by cost-of-service, a basic formula is followed:

RR = O&M Expense + "Depreciation" + Taxes + Return% x Rate Base

- Depreciation expense and reserve in UE 399 is derived by (Depreciation rate) x (plant in service) x (allocation factor, if any).
- Depreciation expense represents a large percentage of total operating expenses. The deferred income taxes, rate base, and cost of capital are all affected by the depreciation. Therefore, to calculate depreciation expense and reserve, we must use the Commission authorized depreciation parameters.

Q. Have you proposed any adjustments to PAC's depreciation parameters and expense in the UE 399 rate case filing?

A. Yes. I proposed an adjustment to **Net Salvage Percent** for coal-fired power (**coal plant**) production. The depreciation rates are mainly determined by two depreciation parameters: (1) survival curve-projection life, and (2) net salvage percent. In this filing, **I do not propose an adjustment to the extension of coal power life** because that has been reviewed by other staff**.** My net salvage adjustment to depreciation is focused on the coal plants whose **service lives have been extended.** The adjustment would lower the net salvage percent (and consequently lower depreciation rates) and expenses for coal plants, based on the following reasons:

1. ORS 757.140(1), states: “Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission. **The commission may make changes in such rates of depreciation from time to time as the commission may find to be necessary**.”
2. Extending the life of coal-fired power plants will cause the depreciation expense to increase. This is because most coal-fired power plants in the US are nearing retirement, and prolonging the life of coal-fired power stations will increase net salvage percent. The net salvage percent includes an asset’s **interim retirement cost** and **terminal retirement cost** (**decommissioning cost**).[4] When a coal power plant is close to the end of its life, the asset would be close to being fully depreciated. At this stage, extending the service life will increase net salvage cost, and therefore resulting in a depreciation expense increase.
3. Historically, Oregon has had higher depreciation rates and expenses because the Oregon Commission in Order Nos. 08-327 and 08-427 **did not allow PacifiCorp to extend the expected lifespan** beyond the designed life expectancy for coal-fired power plants for the Oregon-based, system-wide depreciation portfolio. But at that time, the service life for 11 coal power plants had been extended in the rest of the five

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[4] To the extent a plant decommissioning costs are estimated in a Kiewit study and addressed in other dockets, Staff is not intending recommendations in this docket to supersede any final outcome of Kiewit decommissioning estimates adopted by the Commission in other dockets.

states in PacifiCorp's service area. Therefore, the net capital to be recovered for Oregon was much larger than the net capital to be recovered by the other five states. Since 2008, Oregon's payment for coal depreciation was faster and earlier than it was in the rest of the five states of WA, CA, UT, WY, and ID. Because of this, Oregon has paid $10 million more each year than the rest of five states for the past 12 years, which includes the decommissioning cost. At year 2020, Oregon extended the service life for PAC's coal power plants.

4. **Decommissioning cost** is when a utility charges their customers through depreciation for **a future unknown cost** associated with a service provided **in the present**. Currently, Oregon's net capital to be recovered is much smaller compared to the other five states, because Oregon has been paying depreciation expense, including decommissioning cost, **12 years earlier** than the other five states. Therefore, the net salvage percent for Oregon should be reduced in UE 399.

Q. Please summarize the adjustment for Net Salvage percent.

A. The estimated dollar impact for the net salvage percent reduction is around $7.95 million. The detailed adjustment on net salvage percent listed in the table below (in yellow).

			UE 399	UM 1968			UE 399	**Staff**
			PROBABLE	**PROBABLE**			**NET**	**Proposed**
			RETIRE	**RETIRE**	**SURVIVOR**		**SALVAGE**	**N.S.**
	ACCOUNT		**DATE**	**DATE**	**CURVE**		**%**	**%**
	(1)		**(2)**	**Oregon**	**(3)**		**(4)**	**Oregon**
	COLSTRIP GENERATING STATION							
311	STRUCTURES AND IMPROVEMENTS		12/31/2027	4/30/2025	110-S0.5		-6	**-4**

312	BOILER PLANT EQUIPMENT		12/31/2027	4/30/2025	65-L0.5		-7	**-5**
314	TURBOGENERATOR UNITS		12/31/2027	4/30/2025	50-S0		-6	**-5**
315	ACCESSORY ELECTRIC EQUIPMENT		12/31/2027	4/30/2025	80-R2.5		-6	**-4**
316	MISCELLANEOUS POWER PLANT EQUIPMENT		12/31/2027	4/30/2025	45-L0		-6	**-4**
	DAVE JOHNSTON UNIT 1							
312	BOILER PLANT EQUIPMENT		12/31/2027	12/31/2023	65-L0.5		-4	**-3**
	DAVE JOHNSTON UNIT 2							
312	BOILER PLANT EQUIPMENT		12/31/2027	12/31/2023	65-L0.5		-4	**-3**
	DAVE JOHNSTON UNIT 4							
314	TURBOGENERATOR UNITS		12/31/2027	12/31/2023	50-S0		-4	**-3**
	NAUGHTON UNIT 2							
316	MISCELLANEOUS POWER PLANT EQUIPMENT		12/31/2025	12/31/2028	45-L0		(8)	**(7)**
	NAUGHTON UNIT 3							
311	STRUCTURES AND IMPROVEMENTS		12/31/2029	12/31/2028	110-S0.5		-9	**-8**
312	BOILER PLANT EQUIPMENT		12/31/2029	12/31/2028	65-L0.5		-9	**-8**
314	TURBOGENERATOR UNITS		12/31/2029	12/31/2028	50-S0		-9	**-8**

For **coal** plants, on a total-company basis, I recommend lowering the depreciation rate from 6.87 percent to 6.81 percent, which will reduce the net salvage value by $7.95 million, from $314.5 million to $306.5 million, and consequently reduce depreciation expenses by $4.1 million, from the PAC-requested $456.07 million to $451.96 million each year, as of the 2020 data that PAC provided in the depreciation calculation summary table.

For **non-coal** depreciable plants, Staff's review is based on the depreciation parameters that have been authorized by OPUC in Order No. 20-470, Docket No. UM 1968.

The work paper supporting this adjustment is in Exhibit Staff/1402-1 Peng Coal NS Adj.

ISSUE 2: AMORTIZATION EXPENSE

Q. Please summarize your recommendation for PAC's Amortization Expense.

A. I have not proposed an adjustment to amortization expense. Staff's review is based on the detailed amortization rates that have been authorized by OPUC in Order No. 20-470, Docket No. UM 1968.

Q. What is amortization expense?

A. In a depreciation study, amortization, like depreciation, relates to **intangible** assets, such as computer software and regulatory assets.

Q. What is the purpose for this review?

A. The purpose of this review is to verify whether Amortization Expense is properly filed using the OPUC-authorized amortization rates from Order No. 20-479, UM 1968.

Q. What is the difference between amortization and depreciation in a depreciation study?

A. Amortization and depreciation are two methods of calculating the value for industrial assets over time. Amortization is the practice of spreading an **intangible asset**'s cost over that asset's useful life. Depreciation is the expensing of a **fixed asset** over its useful life.

Q. Have you proposed any adjustment to amortization expense?

A. No. The amortization expense proposed by the Company is appropriate.

ISSUE 3: DEPRECIATION RESERVE

Q. Please summarize your recommendation for PAC's Depreciation Reserve.

A. Depreciation Reserve is accumulated depreciation. I proposed an adjustment to net salvage for depreciation; and therefore, the depreciation reserve will be changed accordingly as a result of the staff-proposed changes on net salvage percent and Company's proposed changes to coal-fired generating units' depreciable lives.

Q. Describe Depreciation Reserve.

A. Depreciation Reserve is Accumulated Depreciation, at a point in time, the total amount of recorded depreciation, retirements, gross salvage, cost of removal, and other adjustments. As with depreciation expense, the undepreciated balance of the associated assets generally appears in rate base and earns a return at the allowed rate.

Depreciation Reserves are affected by depreciation expenses, asset retirements, gross salvage, cost of removal, and other adjustments. If depreciation expense was changed, the accumulated depreciation and amortization should be changed accordingly.

Q. What is the relationship between depreciation and revenue requirement?

A. Under cost of service regulation, revenue requirement refers to the revenues the utility must earn to recover the costs of providing utility service and the opportunity to earn a reasonable return on its capital investment. To compute the revenue requirement (RR), a basic formula is followed:

RR = Operating & Maintenance Expenses + Depreciation Expenses + Rate of Return% x (Rate Base).

In this formula, “Depreciation” (meaning the gross value of the utility’s property less the accumulated depreciation of utility property) is one of the largest line items in the cost of service; therefore, “Depreciation” is important as both an annual expense and as a reduction of rate base.

Accumulated Depreciation is the cost of the investment in gross plant that is recovered as Depreciation Expense. Accordingly, the depreciation expense is accumulated and is subtracted from the gross plant to reduce the remaining investment to be recovered. The remaining balance is the Net Book Plant. The net book plant represents the portion of gross plant that is not depreciated. Therefore, as reserve increases, the rate base decreases.

Q. Have you proposed any adjustments on PAC’s depreciation reserve in this filing?

A. Yes, the changes result from the changes that were made in depreciation expense.

ISSUE 4: AMORTIZATION RESERVE

Q. Please summarize your recommendation for PAC's Amortization Reserve.

A. Amortization Reserve is accumulated amortization. I proposed no adjustment to Amortization Expense, and therefore no change to Amortization Reserve.

Q. Describe the Amortization Reserve.

A. Amortization reserve is accumulated amortization, and like depreciation, relates to **intangible** assets, such as computer software and regulatory assets. As with amortization expense, the unamortized balance of the associated assets generally appears in rate base and earns a return at the allowed rate.

Amortization Reserves are affected by amortization expenses. If amortization expense was changed, the accumulated amortization should be changed accordingly.

Q. Have you proposed any adjustments to PAC's amortization reserve in this filing?

A. No. I did not propose a change to amortization expense, and therefore, there is no change to the accumulated amortization.

ISSUE 5: AFUDC

Q. Please summarize your recommendation for PAC's AFUDC rate.

A. I recommend no adjustment to PAC's AFUDC filing, because the Company's AFUDC calculations meet the FERC and Oregon regulatory requirements.

Q. What does AFUDC refer to in this filing?

A. Allowance for Funds Used During Construction (AFUDC) is defined as the cost of money used during construction. AFUDC is capitalized as part of Plant in Service. The purpose of AFUDC is a regulatory method of compensating a utility for the financing costs it incurs during construction of new facilities.

Q. What is the purpose of this review?

A. The purpose of this review is to determine whether the Company complied with guidance[5] regarding the capitalization of assets based on FERC regulations and OPUC regulations in this filing.

Q. What is AFUDC?

A. AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. As prescribed by regulatory authorities, AFUDC is capitalized during construction as part of the cost of utility plant. Electric (Gas) Plant Instruction no. 3(17) provides a formula for computing rates used to capitalize AFUDC.[6] The formula includes a component for the weighted

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[5] FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101

[6] https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/allowance- funds-used-during-construction

average cost of long-term debt. The entire issue of the use-restricted long-term debt should be included with other long-term debt used in calculating AFUDC rates. Average balances of the trust or other special funds should be included in the computation of the average balance of construction work in progress (CWIP) used in the formula.

AFUDC assigned to the project should be determined by applying AFUDC rates to the eligible project expenditures and to balances in the trust or special funds. Fund earnings during construction should be credited to the cost of construction of the project facilities.

Q. Please provide more details regarding AFUDC.

A. AFUDC is a non-cash item that is included in the cost of Utility Group utility plant and represents the cost of borrowed and equity funds used to finance construction. AFUDC is the cost of both the debt and equity funds used to finance utility plant additions during the construction period for such additions, determined in accordance with Generally Accepted Accounting Principles (GAAP).

Q. What are the FERC formula elements for the computation of AFUDC?

A. FERC has prescribed two formulas for calculating maximum allowable AFUDC rates:[7]

1) **DEBT**: This formula determines the maximum rate that can be used to capitalize an allowance for borrowed funds (i.e., debt) used for construction purposes.

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[7] FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101

2) **COMMON EQUITY**: This formula determines the maximum rate that can be used to capitalize an allowance for other funds (e.g., common equity) used for construction purposes.

FERC has indicated that if the FERC AFUDC rate is different than the state approved rate, the AFUDC capitalized should be split between utility plant and a regulatory asset. The amount capitalized in utility plant would be based on the FERC AFUDC rate. The amount included in the FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101 regulatory asset would be the difference between the State AFUDC rate and the FERC AFUDC rate.

The FERC formula elements for the computation of the allowance for funds used during construction are:[8]

Ai=s*(S/W)+d*(D/D+P+C)*(1-S/W) = Gross allowance for borrowed funds used during construction rate

Ae=[1-S/W]*[p*(P/D+P+C)+c*(C/D+P+C)] = Allowance for other funds used during construction rate

S=Average short-term debt
s=Short-term debt interest rate
D=Long-term debt
d=Long-term debt interest rate
P=Preferred stock
p=Preferred stock cost rate
C=Common equity
c=Common equity cost rate
W= Average balance in construction work in progress, less asset retirement costs related to plant under construction.

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[8] FERC 18 C.F.R. Part 101 (17) Allowance for funds used during construction (a), (b). https://www.law.cornell.edu/cfr/text/18/part-101

Q. What is the Commission Historical Treatment of Issue?

A. The historical treatment of AFUDC includes:

- AFUDC is a non-cash reporting item accrued until such time as Construction Work in Progress (CWIP) is closed and transferred to a Plant in Service account.
- In Oregon, the Rate Base excludes CWIP, non-utility property, and plant held for future use (it is not yet used and useful, i.e., a Plant that is still under construction and not yet in service).

Q. How did you analyze the AFUDC rates in this filing?

A. Based on PAC's testimony and data responses, I reviewed and analyzed following components:

- FERC's two formulas for calculating maximum allowable AFUDC rates.
- The OPUC-authorized Rate of Return, which is 7.137 percent.

I confirmed that PAC did not include CWIP in the rate base, because the Commission does not allow a utility to put a plant not yet placed in service into a rate-base.

Q. Have you made any adjustments to AFUDC and why?

A. No. I have not proposed an adjustment to AFUDC in this filing, because the Company's AFUDC calculations meet FERC and Oregon regulatory requirements.

ISSUE 6: COST OF LONG TERM DEBT

Q. Please summarize your recommendation for PAC's Cost of LT Debt.

A. I recommend a Cost of LT Debt of 4.588 percent. This value represents the cost of servicing all outstanding and forecasted LT debt, as of the 2023 test year.

Q. What does cost of debt refer to in this filing?

A. Cost of debt refers to the Cost of Long Term (LT) Debt incurred by PacifiCorp to construct or expand its facility assets.

- The cost of debt is the effective interest rate that a company pays on its debts, such as bonds and loans.
- The actual imbedded cost of debt is the weighted average of all the debt issued and the cost at which the debt was issued.

Q. How did you analyze the embedded costs of LT debt in this filing?

A. My analysis includes the use of forward interest rates, historical relationship of security trading patterns. I have five steps to conduct an analysis:

1. Identify the assumptions;
2. Collect and compile historic data (debt Table);
3. Compare interest rate (UST 7,10, 20, 30 years);
4. Forecast new debt issuance cost with respect to portfolio allocation; and
5. Recommend the cost of debt rate (to the Commission).

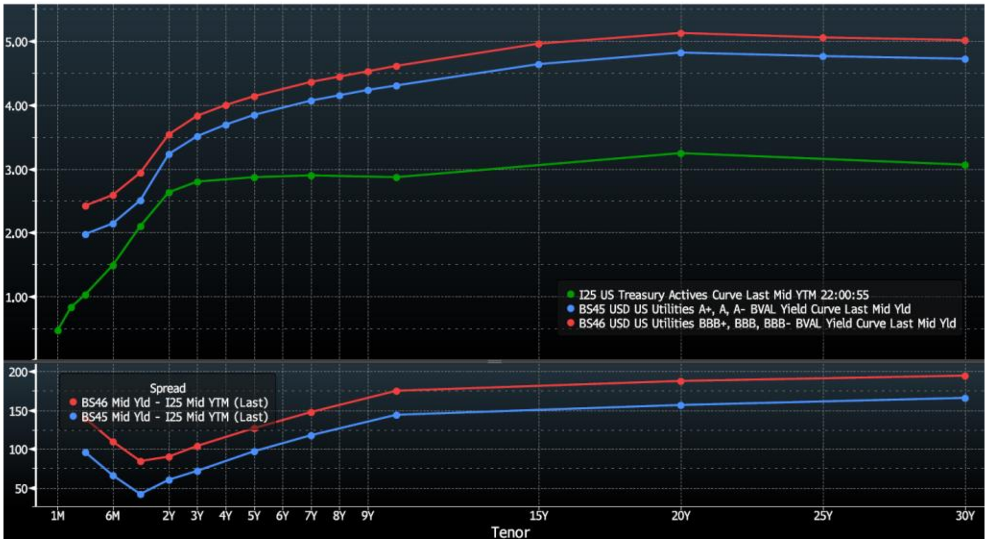
Q. How do you treat the debt that matures in one year or less?

A. All debt that matures in one year or less from the effective date of rates is considered short-term debt, which should be excluded from the long-term debt calculation. Debt that matures more than one year from the effective date of rates is long-term debt.

Q. Did you use any DRs from PAC to see credit spreads over treasuries?

A. Yes. I sent DR 225 to PAC. Based on PAC's response to DR 225, it can be calculated as the difference between the yield on a corporate bond and the benchmark rate. Please see my work paper PAC UE 399 Exhibit 1402-2 Peng Cost LT Debt CONF. A credit spread (also known as "bond spread" or "default spread") is the difference in yield between a U.S. Treasury bond and another debt security of the same maturity but different credit quality. Credit spreads vary from one security to another based on the credit rating of the issuer of the bond. From the chart below that I downloaded from Bloomberg, you may see the comparison of the credit spreads for risk-free rates, A-rated and B-rated bond yield rates:

Green line: US Treasury risk-free rates (yield curve).
Blue line: A-rated (PacifiCorp) bond yield curve
Red line: B-rated bond yield curve.

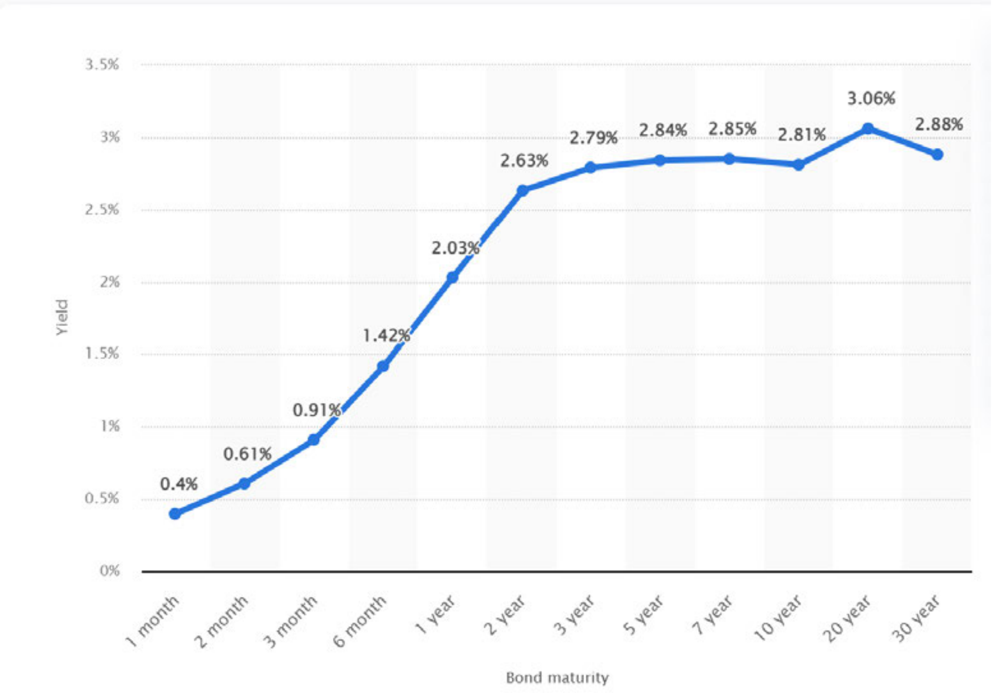


Please note, credit spreads between U.S. Treasuries and other bond issuances are measured in basis points, with a 1 percent difference in yield equal to a spread of 100 basis points.

Q. What risk-free rate did you use in your analysis?

A. I got the risk-free rate from https://www.statista.com/statistics/1058454/yield-curve-usa/.

Treasury yield curve in the United States as of April 25, 2022



The risk-free rate of return is the theoretical rate of return of an investment with zero risk. The risk-free rate represents the interest an investor would expect from an absolutely risk-free investment over a specified period of time. I used 2.91 percent, which is the average of 10, 20, and 30-year average risk-free rate.

Q. Have you made any adjustments to Cost of LT debt?

A. Yes. My adjustments are as follows:

1. Update the Pollution Control Revenue Bonds (PCRB) rates.

Line	Coupon Rate (%)		Coupon Rate (%)
(A)	(B) PCRB%		(B) PCRB%
	PAC 4.8.2022 DR225		Staff 5.19.2022
4			
5	1.43		0.87
6	1.51		0.85
7	1.61		0.85
8	1.47		0.85
9			
10	1.42		0.85
11	1.40		0.94
12	1.50		0.87

2. Calculate Yield to Maturity based on "Coupon Rate (%)", “Maturity Date”, and “Settlement Date issue date”.

3. Calculate weighted historic Yield to Maturity Rates.

4. Calculate forecasted Yield to Maturity Rates for unissued new debt.

5. Sum up issued and unissued Yield to debt maturity rates.

Q. How did you forecast new debt issuance cost?

A. To forecast new debt issuance, I used a portfolio optimization in Excel Solver to calculate the optimum investment weights before I discovered the optimal debt issuance result to use. Solver is an optimization tool that can be used to determine how the desired outcome can be achieved by changing the assumptions in a model.

	PAC 4.8.2022	Staff 5.19.2022	
Line	Forecast coupon rate		Year
39	3.32	4.54	20
40	2.85	4.49	10
41	3.35	4.41	30

Q. Did you modify the maturity terms and investment proportions for the Company's forecasted debt issuances?

A. Yes. After I reviewed PAC's current maturity schedule and forecasted future bond maturity schedule, I considered that the bond maturity terms and investment proportions in the portfolio should not concentrate on a 30-year term, because a highly skewed distribution will contain disadvantages for long-term financing, and an investor would have to face the rising interest rates, market volatility, and credit risk. The longer the term of the bond, reflecting the greater risk of the unknown. To minimize the risks, I made an adjustment to the bond maturity terms and investment proportions in the portfolio based on a portfolio optimization method by using the Excel Solver function.

Q. What is your recommendation for the cost of LT debt rate?

A. I recommend a weighted average cost of LT Debt of **4.588** percent for PAC, which consists of PAC's 4.603 percent cost of historic LT debt rate and Staff proposed 4.529 percent cost of forecasted unissued LT debt rate. Please see my work paper-LT Debt for details on this calculation. The work paper is in Exhibit Staff/1402-2 Peng Cost LT Debt CONF.

Q. How does this cost of LT debt compare to the rate in Order No. 20-473, UE 374?

A. The cost of LT debt in Order 20-473 is 4.774 percent.

Q. Did you make any adjustments to cost of Preferred Stock?

A. No. I verified that PAC's cost of Preferred Stock was appropriate.

ISSUE 7: MINE CLOSURES-DEFERRED AMORTIZATION

Q. Please summarize your recommendation for PAC's Mine Closures-Deferred Amortization.

A. I recommend no adjustment to PAC's forecasted deferred balance on coal mine closures as of December 31, 2022, because the Company's calculations meet the Oregon regulatory requirements.

Q. Please summarize PAC's proposal in this filing.

A. According to PAC, Deer Creek mine costs included closure costs, settlement loss costs, and a credit for Post-retirement Benefits Other than Pension medical savings. The amortization of these deferred costs, and associated carrying charges, is currently recovered through a separate tariff rider, Schedule 198, over three years. The estimated balance as of December 31, 2022, is $1,909,465.

Q. What is the purpose of this review?

A. The purpose of this review is to determine whether the Company complied with guidance regarding the Coal mine depreciation, mine closure, reclamation, deferred balance (the forecasted deferred balance on coal mine closures), based on the OPUC's regulations in this filing.

Q. What is the Commission's historical treatment of this issue?

A. In Docket No. UM 1712, the Company received commission approval to begin recovery of the unrecovered plant balance and to defer costs associated with the closure of the Deer Creek Mine.

Q. How did you analyze the deferred balance on coal mine closures in this filing?

A. Based on PAC's testimony and data responses, I reviewed the following:

1. I checked the Company's **ownership shares** in coal mines in Staff Data Request (DR) No. 268.

   The ownership in coal mines is as follows:

   - Bridger Coal Company (BCC) – 66.67 percent,
   - Trapper Mine Company – 29.14 percent, and
   - Deer Creek Mine (closed, currently in reclamation monitoring stage) – 100 percent.

2. I checked with PAC regarding whether the depreciation for coal-mining asset calculations are based on the **depreciation parameters** in Staff DR 266. In DR 266, PAC replied[9]:

   > There are no depreciation parameters used in this filing for coal mine plants. Bridger and Trapper Mine rate base balances are included in the Company's filing in FERC Account 399 on an end-of-period basis as of December 31, 2022. Deer Creek Mine was closed in 2015, and as such, no mine assets related to Deer Creek Mine are included in the Company's filing. Depreciation expense on coal mine assets flow through fuel costs and are not part of depreciation expense in this general rate case (GRC).

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[9] A copy of Staff DR 266 is attached as Staff Exhibit Staff/1402.

> Fuel costs are addressed in Docket No. UE 400, the Company's annual transition adjustment mechanism (TAM) filing.

3. I checked if there are any **additional costs** related to Deer Creek and sent DR 271. PAC replied:

> In Docket UM 1712, the Company received commission approval to begin recovery of the unrecovered plant balance and to defer costs associated with the closure of the Deer Creek Mine. These costs included closure costs, settlement loss costs, and a credit for Post-retirement Benefits Other than Pension medical savings. The amortization of these deferred costs, and associated carrying charges, is currently recovered through a separate tariff rider, Schedule 198, over three years. The estimated balance as of December 31, 2022, is $1,909,465.
>
> The Company is not requesting additional costs related to Deer Creek in this rate case filing. The Company is including a UMWA pension withdrawal liability payment of approximately $3 million consistent with the Commission order in Docket UE 374. The Company will seek additional costs related to the royalty obligations once those costs have been settled and paid.

Q. Have you made any adjustments to the deferred balance on coal mine closures?

A. No. I have not proposed an adjustment to the deferred balance on coal mine closures in this filing because the Company's proposed deferral was authorized by OPUC in UM 1712, and the deferral value is consistent with the order.

ISSUE 8: TB WIND DEFERRALS AMORTIZATION

Q. Please summarize your recommendation for PAC's TB Wind Deferrals Amortization.

A. I recommend no adjustment to PAC's TB Wind Deferrals Amortization, because the Company's calculations meet the Oregon regulatory requirements.

Q. Please provide some background for TB Wind Deferrals Amortization in this filing.

A. According to PAC, in PAC/1000, Cheung/25, Tab 8-8.14 - Wind Projects Deferrals Amortization, the reason for deferrals amortization is because "[a] portion of the TB Flats Wind Project was placed in-service in December 2020. That portion of the capital costs was included in rates that became effective on January 1, 2021."

The remainder of the TB Flats Wind Project was then placed into commercial operation by July 2021. Upon completion of the remainder of the project, the Company filed an application for approval of deferred accounting to allow it to match the costs and benefits of TB Flats Wind for later inclusion in rates.

Q. What is the purpose of this review?

A. The purpose of this review is to determine whether the Company complied with guidance regarding the Wind Projects Deferrals Amortization and Depreciation parameters used for TB Wind based on the OPUC regulations in this filing.

Q. How did you analyze the TB Wind Projects Deferrals Amortization in this filing?

A. Based on PAC's testimony and data responses, I did the following:

1. I verified the depreciation parameters were used for TB Wind. Staff sent DR 222 to PAC for the verification. PAC replied that in the current general rate case (GRC) filing, the Company is applying the other wind function composite depreciation rate of 4.223 percent to calculate test period depreciation expense. The composite rate (which factors in all wind plants) was calculated using approved rates from Docket No. UM 1968 (Application for Authority to Implement Revised Depreciation Rates).
2. I checked with PAC regarding whether the depreciation for TB Wind Projects Deferrals Amortization asset calculations are based on the depreciation and amortization parameters in Order No. 20-470, UM 1968.

   I found that the Company calculated the wind composite depreciation and amortization rates by using approved depreciation parameters from Order No. 20-470, UM 1968.

Q. Have you made any adjustments to TB Wind Projects Deferrals Amortization?

A. No. I have not proposed an adjustment to the TB Wind Projects Deferrals Amortization asset in this filing, because the Company's calculations meet the Oregon regulatory requirements.

Q. Does this conclude your testimony?

A. Yes.

WITNESS QUALIFICATIONS STATEMENT

NAME: Ms. Ming Peng

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Econometrician
Energy Rates, Finance, and Audit Division

ADDRESS: 201 High Street SE, Suite 100
Salem, OR 97301

EDUCATION & TRAINING:

M.S. Applied Economics
University of Idaho, Moscow

B.S. Statistics
People's University of China, Beijing

CRRA Certified Rate of Return Analyst in 2002
Society of Utility and Regulatory Financial Analysts

Depreciation studies – the Society of
Depreciation Professionals

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing

400+ credit hours on 30+ training topics in the public utility industry

EXPERIENCE: 1/11/1999 – Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 23 years. My roles include:

Expert Witness, Case Manager, Principal Analyst, Econometrician, Economist, Utility Analyst, and Policy Analyst:

I have testified in various formal state hearings and performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in the public utility industry.

Principal Analyst and Case Manager, Settlement Lead/Negotiator for Depreciation Ratemaking:

I have served as a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) for the past 12 years. In this role, I've had a strong focus on Depreciation Rate Determination (fixed cost allocation, and capital recovery). I was also a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) during this time period.

In this position, I investigated, analyzed, and calculated energy asset retirement cost and impact, as well as power plant decommissioning cost and impact, on customer rates. I reviewed, calculated, and analyzed fixed asset depreciation and proposed depreciation parameters for each of FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants. The energy sources I have worked on Steam/Coal, Hydraulic, Natural Gas, Wind, Solar, and Geothermal.

My analyses of "Power-Plant-Shutdown" activities (accelerated plant retirement, and decommissioning cost recovery) include the following cases:

1. PGE closes Boardman Coal-fired plant (UM 1679 & UE 215).
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246).
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under the ORS 757.734 – Recovery of investment in Klamath River dams in OPUC UE 219.
4. Idaho Power Valmy Coal-fired power plant Shutdown (UE 316).
5. PGE Colstrip Coal-fired power plant Shutdown (UM 1809).

I conduct case investigations and analyses on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are: (1) PacifiCorp (serves 6 states), (2) PGE, (3) Northwest Natural Gas (NWN), (4) Idaho Power, (5) Avista Corp (Washington), and (6) Cascade Gas (CNG, Montana).

Lead Analyst and Case Manager on Financial Dockets:

Prior to my current position, I was a Lead Analyst and Case Manager for cost of debt capital for nine years. I reviewed market risks, derivatives and hedging, debt issuance, and stock flotation. My analysis directly informed utility and energy policy.

I advised the Commission on over 60 financial dockets. The Commission incorporated all of my recommendations into final orders.

I was certified by the Society of Utility and Regulatory Financial Analysts as a Certified Rate of Return Analyst in 2002.

Public Utility & Policy Analyst:

Rulemaking: I have formulated energy regulation rules for utility performance incentives and cost-of-service regulation.

Energy Utility Merger & Acquisition: I have testified in formal state hearings involving utility mergers & acquisitions. I conducted Acquisition Premiums & Credit Risk Analysis and testified on behalf of the Commission in MidAmerican Energy Company's application to purchase PacifiCorp. I also reviewed Scottish Power's earlier purchase of PacifiCorp, and PGE's emergence from Enron after the Enron bankruptcy.

Integrated Resource Planning (IRP, Least Cost Planning): I provided comments to the Commission for decision making on Boardman to Hemingway (B2H), a 500-kV transmission power line, which included a cost and benefit list, a pros and cons list, alternatives, and the relevant legal risks. I also provided comments on utility's IRPs, such as total cost for power generation, power capacity (MW) replacement cost, avoided cost for free fuel, and emission trading cost.

Clean Energy – Dollar Impact on Customer Rates: I analyzed and calculated the rate impact and comparative advantage of clean energy. I built the portfolio optimization models to analyze the coal-fired generating capacity replacement.

General Rate Cases: I have been a part of *almost every energy rate case* since I joined the Oregon PUC on 1/11/1999. Historically, my review included fuel price forecasting, property sales, load forecasting, weather normalizations, cost of debt, and capital structures. Currently, my reviews are focused on depreciation and reserve, and AFUDC Capitalization Policy.

Survey Sampling Design: Results of my statistical sampling design and sampling procedures are incorporated into my revenue requirement testimony in Commission Docket No. UM 1288.

Auditing, Interest Rate, Late Payment: I audited cost of capital and financial components. My survey report and analyses are published annually for Oregon (UM 779).

Survey for Market Competition & Economic Policy: I conducted and wrote the report on Telecommunications, “Market Competition and Economic Policy Survey Analysis” for House Bill 2577. This report has been published on the OPUC web annually for 15 years.

Mentor in the ICER - International Confederation of Energy Regulators: I was selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. My “Mentoring Topics” focus on Incentive Regulation; Rate and Economic Impacts of “Cost-of-Service” regulation in the U.S. and “Price-Cap Performance Based Regulation” in Europe; Cost of Capital, Energy Demand and Price Forecasting Modeling; Least Cost Planning; Regulatory Policy; and Renewable Energy issues within regulated rate structures.

CASE: UE 399
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1402

Exhibits in Support
Of Opening Testimony

June 22, 2022

UE 399 / PacifiCorp
April 6, 2022
OPUC Data Request 222

OPUC Data Request 222

TB Flats Wind Project Depreciation Rates - Referring to PAC/1000, Cheung/10: "A portion of the TB Flats Wind Project was placed in-service in December 2020. That portion of the capital costs was included in rates that became effective on January 1, 2021."

(a) What depreciation parameters and rates did the company use for TB Wind?

(b) In OPUC ORDER 20-470, UM 1968, the depreciation parameters and rates that were authorized to use for the TB Wind Plant are:

		PROBABLE		**NET**		**COMPOSITE**
	UM 1968, ORDER 20-470	**RETIREMENT**	**SURVIVOR**	**SALVAGE**	**ACCRUAL**	**REMAINING**
	ACCOUNT	**DATE**	**CURVE**	**PERCENT %**	**RATE %**	**LIFE YEAR**
	TB FLATS - WIND					
341	STRUCTURES AND IMPROVEMENTS	12/31/2050	65-R2	-1	3.44	28.9
343	PRIME MOVERS	12/31/2050	55-R2.5	-1	3.43	28.9
344	GENERATORS	12/31/2050	40-S0	-2	3.85	26
345	ACCESSORY ELECTRIC EQUIPMENT	12/31/2050	60-S0.5	-1	3.49	28.5
346	MIS POWER PLANT EQUIPMENT	12/31/2050	60-R3	0	3.34	29.5
	TOTAL TB FLATS - WIND				3.45	

Please demonstrate that the Company complied with the commission order in the TB Wind depreciation calculation and provide the calculation links.

Response to OPUC Data Request 222

(a) In the current general rate case (GRC) filing, the Company is applying the other wind function composite depreciation rate of 4.223 percent. Please refer to the Company's response to OPUC Data Request 212, specifically Attachment OPUC 212, tab "Oregon GRC Composite Depr Rates", cell G58 for the "TB Wind Plant" to calculate test period depreciation expense. The composite rate (which factors in all wind plants) was calculated using approved rates from Docket UM-1968 (Application for Authority to Implement Revised Depreciation Rates). Specific parameters quoted in this request are provided in Attachment OPUC 212, tab "2020 Summary & RMP Steam", rows 761 to 766. Attachment OPUC 212 documents the step-by-step process with links in-tact demonstrating how the approved rates are walked-forward to develop composite rates that are used in the Company's current GRC filing to calculate depreciation expense.

(b) Please refer to the Company's response to subpart (a) above.

UE 399 / PacifiCorp
April 8, 2022
OPUC Data Request 225

OPUC Data Request 225

> **Cost of Long Term (LT) Debt -** For Long-term debt information, please fill out the attached Excel table DR 2 Attachment A CONF, tab name 399, columns G, H, I, J. The tables should identify:
>
> (a) The Issuance Costs;
>
> (b) The Settled Hedge Loss / (Gain);
>
> (c) The Discount / (Premium); and
>
> (d) Redemption Expenses.
>
> Note that this table when returned with the requested information to Staff should be treated as and identified in its title and file name as Confidential. Please notify Staff and Intervenors if and when PacifiCorp determines this information is public and not in advance of markets.

Response to OPUC Data Request 225

> Please refer to Confidential Attachment OPUC 225 which provides the requested columns G, H, I and J completed with data consistent with that provided in Company "Exhibit No. PAC 201 Wt Ave Cost of LTD – proforma". Also, for consistency, row 13, 14, 16, 21, 24, 25, 27 and 28 were removed in the Confidential Attachment OPUC 225. As indicated by the column R "CUSIP ID" for these listed issuances from the Public Utility Commission of Oregon (OPUC) staff provided attachment, they represent duplicative bond issuances – primarily third party secondary market issuances of outstanding PacifiCorp issuances that are already captured by other outstanding long-term debt lines in the table.
>
> Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 399 / PacifiCorp
April 20, 2022
OPUC Data Request 266

OPUC Data Request 266

Coal mine depreciation, mine closure, reclamation, deferred balance - Please provide the depreciation data that the company used in this filing for coal mine plants, including:

(a) FERC Account;

(b) Original Cost;

(c) Probable Retirement Date;

(d) Survivor Curve;

(e) Net Salvage Rate;

(f) Annual Accrual Amount (Annual Depreciation Expense); and

(g) Accrual Rate (see DR 266, Attachment B in Excel).

The depreciation and accumulated depreciation data should support the calculation in the rate base.

Response to OPUC Data Request 266

There are no depreciation parameters used in this filing for coal mine plants. Bridger and Trapper Mine rate base balances are included in the Company's filing in FERC Account 399 on an end-of-period basis as of December 31, 2022. Deer Creek Mine was closed in 2015, and as such, no mine assets related to Deer Creek Mine are included in the Company's filing. Depreciation expense on coal mine assets flow through fuel costs and are not part of depreciation expense in this general rate case (GRC). Fuel costs are addressed in Docket No. UE 400, the Company's annual transition adjustment mechanism (TAM) filing.

UE 399 / PacifiCorp
April 20, 2022
OPUC Data Request 268

OPUC Data Request 268

> **Coal mine depreciation, mine closure, reclamation, deferred balance -** What are the Company's ownership shares for coal mine companies in the Oregon filing? Specifically, what are the ownership shares for Bridger Coal Company (BCC), Trapper Mine Company, and Deer Creek Mine (see DR 266, Attachment B in Excel).

Response to OPUC Data Request 268

The Company's ownership in coal mines is as follows:

- Bridger Coal Company (BCC) – 66.67 percent
- Trapper Mine Company – 29.14 percent
- Deer Creek Mine (closed, currently in reclamation monitoring stage) – 100 percent

UE 399 / PacifiCorp
April 20, 2022
OPUC Data Request 271

OPUC Data Request 271

Coal mine depreciation, mine closure, reclamation, deferred balance - What is the forecasted deferred balance on coal mine closures as of 12-31-2022?

Response to OPUC Data Request 271

The Company interprets this question as relating to the closure of the Deer Creek mine and responds as follows:

In Docket UM 1712, the Company received commission approval to begin recovery of the unrecovered plant balance and to defer costs associated with the closure of the Deer Creek Mine. These costs included closure costs, settlement loss costs, and a credit for Post-retirement Benefits Other than Pension medical savings. The amortization of these deferred costs, and associated carrying charges, is currently recovered through a separate tariff rider, Schedule 198, over three years. The estimated balance as of December 31, 2022, is $1,909,465.

The Company is not requesting additional costs related to Deer Creek in this rate case filing. The Company is including a UMWA pension withdrawal liability payment of approximately $3 million consistent with the Commission order in Docket UE 374. The Company will seek additional costs related to the royalty obligations once those costs have been settled and paid.

Staff 1402

OPUC 496 Attach Coal Life

Is filed in electronic format

CASE: UE 399
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1500

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Paul Rossow. I am a Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1501.

Q. What is the purpose of your testimony?

A. I reviewed two main areas of PacifiCorp's (Company) proposed Test Year expenses: Memberships, Subscriptions, and Dues, and Meals and Entertainment. From that review, I recommend an adjustment to Test Year expenses. The proposed adjustments I recommend are derived from review of multiple data responses, analysis of PacifiCorp 2021 Operations and Maintenance (O&M) non-payroll transactions for FERC Accounts 500 through 935, and Commission policy regarding Memberships and Meals and Entertainment expense. My recommendations may change based on further review and based on the testimonies offered by other parties.

Q. Did you prepare any exhibits for this docket?

A. Yes, I prepared the following Staff Exhibits:

Staff/1501	Witness Qualifications Statement
Staff/1502	Adjustment Summary
Staff/1503	Memberships and Subscriptions – PacifiCorp response to Staff Data Request

Staff/1504 Meals and Entertainment and Awards – PacifiCorp's response to Staff Data Request

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. I recommend reducing expenses associated with memberships and subscriptions; meals and entertainment, and awards by ($213,720). This recommendation is based on reviewing PacifiCorp's filing, as well as responses to Staff data requests relating to memberships, subscriptions, meals, entertainment, awards, and miscellaneous operation and maintenance expenses. My adjustment applies long-standing Commission practices for these areas of company activities. The ($213,720) is comprised of a ($185,528) adjustment to Oregon allocated Test Year associated with memberships and subscriptions; and meals and entertainment, and awards expense of ($28,192).

ISSUE 1, MEMBERSHIPS AND SUBSCRIPTIONS

Q. Please provide a summary of the Company's proposal for memberships and subscriptions.

A. PacifiCorp's forecast of Test Year non-labor expenses for memberships and subscriptions consists of the 12-month period ending December 31, 2023. According to PacifiCorp's testimony, it removed excess memberships and subscriptions in accordance with Commission Order No. 01-502. The Company applied its IHS Markit indices escalation rate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. As stated by PacifiCorp, national and regional trade organizations are recognized at 75 percent.[1] This resulted in a removal of ($146,082) from Test Year expense.

Q. What is the Commission's historical treatment of memberships and subscriptions?

A. The Commission has determined that some expense associated with membership, dues, or subscription fees to various organizations is not appropriately included in a utility's revenue requirement, primarily because some or all of the organizational activities are:[2]

- Not necessary for utility service;
- Primarily to promote the company within the community;

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[1] Exhibit PAC/1000, Cheung/22 at 5-7.

[2] *In* the *Matter of Revised Tariff Schedules filed by Pacific Northwest Bell Telephone Company (PNB)*, Docket No. UT 43, Order No. 87-406, p. 40 (March 31, 1987) ("Only expenditures necessary for furnishing utility service should be reflected in rates. As a result, stockholders are responsible for charitable donations, community affairs expenditures, and non-professional dues." (Citations omitted).

- Do not benefit customers; or
- Would not be recoverable in rates if done by the utility itself.

Based on these principles and Commission practice Staff recommends recovery of memberships, dues, and subscriptions for:

1. Industry Research Organizations (e.g., Electric Power Research Institute) at 100 percent, except where organizations perform redundant services;
2. National and Regional Industry Trade Organizations (e.g., Edison Electric Institute or EEI) at 75 percent, on the basis that certain activities are promotional or lobbying in nature or otherwise do not benefit customers;[3] and
3. Disallowing all memberships, dues, subscriptions paid to other types of organizations unless the utility can present a convincing argument that the membership is necessary for utility service or otherwise to benefit customers.

Q. Please explain your analysis for the memberships and subscriptions adjustment.

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[3] *See e.g., In the Matter of Revised Tariff Schedules File by Northwest Natural Gas Company for a* General *Rate* Increase, Docket No. UG 81, Order No. 89-1372 (October 18, 1989) ("Trade associations provide valuable research and other services to utilities. They also engage in promotional activities of a type that may not be recoverable from ratepayers. So, an apportioning between ratepayers and stockholders is appropriate. The Commission has in the past generally allowed 75 percent of trade association dues to be passed on to ratepayers by Oregon utilities. The Commission will apply that policy in this case. However, Staff pointed out that significant expenditures by the EEI were related to promotional and marketing activities. The Commission is concerned about that and will disallow a greater portion of trade association dues in the future if an excessive proportion of an association's expenditures are for such activities.").

A. Staff's analysis included review of PacifiCorp's memberships, subscriptions, and dues expenses recorded to FERC Accounts 500 through 935 provided in electronic spreadsheet format in responses to SDR 57 Attachment 1,[4] FERC Accounts 930.2 provided in electronic spreadsheet format in responses to SDR 90 Attachment 1, and Exhibit PAC/1002, Cheung/104-106, pages 4.8-4.8.2. Staff then issued Data Request No. 391 to have PacifiCorp perform a memberships and subscriptions adjustment using a Base Period January 1, 2021, ending December 31, 2021. The Company responded using Oregon Results of Operation ending December 2021.

Staff's adjustment utilizes PacifiCorp's response to Staff Data Request No. 391,[5] which reveals a factored Oregon allocated removal amount of ($528,485), while adding back a factored Oregon allocated amount of $359,172 in non-payroll expenses, resulting in a Test Year amount of ($169,313). Next, Staff applied the All-Urban Consumer Price Index (CPI) of 6.8 percent and 2.6 percent, respectively, to arrive at the Test Year escalated Test Year adjustment of ($185,528).

Q. Why does Staff use CPI over IHS Markit indices?

A. Staff usually approximates the company's test year amount for its disallowance by escalating the proposed adjustment with the CPI factors. As the Commission has noted, "the All-Urban CPI measures price changes

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[4] The data in the Company's response to Staff Data Request No. 57 is too voluminous to include as an exhibit. However, Staff does include data showing the FERC account totals for each account as Exhibit Staff/1502, Rossow/1.

[5] See Exhibit Staff/1503 for PacifiCorp's response to Staff DR 391.

in a fixed market basket of goods and services in 200 categories, generally including housing, apparel, transportation, medical care, recreation, education, and others to urban consumers."[6] "Local economic conditions are represented in the All-Urban CPI, as the Bureau of Labor Statistics includes prices in Oregon when it conducts its survey."[7]

Q. What was the result of Staff's analysis for memberships and subscriptions?

A. Staff's analysis results in an escalated Oregon allocated Test Year disallowance to memberships and subscriptions of ($185,528).

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[6] Northwest Natural, Docket No. UG 132, p. 37, n10.

[7] *Ibid*., p.38.

ISSUE 2, MEALS AND ENTERTAINMENT AND AWARDS

Q. Please explain the Commission's historical treatment of O&M non-payroll discretionary expenses.

A. O&M non-labor discretionary expenses include expenses for items such as awards, food, gifts, meals, and entertainment. In Docket No. UE 197, the Commission clarified its policy that expenses for meals and entertainment, office refreshments, catering, gifts, and awards are discretionary and should be shared equally by customers and shareholders.[8] Accordingly, a 50 percent sharing of such expenses between customers and shareholders is routinely recommended by Staff. In addition, Staff recommends disallowance of O&M non-payroll expenses that are imprudent or excessive or do not benefit Oregon regulated utility operations at a transactional level.

Q. Did the Company propose an adjustment for meals and entertainment and awards expenses?

A. Yes. PacifiCorp's adjustment for these O&M non-labor expenses on a total company base period reveal an amount of $118,783 and removes 50 percent of these costs from each expense category resulting in a total disallowance of ($61,751), ending in an Oregon allocated disallowance of ($20,671).

Q. Please explain your analysis for the O&M non-payroll expenses.

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[8] *See In the* Matter *of Portland General Electric Company Request for a Rate Revision*, Docket No. UE 197, Order No. 09-020, p. 16 (January 22, 2009).

A. Staff reviewed Exhibit PAC/1002, Cheung/107-108, pages 4.9-4.9.1 and PacifiCorp's response to SDR 57[9] to identify any O&M non-payroll discretionary expenses that appear to be excessive, without sufficient business purpose, or not related to the provision of safe and reliable energy to customers. In the Company's response to SDR 57,[10] the Company provided its Base Period, 12 months ended June 30, 2021, O&M non-payroll transactional expenses in Excel format. The accounting data includes multiple spreadsheets, category fields, including account number, account number name, FERC accounts, transaction descriptions, supplier name, and currency amount.

From these spreadsheets, Staff created workbooks to aid in Staff's analysis of O&M non-payroll discretionary expenses. Staff filtered the data by transaction description and account number name. Some of the selected expenditure types were Airfare, Coffee/Water/Beverages Service-Employees, Employee Convenience Supplies, Lodging, Meals and Entertainment, Mileage Reimbursement, Miscellaneous Administrative/General Expenses, Non-Employee Gifts, Office Supplies, On-Site Meals & Refreshments, Other Employee Related Expenses, and Travel.

Staff reviewed the O&M non-labor expenses to determine whether they benefit customers or are discretionary and should be shared between

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[9] SDR No. 57 requested the Company to provide information for all non-payroll expenses recorded in all FERC accounts for the base year.

[10] See Exhibit Staff/1502, Rossow/1.

customers and shareholders according to Commission policy.[11] The Commission has historically agreed with Staff that such discretionary expenses are not required to provide safe and adequate service to customers. Additionally, Commission policy does not require customers to support causes through natural gas rates that customers do not necessarily support.[12]

Staff excluded items that had no benefit to at 100 percent. For expenses that Staff believed benefitted both customers and shareholders, Staff excluded at 50 percent. After reviewing the non-labor expenses provided within SDR 57, Staff issued Data Request No. 390 to have the Company perform a meals and entertainment adjustment scenario using a Base Period January 1, 2021, ending December 31, 2021. The Company's response provided a meals and entertainment adjustment using its Oregon December 2021 Results of Operations on the grounds that transactional level detail is not prepared for results of operations and is not readily available to be provided.

Staff's adjustment utilizes PacifiCorp's response to Staff Data Request No. 390,[13] which reveals a total Company meals and entertainment amount of $151,856 and a total Company awards amount of $2,038, totaling $153,894. PacifiCorp removed 50 percent of these non-payroll expenses, resulting in a

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[11] Examples of key words Staff used to search transactions included candy, gum, b-fast, bfast, dessert, party, balloon, bereavement, flower, meal, Christmas, floral, recognition, appreciation, food, award, going away, cake, birthday, b-day, snack, coffee, donut, doughnut, bowling, golf, blazer, ball, ticket, prize, gift, dinner, lunch, supper, wine, breakfast, diner, restaurant, napkins, photo, xmas, flight, hotel, airfare, air fare, air, travel, parking, luggage, baggage, shuttle, motel, taxi, lodging, and airport.

[12] See *Portland General Electric Company,* Docket No. UE 197, Order No. 09-020, p. 16 ("We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders.").

[13] See Exhibit Staff/1504 for PacifiCorp's response to Staff DR 390.

factored Oregon allocated amount of ($25,728). Next, Staff applied the All-Urban Consumer Price Index (CPI) of 6.8 percent and 2.6 percent, respectively, to arrive at the Test Year escalated Test Year adjustment of ($28,191). Staff usually approximates the Company's Test Year amount for its disallowance by escalating the proposed adjustment with the CPI factors.

Q. What was the result of Staff's review of Data Request No. 390?

A. Staff's analysis results in an escalated Oregon allocated Test Year disallowance to meals and entertainment awards of ($28,191).

Q. What is Staff's total adjustment?

A. Staff's total adjustment is a decrease to the Oregon Test Year expense of ($213,719) for O&M non-payroll expenses.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1501

Witness Qualifications Statement

June 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME: Paul Rossow

EMPLOYER: Public Utility Commission of Oregon

TITLE: Utility Analyst
Energy Resources & Planning Division

ADDRESS: 201 High Street SE Suite 100
Salem OR 97302-1166

EDUCATION: Professional Accounting and Computer Application Diplomas, Trend College of Business 1987

EXPERIENCE: I have been employed with the Public Utility Commission of Oregon as a Utility Analyst since October of 2002. Current responsibilities include research issues relating to energy utilities. I have actively participated in regulatory proceedings in Oregon, including UE 147, UE 167, UE 170, UE 179, UE 180, UE 197, UE 210, UE 213, UE 215, UE 217, UE 233, UE 246, UE 262, UE 263, UE 283, UE 335, UE 374, UE 394, UG 152, UG 153, UG 181, UG 186, UG 201, UG 221, UG 246, UG 284, UG 344, UG 347, UG 388, UG 389, UG 390, and UG 435.

I have attended the Utility Rate School sponsored by the Committee on Water of the National Association of Regulatory Utility Commissioners in May of 2005 and the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2005.

CASE: UE 399
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1502
To
STAFF EXHIBIT 1504

(FILED IN ELECTRONIC FORMAT)

Exhibits in Support
Of Opening Testimony

June 22, 2022

CASE: UE 399
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1600

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Eric Shierman. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1601.

Q. What is the purpose of your testimony?

A. MY OPENING TESTIMONY DISCUSSES PACIFIC POWER'S REQUEST TO RECOVER EXPENDITURES ON TRANSPORTATION ELECTRIFICATION (TE) ACTIVITIES THAT WERE FUNDED BY THE OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY'S (DEQ) CLEAN FUELS PROGRAM (CFP) CREDIT REVENUE.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1601

Q. Did you prepare any other exhibits?

A. Yes, I prepared Exhibit Staff/1602 consisting of 2 pages and containing the response to a data request I relied upon in my testimony.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF RECOMMENDATIONS

Q. Please summarize the recommendations included in your opening testimony.

A. Staff recommends the Commission:

1. Remove $1,377,595 in expenses from base rates.

ISSUE 1. CFP CREDIT REVENUE

Q. What is CFP credit revenue?

A. CFP credit revenue is money the Company receives from selling CFP credits received from DEQ for the use of electricity as a motor fuel to fossil fuel companies seeking permits to sell carbon-emitting fuel beyond the level DEQ has allocated. CFP is essentially a cap-and-trade policy design for motor fuel in Oregon.

Q. Under what use of electricity as a motor fuel did Pacific Power receive these credits from DEQ?

A. Residential, under DEQ rules, a utility has the first claim to CFP credits from EV charging from residential meters.

Q. Does the expenditure of CFP credit revenue represent an expense to the Company?

A. No, this is a monetary transfer from the firms that sell gasoline or diesel in Oregon to Pacific Power brokered by DEQ.

Q. How much expenditure of CFP credit revenue is the Company seeking recovery of in this proceeding?

A. Pacific Power is seeking to recover $1,377,595 of expenditures of CFP credit revenue.

Q. Does the Company agree this was a mistake, and has it offered to remove this request?

A. Yes, in Pacific Power’s response to OPUC DR 428, the Company stated: “The referenced expenses should have been excluded as they should not be included in base rates. The Company will remove them in its Reply Testimony filing.” [1]

Q. Does this end your testimony?

A. Yes.

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[1] Staff/1602 1.

CASE: UE 399
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1601

Witness Qualifications Statement

June 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME: Eric Shierman

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Resources and Planning Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: MS Economics; Portland State University; Portland, Oregon
BA Political Economy; Hillsdale College; Hillsdale, Michigan

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since June 2019, first as a Utility Analyst, and for the past year and a half as a Senior Utility Analyst. I was previously employed by McCullough Research as a Research Associate for two years.

CASE: UE 399
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1602

Exhibits in Support
Of Opening Testimony

June 22, 2022

OPUC Data Request 428

Transportation Electrification - Referencing the Company's response to OPUC DR 142:

(a) Please explain why "OR Clean Fuels Program Amortz Expense" is an account number name for ratepayer expenses of $137,094.11 from 2019-2020 and $1,240,500.55 from 2020-2021.

(b) Please provide a more detailed description for each row of OR Clean Fuels Program Amortz Expense expenditures.

Response to OPUC Data Request 428

The referenced expenses should have been excluded as they should not be included in base rates. The Company will remove them in its Reply Testimony filing.

CASE: UE 399
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1700

Opening Testimony

June 22, 2022

Q. Please state your name, occupation, and business address.

A. My name is Steve Storm. I am a Senior Economist employed in the Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1701.

Q. What is the purpose of your testimony?

A. My testimony examines several issues that either pertain to or can be associated with PacifiCorp's case in this proceeding. I provide recommendations for several of these issues.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/1701, which is my witness qualification statement; Exhibit Staff/1702, which is a November 22, 2021, Wall Street Journal article concerning pension funding; Exhibit Staff/1703, which is PacifiCorp's confidential response to Standard Data Request 60; Exhibit Staff/1704, which is PacifiCorp's non-confidential response to Standard Data Request 59; and Exhibit Staff/1705, which is Safety Report E21-54L, E21-54R, and related materials provided to PacifiCorp on August 31, 2021.

Q. How is your testimony organized?

A. I have organized my testimony as follows:

ISSUE 1. MULTI-STATE PROCESS

Allocation Rates

Q. What are Multi-State Process (MSP) allocation rates?

A. PacifiCorp, as an operating utility serving customers in six states and having components of rate base in a few more, plus its Federal Energy Regulatory Commission (FERC) jurisdiction, largely operates as one system. One result is that not all incurred costs are directly attributable to an individual state or jurisdiction. As a result, the MSP is used to negotiate a set of allocation factors to be used by the Company for allocating its costs to individual jurisdictions as well as establishing how the allocation factors are to be calculated. The current set of allocation factors used by the Company are the result of the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol).[1] The set of allocation factors prescribed in the 2020 Protocol and their values, as calculated for a given year, represent the MSP allocation rates.

Q. What does PacifiCorp, in Direct Testimony, say regarding 2020 Protocol allocation factors and their rates as used in this proceeding?

A. The Company states that its Oregon-allocated revenue requirement in this proceeding was calculated using the 2020 Protocol.[2] PacifiCorp's primary exposition of the 2020 Protocol factors and rates used in this proceeding are in Tab 10 of Exhibit PAC/1002.[3]

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[1] Page 3 of Appendix A to PacifiCorp's initial filing in Docket No. UE 399.

[2] Exhibit PAC/1000, Cheung/14.

[3] *Id.*, page 15. Tab 10 and its associated detail are located at Exhibit PAC/1002, Cheung/293-417.

Q. How does PacifiCorp illustrate the 2020 Protocol allocation factors and their values?

A. The Company lists the 2020 Protocol Factors, a label ("description") for each factor, and their respective percentage value for each jurisdiction at Exhibit PAC/1002, Cheung/294, which is also identified as Page 10.2 of Tab 10.[4] Information at Exhibit Pac/1002, Cheung/294 – 305 shows the calculation of pro forma allocation factors for the Test Year.

Table 17-1 below provides an index to the location in PacifiCorp's testimony of tables by category, where the tables include allocation factors by account on an actual basis for the year ending June 30, 2021.

Table 17-1: Location of Accounting Information by Table and Type

Table	FERC Account Type	Exhibit PAC/1002, Cheung/
B1	Revenue	309 - 316
B2	O&M Expense	317 - 329
B3	Depreciation Expense	330 - 335
B4	Amortization Expense	336 - 338
B5	Taxes Other Than Income	339 - 340
B6	Federal Income Taxes	341 - 346
B7	D.I.T. Expense and I.T.C Adjustment	347 - 353
B8	Plant in Service	354 - 363
B9	Capital Lease Plant	364 - 365
B10	Plant Held for Future Use	366 - 367
B11	Misc. Deferred Debits	368 – 369
B13	Materials and Supplies	370 - 373
B14	Cash Working Capital	374 – 375
B15	Misc. Rate Base	376 – 379
B16	Regulatory Assets	380 - 398
B17	Depreciation Reserve	399 – 405
B18	Amortization Reserve	406 - 408
B19	D.I.T. Balance and I.T.C.	409 - 415
B20	Customer Advances	416 - 417

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[4] *See* also PacifiCorp's table at Exhibit PAC/1002, Cheung/308.

Q. Have you reviewed PacifiCorp's use of allocation factors and verified their use conforms with the 2020 Protocol?

A. I have reviewed the allocation factors PacifiCorp uses in developing its Oregon revenue requirement values for this proceeding. I cannot concur with those used for Accumulated Depreciation – Other Production, Accumulated Depreciation – Transmission, Accumulated Depreciation – General Plant, or for the Deferred Income Tax Balance at this time and have issued data requests to the Company regarding certain factors it uses for accounts in these categories.

Q. Do you have any recommendations for the Commission regarding PacifiCorp's use of allocation factors in this proceeding?

A. No – not at this time.

Embedded Cost Differential

Q. What is the Embedded Cost Differential?

A. PacifiCorp states that the Dynamic Embedded Cost Differential, "as used in the 2010 Protocol, will continue for Oregon through the end of 2023, capped at $11,000,000."[5] The Embedded Cost Differential (ECD) is defined in the 2020 Protocol as:

> [T]he sum of PacifiCorp's production costs of pre-2005 resources as defined in the 2010 Protocol, excluding west side hydro, Mid-Columbia Contracts, and Qualified Facility contracts, referred to as "all other generation resources" expressed in dollars per megawatt-hour compared to west hydro-electric resources production costs expressed in dollars per megawatt-hour with the difference multiplied by the hydro-electric resources megawatt-hours of production, and the differential between the all other generation resources dollars

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[5] Exhibit Pac/1000, Cheung/40. *See also* the Stipulation filed December 30, 2019, in Docket No. UM 1050 and approved in Order No.20-024 (January 23, 2020). See Appendix A.

per megawatt hour compared to Mid-Columbia Contracts costs dollars per megawatt-hour multiplied by the Mid-Columbia Contracts megawatt-hours.

- **"Dynamic Embedded Cost Differential" or "Dynamic ECD"** means the ECD components are updated to the test period utilized in the filing.
- **"Fixed Embedded Cost Differential" or "Fixed ECD"** means the ECD amount for a State is set at a point of time and not updated.[6]

Q. How does PacifiCorp describe the dynamic embedded cost differential in testimony?

A. PacifiCorp's description includes that:

> The Dynamic ECD measures the embedded cost differentials between the production costs of pre-2005 resources, as defined in the 2010 Protocol, and the production cost of west hydro-electric resources and certain Mid-Columbia Contracts. The first part is computed by taking PacifiCorp's production costs related to pre-2005 resources, expressed in dollars per MWh, compared to production costs of west-side hydroelectric resources expressed in dollars per MWh with the difference multiplied by the hydro-electric resources' MWhs of production. The second part is computed by taking the differential between the pre-2005 resources' dollars per MWh compared to Mid-Columbia Contracts' costs on a dollars per MWh multiplied by the Mid-Columbia Contracts' MWhs.[7]

Q. Was the ECD a part of previous allocation protocols, including the 2017 Protocol?

A. Yes. The dynamic ECD in the 2020 Protocol, as pertaining to Oregon, removes the "floor" in the 2017 Protocol, but retains a "cap" of $11 million.[8]

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[6] Docket No. UM 1050, Order No. 20-024, Appendix B. Emphasis in the original included here.

[7] Exhibit PAC/1000, Cheung/41. See also Exhibit PAC/200, McDougal/3-4 in PacifiCorp's December 3, 2019, filing in Docket No. UM 1050.

[8] *See* page 5 of Order No. 20-024 in Docket No. UM 1050 regarding this cap.

Q. Where does PacifiCorp show the $11 million credit to Oregon for the dynamic ECD?

A. This is shown at PAC/1002, Cheung/20, as a $11 million credit to Oregon for both the year-ending June 2021 (on an unadjusted basis) and the year-ending December 2023 (the Test Year and on a normalized basis).

Q. Do you have any recommendations regarding the ECD, as it pertains to the proceeding at hand?

A. No.

ISSUE 2. KLAMATH HYDROELECTRIC SETTLEMENT AGREEMENT AND KLAMATH RIVER RENEWAL CORPORATION

Q. Does PacifiCorp, in Direct Testimony, describe an adjustment to the Test Year which removes costs associated with the Klamath Hydroelectric Settlement Agreement (KHSA)?

A. Yes. The Company states that it has made an adjustment that "removes an accounting entry made to an expense account during the Base Period that is non-recurring in nature," so as to normalize Test Year results.[9] The Company shows the removal of $33 million, on a system basis and from FERC Account 545, at Page 4.4 of Tab 4 O&M Expense, which includes that this adjustment, "removes the accrual of environmental costs related to the Klamath Settlement. Environmental remediation spending, once incurred and actual amounts known, are recorded to a regulatory asset and amortized straight-line over a 10-year period since approval in Docket No. UE-147."[10] The following Page 4.4.1 shows the accrual reversal in same amount.

Q. What costs are coded to FERC Account 545?

A. This account is titled "Maintenance of miscellaneous hydraulic plant (Major only)," and includes the cost of labor, materials used, and other expenses incurred in the maintenance of: a) fish and wildlife, and b) recreation facilities.[11]

Q. What is the amount allocated to Oregon?

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[9] Exhibit PAC/1000, Cheung/19.

[10] Exhibit PAC/1002, Cheung/89.

[11] USOC at https://www.law.cornell.edu/cfr/text/18/part-101 (accessed June 3, 2022).

A. Page 4.4 shows the Company used the “SG” factor to allocate $8,603,213, or 26.070 percent, of the $33 million to Oregon. Staff concurs with the allocation methodology used by the Company. PacifiCorp shows this is a $8,897,991 “approximate price change” after accounting for income taxes, working capital, and rate base impacts.

Q. How was the $33 million established?

A. Staff has submitted a data request to PacifiCorp regarding this amount.

ISSUE 3. PENSION AND POST-RETIREMENT MEDICAL BENEFITS

Q. Please summarize PacifiCorp's proposals concerning Test Year pension and post-retirement medical costs.

A. The Company proposes a total Test Year pension cost of $3.1 million and a Test Year post-retirement medical benefits cost of $373 thousand.

Q. Please provide an overview of pension costs and the relevant parameters when calculating establishing these costs.

A. Pension costs, known formally as FAS 87 costs, can be positive or negative. These are typically calculated based on the values of a small number of components or parameters:

- Fair value and funded status of the plan;
- Service cost;
- Interest cost;
- Recognized Gain or Loss;
- Expected Return on Assets (EROA); and
- Discount rate.

Increases to the service cost and interest cost tend to increase a pension plan's costs, while recognizing a gain (loss) tends to decrease (increase) a pension plan's cost. The EROA and the discount rate are percentages whose values should broadly reflect market conditions, future benefit obligations, and how plan investments will perform in the market. While the fair value of the plan, recognized gain or loss, service cost, and interest cost are largely predetermined by the choice and operation of the plan, the EROA and discount rate are items that the Company has considerable discretion in choosing when projecting future pension plan costs. I discuss both the EROA and discount rate in greater detail later in my testimony.

The above parameters and discussion are also relevant when calculating PacifiCorp's post-retirement medical benefits plan's cost, also known as the FAS 106 cost, as well. As noted above for FAS 87 costs, FAS 106 costs can be positive or negative. For both the FAS 87 and FAS 106 costs, a negative cost suggests that a plan is in good financial health and that earnings from its investments exceeds the amount it needs to pay out to beneficiaries. Similarly, a positive expense means that benefit payments are reducing the asset balance of the plan more quickly that returns are replenishing it.

<u>Pension Plan</u>

Q. Do you believe PacifiCorp's proposed Test Year pension cost of approximately $3.1 million is appropriate?

A. No. As previously stated, the two primary levers the Company can use to establish the pension cost are the discount rate and the EROA. I find that PacifiCorp's proposed EROA value underestimates the Company's actual and projected market returns and is among the lowest among jurisdictional energy utilities.

Q. What is the discount rate and how does it influence pension plan costs?

A. The discount rate is the expected market interest rate for the relevant asset or portfolio of assets by which to discount future pension plan obligations. It is a key parameter for calculating the present value of a portfolio's stream of future income. An increase in the discount rate decreases the present value of projected future pension obligations, which lowers periodic pension plan costs.

Q. What analysis have you done to check whether PacifiCorp's proposed discount rate is appropriate?

A. I compared PacifiCorp's proposed discount rate to the market yield of bonds that have a similar risk profile to the assets held in the Company's pension plan, namely the yields on U.S. Corporate AA-rated bonds. I also compared the Company's choice of a discount rate to the average of discount rates used by its Oregon-regulated utility peers.

Q. How does PacifiCorp's proposed pension plan discount rate compare to the discount rate implied by the market?

A. While it is probably overly simplistic to believe the Company's pension plan discount rate should perfectly track the yield U.S. Corporate AA-rated bonds, comparing the change in the discount rate between 2021 and the test year of 2023 to the change in the Corporate AA-rated bond yield over a portion of that time can be informative and provide insight into whether the Company's change in discount rate is moving in the same direction as the market and whether the magnitude of the change is roughly in line with the market. For both 2021 and as proposed for the Test Year, PacifiCorp's pension plan discount rate is 2.90 percent.[12]

When evaluating the change in proxy market yields from 2021 to the Test Year, I treat the market yield on November 30, 2020, as a suitable comparator for the Base Year yield and the yield on November 30, 2021, or one month before the filing of this testimony, as suitable for the Test Year yield. The yield for U.S. Corporate AA-rated bonds on November 30, 2020, was 1.45 percent. This rose to a market yield of 1.95 percent on November 30, 2021, for an increase of 50 basis points (bps). This change is represented in Figure 17-1,[13] where I plot the U.S. Corporate AA-rated bond yields over the May 19, 2020 – May 19, 2022, timeframe on a bi-weekly basis. Although the yield on U.S. AA-rated corporate bonds has been increasing, PacifiCorp proposed the same 2.90 percent discount rate for the Test Year that the Company used in 2021.

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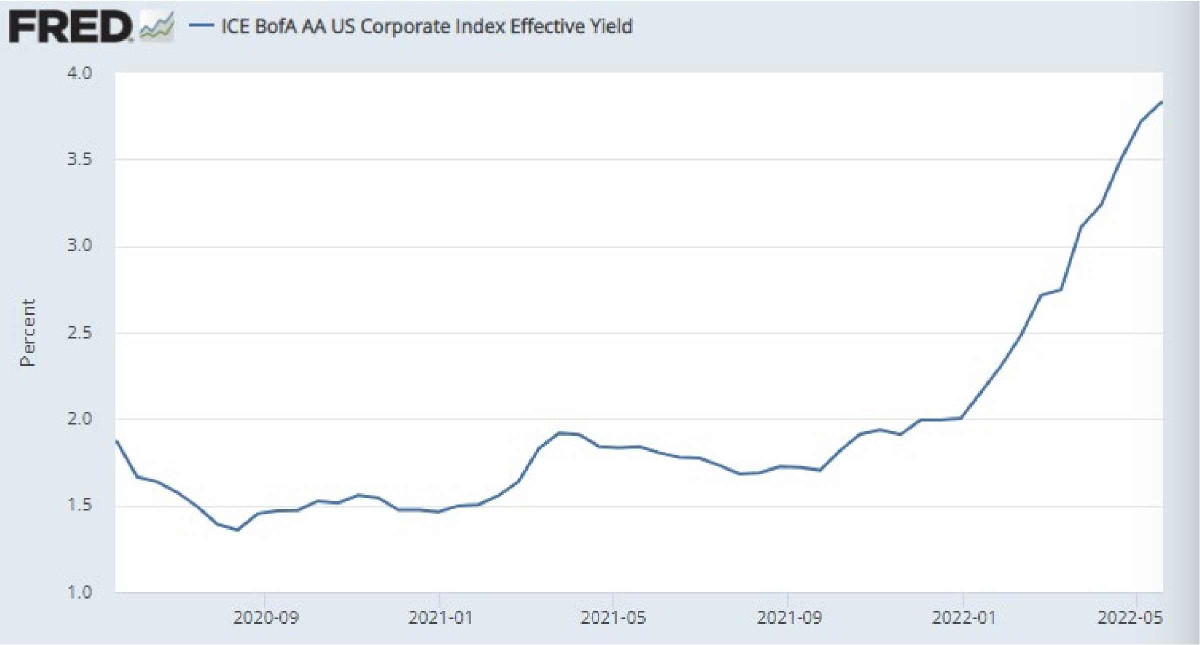
[12] Attachment to PacifiCorp's response to Standard Data Request 59, included as Exhibit Staff/1704.

[13] Figure 17-1 chart and underlying data obtained from FRED (accessed May 21, 2022).

Figure 17-1: Yields on U.S. AA Corporate Bonds for May 2020 – May 2022



Q. What changes do you recommend the Company make to its proposed Test Year pension plan discount rate?

A. I recommend a 50 bps increase to PacifiCorp's proposed 2.90 percent discount rate for its pension plan.

Q. How does the resulting 3.40 percent discount rate compare with those recently used by other jurisdictional energy utilities?

A. This level of discount rates exceeds the average of those used by four other jurisdictional energy utilities, for which the latest publicly available rates average 2.81 percent[14] without including PacifiCorp in the calculation. I note that, as in Figure 17-1 above, the average yield on U.S. AA-rated corporate bonds has been increasing since late September 2021, and it is not difficult to

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[14] Sources are the 2021 SEC Form 10K reports for Avista, Idaho Power, NW Natural, and PGE.

see a trend of rising discount rates for all Oregon jurisdictional energy utilities beginning with discount rates used for 2023.

Q. What effect does a 50 bps increase to the PacifiCorp's discount rate have on the Company's Test Year pension plan costs?

A. The Company estimates an increase of an additional 25 bps decreases its pension plan costs for the Test Year by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a system basis.[15] A linear extrapolation of this result has a 50 bps increase in the discount rate decreasing PacifiCorp's Test Year pension costs by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a system basis.

Q. Is PacifiCorp's proposed Test Year EROA for its pension plan appropriate?

A. No. I conclude that PacifiCorp's proposed EROA of 4.70 percent[16] is inappropriately low after comparing the EROA to other Oregon-regulated utilities and a very large pension plan, and to its actual pension plan returns over the last several years. The Company's proposed EROA for its pension plan is well below at least four of its energy utility peers in Oregon and well below the 6.8 percent EROA used by the California Public Employees' Retirement System (CalPERS).[17]

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[15] Confidential Exhibit Staff/1703, Storm/2.
[16] Exhibit Staff/1704, Storm/3.
[17] Exhibit Staff/1702, Storm/2.

Additionally, the EROA used has been a fraction of the actual rate of return over the last three years: 34.7 percent in 2019 (7.00 percent EROA versus 20.20 percent actual); 47.8 percent in 2020 (6.50 percent EROA versus 13.59 percent actual); and 54.7 percent (6.00 percent EROA versus 10.96 percent actual) in 2021.[18] I expect this trend of PacifiCorp underestimating its actual ROA to continue if no changes are made to the Company's proposed EROA.

Q. What do you say regarding recent turmoil in the stock and bond markets?

A. I acknowledge the volatility in both markets for 2022 through the mid-June date this testimony was finalized. However, actual returns for 2022 will not be known until year-end. Additionally, and importantly, the Test Year in this proceeding is calendar year 2023.

Q. Why is the Company's EROA for the Test Year important?

A. Funding PacifiCorp's pension plan cost can come from at least two sources: ultimately ratepayers and returns on plan investments.[19] To the extent more funding comes from investment returns, the share of the pension plan's cost that must come from customers is reduced, with all else being equal.

Q. How does the PacifiCorp's proposed EROA for 2023 compare to the 2021 EROA of other Oregon-regulated utilities?

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[18] Actual ROA and EROA values from Exhibit Staff/1704, Storm/3.

[19] The Company could make cash infusions into the pension fund that are potentially recoverable through rates charged to customers.

A. The Company's proposed Test Year EROA can be found in Table 17-2. As can be seen, the Company's proposed EROA of 4.70 percent is lower than certain of its Oregon-jurisdictional utility peers. Given the small sample size of Oregon utilities, this might be warranted if there is a trend of pension plans seeking out less risky investments than this sample. However, as evidenced by CalPERS, this is not the case.

Table 17-2: Pension EROAs for Certain Jurisdictional Utilities[20]

Company	EROA
Avista	5.40%
Idaho Power	7.40%
NW Natural	7.25%
PacifiCorp	4.70%
Portland General	6.88%
Average without PacifiCorp	6.73%

Q. What EROA is used by CalPERS?

A. CalPERS uses a long-term EROA of 6.8 percent, as stated in the Wall Street Journal article I include as Exhibit Staff/1702.[21] The article also states that the average EROA of state and local government retirement funds is 7.0 percent, meaning that PacifiCorp's 4.70 percent EROA appears to be an outlier, even considering it is proposed for application to 2023 and potentially even more of an outlier given the trend in interest rates.

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[20] EROA values for utilities other than PacifiCorp are from each utility's 2021 SEC Form 10K filing in early 2022; i.e., they are historical rates used in 2021. PacifiCorp's EROA is as proposed for the Test Year in this proceeding, as at Exhibit Staff/1704, Storm/3.

[21] Staff/1702, Storm/2.

Q. If the EROA is forward looking, why should the PacifiCorp's EROA be adjusted based on past results?

A. While it is true that the EROA is forward looking and markets fluctuate, I consider PacifiCorp's recent experience of actuals exceeding EROA to be indicative of its pension plan's future performance. Note that I am not suggesting PacifiCorp's pension plan will realize future returns of similar magnitude as those experienced in 2019 – 2021 but am suggesting that future performance is, on average, likely to exceed the 4.70 percent EROA PacifiCorp proposes for 2023.

Q. What changes do you recommend regarding PacifiCorp's pension plan EROA?

A. I conditionally recommend PacifiCorp increase its EROA for the Test Year to 6.7 percent. This value nearly matches both the average value used by state and local government retirement plans and the average of other Oregon-regulated utilities. This is an increase of 300 bps to its proposed EROA, which is still comfortably below the Company's actual returns for each of the past three years and provides the Company some amount of cushion if its recent returns are not sustained in the future.

Q. How does increasing PacifiCorp's EROA to 6.7 percent impact the Company's pension cost in this proceeding?

A. The Company estimates an increase of 25 bps in the pension plan's EROA <u>increases</u> its pension plan costs for the Test Year by approximately **[BEGIN**

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]** on a system basis.[22] I believe this value results from a "typo," as intuition suggests an increase in EROA would <u>decrease</u> pension plan costs, as discussed above.[23] Accordingly, I have conditionally changed the sign of this result, such that an increase of 25 bps <u>reduces</u> pension plan costs by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a system basis. A linear extrapolation of this result has the 200 bps increase in the discount rate decreasing PacifiCorp's Test Year pension costs by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a system basis.

Q. What is the conditional aspect of this?

A. My recommendation regarding adjustments to PacifiCorp's pension costs is conditional upon reviewing the testimony offered by other Parties, as well as PacifiCorp providing an adequate response to my data requests regarding this issue, and a comprehensive explanation in the Company's next round of testimony in this proceeding. A satisfactory explanation of PacifiCorp's sensitivity parameters' values may result in a different Staff recommendation.

Q. Might PacifiCorp's proposed accounting for a forecasted 2023 settlement loss account for the non-intuitive result of a hypothetical change in the EROA?

A. Perhaps.

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[22] Confidential Exhibit Staff/1703, Storm/2.

[23] I have submitted data requests to PacifiCorp regarding this issue.

<u>Post-Retirement Medical Benefits Plan</u>

Q. What values does PacifiCorp propose for its post-Retirement Medical Benefits Plan?

A. The Company proposes a 2.90 percent Discount Rate and a 3.39 percent EROA.[24]

Q. Is PacifiCorp's proposed value for the Discount Rate appropriate?

A. No, and for essentially the same reasons the proposed Discount Rate for the Company's pension plant is inappropriate.

Q. What do you recommend regarding the Discount Rate?

A. I conditionally recommend use of the same 3.40 percent Discount Rate I recommended for the pension plan, which represents a 50 bps increase from PacifiCorp's proposed value.

Q. How does the resulting 3.40 percent discount rate compare with those recently used by other jurisdictional energy utilities?

A. This level of discount rate exceeds the average of those used by three other jurisdictional energy utilities, for which the latest publicly available discount rates average 2.52 percent[25] without including PacifiCorp in the calculation. I note that, as above, the average yield on U.S. AA-rated corporate bonds has been increasing since late September 2021, and it is not difficult to see a trend of rising discount rates for all Oregon jurisdictional energy utilities beginning with actual discount rates used for 2023.

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[24] Exhibit Staff/1704, Storm/4.

[25] Sources are the 2021 SEC Form 10K reports for Avista, Idaho Power, NW Natural, and PGE. PGE provided a range of rates and therefore was not included in calculation of the average.

Q. What effect does a 50 bps increase to the PacifiCorp's discount rate have on the Company's Test Year post-retirement medical benefits plan costs?

A. The Company estimates an increase of 25 bps <u>increases</u> its plan costs for the Test Year by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and a decrease of 25 bps <u>decreases</u> its costs by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, both on a system basis.[26] I find the results in both directions not intuitive, and have, pending PacifiCorp's response to data requests regarding this issue, reversed each sign. A linear extrapolation of the result after my change of signs has a 50 bps increase in the discount rate decreasing PacifiCorp's Test Year pension costs by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a system basis.

Q. Is PacifiCorp's proposed 3.39 percent value for the EROA appropriate?

A. No. The Company's actual history is that the EROA used has been a fraction of the actual rate of return over the last three years: 35.0 percent in 2019 (6.86 percent EROA versus 19.59 percent actual); 84.2 percent in 2020 (4.92 percent EROA versus 5.84 percent actual); and 50.5 percent (2.90 percent EROA versus 5.74 percent actual) in 2021.[27] I expect this trend of PacifiCorp underestimating its actual ROA to continue if no changes are

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[26] Confidential Exhibit Staff/1703, Storm/3.
[27] Exhibit Staff/1704, Storm/4.

made to the Company’s proposed EROA for its post-retirement medical benefits plan.

Q. What do you recommend regarding the EROA?

A. I conditionally recommend the same 6.7 percent EROA I recommend above for the pension plan, which represents a 331 bps increase from PacifiCorp’s proposed value.

Q. What effect does a 331 bps increase to the PacifiCorp’s discount rate have on the Company’s Test Year post-retirement medical benefits plan costs?

A. The Company estimates an increase of 25 bps decreases its plan costs for the Test Year by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and a decrease of 25 bps increases its costs by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**,[28] both on a system basis. A linear extrapolation of this result has a 331 bps increase in the discount rate decreasing PacifiCorp’s Test Year post-retirement medical benefits plan’s costs by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a system basis.

Q. What is the conditional aspect of this recommendation?

A. My conditional recommendation regarding adjustments to PacifiCorp’s post-Retirement medical benefits plan’s costs is similar to my recommendation regarding the Company’s pension plan costs, conditional upon reviewing the testimony offered by other Parties as well as PacifiCorp providing an adequate

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[28] Confidential Exhibit Staff/1703, Storm/3.

response to my data requests regarding this issue, and a comprehensive explanation in the Company's next round of testimony in this proceeding. A satisfactory explanation of PacifiCorp's discount rate sensitivity result may result in a different Staff recommendation.

Q. Does PacifiCorp, in its direct testimony regarding the accounting for settlement losses,[29] distinguish between an impact on its qualified pension plan and its post-retirement medical benefits plan?

A. No. The language used by the Company is "pension settlement losses" and "pension settlement accounting."[30]

Q. Please provide a summary table of the impact of your recommendations for the discount rate and the EROA for both the pension plan and the post-retirement medical benefits plan.

A. Table 17-3[31] provides such a summary.

Table 17-3: Impacts of Staff's Recommendations on Pension Plan and post-Retirement Medical Benefits Plan Costs ($Millions on a system basis)

[BEGIN CONFIDENTIAL]

Plan	Discount Rate Impact	EROA Impact	Total
Pension	[redacted]	[redacted]	[redacted]
Post-Retirement Medical Benefits	[redacted]	[redacted]	[redacted]
Total			[redacted]

[END CONFIDENTIAL]

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[29] This appears at Exhibit PAC/200, Kobliha/28-32.

[30] *Id.*

[31] Numerical tables in this testimony that include one or more total values may have these values disagree with the sum of values as displayed due to rounding errors.

ISSUE 4. UM 2185 NON-CONTRIBUTORY PENSION PLANS

Q. What did PacifiCorp file in Docket No. UM 2185?

A. The Company, on July 27, 2021, filed an application to defer costs associated with the pension settlement losses expected to occur in 2021. PacifiCorp also filed for an accounting order for approval of an accounting amortization process.

Q. Were the issues in UM 2815 resolved in that proceeding?

A. No. PacifiCorp filed, on March 22, 2022, a motion in both UM 2185 and UE 399 to consolidate issues in UE 2185 into UE 399. Staff did not oppose the Company's motion.[32] Administrative Law Judge Lackey granted the motion in her ruling issued April 11, 2022.

Q. What did PacifiCorp request in its initial UM 2185 application?

A. The Company's filing included two requests. PacifiCorp requested an order authorizing PacifiCorp to defer pension settlement losses expected to occur in 2021. Additionally, it requested authorization "…to amortize the impact of the pension settlement loss to expense over the same period that is used to amortize the underlying net pension regulatory asset with the opportunity to recover the amount in rates as part of pension cost in the next general rate case."[33] PacifiCorp explained that the two requests allow the Company to account for the impact of the pension settlement loss through deferral and amortization in a manner that closely approximates the amortization that would

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[32] *See* Corrected Staff Response to PacifiCorp Motion to Consolidate filed March 30, 2022, in UM 2185.

[33] Page 1 of the July 27, 2021, filing in Docket No. UM 2185.

have continued if it were not for the accelerated recognition required by Generally Accepted Accounting Principles (GAAP) due to occurrence of a pension settlement event.[34]

Q. Did a pension settlement occur?

A. PacifiCorp stated that a settlement would be triggered in July 2021 based on lump sum distributions that will have occurred through July 30, 2021, requiring pension settlement accounting.[35]

Q. What amount did PacifiCorp's actuaries estimate the loss to be?

A. PacifiCorp states in its application, that the resulting pension settlement loss would not be known until its actuaries complete the remeasurement of the pension plan benefit obligation, plan assets, and net unrecognized actuarial losses, its actuaries estimated the loss to be approximately $8.7 million. The Company added that additional losses expected to total $4.8 million would be incurred as retirees continued to elect lump sum distributions.[36]

Q. What loss amounts did PacifiCorp recognize?

A. According to the Company, updated estimates were $8.947 million of settlement loss, which was the amount recognized by the Company. The plan assets and benefit obligation were again remeasured as of December 31, 2021, and an additional $6.699 million settlement loss was then recognized.

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[34] *Id.*

[35] *Id.*, page 2.

[36] *Id.*

As a result, pension settlement losses in 2021 total $15.646 on a total company basis.[37]

Q. Did the Commission, in PacifiCorp's UE 374 general rate case proceeding, express a concern regarding the potential for double recovery of settlement losses?

A. Yes. The Commission was concerned that PacifiCorp's suggested alternative to placing settlement losses in base rates, which was to allow deferral of all future pension settlement loss expenses, and to amortize them over the time period that such costs would have otherwise been amortized absent the settlement loss.[38]

Q. How did the Commission resolve this issue in the UE 374 general rate case?

A. The Commission declined to grant PacifiCorp's alternative request for a deferral, as part of the UE 374 proceeding, for the Company's expected pension settlement loss.[39]

Q. Did the Commission address a process by which PacifiCorp might recover a pension settlement loss in the test year of a general rate case going forward?

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[37] Exhibit PAC/200, Kobliha/31.

[38] Pages 95-96 of Order No. 20-473 in Docket No. UE 374.

[39] *Id*., page 96.

A. Yes. The Company would first have to address its concern for double recovery. Additionally, the Company should detail how to account for the changes to ongoing FAS 87 expenses due to any pension settlement losses.[40]

Q. Did the Commission include additional direction regarding settlement losses in test years of future general rate cases?

A. Yes. The Commission stated that:

> Using a deferral…would provide a more appropriate ratemaking treatment than building into base rates an expense that is still somewhat uncertain and would be unlikely to recur in the future. We would evaluation any other deferral applications related to pension settlement losses within their own specific context, and reserve our authorities to determine whether such amounts are significant enough to warrant deferral and tailored to address the various relevant concerns.[41]

Q. How did PacifiCorp account for Oregon's share of these losses?

A. The Company, for each of the two settlement losses recognized in 2021, deferred Oregon's allocated share to a regulatory asset, with amortization over the approximately 20-year average remaining life expectancy of the plan's participants beginning immediately after each loss was recognized. PacifiCorp asserts that, as a result, amortization of these losses approximates what is currently included in base rates resulting from the Company's 2021 general rate case proceeding UE 374 and that this treatment is consistent with the Commission's Order in UE 374.[42]

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[40] *Id*.
[41] *Id*., page 96.
[42] Exhibit PAC/200, Kobliha/31.

PacifiCorp states that, due to the proximity of the 2021 settlement losses to the timing of when base rates reset, and with a similar level of amortization reflected in base rates, the Company deferred the 2021 settlement losses to a regulatory asset.[43]

Q. How did PacifiCorp reflect the 2021 pension settlement losses in the current proceeding's test year?

A. The Company states that as a result of the accounting it describes in testimony and is summarized above, approximately 1/20th of those losses is included in the test year pension cost.

Q. Are there additional pension settlement losses after 2021, and are any of these reflected in test year pension costs?

A. Yes. According to PacifiCorp, its actuaries have projected settlement losses of $9.781 million and $7.145 million in 2022 and 2023, respectively, with the threshold for recognition assumed to be exceeded at the end of the respective year and amortization beginning immediately. PacifiCorp states that, as a result, approximately 1/20th of the $9.781 million projected 2022 settlement loss is included in the test year pension cost. Additionally, although no specific amortization or recognition of the 2023 settlement is included in test year pension costs, the associated unrecognized loss is "included in the forecast test year expense based on the normal amortization component of net periodic pension costs." The Company asserts this treatment of both the projected 2022 and 2023 settlements' losses is consistent with Order No. 20-473.

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[43] *Id*., page 32.

Q. Do you have any recommendation regarding this issue?

A. No.

ISSUE 5. AMMORTIZATION OF COVID-19 DEFERRALS AND RATE SPREAD

Q. What costs are pertinent to this issue regarding rate spread?

A. The costs pertinent to the rate spread issue are those discussed in Exhibit Staff/700 and reflect COVID-19 deferrals for 2020 and 2021. Amounts included in Table 17-4 are those reported by PacifiCorp that Staff finds are appropriately included in the deferral.[44] My rate spread analysis uses amounts resulting from Staff's adjustments.

Q. How did you approach this issue?

A. I recommend two different approaches to rate spread for the three different COVID-19 costs, or groups of costs, considered in this proceeding and shown in Table 17-4. These are:

- Incremental Bad Debt;
- Increased Expense (Savings); and
- Costs associated with PacifiCorp's Bill Payment Assistance Program plus waived late fees and foregone reconnection fees.

The recommended rate spread approaches use deferral dollar amounts after Staff's adjustments; i.e., as shown in Table 17-4. I first discuss the rate spread and amortization of annual totals associated with PacifiCorp's bill payment assistance program[45] plus waived late fees and forgone reconnection charges.

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[44] *See* Exhibit Staff/700 for discussion of Staff's adjustments.

[45] The Bill Payment Assistance Program is sometimes referred to as the Arrearage Management Program (AMP), as noted above. *See* Section f on page 20 of Attachment A to Order No. 20-401 in UM 2114.

Q. Please provide your perspective on the credits PacifiCorp has provided customers during the COVID-19 pandemic.

A. I view the credits as conceptually similar to short-term transfer payments from a government agency to consumers because these costs are being incurred by PacifiCorp in concert with and at the behest of the Commission.[46]

Q. What PacifiCorp costs are included?

A. These are reproduced in Table 17-4 below and reflect Staff's adjustments discussed at Exhibit Staff/700.

Table 17-4: Certain COVID-19 Related Costs for 2020 and 2021

($Thousands)

Description of Cost	Total 2020	Total 2021
Incremental Bad Debt	$583.4	$1,194.9
Incremental Costs (Savings)	($954.7)	($1,465.0)
Bill Payment Assistance Program + Waived Late Fees & Foregone Reconnection Charges	$2,965.8	$14,685.8
Total	$2.594.5	$14,415.7

Q. How do you propose to spread the 2020 and 2021 amounts in Table 17-4 for PacifiCorp's Bill Payment Assistance Program plus Waived Late Fees and foregone Reconnection Charges between customer classes?

A. I rely upon the proposal that certain subsets of consumers were provided a short-term credit against their energy bills, which allows them to spend more than they otherwise would on other categories in their budget, such as food,

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[46] *See* Order No. 20-401, which authorized multiple changes in prior Oregon investor-owned energy utility operating policies resulting from a Stipulated Agreement between numerous parties to the proceeding. One authorized change was the utilities' use of deferred accounting of costs and benefits related to COVID-19, with recovery of those amounts to be subject to a future Commission prudence review proceeding.

shelter, and transportation.[47] This leads to a fiscal multiplier effect on the total output of Oregon's economy, with benefits received well beyond the actual recipients of the credits.

Q. What principles do you rely upon in determining the amount to be allocated to the different customer classes?

A. A key principle I followed was to allocate to customer groups in the proportion that each group is estimated to have received benefits. This is the principle of *cui bono*, defined as the "usefulness or utility as a principle in estimating the value of an act or policy."[48] A second "principle" or key concept is Gross Domestic Product (or "GDP"), which the U.S. Bureau of Economic Analysis defines as "a comprehensive measure of…economic activity" and is a useful (and used) proxy for economic welfare. If GDP per capita (or GDP itself in the short run) increases, the economic "pie" is larger and there is more available to each citizen (or economic agent).

Q. How is the total output of an economy measured?

A. There are three common ways economists measure the total output, or GDP, of an economy.[49] The first is by adding the amount of goods and services sold to final users, which are persons, businesses, governments, and non-U.S. entities. This is also described as the expenditures approach.

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[47] I note that, for residential customers of energy utilities, such credits may not have allowed customers to increase their spending on other categories, but only to maintain such spending at some level.

[48] Meriam-Webster online dictionary at "cui bono" (accessed June 4, 2022). I use the second definition at this location.

[49] *See* pages 2-7 – 2-11 of Chapter 2: Fundamental Concepts of BEA's National Income and Product Accounts (NIPA) Handbook (BEA, updated December 2020), retrieved on March 28, 2022, from https://www.bea.gov/resources/methodologies/nipa-handbook.

Q. What are the components of “goods and services sold to final users” in the expenditure approach?

A. I follow the U.S. Bureau of Economic Analysis’ (BEA) national income taxonomy on this point, where BEA categorizes such amounts as either personal consumption expenditures, gross private fixed investments, the change in private inventories, government consumption expenditures and gross investment, or the net exports of goods and services.

Q. What are the other two approaches to measuring GDP?

A. The second approach is the sum of income payments and other costs incurred in the production of goods and services, known as the income approach. The components of this approach are compensation of employees, taxes on production and imports, subsidies paid by government (a subtraction), net operating surplus (related to some concepts of “profit”), and the consumption of fixed capital (similar to depreciation).

The third approach is to use the sum of “value added” by all industries in the economy.

Q. Is GDP compiled and reported for Oregon?

A. Yes, and actual values as well as forecasts of GDP and certain components are provided by Oregon’s Office of Economic Analysis, an organization within the State’s Department of Administrative Services (DAS).[50] Actuals for both GDP and certain components of GDP are reported not only by OEA, but also

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[50] *See* at https://www.oregon.gov/das/OEA/Pages/Index.aspx (accessed by on March 28, 2022).

by agencies of the Federal government, such as BEA. BEA is part of the U.S. Department of Commerce.

Q. What component has the largest share of Oregon's GDP?

A. The largest component is personal consumption expenditures, which is the largest by far. During a three-year pre-COVID-19 baseline of 2017 – 2019, Oregon's personal consumption expenditures averaged 73.2 percent of Oregon's GDP.[51]

Q. You mentioned a fiscal multiplier effect due to the credits PacifiCorp's residential customers received. How large is this multiplier effect?

A. The Congressional Budget Office (CBO) prepared estimates of the fiscal multiplier for the U.S. economy associated with the effects of Federal COVID-19 pandemic-related legislation.[52] These were estimated as the cumulative effect of such incremental fiscal policies over a four-quarter period corresponding to Q2 2020 through Q1 2021. I include in Table 17-5 below key estimates included in CBO's Table 2.[53] Note that CBO's estimated central values ("point estimates") are averages of the "Low" and "High" values.[54]

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[51] Calculated using values retrieved from BEA on March 23, 2022.

[52] *See* "Key Methods That CBO Used to Estimate the Effects of Pandemic-Related Legislation on Output, "Working Paper 2020-07" by Seliski, et al (CBO, October 2020). Retrieved on March 28, 2022, from https://www.cbo.gov/publication/56612 .

[53] *Id.*, page 24.

[54] *Id.*, page 5.

Table 17-5: Changes in Output from One Dollar of Direct Effects on Overall Demand When Output Is Well Below Potential and the Federal Reserve's Responses Are Limited

			Under Social Distancing	
	Low Estimate	**High Estimate**	**Low Estimate**	**High Estimate**
Cumulative Effect Over 4 Quarters	0.50	2.50	0.31	1.78

Q. What key assumptions did CBO make in developing these estimated multiplier values?

A. CBO assumed, as stated above, that there would not be any effects beyond the fourth quarter following the initial impact of a measure.

Q. Is this a reasonable assumption given the credits to PacifiCorp's residential customers in this context?

A. Probably, and especially as pertaining to expenditures made by residential customers receiving credits, i.e., the direct effects. I believe it likely that recipients collectively spent most of the value of the credits in short order. Again, the credits may have only allowed recipients to continue their usual expenditure patterns on things like food, shelter, and transportation. Some indirect effects will likely take somewhat longer to be realized.

Q. What are other key assumptions?

A. Two other key assumptions are indicated by the language in the label for Table 17-5:[55] 1) output (GDP) is well below potential and 2) the Federal Reserve's policy responses to COVID-19-related fiscal stimulus are limited.

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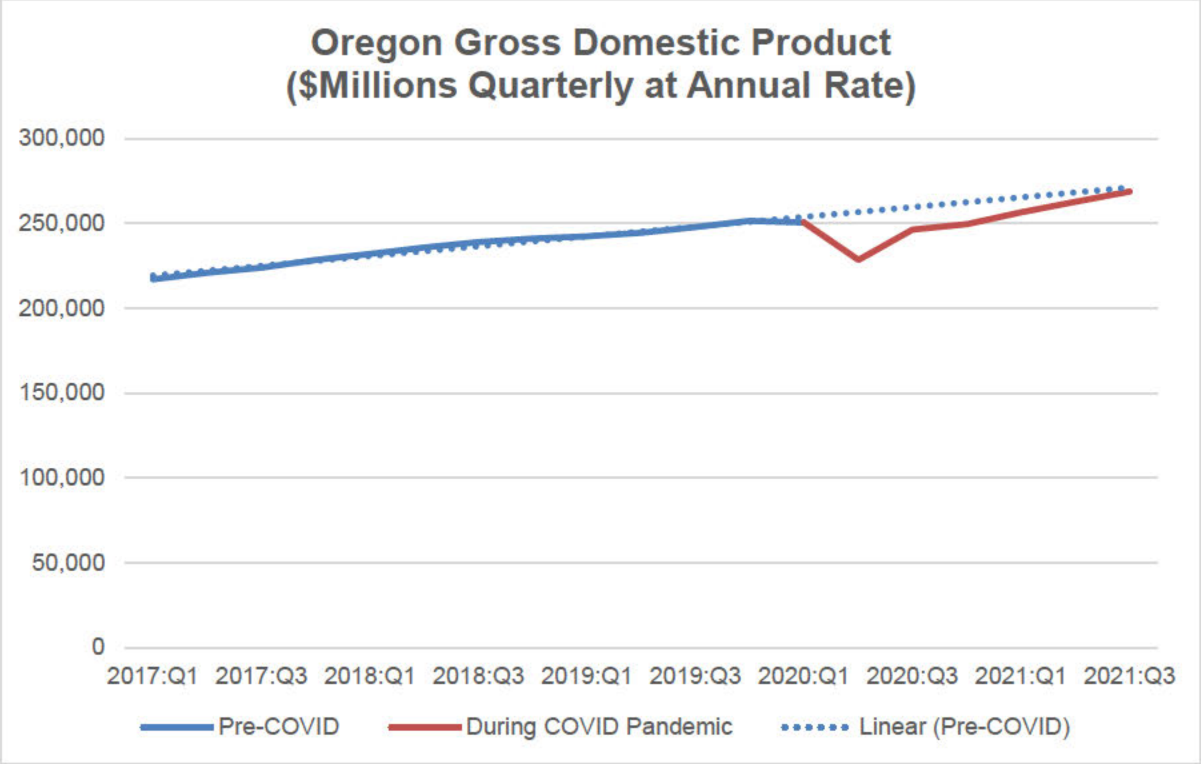
[55] *Id.*, page 24. *See* CBO's label for their Table 2, which I have replicated for Table 17-5.

Q. Do you believe each of these assumptions applied to Oregon in the 2020 through Q3 2021 period?

A. Yes. Figure 17-2[56] shows that Oregon's nominal GDP was below the Q1 2017 – Q4 2019 trend from the pandemic's onset in Q1 2020 until recently. Data not yet available as of the date of this testimony will presumably indicate whether Oregon's GDP is fully "on trend" in the near-term.

Figure 17-2: Oregon Nominal Gross Domestic Product: Q1 2017 – Q3 2021



Reviewing labor market data indicates Oregon may not have reached potential levels of demand, as the nonfarm employment level remains not only

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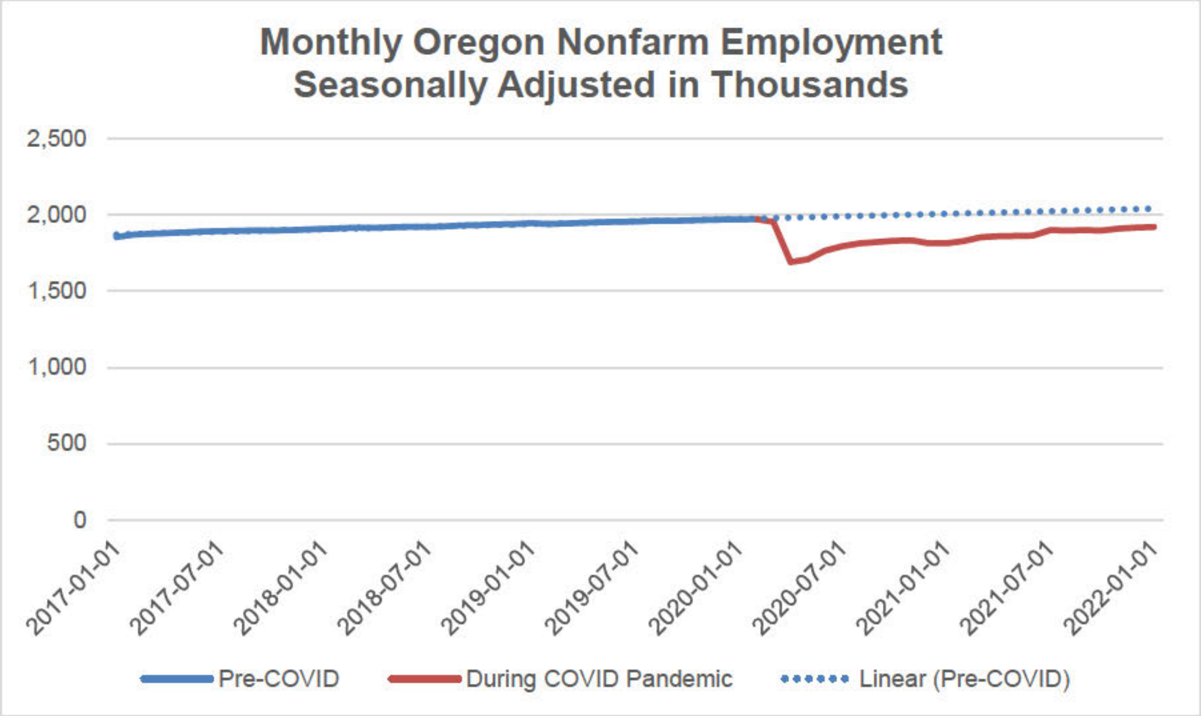
[56] Underlying data retrieved from BEA on March 23, 2022.

under the 2017 – 2019 trend, as shown in Figure 17-3,[57] but also below the pre-COVID-19 peak.

Figure 17-3: Oregon's Nonfarm Employment 2017 – 2021



Q. What about the assumption that the Federal Reserve's policy responses to the COVID-19 pandemic were limited?

A. Oregon has neither its own currency nor associated money supply, and U.S. monetary policy is largely implemented by the Federal Reserve Bank (Federal Reserve or Fed). Given that, this assumption is also largely validated. The Federal Reserve, early in the pandemic, reduced the Fed Funds rate to near zero; i.e., the Fed's incremental policy moves were constrained by a zero lower

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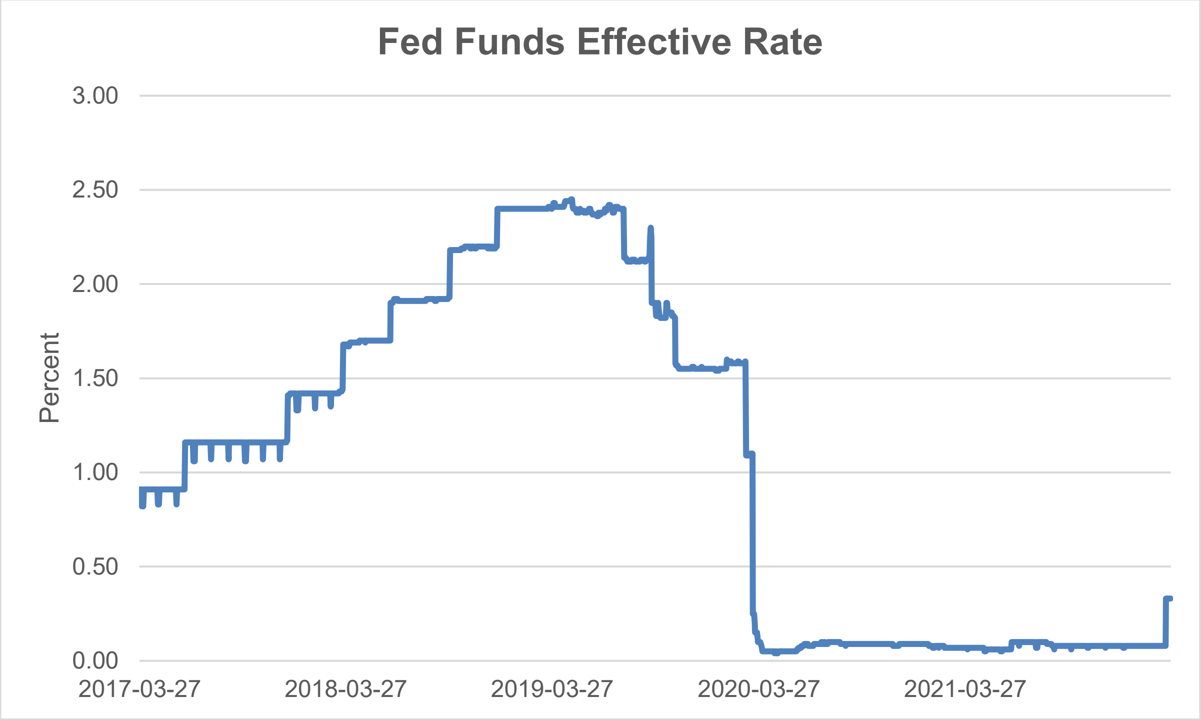
[57] Underlying data retrieved on March 23, 2022, from FRED.

bound (ZLB) on the Fed Funds rate, as shown in Figure 17-4.[58] After the initial reduction at the pandemic's onset, the Federal Reserve's primary policy tool could not be effectively lowered, indicating it had limited policy options at the time PacifiCorp's customers began receiving the Company's credits.

Figure 17-4: Federal Funds Effective Rate



Q. Returning to potential values of a multiplier to use for analyzing the impact of PacifiCorp's credits to ratepayers, which CBO value do you advocate using?

A. None of them. I believe a more realistic value for the multiplier results from assuming the amount of the provided credit residential customers spent – as opposed to saved – was larger than that implied by any of CBO's multiplier

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[58] Underlying data retrieved on March 23, 2022, from FRED.

values. I use a 0.90 marginal propensity to consume (MPC) value, which implies a fiscal multiplier value of 10. The intuition here is that a large share of customers receiving credits during the pandemic were probably not doing much—if any—incremental savings, and a 0.10 value for the marginal propensity to save (MPS), which implies the average customer receiving one or more credits spent 90 percent of the credits' aggregate value, seems eminently reasonable to me.

Q. What is the marginal propensity to consume?

A. It is the proportion of fiscal stimulus that will be spent, and not saved, by residential customers.

Q. If Personal Consumption Expenditures represented 73.2 percent of Oregon's GDP during the 2017 – 2019 baseline period, and recipients of PacifiCorp's credits spend 90 percent of those credits, should residential customers pay for the entire cost of PacifiCorp's having provided those credits?

A. I have concluded they should not and consider two additional facets to this question. Who else benefits when a residential customer spends $0.90 of each dollar's worth of credit received? Indirect benefits accrue to residential customers as a class, and one example of this is that spending assists in keeping employment levels higher than would otherwise be the case.

Additionally, the owners of commercial and industrial enterprises benefit, in the form of increased earnings paid to proprietors (for non-corporate ownership structures) or corporate owners benefiting from one or both of increased dividends or increased retained earnings in the future. As stated above, such benefits may take the form of a lower reduction that might otherwise be the case.

Q. Are these "corporate owners" shareholders?

A. Yes. If the enterprise is a share-issuing corporation, shareholders are the owners and beneficiaries of share-issuing corporations. Terms used for owners of other organizational structures may differ; e.g., a limited liability company (LLC)[59] may have "members" and not "shareholders," while owners of partnerships have "partners."

Q. Shareholders of some corporations are other corporations, foundations, or government entities, such as Oregon's PERS through its investment portfolio. Who benefits in these situations?

A. The corporate owner and its shareholders are the beneficiaries in corporate ownership structures. The beneficiaries of a foundation having shares of corporations in its investment portfolio are presumably individuals and PERS beneficiaries are individual retirees and future retirees from the State of Oregon.

Q. If individuals are the beneficiaries of incremental amounts received from such organizations, what happens to the amounts they receive as dividends, charitable benefits, pension payments, etc.?

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[59] LLCs may have features of both partnerships and corporations. See; e.g., Investopedia at https://www.investopedia.com/terms/l/llc.asp#:~:text=A%20limited%20liability%20company%20(LLC)%20is%20a%20business%20structure%20in,a%20partnership%20or%20sole%20proprieTorship. (Accessed on April 11, 2022).

A. Individuals, on average, both spend a portion and save a portion of such amounts.

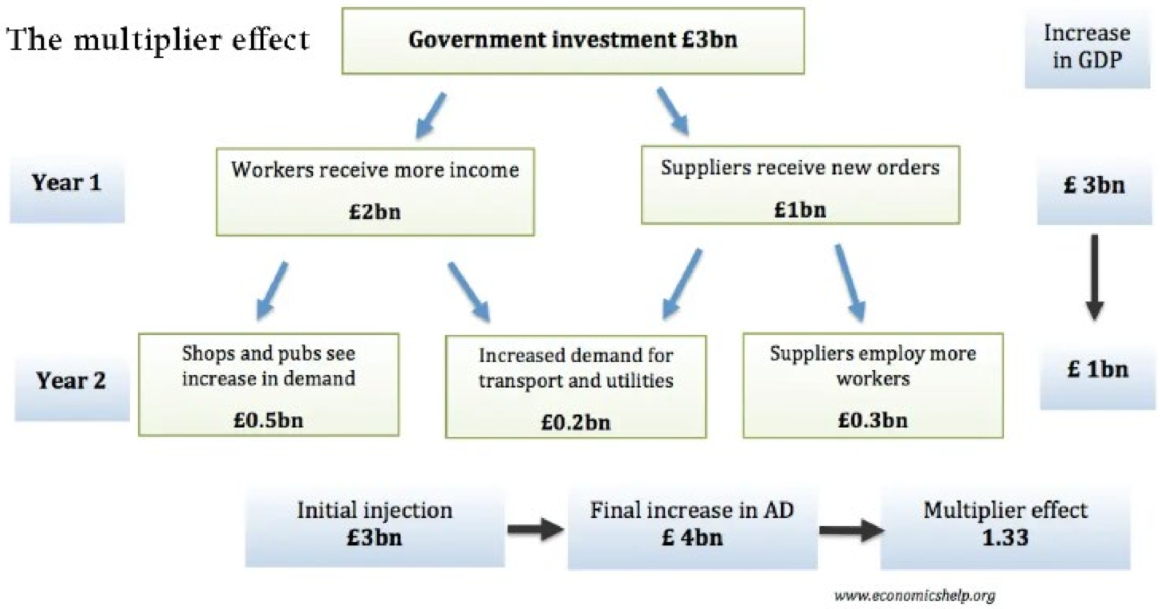
Q. Why do you include the owners of Industrial companies as indirect beneficiaries of credits received by residential customers of PacifiCorp?

A. Benefits to owners of industrial companies are illustrated by the increase in sales, prices, or both as a result of the toilet paper shortage early in the pandemic, as an example. Consumers depleted existing stocks from retail stores (commercial customers), and production ramped-up to rebuild inventories to a sustainable level (perhaps at higher prices). This product is produced by industrial firms, such as Georgia Pacific (GP), and GP has multiple production facilities within Oregon, potentially including within PacifiCorp's Oregon service area. This production may have occurred within Oregon's borders or in different states (or countries).

Q. Is it accurate to say that, if consumers receive an extra dollar, a portion of that dollar ends up being spent not only by the recipient consumer, but also by multiple organizations, as inputs to some organizations are the outputs of others?

A. Yes. Additionally, as most organizations have employees and some of the downstream incremental spending by such organizations may be on incremental payroll, incremental employment creates an indirect benefit to consumers as a result of the incremental employment. Such spending results in additional "rounds" (or "cycles") of spending, e.g., employees spending incremental amounts of the incremental payroll paid by organizations. I include a simple multi-year illustration of the multiplier effect from government investment in Figure 17-5.[60]

Figure 17-5: Example of Multiplier Effect 1 from Government Investment



www.economicshelp.org

Q. Do you believe the owners of PacifiCorp's Oregon commercial and industrial customers have benefited from the credits to residential customers?

A. Yes, although there is a representation issue here.

Q. What do you mean by a "representation issue?"

A. Oregon is not known as a state with a large concentration of corporate headquarters. As an example, while Intel may be Oregon's largest private

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[60] See "Economics Help" at https://www.economicshelp.org/blog/1948/economics/the-multipliereffect/ (accessed April 11, 2022).

sector employer, it is not headquartered in Oregon, and it is highly unlikely that most of its shareholders reside in Oregon.[61]

Q. Why is this important?

A. While employees at the local, Oregon-located, operations of national or international firms may receive indirect benefits resulting from PacifiCorp's credits to its residential customers, the owners of such firms—also receiving indirect benefits—may not all reside in PacifiCorp's Oregon service area.[62] For that reason, I allocate some of the indirect benefits, and thereby some of the direct costs of PacifiCorp's credits provided to its residential customers, to the Company's Commercial and Industrial customers and to its Public Street Lighting customers as proxies—X or "flow-through'' entities—for the owners of such firms. Additionally, employees at locations outside Oregon may benefit. Related to the example above, consider employees working in a plant producing toilet paper that is located outside Oregon.

Q How did you implement this assignment of customer credits and PacifiCorp's costs for its bill payment assistance program plus waived late fees and foregone reconnection fees?

A. I developed and evaluated three alternative scenarios, which varied on the values of the Multiplier and the MPC used. These values for each scenario are shown in Table 17-6, which includes CBO's multiplier values for Scenarios 1 and 2.

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[61] This is probably the case for Georgia Pacific and many other firms having Oregon operations as well.

[62] This is related to what is termed the "border effect" in regional economics.

Table 17-6: Multiplier and Marginal Propensity to Consume Values in Three Scenarios

	Multiplier	MPC
Scenario 1	2.50	0.60
Scenario 2	1.78	0.44
Scenario 3	10.00	0.90

These are CBO's High Estimate in each of these two scenarios.[63] The difference between the two scenarios is that Scenario 2 uses the 1.78 Multiplier value associated with CBO's Social Distancing alternative. For both Scenarios 1 and 2, the MPC values are as I calculated them. I selected the MPC value for Scenario 3 and calculated the Multiplier value based on the selected MPC value.

Q. What is the significance of the MPC value?

A. The MPC directly impacts the assumed multiplier. My analysis incorporates the standard assumption that recipients of the credits spend (consume) a portion of the credited amount and save a portion.[64] I additionally assume consumption occurs in same approximate timeframe in which credits are received and that savings remain savings throughout this timeframe. Recall that consumption might mean *less reduction* in consumption than would be the case absent the credits, and not necessarily more consumption *per se*.

A significant feature, given these assumptions, is that residential customers receiving credits save (or use to mitigate a reduction in savings) 40 percent of the dollar amount of credits received in Scenario 1, 56 percent of

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[63] I did not find the Low Estimates, in which a credit recipient would spend 50 percent or less of his/her credits' value and save the remainder, to be plausible in the current context.

[64] The Marginal Propensity to Save (MPS) is calculated as 1 – MPC.

the dollar amount of credits received in Scenario 2, and 10 percent of the dollar amount of credits received in Scenario 3. I contend that Scenario 3 is the most likely of the three to represent the behavior of PacifiCorp's residential customers who received credits during the COVID-19 pandemic.

Q. How is the multiplier involved in allocating the recovery of PacifiCorp's credits between the Company's Residential, Commercial and Industrial, and Public Street Lighting customers?

A. My model assigns, for residential customers, the implied Marginal Propensity to Save (MPS) as the Savings portion of the credits received and the MPC as the direct effect. There are no direct effects assigned to Commercial and Industrial or Public Street Lighting customers.

My model calculates the indirect effect for residential customers as Oregon's pre-COVID-19 baseline 2017 – 2019 Personal Consumption Expenditures (73.2 percent) multiplied by the quantity Multiplier less residential direct effect. The indirect effect for Commercial and Industrial customers and for Public Street Lighting customers is the quantity Multiplier less Total Residential effect multiplied by the respective share of COM+IND versus Public Street Lighting revenue.

Q. What do the indirect effects allocated to Commercial and Industrial or Public Street Lighting customers represent?

A. These indirect effects represent benefits accruing to employees and owners of these organizations who reside outside Oregon[65] as well as other components of the expenditures approach, both within and outside of Oregon, such as gross private fixed investments, the change in private inventories, government consumption expenditures and gross investment, and the net exports of goods and services.

Q. How do allocation shares differ between the three scenarios you used?

A. Table 17-7 includes the allocation for each customer class for costs associated with PacifiCorp's Bill Payment Assistance Program plus waived late fees and foregone reconnection fees. I note that, despite using a wide range of multiplier values, the impacts by customer class are similar for the three scenarios.

Table 17-7: Allocation Results by Customer Class for Each Scenario

	Multiplier	RES	COM & IND	Public Street Lighting	Total
Scenario 1	2.50	79.64%	16.93%	3.43%	100.0%
Scenario 2	1.78	79.80%	16.80%	3.40%	100.0%
Scenario 3	10.00	75.62%	20.27%	4.11%	100.0%

Q. The discussion above pertains to PacifiCorp's bill payment assistance program plus waived late fees and foregone reconnection fees. How do you propose to allocate Incremental Bad Debt Expense between customer classes?

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[65] With the result that their Personal Consumption Expenditures are captured in another state's GDP.

A. PacifiCorp's values, after Staff's adjustments previously discussed, are shown in Table 17-7. For Opening Testimony, I use shares of Base Year Total Revenue[66] to allocate this cost, after Staff adjustments, to customer classes. In other words, I allocate by an equal percent of revenue.

Q. How do you propose to allocate Incremental Expense (Savings)?

A. PacifiCorp's reporting provides limited detail regarding direct costs or savings in its RE 189 filings. I propose to allocate these based on Base Year revenue.[67]

Q. Please provide summary tables showing the results by customer class of each of the three allocations.

A. First, Table 17-8 summarizes the rate increase percent by customer class.

Table 17-8: Rate Increase Percent by Category by Customer Class for 2020 and 2021

Description	RES	COM & IND	Public Street Lighting
Incremental Bad Debt	0.05%	0.5%	0.05%
Incremental Costs (Savings)	-0.07%	-0.07%	-0.07%
Bill Payment Assistance Program + Waived Late Fees & Foregone Reconnection Charges	0.75%	0.23%	0.23%
Total	0.74%	0.21%	0.21%

Table 17-9 summarizes the amortization amounts and rate impacts by deferral year and customer class.

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[66] I use values in PacifiCorp's "OR CY2023 GRC PAC 1100 Meredith Rate Design Workpapers," submitted in this proceeding, as the basis for this allocation.

[67] *Id.*

Table 17-9: Summary of Amortization Impacts on Test Year

	Test Year Amortization ($Thousands)			Test Year Rate Impact		
	Deferral Year			Deferral Year		
	2020	2021	Total	2020	2021	Total
RES	$706.4	$3,758.7	$4,465.1	0.12%	0.62%	0.74%
COM & IND	$180.6	$1,168.1	$1,348.7	0.03%	0.18%	0.21%
Public Street Lighting	$1.7	$10.7	$12.4	0.03%	0.18%	0.21%
Total	$888.7	$4,937.5	$5,826.2	0.07%	0.39%	0.47%

Table 17-10 shows the dollar impact of amortization on the Test Year revenue requirement by customer class for each deferral year and Table 17-11 shows the incremental rate increase percent over Base Year Total Revenue by customer class for each deferral year. Values in Tables 17-10 and 17-11 are based on a three-year amortization period[68] beginning January 1, 2023, which is the rate effective date for this proceeding.

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[68] *See* Exhibit Staff/200.

Table 17-10: Amortization Impact in Test Year ($Thousands)

	Incremental Bad Debt Expense		Incremental Expense (Savings)		Bill Payment Assistance Program + Waived Late Fees & Foregone Reconnection Charges	
	Deferral Year					
	2020	2021	2020	2021	2020	2021
RES	$97.0	$198.6	($158.7)	($243.6)	$768.1	$3,803.6
COM & IND	$101.9	$208.7	($166.8)	($255.9)	$245.4	$1,215.3
Public Street Lighting	$0.9	$1.9	($1.5)	($2.3)	$2.3	$11.2
Total	$199.8	$409.3	($327.0)	($501.8)	$1,015.8	$5,030.0

Table 17-11: Amortization Impact on Test Year Rates

	Incremental Bad Debt Expense		Incremental Expense (Savings)		Bill Payment Assistance Program + Waived Late Fees & Foregone Reconnection Charges	
	Deferral Year					
	2020	2021	2020	2021	2020	2021
RES	0.02%	0.03%	-0.03%	-0.04%	0.13%	0.63%
COM & IND	0.02%	0.03%	-0.03%	-0.04%	0.04%	0.19%
Public Street Lighting	0.02%	0.03%	-0.03%	-0.04%	0.04%	0.19%
Total	0.02%	0.03%	-0.03%	-0.04%	0.08%	0.40%

Q. What recommendation do you have for the Commission regarding the rate spread and the amortization period?

A. My recommendation has three parts:

Authorize PacifiCorp to include in its compliance filing for this proceeding a new rate schedule, effective on the same January 1, 2023, date on which rates are generally to be effective as a result of this proceeding, that includes rates for each base rate schedule reflecting the total of:

1. The revenue requirement for amortizing the deferral balance associated with Incremental Bad Debt, inclusive of the adjustments recommended by Staff and for the total of both the 2020 and 2021 deferrals, is amortized over a three-year period using the Base Year revenue shares by customer class; i.e., an equal percent of revenue allocation.
2. The revenue requirement for amortizing the deferral balance associated with Incremental Costs (Savings), inclusive of the adjustments recommended by Staff and for the total of both the 2020 and 2021 deferrals, is amortized over a three-year period using the Base Year revenue shares by customer class; i.e., an equal percent of revenue allocation.
3. The revenue requirement for amortizing the deferral balance associated with total of PacifiCorp's bill payment assistance program plus waived late fees and foregone reconnection charges, inclusive of the adjustments recommended by Staff and for both the 2020 and 2021 deferrals, is amortized over a three-year period using the Scenario 3 share by customer class derived using the methodology described in Staff's testimony.

4. Rates for each base rate schedule within a given customer class are to be the same rate per kWh. Use of the new rate schedule is to be discontinued three years from the date rates are effective in this proceeding.

Q. Do you have any alternatives for Commission consideration?

A. Yes. If the Commission has concerns regarding rate shock, the Commission could delay for one year the amortizations recommended in this testimony.

ISSUE 6. WILDFIRE MITIGATION AND VEGETATION MANAGEMENT COST RECOVERY RATE MECHANISM[69]

Q. What is the focus of PacifiCorp's vegetation management efforts?

A. According to the Company, it "includes pruning and tree removal."[70]

Q. Is there currently a rate mechanism for recovery of costs associated with increased vegetation management and wildfire mitigation O&M expense and wildfire mitigation capital costs?

A. Yes. The Commission adopted a Wildfire Mitigation and Vegetation Management cost recovery (WMVM) mechanism as an outcome of PacifiCorp's most recently completed general rate case proceeding, docketed as UE 374.[71]

Q. What are the Commission's objectives for the adopted mechanism?

A. The Commission sought to provide a means for recovery of incremental costs of vegetation management and wildfire mitigation between the test years of general rate case proceedings that ensures PacifiCorp has "both the obligation and the incentive to complete those investments and improve its vegetation management practices in an appropriate timeframe."[72] The Commission found that the annual deferral of costs, coupled with a mechanism for annual

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[69] Staff testimony in Exhibit Staff/1700 concerns issues related to the WMVM mechanism and changes thereto proposed by PacifiCorp. Staff includes testimony related to the level of costs associated wildfire mitigation and vegetation management in Exhibit Staff/1300.

[70] Exhibit PAC/700, Berreth/21.

[71] Order No. 20-473 in Docket No. UE 374 at 120 – 125.

[72] *Id.*, page 120.

recovery of prudently incurred costs, will appropriately match the costs borne by and benefits received by ratepayers.

An additional objective was to "fairly balance the costs and risks associated with responding to changing wildfire risk"[73] between shareholders and PacifiCorp's customers. A third objective was to improve public safety.

Q. What amount did PacifiCorp propose for spending, in the UE 374 test-year, for wildfire mitigation and vegetation management?

A. The Company had proposed $33.225 million for the test-year.[74]

Q. What was this level of spending in the UE 374 test-year intended to cover?

A. Spending in the test-year was to include costs for planned vegetation management program enhancements, including increased local supervision, implementation of work management software and vegetation analytics.[75]

Q. What are the features of the WMVM mechanism in its current form?

A. There are several. First, the Commission apportioned the cost increase between base rates and the WMVM mechanism, with $30 million of O&M expense to be recovered in base rates and recovery of the first incremental $6.645 million in capital and O&M expense to be subject to a performance metric and an earnings test.[76]

Q. What is the performance metric?

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[73] *Id.*, pages 120-121.

[74] *Id.*, page 121. Footnote 577 on pages 116-117 shows development of the $33.225 million.

[75] *Id.*, citing Staff/2702, Moore/1 and PAC/2900, Lucas/18-19

[76] *Id.*

A. Levels of the performance metric, as well as information regarding the earnings test corresponding with each performance metric level, appear in Table 17-12 below, which I have replicated from the table appearing in the Order.[77]

Table 17-12: WMVM Mechanism Performance Metric and Earnings Test

Performance Metric	Earnings Test
Below Violation Level I	No earnings test
At or above Violation Level I, but below Violation Level II	Earnings test of UE 374 authorized ROE minus 100 basis points
At or above Violation Level II, but below Violation Level III	Earnings test of UE 374 authorized ROE minus 150 basis points
At or above Violation Level III	Earnings test of UE 374 authorized ROE minus 200 basis points

Q. What is represented by the different Violation Levels in Table 17-12?

A. The Violation Levels represents three levels of vegetation clearance violations, with values of 75 for Level I, 150 for Level II, and 200 for Level III.[78]

Q. Why did the Commission adopt these levels of vegetation clearance violations?

A. The Commission adopted these levels "in order to incentivize a rapid improvement over current performance."[79]

Q. What is the source of vegetation clearance violations?

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[77] The information in Table 17-12 appears in the table on page 117 of Order No. 20-473 in Docket No. UE 374.

[78] Page 124 of Order No. 20-473 in Docket No. UE 374.

[79] *Id.*

A. Employees in OPUC's Utility Safety, Reliability and Security Division ("Commission Safety Staff") perform an annual audit which establishes PacifiCorp's number of vegetation clearance violations for each year.

Q. Once a specific violation has been detected in the annual audit, is it carried forward as a violation in future years?

A. Yes; until PacifiCorp has demonstrated each violation has been cleared by providing adequate documentation to Safety Staff.[80]

Q. If PacifiCorp spends more than the $36.645 million in a given year, can the Company recover more than $36.645 million?

A. Yes. The Company may recover prudently incurred costs above $36.645 million in a given year subject to an earnings test set at PacifiCorp's authorized ROE.

Q. Is there an exception to this?

A. Yes. If violations occur at or above Level II (150 violations) and at least one violation occurs in a Fire High Consequence Area (FHCA) zone, the earnings test uses the authorized ROE minus 50 bps.[81]

Q. What is the annual timing related to the WMVM mechanism?

A. PacifiCorp is to annually file on May 5 for a rate adjustment to be effective November 5, with the first annual filing on May 5, 2022. The annual filing is to include deferred incremental O&M costs and the revenue requirement for

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[80] *Id.*

[81] *Id.*, page 122.

incremental wildfire mitigation capital projects placed in service from January 1st through December 31st of the prior year.[82]

Q. What happens if cost recovery under the WMVM for a prudent incremental wildfire mitigation capital project that – as a result of an earnings test – does not begin on November 5 of the year following its being placed in service?

A. The revenue requirement of the depreciated balance of such investments may be recovered in future years, subject to the earnings test without further prudence review.[83]

Q. Does the deferred revenue requirement balance of an incremental capital investment earn interest from the day the investment is placed in service?

A. No. The Commission determined that the costs of this aspect of regulatory lag should be borne by shareholders. Additionally, the revenue requirement for these investments is to be based on the undepreciated balance as of the rate effective date. As one result, PacifiCorp's annual deferral "need only include the incremental O&M costs subject to the mechanism."[84]

Q. What did the Commission say regarding capital investments currently being recovered under the WMVM in a given year?

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[82] *Id*.

[83] *Id*.

[84] *Id*., pages 122-123.

A. Such investments, with cost recovery beginning in an earlier year, are to have their undepreciated balance updated with the May 5th filing, such that their accumulated depreciation is taken into account.[85]

Q. What is the timing of the applicable Safety Staff audit?

A. The audit performed in the same year is used to establish the number of violations, augmented by any carry-forward of violations in one or more prior years, as discussed above. The number of violations, and whether one or more occurred in a HCFA, establishes the specifics of the earnings test to be applied as per Table 17-12.

Q. For what period did the Commission authorize the WMVM?

A. The Commission's authorization was for three years, which it said was consistent with the Company's stated intent to "dramatically decrease the vegetation clearance violations over a three-year period (2021-2023)."[86]

Q. What will the Commission do after three years (2022 – 2024) of WMVM filings?

A. It will reevaluate the available performance metrics and efficacy of the earnings tests. PacifiCorp, within its May 5, 2024, annual filing, "must demonstrate the WMVM mechanism has been effective and that its continued use is warranted."[87]

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[85] *Id.*, page 123.

[86] *Id.*, page 121, citing Staff/2702, Moore/1 and PAC/2900, Lucas/18-20. The cited language appears in PacifiCorp's response to Staff data request 677 in Docket No. UE 374, and the response is included in that proceeding as Exhibit Staff/2072.

[87] *Id.*

Q. How many violations did Commission Safety Staff identify in its 2021 audit?

A. Safety Staff identified 464 probable violations in its 2021 audit, which included 52 in a HFCA.[88] The WMVM mechanism has been in effect since the January 1, 2021, rate effective date of UE 374.

Q. How do these values compare with those from its 2020 audit?

A. Safety Staff identified 353 violations in its 2020 audit,[89] none of which were in a HFCA.

Q. What would the 464 probable violations documented in the 2021 audit hypothetically imply as to cost recovery and an earnings test if the WMVM mechanism was operating in 2021?

A. As 464 probable violations greatly exceeds the Level III amount of 200, the earnings test would be against PacifiCorp's authorized ROE less 200 basis points.

Q. What is PacifiCorp's current authorized ROE?

A. PacifiCorp's currently authorized ROE is 9.5 percent.[90] Therefore the earnings test would be against 7.5 percent.

Q. Did PacifiCorp, in its Direct Testimony, propose changes to the current WMVM mechanism?

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[88] Exhibit Staff/1705, which includes portions of OPUC Safety Reports E21-54R and E21-54L dated August 31, 2021, as well as the attached Historical Vegetation Graph.

[89] *Id*.

[90] Page 31 of Order No. 20-473 in Docket No. UE 374.

A. Yes. The Company proposed multiple modifications to the existing WMVM mechanism. At a high level, these are:

1. Remove the recovery of capital costs and O&M expenses associated with its wildfire protection plan from the WMVM mechanism;[91]
2. Modify the violation criteria for the level of violations;
3. Modify the Commission Safety Staff audit to verifiable violations on lines trimmed within two years;
4. Change the basis point adjustments in the earnings test to a sharing percentage; and
5. Provide for full recovery of costs due to inflation and new regulatory mandates.[92]

Q. What timing does PacifiCorp propose for implementation of its proposed changes?

A. The Company recommends removing costs associated with its wildfire protection plan beginning with costs incurred in 2022.[93] The implies that the first filing for cost recovery after removal of these costs will be May 5, 2023.

Q. What is PacifiCorp's reasoning behind its recommendation to remove the recovery of capital costs and O&M expenses associated with its wildfire protection plan from the WMVM mechanism?

A. Section 8 of Senate Bill (SB) 762 has that:

> All reasonable operating costs incurred by, and prudent investments made by, a public utility to develop, implement or

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[91] Exhibit PAC/100, Steward/26.
[92] *Id*., page 29.
[93] *Id*., page 26.

> operate a wildfire protection plan under this section are recoverable in the rates of the public utility from all customers through a filing under ORS 757.210 to 757.220. The commission shall establish an automatic adjustment clause, as defined in ORS 757.210, or another method to allow timely recovery of the costs.

While I am not an attorney, I conclude from the plain language of Section 8 that PacifiCorp may file for an automatic adjustment clause (AAC) to recover eligible costs of a Commission-approved Wildfire Protection Plan (WPP). However, having a cost being recoverable does not guarantee or bind Commission treatment such that all costs are "reimbursed" from customers. My attorneys will address this issue in legal briefs.

Q. Has PacifiCorp indicated it will file an application for an AAC to recover these costs?

A. Yes. The Company asserts in Direct Testimony it will do so "in the second quarter of 2022."[94] It previously filed its WPP with the Commission on December 30, 2021, in Docket No. UM 2207 and an application for deferral accounting of 2022 costs associated with its WPP on January 5, 2022.[95]

Q. Does removal of WPP cost recovery leave only costs of vegetation management to be recovered by the WMVM mechanism?

A. PacifiCorp asserts this is the result.[96]

Q. Does this change result in all vegetation management costs being recovered in the WMVM mechanism?

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[94] *Id.*

[95] *Id.*

[96] PAC/700, Berreth/23, lines 3 – 4.

A. No. PacifiCorp has planned vegetation management costs associated with its WPP in 2022. I note that the Company's WPP, filed on December 20, 2021, in Docket No. UM 2207, includes $15.6 million annually over the 2022 through 2026 period for planned incremental vegetation management expense.[97]

Q. What amount has PacifiCorp proposed in this proceeding for incremental vegetation management expense for the 2023 Test Year to be recovered by the WMVM mechanism?

A. The Company has proposed approximately $15.3 million.[98] In addition, PacifiCorp has proposed amounts for WPP vegetation management expense that would be recovered by a new AAC mechanism.

Q. Do you concur with PacifiCorp's recommendation to remove the recovery of capital costs and O&M expenses associated with its wildfire protection plan from the WMVM mechanism?

A. No, not as a result of this general rate case proceeding. Until an evaluation of a PAC-proposed AAC mechanism is completed, I believe the most efficient approach is to allow the authorized Test Year amount of vegetation management expense, to be established as an outcome of this proceeding and including amounts proposed by PacifiCorp as WPP vegetation management expense,[99] to be recovered through the WMVM mechanism.

In other words and for this rate case, all vegetation management costs in this rate case should be recovered through the WMVM mechanism. As a

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[97] See Table 13 on page 78 of PacifiCorp's WPP, located here.

[98] See Table 2 at Exhibit PAC/700, Berreth/17.

[99] Staff discusses expenses proposed by PacifiCorp and included in its WPP in Exhibit Staff/1300.

result of reviewing the forthcoming proposed AAC mechanism, Staff may recommend removing some of the vegetation management cost from the "rate case" cost recovery mechanism and moving it to the AAC, along with wildfire-related costs.

I recommend establishing the baseline at $57.8 million, which is equal to 90 percent of the $64.2 million total vegetation management expense proposed by Staff for the Test Year.[100] This results in a 10 percent "holdback" amount, consistent with the Commission's reasoning in Order No. 20-473,[101] which here equates to $6.4 million. The baseline amount and "holdback" amounts can be adjusted should the authorized total change.

Q. What are the details of PacifiCorp's proposal to modify the violation criteria for the level of violations?

A. The Company proposes the Level I through III threshold values be approximately doubled for Levels I and II; i.e., Level I is 151 (not 75) violation, and Level II is 300 (not 150) violations. Level III begins at 500 (not 200). I note that, from my perspective, the Level I and II values are internally consistent only if they are 151 and 301, respectively, or 150 and 300, respectively. Additionally, I note that originally Level III was one-third (33.3 percent) greater than Level II. PacifiCorp's proposed Level III value of 500 makes Level III 40 percent greater than its proposed Level II value.

Q. What is PacifiCorp's reasoning in support of this change?

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[100] *See* Exhibit Staff/1300.

[101] Pages 121-122 of Order No. 20-473 in Docket No. UE 374.

A. The Company's argument is that Staff proposed violation levels for Portland General Electric (PGE) "that are set at exactly twice the number of violations for each violation level when compared to those that were set for PacifiCorp."[102]

Q. How do you respond to this argument?

A. I do not support PacifiCorp's proposal. One reason I do not support PacifiCorp's recommendation is that its performance in vegetation management has not improved but has degraded. As mentioned above, the number of violations in 2020 was 353. In 2021, the number of violations increased by over 31 percent to 464 violations. It is understandable when the Company's performance is getting worse that it would seek to reduce the monies at risk under the mechanism as well as revise the benchmarks to allow for more violations per threshold. It seems unreasonable to reward bad performance in the first year of a three-year period by revising the mechanism to more favorable terms to the Company.

I also note that in Docket No. UE 394, PGE's most recent general rate case filing, the Commission declined to adopt either Staff's proposal or PGE's proposal regarding a rate adjustment mechanism, stating that, while Staff's proposal "closely tracks the mechanism established in [PacifiCorp's last general rate case proceeding] UE 374…the record of this proceeding does not contain support for the amount of the holdback or the metrics proposed."[103] As

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[102] *Id.*, page 27.

[103] Page 25 of Order No. 22-129 in Docket No. UE 394.

a result, I consider PacifiCorp's argument essentially irrelevant, and perhaps even unwarranted, given the circumstances.

Q. What is the practical effect of this proposed change?

A. PacifiCorp also proposed to change the earnings test metric to a sharing percentage. Absent this latter change, the effect of the change in numerical level values would be to allow PacifiCorp to recover a greater proportion of its costs in the approximate $6.6 million range between $30 million and approximately $36.6 million where recovery is subject to an earnings test.

Q. You use the range from the $30 million amount in base rates as a result of UE 394 to the approximate $36.6 million in Order No. 22-129 above. Did PacifiCorp's filing in this proceeding propose different amounts than these?

A. Yes. The Company proposed an increase in baseline O&M for vegetation management from $30 million to $50 million and proposed amounts above $50 million be subject to the Company's proposed mechanism. Staff discusses the proposed increase to the amount in base rates in Exhibit Staff/1300. I use the dollar amounts from UE 394 above for continuity, as the actual amount that will be in rates resulting from the proceeding at hand is yet to be determined.

Q. What did PacifiCorp propose as a sharing mechanism?

A. The Company's proposal is the "Proposed Mechanism" in Table 3 at Exhibit PAC/700, Berreth/29. There would be no sharing up to 150 "actual violations," 95/5 sharing between 151 and 300 (inclusive) actual violations, 90/10 sharing between 300 and 500 (inclusive) actual violations, and 80/20 sharing for filing years in which there are more than 500 actual violations.

Q. How do you interpret the proposed sharing percentages?

A. It seems clear PacifiCorp intends that the larger value at each level is the "share" that is to be collected in customer rates and the smaller value is the "share" that is to be borne by shareholders within each "tier" of violations, as the Company believes "it is more appropriate to create a sharing mechanism, whereby a greater level of violations results in otherwise prudent expenditures partially shifting to shareholders if violations do not meet the criteria."[104]

Q. Does PacifiCorp's proposal include an exception?

A. Yes, but one that differs considerably from the exception in the current mechanism. PacifiCorp's Table 3 shows that the Company's proposal now uses the current mechanism's Level 1 of 75 violations, below which there is no sharing and at or above which there is 50/50 sharing.[105] I note here that PacifiCorp also modifies what counts as a violation and how Commission Safety Staff is to inspect the Company's facilities.

Q. Do you support these proposed changes in the WMVM mechanism?

A. No. I discuss some individual changes below.

Q. PacifiCorp's language is "actual violations." Is this a proposed change and what is the Company's reasoning behind it?

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[104] Exhibit PAC/700, Berreth/28.

[105] *Id.*, page 29.

A. It is a proposed change. The current situation is that violations for purposes of the earnings test are taken from Commission Safety Staff's annual report, in which they are considered probable violations based on Staff's observations.

Q. Does PacifiCorp define what is meant by "actual violation."

A. No. Absent a proposed definition, I conclude that a violation is probable if observed and documented by Commission Safety Staff, and either a) not an actual violation or b) an actual violation once it has been subsequently observed by PacifiCorp.

Q. What support does PacifiCorp provide for this change?

A. The Company's testimony asserts that "[a]ny violation that is used to prevent recovery of reasonable and prudent vegetation management costs should be verified."

Q. What is your reaction to this?

A. I think PacifiCorp spending additional amounts to verify what Commission Safety Staff has identified as a probable violation is an inefficient use of customer resources and exclusively serves the interests of shareholders. Such expenditures by the Company are, in my opinion, better directed at remedying violations, not verifying them. I include the first page of Attachment A to OPUC Safety Report E21-54R, for the Portland district and provided to the Company on August 31, 2021, as Exhibit Staff/1705, Storm/4. This page provides two examples of what Safety Staff observed and—to the extent practicable—captured as a photographic image showing the near-proximate location of the violation, in addition to providing the street address.

I note that the Commission's language appears to take the actual presence of a violation and burden of proof somewhat differently, where "[t]he burden will be on PacifiCorp to provide adequate documentation to Safety Staff to show the individual violations are resolved"[106] before a violation from a prior year can be removed from the violation count for a given year. In other words, absent the provision of adequate documentation, a violation in a given year is "carried-forward" in the count of violations used to establish the earnings test until such documentation is provided by PacifiCorp.

It is probable violations documented by OPUC Safety Staff that establish the status of PacifiCorp's system and wildfire risks associated with vegetation contacts.

Q. Does PacifiCorp propose to modify Commission Safety Staff's current audit process?

A. Yes. The Company proposes to have violations not include any observed by Staff that occur on "lines that are not trimmed within the cycle covered by the vegetation management mechanism."[107]

Q. What support does PacifiCorp provide for this change?

A. The Company asserts that "[a]ny audit can only be valid once the utility goes through a full cycle for all rights-of-way. Otherwise, audit results from outside recently worked lines result in a penalty to the utility unless it spends the money to trim every line every year."[108]

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[106] Page 124 of Order No. 20-473 in Docket No. UE 374.
[107] *Id.*, pages 27-28.
[108] *Id.*, page 28.

Q. What is your reaction to this?

A. I find this somewhat confusing, as I would otherwise understand that a "full cycle" is always being completed. In other words, no matter where you identify the starting location, once it and all other subsequent locations have been worked, a full cycle has been completed.

Additionally, if the audits performed by OPUC Safety Staff are restricted in the manner proposed by PacifiCorp, the audit is now of the Company's trimming program, not of wildfire risks caused by vegetation proximity to infrastructure.

I am of the persuasion that vegetation growth or position change relative to a nearby conductor may not be as consistent as the use of a fixed cycle period might indicate. Vegetation can change in a year's time and can contact a conductor within 12 months of its last trimming. Limiting audits to lines that are "trimmed within the cycle covered by the vegetation management mechanism"[109] would be to forgo the acquisition of potentially important information the inclusion of lines outside the cycle might provide.

Q. Does PacifiCorp discuss its vegetation management cycle?

A. Yes, minimally. One cause behind the Company's proposed increase in vegetation management costs is to shift to a three-year cycle[110] from a four year cycle (for distribution facilities).[111] Additionally, the Company proposes to

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[109] *Id*., page 27.
[110] *Id*., page 24.
[111] *Id*., page 22.

modify "the Safety Staff audit results to verifiable violations on lines trimmed within two years."[112]

Q. Does PacifiCorp specify what it means by "verifiable" or propose a process by which a violation might be verified?

A. No. It does not. I assume the proposed increase from $30 million in current base rates for vegetation management to a proposed $50 million in base rates includes amounts for verification of probable violations.

Q. What is your reaction to the proposed "lines trimmed within two years" limitation?

A. Lines that have not been trimmed within two to three years may be those having the greatest need for investigation, whether as part of Commission Safety Staff's audit, as a result of that audit, or an examination by the Company or its contractors unrelated to any previous audit.

Additionally, and as a thought exercise, consider potential outcomes of PacifiCorp hypothetically having a much longer cycle in conjunction with this proposed "trimmed within two years" limitation for an audit. Audit results might show good to excellent results, while PacifiCorp's system has a much greater wildfire risk than under a much shorter cycle due to large numbers of violations in areas not recently trimmed.

Q. Does PacifiCorp propose a change "to allow for full recovery of costs related to inflation and regulatory mandates?"

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[112] *Id*., page 27.

A. Yes. The Company asserts that “[c]osts related to inflation and new regulatory mandates are entirely outside of PacifiCorp’s control” and it is therefore “not appropriate that the Company be denied recovery of these costs.”[113]

Q. Do you believe that such costs are “entirely outside PacifiCorp’s control?”

A. No; not as the categorical statement above would have it. The presence of both inflation and regulatory lag can easily be seen to be an incentive for a utility to explore ways in which to operate more efficiently. I also note that new regulatory mandates are often intended to change organizational behavior, and not to result in organizations continuing to do the same thing the same way.

Q. Does PacifiCorp propose a change to recovery of vegetation management “costs related to inflation and new regulatory mandates?”

A. Yes. The Company proposes “that the recovery of those costs occur on a dollar-for-dollar level outside of the performance-based limitations …”[114] In other words, the inflation component of cost increases plus costs associated with compliance with regulatory mandates are not to be subject of the WMVM mechanism.

Q. Does PacifiCorp propose a method or process by which this might be effected?

A. Yes, to a very limited extent. For the inflationary component, the Company proposes to calculate “annual inflation” based on IHS Market indices and

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[113] *Id.*, page 28.

[114] *Id.*, pages 28-29.

include “these costs” in the Company’s annual filing as a separate line item for full recovery, subject to review by parties.[115]

Q. Does PacifiCorp state the existing WMVM mechanism has a “perverse incentive?”

A. Yes. The Company claims that the mechanism incents it to “overspend on O&M related to vegetation management instead of strategically incurring O&M in a manner that decreases violations in a cost-conscious manner.”[116] PacifiCorp explains that “under the current mechanism, the Company is incented to spend the minimum or maximum amounts to receive recovery, which does not make economic sense and would negatively impact customers.”[117] The Company may be speaking to the same issue in “the WMVM, as currently configured, only allows PacifiCorp to recover all of its costs if it either spends only up to what is included in base rates or spends an enormous amount to send crews to every line every year to ensure there are less than 75 probable violations found in the audit the following year.”[118]

Q. Do you agree the existing WMVM mechanism incorporates a “perverse incentive?”

A. No. However, to address PacifiCorp’s concern, I include a recommendation which addresses PacifiCorp’s “does not make economic sense” claim.

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[115] *Id.*, page 29.
[116] Exhibit PAC/100, Steward/30.
[117] *Id.*
[118] PAC/700, Berreth/26.

Q. What does PacifiCorp say is the reason for proposing changes to the existing WMVM mechanism?

A. The Company asserts it is "proposing revisions to the mechanism to allow it to engage in a methodological spend over the course of several years that allows for the fair recovery of costs."[119]

Q. What other language has PacifiCorp used to describe its multi-year approach?

A. The Commission said PacifiCorp's "stated intent [is] to 'dramatically decrease the vegetation clearance violations over a three-year period (2021-2023).' "[120]

Q. Did PacifiCorp provide any testimony or a recommendation regarding normalizing the violation levels?

A. No.

Q. What do you recommend?

A. The Commission, in Order No. 20-473 in UE 374, authorized the existing mechanism with consideration for future changes. However, not even one year of actual reporting has occurred. I support the idea that the WMVM mechanism be allowed to run for three years before making wholesale changes. I recommend the Commission:

1. Cap PacifiCorp's vegetation management expenses in base rates at 90 percent of the authorized total amount, included amounts proposed by PacifiCorp within the WPP, with the remaining 10 percent to be recovered

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[119] Exhibit PAC/100, Steward/30.

[120] Page 121 of Order No. 20-473 in UE 374, citing Exhibits Staff/2702, Moore/1 and PAC/2900, Lucas/18-20 in that proceeding.

through the WMVM mechanism, which is consistent with the Commission’s reasoning in UE 374.

2. Reject all other changes proposed by PacifiCorp for the WMVM mechanism.
3. Make recovery of all prudent costs above the amount in base rates, less the ten percent hold back, subject to the same earnings test as the amount equating to 10 percent. This change, in conjunction with the amount to be authorized for inclusion in base rates as a result of this proceeding will significantly strengthen the incentive for PacifiCorp to “dramatically decrease the vegetation clearance violations over a three-year period (2021-2023).”[121]

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[121] Page 121 of Order No. 20-473 in Docket No. UE 374, citing Staff/2702, Moore/1 and PAC/2900, Lucas/18-20. The cited language appears in PacifiCorp’s response to Staff data request 677 in Docket No. UE 374, which is included in that proceeding as Exhibit Staff/2072.

ISSUE 7. ENERGY VISION 2020 PROJECTS

Q. What did Docket No. UE 369 concern?

A. Docket No. UE 369 involved cost recovery for repowering two PacifiCorp wind projects: Glenrock III and Dunlap. Cost recovery of a third wind repowering project, Foote Creek, was a result of the Company's UE 374 general rate case proceeding.

Q. What was a key feature of the Stipulation amongst Parties to UE 369?

A. The repowering projects left approximately $33.7 million in undepreciated equipment associated with the Glenrock III and Dunlap wind projects. The UE 369 Stipulation allowed PacifiCorp to recover this approximate amount with an offset from the Company's Open Access Transmission Tariff (OATT) revenue deferred for 2017 through 2019 as a result of Docket No. UM 1639, which, when otherwise amortized, would represent a credit to customers.

The intent of this aspect of the Stipulation in UE 369 was to remove, or "buy-down," both the undepreciated replaced equipment net book balance and a corresponding amount of the OATT deferral, both estimated by the Company at $33.7 million.[122] This was viewed by UE 369 Parties as a "buy-down" of the remaining net book value of the equipment replaced as these wind projects were repowered.

Q. Did the Commission approve this aspect of the UE 369 Stipulation?

A. Yes.

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[122] See page 5 or Order No. 20-067 in Docket No. UE 369.

Q. What did PacifiCorp's testimony in the current proceeding include regarding the "buy-down?"

A. PacifiCorp states that, as a result of the UE 369 Stipulation, the undepreciated equipment balances were "bought down in part with Excess Deferred Income Tax (EDIT) balances … and a portion of the Company's deferred FERC Open Access Transmission Tariff revenues."[123] The Company additionally states that the adjustment in this proceeding:

1. "[C]orrects the allocation of expenses recorded in the Base Period as a result of the buy-downs for the Dunlap and Foote Creek wind facilities" and "brings into results the amortization expense and accumulated reserves for wind facilities buy-downs for all repowered projects; and
2. [A]dds into results pro forma amortization to reflect expense and reserves for these balances at the appropriate Test Year levels."[124]

Q. Have you examined the materials PacifiCorp provided in support of this adjustment?

A. Yes. The materials show an amortization expense for January through June of 2021 of approximately $3.3596 million, with an accumulated amortization balance as of June 31, 2021, of the same $3.3596 million.[125] PacifiCorp's materials show amortization expense and accumulated amortization balance for the period July 2021 through December 2022, with an annual amortization expense amount of approximately $6.7486 million, representing a net

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[123] Exhibit PAC/1000, Cheung/27.
[124] *Id*.
[125] Exhibit PAC/1002, Cheung,165.

adjustment to expense of approximately $3.389 million and an adjustment to accumulated amortization of approximately $10.1228 million.[126]

Q. What do you conclude regarding these two adjustments?

A. I conclude these adjustments are necessary to accurately reflect the accounting associated with the “buy-down” for the repowered wind projects.

Q. Does this conclude your testimony?

A. Yes.

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[126] *Id*., page 166.

CASE: UE 399
WITNESS: STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1701

Witness Qualification Statement

June 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME	Steve Storm
EMPLOYER	Public Utility Commission of Oregon
TITLE	Senior Economist
ADDRESS	201 High Street SE, Suite 100 Salem, OR 97301
EDUCATION	MBA; University of Oregon; Eugene, Oregon AB (Economics); Harvard University; Cambridge, Massachusetts

EXPERIENCE I have been employed by the Public Utility Commission of Oregon since October 2018 as a Senior Economist. I was previously employed by the Commission as a Senior Economist 2007–2008, as the Program Manager of the Economic and Policy Analysis section 2008–2012, and as an Economist 4 2012–2013. My responsibilities have included performing as well as leading a team of analysts performing economic and financial research and providing technical support on a wide range of policy issues involving electric, natural gas, and telecommunications utilities. I have testified before the Commission on policy and technical issues in multiple dockets.

I have over 35 years of professional experience performing and directing the performing of economic, financial, and other quantitative analysis.

I was employed by NW Natural as a Senior Economist in its IRP team 2013–2018, where my responsibilities included customer and industrial load forecasting; performing cost of service and related financial analysis on a variety of infrastructure projects and alternatives; and preparing economic information for executive communications.

I was a self-employed financial planner for eight years following an 18-year career in a variety of management positions in which I was responsible for pricing and cost analysis; financial analysis, planning and management; and strategic planning in the publishing and telecommunications industries. I managed the pricing and cost accounting functions for Pacific Northwest Bell's Directory department and its successor company, US WEST Direct, for five years. I managed the departmental budgeting and management reporting functions at US WEST Direct for three years and had seven years management experience in capital budgeting, financial analysis, and strategic planning functions at US WEST Communications. I managed the corporate financial planning, analysis, and management reporting functions for one year at Electric Lightwave.

CASE: UE 399
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1702

Wall Street Journal Article

June 22, 2022

Pension Cash Dwindles, Risking Liquidity Crunch

by Heather Gillers – WSJ – Nov. 22, 2021

Cash allocations have dropped to a seven-year low, with pensions seeking greater returns in private markets.

CalPERS plans to invest more in private markets and keep less cash on hand to meet its target.

Bigger **private-market bets**, **inflation** fears and a **surge of retirees** are putting **public retirement funds** at **risk** of a **cash crunch** that would **force them** to **sell assets at losses to pay pension checks**.

Cash allocations have **dropped** to a **seven-year low** at the funds that manage more than $4.5 trillion in retirement savings for America's teachers, police and firefighters. **Public pension funds**, which have **increasingly turned** to **illiquid private markets** to drive up returns, are **now aiming** to **keep** about **0.8%** of their **holdings in cash**, according to data from the Boston College Center for Retirement Research.

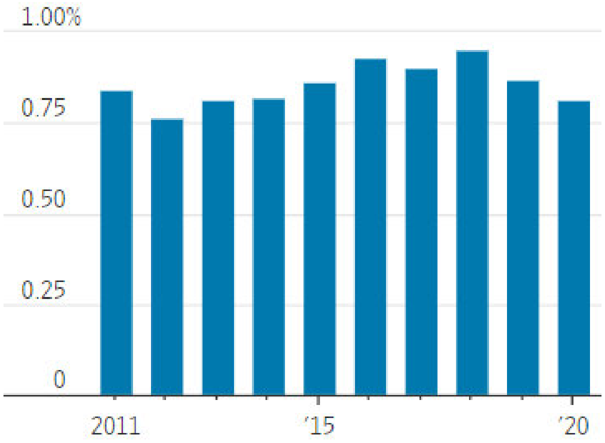
These funds are managing a **juggling act** faced by many institutional and household investors who want to put their money to work but also want easy access to it in a pinch.

"The first report I look at every day is our cash report," said Jonathan Grabel, investment chief of the **$75 billion Los Angeles County Employees Retirement Association**, which aims to keep 1% of its assets in cash. "We have plenty of liquidity across the portfolio, but you **never know when** and **if markets** are **going to seize up**."

Low on Cash

Facing inflation fears and high return expectations, pensions have reduced the share of assets they aim to keep in cash.

Average pension cash allocation target



Source: Boston College Center for Retirement Research

Mr. Grabel's fund in May reduced its target allocation to investment-grade bonds to 12% from 19% and increased the amount it wants to keep in private equity, infrastructure, and illiquid credit to a combined 29% from 16%. The **fund's long-term expected annual return** of **7% is** the **average for state and local government retirement funds**, according to the National Association of State Retirement Administrators.

The **$496 billion California P**ublic **E**mployees' **R**etirement **S**ystem, despite **aiming for** a slightly more conservative **6.8%, still plans** to invest more in private markets, borrow against up to 5% of the fund, and **keep less cash on hand**, to meet that target, under a plan the board approved this month.

Meanwhile, smaller pension funds serving school employees in Ohio, city workers in Illinois and other public employees across the country are putting more of their money into real estate, private equity or private debt.

Public pension funds have hundreds of billions of **dollars less on hand** than the amount they will need to cover promised benefits after two decades of underfunding, unrealistic demands from public-employee unions, and losses during the 2007-2009 financial crisis.

Over the same period, their cash-flow margins have thinned **as retirees** have **multiplied relative to** the **number** of **current workers**. In **Connecticut**, for example, more than a **quarter** of the **state workforce** are **eligible to retire between June 2020 and June 2022**, Boston Consulting Group found.

Public pension funds have historically been able to access cash when **equity** markets faltered by selling bonds. But **over** the past **two decades**, **fixed** income **portfolios shrank to 24% of assets from 33%**, according to the Boston College data, as falling rates turned bonds into a drag on returns. **Now inflation threatens** to **further erode** the **value of fixed-income investments**.

But assets that promise rapid growth – from **common stocks to complex alternative investments** – also **carry** the **risk of losses when sold into rocky markets or before maturity**. After the Pennsylvania Public School Employees' Retirement System last year decided to shrink its private equity allocation, in part to increase liquidity, consultants warned that selling assets early would mean accepting an **average discount** of **15%** of **net asset value**.

Some growth strategies can also require sudden diversions of cash in the form of capital calls and margin calls, often at inconvenient times.

When markets cratered in **2008**, some of the **biggest U.S. pension funds sold stocks** to **raise cash and fund capital calls** from private-equity firms. In the aftermath many, including CalPERS and the California State Teachers' Retirement System reviewed their allocations to alternatives.

A CalPERS spokesman said the fund has improved liquidity management since the financial crisis and as a result was able to take advantage of low prices during the market dislocation in March 2020 at the start of the Covid-19 pandemic.

CalPERS staff said at a meeting earlier this month that the fund uses a dashboard to closely monitor liquidity, which is a measure of how easily holdings can be converted to cash without losses. The retirement fund, which is the nation's largest, **eliminated** its **target** of **holding 1%** of its **assets in cash** as part of the new asset allocation approved this month, which takes effect July 1, 2022.

Finding a **strategy that can accomplish what bonds once did**, providing **yield** in **good times** and **accessible cash** in **bad**, is "**not** a problem with an **easy** solution," said Ash Williams, who recently retired as executive director and chief investment officer of the State Board of Administration, which manages investments for the Florida Retirement System.

"Everybody's wrestling with this same thing," he said.

CASE: UE 399
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF CONFIDENTIAL EXHIBIT 1703

Confidential Response to
Standard Data Request 60

June 22, 2022

Standard Data Request – OPUC 060

For FAS 87 and FAS 106, please provide the estimated effect on the Test Period Net periodic postretirement cost (income) if the discount rate is changed 25 basis points in both directions and expected rate of return is changed 25 basis points in both directions.

Response to Standard Data Request – OPUC 060

Please refer to Confidential Attachment OPUC 060 which provides details on the effect of a +/- 25 basis point change to the net periodic cost (income) for PacifiCorp's Pension and Post-Retirement plans for the Test Period.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

CASE: UE 399
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

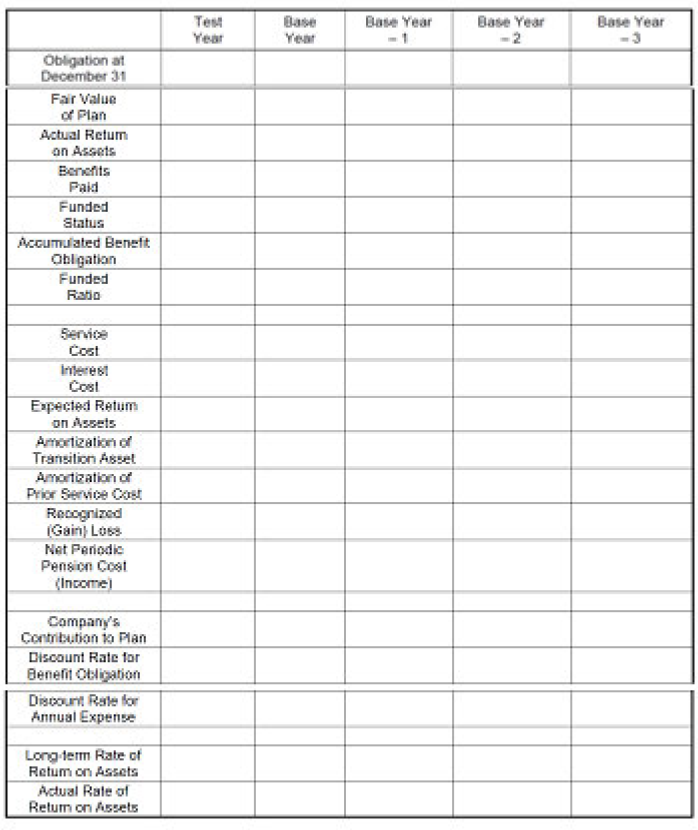
STAFF EXHIBIT 1704

Response to
Standard Data Request 59

June 22, 2022

Standard Data Request – OPUC 059

In the following table format, please provide the FAS 87 and FAS 106 Post-retirement Plan information for the Test Year, Base Year, and the three years prior to the Base Year. Please explain any variation between Long-term Rate of Return on Assets, and Actual Rate of Return on Assets.



	Test Year	Base Year	Base Year – 1	Base Year – 2	Base Year – 3
Obligation at December 31					
Fair Value of Plan					
Actual Return on Assets					
Benefits Paid					
Funded Status					
Accumulated Benefit Obligation					
Funded Ratio					
Service Cost					
Interest Cost					
Expected Return on Assets					
Amortization of Transition Asset					
Amortization of Prior Service Cost					
Recognized (Gain) Loss					
Net Periodic Pension Cost (Income)					
Company's Contribution to Plan					
Discount Rate for Benefit Obligation					
Discount Rate for Annual Expense					
Long-term Rate of Return on Assets					
Actual Rate of Return on Assets					

Response to Standard Data Request – OPUC 059

Please refer to Attachment OPUC 059. Note: the information provided is by plan (PacifiCorp Retirement Plan and PacifiCorp Post-Retirement Welfare Plan), as well as in aggregate. PacifiCorp has provided calendar year information for 2019 through 2021, instead of three years prior to base year as this information is more meaningful and agrees to actuarial reports provided with the Company's response to Standard Data Request – OPUC 082. Base year information is a blend of calendar year 2020 and 2021, with actual expenses for the 12 months ended June 30, 2021.

Per Accounting Standards Codification 715-30-35, the expected return on plan assets should reflect the expected long-term rate of return on plan assets invested to satisfy plan benefits. By its definition as a long-term measure, this assumption is relatively stable and not subject to the volatility of currently observed returns on investment.

Qualified Pension Plan FAS 87 Summary

			Calendar Year		
	Test Year	Base Year	2021	2020	2019
Obligation at December 31 (PBO)	$ 855,357,519	N/A	$ 994,413,965	$ 1,144,076,781	$ 1,111,865,569
Fair Value of Plan	957,606,170	N/A	1,057,637,012	1,064,045,878	1,036,472,553
Actual Return on Assets	43,151,878	N/A	108,816,050	124,075,975	181,660,130
Benefits Paid	86,998,716	N/A	115,224,916	96,502,650	86,615,654
Funded Status	102,248,651	N/A	63,223,047	(80,030,903)	(75,393,016)
Accumulated Benefit Obligation	(855,357,519)	N/A	994,413,965	1,144,076,781	1,111,865,569
Funded Ratio	112.0%	N/A	106.4%	93.0%	93.2%
Service Cost	$ -	$ -	$ -	$ -	$ 4,524
Interest Cost	25,465,747	30,949,516	27,502,886	34,396,146	42,580,869
Expected Return on Assets	(41,071,789)	(53,272,118)	(50,560,106)	(55,984,130)	(67,211,163)
Amortization of Actuarial (gain) loss	12,415,698	17,877,763	18,654,496	17,101,030	13,154,893
Amortization of Prior Service Cost	-	-	-	-	-
Recognized (Gain) Loss	-	-	-	-	-
Establishment of Regulatory Liability (Asset)	(1,602,380)	-	(9,621,638)	(488,739)	(1,492,119)
Amortization of Regulatory Liability (Asset)	756,291	99,444	193,969	90,127	(1,567,925)
Settlement loss	7,144,907	-	15,646,387	-	-
Net Periodic Pension Cost (Income)	3,108,474	(4,345,395)	1,815,994	(4,885,566)	(14,530,921)
Company's Contribution to Plan	$ -	$ -	$ -	$ -	$ -
Discount Rate for Benefit Obligation	2.90%	N/A	2.90%	2.50%	3.25%
Discount Rate for Annual Expense	2.90%	N/A	2.50%	3.25%	4.25%
Long-term Rate of Return on Assets	4.70%	N/A	6.00%	6.50%	7.00%
Actual Rate of Return on Assets	N/A	N/A	10.96%	13.59%	20.20%

PacifiCorp

Post Retirement Welfare Plan FAS 106 Summary

			Calendar Year		
	Test Year	**Base Year**	**2021**	**2020**	**2019**
Obligation at December 31 (APBO)	$ 260,017,604	N/A	$ 287,871,508	$ 306,867,170	$ 303,623,792
Fair Value of Plan	298,838,410	N/A	323,945,784	327,058,833	333,778,560
Actual Return on Assets	10,088,591	N/A	14,351,512	14,618,698	55,896,288
Benefits Paid	22,828,233	N/A	24,347,161	25,975,783	24,476,422
Funded Status	38,820,806	N/A	36,074,276	20,191,663	30,154,768
Accumulated Benefit Obligation	N/A	N/A	N/A	N/A	N/A
Funded Ratio	114.9%	N/A	112.5%	106.6%	109.9%
Service Cost	$ 1,547,507	$ 1,761,417	$ 1,858,552	$ 1,664,282	$ 1,436,155
Interest Cost	7,610,244	8,345,871	7,378,910	9,312,831	12,188,368
Expected Return on Assets	(9,800,728)	(11,371,991)	(8,778,746)	(13,965,236)	(20,857,382)
Amortization of Actuarial (gain) loss	-	-	-	-	-
Amortization of Prior Service Cost	-	-	-	-	-
Recognized (Gain) Loss	-	-	-	-	-
Establishment of Regulatory Liability (Asset)	-	-	-	-	-
Amortization of Regulatory Liability (Asset)	1,016,031	3,730,229	735,190	3,337,654	353,077
Settlement loss	-				
Net Periodic Pension Cost (Income)	373,054	2,465,526	1,193,906	349,531	(6,879,782)
Company's Contribution to Plan	$ -	$ -	$ -	$ -	$ -
Discount Rate for Benefit Obligation	2.90%	N/A	2.90%	2.50%	3.20%
Discount Rate for Annual Expense	2.90%	N/A	2.50%	3.20%	4.25%
Long-term Rate of Return on Assets	3.39%	N/A	2.90%	4.92%	6.86%
Actual Rate of Return on Assets	N/A	N/A	5.74%	5.84%	19.59%

CASE: UE 399
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1705

OPUC Safety Reports E21-54R and E21-54L

June 22, 2022

August 31, 2021

STEFAN BIRD
PRESIDENT& CEO
PACIFICORP
825 N.E. MULTNOMAH STREET
PORTLAND, OR 97232

RE: OPUC Report No. E21-54R, PacifiCorp, (Annual vegetation review)

OPUC Safety Staff recently performed the annual review of PacifiCorp's vegetation management program beginning July 19, 2021 and concluding August 20, 2021. The review occurred on many Oregon facilities operating in the communities and districts listed within the body of the report.

Staff's report identifies locations where contact between vegetation and energized primary conductors have been observed. Additionally, Staff notes when it appears minimum vegetation clearance requirements established by Oregon Administrative Rule (OAR) 860-024-0016, have not been maintained. Staff notes these as observations because direct measurement is not possible or feasible during the review. In several areas reviewed, many violations appeared to be of the "cycle buster" type and end of cycle encroachment due to inadequate initial vegetation clearances.

Staff analysis and details are contained in the remarks section of the report. A historical graph of readily climbable trees and primary conductor vegetation contacts is attached for your reference.

Executive Summary

The high number of energized primary conductor vegetation contacts in OPUC Report E21-54R and "Caution" notices in past reports E17-44R, E19-58R and E20-48R, leads Staff to issue a **"WARNING"** notice regarding PacifiCorp's vegetation management program.
A **"WARNING"** notice is indicative of program deficiencies of a more serious, potentially system wide nature.

Staff acknowledges the impacts of the Covid-19 pandemic on the electric utility operations and vegetation management programs while attempting to mitigate the impacts of recent fires, ice storms, and statewide wildfire activities.

Staff observed **464** locations where evidence existed of contact between vegetation and primary electrical conductors. The identified locations resulted in conservatively over **614** primary conductor vegetation contacts.

A breakdown of the highest risk probable violations follows:

- **Twenty-six** locations are readily climbable trees noted as **hazardous conditions** in Citation: A.
- **Six** of the twenty-six readily climbable tree locations noted above, involve two or more trees contacting primary conductors.
- Of the **four hundred and thirty-four** locations identified in Citation: B, **ninety-three** locations involve two or more trees contacting primary conductors.
- **Fifty-two** locations within Citations A and B, were located within a PacifiCorp High Fire Consequence Area (HFCA). The number of violations identified indicates the company's vegetation management program is not adequately addressing the vegetation energized conductor contacts in the elevated risk High Fire Consequence Areas (HFCAs).
- **Four** locations in Citation: C, involve vines that have grown up poles and guy wires until they are contacting, or about to contact, energized primary conductors. These violations are **hazardous** conditions.
- **Ten** locations in Citation: C, involve vines or trees that have engulfed poles creating climbing **hazards.**
- **Two** locations: Citation: A, 10 and 26 involve orchards with agriculture workers working in or around trees contacting energized conductors. This issue has been previously identified in Staff Report E19-58R, recommendation three. "On or before February 28, 2020, submit documentation detailing a long-term strategy mitigating the hazards associated with orchards and powerline interference." PacifiCorp has not adequately addressed this issue.
- **One** location Citation: B199, involved two trees contacting transmission conductors. The OAR minimum clearance is Seven and one-half feet for conductors energized at 50,001 through 200,000 volts.

In response to this report:

1. On or before October 1, 2021, submit documentation confirming correction of the probable violations related to **readily climbable trees**, as well as those listed specifically as **hazardous conditions**.

2. On or before April 1, 2022, submit documentation confirming correction of the remaining probable violations cited in this report.

3. On or before April 1, 2022, submit documentation outlining a PacifiCorp plan to modify the current vegetation management program to maintain reduced vegetation energized conductor interference levels and comply with OAR 860-024-0016 Minimum Vegetation Clearance Requirements.

If a time extension is needed, submit a written request stating the reason(s) for the delay and the proposed schedule to complete the work. If government permits are causing a delay, include the date the permits were applied for and a permitting agency contact person and telephone number. If you disagree with any cited probable violation, please furnish Staff a letter within 30 days requesting an informal conference.

Each electric supply and telecommunication operator (as defined in OAR 860-024-0001(5) in Oregon is responsible to construct, operate, and maintain its line facilities in compliance with the NESC. Refer to ORS 757.035 and OARs 860-024-0010 and 860-023-0005 for Oregon laws and rules regarding minimum OPUC safety standards. Particular focus should be given to NESC Rules 090,110 121, 214, 313, and OAR 860-024-0011, which address ongoing inspection and maintenance responsibilities. OAR 860-024-0016 addresses Minimum Vegetation Clearance Requirements

If you have any questions regarding this letter or report, please contact me at the number listed below, Leon Grumbo (503) 881-7707, Steve Sims (503) 339-6749 or Alex Chaney (503) 559-4011. Please reply to OPUC.NESCSafety@puc.oregon.gov for report updates, time extensions, or to close the report in the OPUC enforcement log.

Mark Rettmann
Electric Safety Program Manager
Utility Safety Reliability & Security Division
(503) 881-6739
mark.rettmann@puc.oregon.gov
OPUC.NESCSafety@puc.oregon.gov

Attachments: Violation Report
Historical Vegetation Graph

Attachment A
OPUC Safety Report
E21-54R Portland District

Probable violation B.1: Two deciduous trees show evidence of contacting the primary conductor at 2854 NE Elrod Drive, Portland.

Probable violation B.2: Deciduous tree shows evidence of contacting primary conductors at 1611 NE Marine Drive, Portland.

PacifiCorp: Historical Vegetation Trend