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March 25, 2024

***Via Electronic Filing***

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

**RE: Docket No. UE 426 – In the Matter of IDAHO POWER COMPANY, Request for a General Rate Revision.**

Attached for Opening Testimony filing are the following exhibits:
Exh 100-110 Muldoon
Exh 200-205 Chipanera
Exh 300-301 Scala
Exh 400-402 Nottingham
Exh 500-502 Beitzel
Exh 600-604 Farrell
Exh 700-702 Kim
Exh 800-805 Lockwood
Exh 900-904 Mondragon Non-Confidential, (Exh 903-904 are confidential)
Exh 100-1002 Moore
Exh 1100-1102 Peng
Exh 1200-1203 Pileggi Non-Confidential, (Exh 1203 is confidential)
Exh 1300-1302 Rossow
Exh 1400-1401 Shearer
Exh 1500-1501 Stevens
Exh 1600-1603 Kim-Lockwood
Exh 1700-1704 Yamada Redacted

Confidential and non-confidential Excel exhibits including with this filing are:
Confidential exhibits:
Exh 1703

Non-Confidential exhibits:
Exh 102-106
Exh 602
Exh 802-803
Exh 902 (8 supporting exhibits)
Exh 1102
Exh 1303
Exh 1702

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CASE: UE 426
WITNESS: Matt Muldoon

# PUBLIC UTILITY COMMISSION OF OREGON

## STAFF EXHIBIT 100

## OPENING TESTIMONY
## Overview, and Return on Equity

March 25, 2024

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

A. My name is Matt Muldoon. I am a manager employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) 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 Idaho Power Company (Idaho Power, IPC, or Company) request for a general rate revision, docketed as Docket No. UE 426 and articulate some of Staff's overarching concerns regarding the magnitude of the Company's proposed increase in this rate case. I also address Cost of Capital components and overall Rate of Return (ROR), going into greater detail regarding Return on Common Equity (ROE) and finally, review Idaho Power's Pensions and Post Retirement Medical Expense.

Further detail on Capital Structure and Cost of Long-Term (LT) Debt are found in Rose Pileggi's testimony in Exhibit Staff/1200 and additional detail about revenue, expense, and rate base components of Staff's proposed adjustments as well as Staff's recommended approach to escalations are found in Itayi Chipanera's testimony in Exhibit Staff/200.

**Q. Are other Staff witnesses submitting testimony?**

A. Yes. Each Staff assigned to Docket No. UE 426 is submitting separate testimony. My testimony introduces the Staff witnesses and their respective assignments and estimates the revenue requirement impact of Staff recommended adjustments to the Company's initial filing. The issues identified in Staff testimony are those identified to date. Staff's recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

1. Revenue Requirement Impact by Staff Topic .......... 4
2. Introduction to Other Staff's Opening Testimony .......... 6
3. Key Concern – Size of Co. Proposed Increase .......... 9
4. Overall Rate of Return (ROR) .......... 15
5. Return on Equity (ROE) .......... 15
6. Pensions and Post Retirment Medical Expense .......... 45
7. Conclusion .......... 46

**Q. Did you prepare exhibits for this docket?**

A. Yes. In addition to my witness qualifications statement, I prepared the following exhibits:

**Other Supporting Exhibits**

Exhibit Staff/102 .. ROE – Peer Screen, Dividends, EPS, Hamada Adjustments
Exhibit Staff/103 .......... ROE - Three Stage DCF Modeling
Exhibit Staff/104 .......... ROE - Three Stage DCF Modeling Results
Exhibit Staff/105 .......... ROE – Capital Asset Pricing Model (CAPM)
Exhibit Staff/106 .......... ROE – Gordon Growth, Single Stage DCF
Exhibit Staff/107 .......... ROE – US BEA Historical GDP Growth
Exhibit Staff/108 .......... ROE – TIPS Implies Inflation
Exhibit Staff/109 .......... Value Line (VL) Electric Utilities
Exhibit Staff/110 .......... Financial News Investors Are Seeing

**Q. Could there be changes or updates to Staff's position and recommendations?**

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

## 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

| Staff Issue Summary Table -Test Year Ended December 31, 2024 ($000) | | | | |
|---|---|---|---|---|
| Total Incremental Revenue Requirement on the Company's Filed General Rate Case | | | | $10,695 |
| **Exhibit** | **Issue** | **Staff** | **Staff Issues and Proposed Adjustments** | **Staff Revenue Requirement Effect** |
| 100 | 1 | Muldoon | Introduction | - |
| | 2 | | Concerns | - |
| | 3 | | Return on Equity (ROE) @ 9.3% - Mid Level) | (1,463.84) |
| | 4 | | Pensions and Post Retirement Medical Expense | - |
| 200 | 1 | Chipanera | Income Taxes & Corporate Activity (CAT) Tax | (65.44) |
| | 2 | | Oregon Regulatory Commission Fees | (79.20) |
| | 3 | | KiloWatt Hour Taxes | (77.20) |
| | 4 | | Valmy Plant Revenue Requirement | |
| | 5 | | Utility Plant in Service | |
| | 6 | | Oregon Jurisdictional Allocation | |
| | 7 | | Cash Working Capital | (15.27) |
| 300 | 1 | Scala | Energy Justice Overview | - |
| 400 | 1 | Nottingham | Overview of Public Comments Received to Date | - |
| 500 | 1 | Beitzel | Administrative and General (A&G) Expenses | - |
| | 2 | | Pensions and Benefits | (151.26) |
| 600 | 1 | Farrell | Uncollectible Accounts | (322.01) |
| | 2 | | Other Operating Revenue | - |
| | 3 | | Bill Discount Program | - |
| 700 | 1 | Kim | Jim Bridger Plant Conversion to Natural Gas | - |
| 800 | 1 | Lockwood | Advertising and Marketing | (1.59) |
| | 2 | | Intervenor Funding - Covid-19 and Low Income Weatherization | (10.83) |
| 900 | 1 | Mondragon | Customer Accounts and Customer Service Operations and Maintenance (O&M) Non Labor (NL) | (0.91) |
| | 2 | | Affiliated Interests | - |
| | 3 | | Gains / Loss on Sale of Property | - |
| | 4 | | Transmission and Distribution (T&D) | (0.87) |
| | 5 | | Operation Supervision and Engineering | (41.20) |
| | 6 | | Wildfire Mitigation Costs | (1,086.02) |

Continued on Next Page

Concluded

| | | | | |
|---|---|---|---|---|
| 1000 | 1 | Moore | NL Generation O&M | - |
| | 2a | | Board of Directors (BOD) Compensation | (111.78) |
| | 2b | | BOD Travel / Meals | (5.13) |
| | 3 | | Materials and Supplies | (60.36) |
| | 4 | | Miscellaneous Deferred Debits | - |
| 1100 | 1a | Peng | Depreciation Expense | 1,157.45 |
| | 1b | | Accumulated Depreciation | (102.28) |
| | 2 | | Amortization Expense | - |
| | 3 | | Depreciation Reserve | - |
| | 4 | | Ammortization Reserve | - |
| 1200 | 1 | Pileggi | Hydro Facility Investments | (50.33) |
| | 2 | | 2023 and 2024 Resource Additions | |
| | 3 | | Capital Structure & | |
| | 4 | | Cost of Lont-Term (LT) Debt | $139 |
| 1300 | 1 | Rossow | Promotional Activities and Concessions | (0.91) |
| | 2 | | Meals and Entertainment | (21.21) |
| | 3 | | Memberships Dues and Donations | (1.79) |
| 1400 | | Shearer | Low-Income Customer Protections | - |
| 1500 | 1 | Brett Stevens | Load Forecasting | - |
| | 2 | | Class Cost of Service Study | - |
| | 3 | | Rate Spread | - |
| | 4 | | Rate Design | - |
| | 5 | | Rate Base & Jurisdictional Allocation | (2,254.50) |
| 1600 | 1 | Kim / Lochwood | Energy Efficiency Disallowance | (77.37) |
| 1700 | 1a | Yamada | Wage and Salaries - O&M | (10.85) |
| | 1b | | Wage and Salaries - Capital Adjustment | (232.39) |
| | 2 | | Incentives | - |
| | | | Total Staff Proposed Adjustments (Base Rates): | **(4,948)** |
| | | | Staff-Calculated Revenue Requirements Change (Base Rates): | **$5,747** |

## 2. INTRODUCTION TO OTHER STAFF'S OPENING TESTIMONY

**Q. Please describe the opening testimony submitted by Staff in this rate case.**

A. The Staff exhibit number, respective Staff witness, and topics published on this date are presented below.

**Topics addressed in Opening Testimony published March 25, 2024:**

In **Exhibit 200, Itayi Chipanera**, Senior Financial Analyst, discusses revenue requirements, income taxes, Oregon regulatory commission fees, kilowatt hour taxes, Valmy plant revenue requirement, utility plant in service, Oregon jurisdictional allocation, cash working capital, and other topics.

In **Exhibit 300, Michell Scala**, Energy Justice Program Manager, provides an Energy Justice overview for this general rate case and discusses energy justice foci.

In **Exhibit 400, Melissa Nottingham** summarizes public comments received by the Commission as of March 12, 2024. Staff will also publish Supplemental Opening Testimony on April 15, 2024, to summarize incremental public comments received by the Commission as well as public comments shared with the Commission in a virtual public comment hearing on March 14 and in an in-person public comment hearing on March 20 in Ontario.

In **Exhibit 500 Russ Beitzel**, Senior Utility Analyst, reviews Administrative and General (A&G) Expenses – Non-Labor (NL), and current pensions and benefits.

In **Exhibit 600, Bret Farrell**, Senior Utility and Energy Analyst, reviews Idaho Power's proposals for uncollectible expense, miscellaneous operating revenues, Idaho Power's bill discount program, and other issues.

In **Exhibit 700, Anna Kim**, Energy Costs Section Manager, reviews the Company's Demand-Side Management and Jim Bridger Conversion.

In **Exhibit 800, Charles Lockwood**, Utility Analyst, analyzes expense for advertising and marketing, low-income energy efficiency, intervenor funding, and COVID-19 Adjustments.

In **Exhibit 900, Luz Mondragon**, Senior Financial Analyst, reviews customer account expenses and customer service operations and maintenance (O&M) non-labor (NL), Transmission and Distribution O&M NL, and Wildfire Mitigation Costs.

In **Exhibit 1000, Mitch Moore**, Senior Utility Analyst, analyzes non-labor (NL) generation (O&M), Board of Directors' (BOD) fees, materials and supplies, and miscellaneous deferred debits in rate base.

In **Exhibit 1100, Ming Peng**, Senior Economist, analyzes depreciation expense, amortization expense, depreciation reserve, amortization reserve, and Allowance for Funds Used During Construction (AFUDC).

In **Exhibit 1200, Rose Pileggi**, Senior Utility Analyst, analyzes Idaho Power's hydro facilities investments, 2023 and 2024 resource additions, Capital Structure, and Cost of Long-Term (LT) Debt.

In **Exhibit 1300, Paul Rossow**, Utility Analyst, review Idaho Power's promotional activities and concessions, memberships, dues and donations, and meals and entertainments.

In **Exhibit 1400, Scott Shearer**, Utility Analyst, analyzes Idaho Power's protections for low-income customers.

In **Exhibit 1500, Dr. Bret Stevens, Ph.D.** analyzes the Company's load forecasting, class cost-of-service study, rate spread, rate design, and rate base.

In **Exhibit 1600 Joint Testimony, Anna Kim** and **Charles Lockwood** jointly review Idaho Power's Demand-Side Management programs.

In **Exhibit 1700, Steph Yamada**, Senior Utility Analyst examines Idaho Power's test year wages and salaries (W&S) and overtime, W&S model adjustments to base salaries and wages, and W&S model adjustments to overtime.

## 3. KEY CONCERN – SIZE OF CO. PROPOSED INCREASE

**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 impacts of this general rate case, deferrals, and power costs may constitute rate shock for Idaho Power's Oregon utility customers outpacing Oregon wages. According to the Wall Street Journal (WSJ), necessities like food have become much more expense in recent years.[1] Further, the U.S. Federal Reserve (Fed) is tightening monetary policy to control high inflation.[2] This increases the cost of borrowing for utility rate payers as well as the cost of debt for utilities. Staff understands that the Company's last general rate increase was in 2011, never-the-less Idaho Power now proposes a very large increase.

**Q. Please show the approximate impact on residential customer rates were the Company's rate increase implemented as requested.**

A. Staff cautions that it is still early in this proceeding and the following depiction reflects a point estimate prior to Staff's filing its Opening Testimony:

1 See Exhibit Staff/110 Muldoon/45 for "It's Been 30 Years Since Food Ate Up This Much of Your Income" by Jesse Newman and Heather Haddon of the WSJ – Feb 26, 2024.

2 See Exhibit Staff/110 Muldoon/51 for Fed activity on interest rates.

**Table 2**

| Current | Avg. Usage/Mo. | Residential Avg. Basic Charge $/Mo. | Residential Avg. Bill $/Mo. |
|---|---|---|---|
| Residential | 1,164 | $8.00 | $139.92 |

| IPC Proposed | Oct 15, 2024 Increase | Scenario if increase were $10.7 M* | | | |
|---|---|---|---|---|---|
| | $10.7 Million* | New Residential Basic Charge $/Mo. | New Residential Avg. Bill $/Mo. ** | Increase $/Mo | % Increase |
| Residential | | $15.00 | $172.29 | $32.37 | 23.14% |

* Oregon jurisdictional overall base rate revenue increase equates to 19.28 percent

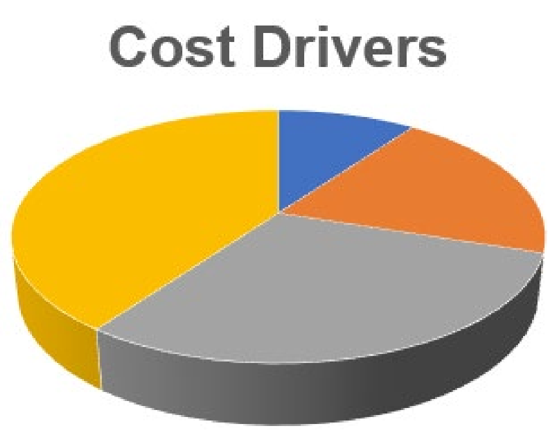
** Includes the following Riders: Schedule 55 (APCU), Schedule 56 (PCAM), Schedule 91 (Energy Efficiency), Schedule 93 (Solar PV), and the proposed Schedule 64 (Bill Discount for Qualified Customers Cost Recovery Mechanism).

This information does not yet reflect recommendations offered by Staff and intervenors for Commission consideration, which if adopted, would reduce the impact of IDAHO POWER's proposed rate increase.

**Q. What does the Company identify as key cost drivers when describing this rate case to investors and analysts?**

A. With the caution that this is at a very general level, and importantly without showing Idaho Power's offsetting revenues and cost controls, the largest driver of costs in this general rate increase is capital investments.

**Table 3**



| | Cost Driver | % |
|---|---|---|
| 1 | Capital Investments | 51% |
| 2 | Cost of Capital | 1% |
| 3 | Operations and Maintenance | 35% |
| 4 | Depreciation | 14% |
| | | 100% |

| **OREGON Rate Case Cost Drivers** | **Approximate Idaho Power Proposed Revenue Impact** | |
|---|---|---|
| | **$ Millions** | **Percent** |
| **Driver 1: Capital Projects** (Examples Below)<br>Current Rate Base $189 Million | **7.3** | **13.2%** |
| Example 1: Transmission Plant | **1.2** | **2.2%** |
| Example 2: Batteries (Incl in Dist Plant) | **1.1** | **2.0%** |
| Example 3: Account 368 | **2.0** | **3.6%** |
| Example 4: Other Distribution Plant | **2.0** | **3.6%** |
| Example 5: General Plant | **1.0** | **1.8%** |
| **Driver 2: Cost of Capital** (as requested)<br>10.4% ROE, 51% Equity, 5.104% Cost LT Debt | **0.13** | **0.2%** |
| **Driver 3: O&M + Regulatory Debits and Credits** | **5.0** | **9.1%** |
| **Driver 4: Depreciation** | **2.0** | **3.6%** |
| **Driver 5: Taxes (offset)** | **-0.6** | **-1.2%** |
| **Driver 6: Operating Revenues (offset)** | **-3.1** | **-5.8%** |
| **Total** | **10.7** | **19.2%** |

Staff's testimony will provide more detail on the above costs. Note that the pie chart above does not capture the Company's tax offsets and offsetting operating revenues that reduce the impact to customers rates.

Customers participating in the March 14, 2024, Public Comment Hearing remain concerned about the proposed rate increase and urge the Commission to reduce the impact on Oregon customers of Idaho Power, and in particular for those on fixed income or with limited means.

**Q. What could the Commission do to address general rate increases of the magnitude proposed by Idaho Power in this general rate case?**

A. One solution proposed by Bob Jenks of the Oregon Citizens' Utility Board (CUB) on that organization's website is for the Commission to set the utility's profit margin at the lowest reasonable point.[3]

**Q. Does Staff agree with CUB that this is the Commission's best option?**

A. Staff analyzing Cost of Capital (CoC) in this general rate case would not use terms like "allowable profit margins" interchangeably with allowed Return on Equity (ROE). Staff also think holistically about Cost of Capital considering credit ratings and the financial health of Commission jurisdictional energy utilities and their relative strength in financial markets in comparison to their peer or similarly situated like utilities.

3 Posted January 25, 2024, on https://oregoncub.org/ this proposal within "Is Oregon Utility Regulation Part of the Problem?" by Bob Jenks is reproduced with some small editing changes to fit a written rather than on-screen format at Exhibit Staff/110 Muldoon/37-44 to capture the context in which the suggestion was made. Also see Exhibit Staff/110 Muldoon/53.

However, in advance of reading any testimony by CUB in this general rate case, Staff agrees that the Commission could consider any ROE in Staff's range of reasonable ROE's for Commission Authorized ROE in its final order in this general rate case.

**Q. Are there other ways that the Commission could look at using ROE to mitigate the magnitude and frequency of general rate cases.**

A. Yes. The Commission could consider using ROE as a throttle to control the frequency of general rate cases. For example, were a utility to file three general rate case in a five-year period, the Commission might consider that activity sufficient to reduce regulatory lag and reduce financial risk in terms of metrics like ratio of cash flow from operations before changes in working capital (CFO pre-WC) to debt, in a form meaningful to credit rating agencies.

**Q. Would that last approach be immediately applicable in this general rate case?**

A. No. Idaho Power last filed a rate case in Oregon, in 2011.[4] However, consideration of recommendations raised in this general rate case could give the Commission vetted tools it could use when seeking to mitigate the impact of frequent rate cases on jurisdictional utility customers. Staff will continue to monitor suggestions on intervenors in this case and closely review the analysis

[4] See Order No. 12-055 in Docket No. UE 233 entered February 23, 2012, posted on the Commission's website at: https://apps.puc.state.or.us/edockets/srchlist.asp?Prefix=UE++&DocketNumber=233&submit1=GO .

and justifications provided to support such recommendations to the Commission.

The Commission’s evaluation of such proposals is consistent with public comments and posting by intervenors asking that the Commission consider impacts on utility customers in its determination of most appropriate just and reasonable outcomes in this case.

## 4. OVERALL RATE OF RETURN (ROR)

**Q. What is Idaho Power's proposal for its overall Rate of Return?**

A. The Company. proposes a rate of return of 7.807 percent, with a capital structure comprised of 51 percent equity and 49 percent debt, a 5.104 percent cost of debt, and a 10.40 percent return on equity.

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

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

**TABLE 4**

| IPC Current OPUC Authorized ( UE 233 Order No. 12-055 ) | | | IPC |
|---|---|---|---|
| **Component** | **Percent of Total** | **Stipulated or Implied Cost** | **Weighted Average** |
| Long-Term Debt | 50.1% | 5.623% | 2.817% |
| Preferred Stock | 0.0% | 0.0% | 0.000% |
| Common Stock | 49.9% | 9.90% | 4.940% |
| | 100.00% | **ROR** | **7.757%** |

**TABLE 5**[5]

| IPC Requested – UE 426 | | IPC Direct Testimony | | |
|---|---|---|---|---|
| **Component** | **Percent of Total** | **Cost** | **Weighted Average** | **ROR vs. Current** |
| Long-Term Debt | 49% | **5.104%** | 2.501% | **0.048%** |
| Preferred Stock | 0% | 0.0% | 0.000% | |
| Common Stock | 51% | **10.40%** | 5.304% | |
| | 100.00% | **ROR** | **7.805%** | |

[5] Idaho Power/100, Grow/13.

**TABLE 6**

| Staff Proposed – UE 416 | | Staff Opening Testimony | | |
|---|---|---|---|---|
| **Component** | **Percent of Total** | **Cost** | **Weighted Average** | **ROR vs. Current** |
| Long-Term Debt | **50.00%** | **4.999%** | 2.500% | **-0.608%** |
| Preferred Stock | 0% | 0.0% | 0.000% | |
| Common Stock | **50.00%** | **9.30%** | 4.650% | |
| | 100.00% | **ROR** | **7.150%** | |

## CAPITAL STRUCTURE

**Q. Has the Commission recently considered a preferred target capital structure?**

A. Yes. In PacifiCorp's 2020 GRC, the Commission adopted a notional 50 percent equity capital structure. The Commission noted that "[w]e 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 [,]" and that 50/50 capital structure was an optimal structure for ratemaking.[6]

**Q. Does Idaho Power continue to target a 50 percent Common Equity / 50 percent LT Debt capital structure?**

A. Yes. At the Sidoti Small-Cap Virtual Conference[7] on March 14, 2024, Idaho Power reiterated its target of a 50 percent equity layer in its capital structure. In Exhibit Staff/200, Staff Senior Utility Analyst Rose Pileggi analyzes the Company's capital structure. She will continue to monitor the Company's use of its 2023 equity forward and any incremental debt issuances.

### Cost of Long-Term Debt

**Q. Is Rose Pileggi also analyzing the Company's Cost of Long-Term Debt.**

A. Yes. In Exhibit Staff/200, she develops the recommendation shown in Table 6 above.

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6 *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, UE 374, Order No. 20-473, p. 24 (December 18, 2020).

7 The Company presented at the Sidoti Small-Cap Virtual Conference.

## 5. RETURN ON EQUITY (ROE)

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

A. Staff observes a range of reasonable ROEs of 9.1 percent to 9.5 percent, with a mean ROE of 9.3, derived from Staff's two separate Three-Stage Discounted-Cash-Flow (DCF) models. Staff does not have a recommended point ROE estimate in this case, which is a departure from its typical practice.

**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 8.7 percent using Staff's peer electric utilities and 7.2 percent with the Company's peer electric utilities. If Staff sensitivity screening permitting a wider range or capital structure than Idaho Power's is used, Staff's results would be increased by 10 basis points (bps) to 8.8 percent. This model points to the lower end of Staff's three-stage discounted cash flow results.

The CAPM using Staff's usual inputs and methodology generated a mean ROE of 9.3 percent using Staff's peer electric utilities and 9.1 percent with the Company's peer electric utilities. If Staff sensitivity screening permitting a wider range or capital structure than Idaho Power's is used, Staff's results would be decreased by 10 basis points (bps) to 9.2 percent.

Based on these checks, Staff utilizes the midpoint estimate of 9.3 percent for ROE in Table 6 above. However, any point within Staff's range of reasonable ROEs from 9.1 percent to 9.5 percent (rounded up) would be supportive of a just and reasonable decision by the Commission regarding ROE.

**Q. Does your recommended ROE meet appropriate standards?**

A. Yes. The range or reasonable ROEs 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.[8] 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."[9] However, a higher point within Staff's range would be more supportive of current Idaho Power credit ratings and financial market expectations.

[8] *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).

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

## PEER SCREEN

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

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

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 A to BBB- inclusive from S&P;
4. No decline in annual dividend in last five years based on VL;
5. Has heavily regulated electric utility revenue;
6. Has LT Debt from 45 percent to 55 percent inclusive in VL Capital Structure; and[10]
7. Has no recent merger and acquisition activity.[11]

**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 402, page 2, Staff flags electric utilities not selected as it shows how each element of its screening was applied. Table 7 shows a fair amount of overlap between Idaho Power's and Staff's peer groups.

**Q. Did the Company apply some different criteria?**

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[10] Staff also performs sensitivity analysis looking at a peer screen of 40 percent to 60 percent long-term debt in capital structure. Sensitivity analysis does not impact Staff's modeling results but does answer questions looking at alternative inputs and scenarios.

[11] See Staff/100, Muldoon/50 for an example of financial news on mergers monitored by Staff.

A. Yes. However, there was much overlap between Idaho Power's and Staff's screening criteria.

**TABLE 7**[12]

| | | |
|---|---|---|
| Allete | Yes | No |
| Alliant | No | Yes |
| Ameren | Yes | Yes |
| AEP | No | No |
| Avangrid | Yes | No |
| Avista | Yes | Yes |
| Black Hills | Yes | Yes |
| CenterPoint | No | No |
| CMS | Yes | No |
| Consol Ed | No | Yes |
| Dominion | Yes | No |
| DTE | Yes | No |
| Duke | Yes | No |
| Edison Int'l | No | No |
| Entergy | Yes | No |
| Evergy | No | Yes |
| Eversource | No | No |
| Exelon | Yes | No |
| First Energy | No | No |
| Fortis | No | No |
| Hawaiian | No | No |
| IDACORP | Yes | Yes |
| MGE | No | No |
| NextEra | No | No |
| NorthWestern | Yes | Yes |
| OGE | Yes | Yes |
| Otter Tail | Yes | No |
| PG&E | No | No |
| PGE | Yes | Yes |
| Pinnacle | Yes | Yes |
| PNM | Yes | No |
| PPL | No | No |
| Public Serv. | Yes | Yes |
| Sempra | Yes | Yes |
| Southern | Yes | No |
| WEC | No | Yes |
| Xcel | No | No |
| **No. of Peers:** | **21** | **14** |

12 See Exhibit Staff 102, Muldoon/2 for the full peer screening table.

A comparison of the peer groups used by Staff and Idaho Power are set forth in Table 9 above. Staff excluded some of the companies used by Idaho Power based on the Staff screening criteria described above. Idaho Power also excludes some of the companies used by Staff. Ten companies were relied upon by both Staff and Idaho Power.

## MODEL RESULTS

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

A. See Table 8 below for the results from Staff's Three-Stage DCF modeling.

**TABLE 8 – RESULTS OF STAFF'S 3-STAGE DCF MODELING[13]**

| | | | | |
|---|---|---|---|---|
| | 9.07% | to | 9.46% | ROE |
| | Midpoint | 9.3% | ROE | Testimony |
| Staff Point ROE: | | 9.3% | | |

Supporting Exhibit Staff/404, Muldoon/1 shows step-by-step how Staff's Hamada adjusted[14] Three-Stage DCF modeling, using Staff peers and growth rates, generates a higher recommended ROE than using Idaho Power's peer electric utility group. Note that Staff rounds upward to generate a top of range value of 9.5 percent.

**Q. Does Staff agree with the Idaho Power's assertion that the Company's requested ROE of 10.4 percent is reasonable?**

A. No. Idaho Power comes up with a range of 10.0 percent to 11.4 percent with a recommended point estimate of 10.4 percent.[15] This is a very

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

14 As Staff explains in more detail below, Staff applies the Hamada equation to better compare companies with different capital structures.

15 See Idaho Power/801, Buckham/1.

interesting range as most of the Company's similarly situated and sized (in terms of capitalization) utilities have ROE's authorized within the last two years that are below even the lowest point of this range. Staff invites the Company to explain further in its Reply Testimony why its results exceed recent state commission authorized ROE's for its modeling peers.

**Q. Please provide an example of an extreme input used in the Company's modeling.**

A. **Example 1 below shows how important inputs are to ROE modeling. Looking at the difference between Idaho Power and Staff inputs, one** can see how use of an inflated market return can skew results upward.

**Example 1 – NOT a Staff Recommendation:**

| | | | |
|---|---|---|---|
| IPC | 3.94% | Rf Rate as shown in Exhibit IPC/801Buckham/3 | |
| Direct | 11.38% | IPC Mkt Return | |
| Testimony | 7.44% | IPC Mkt Risk Premium (MRP) | |
| **Staff** | 4.348% | $R_f$ Feb. 24, 2024 30-Yr UST Yield /WSJ | www.wsj.com/market-data/bonds |
| | 9.75% | 30-Year S&P 500 Proxy Market Return | Geometric Return |
| | 5.40% | Staff 30-Yr Mkt Risk Premium (MRP) | |

**Q. Please show a Capital Asset Pricing Model with Staff's and other more inflated inputs that may be preferred by the Company.**

A. In Table 9 below one can see how applying inputs from the table above to all the peer utilities changes ROE results of CAPM modeling.

## Table 9 – Capital Asset Pricing Model (CAPM) Examples

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

| | Screen # | Abbreviated Utility | UE 426 IPC | UE 426 Staff | LT Debt UE 426 Sensitivity | Ticker | VL Q3 2023 Beta | Staff MRP 30 Yr ROE w VL Beta CAPM | IPC MRP IPC/800 ROE w VL Beta CAPM | Screen # | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | Allete | Yes | No | No | ALE | 0.95 | 9.48% | 11.01% | 1 | 1 |
| 2 | 2 | Alliant | No | Yes | Yes | LNT | 0.90 | 9.21% | 10.64% | 2 | 2 |
| 3 | 3 | Ameren | Yes | Yes | Yes | AEE | 0.90 | 9.21% | 10.64% | 3 | 3 |
| 4 | 4 | AEP | No | No | Yes | AEP | 0.80 | 8.67% | 9.89% | 4 | 4 |
| 5 | 5 | Avangrid | Yes | No | No | AGR | 0.85 | 8.94% | 10.26% | 5 | 5 |
| 6 | 6 | Avista | Yes | Yes | Yes | AVA | 0.90 | 9.21% | 10.64% | 6 | 6 |
| 7 | 7 | Black Hills | Yes | Yes | Yes | BKH | 1.00 | 9.75% | 11.38% | 7 | 7 |
| 8 | 9 | CMS | Yes | No | No | CMS | 0.85 | 8.94% | 10.26% | 9 | 8 |
| 9 | 10 | Consol Ed | No | Yes | Yes | ED | 0.75 | 8.40% | 9.52% | 10 | 9 |
| 10 | 11 | Dominion | Yes | No | No | D | 0.85 | 8.94% | 10.26% | 11 | 10 |
| 11 | 12 | DTE | Yes | No | No | DTE | 1.00 | 9.75% | 11.38% | 12 | 11 |
| 12 | 13 | Duke | Yes | No | Yes | DUK | 0.85 | 8.94% | 10.26% | 13 | 12 |
| 13 | 15 | Entergy | Yes | No | No | ETR | 0.95 | 9.48% | 11.01% | 15 | 13 |
| 14 | 16 | Evergy | No | Yes | Yes | EVRG | 0.95 | 9.48% | 11.01% | 16 | 14 |
| 15 | 17 | Eversource | No | No | Yes | ES | 0.90 | 9.21% | 10.64% | 17 | 15 |
| 16 | 18 | Exelon | Yes | No | No | EXC | 0.00 | 4.35% | 3.94% | 18 | 16 |
| 17 | 22 | IDACORP | Yes | Yes | Yes | IDA | 0.85 | 8.94% | 10.26% | 22 | 17 |
| 18 | 25 | NorthWestern | Yes | Yes | Yes | NWE | 0.95 | 9.48% | 11.01% | 25 | 18 |
| 19 | 26 | OGE | Yes | Yes | Yes | OGE | 1.05 | 10.02% | 11.75% | 26 | 19 |
| 20 | 27 | Otter Tail | Yes | No | Yes | OTTR | 0.90 | 9.21% | 10.64% | 27 | 20 |
| 21 | 29 | PGE | Yes | Yes | Yes | POR | 0.90 | 9.21% | 10.64% | 29 | 21 |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | PNW | 0.95 | 9.48% | 11.01% | 30 | 22 |
| 23 | 31 | PNM | Yes | No | No | PNM | 0.90 | 9.21% | 10.64% | 31 | 23 |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | PEG | 0.90 | 9.21% | 10.64% | 33 | 24 |
| 25 | 34 | Sempra | Yes | Yes | Yes | SRE | 1.00 | 9.75% | 11.38% | 34 | 25 |
| 26 | 35 | Southern | Yes | No | No | SO | 0.90 | 9.21% | 10.64% | 35 | 26 |
| 27 | 36 | WEC | No | Yes | Yes | WEC | 0.85 | 8.94% | 10.26% | 36 | 27 |
| 28 | 37 | Xcel | No | No | Yes | XEL | 0.85 | 8.94% | 10.26% | 37 | 28 |
| | | **No. of Peers:** | **21** | **14** | **19** | | | VL Betas | VL Betas | | |
| | | | | | **Company Screen** | | **Mean** | **9.1%** | 10.5% | **ROE** | |
| | | | | | **Staff Screen** | | **Mean** | **9.3%** | 10.8% | **ROE** | |
| | | | | | **Staff Sensitivity Screen** | | **Mean** | 9.2% | 10.7% | **ROE** | |

Staff usually relies on a U.S. Treasury (UST) thirty-year bond as reported by the Wall Street Journal (WSJ) and 30-year monthly geometric returns for the Standard and Poor's (S&P) 500 index as a proxy for market returns. If one instead uses **an extreme arithmetic market return,** one can inflate the results of a CAPM model with few inputs.[16] One can also boost results by using a starting point for data collection in the Great Depression and then including World War II era boom times unlikely to be repeated in the U.S. economy.

[16] See Staff/105, Muldoon/1 for this CAPM modeling example.

**Q. Is calculation of a market risk premium calculated from 1926-2003 a good predictor of future U.S. stock returns?**

A. No. Since returns over the last thirty years are lower than those experienced earlier in the Country's history, which includes post-World-War II economic expansion in the U.S, expectations should mirror the recent 30 years returns. According to Ibbotson, reliance on a date range like Idaho Power's would overstate likely future market returns.[17] The combination of a 20-year UST as a risk-free rate and a very long (almost 100-year) arithmetic market return can inflate results in CAPM models.

**Q. Is Staff suggesting that CAPM is not a good model to check results of other modeling Staff performs, as advised by the Commission?**

A. No. Rather, Staff shows why the Commission accepts CAPM only as a check on ROE modeling and demonstrates how one can abuse the model. If one eliminates unreasonable modeling inputs, selects only peer electric utilities most like Idaho Power using Staff's standard screening methods, and eliminates unreasonable inputs, you arrive at a result equal to Staff's ROE recommendations.[18]

According to Regulatory Research Associates (RRA), an affiliate of S&P, the average ROE authorized for electric utilities rose to 9.54 percent for rate cases decided in 2022 from the 9.38 percent average for cases decided in

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[17] See "The Equity Risk Premium" by William N. Goetzmann and Roger G. Ibbotson available on Amazon.com.

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

2021.[19] Idaho Power's recommendations do not seem to have any correlation whatsoever to prevailing state commission decisions regarding authorized ROE in rate case decisions in the last year.[20]

## STAFF MODELS

**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"). 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

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19 See Exhibit Staff/110, Muldoon/1 for Average Authorized ROEs in 2021, 2022 and 2023 by Lisa Fontanella, RRA.

20 The ROE determinations authorized by state public utility commissions for electric utilities in 2022 ranged from 7.85% to 10.80%, with an average of 9.54% and a median of 9.50%, according to Regulatory Research Associates (RRA) an affiliate of S&P Global Market Intelligence. CIQ Pro: RRA Regulatory Focus: Electric authorized ROEs rebound in 2022 as interest rates bounce higher (spglobal.com)

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?**[21]

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 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?**

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

A. Staff used the average of closing prices for each utility from the first trading day in December 2023, January 2024, and February 2024, to represent a reasonable snapshot of utility stock prices.

**GROWTH RATES USED IN THIRD STAGE OF DCF MODELS**[22,23]

**Q. What long-term growth rates did you use in Staff's two three-stage DCF models?**[24,25]

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) 4.46 percent nominal 20-year GDP growth rate estimate.

Staff's second method uses the Energy Information Administration (EIA) 4.69 percent nominal GDP Growth rate.

Staff's third Composite Growth Rate applies a 20 percent weight to each of the following referent entities long-term growth rates: EIA, Organization for Economic Co-operation and Development (OECD), the U.S. Social Security Administration (SSA), the Congressional Budget Office's (CBO), with the remaining 20 percent as the average annual historical real GDP growth rate, established using regression analysis of U.S. Bureau of Economic Analysis

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22 See Exhibit Staff/106, Muldoon1 for BEA historical GDP growth rates.

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

24 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

25 See three-stage DCF models X and Y in Exhibit Staff/103.

(BEA) Nominal Historical,1980 Q1 – 2022 Q4, for the period 1980 through 2021, to which we apply a TIPS implied inflation forecast. These growth rates are shown below in Table 10.

**TABLE 10**
**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) | 2.24% | 2.39% | 4.69% | 20.0% | 0.94% | |
| Organization for Economic Co-operation | 1.81% | 2.39% | 4.24% | 20.0% | 0.85% | |
| Social Security Administration (SSA) | 1.95% | 2.39% | 4.39% | 20.0% | 0.88% | |
| Congressional Budget Office (CBO) | 2.02% | 2.39% | 4.46% | 20.0% | 0.89% | |
| BEA Nominal Historical,1980 Q1 – 2023 Q4 | 2.65% | 2.39% | 5.10% | 20.0% | 1.02% | |
| Composite | | | | 100% | 4.58% | Composite |
| Congressional Budget Office (CBO) Long-Term 20-Year Budget Outlook | | | 3.80% | 100.0% | 4.46% | CBO |
| Energy Information Administration (EIA) | 2.65% | 2.39% | 5.10% | 100.0% | 4.69% | EIA |

**Q. Did your analysis reflect a synthetic forward curve?**

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. 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.[26]

**Q. 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 9.1 to 9.5 percent range of reasonable ROEs 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.

**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.

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[26] See Exhibit Staff/110, Muldoon/1-54 for news that investors in electric utilities are seeing.

**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 not yet impacted by retirement of persons born in 1960 or persons not

[27] See Exhibit Staff/110, Muldoon/53 for concerns about Oregon population growth.

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 IDAHO POWER'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

[28] Dr. Robert Hamada's Equation as used in Staff/404 separates the financial risk of a levered firm, represented by its mix of common stock, preferred stock, and debt, from its fundamental

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 Staff consider what modeling outcomes would result from using a larger peer capital structure screen with a sensitivity peer group with 40 percent to 60 percent debt, carrying more interest rate risk than Idaho Power?**

A. Yes. Inclusive of Hamada adjustments, the higher debt sensitivity peer group would decrease Staff's recommended ROE by 24 basis points. While the

business risk. Staff corrects its ROE modeling for divergent amounts of debt, also referred to as leverage, between the Company and its peers.

Hamada equation addresses the capital structure itself to a certain degree, companies taking on more debt may also be taking on more risk in other areas than finance. In general, Staff screens to select companies most like the utility it seeks to identify a best range of reasonable ROEs and point ROE for.

**Q. Did Staff use robust and proven analytical methodologies?**

A. Yes. Staff's methods are robust, proven, and parallel Staff's work for many years. The Commission, for example, expressly relies on the multi-stage DCF 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 Portland General Electric Company's GRC (Docket No. UE 394) as well as in Order No. 20-473 in PacifiCorp's GRC (Docket No. 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 range of reasonable ROE's from9.1 percent to 9.5 percent?**

A. Yes.

<u>**Balanced Approach to ROE**</u>

**Q. Is picking a best fit ROE within Staff's suggested range of reasonable ROE's an easy decision for the Commission.**

A. No. On the one hand, a lower ROE would reduce the impact of this general rate increase on Idaho Power's utility customers in Oregon. This thought is likely foremost for CUB members and employees based on the earlier cited statement by Director Bob Jenks.

On the other hand, a higher ROE is more supportive of the Company's credit ratings, which are under pressure based on financial metrics and the Western U.S. challenge of wildfire risks. Though Oregon only represents about five percent of the Company's revenues, the overall regulatory environment in Oregon and Idaho is a very large part of rating agency decision making. And these ratings influence the Company's borrowing cost in a period of significant spending for plant additions. A utility customer might think of this like buying the same house at low or high interest / mortgage rates.

Balancing these and other considerations is necessary for the Commission to make decisions consistent with the Hope and Bluefield legal decisions mentioned earlier.

**Q. Are we in a rising interest rate environment that compels higher ROEs.**

A. No. The U.S. Federal Reserve expects to lower interest rates in the next year.[29] Further interest rates and ROEs are both declining when looked at over a 30-year time frame. 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. These are downward pressures on GDP growth.

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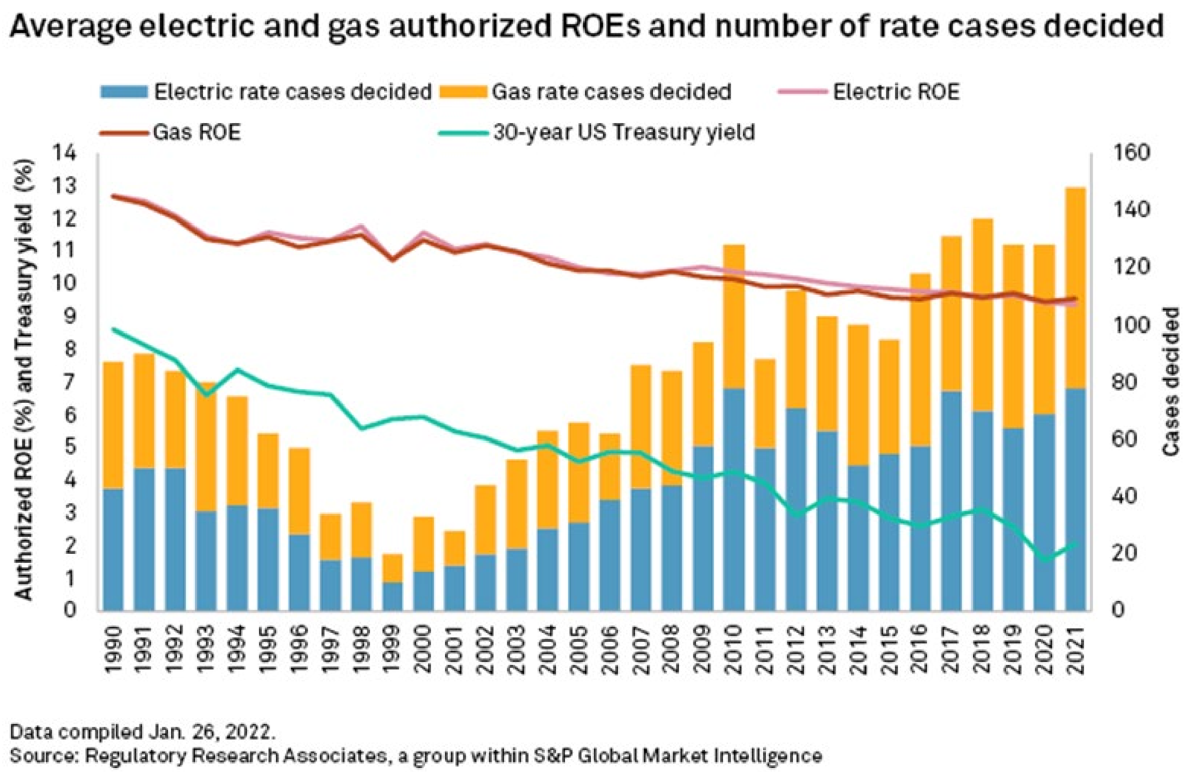
[29] See Staff/100, Muldoon/51.

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




**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 recently raised interest rates, the Fed now anticipates loosening money supply soon.

**<u>GORDON GROWTH MODEL – As Check on ROE Findings</u>**

**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

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

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:

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

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

[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.

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 does Staff use 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 8.7 percent.

# TABLE 11[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 Lower End of Staff's 3-Stage DCF Modeling Results**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11<br>= 9 + 10 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Screen # | Abbreviated Utility | UE 426 IPC | UE 426 Staff | LT Debt UE 426 Sensitivity | Ticker | Recent Stock $ Price | Current Dividend Yield | Next VL Annual Dividend | Anticipated Dividend Yield | VL Dividend Growth | Investor d ROE | Screen # | |
| 1 | 1 | Allete | Yes | No | No | ALE | 59.87 | 4.5% | 2.79 | 4.7% | 2.9% | 7.5% | 1 | 1 |
| 2 | 2 | Alliant | No | Yes | Yes | LNT | 49.71 | 3.6% | 1.92 | 3.9% | 6.0% | 9.9% | 2 | 2 |
| 3 | 3 | Ameren | Yes | Yes | Yes | AEE | 70.70 | 3.6% | 2.65 | 3.7% | 7.1% | 10.8% | 3 | 3 |
| 4 | 4 | AEP | No | No | Yes | AEP | 79.24 | 4.2% | 3.52 | 4.4% | 5.6% | 10.0% | 4 | 4 |
| 5 | 5 | Avangrid | Yes | No | No | AGR | 31.06 | 5.7% | 1.76 | 5.7% | 1.1% | 6.8% | 5 | 5 |
| 6 | 6 | Avista | Yes | Yes | Yes | AVA | 34.45 | 5.3% | 1.92 | 5.6% | 4.5% | 10.1% | 6 | 6 |
| 7 | 7 | Black Hills | Yes | Yes | Yes | BKH | 52.19 | 4.8% | 2.65 | 5.1% | 4.7% | 9.7% | 7 | 7 |
| 8 | 9 | CMS | Yes | No | No | CMS | 57.52 | 3.4% | 2.04 | 3.5% | 4.8% | 8.3% | 9 | 8 |
| 9 | 10 | Consol Ed | No | Yes | Yes | ED | 90.94 | 3.6% | 3.34 | 3.7% | 3.7% | 7.4% | 10 | 9 |
| 10 | 11 | Dominion | Yes | No | No | D | 46.21 | 5.8% | 2.67 | 5.8% | -0.8% | 5.0% | 11 | 10 |
| 11 | 12 | DTE | Yes | No | No | DTE | 107.35 | 3.5% | 4.05 | 3.8% | 3.8% | 7.5% | 12 | 11 |
| 12 | 13 | Duke | Yes | No | Yes | DUK | 96.68 | 4.2% | 4.14 | 4.3% | 1.6% | 5.9% | 13 | 12 |
| 13 | 15 | Entergy | Yes | No | No | ETR | 100.53 | 4.3% | 4.56 | 4.5% | 4.2% | 8.8% | 15 | 13 |
| 14 | 16 | Evergy | No | Yes | Yes | EVRG | 51.16 | 4.8% | 2.61 | 5.1% | 5.7% | 10.8% | 16 | 14 |
| 15 | 17 | Eversource | No | No | Yes | ES | 57.44 | 4.7% | 2.86 | 5.0% | 6.0% | 11.0% | 17 | 15 |
| 16 | 18 | Exelon | Yes | No | No | EXC | 35.31 | 4.1% | 1.60 | 4.5% | 3.4% | 8.0% | 18 | 16 |
| 17 | 22 | IDACORP | Yes | Yes | Yes | IDA | 95.05 | 3.4% | 3.40 | 3.6% | 6.3% | 9.9% | 22 | 17 |
| 18 | 25 | NorthWestern | Yes | Yes | Yes | NWE | 49.05 | 5.2% | 2.60 | 5.3% | 1.9% | 7.2% | 25 | 18 |
| 19 | 26 | OGE | Yes | Yes | Yes | OGE | 33.81 | 4.9% | 1.78 | 5.3% | 2.4% | 7.6% | 26 | 19 |
| 20 | 27 | Otter Tail | Yes | No | Yes | OTTR | 88.59 | 2.0% | 1.81 | 2.0% | 5.9% | 7.9% | 27 | 20 |
| 21 | 29 | PGE | Yes | Yes | Yes | POR | 41.46 | 4.5% | 1.98 | 4.8% | 6.0% | 10.7% | 29 | 21 |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | PNW | 71.04 | 4.9% | 3.54 | 5.0% | 2.1% | 7.1% | 30 | 22 |
| 23 | 31 | PNM | Yes | No | No | PNM | 38.27 | 3.9% | 1.59 | 4.2% | -8.8% | -4.7% | 31 | 23 |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | PEG | 59.09 | 3.9% | 2.40 | 4.1% | 5.4% | 9.5% | 33 | 24 |
| 25 | 34 | Sempra | Yes | Yes | Yes | SRE | 72.55 | 3.3% | 2.50 | 3.4% | -2.6% | 0.8% | 34 | 25 |
| 26 | 35 | Southern | Yes | No | No | SO | 69.80 | 4.0% | 2.86 | 4.1% | 2.8% | 6.9% | 35 | 26 |
| 27 | 36 | WEC | No | Yes | Yes | WEC | 81.90 | 3.8% | 3.33 | 4.1% | 5.8% | 9.8% | 36 | 27 |
| 28 | 37 | Xcel | No | No | Yes | XEL | 60.72 | 3.4% | 2.22 | 3.7% | 6.7% | 10.3% | 37 | 28 |
| | | No. of Peers: | 21 | 14 | 19 | | | | | | | Mean | | |
| | | | | | | | | | | | Company Screen | 7.2% | ROE | |
| | | | | | | | | | | | Staff Screen | 8.7% | ROE | |
| | | | | | | | | | | | Staff Sensitivity Screen | 8.8% | ROE | |

The average required ROE increased to 7.2 percent if the Company's larger peer screen is used. Staff's sensitivity peer group allowing for debt up to 60 percent of capital structure also increases the modeling result to 8.8 percent. Findings in Table 12 above support selection in the lower end of Staff's range of reasonable ROEs.

32 See Exhibit Staff/106, Muldoon/1 for Staff's full Gordon Growth Model.

## 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 $\beta$. 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-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 bonds 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. As earlier discussed, 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 up to three percent 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. Staff also calculates market risk premiums as described herein using annualized monthly data for 30 years of geometric S&P 500 returns paired with current 30-year UST yields.

**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 9.3 percent. Using the Company's peer screen and Staff's methods, the average estimated ROE observed is 9.1 percent. If one uses a nearly 100-year <u>arithmetic</u> return combined with a 20-year UST risk free rate, one can boost results to 10.8 percent similar to that found in Idaho Power's testimony.

**Q. Has the Commission determined that CAPM should not be relied upon as a stand-alone modeling method?**

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, but still permits use of the CAPM as a check on other modeling methods employed.[33]

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

## 6. PENSIONS AND POST RETIRMENT MEDICAL EXPENSE

**Q. Does Staff recommend an adjustment to the Company's pensions and post-retirement medical expense in this general rate case.**

A. No.

**Q. Did Staff carefully analyze the Expected Return on Assets for each of the Company's pensions and post-retirement medical expense?**

A. Yes. Staff performed its usual robust analysis, discussed these issues in detail at a workshop with the Company on February 13, 2024, and issued follow-up data requests, the responses to which corroborated Staff's findings. Staff found the Company's actuarial work consistent with the Company's benchmarks inclusive of EROA for Oregon Public Employee Retirement System (PERS), CA PERS, and California State Teachers' Retirement System.

**Q. Did Staff carefully analyze the discount rate assumptions for each of the Company's pensions and post-retirement medical expense?**

A. Yes. Staff also calibrated the revenue requirement impact of each of the above factors and confirmed that in aggregate the Company's work in this area was reasonable and no adjustment is required in this general rate case.

## 7. CONCLUSION

**Q. What is Staff's recommendation regarding ROE?**

A. Staff recommends that the Commission select a point ROE from within Staff's range of reasonable ROE's from 9.1 percent to 9.5 percent (after rounding). This is a difficult decision balancing financial market criteria and credit ratings on the one hand against reducing energy burden for Oregon customers of Idaho Power on the other.

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

A. Staff provides an illustrative 7.150 percent Overall Rate of Return (ROR), based on the midpoint of Staff's range of reasonable ROEs of 9.30 percent, a 50 percent equity layer Capital Structure and a 4.999 percent Cost of Long-Term Debt.

**Q. What recommendation does Staff have regarding a point estimate within Staff's range of reasonable ROEs.**

A. Staff finds that recommending a range is appropriate rather than any single point estimate. The range is from 9.1 percent to 9.5 percent. The range provides values from which the Commission can use to balance the interests of shareholders and energy affordability for Oregon utility customers and still meet statutory requirements to provide for a fair return on equity.

**Q. Does Staff recommend an adjustment to pensions and post-retirement expense in this general rate case?**

A. No. Staff's usual robust analysis found the Company's work on these issues to be reasonable and in aggregate consistent with Staff's benchmarks.

**Q. Does that conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: MATT MULDOON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 101

## Witness Qualifications Statement
## Staff: Muldoon

**March 25, 2024**

## WITNESS QUALIFICATION STATEMENT

| | |
|---|---|
| NAME: | Matthew (Matt) J. Muldoon |
| EMPLOYER: | PUBLIC UTIILTY COMMISSION OF OREGON |
| TITLE: | Manager, Accounting and Finance Section of Rates, Safety and Utility Performance Program (RSUP) of the Public Utility Commission of Oregon (OPUC) |
| 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 (MBA) 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, UG 433 and UG 461; CNG UG 287, UG 305, UG 347, and UG 390; IPC current UE 426; NWN UG 221, UG 344, UG 388, UG 435, and current UG 490; PAC UE 246, UE 263, UG 374, UE 399, and current UE 433; and PGE UE 262, UE 283, UE 294, UE 319, UE 335, UE 394, UE 416 and current UE 435. |
| | 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 ensure 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 426
WITNESS: MATT MULDOON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 102

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

**March 25, 2024**

## Acronyms and Abbreviations Used

| | |
|---|---|
| **BOE** | U.S. Bureau of Economic Analysis |
| **CBO** | U.S. Congressional Budget Office |
| **CIK** | SEC Central Index Key |
| **EDGAR** | SEC Electronic Data Gathering, Analysis and Retrieval System |
| **EEI** | Edison Electric Institute |
| **EIN** | IRS Employer Identification Number |
| **IRS** | U.S. Internal Revenue Service |
| **SEC** | U.S. Securities and Exchange Commission |
| **SIC** | Standard Industrial Code |
| **SPG** | Standard & Poors Global Market Intelligence |
| **TIPS** | UST Treasury Inflation-Protected Securities |
| **U.S.** | United States of America |
| **UST** | U.S. Treasuries |
| **VL** | Value Line Investment Survey |

| Moody's | | S&P | | Fitch | | DBRS | | |
|---|---|---|---|---|---|---|---|---|
| Long-term | Short-term | Long-term | Short-term | Long-term | Short-term | Long-term | Short-term | |
| Aaa | P-1 | AAA | A-1+ | AAA | F1+ | AAA | R-1H | High Grade |
| Aa1 | | AA+ | | AA+ | | AA(high) | | High grade |
| Aa2 | | AA | | AA | | AA | R-1M | |
| Aa3 | | AA- | | AA- | | AA(low) | | |
| A1 | | A+ | A-1 | A+ | F1 | A(high) | R-1L | Upper medium grade |
| A2 | | A | | A | | A | | |
| A3 | P-2 | A- | A-2 | A- | F2 | A(low) | | |
| Baa1 | | BBB+ | | BBB+ | | BBB(high) | R-2H | Lower medium grade |
| Baa2 | P-3 | BBB | A-3 | BBB | F3 | BBB | R-2M | |
| Baa3 | | BBB- | | BBB- | | BBB(low) | R-2L, R-3 | |
| Ba1 | Not prime | BB+ | B | BB+ | B | BB(high) | R-4 | Non-investment grade speculative |
| Ba2 | | BB | | BB | | BB | | |
| Ba3 | | BB- | | BB- | | BB(low) | | |
| B1 | | B+ | | B+ | | B(high) | | Highly speculative |
| B2 | | B | | B | | B | R-5 | |
| B3 | | B- | | B- | | B(low) | | |
| Caa1 | | CCC+ | C | CCC | C | CCC(high) | | Substantial risks |
| Caa2 | | CCC | | | | CCC | | |
| Caa3 | | CCC- | | | | CCC(low) | | |
| | | CC | | | | CC(high) | | |
| | | | | | | CC | | |

| | | |
|---|---|---|
| S | Small Cap | Under 2 Billion |
| M | Mid Cap | 2 to 10 Billion |
| L | Large Cap | Over 10 Billion |

| 1<br>VL # | 2<br>Abbreviated Utility | 3<br>UE 426 IPC | 4<br>UE 426 Staff | 12<br>LT Debt Sensitivity UE 426 Staff | 13<br>VL 1/16/2024 Beta | 14<br>VL $B 1/16/2024 Mkt Cap $ Billions | 15<br>VL 1/16/2024 S,M,L CAP | 16<br>Yahoo Fin. 1/16/2024 Beta | 17<br>Yahoo Fin. 1/16/2024 Mkt Cap $ Billions | 18<br>Covered by Value Line 1/16/2024 ( VL ) | 19<br>VL 1/16/2024 No Div Declines 5 years | 20<br>Moody's 1/16/2024 A1 to Baa2 Local LT Unsecured Debt Rating | 21<br>S&P 1/16/2024 A to BBB- Local LT Unsecured Debt Rating | 22<br>+ / - 2 Notches S&P & Moody's | 23<br>SEC 10-K 2/10/2023 Percentage Regulated Revenue | 24<br>EEI 7/7/2023 80%+ Regulated Assets | 25<br>VL 1/16/2024 LT Debt 45% - 55% of Capital | 26<br>Sensitivity VL 1/16/2024 LT Debt 40% - 60% of Capital | 27<br>VL 2/2/2023 Div. Growth 5 Yr Rate Forecast > 0% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Allete | Yes | No | No | 0.95 | 3.20 | M | 0.75 | 3.44 | Yes | Pass | Baa1 | BBB | Pass | 80% | 50% to 80% | 39.5% | 39.5% | Yes |
| 2 | Alliant | No | Yes | Yes | 0.90 | 12.60 | L | 0.55 | 12.83 | Yes | Pass | Baa2 | A- | Pass | 97% | 80% + | 52.5% | 52.5% | Yes |
| 3 | Ameren | Yes | Yes | Yes | 0.90 | 20.40 | L | 0.46 | 18.72 | Yes | Pass | Baa1 | BBB+ | Pass | 100% | 80% + | 53.5% | 53.5% | Yes |
| 4 | AEP | No | No | Yes | 0.80 | 41.30 | L | 0.50 | 42.59 | Yes | Pass | Baa2 | A- | Pass | 83% | 80% + | 58.0% | 58.0% | Yes |
| 5 | Avangrid | Yes | No | No | 0.85 | 11.30 | L | 0.52 | 12.34 | Yes | Pass | Baa2 | BBB+ | Pass | N/A | 50% to 80% | 32.0% | 32.0% | Yes |
| 6 | Avista | Yes | Yes | Yes | 0.90 | 2.40 | M | 0.49 | 2.62 | Yes | Pass | Baa2 | BBB | Pass | 99% | 80% + | 50.5% | 50.5% | Yes |
| 7 | Black Hills | Yes | Yes | Yes | 1.00 | 3.30 | M | 0.66 | 3.51 | Yes | Pass | Baa2 | BBB+ | Pass | 100% | 80% + | 54.0% | 54.0% | Yes |
| 8 | CenterPoint | No | No | No | 1.15 | 17.60 | L | 0.95 | 18.01 | Yes | Fail | Baa2 | BBB+ | Pass | 80% | 80% + | 58.0% | 58.0% | Fail |
| 9 | CMS | Yes | No | No | 0.85 | 16.70 | L | 0.39 | 16.94 | Yes | Pass | Baa2 | BBB+ | Pass | 94% | 80% + | 64.0% | 64.0% | Yes |
| 10 | Consol Ed | No | Yes | Yes | 0.75 | 30.20 | L | 0.37 | 31.61 | Yes | Pass | Baa1 | A- | Pass | 84% | 80% + | 48.0% | 48.0% | Yes |
| 11 | Dominion | Yes | No | No | 0.85 | 33.50 | L | 0.59 | 39.13 | Yes | Fail | Baa2 | BBB+ | Pass | 95% | 80% + | 56.0% | 56.0% | Fail |
| 12 | DTE | Yes | No | No | 1.00 | 21.60 | L | 0.66 | 22.19 | Yes | Fail | Baa2 | BBB+ | Pass | 52% | 80% + | 61.5% | 61.5% | Fail |
| 13 | Duke | Yes | No | Yes | 0.85 | 67.70 | L | 0.47 | 75.55 | Yes | Pass | Baa2 | BBB+ | Pass | 100% | 80% + | 58.5% | 58.5% | Yes |
| 14 | Edison Int'l | No | No | No | 1.00 | 24.00 | L | 0.95 | 26.92 | Yes | Pass | Baa2 | BBB | Pass | 100% | 80% + | 65.5% | 65.5% | Yes |
| 15 | Entergy | Yes | No | No | 0.95 | 21.50 | L | 0.70 | 21.77 | Yes | Pass | Baa2 | BBB+ | Pass | 98% | 80% + | 64.5% | 64.5% | Yes |
| 16 | Evergy | No | Yes | Yes | 0.95 | 11.70 | L | 0.55 | 12.14 | Yes | Pass | Baa2 | BBB+ | Pass | 100% | 80% + | 51.5% | 51.5% | Yes |
| 17 | Eversource | No | No | Yes | 0.90 | 18.60 | L | 0.60 | 19.65 | Yes | Pass | Baa2 | A- | Pass | 100% | 80% + | 57.0% | 57.0% | Yes |
| 18 | Exelon | Yes | No | No | 0.00 | 38.30 | L | 0.61 | 35.54 | Yes | Fail | Baa2 | BBB+ | Pass | 67% | 80% + | 61.0% | 61.0% | Fail |
| 19 | First Energy | No | No | No | 0.85 | 20.30 | L | 0.49 | 21.72 | Yes | Pass | Ba1 | BBB- | Fail | 100% | 80% + | 66.0% | 66.0% | Fail |
| 20 | Fortis | No | No | No | 0.70 | 27.10 | L | 0.19 | 20.16 | Yes | Pass | Baa3 | A- | Fail | 55% | N/A | 53.0% | 53.0% | Yes |
| 21 | Hawaiian | No | No | No | 0.95 | 1.30 | S | 0.56 | 1.47 | Yes | Fail | Ba3 | B- | Fail | 77% | 50% to 80% | 48.5% | 48.5% | Fail |
| 22 | IDACORP | Yes | Yes | Yes | 0.85 | 4.90 | M | 0.58 | 4.77 | Yes | Pass | Baa2 | BBB | Pass | 99% | 80% + | 47.0% | 47.0% | Yes |
| 23 | MGE | No | No | No | N/A | N/A | M | 0.72 | 2.53 | No | Fail | A1 | AA- | Fail | 99% | 80% + | N/A | N/A | Fail |
| 24 | NextEra | No | No | No | 0.95 | 116.00 | L | 0.52 | 123.82 | Yes | Pass | Baa1 | A- | Pass | 70% | 50% to 80% | 59.0% | 59.0% | Yes |
| 25 | NorthWestern | Yes | Yes | Yes | 0.95 | 3.00 | M | 0.47 | 2.95 | Yes | Pass | Baa2 | BBB | Pass | 99% | 80% + | 46.5% | 46.5% | Yes |
| 26 | OGE | Yes | Yes | Yes | 1.05 | 7.00 | M | 0.72 | 6.73 | Yes | Pass | Baa1 | BBB+ | Pass | 100% | 80% + | 52.0% | 52.0% | Yes |
| 27 | Otter Tail | Yes | No | Yes | 0.90 | 3.10 | M | 0.54 | 3.44 | Yes | Pass | Baa2 | BBB | Pass | 80% | 80% + | 41.5% | 41.5% | Yes |
| 28 | PG&E | No | No | No | N/A | N/A | L | 1.16 | 43.52 | No | Fail | Ba2 | BB- | Fail | N/A | 80% + | N/A | N/A | Fail |
| 29 | PGE | Yes | Yes | Yes | 0.90 | 4.20 | M | 0.60 | 4.14 | Yes | Pass | A3 | BBB+ | Pass | 100% | 80% + | 53.5% | 53.5% | Yes |
| 30 | Pinnacle | Yes | Yes | Yes | 0.95 | 8.30 | M | 0.48 | 7.92 | Yes | Pass | Baa1 | BBB+ | Pass | 100% | 80% + | 52.5% | 52.5% | Yes |
| 31 | PNM | Yes | No | No | 0.90 | 3.80 | M | 0.37 | 3.13 | Yes | Pass | Baa3 | BBB | Fail | 100% | 80% + | 62.0% | 62.0% | Pass |
| 32 | PPL | No | No | No | 1.05 | 18.00 | L | 0.85 | 19.76 | Yes | Fail | Baa1 | A- | Pass | 100% | 80% + | 46.5% | 46.5% | Pass |
| 33 | Public Serv. | Yes | Yes | Yes | 0.90 | 30.00 | L | 0.58 | 29.59 | Yes | Pass | Baa2 | BBB+ | Pass | 80% | 80% + | 53.5% | 53.5% | Yes |
| 34 | Sempra | Yes | Yes | Yes | 1.00 | 43.10 | L | 0.74 | 46.86 | Yes | Pass | Baa2 | BBB+ | Pass | 80% | 80% + | 49.0% | 49.0% | Yes |
| 35 | Southern | Yes | No | No | 0.90 | 72.80 | L | 0.53 | 76.69 | Yes | Pass | Baa2 | BBB+ | Pass | 96% | 80% + | 64.0% | 64.0% | Yes |
| 36 | WEC | No | Yes | Yes | 0.85 | 25.90 | L | 0.42 | 26.05 | Yes | Pass | Baa1 | A- | Pass | 100% | 80% + | 55.0% | 55.0% | Yes |
| 37 | Xcel | No | No | Yes | 0.85 | 31.80 | L | 0.42 | 33.61 | Yes | Pass | Baa1 | A- | Pass | 100% | 80% + | 58.0% | 58.0% | Yes |
| | No. of Peers: | 21 | 14 | 19 | 0.89 | | | | | | | | | | | | | | |

| | Moody's | S&P |
|---|---|---|
| IPC | A3 | A |
| Range | A1 to Baa2 | A to BBB- |

Edision Electric Instutute (EEI)

| Assets | EEI | Meaning |
|---|---|---|
| 80% Plus | R | Regulated |
| 50% to 80% | MR | Mostly Regulated |
| Under 50% | D | Diversified |

EEI Updates each June to end of prior year.

| 1 | 2 | 3 | 4 | 28 | |
|---|---|---|---|---|---|
| S | Small Cap | Under 2 Billion | | | |
| M | Mid Cap | 2 to 10 Billion | | | |
| L | Large Cap | Over 10 Billion | | | |
| VL # | Abbreviated Utility | UE 426 IPC | UE 426 Staff | No M&A Executed in Last 5 Years | # |
| 1 | Allete | Yes | No | | 1 |
| 2 | Alliant | No | Yes | | 2 |
| 3 | Ameren | Yes | Yes | | 3 |
| 4 | AEP | No | No | Sale of KY Power Subsidiary for $1.45 Billion expected to be completed in 2022 Q2 | 4 |
| 5 | Avangrid | Yes | No | Avangrid terminated the attempt to buy PNM for $8.3 Billion. | 5 |
| 6 | Avista | Yes | Yes | H1 Failed to Buy Avista 2019 | 6 |
| 7 | Black Hills | Yes | Yes | | 7 |
| 8 | CenterPoint | No | No | CenterPoint Acquired Vectren Feb 2019 $6 B Deal, Sold 2 Gas Utilities in AR and OK 2022<br>In 2024 Sold Gas Utilities in LA and MS to Bernard Capital 's Delta Uitilities for $1.2B | 8 |
| 9 | CMS | Yes | No | | 9 |
| 10 | Consol Ed | No | Yes | | 10 |
| 11 | Dominion | Yes | No | ase of Scana, 2020 Sale gas pipeline / storage $9.7B to Berkshire Energy, 9/2023 Sell several gas distribution utilities for | 11 |
| 12 | DTE | Yes | No | 2021 Spun Off subsidiary into DT Midstream NYSE:DTM | 12 |
| 13 | Duke | Yes | No | 12/27/22 GIC Pte. Ltd purchased minor stake in Duke Energy Indiana LLC all-cash valued at $2.05B for a total interest to 19.9%. | 13 |
| 14 | Edison Int'l | No | No | Aug **2000** Bought Citizens Power, Nuclear Gen w San Onofre Nuclear Generation Station (SONGS) | 14 |
| 15 | Entergy | Yes | No | Sold Natural Gas for $1.2B Gas Utility Assets to Bernard Capital 's Delta Ultilities | 15 |
| 16 | Evergy | No | Yes | | 16 |
| 17 | Eversource | No | No | | 17 |
| 18 | Exelon | Yes | No | Exelon completed Spin Off of Nonutility Opertions on Feb. 1, 2022 | 18 |
| 19 | First Energy | No | No | | 19 |
| 20 | Fortis | No | No | | 20 |
| 21 | Hawaiian | No | No | | 21 |
| 22 | IDACORP | Yes | Yes | | 22 |
| 23 | MGE | No | No | | 23 |
| 24 | NextEra | No | No | | 24 |
| 25 | NorthWestern | Yes | Yes | | 25 |
| 26 | OGE | Yes | Yes | | 26 |
| 27 | Otter Tail | Yes | No | | 27 |
| 28 | PG&E | No | No | 2019 Chapter 11 bankruptcy liability for 2017 and 2018 wildfires in CA | 28 |
| 29 | PGE | Yes | Yes | | 29 |
| 30 | Pinnacle | Yes | Yes | | 30 |
| 31 | PNM | Yes | No | Avangrid terminated attempt to buy PNM for $8.3B 2/6/2023. | 31 |
| 32 | PPL | No | No | 2021 Sold operations in UK, Buying Narragansett Electric for $3.8B | 32 |
| 33 | Public Serv. | Yes | Yes | | 33 |
| 34 | Sempra | Yes | Yes | | 34 |
| 35 | Southern | Yes | No | | 35 |
| 36 | WEC | No | Yes | | 36 |
| 37 | Xcel | No | No | | 37 |
| | No. of Peers: | 21 | 14 | *20% of MKT Cap will pass the M&A screen test. | |

**Value Line**
**Historical and Near Term**
**Dividends Declared per Share**
**( Div )**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Staff Sensitivity | | | | | | | | | | |
| | Screen # | Abbreviated Utility | UE 426 IPC | UE 426 Staff | UE 426 LT Debt | 2019 Q1 | 2019 Q2 | 2019 Q3 | 2019 Q4 | 2019 Yr | 2020 Q1 | 2020 Q2 | 2020 Q3 | 2020 Q4 | 2020 Yr |
| 1 | 1 | Allete | Yes | No | No | 0.5875 | 0.5875 | 0.5875 | 0.5875 | 2.35 | 0.6175 | 0.6175 | 0.6175 | 0.6175 | 2.47 |
| 2 | 2 | Alliant | No | Yes | Yes | 0.355 | 0.355 | 0.355 | 0.355 | 1.42 | 0.38 | 0.38 | 0.38 | 0.38 | 1.52 |
| 3 | 3 | Ameren | Yes | Yes | Yes | 0.4750 | 0.4750 | 0.4750 | 0.495 | 1.92 | 0.495 | 0.495 | 0.495 | 0.515 | 2.00 |
| 4 | 4 | AEP | No | No | Yes | 0.670 | 0.670 | 0.670 | 0.700 | 2.71 | 0.700 | 0.700 | 0.700 | 0.740 | 2.84 |
| 5 | 5 | Avangrid | Yes | No | No | 0.44 | 0.44 | 0.44 | 0.44 | 1.76 | 0.4400 | 0.4400 | 0.4400 | 0.4400 | 1.76 |
| 6 | 6 | Avista | Yes | Yes | Yes | 0.3875 | 0.3875 | 0.3875 | 0.3875 | 1.55 | 0.4050 | 0.4050 | 0.4050 | 0.4050 | 1.62 |
| 7 | 7 | Black Hills | Yes | Yes | Yes | 0.505 | 0.505 | 0.505 | 0.535 | 2.05 | 0.535 | 0.535 | 0.535 | 0.565 | 2.17 |
| 8 | 9 | CMS | Yes | No | No | 0.383 | 0.383 | 0.383 | 0.383 | 1.53 | 0.408 | 0.408 | 0.408 | 0.408 | 1.63 |
| 9 | 10 | Consol Ed | No | Yes | Yes | 0.740 | 0.740 | 0.740 | 0.740 | 2.96 | 0.765 | 0.765 | 0.765 | 0.765 | 3.06 |
| 10 | 11 | Dominion | Yes | No | No | 0.9175 | 0.9175 | 0.9175 | 0.9175 | 3.67 | 0.9400 | 0.9400 | 0.9400 | 0.6300 | 3.45 |
| 11 | 12 | DTE | Yes | No | No | 0.945 | 0.945 | 0.945 | 0.945 | 3.78 | 1.0125 | 1.0125 | 1.0125 | 1.0125 | 4.05 |
| 12 | 13 | Duke | Yes | No | Yes | 0.928 | 0.928 | 0.945 | 0.945 | 3.75 | 0.945 | 0.945 | 0.965 | 0.965 | 3.82 |
| 13 | 15 | Entergy | Yes | No | No | 0.910 | 0.910 | 0.910 | 0.930 | 3.66 | 0.930 | 0.930 | 0.930 | 0.950 | 3.74 |
| 14 | 16 | Evergy | No | Yes | Yes | 0.475 | 0.475 | 0.475 | 0.505 | 1.93 | 0.505 | 0.505 | 0.505 | 0.535 | 2.05 |
| 15 | 17 | Eversource | No | No | Yes | 0.535 | 0.535 | 0.535 | 0.535 | 2.14 | 0.568 | 0.568 | 0.568 | 0.568 | 2.27 |
| 16 | 18 | Exelon | Yes | No | No | 0.363 | 0.363 | 0.363 | 0.363 | 1.45 | 0.3825 | 0.3825 | 0.3825 | 0.3825 | 1.53 |
| 17 | 22 | IDACORP | Yes | Yes | Yes | 0.630 | 0.630 | 0.630 | 0.6700 | 2.56 | 0.670 | 0.670 | 0.670 | 0.710 | 2.72 |
| 18 | 25 | NorthWestern | Yes | Yes | Yes | 0.575 | 0.575 | 0.575 | 0.575 | 2.30 | 0.600 | 0.600 | 0.600 | 0.600 | 2.40 |
| 19 | 26 | OGE | Yes | Yes | Yes | 0.3650 | 0.3650 | 0.3650 | 0.388 | 1.48 | 0.388 | 0.388 | 0.388 | 0.403 | 1.57 |
| 20 | 27 | Otter Tail | Yes | No | Yes | 0.350 | 0.350 | 0.350 | 0.3500 | 1.40 | 0.370 | 0.370 | 0.370 | 0.370 | 1.48 |
| 21 | 29 | PGE | Yes | Yes | Yes | 0.363 | 0.363 | 0.385 | 0.385 | 1.50 | 0.385 | 0.385 | 0.385 | 0.4075 | 1.56 |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | 0.737 | 0.738 | 0.738 | 0.782 | 3.00 | 0.783 | 0.783 | 0.783 | 0.830 | 3.18 |
| 23 | 31 | PNM | Yes | No | No | 0.290 | 0.290 | 0.290 | 0.290 | 1.16 | 0.308 | 0.308 | 0.308 | 0.308 | 1.23 |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | 0.47 | 0.47 | 0.47 | 0.47 | 1.88 | 0.49 | 0.49 | 0.49 | 0.49 | 1.96 |
| 25 | 34 | Sempra | Yes | Yes | Yes | 0.8950 | 0.968 | 0.968 | 0.968 | 3.80 | 0.9675 | 1.0450 | 1.0450 | 1.0450 | 4.10 |
| 26 | 35 | Southern | Yes | No | No | 0.600 | 0.620 | 0.620 | 0.620 | 2.46 | 0.620 | 0.640 | 0.640 | 0.640 | 2.54 |
| 27 | 36 | WEC | No | Yes | Yes | 0.5900 | 0.5900 | 0.5900 | 0.5900 | 2.36 | 0.633 | 0.633 | 0.633 | 0.633 | 2.53 |
| 28 | 37 | Xcel | No | No | Yes | 0.380 | 0.405 | 0.405 | 0.405 | 1.60 | 0.405 | 0.430 | 0.430 | 0.430 | 1.70 |
| | | No. of Peers: | 21 | 14 | 19 | | | | | | | | | | |

| 1 | 2 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | Value Line Estimated Dividends | | | | | | VL | VL % Div Growth | | |
| Screen # | Abbreviated Utility | 2021 Q1 | 2021 Q2 | 2021 Q3 | 2021 Q4 | 2021 Yr | 2022 Q1 | 2022 Q2 | 2022 Q3 | 2022 Q4 | 2022 Yr | 2020 - 22 Average | 2023 Yr | 2024 Yr | 2025 Yr | 2026 Yr | 2027 Yr | 2028 Yr | 2026 - 28 Average | 2026 - 28 vs. 2020 - 22 | Screen # | |
| 1 | Allete | 0.630 | 0.630 | 0.630 | 0.630 | 2.52 | 0.650 | 0.650 | 0.650 | 0.650 | 2.60 | 2.53 | 2.71 | 2.79 | 2.86 | 2.93 | 3.00 | 3.07 | 3.00 | 2.9% | 1 | 1 |
| 2 | Alliant | 0.4025 | 0.4025 | 0.4025 | 0.4025 | 1.61 | 0.4275 | 0.4275 | 0.4275 | 0.4275 | 1.71 | 1.61 | 1.81 | 1.92 | 2.04 | 2.16 | 2.29 | 2.42 | 2.29 | 6.0% | 2 | 2 |
| 3 | Ameren | 0.550 | 0.550 | 0.550 | 0.550 | 2.20 | 0.590 | 0.590 | 0.590 | 0.590 | 2.36 | 2.19 | 2.52 | 2.65 | 2.85 | 3.07 | 3.30 | 3.53 | 3.30 | 7.1% | 3 | 3 |
| 4 | AEP | 0.740 | 0.740 | 0.740 | 0.780 | 3.00 | 0.780 | 0.780 | 0.780 | 0.830 | 3.17 | 3.00 | 3.35 | 3.52 | 3.72 | 3.93 | 4.16 | 4.39 | 4.16 | 5.6% | 4 | 4 |
| 5 | Avangrid | 0.44 | 0.44 | 0.44 | 0.44 | 1.76 | 0.4400 | 0.4400 | 0.4400 | 0.4400 | 1.76 | 1.76 | 1.76 | 1.76 | 1.80 | 1.84 | 1.88 | 1.92 | 1.88 | 1.1% | 5 | 5 |
| 6 | Avista | 0.4225 | 0.4225 | 0.4225 | 0.4225 | 1.69 | 0.4400 | 0.4400 | 0.4400 | 0.4400 | 1.76 | 1.69 | 1.84 | 1.92 | 2.01 | 2.10 | 2.20 | 2.30 | 2.20 | 4.5% | 6 | 6 |
| 7 | Black Hills | 0.565 | 0.565 | 0.565 | 0.5960 | 2.29 | 0.595 | 0.595 | 0.595 | 0.625 | 2.41 | 2.29 | 2.53 | 2.65 | 2.76 | 2.88 | 3.01 | 3.14 | 3.01 | 4.7% | 7 | 7 |
| 9 | CMS | 0.435 | 0.435 | 0.435 | 0.435 | 1.74 | 0.46 | 0.46 | 0.46 | 0.46 | 1.84 | 1.74 | 1.95 | 2.04 | 2.12 | 2.21 | 2.30 | 2.39 | 2.30 | 4.8% | 9 | 8 |
| 10 | Consol Ed | 0.775 | 0.775 | 0.775 | 0.775 | 3.10 | 0.790 | 0.790 | 0.790 | 0.790 | 3.16 | 3.11 | 3.24 | 3.34 | 3.51 | 3.68 | 3.86 | 4.04 | 3.86 | 3.7% | 10 | 9 |
| 11 | Dominion | 0.63 | 0.63 | 0.63 | 0.63 | 2.52 | 0.6675 | 0.6675 | 0.6675 | 0.6675 | 2.67 | 2.88 | 2.67 | 2.67 | 2.70 | 2.72 | 2.75 | 2.78 | 2.75 | -0.8% | 11 | 10 |
| 12 | DTE | 0.9225 | 0.9225 | 0.9225 | 0.825 | 3.59 | 0.885 | 0.885 | 0.885 | 0.885 | 3.54 | 3.73 | 3.81 | 4.05 | 4.24 | 4.44 | 4.65 | 4.86 | 4.65 | 3.8% | 12 | 11 |
| 13 | Duke | 0.965 | 0.965 | 0.985 | 0.985 | 3.90 | 0.985 | 0.985 | 1.005 | 1.005 | 3.98 | 3.90 | 4.06 | 4.14 | 4.19 | 4.25 | 4.30 | 4.35 | 4.30 | 1.6% | 13 | 12 |
| 15 | Entergy | 0.950 | 0.950 | 0.950 | 1.010 | 3.86 | 1.010 | 1.010 | 1.010 | 1.070 | 4.10 | 3.90 | 4.34 | 4.56 | 4.70 | 4.85 | 5.00 | 5.15 | 5.00 | 4.2% | 15 | 13 |
| 16 | Evergy | 0.535 | 0.535 | 0.535 | 0.573 | 2.18 | 0.573 | 0.573 | 0.573 | 0.613 | 2.33 | 2.19 | 2.48 | 2.61 | 2.75 | 2.90 | 3.05 | 3.20 | 3.05 | 5.7% | 16 | 14 |
| 17 | Eversource | 0.603 | 0.603 | 0.603 | 0.603 | 2.41 | 0.6375 | 0.6375 | 0.6375 | 0.6375 | 2.55 | 2.41 | 2.70 | 2.86 | 3.04 | 3.22 | 3.42 | 3.62 | 3.42 | 6.0% | 17 | 15 |
| 18 | Exelon | 0.3825 | 0.3825 | 0.3825 | 0.3825 | 1.53 | 0.3375 | 0.3375 | 0.3375 | 0.3375 | 1.35 | 1.47 | 1.44 | 1.60 | 1.66 | 1.73 | 1.80 | 1.87 | 1.80 | 3.4% | 18 | 16 |
| 22 | IDACORP | 0.710 | 0.710 | 0.710 | 0.750 | 2.88 | 0.750 | 0.750 | 0.750 | 0.790 | 3.04 | 2.88 | 3.20 | 3.40 | 3.63 | 3.88 | 4.15 | 4.42 | 4.15 | 6.3% | 22 | 17 |
| 25 | NorthWestern | 0.620 | 0.620 | 0.620 | 0.620 | 2.48 | 0.630 | 0.6300 | 0.6300 | 0.6300 | 2.52 | 2.47 | 2.56 | 2.60 | 2.65 | 2.71 | 2.76 | 2.81 | 2.76 | 1.9% | 25 | 18 |
| 26 | OGE | 0.4025 | 0.4025 | 0.4025 | 0.4100 | 1.62 | 0.4100 | 0.4100 | 0.4100 | 0.41 | 1.64 | 1.61 | 1.66 | 1.78 | 1.80 | 1.83 | 1.85 | 1.87 | 1.85 | 2.4% | 26 | 19 |
| 27 | Otter Tail | 0.390 | 0.390 | 0.390 | 0.390 | 1.56 | 0.4125 | 0.4125 | 0.4125 | 0.4125 | 1.65 | 1.56 | 1.75 | 1.81 | 1.93 | 2.06 | 2.20 | 2.34 | 2.20 | 5.9% | 27 | 20 |
| 29 | PGE | 0.4075 | 0.4075 | 0.430 | 0.430 | 1.68 | 0.430 | 0.430 | 0.4525 | 0.4525 | 1.77 | 1.67 | 1.88 | 1.98 | 2.10 | 2.23 | 2.36 | 2.49 | 2.36 | 6.0% | 29 | 21 |
| 30 | Pinnacle | 0.830 | 0.830 | 0.830 | 0.850 | 3.34 | 0.85 | 0.85 | 0.85 | 0.85 | 3.40 | 3.31 | 3.48 | 3.54 | 3.61 | 3.68 | 3.75 | 3.82 | 3.75 | 2.1% | 30 | 22 |
| 31 | PNM | 0.328 | 0.328 | 0.328 | 0.328 | 1.31 | 0.35 | 0.35 | 0.35 | 0.35 | 1.39 | 3.31 | 1.49 | 1.59 | 1.69 | 1.79 | 1.90 | 2.01 | 1.90 | -8.8% | 31 | 23 |
| 33 | Public Serv. | 0.51 | 0.51 | 0.51 | 0.51 | 2.04 | 0.54 | 0.54 | 0.54 | 0.54 | 2.16 | 2.05 | 2.28 | 2.40 | 2.53 | 2.67 | 2.82 | 2.97 | 2.82 | 5.4% | 33 | 24 |
| 34 | Sempra | 1.045 | 1.100 | 1.100 | 1.100 | 4.35 | 0.550 | 0.573 | 0.573 | 0.573 | 2.27 | 3.57 | 2.38 | 2.50 | 2.67 | 2.85 | 3.05 | 3.25 | 3.05 | -2.6% | 34 | 25 |
| 35 | Southern | 0.640 | 0.660 | 0.660 | 0.660 | 2.62 | 0.66 | 0.68 | 0.68 | 0.68 | 2.70 | 2.62 | 2.78 | 2.86 | 2.94 | 3.02 | 3.10 | 3.18 | 3.10 | 2.8% | 35 | 26 |
| 36 | WEC | 0.6775 | 0.6775 | 0.6775 | 0.6775 | 2.71 | 0.7275 | 0.7275 | 0.7275 | 0.7275 | 2.91 | 2.72 | 3.12 | 3.33 | 3.48 | 3.64 | 3.80 | 3.96 | 3.80 | 5.8% | 36 | 27 |
| 37 | Xcel | 0.430 | 0.458 | 0.458 | 0.458 | 1.80 | 0.4575 | 0.4875 | 0.4875 | 0.4875 | 1.92 | 1.81 | 2.08 | 2.22 | 2.36 | 2.50 | 2.66 | 2.82 | 2.66 | 6.7% | 37 | 28 |

| | Mean |
|---|---|
| Company Screen | 2.8% |
| Staff Screen | 4.2% |
| Staff LT Screen | 4.5% |

# Value Line
# Historical and Near Term
# Earnings Per Share
# ( EPS )

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Staff Sensitivity | | | | | | | | | | | Value Line Estimated EPS | | | | | | | | | | | | | | | | | | | | VL | VL EPS Growth | | |
| | Screen # | Abbreviated Utility | UE 426 IPC | UE 426 Staff | UE 426 LT Debt | 2020 Q1 | 2020 Q2 | 2020 Q3 | 2020 Q4 | 2020 Yr | 2021 Q1 | 2021 Q2 | 2021 Q3 | 2021 Q4 | 2021 Yr | 2022 Q1 | 2022 Q2 | 2022 Q3 | 2022 Q4 | 2022 Yr | 2020 - 22 Average | 2023 Q1 | 2023 Q2 | 2023 Q3 | 2023 Q4 | 2023 Yr | 2024 Q1 | 2024 Q2 | 2024 Q3 | 2024 Q4 | 2024 Yr | 2025 Yr | 2026 Yr | 2027 Yr | 2028 Yr | 2026 - 28 Average | 2026 - 28 vs. 2020 - 22 | Screen # | |
| 1 | 1 | Allete | Yes | No | No | 1.28 | 0.39 | 0.78 | 0.90 | 3.35 | 0.99 | 0.53 | 0.53 | 1.18 | 3.23 | 1.24 | 0.67 | 0.59 | 0.90 | 3.40 | 3.33 | 1.02 | 0.90 | 1.49 | 0.94 | 4.35 | 1.35 | 0.65 | 0.90 | 1.15 | 4.05 | 4.34 | 4.66 | 5.00 | 5.34 | 5.00 | 7.0% | 1 | 1 |
| 2 | 2 | Alliant | No | Yes | Yes | 0.72 | 0.54 | 0.94 | 0.26 | 2.46 | 0.68 | 0.57 | 1.02 | 0.35 | 2.62 | 0.77 | 0.63 | 0.90 | 0.43 | 2.73 | 2.60 | 0.65 | 0.64 | 1.02 | 0.54 | 2.85 | 0.65 | 0.64 | 1.02 | 0.54 | 2.85 | 3.14 | 3.45 | 3.80 | 4.15 | 3.80 | 6.5% | 2 | 2 |
| 3 | 3 | Ameren | Yes | Yes | Yes | 0.59 | 0.98 | 1.47 | 0.46 | 3.50 | 0.91 | 0.80 | 1.65 | 0.48 | 3.84 | 0.97 | 0.80 | 1.74 | 0.63 | 4.14 | 3.83 | 1.00 | 0.90 | 1.87 | 0.63 | 4.40 | 1.03 | 0.90 | 2.00 | 0.77 | 4.70 | 4.95 | 5.22 | 5.50 | 5.78 | 5.50 | 6.2% | 3 | 3 |
| 4 | 4 | AEP | No | No | Yes | 1.00 | 1.05 | 1.50 | 0.87 | 4.42 | 1.15 | 1.15 | 1.59 | 1.07 | 4.96 | 1.22 | 1.20 | 1.62 | 1.05 | 5.09 | 4.82 | 1.11 | 1.13 | 1.77 | 1.24 | 5.25 | 1.35 | 1.35 | 1.75 | 1.15 | 5.60 | 5.97 | 6.37 | 6.80 | 7.23 | 6.80 | 5.9% | 4 | 4 |
| 5 | 5 | Avangrid | Yes | No | No | 0.76 | 0.32 | 0.32 | 0.62 | 2.02 | 1.14 | 0.35 | 0.34 | 0.44 | 2.27 | 1.16 | 0.46 | 0.31 | 0.39 | 2.32 | 2.20 | 0.64 | 0.21 | 0.27 | 0.98 | 2.10 | 0.69 | 0.48 | 0.58 | 0.66 | 2.41 | 2.53 | 2.66 | 2.80 | 2.94 | 2.80 | 4.1% | 5 | 5 |
| 6 | 6 | Avista | Yes | Yes | Yes | 0.72 | 0.26 | 0.07 | 0.85 | 1.90 | 0.98 | 0.20 | 0.20 | 0.71 | 2.09 | 0.99 | 0.16 | -0.08 | 1.05 | 2.12 | 2.04 | 0.73 | 0.23 | 0.15 | 1.19 | 2.30 | 0.75 | 0.25 | 0.25 | 1.25 | 2.50 | 2.63 | 2.76 | 2.90 | 3.04 | 2.90 | 6.1% | 6 | 6 |
| 7 | 7 | Black Hills | Yes | Yes | Yes | 1.59 | 0.33 | 0.58 | 1.23 | 3.73 | 1.54 | 0.40 | 0.70 | 1.11 | 3.75 | 1.82 | 0.52 | 0.54 | 1.11 | 3.99 | 3.82 | 1.73 | 0.35 | 0.52 | 1.15 | 3.75 | 1.77 | 0.43 | 0.55 | 1.15 | 3.90 | 4.09 | 4.29 | 4.50 | 4.71 | 4.50 | 2.8% | 7 | 7 |
| 8 | 9 | CMS | Yes | No | No | 0.85 | 0.48 | 0.76 | 0.55 | 2.64 | 1.09 | 0.55 | 0.54 | 0.40 | 2.58 | 1.20 | 0.50 | 0.56 | 0.58 | 2.84 | 2.69 | 0.69 | 0.67 | 0.60 | 1.09 | 3.05 | 0.75 | 0.70 | 0.75 | 1.10 | 3.30 | 3.44 | 3.59 | 3.75 | 3.91 | 3.75 | 5.7% | 9 | 8 |
| 9 | 10 | Consol Ed | No | Yes | Yes | 1.35 | 0.60 | 1.48 | 0.74 | 4.17 | 1.44 | 0.53 | 1.41 | 1.00 | 4.38 | 1.47 | 0.64 | 1.63 | 0.81 | 4.55 | 4.37 | 1.83 | 0.61 | 1.63 | 0.83 | 4.90 | 1.85 | 0.65 | 1.75 | 0.95 | 5.20 | 5.50 | 5.82 | 6.15 | 6.48 | 6.15 | 5.9% | 10 | 9 |
| 10 | 11 | Dominion | Yes | No | No | 0.92 | 0.73 | 1.08 | 0.81 | 3.54 | 1.09 | 0.76 | 1.11 | 0.90 | 3.86 | 1.18 | 0.77 | 1.11 | 1.06 | 4.12 | 3.84 | 0.99 | 0.53 | 0.80 | 0.83 | 3.15 | 1.02 | 0.60 | 0.85 | 0.88 | 3.35 | 3.55 | 3.77 | 4.00 | 4.23 | 4.00 | 0.7% | 11 | 10 |
| 11 | 12 | DTE | Yes | No | No | 1.76 | 1.44 | 2.26 | 1.42 | 6.88 | 1.65 | 0.60 | 0.30 | 1.55 | 4.10 | 2.03 | 0.19 | 1.99 | 1.31 | 5.52 | 5.50 | 1.33 | 0.99 | 1.44 | 1.99 | 5.75 | 2.30 | 1.20 | 1.90 | 1.30 | 6.70 | 7.20 | 7.73 | 8.30 | 8.87 | 8.30 | 7.1% | 12 | 11 |
| 12 | 13 | Duke | Yes | No | Yes | 1.14 | 1.08 | 1.87 | 1.03 | 5.12 | 1.26 | 1.15 | 1.88 | 0.94 | 5.23 | 1.30 | 1.14 | 1.78 | 1.11 | 5.33 | 5.23 | 1.20 | 0.91 | 1.98 | 1.51 | 5.60 | 1.35 | 1.30 | 2.05 | 1.30 | 6.00 | 6.32 | 6.65 | 7.00 | 7.35 | 7.00 | 5.0% | 13 | 12 |
| 13 | 15 | Entergy | Yes | No | No | 0.59 | 1.79 | 2.59 | 1.93 | 6.90 | 1.66 | 1.30 | 2.63 | 1.28 | 6.87 | 1.36 | 0.78 | 2.74 | 0.51 | 5.39 | 6.39 | 1.47 | 1.84 | 3.14 | 0.80 | 7.25 | 1.50 | 1.05 | 2.95 | 0.95 | 6.45 | 6.78 | 7.13 | 7.50 | 7.87 | 7.50 | 2.7% | 15 | 13 |
| 14 | 16 | Evergy | No | Yes | Yes | 0.31 | 0.59 | 1.60 | 0.22 | 2.72 | 0.84 | 0.81 | 1.95 | 0.23 | 3.83 | 0.53 | 0.84 | 1.86 | 0.03 | 3.26 | 3.27 | 0.62 | 0.78 | 1.53 | 0.67 | 3.60 | 0.65 | 0.80 | 2.00 | 0.40 | 3.85 | 4.16 | 4.49 | 4.85 | 5.21 | 4.85 | 6.8% | 16 | 14 |
| 15 | 17 | Eversource | No | No | Yes | 1.02 | 0.76 | 1.01 | 0.85 | 3.64 | 1.15 | 0.79 | 1.02 | 0.91 | 3.87 | 1.30 | 0.86 | 1.01 | 0.92 | 4.09 | 3.87 | 1.41 | 1.00 | 1.00 | 0.94 | 4.35 | 1.45 | 1.00 | 1.10 | 1.05 | 4.60 | 4.90 | 5.21 | 5.55 | 5.89 | 5.55 | 6.2% | 17 | 15 |
| 16 | 18 | Exelon | Yes | No | No | 0.87 | 0.55 | 1.04 | 0.76 | 3.22 | -0.06 | 0.89 | 1.09 | 0.90 | 2.82 | 0.64 | 0.44 | 0.75 | 0.43 | 2.26 | 2.77 | 0.70 | 0.41 | 0.79 | 0.50 | 2.40 | 0.70 | 0.50 | 0.80 | 0.50 | 2.50 | 2.66 | 2.82 | 3.00 | 3.18 | 3.00 | 1.4% | 18 | 16 |
| 17 | 22 | IDACORP | Yes | Yes | Yes | 0.74 | 1.19 | 2.02 | 0.74 | 4.69 | 0.89 | 1.38 | 1.93 | 0.65 | 4.85 | 0.91 | 1.27 | 2.10 | 0.83 | 5.11 | 4.88 | 1.11 | 1.35 | 1.95 | 0.74 | 5.15 | 1.20 | 1.40 | 2.05 | 0.75 | 5.40 | 5.62 | 5.86 | 6.10 | 6.34 | 6.10 | 3.8% | 22 | 17 |
| 18 | 25 | NorthWestern | Yes | Yes | Yes | 1.00 | 0.43 | 0.58 | 1.21 | 3.22 | 1.24 | 0.59 | 0.70 | 0.97 | 3.50 | 1.08 | 0.58 | 0.47 | 1.16 | 3.29 | 3.34 | 1.10 | 0.32 | 0.88 | 1.15 | 3.45 | 1.10 | 0.50 | 0.85 | 1.15 | 3.60 | 3.77 | 3.96 | 4.15 | 4.34 | 4.15 | 3.7% | 25 | 18 |
| 19 | 26 | OGE | Yes | Yes | Yes | 0.23 | 0.51 | 1.04 | 0.30 | 2.08 | 0.26 | 0.56 | 1.26 | 0.27 | 2.35 | 0.33 | 0.36 | 1.31 | 0.25 | 2.25 | 2.23 | 0.19 | 0.44 | 1.20 | 0.22 | 2.05 | 0.35 | 0.30 | 1.25 | 0.25 | 2.15 | 2.44 | 2.77 | 3.15 | 3.53 | 3.15 | 6.0% | 26 | 19 |
| 20 | 27 | Otter Tail | Yes | No | Yes | 0.60 | 0.42 | 0.87 | 0.45 | 2.34 | 0.73 | 1.01 | 1.26 | 1.23 | 4.23 | 1.72 | 2.05 | 2.01 | 1.00 | 6.78 | 4.45 | 1.49 | 1.95 | 2.19 | 0.77 | 6.40 | 1.00 | 1.10 | 1.20 | 0.70 | 4.00 | 3.88 | 3.76 | 3.65 | 3.54 | 3.65 | -3.2% | 27 | 20 |
| 21 | 29 | PGE | Yes | Yes | Yes | 0.91 | 0.43 | 0.84 | 0.57 | 2.75 | 1.07 | 0.36 | 0.56 | 0.73 | 2.72 | 0.67 | 0.72 | 0.65 | 0.70 | 2.74 | 2.74 | 0.80 | 0.44 | 0.76 | 0.70 | 2.70 | 0.80 | 0.65 | 0.80 | 0.75 | 3.00 | 3.20 | 3.42 | 3.65 | 3.88 | 3.65 | 4.9% | 29 | 21 |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | 0.27 | 1.71 | 3.07 | -0.17 | 4.88 | 0.32 | 1.91 | 3.00 | 0.24 | 5.47 | 0.15 | 1.45 | 2.88 | -0.21 | 4.27 | 4.87 | -0.03 | 0.94 | 3.30 | -0.01 | 4.20 | 0.05 | 1.35 | 3.11 | -0.01 | 4.50 | 4.87 | 5.27 | 5.70 | 6.13 | 5.70 | 2.6% | 30 | 22 |
| 23 | 31 | PNM | Yes | No | No | 0.18 | 0.55 | 1.40 | 0.15 | 2.28 | 0.32 | 0.55 | 1.37 | 0.21 | 2.45 | 0.50 | 0.57 | 1.46 | 0.15 | 2.68 | 2.47 | 0.55 | 0.65 | 1.33 | 0.27 | 2.80 | 0.55 | 0.60 | 1.40 | 0.30 | 2.85 | 3.01 | 3.17 | 3.35 | 3.53 | 3.35 | 5.2% | 31 | 23 |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | 1.03 | 0.79 | 0.96 | 0.65 | 3.43 | 1.26 | 0.70 | 0.98 | 0.69 | 3.63 | 1.33 | 0.64 | 0.86 | 0.64 | 3.47 | 3.51 | 1.39 | 0.70 | 0.85 | 0.56 | 3.50 | 1.40 | 0.75 | 0.85 | 0.70 | 3.70 | 3.92 | 4.15 | 4.40 | 4.65 | 4.40 | 3.8% | 33 | 24 |
| 25 | 34 | Sempra | Yes | Yes | Yes | 1.27 | 0.79 | 0.66 | 0.94 | 3.66 | 1.48 | 0.82 | 0.85 | 1.08 | 4.23 | 1.46 | 0.99 | 0.99 | 1.18 | 4.62 | 4.17 | 1.46 | 0.94 | 0.97 | 1.13 | 4.50 | 1.55 | 1.00 | 1.05 | 1.20 | 4.80 | 5.17 | 5.57 | 6.00 | 6.43 | 6.00 | 6.3% | 34 | 25 |
| 26 | 35 | Southern | Yes | No | No | 0.81 | 0.75 | 1.18 | 0.51 | 3.25 | 1.09 | 0.67 | 1.22 | 0.44 | 3.42 | 0.97 | 1.07 | 1.31 | 0.26 | 3.61 | 3.43 | 0.79 | 0.79 | 1.32 | 0.70 | 3.60 | 1.20 | 1.00 | 1.30 | 0.50 | 4.00 | 4.35 | 4.73 | 5.15 | 5.57 | 5.15 | 7.0% | 35 | 26 |
| 27 | 36 | WEC | No | Yes | Yes | 1.43 | 0.76 | 0.84 | 0.76 | 3.79 | 1.61 | 0.87 | 0.92 | 0.71 | 4.11 | 1.79 | 0.91 | 0.96 | 0.80 | 4.46 | 4.12 | 1.61 | 0.92 | 1.00 | 1.07 | 4.60 | 1.90 | 1.00 | 1.15 | 0.85 | 4.90 | 5.21 | 5.55 | 5.90 | 6.25 | 5.90 | 6.2% | 36 | 27 |
| 28 | 37 | Xcel | No | No | Yes | 0.56 | 0.54 | 1.14 | 0.54 | 2.78 | 0.67 | 0.58 | 1.13 | 0.58 | 2.96 | 0.70 | 0.60 | 1.18 | 0.69 | 3.17 | 2.97 | 0.76 | 0.52 | 1.30 | 0.77 | 3.35 | 0.80 | 0.60 | 1.35 | 0.80 | 3.55 | 3.77 | 4.00 | 4.25 | 4.50 | 4.25 | 6.2% | 37 | 28 |
| | | No. of Peers: | 21 | 14 | 19 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |

| | Mean |
|---|---|
| Company Screen | 4.2% |
| Staff Screen | 5.1% |
| Staff Sensitivity Screen | 4.8% |

$$B_U = \frac{B_L}{[1+(1-T_C)\times(D/E)]}$$

| | Screen # | Abbreviated Utility | IPC Yes | Staff No | LT Debt Staff Sensitivity | Ticker | Yahoo Finance $ Stock Closing Price 1st Trading Day of Month Dec. 12/1/2023 | Jan. 1/1/2024 | Feb. 2/1/2024 | 3-Day Avg $ Stock Price | Div Yield at Recent Price | VL 2024 Return on Common Equity | VL Cap Structure Percentages 2024 % LT Debt | 2024 Common Equity | 2024 Preferred Stock | VL Beta | VL 2024 Tax Rate | 2024 Unlevered Beta | 2024 Relevered Beta Equity at 50.0% | Equity Risk Premium | Hamada 2024 Adjustment Equity at 50.0% | Screen # | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 13 | 14 | 15 | 19 | 20 | 22 | 24 | 26 | 27 | | |
| 1 | 1 | Allete | Yes | No | No | ALE | 61.16 | 59.01 | 59.44 | 59.87 | 4.5% | 8.0% | 39.5 | 60.5 | 0.0 | 0.95 | 0.0% | 0.57 | 115% | 4.50% | 0.90% | 1 | 1 |
| 2 | 2 | Alliant | No | Yes | Yes | LNT | 51.30 | 48.85 | 48.97 | 49.71 | 3.6% | 11.0% | 52.5 | 47.5 | 0.0 | 0.90 | 2.0% | 0.43 | 86% | 4.50% | -0.20% | 2 | 2 |
| 3 | 3 | Ameren | Yes | Yes | Yes | AEE | 72.34 | 69.51 | 70.26 | 70.70 | 3.6% | 11.0% | 53.5 | 46.0 | 0.5 | 0.90 | 12.0% | 0.44 | 83% | 4.50% | -0.30% | 3 | 3 |
| 4 | 4 | AEP | No | No | Yes | AEP | 81.22 | 77.84 | 78.65 | 79.24 | 4.2% | 10.0% | 58.0 | 42.0 | 0.0 | 0.80 | 21.0% | 0.38 | 68% | 4.50% | -0.52% | 4 | 4 |
| 5 | 5 | Avangrid | Yes | No | No | AGR | 32.41 | 30.38 | 30.38 | 31.06 | 5.7% | 4.5% | 32.0 | 68.0 | 0.0 | 0.85 | 7.0% | 0.59 | 114% | 4.50% | 1.31% | 5 | 5 |
| 6 | 6 | Avista | Yes | Yes | Yes | AVA | 35.74 | 33.78 | 33.82 | 34.45 | 5.3% | 7.5% | 50.5 | 49.5 | 0.0 | 0.90 | 15.0% | 0.48 | 89% | 4.50% | -0.04% | 6 | 6 |
| 7 | 7 | Black Hills | Yes | Yes | Yes | BKH | 53.95 | 50.80 | 51.81 | 52.19 | 4.8% | 8.0% | 55.5 | 45.5 | -1.0 | 1.00 | 8.5% | 0.48 | 91% | 4.50% | -0.39% | 7 | 7 |
| 8 | 9 | CMS | Yes | No | No | CMS | 58.07 | 56.39 | 58.09 | 57.52 | 3.4% | 12.0% | 64.0 | 35.0 | 1.0 | 0.85 | 15.0% | 0.33 | 61% | 4.50% | -1.08% | 9 | 8 |
| 9 | 10 | Consol Ed | No | Yes | Yes | ED | 90.97 | 90.02 | 91.82 | 90.94 | 3.6% | 8.5% | 48.0 | 52.0 | 0.0 | 0.75 | 18.0% | 0.43 | 78% | 4.50% | 0.12% | 10 | 9 |
| 10 | 11 | Dominion | Yes | No | No | D | 47.00 | 45.56 | 46.06 | 46.21 | 5.8% | 10.0% | 56.0 | 41.0 | 3.0 | 0.85 | 16.0% | 0.38 | 71% | 4.50% | -0.64% | 11 | 10 |
| 11 | 12 | DTE | Yes | No | No | DTE | 110.26 | 105.42 | 106.38 | 107.35 | 3.5% | 11.5% | 61.5 | 38.5 | 0.0 | 1.00 | 5.0% | 0.40 | 77% | 4.50% | -1.01% | 12 | 11 |
| 12 | 13 | Duke | Yes | No | Yes | DUK | 97.04 | 95.87 | 97.13 | 96.68 | 4.2% | 9.0% | 58.5 | 40.0 | 1.5 | 0.85 | 9.0% | 0.36 | 69% | 4.50% | -0.74% | 13 | 12 |
| 13 | 15 | Entergy | Yes | No | No | ETR | 101.19 | 99.31 | 101.10 | 100.53 | 4.3% | 9.5% | 64.5 | 35.5 | 0.0 | 0.95 | 23.0% | 0.40 | 70% | 4.50% | -1.12% | 15 | 13 |
| 14 | 16 | Evergy | No | Yes | Yes | EVRG | 52.20 | 49.76 | 51.52 | 51.16 | 4.8% | 9.0% | 51.5 | 48.5 | 0.0 | 0.95 | 9.0% | 0.48 | 92% | 4.50% | -0.12% | 16 | 14 |
| 15 | 17 | Eversource | No | No | Yes | ES | 61.72 | 55.12 | 55.49 | 57.44 | 4.7% | 9.5% | 57.0 | 42.5 | 0.5 | 0.90 | 24.0% | 0.44 | 78% | 4.50% | -0.54% | 17 | 15 |
| 16 | 18 | Exelon | Yes | No | No | EXC | 35.90 | 35.01 | 35.03 | 35.31 | 4.1% | 10.0% | 61.0 | 39.0 | 0.0 | 0.00 | 15.0% | 0.00 | 0% | 4.50% | 0.00% | 18 | 16 |
| 17 | 22 | IDACORP | Yes | Yes | Yes | IDA | 98.32 | 92.57 | 94.25 | 95.05 | 3.4% | 9.0% | 47.0 | 53.0 | 0.0 | 0.85 | 13.0% | 0.48 | 90% | 4.50% | 0.21% | 22 | 17 |
| 18 | 25 | NorthWestern | Yes | Yes | Yes | NWE | 50.89 | 47.79 | 48.47 | 49.05 | 5.2% | 7.5% | 46.5 | 53.5 | 0.0 | 0.95 | 6.0% | 0.52 | 101% | 4.50% | 0.29% | 25 | 18 |
| 19 | 26 | OGE | Yes | Yes | Yes | OGE | 34.93 | 32.89 | 33.62 | 33.81 | 4.9% | 12.0% | 52.0 | 48.0 | 0.0 | 1.05 | 12.0% | 0.54 | 101% | 4.50% | -0.18% | 26 | 19 |
| 20 | 27 | Otter Tail | Yes | No | Yes | OTTR | 84.97 | 88.39 | 92.41 | 88.59 | 2.0% | 13.0% | 41.5 | 58.5 | 0.0 | 0.90 | 20.0% | 0.57 | 103% | 4.50% | 0.60% | 27 | 20 |
| 21 | 29 | PGE | Yes | Yes | Yes | POR | 43.34 | 40.93 | 40.11 | 41.46 | 4.5% | 8.5% | 53.5 | 46.5 | 0.0 | 0.90 | 17.5% | 0.46 | 84% | 4.50% | -0.26% | 29 | 21 |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | PNW | 71.84 | 71.37 | 69.92 | 71.04 | 4.9% | 8.0% | 52.5 | 47.5 | 0.0 | 0.95 | 12.0% | 0.48 | 91% | 4.50% | -0.20% | 30 | 22 |
| 23 | 31 | PNM | Yes | No | No | PNM | 41.60 | 36.23 | 36.99 | 38.27 | 3.9% | 10.0% | 62.0 | 37.5 | 0.5 | 0.90 | 16.0% | 0.38 | 69% | 4.50% | -0.95% | 31 | 23 |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | PEG | 61.15 | 57.67 | 58.44 | 59.09 | 3.9% | 12.5% | 53.5 | 46.5 | 0.0 | 0.90 | 20.0% | 0.47 | 84% | 4.50% | -0.25% | 33 | 24 |
| 25 | 34 | Sempra | Yes | Yes | Yes | SRE | 74.73 | 70.91 | 72.01 | 72.55 | 3.3% | 10.5% | 49.0 | 49.5 | 1.5 | 1.00 | 19.0% | 0.55 | 99% | 4.50% | -0.04% | 34 | 25 |
| 26 | 35 | Southern | Yes | No | No | SO | 70.12 | 69.11 | 70.17 | 69.80 | 4.0% | 13.0% | 64.0 | 36.0 | 0.0 | 0.90 | 15.0% | 0.36 | 66% | 4.50% | -1.07% | 35 | 26 |
| 27 | 36 | WEC | No | Yes | Yes | WEC | 84.17 | 79.87 | 81.65 | 81.90 | 3.8% | 12.5% | 55.0 | 44.5 | 0.5 | 0.85 | 19.0% | 0.42 | 77% | 4.50% | -0.38% | 36 | 27 |
| 28 | 37 | Xcel | No | No | Yes | XEL | 61.91 | 59.39 | 60.86 | 60.72 | 3.4% | 10.5% | 58.0 | 42.0 | 0.0 | 0.85 | 0.0% | 0.36 | 71% | 4.50% | -0.61% | 37 | 28 |
| | | No. of Peers: | 21 | 14 | 19 | | | | | | | | | | | | | | | | | | |

| | Mean | | Mean |
|---|---|---|---|
| Company Screen | 46.4% | Company Screen | -0.24% |
| Staff Screen | 48.4% | Staff Screen | -0.12% |
| Staff Sensitivity Screen | 47.5% | Staff Sensitivity Screen | -0.19% |

Unlevered Beta = Levered Beta / (1 + ((1 – Tax Rate) x (Debt/Equity)))

Levered Beta = Unlevered Beta x (1 + ((1 – Tax Rate) x (Debt/Equity)))

*Note: MGE Was Not Covered by VL as of Mar 1, 2023, VL Data Shown is from March 11, 2022 VL Sheet*

CASE: UE 426
WITNESS: MATT MULDOON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 103

# ROE – Three-Stage DCF: Models X and Y

# March 25, 2024

4.46% Annual Growth Rate - Stage 3

**Dividend Growth with Terminal Value as Perpetuity**

## E.O.Y. Cash Flows Staff Model X

| | Screen # | Abbreviated Utility | IPC Yes | Staff No | LT Debt Staff Sensitivity | IRR | Terminal Value as % of $NPV_{DIV}$ | NPV @ IRR | Recent Price* | 2020 (Initial Stage) | 2021 | 2022 | 2023 | 2024 | 2025 (Transition Stage) | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
| 1 | 1 | Allete | Yes | No | No | 8.8% | 30.9% | 0.00 | (59.87) | 2.71 | 2.79 | 2.86 | 2.93 | 3.00 | 3.07 | 3.28 | 3.47 | 3.65 | 3.82 |
| 2 | 2 | Alliant | No | Yes | Yes | 8.6% | 33.1% | 0.00 | (49.71) | 1.81 | 1.92 | 2.04 | 2.16 | 2.29 | 2.42 | 2.64 | 2.84 | 3.01 | 3.15 |
| 3 | 3 | Ameren | Yes | Yes | Yes | 8.8% | 32.2% | 0.00 | (70.70) | 2.52 | 2.65 | 2.85 | 3.07 | 3.30 | 3.53 | 3.89 | 4.20 | 4.46 | 4.66 |
| 4 | 4 | AEP | No | No | Yes | 9.2% | 28.6% | 0.00 | (79.24) | 3.35 | 3.52 | 3.72 | 3.93 | 4.16 | 4.39 | 4.77 | 5.12 | 5.42 | 5.66 |
| 5 | 5 | Avangrid | Yes | No | No | 9.6% | 24.7% | 0.00 | (31.06) | 1.76 | 1.76 | 1.80 | 1.84 | 1.88 | 1.92 | 2.02 | 2.13 | 2.23 | 2.33 |
| 6 | 6 | Avista | Yes | Yes | Yes | 10.1% | 22.3% | 0.00 | (34.45) | 1.84 | 1.92 | 2.01 | 2.10 | 2.20 | 2.30 | 2.48 | 2.65 | 2.80 | 2.92 |
| 7 | 7 | Black Hills | Yes | Yes | Yes | 9.5% | 25.6% | 0.00 | (52.19) | 2.53 | 2.65 | 2.76 | 2.88 | 3.01 | 3.14 | 3.39 | 3.62 | 3.83 | 4.00 |
| 8 | 9 | CMS | Yes | No | No | 8.0% | 38.5% | (0.00) | (57.52) | 1.95 | 2.04 | 2.12 | 2.21 | 2.30 | 2.39 | 2.59 | 2.77 | 2.92 | 3.05 |
| 9 | 10 | Consol Ed | No | Yes | Yes | 8.2% | 36.6% | 0.00 | (90.94) | 3.24 | 3.34 | 3.51 | 3.68 | 3.86 | 4.04 | 4.34 | 4.61 | 4.86 | 5.08 |
| 10 | 11 | Dominion | Yes | No | No | 9.4% | 25.7% | 0.00 | (46.21) | 2.67 | 2.67 | 2.70 | 2.72 | 2.75 | 2.78 | 2.88 | 3.00 | 3.13 | 3.27 |
| 11 | 12 | DTE | Yes | No | No | 8.3% | 36.0% | 0.00 | (107.35) | 3.81 | 4.05 | 4.24 | 4.44 | 4.65 | 4.86 | 5.22 | 5.55 | 5.85 | 6.11 |
| 12 | 13 | Duke | Yes | No | Yes | 8.2% | 35.6% | 0.00 | (96.68) | 4.06 | 4.14 | 4.19 | 4.25 | 4.30 | 4.35 | 4.60 | 4.85 | 5.09 | 5.31 |
| 13 | 15 | Entergy | Yes | No | No | 8.8% | 30.9% | 0.00 | (100.53) | 4.34 | 4.56 | 4.70 | 4.85 | 5.00 | 5.15 | 5.55 | 5.92 | 6.25 | 6.53 |
| 14 | 16 | Evergy | No | Yes | Yes | 9.8% | 24.3% | 0.00 | (51.16) | 2.48 | 2.61 | 2.75 | 2.90 | 3.05 | 3.20 | 3.49 | 3.75 | 3.97 | 4.15 |
| 15 | 17 | Eversource | No | No | Yes | 9.8% | 24.3% | 0.00 | (57.44) | 2.70 | 2.86 | 3.04 | 3.22 | 3.42 | 3.62 | 3.95 | 4.25 | 4.50 | 4.70 |
| 16 | 18 | Exelon | Yes | No | No | 8.9% | 30.4% | 0.00 | (35.31) | 1.44 | 1.60 | 1.66 | 1.73 | 1.80 | 1.87 | 2.00 | 2.13 | 2.24 | 2.34 |
| 17 | 22 | IDACORP | Yes | Yes | Yes | 8.4% | 34.9% | 0.00 | (95.05) | 3.20 | 3.40 | 3.63 | 3.88 | 4.15 | 4.42 | 4.83 | 5.20 | 5.52 | 5.76 |
| 18 | 25 | NorthWestern | Yes | Yes | Yes | 9.2% | 27.1% | 0.00 | (49.05) | 2.56 | 2.60 | 2.65 | 2.71 | 2.76 | 2.81 | 2.98 | 3.14 | 3.30 | 3.45 |
| 19 | 26 | OGE | Yes | Yes | Yes | 9.1% | 28.0% | 0.00 | (33.81) | 1.66 | 1.78 | 1.80 | 1.83 | 1.85 | 1.87 | 1.99 | 2.10 | 2.21 | 2.31 |
| 20 | 27 | Otter Tail | Yes | No | Yes | 6.7% | 54.4% | 0.00 | (88.59) | 1.75 | 1.81 | 1.93 | 2.06 | 2.20 | 2.34 | 2.55 | 2.74 | 2.90 | 3.03 |
| 21 | 29 | PGE | Yes | Yes | Yes | 9.6% | 25.8% | 0.00 | (41.46) | 1.88 | 1.98 | 2.10 | 2.23 | 2.36 | 2.49 | 2.72 | 2.93 | 3.10 | 3.24 |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | 9.0% | 29.3% | 0.00 | (71.04) | 3.48 | 3.54 | 3.61 | 3.68 | 3.75 | 3.82 | 4.06 | 4.28 | 4.50 | 4.70 |
| 23 | 31 | PNM | Yes | No | No | 8.2% | 35.1% | 0.00 | (38.27) | 1.49 | 1.59 | 1.69 | 1.79 | 1.90 | 2.01 | 1.96 | 1.95 | 1.99 | 2.08 |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | 8.7% | 32.0% | 0.00 | (59.09) | 2.28 | 2.40 | 2.53 | 2.67 | 2.82 | 2.97 | 3.23 | 3.46 | 3.66 | 3.83 |
| 25 | 34 | Sempra | Yes | Yes | Yes | 7.9% | 39.0% | 0.00 | (72.55) | 2.38 | 2.50 | 2.67 | 2.85 | 3.05 | 3.25 | 3.32 | 3.43 | 3.56 | 3.71 |
| 26 | 35 | Southern | Yes | No | No | 8.3% | 35.3% | 0.00 | (69.80) | 2.78 | 2.86 | 2.94 | 3.02 | 3.10 | 3.18 | 3.39 | 3.60 | 3.78 | 3.95 |
| 27 | 36 | WEC | No | Yes | Yes | 8.6% | 32.9% | 0.00 | (81.90) | 3.12 | 3.33 | 3.48 | 3.64 | 3.80 | 3.96 | 4.32 | 4.64 | 4.91 | 5.13 |
| 28 | 37 | Xcel | No | No | Yes | 8.5% | 34.6% | 0.00 | (60.72) | 2.08 | 2.22 | 2.36 | 2.50 | 2.66 | 2.82 | 3.09 | 3.33 | 3.54 | 3.69 |
| | | No. of Peers: | 21 | 14 | 19 | | | | | | | | | | | | | | |

| | 2030 (Final Stage) | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2046 Terminal Value | 2049 Div | 2049 Perpetuity | Screen # | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | | |
| 1 | 3.99 | 4.16 | 4.35 | 4.54 | 4.75 | 4.96 | 5.18 | 5.41 | 5.65 | 5.90 | 6.17 | 6.44 | 6.73 | 7.03 | 7.34 | 7.67 | 8.01 | 8.37 | 8.74 | 230.60 | 9.13 | 221.46 | 1 | 1 |
| 2 | 3.29 | 3.43 | 3.59 | 3.75 | 3.91 | 4.09 | 4.27 | 4.46 | 4.66 | 4.87 | 5.08 | 5.31 | 5.55 | 5.80 | 6.05 | 6.32 | 6.61 | 6.90 | 7.21 | 196.50 | 7.53 | 188.97 | 2 | 2 |
| 3 | 4.87 | 5.09 | 5.31 | 5.55 | 5.80 | 6.06 | 6.33 | 6.61 | 6.90 | 7.21 | 7.53 | 7.87 | 8.22 | 8.59 | 8.97 | 9.37 | 9.79 | 10.23 | 10.68 | 282.64 | 11.16 | 271.49 | 3 | 3 |
| 4 | 5.92 | 6.18 | 6.46 | 6.74 | 7.05 | 7.36 | 7.69 | 8.03 | 8.39 | 8.76 | 9.15 | 9.56 | 9.99 | 10.43 | 10.90 | 11.39 | 11.89 | 12.42 | 12.98 | 314.70 | 13.56 | 301.14 | 4 | 4 |
| 5 | 2.43 | 2.54 | 2.65 | 2.77 | 2.89 | 3.02 | 3.16 | 3.30 | 3.44 | 3.60 | 3.76 | 3.93 | 4.10 | 4.28 | 4.47 | 4.67 | 4.88 | 5.10 | 5.33 | 119.26 | 5.56 | 113.69 | 5 | 5 |
| 6 | 3.05 | 3.19 | 3.33 | 3.48 | 3.63 | 3.80 | 3.97 | 4.14 | 4.33 | 4.52 | 4.72 | 4.93 | 5.15 | 5.38 | 5.62 | 5.87 | 6.14 | 6.41 | 6.70 | 137.06 | 6.99 | 130.06 | 6 | 6 |
| 7 | 4.18 | 4.36 | 4.56 | 4.76 | 4.97 | 5.19 | 5.42 | 5.67 | 5.92 | 6.18 | 6.46 | 6.75 | 7.05 | 7.36 | 7.69 | 8.03 | 8.39 | 8.77 | 9.16 | 206.14 | 9.57 | 196.57 | 7 | 7 |
| 8 | 3.19 | 3.33 | 3.48 | 3.64 | 3.80 | 3.97 | 4.14 | 4.33 | 4.52 | 4.72 | 4.93 | 5.15 | 5.38 | 5.62 | 5.87 | 6.14 | 6.41 | 6.70 | 6.99 | 222.82 | 7.31 | 215.51 | 9 | 8 |
| 9 | 5.31 | 5.54 | 5.79 | 6.05 | 6.32 | 6.60 | 6.90 | 7.20 | 7.52 | 7.86 | 8.21 | 8.58 | 8.96 | 9.36 | 9.78 | 10.21 | 10.67 | 11.14 | 11.64 | 353.03 | 12.16 | 340.87 | 10 | 9 |
| 10 | 3.41 | 3.57 | 3.73 | 3.89 | 4.07 | 4.25 | 4.44 | 4.63 | 4.84 | 5.06 | 5.28 | 5.52 | 5.76 | 6.02 | 6.29 | 6.57 | 6.86 | 7.17 | 7.49 | 174.45 | 7.82 | 166.63 | 11 | 10 |
| 11 | 6.39 | 6.67 | 6.97 | 7.28 | 7.61 | 7.94 | 8.30 | 8.67 | 9.06 | 9.46 | 9.88 | 10.32 | 10.78 | 11.26 | 11.77 | 12.29 | 12.84 | 13.41 | 14.01 | 417.23 | 14.63 | 402.60 | 12 | 11 |
| 12 | 5.55 | 5.80 | 6.06 | 6.33 | 6.61 | 6.90 | 7.21 | 7.53 | 7.87 | 8.22 | 8.59 | 8.97 | 9.37 | 9.79 | 10.22 | 10.68 | 11.15 | 11.65 | 12.17 | 366.91 | 12.71 | 354.20 | 13 | 12 |
| 13 | 6.82 | 7.12 | 7.44 | 7.77 | 8.12 | 8.48 | 8.86 | 9.25 | 9.67 | 10.10 | 10.55 | 11.02 | 11.51 | 12.02 | 12.56 | 13.12 | 13.70 | 14.31 | 14.95 | 390.79 | 15.62 | 375.17 | 15 | 13 |
| 14 | 4.33 | 4.52 | 4.73 | 4.94 | 5.16 | 5.39 | 5.63 | 5.88 | 6.14 | 6.42 | 6.70 | 7.00 | 7.31 | 7.64 | 7.98 | 8.34 | 8.71 | 9.10 | 9.50 | 204.63 | 9.92 | 194.71 | 16 | 14 |
| 15 | 4.91 | 5.13 | 5.36 | 5.60 | 5.85 | 6.11 | 6.38 | 6.67 | 6.96 | 7.27 | 7.60 | 7.94 | 8.29 | 8.66 | 9.05 | 9.45 | 9.87 | 10.31 | 10.77 | 231.13 | 11.25 | 219.88 | 17 | 15 |
| 16 | 2.45 | 2.55 | 2.67 | 2.79 | 2.91 | 3.04 | 3.18 | 3.32 | 3.47 | 3.62 | 3.78 | 3.95 | 4.13 | 4.31 | 4.51 | 4.71 | 4.92 | 5.14 | 5.36 | 137.91 | 5.60 | 132.31 | 18 | 16 |
| 17 | 6.02 | 6.29 | 6.57 | 6.86 | 7.17 | 7.49 | 7.82 | 8.17 | 8.53 | 8.91 | 9.31 | 9.73 | 10.16 | 10.61 | 11.09 | 11.58 | 12.10 | 12.64 | 13.20 | 376.19 | 13.79 | 362.40 | 22 | 17 |
| 18 | 3.60 | 3.76 | 3.93 | 4.10 | 4.29 | 4.48 | 4.68 | 4.89 | 5.10 | 5.33 | 5.57 | 5.82 | 6.08 | 6.35 | 6.63 | 6.93 | 7.24 | 7.56 | 7.90 | 188.40 | 8.25 | 180.15 | 25 | 18 |
| 19 | 2.41 | 2.52 | 2.63 | 2.75 | 2.87 | 3.00 | 3.14 | 3.28 | 3.42 | 3.57 | 3.73 | 3.90 | 4.07 | 4.26 | 4.45 | 4.64 | 4.85 | 5.07 | 5.29 | 129.76 | 5.53 | 124.23 | 26 | 19 |
| 20 | 3.17 | 3.31 | 3.46 | 3.61 | 3.77 | 3.94 | 4.12 | 4.30 | 4.49 | 4.69 | 4.90 | 5.12 | 5.35 | 5.59 | 5.84 | 6.10 | 6.37 | 6.65 | 6.95 | 340.58 | 7.26 | 333.32 | 27 | 20 |
| 21 | 3.38 | 3.53 | 3.69 | 3.86 | 4.03 | 4.21 | 4.40 | 4.59 | 4.80 | 5.01 | 5.23 | 5.47 | 5.71 | 5.97 | 6.23 | 6.51 | 6.80 | 7.10 | 7.42 | 166.10 | 7.75 | 158.35 | 29 | 21 |
| 22 | 4.90 | 5.12 | 5.35 | 5.59 | 5.84 | 6.10 | 6.37 | 6.66 | 6.95 | 7.26 | 7.59 | 7.93 | 8.28 | 8.65 | 9.04 | 9.44 | 9.86 | 10.30 | 10.76 | 272.42 | 11.24 | 261.19 | 30 | 22 |
| 23 | 2.18 | 2.27 | 2.37 | 2.48 | 2.59 | 2.71 | 2.83 | 2.95 | 3.09 | 3.22 | 3.37 | 3.52 | 3.67 | 3.84 | 4.01 | 4.19 | 4.37 | 4.57 | 4.77 | 143.55 | 4.99 | 138.57 | 31 | 23 |
| 24 | 4.00 | 4.17 | 4.36 | 4.55 | 4.76 | 4.97 | 5.19 | 5.42 | 5.67 | 5.92 | 6.18 | 6.46 | 6.75 | 7.05 | 7.36 | 7.69 | 8.03 | 8.39 | 8.76 | 232.96 | 9.15 | 223.81 | 33 | 24 |
| 25 | 3.88 | 4.05 | 4.23 | 4.42 | 4.62 | 4.83 | 5.04 | 5.27 | 5.50 | 5.75 | 6.00 | 6.27 | 6.55 | 6.84 | 7.15 | 7.47 | 7.80 | 8.15 | 8.51 | #VALUE! | 8.89 | 269.01 | 34 | 25 |
| 26 | 4.13 | 4.31 | 4.50 | 4.71 | 4.92 | 5.13 | 5.36 | 5.60 | 5.85 | 6.11 | 6.39 | 6.67 | 6.97 | 7.28 | 7.60 | 7.94 | 8.30 | 8.67 | 9.05 | 267.98 | 9.46 | 258.52 | 35 | 26 |
| 27 | 5.36 | 5.60 | 5.85 | 6.11 | 6.38 | 6.67 | 6.97 | 7.28 | 7.60 | 7.94 | 8.29 | 8.66 | 9.05 | 9.45 | 9.88 | 10.32 | 10.78 | 11.26 | 11.76 | 321.40 | 12.28 | 309.11 | 36 | 27 |
| 28 | 3.86 | 4.03 | 4.21 | 4.40 | 4.59 | 4.80 | 5.01 | 5.24 | 5.47 | 5.71 | 5.97 | 6.23 | 6.51 | 6.80 | 7.11 | 7.42 | 7.75 | 8.10 | 8.46 | 240.08 | 8.84 | 231.24 | 37 | 28 |

| Mean IRR | Mean Terminal Value as % of $NPV_{DIV}$ | Mean NPV @ IRR | |
|---|---|---|---|
| 8.74% | 32.07% | 0.00% | Company Screen |
| 8.97% | 30.22% | 0.00% | Staff Screen |
| 8.84% | 31.61% | 0.01% | Staff Sensitivity Screen |

## B.O.Y. Cash Flows Staff Model X

| | Screen # | Abbreviated Utility | IPC Yes | Staff No | LT Debt Staff Sensitivity | IRR | Terminal Value as % of $NPV_{DIV}$ | NPV @ IRR | Recent Price* | 2020 (Initial Stage) | 2021 | 2022 | 2023 | 2024 | 2025 (Transition Stage) | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
| 1 | 1 | Allete | Yes | No | No | 9.0% | 29.5% | 0.00 | (59.87) | 2.79 | 2.86 | 2.93 | 3.00 | 3.07 | 3.28 | 3.47 | 3.65 | 3.82 | 3.99 |
| 2 | 2 | Alliant | No | Yes | Yes | 8.8% | 31.2% | 0.00 | (49.71) | 1.92 | 2.04 | 2.16 | 2.29 | 2.42 | 2.64 | 2.84 | 3.01 | 3.15 | 3.29 |
| 3 | 3 | Ameren | Yes | Yes | Yes | 9.0% | 30.3% | 0.00 | (70.70) | 2.65 | 2.85 | 3.07 | 3.30 | 3.53 | 3.89 | 4.20 | 4.46 | 4.66 | 4.87 |
| 4 | 4 | AEP | No | No | Yes | 9.4% | 26.8% | 0.00 | (79.24) | 3.52 | 3.72 | 3.93 | 4.16 | 4.39 | 4.77 | 5.12 | 5.42 | 5.66 | 5.92 |
| 5 | 5 | Avangrid | Yes | No | No | 9.8% | 23.6% | 0.00 | (31.06) | 1.76 | 1.80 | 1.84 | 1.88 | 1.92 | 2.02 | 2.13 | 2.23 | 2.33 | 2.43 |
| 6 | 6 | Avista | Yes | Yes | Yes | 10.3% | 20.8% | 0.00 | (34.45) | 1.92 | 2.01 | 2.10 | 2.20 | 2.30 | 2.48 | 2.65 | 2.80 | 2.92 | 3.05 |
| 7 | 7 | Black Hills | Yes | Yes | Yes | 9.8% | 24.0% | 0.00 | (52.19) | 2.65 | 2.76 | 2.88 | 3.01 | 3.14 | 3.39 | 3.62 | 3.83 | 4.00 | 4.18 |
| 8 | 9 | CMS | Yes | No | No | 8.2% | 36.8% | 0.00 | (57.52) | 2.04 | 2.12 | 2.21 | 2.30 | 2.39 | 2.59 | 2.77 | 2.92 | 3.05 | 3.19 |
| 9 | 10 | Consol Ed | No | Yes | Yes | 8.4% | 34.9% | 0.00 | (90.94) | 3.34 | 3.51 | 3.68 | 3.86 | 4.04 | 4.34 | 4.61 | 4.86 | 5.08 | 5.31 |
| 10 | 11 | Dominion | Yes | No | No | 9.5% | 24.7% | 0.00 | (46.21) | 2.67 | 2.70 | 2.72 | 2.75 | 2.78 | 2.88 | 3.00 | 3.13 | 3.27 | 3.41 |
| 11 | 12 | DTE | Yes | No | No | 8.4% | 34.2% | 0.00 | (107.35) | 4.05 | 4.24 | 4.44 | 4.65 | 4.86 | 5.22 | 5.55 | 5.85 | 6.11 | 6.39 |
| 12 | 13 | Duke | Yes | No | Yes | 8.4% | 34.3% | 0.00 | (96.68) | 4.14 | 4.19 | 4.25 | 4.30 | 4.35 | 4.60 | 4.85 | 5.09 | 5.31 | 5.55 |
| 13 | 15 | Entergy | Yes | No | No | 9.0% | 29.3% | 0.00 | (100.53) | 4.56 | 4.70 | 4.85 | 5.00 | 5.15 | 5.55 | 5.92 | 6.25 | 6.53 | 6.82 |
| 14 | 16 | Evergy | No | Yes | Yes | 10.0% | 22.6% | 0.00 | (51.16) | 2.61 | 2.75 | 2.90 | 3.05 | 3.20 | 3.49 | 3.75 | 3.97 | 4.15 | 4.33 |
| 15 | 17 | Eversource | No | No | Yes | 10.1% | 22.5% | 0.00 | (57.44) | 2.86 | 3.04 | 3.22 | 3.42 | 3.62 | 3.95 | 4.25 | 4.50 | 4.70 | 4.91 |
| 16 | 18 | Exelon | Yes | No | No | 9.1% | 28.6% | 0.00 | (35.31) | 1.60 | 1.66 | 1.73 | 1.80 | 1.87 | 2.00 | 2.13 | 2.24 | 2.34 | 2.45 |
| 17 | 22 | IDACORP | Yes | Yes | Yes | 8.6% | 32.9% | 0.00 | (95.05) | 3.40 | 3.63 | 3.88 | 4.15 | 4.42 | 4.83 | 5.20 | 5.52 | 5.76 | 6.02 |
| 18 | 25 | NorthWestern | Yes | Yes | Yes | 9.4% | 25.8% | 0.00 | (49.05) | 2.60 | 2.65 | 2.71 | 2.76 | 2.81 | 2.98 | 3.14 | 3.30 | 3.45 | 3.60 |
| 19 | 26 | OGE | Yes | Yes | Yes | 9.3% | 26.7% | 0.00 | (33.81) | 1.78 | 1.80 | 1.83 | 1.85 | 1.87 | 1.99 | 2.10 | 2.21 | 2.31 | 2.41 |
| 20 | 27 | Otter Tail | Yes | No | Yes | 6.8% | 52.7% | (0.00) | (88.59) | 1.81 | 1.93 | 2.06 | 2.20 | 2.34 | 2.55 | 2.74 | 2.90 | 3.03 | 3.17 |
| 21 | 29 | PGE | Yes | Yes | Yes | 9.8% | 24.0% | 0.00 | (41.46) | 1.98 | 2.10 | 2.23 | 2.36 | 2.49 | 2.72 | 2.93 | 3.10 | 3.24 | 3.38 |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | 9.1% | 28.0% | 0.00 | (71.04) | 3.54 | 3.61 | 3.68 | 3.75 | 3.82 | 4.06 | 4.28 | 4.50 | 4.70 | 4.90 |
| 23 | 31 | PNM | Yes | No | No | 8.4% | 33.6% | 0.00 | (38.27) | 1.59 | 1.69 | 1.79 | 1.90 | 2.01 | 1.96 | 1.95 | 1.99 | 2.08 | 2.18 |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | 8.9% | 30.2% | 0.00 | (59.09) | 2.40 | 2.53 | 2.67 | 2.82 | 2.97 | 3.23 | 3.46 | 3.66 | 3.83 | 4.00 |
| 25 | 34 | Sempra | Yes | Yes | Yes | 8.1% | 37.3% | 0.00 | (72.55) | 2.50 | 2.67 | 2.85 | 3.05 | 3.25 | 3.32 | 3.43 | 3.56 | 3.71 | 3.88 |
| 26 | 35 | Southern | Yes | No | No | 8.4% | 33.8% | 0.00 | (69.80) | 2.86 | 2.94 | 3.02 | 3.10 | 3.18 | 3.39 | 3.60 | 3.78 | 3.95 | 4.13 |
| 27 | 36 | WEC | No | Yes | Yes | 8.8% | 31.2% | 0.00 | (81.90) | 3.33 | 3.48 | 3.64 | 3.80 | 3.96 | 4.32 | 4.64 | 4.91 | 5.13 | 5.36 |
| 28 | 37 | Xcel | No | No | Yes | 8.6% | 32.7% | 0.00 | (60.72) | 2.22 | 2.36 | 2.50 | 2.66 | 2.82 | 3.09 | 3.33 | 3.54 | 3.69 | 3.86 |
| | | No. of Peers: | 21 | 14 | 19 | | | | | | | | | | | | | | |

| | 2030 (Final Stage) | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2046 Terminal Value | 2049 Div | 2049 Perpetuity | Screen # | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | | |
| 1 | 4.16 | 4.35 | 4.54 | 4.75 | 4.96 | 5.18 | 5.41 | 5.65 | 5.90 | 6.17 | 6.44 | 6.73 | 7.03 | 7.34 | 7.67 | 8.01 | 8.37 | 8.74 | 9.13 | 231.47 | 9.54 | 221.93 | 1 | 1 |
| 2 | 3.43 | 3.59 | 3.75 | 3.91 | 4.09 | 4.27 | 4.46 | 4.66 | 4.87 | 5.08 | 5.31 | 5.55 | 5.80 | 6.05 | 6.32 | 6.61 | 6.90 | 7.21 | 7.53 | 196.08 | 7.87 | 188.21 | 2 | 2 |
| 3 | 5.09 | 5.31 | 5.55 | 5.80 | 6.06 | 6.33 | 6.61 | 6.90 | 7.21 | 7.53 | 7.87 | 8.22 | 8.59 | 8.97 | 9.37 | 9.79 | 10.23 | 10.68 | 11.16 | 281.62 | 11.66 | 269.96 | 3 | 3 |
| 4 | 6.18 | 6.46 | 6.74 | 7.05 | 7.36 | 7.69 | 8.03 | 8.39 | 8.76 | 9.15 | 9.56 | 9.99 | 10.43 | 10.90 | 11.39 | 11.89 | 12.42 | 12.98 | 13.56 | 314.22 | 14.16 | 300.05 | 4 | 4 |
| 5 | 2.54 | 2.65 | 2.77 | 2.89 | 3.02 | 3.16 | 3.30 | 3.44 | 3.60 | 3.76 | 3.93 | 4.10 | 4.28 | 4.47 | 4.67 | 4.88 | 5.10 | 5.33 | 5.56 | 120.09 | 5.81 | 114.28 | 5 | 5 |
| 6 | 3.19 | 3.33 | 3.48 | 3.63 | 3.80 | 3.97 | 4.14 | 4.33 | 4.52 | 4.72 | 4.93 | 5.15 | 5.38 | 5.62 | 5.87 | 6.14 | 6.41 | 6.70 | 6.99 | 137.11 | 7.31 | 129.81 | 6 | 6 |
| 7 | 4.36 | 4.56 | 4.76 | 4.97 | 5.19 | 5.42 | 5.67 | 5.92 | 6.18 | 6.46 | 6.75 | 7.05 | 7.36 | 7.69 | 8.03 | 8.39 | 8.77 | 9.16 | 9.57 | 206.24 | 9.99 | 196.25 | 7 | 7 |
| 8 | 3.33 | 3.48 | 3.64 | 3.80 | 3.97 | 4.14 | 4.33 | 4.52 | 4.72 | 4.93 | 5.15 | 5.38 | 5.62 | 5.87 | 6.14 | 6.41 | 6.70 | 6.99 | 7.31 | 222.92 | 7.63 | 215.29 | 9 | 8 |
| 9 | 5.54 | 5.79 | 6.05 | 6.32 | 6.60 | 6.90 | 7.20 | 7.52 | 7.86 | 8.21 | 8.58 | 8.96 | 9.36 | 9.78 | 10.21 | 10.67 | 11.14 | 11.64 | 12.16 | 353.19 | 12.70 | 340.48 | 10 | 9 |
| 10 | 3.57 | 3.73 | 3.89 | 4.07 | 4.25 | 4.44 | 4.63 | 4.84 | 5.06 | 5.28 | 5.52 | 5.76 | 6.02 | 6.29 | 6.57 | 6.86 | 7.17 | 7.49 | 7.82 | 176.11 | 8.17 | 167.94 | 11 | 10 |
| 11 | 6.67 | 6.97 | 7.28 | 7.61 | 7.94 | 8.30 | 8.67 | 9.06 | 9.46 | 9.88 | 10.32 | 10.78 | 11.26 | 11.77 | 12.29 | 12.84 | 13.41 | 14.01 | 14.63 | 417.11 | 15.29 | 401.82 | 12 | 11 |
| 12 | 5.80 | 6.06 | 6.33 | 6.61 | 6.90 | 7.21 | 7.53 | 7.87 | 8.22 | 8.59 | 8.97 | 9.37 | 9.79 | 10.22 | 10.68 | 11.15 | 11.65 | 12.17 | 12.71 | 368.93 | 13.28 | 355.64 | 13 | 12 |
| 13 | 7.12 | 7.44 | 7.77 | 8.12 | 8.48 | 8.86 | 9.25 | 9.67 | 10.10 | 10.55 | 11.02 | 11.51 | 12.02 | 12.56 | 13.12 | 13.70 | 14.31 | 14.95 | 15.62 | 391.48 | 16.32 | 375.16 | 15 | 13 |
| 14 | 4.52 | 4.73 | 4.94 | 5.16 | 5.39 | 5.63 | 5.88 | 6.14 | 6.42 | 6.70 | 7.00 | 7.31 | 7.64 | 7.98 | 8.34 | 8.71 | 9.10 | 9.50 | 9.92 | 204.37 | 10.37 | 194.00 | 16 | 14 |
| 15 | 5.13 | 5.36 | 5.60 | 5.85 | 6.11 | 6.38 | 6.67 | 6.96 | 7.27 | 7.60 | 7.94 | 8.29 | 8.66 | 9.05 | 9.45 | 9.87 | 10.31 | 10.77 | 11.25 | 230.54 | 11.75 | 218.78 | 17 | 15 |
| 16 | 2.55 | 2.67 | 2.79 | 2.91 | 3.04 | 3.18 | 3.32 | 3.47 | 3.62 | 3.78 | 3.95 | 4.13 | 4.31 | 4.51 | 4.71 | 4.92 | 5.14 | 5.36 | 5.60 | 137.77 | 5.85 | 131.91 | 18 | 16 |
| 17 | 6.29 | 6.57 | 6.86 | 7.17 | 7.49 | 7.82 | 8.17 | 8.53 | 8.91 | 9.31 | 9.73 | 10.16 | 10.61 | 11.09 | 11.58 | 12.10 | 12.64 | 13.20 | 13.79 | 375.09 | 14.41 | 360.68 | 22 | 17 |
| 18 | 3.76 | 3.93 | 4.10 | 4.29 | 4.48 | 4.68 | 4.89 | 5.10 | 5.33 | 5.57 | 5.82 | 6.08 | 6.35 | 6.63 | 6.93 | 7.24 | 7.56 | 7.90 | 8.25 | 189.49 | 8.62 | 180.88 | 25 | 18 |
| 19 | 2.52 | 2.63 | 2.75 | 2.87 | 3.00 | 3.14 | 3.28 | 3.42 | 3.57 | 3.73 | 3.90 | 4.07 | 4.26 | 4.45 | 4.64 | 4.85 | 5.07 | 5.29 | 5.53 | 130.29 | 5.78 | 124.51 | 26 | 19 |
| 20 | 3.31 | 3.46 | 3.61 | 3.77 | 3.94 | 4.12 | 4.30 | 4.49 | 4.69 | 4.90 | 5.12 | 5.35 | 5.59 | 5.84 | 6.10 | 6.37 | 6.65 | 6.95 | 7.26 | 340.13 | 7.58 | 332.55 | 27 | 20 |
| 21 | 3.53 | 3.69 | 3.86 | 4.03 | 4.21 | 4.40 | 4.59 | 4.80 | 5.01 | 5.23 | 5.47 | 5.71 | 5.97 | 6.23 | 6.51 | 6.80 | 7.10 | 7.42 | 7.75 | 165.74 | 8.10 | 157.65 | 29 | 21 |
| 22 | 5.12 | 5.35 | 5.59 | 5.84 | 6.10 | 6.37 | 6.66 | 6.95 | 7.26 | 7.59 | 7.93 | 8.28 | 8.65 | 9.04 | 9.44 | 9.86 | 10.30 | 10.76 | 11.24 | 273.90 | 11.74 | 262.16 | 30 | 22 |
| 23 | 2.27 | 2.37 | 2.48 | 2.59 | 2.71 | 2.83 | 2.95 | 3.09 | 3.22 | 3.37 | 3.52 | 3.67 | 3.84 | 4.01 | 4.19 | 4.37 | 4.57 | 4.77 | 4.99 | 143.84 | 5.21 | 138.63 | 31 | 23 |
| 24 | 4.17 | 4.36 | 4.55 | 4.76 | 4.97 | 5.19 | 5.42 | 5.67 | 5.92 | 6.18 | 6.46 | 6.75 | 7.05 | 7.36 | 7.69 | 8.03 | 8.39 | 8.76 | 9.15 | 232.66 | 9.56 | 223.10 | 33 | 24 |
| 25 | 4.05 | 4.23 | 4.42 | 4.62 | 4.83 | 5.04 | 5.27 | 5.50 | 5.75 | 6.00 | 6.27 | 6.55 | 6.84 | 7.15 | 7.47 | 7.80 | 8.15 | 8.51 | 8.89 | 277.85 | 9.29 | 268.57 | 34 | 25 |
| 26 | 4.31 | 4.50 | 4.71 | 4.92 | 5.13 | 5.36 | 5.60 | 5.85 | 6.11 | 6.39 | 6.67 | 6.97 | 7.28 | 7.60 | 7.94 | 8.30 | 8.67 | 9.05 | 9.46 | 268.82 | 9.88 | 258.94 | 35 | 26 |
| 27 | 5.60 | 5.85 | 6.11 | 6.38 | 6.67 | 6.97 | 7.28 | 7.60 | 7.94 | 8.29 | 8.66 | 9.05 | 9.45 | 9.88 | 10.32 | 10.78 | 11.26 | 11.76 | 12.28 | 321.14 | 12.83 | 308.31 | 36 | 27 |
| 28 | 4.03 | 4.21 | 4.40 | 4.59 | 4.80 | 5.01 | 5.24 | 5.47 | 5.71 | 5.97 | 6.23 | 6.51 | 6.80 | 7.11 | 7.42 | 7.75 | 8.10 | 8.46 | 8.84 | 239.46 | 9.23 | 230.23 | 37 | 28 |

| Mean IRR | Mean Terminal Value as % of $NPV_{DIV}$ | Mean NPV @ IRR | |
|---|---|---|---|
| 8.93% | 30.53% | -0.02% | Company Screen |
| 9.18% | 28.56% | 0.00% | Staff Screen |
| 9.04% | 29.95% | -0.02% | Staff Sensitivity Screen |

## Average B.O.Y. & E.O.Y. Cash Flows Model X

| | 1 | 2 | 3 | 4 | | 5 | 6 | 7 | 8 | 9 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Screen # | Abbreviated Utility | IPC Yes | Staff No | LT Debt Staff Sensitivity | Average IRR | Terminal Value as % of $NPV_{DIV}$ | Average 2020- 2024 Dividend Growth Rates EOY | BOY | Average | Screen # | |
| 1 | 1 | Allete | Yes | No | No | 8.9% | 30.2% | 2.6% | 2.4% | 2.5% | 1 | 1 |
| 2 | 2 | Alliant | No | Yes | Yes | 8.7% | 32.1% | 6.1% | 6.0% | 6.0% | 2 | 2 |
| 3 | 3 | Ameren | Yes | Yes | Yes | 8.9% | 31.2% | 7.0% | 7.5% | 7.2% | 3 | 3 |
| 4 | 4 | AEP | No | No | Yes | 9.3% | 27.7% | 5.6% | 5.6% | 5.6% | 4 | 4 |
| 5 | 5 | Avangrid | Yes | No | No | 9.7% | 24.1% | 1.7% | 2.2% | 1.9% | 5 | 5 |
| 6 | 6 | Avista | Yes | Yes | Yes | 10.2% | 21.5% | 4.6% | 4.6% | 4.6% | 6 | 6 |
| 7 | 7 | Black Hills | Yes | Yes | Yes | 9.7% | 24.8% | 4.4% | 4.3% | 4.4% | 7 | 7 |
| 8 | 9 | CMS | Yes | No | No | 8.1% | 37.6% | 4.2% | 4.0% | 4.1% | 9 | 8 |
| 9 | 10 | Consol Ed | No | Yes | Yes | 8.3% | 35.8% | 4.5% | 4.9% | 4.7% | 10 | 9 |
| 10 | 11 | Dominion | Yes | No | No | 9.5% | 25.2% | 0.7% | 1.0% | 0.9% | 11 | 10 |
| 11 | 12 | DTE | Yes | No | No | 8.3% | 35.1% | 5.1% | 4.7% | 4.9% | 12 | 11 |
| 12 | 13 | Duke | Yes | No | Yes | 8.3% | 34.9% | 1.4% | 1.3% | 1.4% | 13 | 12 |
| 13 | 15 | Entergy | Yes | No | No | 8.9% | 30.1% | 3.6% | 3.1% | 3.3% | 15 | 13 |
| 14 | 16 | Evergy | No | Yes | Yes | 9.9% | 23.5% | 5.3% | 5.3% | 5.3% | 16 | 14 |
| 15 | 17 | Eversource | No | No | Yes | 9.9% | 23.4% | 6.1% | 6.1% | 6.1% | 17 | 15 |
| 16 | 18 | Exelon | Yes | No | No | 9.0% | 29.5% | 5.7% | 4.0% | 4.9% | 18 | 16 |
| 17 | 22 | IDACORP | Yes | Yes | Yes | 8.5% | 33.9% | 6.7% | 6.8% | 6.7% | 22 | 17 |
| 18 | 25 | NorthWestern | Yes | Yes | Yes | 9.3% | 26.4% | 1.9% | 2.0% | 1.9% | 25 | 18 |
| 19 | 26 | OGE | Yes | Yes | Yes | 9.2% | 27.4% | 2.7% | 1.3% | 2.0% | 26 | 19 |
| 20 | 27 | Otter Tail | Yes | No | Yes | 6.8% | 53.6% | 5.9% | 6.6% | 6.3% | 27 | 20 |
| 21 | 29 | PGE | Yes | Yes | Yes | 9.7% | 24.9% | 5.8% | 5.9% | 5.9% | 29 | 21 |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | 9.0% | 28.6% | 1.9% | 1.9% | 1.9% | 30 | 22 |
| 23 | 31 | PNM | Yes | No | No | 8.3% | 34.3% | 6.3% | 6.0% | 6.1% | 31 | 23 |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | 8.8% | 31.1% | 5.5% | 5.5% | 5.5% | 33 | 24 |
| 25 | 34 | Sempra | Yes | Yes | Yes | 8.0% | 38.1% | 6.4% | 6.7% | 6.6% | 34 | 25 |
| 26 | 35 | Southern | Yes | No | No | 8.4% | 34.5% | 2.8% | 2.7% | 2.7% | 35 | 26 |
| 27 | 36 | WEC | No | Yes | Yes | 8.7% | 32.0% | 5.1% | 4.5% | 4.8% | 36 | 27 |
| 28 | 37 | Xcel | No | No | Yes | 8.6% | 33.7% | 6.3% | 6.1% | 6.2% | 37 | 28 |
| | | No. of Peers: | 21 | 14 | 19 | Mean | | | | | | |
| | | | | | | 8.83% | 31.30% | 4.14% | Company Screen | | | |
| | | | | | | 9.07% | 29.39% | 4.84% | Staff Screen | | | |
| | | | | | | 8.94% | 30.78% | 4.90% | Staff Sensitivity Screen | | | |

4.58% Annual Growth Rate - Stage 3

EPS Growth to Determine a Sale Terminal Value

EPS Growth

# E.O.Y. Cash Flows Staff Model Y

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Screen # | Abbreviated Utility | IPC Peers | Staff Peers | LT Debt Staff Sensitivity | IRR | Terminal Value as % of NPV$_{DIV}$ | NPV @ IRR | Recent Price* | 2020 Initial Stage | 2021 | 2022 | 2023 | 2024 | 2025 Transition Stage | 2026 | 2027 | 2028 | 2029 |
| 1 | 1 | Allete | Yes | No | No | 9.0% | 32.3% | 0.00 | (59.87) | 2.71 | 2.79 | 2.86 | 2.93 | 3.00 | 3.07 | 3.28 | 3.48 | 3.67 | 3.83 |
| | | | | e | e | | | | | 4.35 | 4.05 | 4.34 | 4.66 | 5.00 | 5.34 | 5.88 | 6.36 | 6.76 | 7.07 |
| 2 | 2 | Alliant | No | Yes | Yes | 9.2% | 36.5% | 0.00 | (49.71) | 1.81 | 1.92 | 2.04 | 2.16 | 2.29 | 2.42 | 2.64 | 2.85 | 3.02 | 3.16 |
| | | | | e | e | | | | | 2.85 | 2.85 | 3.14 | 3.45 | 3.80 | 4.15 | 4.55 | 4.91 | 5.21 | 5.45 |
| 3 | 3 | Ameren | Yes | Yes | Yes | 9.0% | 34.0% | 0.00 | (70.70) | 2.52 | 2.65 | 2.85 | 3.07 | 3.30 | 3.53 | 3.89 | 4.21 | 4.48 | 4.68 |
| | | | | e | e | | | | | 4.40 | 4.70 | 4.95 | 5.22 | 5.50 | 5.78 | 6.33 | 6.82 | 7.24 | 7.57 |
| 4 | 4 | AEP | No | No | Yes | 9.5% | 31.0% | 0.00 | (79.24) | 3.35 | 3.52 | 3.72 | 3.93 | 4.16 | 4.39 | 4.78 | 5.13 | 5.44 | 5.69 |
| | | | | e | e | | | | | 5.25 | 5.60 | 5.97 | 6.37 | 6.80 | 7.23 | 7.89 | 8.49 | 9.01 | 9.42 |
| 5 | 5 | Avangrid | Yes | No | No | 10.0% | 27.3% | 0.00 | (31.06) | 1.76 | 1.76 | 1.80 | 1.84 | 1.88 | 1.92 | 2.03 | 2.13 | 2.23 | 2.34 |
| | | | | e | e | | | | | 2.10 | 2.41 | 2.53 | 2.66 | 2.80 | 2.94 | 3.16 | 3.38 | 3.57 | 3.73 |
| 6 | 6 | Avista | Yes | Yes | Yes | 10.4% | 24.0% | 0.00 | (34.45) | 1.84 | 1.92 | 2.01 | 2.10 | 2.20 | 2.30 | 2.48 | 2.65 | 2.81 | 2.94 |
| | | | | e | e | | | | | 2.30 | 2.50 | 2.63 | 2.76 | 2.90 | 3.04 | 3.32 | 3.58 | 3.80 | 3.97 |
| 7 | 7 | Black Hills | Yes | Yes | Yes | 9.7% | 26.2% | 0.00 | (52.19) | 2.53 | 2.65 | 2.76 | 2.88 | 3.01 | 3.14 | 3.39 | 3.63 | 3.84 | 4.02 |
| | | | | e | e | | | | | 3.75 | 3.90 | 4.09 | 4.29 | 4.50 | 4.71 | 5.03 | 5.33 | 5.61 | 5.87 |
| 8 | 9 | CMS | Yes | No | No | 8.3% | 40.1% | 0.00 | (57.52) | 1.95 | 2.04 | 2.12 | 2.21 | 2.30 | 2.39 | 2.59 | 2.77 | 2.93 | 3.07 |
| | | | | e | e | | | | | 3.05 | 3.30 | 3.44 | 3.59 | 3.75 | 3.91 | 4.26 | 4.58 | 4.86 | 5.08 |
| 9 | 10 | Consol Ed | No | Yes | Yes | 8.6% | 38.8% | 0.00 | (90.94) | 3.24 | 3.34 | 3.51 | 3.68 | 3.86 | 4.04 | 4.34 | 4.63 | 4.88 | 5.10 |
| | | | | e | e | | | | | 4.90 | 5.20 | 5.50 | 5.82 | 6.15 | 6.48 | 7.08 | 7.62 | 8.08 | 8.45 |
| 10 | 11 | Dominion | Yes | No | No | 9.6% | 27.3% | 0.00 | (46.21) | 2.67 | 2.67 | 2.70 | 2.72 | 2.75 | 2.78 | 2.89 | 3.01 | 3.14 | 3.28 |
| | | | | e | e | | | | | 3.15 | 3.35 | 3.55 | 3.77 | 4.00 | 4.23 | 4.45 | 4.67 | 4.89 | 5.11 |
| 11 | 12 | DTE | Yes | No | No | 9.0% | 40.7% | 0.00 | (107.35) | 3.81 | 4.05 | 4.24 | 4.44 | 4.65 | 4.86 | 5.22 | 5.57 | 5.87 | 6.14 |
| | | | | e | e | | | | | 5.75 | 6.70 | 7.20 | 7.73 | 8.30 | 8.87 | 9.77 | 10.57 | 11.25 | 11.76 |
| 12 | 13 | Duke | Yes | No | Yes | 8.6% | 37.7% | 0.00 | (96.68) | 4.06 | 4.14 | 4.19 | 4.25 | 4.30 | 4.35 | 4.61 | 4.86 | 5.10 | 5.34 |
| | | | | e | e | | | | | 5.60 | 6.00 | 6.32 | 6.65 | 7.00 | 7.35 | 7.97 | 8.54 | 9.04 | 9.46 |
| 13 | 15 | Entergy | Yes | No | No | 8.7% | 29.5% | 0.00 | (100.53) | 4.34 | 4.56 | 4.70 | 4.85 | 5.00 | 5.15 | 5.56 | 5.93 | 6.27 | 6.56 |
| | | | | e | e | | | | | 7.25 | 6.45 | 6.78 | 7.13 | 7.50 | 7.87 | 8.40 | 8.90 | 9.37 | 9.80 |
| 14 | 16 | Evergy | No | Yes | Yes | 10.2% | 27.3% | 0.00 | (51.16) | 2.48 | 2.61 | 2.75 | 2.90 | 3.05 | 3.20 | 3.49 | 3.76 | 3.98 | 4.17 |
| | | | | e | e | | | | | 3.60 | 3.85 | 4.16 | 4.49 | 4.85 | 5.21 | 5.72 | 6.19 | 6.58 | 6.88 |
| 15 | 17 | Eversource | No | No | Yes | 10.1% | 26.3% | 0.00 | (57.44) | 2.70 | 2.86 | 3.04 | 3.22 | 3.42 | 3.62 | 3.95 | 4.26 | 4.52 | 4.72 |
| | | | | e | e | | | | | 4.35 | 4.60 | 4.90 | 5.21 | 5.55 | 5.89 | 6.44 | 6.94 | 7.37 | 7.71 |
| 16 | 18 | Exelon | Yes | No | No | 9.1% | 31.5% | 0.00 | (35.31) | 1.44 | 1.60 | 1.66 | 1.73 | 1.80 | 1.87 | 2.01 | 2.13 | 2.25 | 2.35 |
| | | | | e | e | | | | | 2.40 | 2.50 | 2.66 | 2.82 | 3.00 | 3.18 | 3.36 | 3.53 | 3.71 | 3.88 |
| 17 | 22 | IDACORP | Yes | Yes | Yes | 8.6% | 35.2% | 0.00 | (95.05) | 3.20 | 3.40 | 3.63 | 3.88 | 4.15 | 4.42 | 4.83 | 5.21 | 5.53 | 5.79 |
| | | | | e | e | | | | | 5.15 | 5.40 | 5.62 | 5.86 | 6.10 | 6.34 | 6.82 | 7.27 | 7.67 | 8.02 |
| 18 | 25 | NorthWestern | Yes | Yes | Yes | 9.5% | 28.2% | 0.00 | (49.05) | 2.56 | 2.60 | 2.65 | 2.71 | 2.76 | 2.81 | 2.98 | 3.15 | 3.31 | 3.46 |
| | | | | e | e | | | | | 3.45 | 3.60 | 3.77 | 3.96 | 4.15 | 4.34 | 4.67 | 4.97 | 5.24 | 5.49 |
| 19 | 26 | OGE | Yes | Yes | Yes | 10.0% | 34.0% | 0.00 | (33.81) | 1.66 | 1.78 | 1.80 | 1.83 | 1.85 | 1.87 | 1.99 | 2.11 | 2.22 | 2.32 |
| | | | | e | e | | | | | 2.05 | 2.15 | 2.44 | 2.77 | 3.15 | 3.53 | 3.85 | 4.15 | 4.40 | 4.60 |
| 20 | 27 | Otter Tail | Yes | No | Yes | 4.9% | 40.6% | 0.00 | (88.59) | 1.75 | 1.81 | 1.93 | 2.06 | 2.20 | 2.34 | 2.55 | 2.75 | 2.91 | 3.05 |
| | | | | e | e | | | | | 6.40 | 4.00 | 3.88 | 3.76 | 3.65 | 3.54 | 3.61 | 3.71 | 3.85 | 4.03 |
| 21 | 29 | PGE | Yes | Yes | Yes | 10.0% | 28.4% | 0.00 | (41.46) | 1.88 | 1.98 | 2.10 | 2.23 | 2.36 | 2.49 | 2.72 | 2.93 | 3.11 | 3.25 |
| | | | | e | e | | | | | 2.70 | 3.00 | 3.20 | 3.42 | 3.65 | 3.88 | 4.21 | 4.51 | 4.77 | 4.99 |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | 9.4% | 32.3% | 0.00 | (71.04) | 3.48 | 3.54 | 3.61 | 3.68 | 3.75 | 3.82 | 4.06 | 4.29 | 4.51 | 4.72 |
| | | | | e | e | | | | | 4.20 | 4.50 | 4.87 | 5.27 | 5.70 | 6.13 | 6.54 | 6.93 | 7.29 | 7.63 |
| 23 | 31 | PNM | Yes | No | No | 8.5% | 36.8% | 0.00 | (38.27) | 1.49 | 1.59 | 1.69 | 1.79 | 1.90 | 2.01 | 1.96 | 1.96 | 2.00 | 2.09 |
| | | | | e | e | | | | | 2.80 | 2.85 | 3.01 | 3.17 | 3.35 | 3.53 | 3.83 | 4.11 | 4.35 | 4.55 |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | 9.0% | 33.5% | 0.00 | (59.09) | 2.28 | 2.40 | 2.53 | 2.67 | 2.82 | 2.97 | 3.23 | 3.47 | 3.67 | 3.84 |
| | | | | e | e | | | | | 3.50 | 3.70 | 3.92 | 4.15 | 4.40 | 4.65 | 5.00 | 5.33 | 5.62 | 5.88 |
| 25 | 34 | Sempra | Yes | Yes | Yes | 8.5% | 42.6% | 0.00 | (72.55) | 2.38 | 2.50 | 2.67 | 2.85 | 3.05 | 3.25 | 3.33 | 3.43 | 3.57 | 3.73 |
| | | | | e | e | | | | | 4.50 | 4.80 | 5.17 | 5.57 | 6.00 | 6.43 | 7.04 | 7.59 | 8.06 | 8.42 |
| 26 | 35 | Southern | Yes | No | No | 9.0% | 40.1% | 0.00 | (69.80) | 2.78 | 2.86 | 2.94 | 3.02 | 3.10 | 3.18 | 3.40 | 3.60 | 3.80 | 3.97 |
| | | | | e | e | | | | | 3.60 | 4.00 | 4.35 | 4.73 | 5.15 | 5.57 | 6.13 | 6.63 | 7.05 | 7.37 |
| 27 | 36 | WEC | No | Yes | Yes | 9.0% | 35.4% | 0.00 | (81.90) | 3.12 | 3.33 | 3.48 | 3.64 | 3.80 | 3.96 | 4.32 | 4.65 | 4.93 | 5.16 |
| | | | | e | e | | | | | 4.60 | 4.90 | 5.21 | 5.55 | 5.90 | 6.25 | 6.84 | 7.37 | 7.83 | 8.18 |
| 28 | 37 | Xcel | No | No | Yes | 8.8% | 36.8% | 0.00 | (60.72) | 2.08 | 2.22 | 2.36 | 2.50 | 2.66 | 2.82 | 3.09 | 3.34 | 3.55 | 3.71 |
| | | | | e | e | | | | | 3.35 | 3.55 | 3.77 | 4.00 | 4.25 | 4.50 | 4.92 | 5.30 | 5.63 | 5.88 |
| | | No. of Peers: | 21 | 14 | 19 | | | | | | | | | | | | | | |

| | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Abbreviated Utility | 2030 Final Stage | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2046 Terminal Value | 2049 Div | 2049 Sale | 2050 | Screen # | |
| Allete | 4.01 | 4.19 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.74 | 6.00 | 6.27 | 6.56 | 6.86 | 7.18 | 7.51 | 7.85 | 8.21 | 8.59 | 8.98 | 258.65 | 9.39 | 249.26 | | 1 | 1 |
| | 7.40 | 7.73 | 8.09 | 8.46 | 8.85 | 9.25 | 9.67 | 10.12 | 10.58 | 11.07 | 11.57 | 12.10 | 12.66 | 13.24 | 13.84 | 14.48 | 15.14 | 15.83 | 16.56 | | 17.32 | | 18.11 | | |
| Alliant | 3.31 | 3.46 | 3.61 | 3.78 | 3.95 | 4.13 | 4.32 | 4.52 | 4.73 | 4.95 | 5.17 | 5.41 | 5.66 | 5.92 | 6.19 | 6.47 | 6.77 | 7.08 | 7.40 | 251.31 | 7.74 | 243.57 | | 2 | 2 |
| | 5.70 | 5.96 | 6.24 | 6.52 | 6.82 | 7.13 | 7.46 | 7.80 | 8.16 | 8.53 | 8.92 | 9.33 | 9.76 | 10.21 | 10.68 | 11.16 | 11.68 | 12.21 | 12.77 | | 13.35 | | 13.97 | | |
| Ameren | 4.90 | 5.12 | 5.36 | 5.60 | 5.86 | 6.13 | 6.41 | 6.70 | 7.01 | 7.33 | 7.67 | 8.02 | 8.38 | 8.77 | 9.17 | 9.59 | 10.03 | 10.49 | 10.97 | 323.05 | 11.47 | 311.58 | | 3 | 3 |
| | 7.92 | 8.28 | 8.66 | 9.06 | 9.47 | 9.91 | 10.36 | 10.83 | 11.33 | 11.85 | 12.39 | 12.96 | 13.55 | 14.17 | 14.82 | 15.50 | 16.21 | 16.95 | 17.73 | | 18.54 | | 19.39 | | |
| AEP | 5.95 | 6.22 | 6.51 | 6.81 | 7.12 | 7.44 | 7.79 | 8.14 | 8.52 | 8.91 | 9.31 | 9.74 | 10.19 | 10.65 | 11.14 | 11.65 | 12.18 | 12.74 | 13.33 | 378.00 | 13.94 | 364.07 | | 4 | 4 |
| | 9.85 | 10.30 | 10.77 | 11.27 | 11.78 | 12.32 | 12.89 | 13.48 | 14.09 | 14.74 | 15.41 | 16.12 | 16.86 | 17.63 | 18.44 | 19.28 | 20.17 | 21.09 | 22.06 | | 23.07 | | 24.12 | | |
| Avangrid | 2.44 | 2.55 | 2.67 | 2.79 | 2.92 | 3.06 | 3.20 | 3.34 | 3.50 | 3.66 | 3.82 | 4.00 | 4.18 | 4.37 | 4.57 | 4.78 | 5.00 | 5.23 | 5.47 | 146.98 | 5.72 | 141.26 | | 5 | 5 |
| | 3.90 | 4.08 | 4.27 | 4.46 | 4.67 | 4.88 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.68 | 6.98 | 7.30 | 7.64 | 7.99 | 8.35 | 8.73 | | 9.13 | | 9.55 | | |
| Avista | 3.07 | 3.21 | 3.36 | 3.51 | 3.67 | 3.84 | 4.02 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.50 | 5.75 | 6.01 | 6.29 | 6.57 | 6.87 | 159.55 | 7.19 | 152.36 | | 6 | 6 |
| | 4.15 | 4.34 | 4.54 | 4.75 | 4.97 | 5.20 | 5.43 | 5.68 | 5.94 | 6.22 | 6.50 | 6.80 | 7.11 | 7.44 | 7.78 | 8.13 | 8.50 | 8.89 | 9.30 | | 9.73 | | 10.17 | | |
| Black Hills | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.75 | 6.01 | 6.28 | 6.57 | 6.87 | 7.19 | 7.52 | 7.86 | 8.22 | 8.60 | 8.99 | 9.40 | 218.97 | 9.83 | 209.13 | | 7 | 7 |
| | 6.14 | 6.42 | 6.71 | 7.02 | 7.34 | 7.68 | 8.03 | 8.40 | 8.78 | 9.18 | 9.60 | 10.04 | 10.50 | 10.98 | 11.49 | 12.01 | 12.56 | 13.14 | 13.74 | | 14.37 | | 15.03 | | |
| CMS | 3.21 | 3.35 | 3.51 | 3.67 | 3.84 | 4.01 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.74 | 6.00 | 6.28 | 6.57 | 6.87 | 7.18 | 252.81 | 7.51 | 245.30 | | 9 | 8 |
| | 5.31 | 5.55 | 5.81 | 6.08 | 6.35 | 6.64 | 6.95 | 7.27 | 7.60 | 7.95 | 8.31 | 8.69 | 9.09 | 9.51 | 9.94 | 10.40 | 10.87 | 11.37 | 11.89 | | 12.44 | | 13.01 | | |
| Consol Ed | 5.34 | 5.58 | 5.84 | 6.11 | 6.39 | 6.68 | 6.98 | 7.30 | 7.64 | 7.99 | 8.35 | 8.74 | 9.14 | 9.55 | 9.99 | 10.45 | 10.93 | 11.43 | 11.95 | 414.12 | 12.50 | 401.62 | | 10 | 9 |
| | 8.84 | 9.24 | 9.66 | 10.11 | 10.57 | 11.05 | 11.56 | 12.09 | 12.64 | 13.22 | 13.83 | 14.46 | 15.12 | 15.82 | 16.54 | 17.30 | 18.09 | 18.92 | 19.79 | | 20.69 | | 21.64 | | |
| Dominion | 3.43 | 3.59 | 3.76 | 3.93 | 4.11 | 4.30 | 4.49 | 4.70 | 4.91 | 5.14 | 5.37 | 5.62 | 5.88 | 6.15 | 6.43 | 6.72 | 7.03 | 7.35 | 7.69 | 200.06 | 8.04 | 192.02 | | 11 | 10 |
| | 5.35 | 5.59 | 5.85 | 6.11 | 6.39 | 6.69 | 6.99 | 7.31 | 7.65 | 8.00 | 8.36 | 8.75 | 9.15 | 9.57 | 10.01 | 10.46 | 10.94 | 11.44 | 11.97 | | 12.52 | | 13.09 | | |
| DTE | 6.42 | 6.72 | 7.03 | 7.35 | 7.68 | 8.04 | 8.40 | 8.79 | 9.19 | 9.61 | 10.05 | 10.51 | 11.00 | 11.50 | 12.03 | 12.58 | 13.15 | 13.75 | 14.38 | 577.46 | 15.04 | 562.41 | | 12 | 11 |
| | 12.30 | 12.86 | 13.45 | 14.07 | 14.71 | 15.39 | 16.09 | 16.83 | 17.60 | 18.41 | 19.25 | 20.13 | 21.05 | 22.02 | 23.03 | 24.08 | 25.18 | 26.34 | 27.54 | | 28.80 | | 30.12 | | |
| Duke | 5.58 | 5.84 | 6.10 | 6.38 | 6.68 | 6.98 | 7.30 | 7.64 | 7.99 | 8.35 | 8.73 | 9.13 | 9.55 | 9.99 | 10.45 | 10.93 | 11.43 | 11.95 | 12.50 | 431.29 | 13.07 | 418.22 | | 13 | 12 |
| | 9.89 | 10.35 | 10.82 | 11.31 | 11.83 | 12.37 | 12.94 | 13.53 | 14.15 | 14.80 | 15.48 | 16.19 | 16.93 | 17.71 | 18.52 | 19.36 | 20.25 | 21.18 | 22.15 | | 23.16 | | 24.22 | | |
| Entergy | 6.86 | 7.17 | 7.50 | 7.84 | 8.20 | 8.58 | 8.97 | 9.38 | 9.81 | 10.26 | 10.73 | 11.22 | 11.74 | 12.27 | 12.84 | 13.42 | 14.04 | 14.68 | 15.35 | 363.98 | 16.06 | 347.92 | | 15 | 13 |
| | 10.25 | 10.71 | 11.21 | 11.72 | 12.26 | 12.82 | 13.40 | 14.02 | 14.66 | 15.33 | 16.03 | 16.77 | 17.54 | 18.34 | 19.18 | 20.06 | 20.98 | 21.94 | 22.94 | | 23.99 | | 25.09 | | |
| Evergy | 4.36 | 4.56 | 4.76 | 4.98 | 5.21 | 5.45 | 5.70 | 5.96 | 6.23 | 6.52 | 6.82 | 7.13 | 7.46 | 7.80 | 8.16 | 8.53 | 8.92 | 9.33 | 9.76 | 260.48 | 10.20 | 250.28 | | 16 | 14 |
| | 7.19 | 7.52 | 7.87 | 8.23 | 8.60 | 9.00 | 9.41 | 9.84 | 10.29 | 10.76 | 11.25 | 11.77 | 12.31 | 12.87 | 13.46 | 14.08 | 14.72 | 15.40 | 16.10 | | 16.84 | | 17.61 | | |
| Eversource | 4.94 | 5.17 | 5.40 | 5.65 | 5.91 | 6.18 | 6.46 | 6.76 | 7.07 | 7.39 | 7.73 | 8.08 | 8.45 | 8.84 | 9.25 | 9.67 | 10.11 | 10.58 | 11.06 | 272.23 | 11.57 | 260.66 | | 17 | 15 |
| | 8.06 | 8.43 | 8.82 | 9.22 | 9.64 | 10.08 | 10.54 | 11.03 | 11.53 | 12.06 | 12.61 | 13.19 | 13.80 | 14.43 | 15.09 | 15.78 | 16.50 | 17.26 | 18.05 | | 18.87 | | 19.74 | | |
| Exelon | 2.46 | 2.57 | 2.69 | 2.81 | 2.94 | 3.08 | 3.22 | 3.37 | 3.52 | 3.68 | 3.85 | 4.03 | 4.21 | 4.40 | 4.60 | 4.82 | 5.04 | 5.27 | 5.51 | 151.89 | 5.76 | 146.13 | | 18 | 16 |
| | 4.06 | 4.24 | 4.44 | 4.64 | 4.85 | 5.07 | 5.31 | 5.55 | 5.80 | 6.07 | 6.35 | 6.64 | 6.94 | 7.26 | 7.59 | 7.94 | 8.30 | 8.68 | 9.08 | | 9.50 | | 9.93 | | |
| IDACORP | 6.05 | 6.33 | 6.62 | 6.92 | 7.24 | 7.57 | 7.92 | 8.28 | 8.66 | 9.06 | 9.47 | 9.91 | 10.36 | 10.84 | 11.33 | 11.85 | 12.39 | 12.96 | 13.55 | 393.30 | 14.18 | 379.13 | | 22 | 17 |
| | 8.39 | 8.77 | 9.17 | 9.59 | 10.03 | 10.49 | 10.97 | 11.48 | 12.00 | 12.55 | 13.13 | 13.73 | 14.36 | 15.01 | 15.70 | 16.42 | 17.17 | 17.96 | 18.78 | | 19.64 | | 20.54 | | |
| NorthWestern | 3.62 | 3.79 | 3.96 | 4.14 | 4.33 | 4.53 | 4.74 | 4.95 | 5.18 | 5.42 | 5.67 | 5.93 | 6.20 | 6.48 | 6.78 | 7.09 | 7.41 | 7.75 | 8.11 | 208.20 | 8.48 | 199.72 | | 25 | 18 |
| | 5.74 | 6.00 | 6.27 | 6.56 | 6.86 | 7.18 | 7.50 | 7.85 | 8.21 | 8.58 | 8.98 | 9.39 | 9.82 | 10.27 | 10.74 | 11.23 | 11.74 | 12.28 | 12.84 | | 13.43 | | 14.05 | | |
| OGE | 2.43 | 2.54 | 2.65 | 2.78 | 2.90 | 3.04 | 3.18 | 3.32 | 3.47 | 3.63 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.97 | 5.20 | 5.43 | 200.02 | 5.68 | 194.34 | | 26 | 19 |
| | 4.81 | 5.03 | 5.26 | 5.50 | 5.76 | 6.02 | 6.29 | 6.58 | 6.88 | 7.20 | 7.53 | 7.87 | 8.23 | 8.61 | 9.01 | 9.42 | 9.85 | 10.30 | 10.77 | | 11.27 | | 11.78 | | |
| Otter Tail | 3.19 | 3.33 | 3.48 | 3.64 | 3.81 | 3.99 | 4.17 | 4.36 | 4.56 | 4.77 | 4.99 | 5.21 | 5.45 | 5.70 | 5.96 | 6.24 | 6.52 | 6.82 | 7.13 | 150.19 | 7.46 | 142.73 | | 27 | 20 |
| | 4.21 | 4.40 | 4.61 | 4.82 | 5.04 | 5.27 | 5.51 | 5.76 | 6.02 | 6.30 | 6.59 | 6.89 | 7.21 | 7.54 | 7.88 | 8.24 | 8.62 | 9.02 | 9.43 | | 9.86 | | 10.31 | | |
| PGE | 3.40 | 3.56 | 3.72 | 3.89 | 4.07 | 4.26 | 4.45 | 4.66 | 4.87 | 5.09 | 5.33 | 5.57 | 5.82 | 6.09 | 6.37 | 6.66 | 6.97 | 7.29 | 7.62 | 204.16 | 7.97 | 196.20 | | 29 | 21 |
| | 5.22 | 5.46 | 5.71 | 5.97 | 6.24 | 6.53 | 6.83 | 7.14 | 7.47 | 7.81 | 8.16 | 8.54 | 8.93 | 9.34 | 9.77 | 10.21 | 10.68 | 11.17 | 11.68 | | 12.22 | | 12.78 | | |
| Pinnacle | 4.93 | 5.16 | 5.40 | 5.64 | 5.90 | 6.17 | 6.45 | 6.75 | 7.06 | 7.38 | 7.72 | 8.07 | 8.44 | 8.83 | 9.23 | 9.66 | 10.10 | 10.56 | 11.05 | 342.00 | 11.55 | 330.44 | | 30 | 22 |
| | 7.98 | 8.34 | 8.72 | 9.12 | 9.54 | 9.98 | 10.44 | 10.91 | 11.41 | 11.94 | 12.48 | 13.06 | 13.65 | 14.28 | 14.93 | 15.62 | 16.33 | 17.08 | 17.86 | | 18.68 | | 19.54 | | |
| PNM | 2.19 | 2.29 | 2.39 | 2.50 | 2.62 | 2.74 | 2.86 | 2.99 | 3.13 | 3.28 | 3.43 | 3.58 | 3.75 | 3.92 | 4.10 | 4.28 | 4.48 | 4.69 | 4.90 | 164.45 | 5.13 | 159.33 | | 31 | 23 |
| | 4.76 | 4.98 | 5.21 | 5.44 | 5.69 | 5.95 | 6.23 | 6.51 | 6.81 | 7.12 | 7.45 | 7.79 | 8.15 | 8.52 | 8.91 | 9.32 | 9.74 | 10.19 | 10.66 | | 11.15 | | 11.66 | | |
| Public Serv. | 4.02 | 4.20 | 4.40 | 4.60 | 4.81 | 5.03 | 5.26 | 5.50 | 5.75 | 6.01 | 6.29 | 6.58 | 6.88 | 7.19 | 7.52 | 7.87 | 8.23 | 8.60 | 9.00 | 263.71 | 9.41 | 254.30 | | 33 | 24 |
| | 6.15 | 6.43 | 6.73 | 7.04 | 7.36 | 7.69 | 8.05 | 8.42 | 8.80 | 9.20 | 9.63 | 10.07 | 10.53 | 11.01 | 11.51 | 12.04 | 12.59 | 13.17 | 13.77 | | 14.40 | | 15.06 | | |
| Sempra | 3.90 | 4.08 | 4.27 | 4.46 | 4.67 | 4.88 | 5.11 | 5.34 | 5.58 | 5.84 | 6.11 | 6.39 | 6.68 | 6.99 | 7.31 | 7.64 | 7.99 | 8.36 | 8.74 | 356.97 | 9.14 | 347.83 | | 34 | 25 |
| | 8.81 | 9.21 | 9.64 | 10.08 | 10.54 | 11.02 | 11.53 | 12.05 | 12.61 | 13.18 | 13.79 | 14.42 | 15.08 | 15.77 | 16.49 | 17.25 | 18.04 | 18.86 | 19.73 | | 20.63 | | 21.57 | | |
| Southern | 4.15 | 4.34 | 4.54 | 4.75 | 4.97 | 5.19 | 5.43 | 5.68 | 5.94 | 6.21 | 6.50 | 6.79 | 7.11 | 7.43 | 7.77 | 8.13 | 8.50 | 8.89 | 9.30 | 375.78 | 9.72 | 366.06 | | 35 | 26 |
| | 7.71 | 8.06 | 8.43 | 8.82 | 9.22 | 9.64 | 10.09 | 10.55 | 11.03 | 11.54 | 12.06 | 12.62 | 13.19 | 13.80 | 14.43 | 15.09 | 15.78 | 16.51 | 17.26 | | 18.05 | | 18.88 | | |
| WEC | 5.39 | 5.64 | 5.90 | 6.17 | 6.45 | 6.75 | 7.05 | 7.38 | 7.72 | 8.07 | 8.44 | 8.82 | 9.23 | 9.65 | 10.09 | 10.56 | 11.04 | 11.55 | 12.07 | 385.78 | 12.63 | 373.15 | | 36 | 27 |
| | 8.56 | 8.95 | 9.36 | 9.79 | 10.24 | 10.71 | 11.20 | 11.71 | 12.25 | 12.81 | 13.39 | 14.01 | 14.65 | 15.32 | 16.02 | 16.75 | 17.52 | 18.32 | 19.16 | | 20.04 | | 20.96 | | |
| Xcel | 3.88 | 4.06 | 4.24 | 4.44 | 4.64 | 4.85 | 5.08 | 5.31 | 5.55 | 5.81 | 6.07 | 6.35 | 6.64 | 6.95 | 7.26 | 7.60 | 7.94 | 8.31 | 8.69 | 282.22 | 9.09 | 273.14 | | 37 | 28 |
| | 6.15 | 6.44 | 6.73 | 7.04 | 7.36 | 7.70 | 8.05 | 8.42 | 8.80 | 9.21 | 9.63 | 10.07 | 10.53 | 11.01 | 11.52 | 12.05 | 12.60 | 13.17 | 13.78 | | 14.41 | | 15.07 | | |

| Mean | | | |
|---|---|---|---|
| 8.99% | 33.45% | 0.00% | Company Screen |
| 9.35% | 32.60% | 0.00% | Staff Screen |
| 9.10% | 33.10% | 0.00% | Staff Sensitivity Screen |

## B.O.Y. Cash Flows Staff Model Y EPS Growth

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | LT Debt | | Terminal Value as | | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2046 | | | | | |
| | | Abbreviated | IPC | Staff | Staff | | % of | NPV @ | Recent | Initial Stage | | | | | Transition Stage | | | | | Final Stage | | | | | | | | | | | | | | | | | | | Terminal | 2049 | 2049 | | | |
| | # | Utility | Peers | Peers | Sensitivity | IRR | $NPV_{DIV}$ | IRR | Price* | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | Value | Div | Sale | 2050 | # | |
| 1 | 1 | Allete | Yes | No | No | 9.2% | 30.8% | 0.00 | (59.87) | 2.79 | 2.86 | 2.93 | 3.00 | 3.07 | 3.28 | 3.48 | 3.67 | 3.83 | 4.01 | 4.19 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.74 | 6.00 | 6.27 | 6.56 | 6.86 | 7.18 | 7.51 | 7.85 | 8.21 | 8.59 | 8.98 | 9.39 | 259.08 | 9.82 | 249.26 | | 1 | 1 |
| | | | | e | e | | | | | 4.35 | 4.05 | 4.34 | 4.66 | 5.00 | 5.34 | 5.88 | 6.36 | 6.76 | 7.07 | 7.40 | 7.73 | 8.09 | 8.46 | 8.85 | 9.25 | 9.67 | 10.12 | 10.58 | 11.07 | 11.57 | 12.10 | 12.66 | 13.24 | 13.84 | 14.48 | 15.14 | 15.83 | 16.56 | | 17.32 | | 18.11 | | |
| 2 | 2 | Alliant | No | Yes | Yes | 9.4% | 34.6% | 0.00 | (49.71) | 1.92 | 2.04 | 2.16 | 2.29 | 2.42 | 2.64 | 2.85 | 3.02 | 3.16 | 3.31 | 3.46 | 3.61 | 3.78 | 3.95 | 4.13 | 4.32 | 4.52 | 4.73 | 4.95 | 5.17 | 5.41 | 5.66 | 5.92 | 6.19 | 6.47 | 6.77 | 7.08 | 7.40 | 7.74 | 251.67 | 8.09 | 243.57 | | 2 | 2 |
| | | | | e | e | | | | | 2.85 | 2.85 | 3.14 | 3.45 | 3.80 | 4.15 | 4.55 | 4.91 | 5.21 | 5.45 | 5.70 | 5.96 | 6.24 | 6.52 | 6.82 | 7.13 | 7.46 | 7.80 | 8.16 | 8.53 | 8.92 | 9.33 | 9.76 | 10.21 | 10.68 | 11.16 | 11.68 | 12.21 | 12.77 | | 13.35 | | 13.97 | | |
| 3 | 3 | Ameren | Yes | Yes | Yes | 9.3% | 32.0% | 0.00 | (70.70) | 2.65 | 2.85 | 3.07 | 3.30 | 3.53 | 3.89 | 4.21 | 4.48 | 4.68 | 4.90 | 5.12 | 5.36 | 5.60 | 5.86 | 6.13 | 6.41 | 6.70 | 7.01 | 7.33 | 7.67 | 8.02 | 8.38 | 8.77 | 9.17 | 9.59 | 10.03 | 10.49 | 10.97 | 11.47 | 323.58 | 12.00 | 311.58 | | 3 | 3 |
| | | | | e | e | | | | | 4.40 | 4.70 | 4.95 | 5.22 | 5.50 | 5.78 | 6.33 | 6.82 | 7.24 | 7.57 | 7.92 | 8.28 | 8.66 | 9.06 | 9.47 | 9.91 | 10.36 | 10.83 | 11.33 | 11.85 | 12.39 | 12.96 | 13.55 | 14.17 | 14.82 | 15.50 | 16.21 | 16.95 | 17.73 | | 18.54 | | 19.39 | | |
| 4 | 4 | AEP | No | No | Yes | 9.8% | 29.2% | 0.00 | (79.24) | 3.52 | 3.72 | 3.93 | 4.16 | 4.39 | 4.78 | 5.13 | 5.44 | 5.69 | 5.95 | 6.22 | 6.51 | 6.81 | 7.12 | 7.44 | 7.79 | 8.14 | 8.52 | 8.91 | 9.31 | 9.74 | 10.19 | 10.65 | 11.14 | 11.65 | 12.18 | 12.74 | 13.33 | 13.94 | 378.64 | 14.57 | 364.07 | | 4 | 4 |
| | | | | e | e | | | | | 5.25 | 5.60 | 5.97 | 6.37 | 6.80 | 7.23 | 7.89 | 8.49 | 9.01 | 9.42 | 9.85 | 10.30 | 10.77 | 11.27 | 11.78 | 12.32 | 12.89 | 13.48 | 14.09 | 14.74 | 15.41 | 16.12 | 16.86 | 17.63 | 18.44 | 19.28 | 20.17 | 21.09 | 22.06 | | 23.07 | | 24.12 | | |
| 5 | 5 | Avangrid | Yes | No | No | 10.2% | 26.0% | 0.00 | (31.06) | 1.76 | 1.80 | 1.84 | 1.88 | 1.92 | 2.03 | 2.13 | 2.23 | 2.34 | 2.44 | 2.55 | 2.67 | 2.79 | 2.92 | 3.06 | 3.20 | 3.34 | 3.50 | 3.66 | 3.82 | 4.00 | 4.18 | 4.37 | 4.57 | 4.78 | 5.00 | 5.23 | 5.47 | 5.72 | 147.24 | 5.98 | 141.26 | | 5 | 5 |
| | | | | e | e | | | | | 2.10 | 2.41 | 2.53 | 2.66 | 2.80 | 2.94 | 3.16 | 3.38 | 3.57 | 3.73 | 3.90 | 4.08 | 4.27 | 4.46 | 4.67 | 4.88 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.68 | 6.98 | 7.30 | 7.64 | 7.99 | 8.35 | 8.73 | | 9.13 | | 9.55 | | |
| 6 | 6 | Avista | Yes | Yes | Yes | 10.6% | 22.4% | 0.00 | (34.45) | 1.92 | 2.01 | 2.10 | 2.20 | 2.30 | 2.48 | 2.65 | 2.81 | 2.94 | 3.07 | 3.21 | 3.36 | 3.51 | 3.67 | 3.84 | 4.02 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.50 | 5.75 | 6.01 | 6.29 | 6.57 | 6.87 | 7.19 | 159.88 | 7.52 | 152.36 | | 6 | 6 |
| | | | | e | e | | | | | 2.30 | 2.50 | 2.63 | 2.76 | 2.90 | 3.04 | 3.32 | 3.58 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.97 | 5.20 | 5.43 | 5.68 | 5.94 | 6.22 | 6.50 | 6.80 | 7.11 | 7.44 | 7.78 | 8.13 | 8.50 | 8.89 | 9.30 | | 9.73 | | 10.17 | | |
| 7 | 7 | Black Hills | Yes | Yes | Yes | 9.9% | 24.6% | 0.00 | (52.19) | 2.65 | 2.76 | 2.88 | 3.01 | 3.14 | 3.39 | 3.63 | 3.84 | 4.02 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.75 | 6.01 | 6.28 | 6.57 | 6.87 | 7.19 | 7.52 | 7.86 | 8.22 | 8.60 | 8.99 | 9.40 | 9.83 | 219.42 | 10.28 | 209.13 | | 7 | 7 |
| | | | | e | e | | | | | 3.75 | 3.90 | 4.09 | 4.29 | 4.50 | 4.71 | 5.03 | 5.33 | 5.61 | 5.87 | 6.14 | 6.42 | 6.71 | 7.02 | 7.34 | 7.68 | 8.03 | 8.40 | 8.78 | 9.18 | 9.60 | 10.04 | 10.50 | 10.98 | 11.49 | 12.01 | 12.56 | 13.14 | 13.74 | | 14.37 | | 15.03 | | |
| 8 | 9 | CMS | Yes | No | No | 8.5% | 38.4% | 0.00 | (57.52) | 2.04 | 2.12 | 2.21 | 2.30 | 2.39 | 2.59 | 2.77 | 2.93 | 3.07 | 3.21 | 3.35 | 3.51 | 3.67 | 3.84 | 4.01 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.74 | 6.00 | 6.28 | 6.57 | 6.87 | 7.18 | 7.51 | 253.15 | 7.85 | 245.30 | | 9 | 8 |
| | | | | e | e | | | | | 3.05 | 3.30 | 3.44 | 3.59 | 3.75 | 3.91 | 4.26 | 4.58 | 4.86 | 5.08 | 5.31 | 5.55 | 5.81 | 6.08 | 6.35 | 6.64 | 6.95 | 7.27 | 7.60 | 7.95 | 8.31 | 8.69 | 9.09 | 9.51 | 9.94 | 10.40 | 10.87 | 11.37 | 11.89 | | 12.44 | | 13.01 | | |
| 9 | 10 | Consol Ed | No | Yes | Yes | 8.7% | 37.1% | 0.00 | (90.94) | 3.34 | 3.51 | 3.68 | 3.86 | 4.04 | 4.34 | 4.63 | 4.88 | 5.10 | 5.34 | 5.58 | 5.84 | 6.11 | 6.39 | 6.68 | 6.98 | 7.30 | 7.64 | 7.99 | 8.35 | 8.74 | 9.14 | 9.55 | 9.99 | 10.45 | 10.93 | 11.43 | 11.95 | 12.50 | 414.70 | 13.07 | 401.62 | | 10 | 9 |
| | | | | e | e | | | | | 4.90 | 5.20 | 5.50 | 5.82 | 6.15 | 6.48 | 7.08 | 7.62 | 8.08 | 8.45 | 8.84 | 9.24 | 9.66 | 10.11 | 10.57 | 11.05 | 11.56 | 12.09 | 12.64 | 13.22 | 13.83 | 14.46 | 15.12 | 15.82 | 16.54 | 17.30 | 18.09 | 18.92 | 19.79 | | 20.69 | | 21.64 | | |
| 10 | 11 | Dominion | Yes | No | No | 9.8% | 26.2% | 0.00 | (46.21) | 2.67 | 2.70 | 2.72 | 2.75 | 2.78 | 2.89 | 3.01 | 3.14 | 3.28 | 3.43 | 3.59 | 3.76 | 3.93 | 4.11 | 4.30 | 4.49 | 4.70 | 4.91 | 5.14 | 5.37 | 5.62 | 5.88 | 6.15 | 6.43 | 6.72 | 7.03 | 7.35 | 7.69 | 8.04 | 200.43 | 8.41 | 192.02 | | 11 | 10 |
| | | | | e | e | | | | | 3.15 | 3.35 | 3.55 | 3.77 | 4.00 | 4.23 | 4.45 | 4.67 | 4.89 | 5.11 | 5.35 | 5.59 | 5.85 | 6.11 | 6.39 | 6.69 | 6.99 | 7.31 | 7.65 | 8.00 | 8.36 | 8.75 | 9.15 | 9.57 | 10.01 | 10.46 | 10.94 | 11.44 | 11.97 | | 12.52 | | 13.09 | | |
| 11 | 12 | DTE | Yes | No | No | 9.2% | 38.9% | 0.00 | (107.35) | 4.05 | 4.24 | 4.44 | 4.65 | 4.86 | 5.22 | 5.57 | 5.87 | 6.14 | 6.42 | 6.72 | 7.03 | 7.35 | 7.68 | 8.04 | 8.40 | 8.79 | 9.19 | 9.61 | 10.05 | 10.51 | 11.00 | 11.50 | 12.03 | 12.58 | 13.15 | 13.75 | 14.38 | 15.04 | 578.15 | 15.73 | 562.41 | | 12 | 11 |
| | | | | e | e | | | | | 5.75 | 6.70 | 7.20 | 7.73 | 8.30 | 8.87 | 9.77 | 10.57 | 11.25 | 11.76 | 12.30 | 12.86 | 13.45 | 14.07 | 14.71 | 15.39 | 16.09 | 16.83 | 17.60 | 18.41 | 19.25 | 20.13 | 21.05 | 22.02 | 23.03 | 24.08 | 25.18 | 26.34 | 27.54 | | 28.80 | | 30.12 | | |
| 12 | 13 | Duke | Yes | No | Yes | 8.7% | 36.4% | 0.00 | (96.68) | 4.14 | 4.19 | 4.25 | 4.30 | 4.35 | 4.61 | 4.86 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.68 | 6.98 | 7.30 | 7.64 | 7.99 | 8.35 | 8.73 | 9.13 | 9.55 | 9.99 | 10.45 | 10.93 | 11.43 | 11.95 | 12.50 | 13.07 | 431.89 | 13.67 | 418.22 | | 13 | 12 |
| | | | | e | e | | | | | 5.60 | 6.00 | 6.32 | 6.65 | 7.00 | 7.35 | 7.97 | 8.54 | 9.04 | 9.46 | 9.89 | 10.35 | 10.82 | 11.31 | 11.83 | 12.37 | 12.94 | 13.53 | 14.15 | 14.80 | 15.48 | 16.19 | 16.93 | 17.71 | 18.52 | 19.36 | 20.25 | 21.18 | 22.15 | | 23.16 | | 24.22 | | |
| 13 | 15 | Entergy | Yes | No | No | 8.9% | 28.0% | 0.00 | (100.53) | 4.56 | 4.70 | 4.85 | 5.00 | 5.15 | 5.56 | 5.93 | 6.27 | 6.56 | 6.86 | 7.17 | 7.50 | 7.84 | 8.20 | 8.58 | 8.97 | 9.38 | 9.81 | 10.26 | 10.73 | 11.22 | 11.74 | 12.27 | 12.84 | 13.42 | 14.04 | 14.68 | 15.35 | 16.06 | 364.72 | 16.79 | 347.92 | | 15 | 13 |
| | | | | e | e | | | | | 7.25 | 6.45 | 6.78 | 7.13 | 7.50 | 7.87 | 8.40 | 8.90 | 9.37 | 9.80 | 10.25 | 10.71 | 11.21 | 11.72 | 12.26 | 12.82 | 13.40 | 14.02 | 14.66 | 15.33 | 16.03 | 16.77 | 17.54 | 18.34 | 19.18 | 20.06 | 20.98 | 21.94 | 22.94 | | 23.99 | | 25.09 | | |
| 14 | 16 | Evergy | No | Yes | Yes | 10.5% | 25.6% | 0.00 | (51.16) | 2.61 | 2.75 | 2.90 | 3.05 | 3.20 | 3.49 | 3.76 | 3.98 | 4.17 | 4.36 | 4.56 | 4.76 | 4.98 | 5.21 | 5.45 | 5.70 | 5.96 | 6.23 | 6.52 | 6.82 | 7.13 | 7.46 | 7.80 | 8.16 | 8.53 | 8.92 | 9.33 | 9.76 | 10.20 | 260.95 | 10.67 | 250.28 | | 16 | 14 |
| | | | | e | e | | | | | 3.60 | 3.85 | 4.16 | 4.49 | 4.85 | 5.21 | 5.72 | 6.19 | 6.58 | 6.88 | 7.19 | 7.52 | 7.87 | 8.23 | 8.60 | 9.00 | 9.41 | 9.84 | 10.29 | 10.76 | 11.25 | 11.77 | 12.31 | 12.87 | 13.46 | 14.08 | 14.72 | 15.40 | 16.10 | | 16.84 | | 17.61 | | |
| 15 | 17 | Eversource | No | No | Yes | 10.4% | 24.5% | 0.00 | (57.44) | 2.86 | 3.04 | 3.22 | 3.42 | 3.62 | 3.95 | 4.26 | 4.52 | 4.72 | 4.94 | 5.17 | 5.40 | 5.65 | 5.91 | 6.18 | 6.46 | 6.76 | 7.07 | 7.39 | 7.73 | 8.08 | 8.45 | 8.84 | 9.25 | 9.67 | 10.11 | 10.58 | 11.06 | 11.57 | 272.76 | 12.10 | 260.66 | | 17 | 15 |
| | | | | e | e | | | | | 4.35 | 4.60 | 4.90 | 5.21 | 5.55 | 5.89 | 6.44 | 6.94 | 7.37 | 7.71 | 8.06 | 8.43 | 8.82 | 9.22 | 9.64 | 10.08 | 10.54 | 11.03 | 11.53 | 12.06 | 12.61 | 13.19 | 13.80 | 14.43 | 15.09 | 15.78 | 16.50 | 17.26 | 18.05 | | 18.87 | | 19.74 | | |
| 16 | 18 | Exelon | Yes | No | No | 9.3% | 29.7% | 0.00 | (35.31) | 1.60 | 1.66 | 1.73 | 1.80 | 1.87 | 2.01 | 2.13 | 2.25 | 2.35 | 2.46 | 2.57 | 2.69 | 2.81 | 2.94 | 3.08 | 3.22 | 3.37 | 3.52 | 3.68 | 3.85 | 4.03 | 4.21 | 4.40 | 4.60 | 4.82 | 5.04 | 5.27 | 5.51 | 5.76 | 152.15 | 6.02 | 146.13 | | 18 | 16 |
| | | | | e | e | | | | | 2.40 | 2.50 | 2.66 | 2.82 | 3.00 | 3.18 | 3.36 | 3.53 | 3.71 | 3.88 | 4.06 | 4.24 | 4.44 | 4.64 | 4.85 | 5.07 | 5.31 | 5.55 | 5.80 | 6.07 | 6.35 | 6.64 | 6.94 | 7.26 | 7.59 | 7.94 | 8.30 | 8.68 | 9.08 | | 9.50 | | 9.93 | | |
| 17 | 22 | IDACORP | Yes | Yes | Yes | 8.8% | 33.3% | 0.00 | (95.05) | 3.40 | 3.63 | 3.88 | 4.15 | 4.42 | 4.83 | 5.21 | 5.53 | 5.79 | 6.05 | 6.33 | 6.62 | 6.92 | 7.24 | 7.57 | 7.92 | 8.28 | 8.66 | 9.06 | 9.47 | 9.91 | 10.36 | 10.84 | 11.33 | 11.85 | 12.39 | 12.96 | 13.55 | 14.18 | 393.95 | 14.82 | 379.13 | | 22 | 17 |
| | | | | e | e | | | | | 5.15 | 5.40 | 5.62 | 5.86 | 6.10 | 6.34 | 6.82 | 7.27 | 7.67 | 8.02 | 8.39 | 8.77 | 9.17 | 9.59 | 10.03 | 10.49 | 10.97 | 11.48 | 12.00 | 12.55 | 13.13 | 13.73 | 14.36 | 15.01 | 15.70 | 16.42 | 17.17 | 17.96 | 18.78 | | 19.64 | | 20.54 | | |
| 18 | 25 | NorthWestern | Yes | Yes | Yes | 9.6% | 26.8% | 0.00 | (49.05) | 2.60 | 2.65 | 2.71 | 2.76 | 2.81 | 2.98 | 3.15 | 3.31 | 3.46 | 3.62 | 3.79 | 3.96 | 4.14 | 4.33 | 4.53 | 4.74 | 4.95 | 5.18 | 5.42 | 5.67 | 5.93 | 6.20 | 6.48 | 6.78 | 7.09 | 7.41 | 7.75 | 8.11 | 8.48 | 208.59 | 8.87 | 199.72 | | 25 | 18 |
| | | | | e | e | | | | | 3.45 | 3.60 | 3.77 | 3.96 | 4.15 | 4.34 | 4.67 | 4.97 | 5.24 | 5.49 | 5.74 | 6.00 | 6.27 | 6.56 | 6.86 | 7.18 | 7.50 | 7.85 | 8.21 | 8.58 | 8.98 | 9.39 | 9.82 | 10.27 | 10.74 | 11.23 | 11.74 | 12.28 | 12.84 | | 13.43 | | 14.05 | | |
| 19 | 26 | OGE | Yes | Yes | Yes | 10.2% | 32.5% | 0.00 | (33.81) | 1.78 | 1.80 | 1.83 | 1.85 | 1.87 | 1.99 | 2.11 | 2.22 | 2.32 | 2.43 | 2.54 | 2.65 | 2.78 | 2.90 | 3.04 | 3.18 | 3.32 | 3.47 | 3.63 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.97 | 5.20 | 5.43 | 5.68 | 200.28 | 5.94 | 194.34 | | 26 | 19 |
| | | | | e | e | | | | | 2.05 | 2.15 | 2.44 | 2.77 | 3.15 | 3.53 | 3.85 | 4.15 | 4.40 | 4.60 | 4.81 | 5.03 | 5.26 | 5.50 | 5.76 | 6.02 | 6.29 | 6.58 | 6.88 | 7.20 | 7.53 | 7.87 | 8.23 | 8.61 | 9.01 | 9.42 | 9.85 | 10.30 | 10.77 | | 11.27 | | 11.78 | | |
| 20 | 27 | Otter Tail | Yes | No | Yes | 5.0% | 38.9% | 0.00 | (88.59) | 1.81 | 1.93 | 2.06 | 2.20 | 2.34 | 2.55 | 2.75 | 2.91 | 3.05 | 3.19 | 3.33 | 3.48 | 3.64 | 3.81 | 3.99 | 4.17 | 4.36 | 4.56 | 4.77 | 4.99 | 5.21 | 5.45 | 5.70 | 5.96 | 6.24 | 6.52 | 6.82 | 7.13 | 7.46 | 150.54 | 7.80 | 142.73 | | 27 | 20 |
| | | | | e | e | | | | | 6.40 | 4.00 | 3.88 | 3.76 | 3.65 | 3.54 | 3.61 | 3.71 | 3.85 | 4.03 | 4.21 | 4.40 | 4.61 | 4.82 | 5.04 | 5.27 | 5.51 | 5.76 | 6.02 | 6.30 | 6.59 | 6.89 | 7.21 | 7.54 | 7.88 | 8.24 | 8.62 | 9.02 | 9.43 | | 9.86 | | 10.31 | | |
| 21 | 29 | PGE | Yes | Yes | Yes | 10.2% | 26.6% | 0.00 | (41.46) | 1.98 | 2.10 | 2.23 | 2.36 | 2.49 | 2.72 | 2.93 | 3.11 | 3.25 | 3.40 | 3.56 | 3.72 | 3.89 | 4.07 | 4.26 | 4.45 | 4.66 | 4.87 | 5.09 | 5.33 | 5.57 | 5.82 | 6.09 | 6.37 | 6.66 | 6.97 | 7.29 | 7.62 | 7.97 | 204.53 | 8.33 | 196.20 | | 29 | 21 |
| | | | | e | e | | | | | 2.70 | 3.00 | 3.20 | 3.42 | 3.65 | 3.88 | 4.21 | 4.51 | 4.77 | 4.99 | 5.22 | 5.46 | 5.71 | 5.97 | 6.24 | 6.53 | 6.83 | 7.14 | 7.47 | 7.81 | 8.16 | 8.54 | 8.93 | 9.34 | 9.77 | 10.21 | 10.68 | 11.17 | 11.68 | | 12.22 | | 12.78 | | |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | 9.6% | 30.9% | 0.00 | (71.04) | 3.54 | 3.61 | 3.68 | 3.75 | 3.82 | 4.06 | 4.29 | 4.51 | 4.72 | 4.93 | 5.16 | 5.40 | 5.64 | 5.90 | 6.17 | 6.45 | 6.75 | 7.06 | 7.38 | 7.72 | 8.07 | 8.44 | 8.83 | 9.23 | 9.66 | 10.10 | 10.56 | 11.05 | 11.55 | 342.52 | 12.08 | 330.44 | | 30 | 22 |
| | | | | e | e | | | | | 4.20 | 4.50 | 4.87 | 5.27 | 5.70 | 6.13 | 6.54 | 6.93 | 7.29 | 7.63 | 7.98 | 8.34 | 8.72 | 9.12 | 9.54 | 9.98 | 10.44 | 10.91 | 11.41 | 11.94 | 12.48 | 13.06 | 13.65 | 14.28 | 14.93 | 15.62 | 16.33 | 17.08 | 17.86 | | 18.68 | | 19.54 | | |
| 23 | 31 | PNM | Yes | No | No | 8.7% | 35.3% | 0.00 | (38.27) | 1.59 | 1.69 | 1.79 | 1.90 | 2.01 | 1.96 | 1.96 | 2.00 | 2.09 | 2.19 | 2.29 | 2.39 | 2.50 | 2.62 | 2.74 | 2.86 | 2.99 | 3.13 | 3.28 | 3.43 | 3.58 | 3.75 | 3.92 | 4.10 | 4.28 | 4.48 | 4.69 | 4.90 | 5.13 | 164.69 | 5.36 | 159.33 | | 31 | 23 |
| | | | | e | e | | | | | 2.80 | 2.85 | 3.01 | 3.17 | 3.35 | 3.53 | 3.83 | 4.11 | 4.35 | 4.55 | 4.76 | 4.98 | 5.21 | 5.44 | 5.69 | 5.95 | 6.23 | 6.51 | 6.81 | 7.12 | 7.45 | 7.79 | 8.15 | 8.52 | 8.91 | 9.32 | 9.74 | 10.19 | 10.66 | | 11.15 | | 11.66 | | |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | 9.2% | 31.7% | 0.00 | (59.09) | 2.40 | 2.53 | 2.67 | 2.82 | 2.97 | 3.23 | 3.47 | 3.67 | 3.84 | 4.02 | 4.20 | 4.40 | 4.60 | 4.81 | 5.03 | 5.26 | 5.50 | 5.75 | 6.01 | 6.29 | 6.58 | 6.88 | 7.19 | 7.52 | 7.87 | 8.23 | 8.60 | 9.00 | 9.41 | 264.14 | 9.84 | 254.30 | | 33 | 24 |
| | | | | e | e | | | | | 3.50 | 3.70 | 3.92 | 4.15 | 4.40 | 4.65 | 5.00 | 5.33 | 5.62 | 5.88 | 6.15 | 6.43 | 6.73 | 7.04 | 7.36 | 7.69 | 8.05 | 8.42 | 8.80 | 9.20 | 9.63 | 10.07 | 10.53 | 11.01 | 11.51 | 12.04 | 12.59 | 13.17 | 13.77 | | 14.40 | | 15.06 | | |
| 25 | 34 | Sempra | Yes | Yes | Yes | 8.7% | 40.8% | 0.00 | (72.55) | 2.50 | 2.67 | 2.85 | 3.05 | 3.25 | 3.33 | 3.43 | 3.57 | 3.73 | 3.90 | 4.08 | 4.27 | 4.46 | 4.67 | 4.88 | 5.11 | 5.34 | 5.58 | 5.84 | 6.11 | 6.39 | 6.68 | 6.99 | 7.31 | 7.64 | 7.99 | 8.36 | 8.74 | 9.14 | 357.38 | 9.56 | 347.83 | | 34 | 25 |
| | | | | e | e | | | | | 4.50 | 4.80 | 5.17 | 5.57 | 6.00 | 6.43 | 7.04 | 7.59 | 8.06 | 8.42 | 8.81 | 9.21 | 9.64 | 10.08 | 10.54 | 11.02 | 11.53 | 12.05 | 12.61 | 13.18 | 13.79 | 14.42 | 15.08 | 15.77 | 16.49 | 17.25 | 18.04 | 18.86 | 19.73 | | 20.63 | | 21.57 | | |
| 26 | 35 | Southern | Yes | No | No | 9.2% | 38.6% | 0.00 | (69.80) | 2.86 | 2.94 | 3.02 | 3.10 | 3.18 | 3.40 | 3.60 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.97 | 5.19 | 5.43 | 5.68 | 5.94 | 6.21 | 6.50 | 6.79 | 7.11 | 7.43 | 7.77 | 8.13 | 8.50 | 8.89 | 9.30 | 9.72 | 376.22 | 10.17 | 366.06 | | 35 | 26 |
| | | | | e | e | | | | | 3.60 | 4.00 | 4.35 | 4.73 | 5.15 | 5.57 | 6.13 | 6.63 | 7.05 | 7.37 | 7.71 | 8.06 | 8.43 | 8.82 | 9.22 | 9.64 | 10.09 | 10.55 | 11.03 | 11.54 | 12.06 | 12.62 | 13.19 | 13.80 | 14.43 | 15.09 | 15.78 | 16.51 | 17.26 | | 18.05 | | 18.88 | | |
| 27 | 36 | WEC | No | Yes | Yes | 9.2% | 33.6% | 0.00 | (81.90) | 3.33 | 3.48 | 3.64 | 3.80 | 3.96 | 4.32 | 4.65 | 4.93 | 5.16 | 5.39 | 5.64 | 5.90 | 6.17 | 6.45 | 6.75 | 7.05 | 7.38 | 7.72 | 8.07 | 8.44 | 8.82 | 9.23 | 9.65 | 10.09 | 10.56 | 11.04 | 11.55 | 12.07 | 12.63 | 386.35 | 13.21 | 373.15 | | 36 | 27 |
| | | | | e | e | | | | | 4.60 | 4.90 | 5.21 | 5.55 | 5.90 | 6.25 | 6.84 | 7.37 | 7.83 | 8.18 | 8.56 | 8.95 | 9.36 | 9.79 | 10.24 | 10.71 | 11.20 | 11.71 | 12.25 | 12.81 | 13.39 | 14.01 | 14.65 | 15.32 | 16.02 | 16.75 | 17.52 | 18.32 | 19.16 | | 20.04 | | 20.96 | | |
| 28 | 37 | Xcel | No | No | Yes | 9.0% | 34.9% | 0.00 | (60.72) | 2.22 | 2.36 | 2.50 | 2.66 | 2.82 | 3.09 | 3.34 | 3.55 | 3.71 | 3.88 | 4.06 | 4.24 | 4.44 | 4.64 | 4.85 | 5.08 | 5.31 | 5.55 | 5.81 | 6.07 | 6.35 | 6.64 | 6.95 | 7.26 | 7.60 | 7.94 | 8.31 | 8.69 | 9.09 | 282.64 | 9.50 | 273.14 | | 37 | 28 |
| | | | | e | e | | | | | 3.35 | 3.55 | 3.77 | 4.00 | 4.25 | 4.50 | 4.92 | 5.30 | 5.63 | 5.88 | 6.15 | 6.44 | 6.73 | 7.04 | 7.36 | 7.70 | 8.05 | 8.42 | 8.80 | 9.21 | 9.63 | 10.07 | 10.53 | 11.01 | 11.52 | 12.05 | 12.60 | 13.17 | 13.78 | | 14.41 | | 15.07 | | |
| | | No. of Peers: | 21 | 14 | 19 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |

| Mean | | | |
|---|---|---|---|
| 9.18% | 31.85% | 0.00% | Company Screen |
| 9.56% | 30.89% | 0.00% | Staff Screen |
| 9.30% | 31.39% | 0.00% | Staff Sensitivity Screen |

## Average B.O.Y. & E.O.Y. Cash Flows

**Model Y** EPS Growth

| | 1 | 2 | 3 | 4 | | 5 | 6 | 7 | 8 | 9 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | LT Debt | | Terminal Value as | Average 2017 - 2021 | | | | |
| | Screen # | Abbreviated Utility | IPC Peers | Staff Peers | Staff Sensitivity | Average IRR | % of $NPV_{DIV}$ | Dividend Growth Rates EOY | BOY | Average | Screen # | |
| 1 | 1 | Allete | Yes | No | No | 9.1% | 31.6% | 2.6% | 2.4% | 2.5% | 1 | 1 |
| 2 | 2 | Alliant | No | Yes | Yes | 9.3% | 35.6% | 6.1% | 6.0% | 6.0% | 2 | 2 |
| 3 | 3 | Ameren | Yes | Yes | Yes | 9.2% | 33.0% | 7.0% | 7.5% | 7.2% | 3 | 3 |
| 4 | 4 | AEP | No | No | Yes | 9.7% | 30.1% | 5.6% | 5.6% | 5.6% | 4 | 4 |
| 5 | 5 | Avangrid | Yes | No | No | 10.1% | 26.6% | 1.7% | 2.2% | 1.9% | 5 | 5 |
| 6 | 6 | Avista | Yes | Yes | Yes | 10.5% | 23.2% | 4.6% | 4.6% | 4.6% | 6 | 6 |
| 7 | 7 | Black Hills | Yes | Yes | Yes | 9.8% | 25.4% | 4.4% | 4.3% | 4.4% | 7 | 7 |
| 8 | 9 | CMS | Yes | No | No | 8.4% | 39.3% | 4.2% | 4.0% | 4.1% | 9 | 8 |
| 9 | 10 | Consol Ed | No | Yes | Yes | 8.6% | 37.9% | 4.5% | 4.9% | 4.7% | 10 | 9 |
| 10 | 11 | Dominion | Yes | No | No | 9.7% | 26.8% | 0.7% | 1.0% | 0.9% | 11 | 10 |
| 11 | 12 | DTE | Yes | No | No | 9.1% | 39.8% | 5.1% | 4.7% | 4.9% | 12 | 11 |
| 12 | 13 | Duke | Yes | No | Yes | 8.7% | 37.0% | 1.4% | 1.3% | 1.4% | 13 | 12 |
| 13 | 15 | Entergy | Yes | No | No | 8.8% | 28.8% | 3.6% | 3.1% | 3.3% | 15 | 13 |
| 14 | 16 | Evergy | No | Yes | Yes | 10.4% | 26.5% | 5.3% | 5.3% | 5.3% | 16 | 14 |
| 15 | 17 | Eversource | No | No | Yes | 10.3% | 25.4% | 6.1% | 6.1% | 6.1% | 17 | 15 |
| 16 | 18 | Exelon | Yes | No | No | 9.2% | 30.6% | 5.7% | 4.0% | 4.9% | 18 | 16 |
| 17 | 22 | IDACORP | Yes | Yes | Yes | 8.7% | 34.3% | 6.7% | 6.8% | 6.7% | 22 | 17 |
| 18 | 25 | NorthWestern | Yes | Yes | Yes | 9.6% | 27.5% | 1.9% | 2.0% | 1.9% | 25 | 18 |
| 19 | 26 | OGE | Yes | Yes | Yes | 10.1% | 33.2% | 2.7% | 1.3% | 2.0% | 26 | 19 |
| 20 | 27 | Otter Tail | Yes | No | Yes | 5.0% | 39.8% | 5.9% | 6.6% | 6.3% | 27 | 20 |
| 21 | 29 | PGE | Yes | Yes | Yes | 10.1% | 27.5% | 5.8% | 5.9% | 5.9% | 29 | 21 |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | 9.5% | 31.6% | 1.9% | 1.9% | 1.9% | 30 | 22 |
| 23 | 31 | PNM | Yes | No | No | 8.6% | 36.0% | 6.3% | 6.0% | 6.1% | 31 | 23 |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | 9.1% | 32.6% | 5.5% | 5.5% | 5.5% | 33 | 24 |
| 25 | 34 | Sempra | Yes | Yes | Yes | 8.6% | 41.7% | 6.4% | 6.7% | 6.6% | 34 | 25 |
| 26 | 35 | Southern | Yes | No | No | 9.1% | 39.3% | 2.8% | 2.7% | 2.7% | 35 | 26 |
| 27 | 36 | WEC | No | Yes | Yes | 9.1% | 34.5% | 5.1% | 4.5% | 4.8% | 36 | 27 |
| 28 | 37 | Xcel | No | No | Yes | 8.9% | 35.9% | 6.3% | 6.1% | 6.2% | 37 | 28 |
| | | No. of Peers: | 21 | 14 | 19 | Mean | | | | | | |
| | | | | | | 9.08% | 32.65% | 4.14% | Company Screen | | | |
| | | | | | | 9.46% | 31.75% | 4.84% | Staff Screen | | | |
| | | | | | | 9.20% | 32.24% | 4.90% | Staff Sensitivity Screen | | | |

CASE: UE 426
WITNESS: MATT MULDOON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 104

# ROE – Three-Stage DCF:
# Summary and Recommendation

# March 25, 2024

## UE 426 Staff ROE Summary

| 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) | 2.24% | 2.39% | 4.69% | 20.0% | 0.94% | |
| Organization for Economic Co-operation and Development (OECD) | 1.81% | 2.39% | 4.24% | 20.0% | 0.85% | |
| Social Security Administration (SSA) | 1.95% | 2.39% | 4.39% | 20.0% | 0.88% | |
| Congressional Budget Office (CBO) | 2.02% | 2.39% | 4.46% | 20.0% | 0.89% | |
| BEA Nominal Historical,1980 Q1 – 2023 Q4 | 2.65% | 2.39% | 5.10% | 20.0% | 1.02% | |
| Composite | | | | 100% | 4.58% | Composite |
| Congressional Budget Office (CBO) Long-Term 20-Year Budget Outlook | | | 3.80% | 100.0% | 4.46% | CBO |
| Energy Information Administration (EIA) | 2.65% | 2.39% | 5.10% | 100.0% | 4.69% | EIA |

| Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity | | | | | | | |
|---|---|---|---|---|---|---|---|
| | X | CBO | 4.46% | EIA | 4.69% | Composite | 4.58% |
| 1 | Company Peer Screen | 8.83% | | 9.02% | | 8.93% | |
| 2 | Staff Peer Screen | 9.07% | | 9.26% | | 9.17% | |
| 3 | Staff Sensitivity Peer Screen | 8.94% | | 9.13% | | 9.04% | |

Hamada →

| Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted) | | | | | | | |
|---|---|---|---|---|---|---|---|
| X | CBO | 4.46% | EIA | 4.69% | Composite | 4.58% | |
| Company Peer Screen | 8.59% | | 8.78% | | 8.69% | | 1 |
| Staff Peer Screen | 8.95% | | 9.14% | | 9.05% | | 2 |
| Staff Sensitivity Peer Screen | 8.75% | | 8.94% | | 8.85% | | 3 |

| Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Y | CBO | 4.46% | EIA | 4.69% | Composite | 4.58% |
| 1 | Company Peer Screen | 8.99% | | 9.17% | | 9.08% | |
| 2 | Staff Peer Screen | 9.37% | | 9.54% | | 9.46% | |
| 3 | Staff Sensitivity Peer Screen | 9.11% | | 9.29% | | 9.20% | |

Hamada →

| Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Y | CBO | 4.46% | EIA | 4.69% | Composite | 4.58% | |
| Company Peer Screen | 8.75% | | 8.93% | | 8.84% | | 1 |
| Staff Peer Screen | 9.25% | | 9.42% | | 9.34% | | 2 |
| Staff Sensitivity Peer Screen | 8.92% | | 9.10% | | 9.01% | | 3 |

| | | | | | |
|---|---|---|---|---|---|
| Best Fit Range of Reasonable ROEs | 8.95% | to | 9.34% | ROE | |
| Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by : | | | | 12.5 | bps |
| | 9.07% | to | 9.46% | ROE | |
| | Midpoint | 9.3% | ROE | Testimony | |
| Staff Point ROE: | | 9.3% | | | |

CAPM and Single Stage DCF point to the middle to lower end of Staff's Three Stage DCF Modeling Results

CASE: UE 426
WITNESS: MATT MULDOON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 105

# ROE:
# Capital Asset Pricing Model (CAPM)

**March 25, 2024**

## Staff's CAPM Modeling Results

| | | |
|---|---|---|
| IPC | 3.94% | Rf Rate as shown in Exhibit IPC/801Buckham/3 |
| Direct | 11.38% | IPC Mkt Return |
| Testimony | 7.44% | IPC Mkt Risk Premium (MRP) |
| Staff | 4.348% | $R_f$ Feb. 24, 2024 30-Yr UST Yield /WSJ www.wsj.com/market-data/bonds |
| | 9.75% | 30-Year S&P 500 Proxy Market Return Geometric Return |
| | 5.40% | Staff 30-Yr Mkt Risk Premium (MRP) |

$R_{IPC} = R_f + Beta*MRP$

| | Screen # | Abbreviated Utility | UE 426 IPC | UE 426 Staff | LT Debt UE 426 Sensitivity | Ticker | VL Q3 2023 Beta | Staff MRP 30 Yr ROE w VL Beta CAPM | IPC MRP IPC/800 ROE w VL Beta CAPM | Screen # | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | Allete | Yes | No | No | ALE | 0.95 | 9.48% | 11.01% | 1 | 1 |
| 2 | 2 | Alliant | No | Yes | Yes | LNT | 0.90 | 9.21% | 10.64% | 2 | 2 |
| 3 | 3 | Ameren | Yes | Yes | Yes | AEE | 0.90 | 9.21% | 10.64% | 3 | 3 |
| 4 | 4 | AEP | No | No | Yes | AEP | 0.80 | 8.67% | 9.89% | 4 | 4 |
| 5 | 5 | Avangrid | Yes | No | No | AGR | 0.85 | 8.94% | 10.26% | 5 | 5 |
| 6 | 6 | Avista | Yes | Yes | Yes | AVA | 0.90 | 9.21% | 10.64% | 6 | 6 |
| 7 | 7 | Black Hills | Yes | Yes | Yes | BKH | 1.00 | 9.75% | 11.38% | 7 | 7 |
| 8 | 9 | CMS | Yes | No | No | CMS | 0.85 | 8.94% | 10.26% | 9 | 8 |
| 9 | 10 | Consol Ed | No | Yes | Yes | ED | 0.75 | 8.40% | 9.52% | 10 | 9 |
| 10 | 11 | Dominion | Yes | No | No | D | 0.85 | 8.94% | 10.26% | 11 | 10 |
| 11 | 12 | DTE | Yes | No | No | DTE | 1.00 | 9.75% | 11.38% | 12 | 11 |
| 12 | 13 | Duke | Yes | No | Yes | DUK | 0.85 | 8.94% | 10.26% | 13 | 12 |
| 13 | 15 | Entergy | Yes | No | No | ETR | 0.95 | 9.48% | 11.01% | 15 | 13 |
| 14 | 16 | Evergy | No | Yes | Yes | EVRG | 0.95 | 9.48% | 11.01% | 16 | 14 |
| 15 | 17 | Eversource | No | No | Yes | ES | 0.90 | 9.21% | 10.64% | 17 | 15 |
| 16 | 18 | Exelon | Yes | No | No | EXC | 0.00 | 4.35% | 3.94% | 18 | 16 |
| 17 | 22 | IDACORP | Yes | Yes | Yes | IDA | 0.85 | 8.94% | 10.26% | 22 | 17 |
| 18 | 25 | NorthWestern | Yes | Yes | Yes | NWE | 0.95 | 9.48% | 11.01% | 25 | 18 |
| 19 | 26 | OGE | Yes | Yes | Yes | OGE | 1.05 | 10.02% | 11.75% | 26 | 19 |
| 20 | 27 | Otter Tail | Yes | No | Yes | OTTR | 0.90 | 9.21% | 10.64% | 27 | 20 |
| 21 | 29 | PGE | Yes | Yes | Yes | POR | 0.90 | 9.21% | 10.64% | 29 | 21 |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | PNW | 0.95 | 9.48% | 11.01% | 30 | 22 |
| 23 | 31 | PNM | Yes | No | No | PNM | 0.90 | 9.21% | 10.64% | 31 | 23 |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | PEG | 0.90 | 9.21% | 10.64% | 33 | 24 |
| 25 | 34 | Sempra | Yes | Yes | Yes | SRE | 1.00 | 9.75% | 11.38% | 34 | 25 |
| 26 | 35 | Southern | Yes | No | No | SO | 0.90 | 9.21% | 10.64% | 35 | 26 |
| 27 | 36 | WEC | No | Yes | Yes | WEC | 0.85 | 8.94% | 10.26% | 36 | 27 |
| 28 | 37 | Xcel | No | No | Yes | XEL | 0.85 | 8.94% | 10.26% | 37 | 28 |
| | | No. of Peers: | 21 | 14 | 19 | | | VL Betas | VL Betas | | |
| | | | | | Company Screen | | Mean | 9.1% | 10.5% | ROE | |
| | | | | | Staff Screen | | Mean | 9.3% | 10.8% | ROE | |
| | | | | | Staff Sensitivity Screen | | Mean | 9.2% | 10.7% | ROE | |

Points to Midpoint of Staff's 3-Stage DCF Results

CASE: UE 426
WITNESS: MATT MULDOON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 106

# ROE:
# Gordon Growth – Single Stage DCF

# March 25, 2024

## 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 Lower End of Staff's 3-Stage DCF Modeling Results**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | = 9 + 10 | |
| | Screen # | Abbreviated Utility | UE 426 IPC | UE 426 Staff | LT Debt UE 426 Sensitivity | 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 | No | ALE | 59.87 | 4.5% | 2.79 | 4.7% | 2.9% | 7.5% | 1 |
| 2 | 2 | Alliant | No | Yes | Yes | LNT | 49.71 | 3.6% | 1.92 | 3.9% | 6.0% | 9.9% | 2 |
| 3 | 3 | Ameren | Yes | Yes | Yes | AEE | 70.70 | 3.6% | 2.65 | 3.7% | 7.1% | 10.8% | 3 |
| 4 | 4 | AEP | No | No | Yes | AEP | 79.24 | 4.2% | 3.52 | 4.4% | 5.6% | 10.0% | 4 |
| 5 | 5 | Avangrid | Yes | No | No | AGR | 31.06 | 5.7% | 1.76 | 5.7% | 1.1% | 6.8% | 5 |
| 6 | 6 | Avista | Yes | Yes | Yes | AVA | 34.45 | 5.3% | 1.92 | 5.6% | 4.5% | 10.1% | 6 |
| 7 | 7 | Black Hills | Yes | Yes | Yes | BKH | 52.19 | 4.8% | 2.65 | 5.1% | 4.7% | 9.7% | 7 |
| 8 | 9 | CMS | Yes | No | No | CMS | 57.52 | 3.4% | 2.04 | 3.5% | 4.8% | 8.3% | 9 |
| 9 | 10 | Consol Ed | No | Yes | Yes | ED | 90.94 | 3.6% | 3.34 | 3.7% | 3.7% | 7.4% | 10 |
| 10 | 11 | Dominion | Yes | No | No | D | 46.21 | 5.8% | 2.67 | 5.8% | -0.8% | 5.0% | 11 |
| 11 | 12 | DTE | Yes | No | No | DTE | 107.35 | 3.5% | 4.05 | 3.8% | 3.8% | 7.5% | 12 |
| 12 | 13 | Duke | Yes | No | Yes | DUK | 96.68 | 4.2% | 4.14 | 4.3% | 1.6% | 5.9% | 13 |
| 13 | 15 | Entergy | Yes | No | No | ETR | 100.53 | 4.3% | 4.56 | 4.5% | 4.2% | 8.8% | 15 |
| 14 | 16 | Evergy | No | Yes | Yes | EVRG | 51.16 | 4.8% | 2.61 | 5.1% | 5.7% | 10.8% | 16 |
| 15 | 17 | Eversource | No | No | Yes | ES | 57.44 | 4.7% | 2.86 | 5.0% | 6.0% | 11.0% | 17 |
| 16 | 18 | Exelon | Yes | No | No | EXC | 35.31 | 4.1% | 1.60 | 4.5% | 3.4% | 8.0% | 18 |
| 17 | 22 | IDACORP | Yes | Yes | Yes | IDA | 95.05 | 3.4% | 3.40 | 3.6% | 6.3% | 9.9% | 22 |
| 18 | 25 | NorthWesterr | Yes | Yes | Yes | NWE | 49.05 | 5.2% | 2.60 | 5.3% | 1.9% | 7.2% | 25 |
| 19 | 26 | OGE | Yes | Yes | Yes | OGE | 33.81 | 4.9% | 1.78 | 5.3% | 2.4% | 7.6% | 26 |
| 20 | 27 | Otter Tail | Yes | No | Yes | OTTR | 88.59 | 2.0% | 1.81 | 2.0% | 5.9% | 7.9% | 27 |
| 21 | 29 | PGE | Yes | Yes | Yes | POR | 41.46 | 4.5% | 1.98 | 4.8% | 6.0% | 10.7% | 29 |
| 22 | 30 | Pinnacle | Yes | Yes | Yes | PNW | 71.04 | 4.9% | 3.54 | 5.0% | 2.1% | 7.1% | 30 |
| 23 | 31 | PNM | Yes | No | No | PNM | 38.27 | 3.9% | 1.59 | 4.2% | -8.8% | -4.7% | 31 |
| 24 | 33 | Public Serv. | Yes | Yes | Yes | PEG | 59.09 | 3.9% | 2.40 | 4.1% | 5.4% | 9.5% | 33 |
| 25 | 34 | Sempra | Yes | Yes | Yes | SRE | 72.55 | 3.3% | 2.50 | 3.4% | -2.6% | 0.8% | 34 |
| 26 | 35 | Southern | Yes | No | No | SO | 69.80 | 4.0% | 2.86 | 4.1% | 2.8% | 6.9% | 35 |
| 27 | 36 | WEC | No | Yes | Yes | WEC | 81.90 | 3.8% | 3.33 | 4.1% | 5.8% | 9.8% | 36 |
| 28 | 37 | Xcel | No | No | Yes | XEL | 60.72 | 3.4% | 2.22 | 3.7% | 6.7% | 10.3% | 37 |
| | | No. of Peers: | 21 | 14 | 19 | | | | | | | Mean | |
| | | | | | | | | | | | Company Screen | 7.2% | ROE |
| | | | | | | | | | | | Staff Screen | 8.7% | ROE |
| | | | | | | | | | | | Staff Sensitivity Screen | 8.8% | ROE |

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

CASE: UE 426
WITNESS: MATT MULDOON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 107

# ROE: BEA Historical
# GDP Growth

# March 25, 2024

## Bureau of Economic Analysis (BEA)

Current-Dollar and "Real" Gross Domestic Product (GDP)

Staff Accessed February 20, 2024

Annual https://fred.stlouisfed.org/series/GDPA Quarterly https://fred.stlouisfed.org/series/GDP https://fred.stlouisfed.org/series/GDPC1

https://fred.stlouisfed.org/series/GDPCA

| Yr | GDP in billions of current dollars | GDP in billions of chained 2017 dollars |
|---|---|---|
| 1947 | 249.616 | 2184.614 |
| 1948 | 274.468 | 2274.627 |
| 1949 | 272.475 | 2261.928 |
| 1950 | 299.827 | 2458.532 |
| 1951 | 346.914 | 2656.32 |
| 1952 | 367.341 | 2764.803 |
| 1953 | 389.218 | 2894.411 |
| 1954 | 390.549 | 2877.708 |
| 1955 | 425.478 | 3083.026 |
| 1956 | 449.353 | 3148.765 |
| 1957 | 474.039 | 3215.065 |
| 1958 | 481.229 | 3191.216 |
| 1959 | 521.654 | 3412.421 |
| 1960 | 542.382 | 3500.272 |
| 1961 | 562.209 | 3590.066 |
| 1962 | 603.922 | 3810.124 |
| 1963 | 637.45 | 3976.142 |
| 1964 | 684.46 | 4205.277 |
| 1965 | 742.289 | 4478.555 |
| 1966 | 813.414 | 4773.931 |
| 1967 | 859.959 | 4904.864 |
| 1968 | 940.651 | 5145.914 |
| 1969 | 1017.615 | 5306.594 |
| 1970 | 1073.303 | 5316.391 |
| 1971 | 1164.85 | 5491.445 |
| 1972 | 1279.11 | 5780.048 |
| 1973 | 1425.376 | 6106.371 |
| 1974 | 1545.243 | 6073.363 |
| 1975 | 1684.904 | 6060.875 |
| 1976 | 1873.412 | 6387.437 |
| 1977 | 2081.826 | 6682.804 |
| 1978 | 2351.599 | 7052.711 |
| 1979 | 2627.333 | 7275.999 |
| 1980 | 2857.307 | 7257.316 |
| 1981 | 3207.041 | 7441.485 |
| 1982 | 3343.789 | 7307.314 |
| 1983 | 3634.038 | 7642.266 |
| 1984 | 4037.613 | 8195.295 |
| 1985 | 4338.979 | 8537.004 |
| 1986 | 4579.631 | 8832.611 |
| 1987 | 4855.215 | 9137.745 |
| 1988 | 5236.438 | 9519.427 |
| 1989 | 5641.58 | 9869.003 |
| 1990 | 5963.144 | 10055.129 |
| 1991 | 6158.129 | 10044.238 |
| 1992 | 6520.327 | 10398.046 |
| 1993 | 6858.559 | 10684.179 |
| 1994 | 7287.236 | 11114.647 |
| 1995 | 7639.749 | 11413.012 |
| 1996 | 8073.122 | 11843.599 |
| 1997 | 8577.552 | 12370.299 |
| 1998 | 9062.817 | 12924.876 |
| 1999 | 9631.172 | 13543.774 |
| 2000 | 10250.952 | 14096.033 |
| 2001 | 10581.929 | 14230.726 |
| 2002 | 10929.108 | 14472.712 |
| 2003 | 11456.45 | 14877.312 |
| 2004 | 12217.196 | 15449.757 |
| 2005 | 13039.197 | 15987.957 |
| 2006 | 13815.583 | 16433.148 |
| 2007 | 14474.228 | 16762.445 |
| 2008 | 14769.862 | 16781.485 |
| 2009 | 14478.067 | 16349.11 |
| 2010 | 15048.97 | 16789.75 |
| 2011 | 15599.731 | 17052.41 |
| 2012 | 16253.97 | 17442.759 |
| 2013 | 16880.683 | 17812.167 |
| 2014 | 17608.138 | 18261.714 |
| 2015 | 18295.019 | 18799.622 |
| 2016 | 18804.913 | 19141.672 |
| 2017 | 19612.102 | 19612.102 |
| 2018 | 20656.516 | 20193.896 |
| 2019 | 21521.395 | 20692.087 |
| 2020 | 21322.95 | 20234.074 |
| 2021 | 23594.031 | 21407.692 |
| 2022 | 25744.108 | 21822.037 |
| 2023 | 27356.393 | 22375.307 |

(Seasonally adjusted annual rates) — 1980 through 2023 Q4

| Quarter | GDP in billions of current dollars | GDP in billions of chained 2017 dollars | Qtr# | Average | Ln(Real GDP) | |
|---|---|---|---|---|---|---|
| 1947Q1 | 243.164 | 2182.681 | 1 | 1 | 8.901 | 1980 |
| 1947Q2 | 245.968 | 2176.892 | 2 | 2 | 8.880 | |
| 1947Q3 | 249.585 | 2172.432 | 3 | 3 | 8.879 | |
| 1947Q4 | 259.745 | 2206.452 | 4 | 4 | 8.898 | |
| 1948Q1 | 265.742 | 2239.682 | 5 | 5 | 8.917 | 1981 |
| 1948Q2 | 272.567 | 2276.690 | 6 | 6 | 8.910 | |
| 1948Q3 | 279.196 | 2289.770 | 7 | 7 | 8.922 | |
| 1948Q4 | 280.366 | 2292.364 | 8 | 8 | 8.911 | |
| 1949Q1 | 275.034 | 2260.807 | 9 | 9 | 8.895 | 1982 |
| 1949Q2 | 271.351 | 2253.128 | 10 | 10 | 8.900 | |
| 1949Q3 | 272.889 | 2276.424 | 11 | 11 | 8.896 | |
| 1949Q4 | 270.627 | 2257.352 | 12 | 12 | 8.896 | |
| 1950Q1 | 280.828 | 2346.104 | 13 | 13 | 8.909 | 1983 |
| 1950Q2 | 290.383 | 2417.682 | 14 | 14 | 8.932 | |
| 1950Q3 | 308.153 | 2511.127 | 15 | 15 | 8.952 | |
| 1950Q4 | 319.945 | 2559.214 | 16 | 16 | 8.972 | |
| 1951Q1 | 336.000 | 2593.967 | 17 | 17 | 8.992 | 1984 |
| 1951Q2 | 344.090 | 2638.898 | 18 | 18 | 9.009 | |
| 1951Q3 | 351.385 | 2693.259 | 19 | 19 | 9.018 | |
| 1951Q4 | 356.178 | 2699.156 | 20 | 20 | 9.026 | |
| 1952Q1 | 359.820 | 2727.954 | 21 | 21 | 9.036 | 1985 |
| 1952Q2 | 361.030 | 2733.800 | 22 | 22 | 9.045 | |
| 1952Q3 | 367.701 | 2753.517 | 23 | 23 | 9.060 | |
| 1952Q4 | 380.812 | 2843.941 | 24 | 24 | 9.067 | |
| 1953Q1 | 387.980 | 2896.811 | 25 | 25 | 9.077 | 1986 |
| 1953Q2 | 391.749 | 2919.206 | 26 | 26 | 9.081 | |
| 1953Q3 | 391.171 | 2902.785 | 27 | 27 | 9.091 | |
| 1953Q4 | 385.970 | 2858.845 | 28 | 28 | 9.096 | |
| 1954Q1 | 385.345 | 2845.192 | 29 | 29 | 9.103 | 1987 |
| 1954Q2 | 386.121 | 2848.305 | 30 | 30 | 9.114 | |
| 1954Q3 | 390.996 | 2880.482 | 31 | 31 | 9.123 | |
| 1954Q4 | 399.734 | 2936.852 | 32 | 32 | 9.140 | |
| 1955Q1 | 413.073 | 3020.746 | 33 | 33 | 9.145 | 1988 |
| 1955Q2 | 421.532 | 3069.910 | 34 | 34 | 9.158 | |
| 1955Q3 | 430.221 | 3111.379 | 35 | 35 | 9.164 | |
| 1955Q4 | 437.092 | 3130.068 | 36 | 36 | 9.177 | |
| 1956Q1 | 439.746 | 3117.922 | 37 | 37 | 9.187 | 1989 |
| 1956Q2 | 446.010 | 3143.694 | 38 | 38 | 9.195 | |
| 1956Q3 | 451.191 | 3140.874 | 39 | 39 | 9.202 | |
| 1956Q4 | 460.463 | 3192.570 | 40 | 40 | 9.204 | |
| 1957Q1 | 469.779 | 3213.011 | 41 | 41 | 9.215 | 1990 |
| 1957Q2 | 472.025 | 3205.970 | 42 | 42 | 9.219 | |
| 1957Q3 | 479.490 | 3237.386 | 43 | 43 | 9.219 | |
| 1957Q4 | 474.864 | 3203.894 | 44 | 44 | 9.210 | |
| 1958Q1 | 467.540 | 3120.724 | 45 | 45 | 9.206 | 1991 |
| 1958Q2 | 471.978 | 3141.224 | 46 | 46 | 9.213 | |
| 1958Q3 | 485.841 | 3213.884 | 47 | 47 | 9.218 | |
| 1958Q4 | 499.555 | 3289.032 | 48 | 48 | 9.222 | |
| 1959Q1 | 510.330 | 3352.129 | 49 | 49 | 9.234 | 1992 |
| 1959Q2 | 522.653 | 3427.667 | 50 | 50 | 9.244 | |
| 1959Q3 | 525.034 | 3430.057 | 51 | 51 | 9.254 | |
| 1959Q4 | 528.600 | 3439.832 | 52 | 52 | 9.265 | |
| 1960Q1 | 542.648 | 3517.181 | 53 | 53 | 9.266 | 1993 |
| 1960Q2 | 541.080 | 3498.246 | 54 | 54 | 9.272 | |
| 1960Q3 | 545.604 | 3515.385 | 55 | 55 | 9.277 | |
| 1960Q4 | 540.197 | 3470.278 | 56 | 56 | 9.290 | |
| 1961Q1 | 545.018 | 3493.703 | 57 | 57 | 9.300 | 1994 |
| 1961Q2 | 555.545 | 3553.021 | 58 | 58 | 9.314 | |
| 1961Q3 | 567.664 | 3621.252 | 59 | 59 | 9.319 | |
| 1961Q4 | 580.612 | 3692.289 | 60 | 60 | 9.331 | |
| 1962Q1 | 594.013 | 3758.147 | 61 | 61 | 9.334 | 1995 |
| 1962Q2 | 600.366 | 3792.149 | 62 | 62 | 9.337 | |
| 1962Q3 | 609.027 | 3838.776 | 63 | 63 | 9.346 | |
| 1962Q4 | 612.280 | 3851.421 | 64 | 64 | 9.353 | |
| 1963Q1 | 621.672 | 3893.482 | 65 | 65 | 9.360 | 1996 |
| 1963Q2 | 629.752 | 3937.183 | 66 | 66 | 9.377 | |
| 1963Q3 | 644.444 | 4023.755 | 67 | 67 | 9.385 | |
| 1963Q4 | 653.938 | 4050.147 | 68 | 68 | 9.396 | |
| 1964Q1 | 669.822 | 4135.553 | 69 | 69 | 9.402 | 1997 |
| 1964Q2 | 678.674 | 4180.592 | 70 | 70 | 9.419 | |
| 1964Q3 | 692.031 | 4245.918 | 71 | 71 | 9.431 | |
| 1964Q4 | 697.319 | 4259.046 | 72 | 72 | 9.440 | |
| 1965Q1 | 717.790 | 4362.111 | 73 | 73 | 9.450 | 1998 |
| 1965Q2 | 730.191 | 4417.225 | 74 | 74 | 9.459 | |
| 1965Q3 | 749.323 | 4515.427 | 75 | 75 | 9.471 | |
| 1965Q4 | 771.857 | 4619.458 | 76 | 76 | 9.487 | |
| 1966Q1 | 795.734 | 4731.888 | 77 | 77 | 9.497 | 1999 |
| 1966Q2 | 804.981 | 4748.046 | 78 | 78 | 9.505 | |
| 1966Q3 | 819.638 | 4788.254 | 79 | 79 | 9.518 | |
| 1966Q4 | 833.302 | 4827.537 | 80 | 80 | 9.534 | |
| 1967Q1 | 844.170 | 4870.299 | 81 | 81 | 9.538 | 2000 |
| 1967Q2 | 848.983 | 4873.287 | 82 | 82 | 9.556 | |
| 1967Q3 | 865.233 | 4919.392 | 83 | 83 | 9.557 | |
| 1967Q4 | 881.439 | 4956.477 | 84 | 84 | 9.563 | |
| 1968Q1 | 909.387 | 5057.553 | 85 | 85 | 9.560 | 2001 |
| 1968Q2 | 934.344 | 5142.033 | 86 | 86 | 9.566 | |
| 1968Q3 | 950.825 | 5181.859 | 87 | 87 | 9.562 | |
| 1968Q4 | 968.030 | 5202.212 | 88 | 88 | 9.565 | |
| 1969Q1 | 993.337 | 5283.597 | 89 | 89 | 9.573 | 2002 |
| 1969Q2 | 1009.020 | 5299.625 | 90 | 90 | 9.579 | |
| 1969Q3 | 1029.956 | 5334.600 | 91 | 91 | 9.583 | |
| 1969Q4 | 1038.147 | 5308.556 | 92 | 92 | 9.584 | |
| 1970Q1 | 1051.200 | 5300.652 | 93 | 93 | 9.590 | 2003 |
| 1970Q2 | 1067.375 | 5308.164 | 94 | 94 | 9.599 | |
| 1970Q3 | 1086.059 | 5357.077 | 95 | 95 | 9.615 | |
| 1970Q4 | 1088.608 | 5299.672 | 96 | 96 | 9.627 | |
| 1971Q1 | 1135.156 | 5443.619 | 97 | 97 | 9.632 | 2004 |
| 1971Q2 | 1156.271 | 5473.059 | 98 | 98 | 9.640 | |
| 1971Q3 | 1177.675 | 5518.072 | 99 | 99 | 9.649 | |
| 1971Q4 | 1190.297 | 5531.032 | 100 | 100 | 9.660 | |
| 1972Q1 | 1230.609 | 5632.649 | 101 | 101 | 9.671 | 2005 |
| 1972Q2 | 1266.369 | 5760.470 | 102 | 102 | 9.676 | |
| 1972Q3 | 1290.566 | 5814.854 | 103 | 103 | 9.683 | |
| 1972Q4 | 1328.904 | 5912.220 | 104 | 104 | 9.689 | |
| 1973Q1 | 1377.490 | 6058.544 | 105 | 105 | 9.702 | 2006 |
| 1973Q2 | 1413.887 | 6124.506 | 106 | 106 | 9.705 | |
| 1973Q3 | 1433.838 | 6092.301 | 107 | 107 | 9.706 | |
| 1973Q4 | 1476.289 | 6150.131 | 108 | 108 | 9.715 | |
| 1974Q1 | 1491.209 | 6097.258 | 109 | 109 | 9.718 | 2007 |
| 1974Q2 | 1530.056 | 6111.751 | 110 | 110 | 9.724 | |
| 1974Q3 | 1560.026 | 6053.978 | 111 | 111 | 9.730 | |
| 1974Q4 | 1599.679 | 6030.464 | 112 | 112 | 9.736 | |
| 1975Q1 | 1616.116 | 5957.035 | 113 | 113 | 9.732 | 2008 |
| 1975Q2 | 1651.853 | 5999.610 | 114 | 114 | 9.738 | |
| 1975Q3 | 1709.820 | 6102.326 | 115 | 115 | 9.732 | |
| 1975Q4 | 1761.831 | 6184.530 | 116 | 116 | 9.710 | |
| 1976Q1 | 1820.487 | 6323.649 | 117 | 117 | 9.699 | 2009 |
| 1976Q2 | 1852.332 | 6370.025 | 118 | 118 | 9.697 | |
| 1976Q3 | 1886.558 | 6404.895 | 119 | 119 | 9.701 | |
| 1976Q4 | 1934.273 | 6451.177 | 120 | 120 | 9.711 | |
| 1977Q1 | 1988.648 | 6527.703 | 121 | 121 | 9.716 | 2010 |
| 1977Q2 | 2055.909 | 6654.466 | 122 | 122 | 9.726 | |
| 1977Q3 | 2118.473 | 6774.457 | 123 | 123 | 9.733 | |
| 1977Q4 | 2164.270 | 6774.592 | 124 | 124 | 9.739 | |
| 1978Q1 | 2202.760 | 6796.260 | 125 | 125 | 9.736 | 2011 |
| 1978Q2 | 2331.633 | 7058.920 | 126 | 126 | 9.743 | |
| 1978Q3 | 2395.053 | 7129.915 | 127 | 127 | 9.743 | |
| 1978Q4 | 2476.949 | 7225.750 | 128 | 128 | 9.754 | |
| 1979Q1 | 2526.610 | 7238.727 | 129 | 129 | 9.762 | 2012 |
| 1979Q2 | 2591.247 | 7246.454 | 130 | 130 | 9.767 | |
| 1979Q3 | 2667.565 | 7300.281 | 131 | 131 | 9.768 | |
| 1979Q4 | 2723.883 | 7318.535 | 132 | 132 | 9.769 | |
| 1980Q1 | 2789.842 | 7341.557 | 133 | 133 | 9.779 | 2013 |
| 1980Q2 | 2797.352 | 7190.289 | 134 | 134 | 9.782 | |
| 1980Q3 | 2856.483 | 7181.743 | 135 | 135 | 9.790 | |
| 1980Q4 | 2985.557 | 7315.677 | 136 | 136 | 9.799 | |
| 1981Q1 | 3124.206 | 7459.022 | 137 | 137 | 9.796 | 2014 |
| 1981Q2 | 3162.532 | 7403.745 | 138 | 138 | 9.808 | |
| 1981Q3 | 3260.609 | 7492.405 | 139 | 139 | 9.820 | |
| 1981Q4 | 3280.818 | 7410.768 | 140 | 140 | 9.826 | |
| 1982Q1 | 3274.302 | 7295.631 | 141 | 141 | 9.834 | 2015 |
| 1982Q2 | 3331.972 | 7328.912 | 142 | 142 | 9.841 | |
| 1982Q3 | 3366.322 | 7300.896 | 143 | 143 | 9.845 | |
| 1982Q4 | 3402.561 | 7303.817 | 144 | 144 | 9.847 | |
| 1983Q1 | 3473.413 | 7400.066 | 145 | 145 | 9.852 | 2016 |
| 1983Q2 | 3578.848 | 7568.456 | 146 | 146 | 9.855 | |
| 1983Q3 | 3689.179 | 7719.746 | 147 | 147 | 9.863 | |
| 1983Q4 | 3794.706 | 7880.794 | 148 | 148 | 9.868 | |

**Long Run Historical GDP Growth Rate**

Annualized Real LN GPD Q

**2.65%**

SUMMARY OUTPUT

| Regression Statistics | |
|---|---|
| Multiple R | 0.989672527 |
| R Square | 0.979451711 |
| Adjusted R Square | 0.979333617 |
| Standard Error | 0.048579271 |
| Observations | 176 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 1 | 19.57305439 | 19.57305439 | 8293.858359 | 9.9307E-149 |
| Residual | 174 | 0.410630531 | 0.002359946 | | |
| Total | 175 | 19.98368493 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Lower 95.0% | Upper 95.0% |
|---|---|---|---|---|---|---|---|---|
| Intercept | 8.926549282 | 0.007354921 | 1213.683982 | 0 | 8.912032939 | 8.941065626 | 8.912032939 | 8.941065626 |
| Average | 0.006563839 | 7.20742E-05 | 91.07062292 | 9.9307E-149 | 0.006421587 | 0.006706091 | 0.006421587 | 0.006706091 |

**Note** July 31, 2013, 14th Comprehensive Significant Revision:
BEA revised its tables back to 1929 in to order to count:
1 Artistic Works
2 Research and Development
as Capital Investments that Depreciate Over Time
rather than one time expenditures

From an Economy based on
( Industry and Manufacturing )
to one based on
( Knowledge and Information )

| | | | |
|---|---|---|---|
| 1984Q1 | 3908.054 | 8034.847 | 149 |
| 1984Q2 | 4009.601 | 8173.670 | 150 |
| 1984Q3 | 4084.250 | 8252.465 | 151 |
| 1984Q4 | 4148.551 | 8320.199 | 152 |
| 1985Q1 | 4230.168 | 8400.820 | 153 |
| 1985Q2 | 4294.887 | 8474.787 | 154 |
| 1985Q3 | 4386.773 | 8604.220 | 155 |
| 1985Q4 | 4444.094 | 8668.188 | 156 |
| 1986Q1 | 4507.894 | 8749.127 | 157 |
| 1986Q2 | 4545.340 | 8788.524 | 158 |
| 1986Q3 | 4607.669 | 8872.601 | 159 |
| 1986Q4 | 4657.627 | 8920.193 | 160 |
| 1987Q1 | 4722.156 | 8986.367 | 161 |
| 1987Q2 | 4806.160 | 9083.256 | 162 |
| 1987Q3 | 4884.555 | 9162.024 | 163 |
| 1987Q4 | 5007.994 | 9319.332 | 164 |
| 1988Q1 | 5073.372 | 9367.502 | 165 |
| 1988Q2 | 5190.036 | 9490.594 | 166 |
| 1988Q3 | 5282.835 | 9546.206 | 167 |
| 1988Q4 | 5399.509 | 9673.405 | 168 |
| 1989Q1 | 5511.253 | 9771.725 | 169 |
| 1989Q2 | 5612.463 | 9846.293 | 170 |
| 1989Q3 | 5695.365 | 9919.228 | 171 |
| 1989Q4 | 5747.237 | 9938.767 | 172 |
| 1990Q1 | 5872.701 | 10047.386 | 173 |
| 1990Q2 | 5960.028 | 10083.855 | 174 |
| 1990Q3 | 6015.116 | 10090.569 | 175 |
| 1990Q4 | 6004.733 | 9998.704 | 176 |
| 1991Q1 | 6035.178 | 9951.916 | 177 |
| 1991Q2 | 6126.862 | 10029.510 | 178 |
| 1991Q3 | 6205.937 | 10080.195 | 179 |
| 1991Q4 | 6264.540 | 10115.329 | 180 |
| 1992Q1 | 6363.102 | 10236.435 | 181 |
| 1992Q2 | 6470.763 | 10347.429 | 182 |
| 1992Q3 | 6566.641 | 10449.673 | 183 |
| 1992Q4 | 6680.803 | 10558.648 | 184 |
| 1993Q1 | 6729.459 | 10576.275 | 185 |
| 1993Q2 | 6808.939 | 10637.847 | 186 |
| 1993Q3 | 6882.098 | 10688.606 | 187 |
| 1993Q4 | 7013.738 | 10833.987 | 188 |
| 1994Q1 | 7115.652 | 10939.116 | 189 |
| 1994Q2 | 7246.931 | 11087.361 | 190 |
| 1994Q3 | 7331.075 | 11152.176 | 191 |
| 1994Q4 | 7455.288 | 11279.932 | 192 |
| 1995Q1 | 7522.289 | 11319.951 | 193 |
| 1995Q2 | 7580.997 | 11353.721 | 194 |
| 1995Q3 | 7683.125 | 11450.310 | 195 |
| 1995Q4 | 7772.586 | 11528.067 | 196 |
| 1996Q1 | 7868.468 | 11614.418 | 197 |
| 1996Q2 | 8032.840 | 11808.140 | 198 |
| 1996Q3 | 8131.408 | 11914.063 | 199 |
| 1996Q4 | 8259.771 | 12037.775 | 200 |
| 1997Q1 | 8362.655 | 12115.472 | 201 |
| 1997Q2 | 8518.825 | 12317.221 | 202 |
| 1997Q3 | 8662.823 | 12471.010 | 203 |
| 1997Q4 | 8765.907 | 12577.495 | 204 |
| 1998Q1 | 8866.480 | 12703.742 | 205 |
| 1998Q2 | 8969.699 | 12821.339 | 206 |
| 1998Q3 | 9121.097 | 12982.752 | 207 |
| 1998Q4 | 9293.991 | 13191.670 | 208 |
| 1999Q1 | 9411.682 | 13315.597 | 209 |
| 1999Q2 | 9526.210 | 13426.748 | 210 |
| 1999Q3 | 9686.626 | 13604.771 | 211 |
| 1999Q4 | 9900.169 | 13827.980 | 212 |
| 2000Q1 | 10002.179 | 13878.147 | 213 |
| 2000Q2 | 10247.720 | 14130.908 | 214 |
| 2000Q3 | 10318.165 | 14145.312 | 215 |
| 2000Q4 | 10435.744 | 14229.765 | 216 |
| 2001Q1 | 10470.231 | 14183.120 | 217 |
| 2001Q2 | 10599.000 | 14271.694 | 218 |
| 2001Q3 | 10598.020 | 14214.516 | 219 |
| 2001Q4 | 10660.465 | 14253.574 | 220 |
| 2002Q1 | 10783.500 | 14372.785 | 221 |
| 2002Q2 | 10887.460 | 14460.848 | 222 |
| 2002Q3 | 10984.040 | 14519.633 | 223 |
| 2002Q4 | 11061.433 | 14537.580 | 224 |
| 2003Q1 | 11174.129 | 14614.141 | 225 |
| 2003Q2 | 11312.766 | 14743.567 | 226 |
| 2003Q3 | 11566.669 | 14988.782 | 227 |
| 2003Q4 | 11772.234 | 15162.760 | 228 |
| 2004Q1 | 11923.447 | 15248.680 | 229 |
| 2004Q2 | 12112.815 | 15366.850 | 230 |
| 2004Q3 | 12305.307 | 15512.619 | 231 |
| 2004Q4 | 12527.214 | 15670.880 | 232 |
| 2005Q1 | 12767.286 | 15844.727 | 233 |
| 2005Q2 | 12922.656 | 15922.782 | 234 |
| 2005Q3 | 13142.642 | 16047.587 | 235 |
| 2005Q4 | 13324.204 | 16136.734 | 236 |
| 2006Q1 | 13599.160 | 16353.835 | 237 |
| 2006Q2 | 13753.424 | 16396.151 | 238 |
| 2006Q3 | 13870.188 | 16420.738 | 239 |
| 2006Q4 | 14039.560 | 16561.866 | 240 |
| 2007Q1 | 14215.651 | 16611.690 | 241 |
| 2007Q2 | 14402.082 | 16713.314 | 242 |
| 2007Q3 | 14564.117 | 16809.587 | 243 |
| 2007Q4 | 14715.058 | 16915.191 | 244 |
| 2008Q1 | 14706.538 | 16843.003 | 245 |
| 2008Q2 | 14865.701 | 16943.291 | 246 |
| 2008Q3 | 14898.999 | 16854.295 | 247 |
| 2008Q4 | 14608.208 | 16485.350 | 248 |
| 2009Q1 | 14430.901 | 16298.262 | 249 |
| 2009Q2 | 14381.236 | 16269.145 | 250 |
| 2009Q3 | 14448.882 | 16326.281 | 251 |
| 2009Q4 | 14651.249 | 16502.754 | 252 |
| 2010Q1 | 14764.610 | 16582.710 | 253 |
| 2010Q2 | 14980.193 | 16743.162 | 254 |
| 2010Q3 | 15141.607 | 16872.266 | 255 |
| 2010Q4 | 15309.474 | 16960.864 | 256 |
| 2011Q1 | 15351.448 | 16920.632 | 257 |
| 2011Q2 | 15557.539 | 17035.114 | 258 |
| 2011Q3 | 15647.680 | 17031.313 | 259 |
| 2011Q4 | 15842.259 | 17222.583 | 260 |
| 2012Q1 | 16068.805 | 17367.010 | 261 |
| 2012Q2 | 16207.115 | 17444.525 | 262 |
| 2012Q3 | 16319.541 | 17469.650 | 263 |
| 2012Q4 | 16420.419 | 17489.852 | 264 |
| 2013Q1 | 16648.189 | 17662.400 | 265 |
| 2013Q2 | 16728.687 | 17709.671 | 266 |
| 2013Q3 | 16953.838 | 17860.450 | 267 |
| 2013Q4 | 17192.019 | 18016.147 | 268 |
| 2014Q1 | 17197.738 | 17953.974 | 269 |
| 2014Q2 | 17518.508 | 18185.911 | 270 |
| 2014Q3 | 17804.228 | 18406.941 | 271 |
| 2014Q4 | 17912.079 | 18500.031 | 272 |
| 2015Q1 | 18063.529 | 18666.621 | 273 |
| 2015Q2 | 18279.784 | 18782.243 | 274 |
| 2015Q3 | 18401.626 | 18857.418 | 275 |
| 2015Q4 | 18435.137 | 18892.206 | 276 |
| 2016Q1 | 18525.933 | 19001.690 | 277 |
| 2016Q2 | 18711.702 | 19062.709 | 278 |
| 2016Q3 | 18892.639 | 19197.938 | 279 |
| 2016Q4 | 19089.379 | 19304.352 | 280 |
| 2017Q1 | 19280.084 | 19398.343 | 281 |
| 2017Q2 | 19438.643 | 19506.949 | 282 |
| 2017Q3 | 19692.595 | 19660.766 | 283 |
| 2017Q4 | 20037.088 | 19882.352 | 284 |
| 2018Q1 | 20328.553 | 20044.077 | 285 |
| 2018Q2 | 20580.912 | 20150.476 | 286 |
| 2018Q3 | 20798.730 | 20276.154 | 287 |
| 2018Q4 | 20917.867 | 20304.874 | 288 |
| 2019Q1 | 21104.133 | 20415.150 | 289 |
| 2019Q2 | 21384.775 | 20584.528 | 290 |
| 2019Q3 | 21694.282 | 20817.581 | 291 |
| 2019Q4 | 21902.390 | 20951.088 | 292 |
| 2020Q1 | 21706.513 | 20665.553 | 293 |
| 2020Q2 | 19913.143 | 19034.830 | 294 |
| 2020Q3 | 21647.64 | 20511.785 | 295 |
| 2020Q4 | 22024.502 | 20724.128 | 296 |
| 2021Q1 | 22600.185 | 20990.541 | 297 |
| 2021Q2 | 23292.362 | 21309.544 | 298 |
| 2021Q3 | 23828.973 | 21483.083 | 299 |
| 2021Q4 | 24654.603 | 21847.602 | 300 |

| | | |
|---|---|---|
| **149** | **9.873** | **2017** |
| **150** | **9.879** | |
| **151** | **9.886** | |
| **152** | **9.898** | |
| **153** | **9.906** | **2018** |
| **154** | **9.911** | |
| **155** | **9.917** | |
| **156** | **9.919** | |
| **157** | **9.924** | **2019** |
| **158** | **9.932** | |
| **159** | **9.944** | |
| **160** | **9.950** | |
| **161** | **9.936** | **2020** |
| **162** | **9.854** | |
| **163** | **9.929** | |
| **164** | **9.939** | |
| **165** | **9.952** | **2021** |
| **166** | **9.967** | |
| **167** | **9.975** | |
| **168** | **9.992** | |
| **169** | **9.987** | **2022** |
| **170** | **9.985** | |
| **171** | **9.992** | |
| **172** | **9.998** | |
| **173** | **10.004** | **2023** |
| **174** | **10.009** | |
| **175** | **10.021** | |
| **176** | **10.029** | |

| | |
|---|---|
| Ann'l (Current) | https://fred.stlouisfed.org/series/GDPA |
| Ann'l (2012) | https://apps.bea.gov/national/xls/gdplev.xlsx |
| Qtr (Current) | https://fred.stlouisfed.org/series/GDP |
| Qtr (2012) | https://fred.stlouisfed.org/series/GDPC1 |

On regression:
Docket UE 233, Staff 800, Storm/48-49
"An ordinary least squares (OLS) regression of the natural logarithm of quarterly values of sea
And footnote 100 on Storm/49
"That is to say, the natural logarithms of annual values of real GDP were regressed against va

In the current spreadsheet, this results in column K being the X variable and column L being th sonally adjusted annual rates of real GDP over the period 1980 Q1 through 2011 Q3"

CASE: UE 426
WITNESS: MATT MULDOON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 108

# ROE: TIPS Implied Inflation

# March 25, 2024

**2023 through 2053 TIPs-Implied Average Annual Inflation Rate:** **2.39%**

| Implied Market-based Inflationary Expectations | | | | | | |
|---|---|---|---|---|---|---|
| Qtr | 5-Yr | 7-Yr | 10-Yr | 20-Yr | 30-Yr | |
| 2023-Q4 | 2.2% | 2.3% | 2.3% | 2.6% | 2.4% | IPC UE 426 |

Source: Federal Reserve Statistical Release H.15

See H15 Qtrly Avg for data feed

| Yr. End Mo.-Yr. | Years | Individually Implied Price Levels 5-Yr | 7-Yr | 10-Yr | 20-Yr | 30-Yr | Implied Forward Curve/Price Level 5-Yr | 7-Yr | 10-Yr | 20-Yr | 30-Yr | Implied Price Level | Check |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dec-23 | 0 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | | | | | 100.00 | |
| Dec-24 | 1 | 102.23 | 102.30 | 102.29 | 102.57 | 102.35 | 102.23 | | | | | 102.23 | |
| Dec-25 | 2 | 104.50 | 104.65 | 104.63 | 105.21 | 104.76 | 104.50 | | | | | 104.50 | |
| Dec-26 | 3 | 106.83 | 107.05 | 107.03 | 107.91 | 107.23 | 106.83 | | | | | 106.83 | |
| Dec-27 | 4 | 109.21 | 109.51 | 109.48 | 110.68 | 109.75 | 109.21 | | | | | 109.21 | |
| Dec-28 | 5 | 111.64 | 112.02 | 111.99 | 113.53 | 112.33 | 111.64 | | | | | 111.64 | |
| Dec-29 | 6 | | 114.60 | 114.55 | 116.45 | 114.98 | | 114.40 | | | | 114.40 | |
| Dec-30 | 7 | | 117.23 | 117.17 | 119.44 | 117.68 | | 117.23 | | | | 117.23 | |
| Dec-31 | 8 | | | 119.86 | 122.51 | 120.45 | | | 119.89 | | | 119.89 | |
| Dec-32 | 9 | | | 122.60 | 125.66 | 123.29 | | | 122.62 | | | 122.62 | |
| Dec-33 | 10 | | | 125.41 | 128.89 | 126.19 | | | 125.41 | | | 125.41 | |
| Dec-34 | 11 | | | | 132.20 | 129.16 | | | | 128.99 | | 128.99 | 128.40 |
| Dec-35 | 12 | | | | 135.60 | 132.20 | | | | 132.66 | | 132.66 | 131.46 |
| Dec-36 | 13 | | | | 139.08 | 135.31 | | | | 136.44 | | 136.44 | 134.60 |
| Dec-37 | 14 | | | | 142.65 | 138.49 | | | | 140.33 | | 140.33 | 137.81 |
| Dec-38 | 15 | | | | 146.32 | 141.75 | | | | 144.33 | | 144.33 | 141.10 |
| Dec-39 | 16 | | | | 150.08 | 145.09 | | | | 148.45 | | 148.45 | 144.46 |
| Dec-40 | 17 | | | | 153.94 | 148.50 | | | | 152.68 | | 152.68 | 147.91 |
| Dec-41 | 18 | | | | 157.89 | 152.00 | | | | 157.03 | | 157.03 | 151.43 |
| Dec-42 | 19 | | | | 161.95 | 155.57 | | | | 161.51 | | 161.51 | 155.05 |
| Dec-43 | 20 | | | | 166.11 | 159.24 | | | | 166.11 | | 166.11 | 158.74 |
| Dec-44 | 21 | | | | | 162.98 | | | | | 169.31 | 169.31 | 162.53 |
| Dec-45 | 22 | | | | | 166.82 | | | | | 172.56 | 172.56 | 166.41 |
| Dec-46 | 23 | | | | | 170.74 | | | | | 175.87 | 175.87 | 170.37 |
| Dec-47 | 24 | | | | | 174.76 | | | | | 179.25 | 179.25 | 174.44 |
| Dec-48 | 25 | | | | | 178.88 | | | | | 182.70 | 182.70 | 178.60 |
| Dec-49 | 26 | | | | | 183.08 | | | | | 186.21 | 186.21 | 182.86 |
| Dec-50 | 27 | | | | | 187.39 | | | | | 189.79 | 189.79 | 187.22 |
| Dec-51 | 28 | | | | | 191.80 | | | | | 193.43 | 193.43 | 191.68 |
| Dec-52 | 29 | | | | | 196.32 | | | | | 197.15 | 197.15 | 196.26 |
| Dec-53 | 30 | | | | | 200.94 | | | | | 200.94 | 200.94 | 200.94 |

**Average Quarterly Values for FRB H15 Data**

See FRB H.15 Tab for Data Feed Sources.

**Staff TIPS Analysis** **Quarterly Aggregation**

| Average Monthly Inflation Indexed Rates by Quarter | | | | | |
|---|---|---|---|---|---|
| Qtr | TIPS-05m | TIPS-07m | TIPS-10m | TIPS-20m | TIPS-30m |
| 2003-Q1 | 1.33 | 1.81 | 2.07 | | |
| 2003-Q2 | 1.15 | 1.61 | 1.94 | | |
| 2003-Q3 | 1.36 | 1.84 | 2.21 | | |
| 2003-Q4 | 1.24 | 1.65 | 2.01 | | |
| 2004-Q1 | 0.82 | 1.26 | 1.71 | | |
| 2004-Q2 | 1.26 | 1.69 | 2.05 | | |
| 2004-Q3 | 1.17 | 1.55 | 1.89 | 2.28 | |
| 2004-Q4 | 0.93 | 1.30 | 1.69 | 2.08 | |
| 2005-Q1 | 1.17 | 1.41 | 1.71 | 1.93 | |
| 2005-Q2 | 1.30 | 1.44 | 1.68 | 1.83 | |
| 2005-Q3 | 1.59 | 1.70 | 1.82 | 1.98 | |
| 2005-Q4 | 1.92 | 1.98 | 2.04 | 2.13 | |
| 2006-Q1 | 2.00 | 2.05 | 2.09 | 2.08 | |
| 2006-Q2 | 2.34 | 2.39 | 2.46 | 2.48 | |
| 2006-Q3 | 2.37 | 2.37 | 2.37 | 2.38 | |
| 2006-Q4 | 2.40 | 2.36 | 2.32 | 2.29 | |
| 2007-Q1 | 2.28 | 2.33 | 2.33 | 2.36 | |
| 2007-Q2 | 2.35 | 2.40 | 2.44 | 2.49 | |
| 2007-Q3 | 2.38 | 2.44 | 2.45 | 2.46 | |
| 2007-Q4 | 1.54 | 1.81 | 1.92 | 2.11 | |
| 2008-Q1 | 0.58 | 1.02 | 1.32 | 1.81 | |
| 2008-Q2 | 0.79 | 1.17 | 1.48 | 2.03 | |
| 2008-Q3 | 1.18 | 1.47 | 1.70 | 2.16 | |
| 2008-Q4 | 2.73 | 2.92 | 2.60 | 2.73 | |
| 2009-Q1 | 1.37 | 1.54 | 1.79 | 2.34 | |
| 2009-Q2 | 1.12 | 1.37 | 1.72 | 2.31 | |
| 2009-Q3 | 1.17 | 1.41 | 1.74 | 2.22 | |
| 2009-Q4 | 0.58 | 0.94 | 1.37 | 1.98 | |
| 2010-Q1 | 0.47 | 0.94 | 1.43 | 2.00 | 2.16 |
| 2010-Q2 | 0.46 | 0.91 | 1.36 | 1.77 | 1.88 |
| 2010-Q3 | 0.20 | 0.57 | 1.06 | 1.68 | 1.76 |
| 2010-Q4 | -0.11 | 0.28 | 0.75 | 1.48 | 1.65 |
| 2011-Q1 | 0.07 | 0.67 | 1.09 | 1.71 | 2.00 |
| 2011-Q2 | -0.29 | 0.33 | 0.80 | 1.49 | 1.78 |
| 2011-Q3 | -0.65 | -0.22 | 0.28 | 0.95 | 1.25 |
| 2011-Q4 | -0.75 | -0.39 | 0.05 | 0.61 | 0.85 |
| 2012-Q1 | -1.02 | -0.60 | -0.17 | 0.51 | 0.78 |
| **2012-Q2** | **-1.08** | **-0.75** | **-0.35** | **0.35** | **0.66** |
| 2012-Q3 | -1.27 | -1.01 | -0.63 | 0.02 | 0.43 |
| **2012-Q4** | **-1.42** | **-1.15** | **-0.76** | **-0.02** | **0.36** |
| 2013-Q1 | -1.40 | -0.98 | -0.59 | 0.19 | 0.56 |
| **2013-Q2** | **-1.04** | **-0.62** | **-0.25** | **0.47** | **0.80** |
| 2013-Q3 | -0.32 | 0.17 | 0.56 | 1.16 | 1.43 |
| **2013-Q4** | **-0.29** | **0.25** | **0.57** | **1.19** | **1.50** |
| 2014-Q1 | -0.16 | 0.37 | 0.58 | 1.11 | 1.39 |
| **2014-Q2** | **-0.25** | **0.27** | **0.43** | **0.88** | **1.14** |
| 2014-Q3 | -0.13 | 0.24 | 0.32 | 0.72 | 0.98 |
| **2014-Q4** | **0.19** | **0.39** | **0.45** | **0.75** | **0.95** |
| 2015-Q1 | 0.11 | 0.23 | 0.27 | 0.52 | 0.71 |
| **2015-Q2** | **-0.10** | **0.22** | **0.30** | **0.67** | **0.91** |
| 2015-Q3 | 0.26 | 0.48 | 0.57 | 0.92 | 1.14 |
| **2015-Q4** | **0.36** | **0.51** | **0.66** | **1.02** | **1.24** |
| 2016-Q1 | 0.15 | 0.32 | 0.49 | 0.88 | 1.11 |
| **2016-Q2** | **-0.24** | **-0.05** | **0.19** | **0.62** | **0.85** |
| 2016-Q3 | -0.22 | -0.09 | 0.08 | 0.44 | 0.62 |
| **2016-Q4** | **-0.06** | **0.12** | **0.33** | **0.69** | **0.86** |
| 2017-Q1 | 0.07 | 0.33 | 0.44 | 0.75 | 0.95 |
| **2017-Q2** | **0.10** | **0.30** | **0.44** | **0.76** | **0.94** |
| 2017-Q3 | 0.17 | 0.36 | 0.45 | 0.75 | 0.94 |
| **2017-Q4** | **0.32** | **0.44** | **0.50** | **0.72** | **0.87** |
| 2018-Q1 | 0.56 | 0.65 | 0.68 | 0.82 | 0.93 |
| **2018-Q2** | **0.69** | **0.77** | **0.79** | **0.88** | **0.95** |
| 2018-Q3 | 0.81 | 0.81 | 0.81 | 0.88 | 0.93 |
| **2018-Q4** | **1.06** | **1.06** | **1.06** | **1.15** | **1.23** |
| 2019-Q1 | 0.73 | 0.76 | 0.79 | 0.96 | 1.10 |
| **2019-Q2** | **0.42** | **0.46** | **0.51** | **0.71** | **0.89** |
| 2019-Q3 | 0.18 | 0.16 | 0.15 | 0.37 | 0.59 |
| **2019-Q4** | **0.09** | **0.11** | **0.15** | **0.36** | **0.54** |
| 2020-Q1 | -0.14 | -0.12 | -0.06 | 0.14 | 0.29 |
| **2020-Q2** | **-0.49** | **-0.50** | **-0.48** | **-0.27** | **-0.09** |
| 2020-Q3 | -1.19 | -1.09 | -0.94 | -0.58 | -0.33 |
| **2020-Q4** | **-1.32** | **-1.13** | **-0.91** | **-0.50** | **-0.29** |
| 2021-Q1 | -1.70 | -1.27 | -0.86 | -0.34 | -0.09 |
| **2021-Q2** | **-1.71** | **-1.18** | **-0.79** | **-0.27** | **-0.03** |
| 2021-Q3 | -1.69 | -1.31 | -1.02 | -0.53 | -0.30 |
| **2021-Q4** | **-1.65** | **-1.30** | **-1.00** | **-0.58** | **-0.38** |

| Average Monthly Nominal UST Rates by Quarter | | | | | |
|---|---|---|---|---|---|
| Qtr | UST-05m | UST-07m | UST-10m | UST-20m | UST-30m |
| 2003-Q1 | 2.91 | 3.46 | 3.92 | 4.90 | |
| 2003-Q2 | 2.57 | 3.13 | 3.62 | 4.59 | |
| 2003-Q3 | 3.14 | 3.72 | 4.23 | 5.17 | |
| 2003-Q4 | 3.25 | 3.78 | 4.29 | 5.16 | |
| 2004-Q1 | 2.99 | 3.52 | 4.02 | 4.89 | |
| 2004-Q2 | 3.72 | 4.18 | 4.60 | 5.36 | |
| 2004-Q3 | 3.51 | 3.92 | 4.30 | 5.07 | |
| 2004-Q4 | 3.49 | 3.85 | 4.17 | 4.87 | |
| 2005-Q1 | 3.88 | 4.09 | 4.30 | 4.76 | |
| 2005-Q2 | 3.87 | 3.99 | 4.16 | 4.55 | |
| 2005-Q3 | 4.04 | 4.11 | 4.21 | 4.51 | |
| 2005-Q4 | 4.39 | 4.42 | 4.49 | 4.77 | |
| 2006-Q1 | 4.55 | 4.55 | 4.57 | 4.76 | 4.64 |
| 2006-Q2 | 4.99 | 5.02 | 5.07 | 5.29 | 5.14 |
| 2006-Q3 | 4.84 | 4.85 | 4.90 | 5.09 | 4.99 |
| 2006-Q4 | 4.60 | 4.60 | 4.63 | 4.83 | 4.74 |
| 2007-Q1 | 4.65 | 4.65 | 4.68 | 4.90 | 4.80 |
| 2007-Q2 | 4.76 | 4.79 | 4.85 | 5.07 | 4.99 |
| 2007-Q3 | 4.50 | 4.60 | 4.73 | 5.01 | 4.94 |
| 2007-Q4 | 3.79 | 3.98 | 4.26 | 4.65 | 4.61 |
| 2008-Q1 | 2.75 | 3.15 | 3.66 | 4.40 | 4.41 |
| 2008-Q2 | 3.16 | 3.46 | 3.89 | 4.59 | 4.58 |
| 2008-Q3 | 3.11 | 3.44 | 3.86 | 4.49 | 4.45 |
| 2008-Q4 | 2.18 | 2.63 | 3.25 | 3.97 | 3.68 |
| 2009-Q1 | 1.76 | 2.23 | 2.74 | 3.69 | 3.45 |
| 2009-Q2 | 2.23 | 2.88 | 3.31 | 4.19 | 4.17 |
| 2009-Q3 | 2.47 | 3.12 | 3.52 | 4.28 | 4.32 |
| 2009-Q4 | 2.30 | 2.98 | 3.46 | 4.27 | 4.33 |
| 2010-Q1 | 2.42 | 3.16 | 3.72 | 4.49 | 4.62 |
| 2010-Q2 | 2.25 | 2.93 | 3.49 | 4.20 | 4.37 |
| 2010-Q3 | 1.55 | 2.19 | 2.79 | 3.60 | 3.85 |
| 2010-Q4 | 1.49 | 2.18 | 2.86 | 3.84 | 4.16 |
| 2011-Q1 | 2.12 | 2.83 | 3.46 | 4.32 | 4.56 |
| 2011-Q2 | 1.86 | 2.55 | 3.21 | 4.07 | 4.34 |
| 2011-Q3 | 1.15 | 1.78 | 2.43 | 3.34 | 3.70 |
| 2011-Q4 | 0.95 | 1.50 | 2.05 | 2.75 | 3.04 |
| 2012-Q1 | 0.90 | 1.44 | 2.04 | 2.80 | 3.14 |
| **2012-Q2** | **0.79** | **1.24** | **1.82** | **2.55** | **2.94** |
| 2012-Q3 | 0.67 | 1.08 | 1.64 | 2.37 | 2.75 |
| **2012-Q4** | **0.69** | **1.12** | **1.71** | **2.46** | **2.86** |
| 2013-Q1 | 0.83 | 1.32 | 1.95 | 2.75 | 3.14 |
| **2013-Q2** | **0.92** | **1.39** | **2.00** | **2.78** | **3.15** |
| 2013-Q3 | 1.51 | 2.12 | 2.71 | 3.44 | 3.72 |
| **2013-Q4** | **1.44** | **2.12** | **2.75** | **3.50** | **3.79** |
| 2014-Q1 | 1.60 | 2.22 | 2.76 | 3.42 | 3.68 |
| **2014-Q2** | **1.66** | **2.19** | **2.62** | **3.18** | **2.81** |
| 2014-Q3 | 1.70 | 2.16 | 2.50 | 3.01 | 3.26 |
| **2014-Q4** | **1.60** | **2.00** | **2.28** | **2.69** | **2.97** |
| 2015-Q1 | 1.45 | 1.77 | 1.97 | 2.32 | 2.55 |
| **2015-Q2** | **1.52** | **1.91** | **2.17** | **2.62** | **2.89** |
| 2015-Q3 | 1.55 | 1.94 | 2.22 | 2.65 | 2.96 |
| **2015-Q4** | **1.59** | **1.94** | **2.19** | **2.60** | **2.96** |
| 2016-Q1 | 1.37 | 1.69 | 1.92 | 2.32 | 2.72 |
| **2016-Q2** | **1.24** | **1.54** | **1.75** | **2.15** | **2.57** |
| 2016-Q3 | 1.13 | 1.40 | 1.56 | 1.91 | 2.28 |
| **2016-Q4** | **1.61** | **1.93** | **2.13** | **2.52** | **2.82** |
| 2017-Q1 | 1.94 | 2.25 | 2.44 | 2.78 | 3.04 |
| **2017-Q2** | **1.81** | **2.07** | **2.26** | **2.64** | **2.90** |
| 2017-Q3 | 1.82 | 2.06 | 2.24 | 2.58 | 2.82 |
| **2017-Q4** | **2.07** | **2.25** | **2.37** | **2.62** | **2.82** |
| 2018-Q1 | 2.54 | 2.69 | 2.76 | 2.91 | 3.03 |
| **2018-Q2** | **2.77** | **2.87** | **2.92** | **3.00** | **3.08** |
| 2018-Q3 | 2.81 | 2.88 | 2.93 | 3.00 | 3.07 |
| **2018-Q4** | **2.88** | **2.96** | **3.03** | **3.17** | **3.27** |
| 2019-Q1 | 2.47 | 2.55 | 2.65 | 2.85 | 3.01 |
| **2019-Q2** | **2.12** | **2.22** | **2.33** | **2.58** | **2.78** |
| 2019-Q3 | 1.63 | 1.71 | 1.80 | 2.08 | 2.28 |
| **2019-Q4** | **1.62** | **1.72** | **1.79** | **2.10** | **2.26** |
| 2020-Q1 | 1.16 | 1.29 | 1.38 | 1.71 | 1.88 |
| **2020-Q2** | **0.36** | **0.54** | **0.69** | **1.15** | **1.38** |
| 2020-Q3 | 0.27 | 0.46 | 0.65 | 1.15 | 1.36 |
| **2020-Q4** | **0.37** | **0.61** | **0.86** | **1.40** | **1.62** |
| 2021-Q1 | 0.60 | 0.98 | 1.32 | 1.92 | 2.07 |
| **2021-Q2** | **0.84** | **1.27** | **1.59** | **2.17** | **2.26** |
| 2021-Q3 | 0.80 | 1.10 | 1.32 | 1.86 | 1.93 |
| **2021-Q4** | **1.18** | **1.42** | **1.54** | **1.97** | **1.95** |

| Implied Market-based Inflationary Expectations | | | | | |
|---|---|---|---|---|---|
| Qtr | 5-Yr | 7-Yr | 10-Yr | 20-Yr | 30-Yr |
| 2003-Q1 | 1.58 | 1.65 | 1.85 | | |
| 2003-Q2 | 1.42 | 1.52 | 1.68 | | |
| 2003-Q3 | 1.78 | 1.87 | 2.03 | | |
| 2003-Q4 | 2.01 | 2.13 | 2.28 | | |
| 2004-Q1 | 2.17 | 2.26 | 2.31 | | |
| 2004-Q2 | 2.47 | 2.50 | 2.55 | | |
| 2004-Q3 | 2.34 | 2.37 | 2.41 | 2.79 | |
| 2004-Q4 | 2.56 | 2.55 | 2.48 | 2.79 | |
| 2005-Q1 | 2.72 | 2.68 | 2.58 | 2.83 | |
| 2005-Q2 | 2.57 | 2.55 | 2.48 | 2.72 | |
| 2005-Q3 | 2.44 | 2.41 | 2.39 | 2.52 | |
| 2005-Q4 | 2.47 | 2.44 | 2.45 | 2.64 | |
| 2006-Q1 | 2.55 | 2.50 | 2.48 | 2.69 | |
| 2006-Q2 | 2.65 | 2.62 | 2.61 | 2.80 | |
| 2006-Q3 | 2.47 | 2.48 | 2.52 | 2.71 | |
| 2006-Q4 | 2.20 | 2.24 | 2.31 | 2.54 | |
| 2007-Q1 | 2.36 | 2.32 | 2.35 | 2.54 | |
| 2007-Q2 | 2.41 | 2.39 | 2.41 | 2.58 | |
| 2007-Q3 | 2.13 | 2.16 | 2.28 | 2.55 | |
| 2007-Q4 | 2.24 | 2.17 | 2.34 | 2.54 | |
| 2008-Q1 | 2.17 | 2.13 | 2.34 | 2.59 | |
| 2008-Q2 | 2.37 | 2.29 | 2.40 | 2.56 | |
| 2008-Q3 | 1.93 | 1.96 | 2.16 | 2.33 | |
| 2008-Q4 | -0.55 | -0.29 | 0.65 | 1.24 | |
| 2009-Q1 | 0.39 | 0.69 | 0.95 | 1.35 | |
| 2009-Q2 | 1.11 | 1.51 | 1.60 | 1.88 | |
| 2009-Q3 | 1.30 | 1.72 | 1.77 | 2.06 | |
| 2009-Q4 | 1.72 | 2.04 | 2.09 | 2.29 | |
| 2010-Q1 | 1.96 | 2.22 | 2.28 | 2.49 | 2.47 |
| 2010-Q2 | 1.80 | 2.03 | 2.13 | 2.43 | 2.49 |
| 2010-Q3 | 1.35 | 1.63 | 1.73 | 1.92 | 2.09 |
| 2010-Q4 | 1.59 | 1.90 | 2.12 | 2.36 | 2.51 |
| 2011-Q1 | 2.05 | 2.16 | 2.37 | 2.61 | 2.56 |
| 2011-Q2 | 2.15 | 2.22 | 2.41 | 2.57 | 2.56 |
| 2011-Q3 | 1.81 | 2.00 | 2.15 | 2.39 | 2.45 |
| 2011-Q4 | 1.71 | 1.89 | 1.99 | 2.14 | 2.19 |
| 2012-Q1 | 1.92 | 2.04 | 2.20 | 2.29 | 2.36 |
| **2012-Q2** | **1.86** | **1.99** | **2.17** | **2.21** | **2.28** |
| 2012-Q3 | 1.94 | 2.09 | 2.28 | 2.35 | 2.31 |
| **2012-Q4** | **2.11** | **2.27** | **2.47** | **2.48** | **2.50** |
| 2013-Q1 | 2.23 | 2.31 | 2.54 | 2.55 | 2.58 |
| **2013-Q2** | **1.95** | **2.01** | **2.25** | **2.32** | **2.34** |
| 2013-Q3 | 1.82 | 1.95 | 2.15 | 2.29 | 2.29 |
| **2013-Q4** | **1.73** | **1.86** | **2.17** | **2.31** | **2.29** |
| 2014-Q1 | 1.77 | 1.85 | 2.18 | 2.30 | 2.29 |
| **2014-Q2** | **1.90** | **1.92** | **2.20** | **2.30** | **1.67** |
| 2014-Q3 | 1.83 | 1.92 | 2.18 | 2.28 | 2.29 |
| **2014-Q4** | **1.41** | **1.61** | **1.83** | **1.95** | **2.02** |
| 2015-Q1 | 1.35 | 1.54 | 1.70 | 1.79 | 1.85 |
| **2015-Q2** | **1.63** | **1.69** | **1.86** | **1.95** | **1.97** |
| 2015-Q3 | 1.29 | 1.47 | 1.65 | 1.73 | 1.82 |
| **2015-Q4** | **1.23** | **1.43** | **1.53** | **1.58** | **1.72** |
| 2016-Q1 | 1.23 | 1.37 | 1.43 | 1.45 | 1.61 |
| **2016-Q2** | **1.48** | **1.58** | **1.56** | **1.53** | **1.72** |
| 2016-Q3 | 1.35 | 1.49 | 1.48 | 1.47 | 1.66 |
| **2016-Q4** | **1.67** | **1.80** | **1.80** | **1.83** | **1.96** |
| 2017-Q1 | 1.87 | 1.92 | 2.01 | 2.03 | 2.10 |
| **2017-Q2** | **1.71** | **1.78** | **1.82** | **1.88** | **1.96** |
| 2017-Q3 | 1.65 | 1.70 | 1.79 | 1.83 | 1.88 |
| **2017-Q4** | **1.75** | **1.81** | **1.87** | **1.89** | **1.95** |
| 2018-Q1 | 1.97 | 2.04 | 2.08 | 2.08 | 2.11 |
| **2018-Q2** | **2.07** | **2.11** | **2.13** | **2.12** | **2.14** |
| 2018-Q3 | 2.01 | 2.07 | 2.11 | 2.11 | 2.13 |
| **2018-Q4** | **1.81** | **1.90** | **1.98** | **2.02** | **2.03** |
| 2019-Q1 | 1.73 | 1.79 | 1.86 | 1.89 | 1.91 |
| **2019-Q2** | **1.70** | **1.76** | **1.82** | **1.87** | **1.88** |
| 2019-Q3 | 1.45 | 1.55 | 1.64 | 1.71 | 1.69 |
| **2019-Q4** | **1.53** | **1.61** | **1.64** | **1.74** | **1.72** |
| 2020-Q1 | 1.30 | 1.41 | 1.44 | 1.58 | 1.59 |
| **2020-Q2** | **0.85** | **1.05** | **1.16** | **1.42** | **1.47** |
| 2020-Q3 | 1.46 | 1.55 | 1.59 | 1.73 | 1.69 |
| **2020-Q4** | **1.69** | **1.75** | **1.78** | **1.90** | **1.91** |
| 2021-Q1 | 2.30 | 2.25 | 2.18 | 2.26 | 2.16 |
| **2021-Q2** | **2.55** | **2.45** | **2.39** | **2.44** | **2.29** |
| 2021-Q3 | 2.49 | 2.41 | 2.34 | 2.39 | 2.23 |
| **2021-Q4** | **2.83** | **2.72** | **2.54** | **2.55** | **2.33** |

FRB **H.15** Market Yield on U.S. Treasury (UST) Securities at Constant Maturity, Quoted on an Investment Basis in Percent per Year

Staff Accessed , Feb. 15, 2023: http://federalreserve.gov/releases/h15/data.htm

**Monthly** https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

| Series | Year | Inflation Indexed | H.15 ID |
|---|---|---|---|
| TIPS-05m | 5 | Inflation Indexed | RIFLGFCY05_XII_N.M |
| TIPS-07m | 7 | | RIFLGFCY07_XII_N.M |
| TIPS-10m | 10 | | RIFLGFCY10_XII_N.M |
| TIPS-20m | 20 | | RIFLGFCY20_XII_N.M |
| TIPS-30m | 30 | | RIFLGFCY30_XII_N.M |

**Monthly**

| Series | Year | H.15 ID |
|---|---|---|
| UST-05m | 5 | RIFLGFCY05_N.M |
| UST-07m | 7 | RIFLGFCY07_N.M |
| UST-10m | 10 | RIFLGFCY10_N.M |
| UST-20m | 20 | RIFLGFCY20_N.M |
| UST-30m | 30 | RIFLGFCY30_N.M |

| Month | TIPS-05m | TIPS-07m | TIPS-10m | TIPS-20m | TIPS-30m | UST-05m | UST-07m | UST-10m | UST-20m | UST-30m |
|---|---|---|---|---|---|---|---|---|---|---|
| 2003-01 | 1.65 | 2.10 | 2.29 | | | 3.05 | 3.60 | 4.05 | 5.02 | |
| 2003-02 | 1.24 | 1.74 | 1.99 | | | 2.90 | 3.45 | 3.90 | 4.87 | |
| 2003-03 | 1.09 | 1.60 | 1.94 | | | 2.78 | 3.34 | 3.81 | 4.82 | |
| 2003-04 | 1.36 | 1.85 | 2.18 | | | 2.93 | 3.47 | 3.96 | 4.91 | |
| 2003-05 | 1.18 | 1.61 | 1.91 | | | 2.52 | 3.07 | 3.57 | 4.52 | |
| 2003-06 | 0.91 | 1.37 | 1.72 | | | 2.27 | 2.84 | 3.33 | 4.34 | |
| 2003-07 | 1.30 | 1.76 | 2.11 | | | 2.87 | 3.45 | 3.98 | 4.92 | |
| 2003-08 | 1.48 | 1.97 | 2.32 | | | 3.37 | 3.96 | 4.45 | 5.39 | |
| 2003-09 | 1.29 | 1.80 | 2.19 | | | 3.18 | 3.74 | 4.27 | 5.21 | |
| 2003-10 | 1.21 | 1.68 | 2.08 | | | 3.19 | 3.75 | 4.29 | 5.21 | |
| 2003-11 | 1.27 | 1.64 | 1.96 | | | 3.29 | 3.81 | 4.30 | 5.17 | |
| 2003-12 | 1.23 | 1.64 | 1.98 | | | 3.27 | 3.79 | 4.27 | 5.11 | |
| 2004-01 | 1.09 | 1.48 | 1.89 | | | 3.12 | 3.65 | 4.15 | 5.01 | |
| 2004-02 | 0.86 | 1.31 | 1.76 | | | 3.07 | 3.59 | 4.08 | 4.94 | |
| 2004-03 | 0.52 | 0.98 | 1.47 | | | 2.79 | 3.31 | 3.83 | 4.72 | |
| 2004-04 | 1.02 | 1.49 | 1.90 | | | 3.39 | 3.89 | 4.35 | 5.16 | |
| 2004-05 | 1.34 | 1.77 | 2.09 | | | 3.85 | 4.31 | 4.72 | 5.46 | |
| 2004-06 | 1.41 | 1.80 | 2.15 | TIPS-20 | | 3.93 | 4.35 | 4.73 | 5.45 | |
| 2004-07 | 1.29 | 1.68 | 2.02 | 2.44 | | 3.69 | 4.11 | 4.50 | 5.24 | |
| 2004-08 | 1.12 | 1.51 | 1.86 | 2.23 | | 3.47 | 3.90 | 4.28 | 5.07 | |
| 2004-09 | 1.10 | 1.46 | 1.80 | 2.16 | | 3.36 | 3.75 | 4.13 | 4.89 | |
| 2004-10 | 0.97 | 1.35 | 1.73 | 2.13 | | 3.35 | 3.75 | 4.10 | 4.85 | |
| 2004-11 | 0.90 | 1.27 | 1.68 | 2.09 | | 3.53 | 3.88 | 4.19 | 4.89 | |
| 2004-12 | 0.92 | 1.28 | 1.67 | 2.02 | | 3.60 | 3.93 | 4.23 | 4.88 | |
| 2005-01 | 1.13 | 1.40 | 1.72 | 1.98 | | 3.71 | 3.97 | 4.22 | 4.77 | |
| 2005-02 | 1.08 | 1.33 | 1.63 | 1.85 | | 3.77 | 3.97 | 4.17 | 4.61 | |
| 2005-03 | 1.29 | 1.49 | 1.79 | 1.95 | | 4.17 | 4.33 | 4.50 | 4.89 | |
| 2005-04 | 1.23 | 1.42 | 1.71 | 1.87 | | 4.00 | 4.16 | 4.34 | 4.75 | |
| 2005-05 | 1.28 | 1.41 | 1.65 | 1.82 | | 3.85 | 3.94 | 4.14 | 4.56 | |
| 2005-06 | 1.39 | 1.49 | 1.67 | 1.80 | | 3.77 | 3.86 | 4.00 | 4.35 | |
| 2005-07 | 1.67 | 1.75 | 1.88 | 2.00 | | 3.98 | 4.06 | 4.18 | 4.48 | |
| 2005-08 | 1.71 | 1.79 | 1.89 | 2.02 | | 4.12 | 4.18 | 4.26 | 4.53 | |
| 2005-09 | 1.40 | 1.56 | 1.70 | 1.93 | | 4.01 | 4.08 | 4.20 | 4.51 | |
| 2005-10 | 1.70 | 1.82 | 1.94 | 2.09 | | 4.33 | 4.38 | 4.46 | 4.74 | |
| 2005-11 | 1.97 | 2.03 | 2.06 | 2.16 | | 4.45 | 4.48 | 4.54 | 4.83 | |
| 2005-12 | 2.09 | 2.10 | 2.12 | 2.14 | | 4.39 | 4.41 | 4.47 | 4.73 | |
| 2006-01 | 1.93 | 1.98 | 2.01 | 2.05 | | 4.35 | 4.37 | 4.42 | 4.65 | UST-30 |
| 2006-02 | 1.98 | 2.02 | 2.05 | 2.01 | | 4.57 | 4.56 | 4.57 | 4.73 | 4.54 |
| 2006-03 | 2.09 | 2.15 | 2.20 | 2.17 | | 4.72 | 4.71 | 4.72 | 4.91 | 4.73 |
| 2006-04 | 2.26 | 2.34 | 2.41 | 2.43 | | 4.90 | 4.94 | 4.99 | 5.22 | 5.06 |
| 2006-05 | 2.30 | 2.36 | 2.45 | 2.48 | | 5.00 | 5.03 | 5.11 | 5.35 | 5.20 |
| 2006-06 | 2.45 | 2.48 | 2.53 | 2.54 | | 5.07 | 5.08 | 5.11 | 5.29 | 5.15 |
| 2006-07 | 2.46 | 2.48 | 2.51 | 2.52 | | 5.04 | 5.05 | 5.09 | 5.25 | 5.13 |
| 2006-08 | 2.27 | 2.29 | 2.29 | 2.31 | | 4.82 | 4.83 | 4.88 | 5.08 | 5.00 |
| 2006-09 | 2.38 | 2.35 | 2.32 | 2.31 | | 4.67 | 4.68 | 4.72 | 4.93 | 4.85 |
| 2006-10 | 2.51 | 2.45 | 2.41 | 2.38 | | 4.69 | 4.69 | 4.73 | 4.94 | 4.85 |
| 2006-11 | 2.41 | 2.35 | 2.29 | 2.23 | | 4.58 | 4.58 | 4.60 | 4.78 | 4.69 |
| 2006-12 | 2.28 | 2.28 | 2.25 | 2.26 | | 4.53 | 4.54 | 4.56 | 4.78 | 4.68 |
| 2007-01 | 2.47 | 2.47 | 2.44 | 2.42 | | 4.75 | 4.75 | 4.76 | 4.95 | 4.85 |
| 2007-02 | 2.34 | 2.38 | 2.36 | 2.38 | | 4.71 | 4.71 | 4.72 | 4.93 | 4.82 |
| 2007-03 | 2.04 | 2.14 | 2.18 | 2.27 | | 4.48 | 4.50 | 4.56 | 4.81 | 4.72 |
| 2007-04 | 2.12 | 2.20 | 2.26 | 2.35 | | 4.59 | 4.62 | 4.69 | 4.95 | 4.87 |
| 2007-05 | 2.29 | 2.32 | 2.37 | 2.45 | | 4.67 | 4.69 | 4.75 | 4.98 | 4.90 |
| 2007-06 | 2.65 | 2.67 | 2.69 | 2.67 | | 5.03 | 5.05 | 5.10 | 5.29 | 5.20 |
| 2007-07 | 2.60 | 2.63 | 2.64 | 2.62 | | 4.88 | 4.93 | 5.00 | 5.19 | 5.11 |
| 2007-08 | 2.39 | 2.45 | 2.44 | 2.47 | | 4.43 | 4.53 | 4.67 | 5.00 | 4.93 |
| 2007-09 | 2.14 | 2.24 | 2.26 | 2.30 | | 4.20 | 4.33 | 4.52 | 4.84 | 4.79 |
| 2007-10 | 2.01 | 2.15 | 2.20 | 2.26 | | 4.20 | 4.33 | 4.53 | 4.83 | 4.77 |
| 2007-11 | 1.35 | 1.65 | 1.77 | 1.99 | | 3.67 | 3.87 | 4.15 | 4.56 | 4.52 |
| 2007-12 | 1.27 | 1.62 | 1.79 | 2.08 | | 3.49 | 3.74 | 4.10 | 4.57 | 4.53 |
| 2008-01 | 0.86 | 1.24 | 1.47 | 1.81 | | 2.98 | 3.31 | 3.74 | 4.35 | 4.33 |
| 2008-02 | 0.65 | 1.09 | 1.41 | 1.87 | | 2.78 | 3.21 | 3.74 | 4.49 | 4.52 |
| 2008-03 | 0.23 | 0.73 | 1.09 | 1.76 | | 2.48 | 2.93 | 3.51 | 4.36 | 4.39 |
| 2008-04 | 0.62 | 1.00 | 1.36 | 1.91 | | 2.84 | 3.19 | 3.68 | 4.44 | 4.44 |
| 2008-05 | 0.79 | 1.16 | 1.46 | 2.00 | | 3.15 | 3.46 | 3.88 | 4.60 | 4.60 |
| 2008-06 | 0.97 | 1.35 | 1.63 | 2.19 | | 3.49 | 3.73 | 4.10 | 4.74 | 4.69 |
| 2008-07 | 0.84 | 1.24 | 1.57 | 2.09 | | 3.30 | 3.60 | 4.01 | 4.62 | 4.57 |
| 2008-08 | 1.15 | 1.47 | 1.68 | 2.15 | | 3.14 | 3.46 | 3.89 | 4.53 | 4.50 |
| 2008-09 | 1.55 | 1.71 | 1.85 | 2.25 | | 2.88 | 3.25 | 3.69 | 4.32 | 4.27 |
| 2008-10 | 2.75 | 2.96 | 2.75 | 2.87 | | 2.73 | 3.19 | 3.81 | 4.45 | 4.17 |
| 2008-11 | 3.69 | 3.84 | 2.89 | 3.00 | | 2.29 | 2.82 | 3.53 | 4.27 | 4.00 |
| 2008-12 | 1.76 | 1.96 | 2.17 | 2.32 | | 1.52 | 1.89 | 2.42 | 3.18 | 2.87 |
| 2009-01 | 1.59 | 1.72 | 1.91 | 2.46 | | 1.60 | 1.98 | 2.52 | 3.46 | 3.13 |
| 2009-02 | 1.29 | 1.48 | 1.75 | 2.31 | | 1.87 | 2.30 | 2.87 | 3.83 | 3.59 |
| 2009-03 | 1.23 | 1.43 | 1.71 | 2.26 | | 1.82 | 2.42 | 2.82 | 3.78 | 3.64 |
| 2009-04 | 1.11 | 1.29 | 1.57 | 2.22 | | 1.86 | 2.47 | 2.93 | 3.84 | 3.76 |
| 2009-05 | 1.07 | 1.34 | 1.72 | 2.36 | | 2.13 | 2.81 | 3.29 | 4.22 | 4.23 |
| 2009-06 | 1.18 | 1.48 | 1.86 | 2.36 | | 2.71 | 3.37 | 3.72 | 4.51 | 4.52 |
| 2009-07 | 1.18 | 1.44 | 1.82 | 2.31 | | 2.46 | 3.14 | 3.56 | 4.38 | 4.41 |
| 2009-08 | 1.29 | 1.49 | 1.77 | 2.22 | | 2.57 | 3.21 | 3.59 | 4.33 | 4.37 |
| 2009-09 | 1.03 | 1.29 | 1.64 | 2.13 | | 2.37 | 3.02 | 3.40 | 4.14 | 4.19 |
| 2009-10 | 0.83 | 1.12 | 1.48 | 2.04 | | 2.33 | 2.96 | 3.39 | 4.16 | 4.19 |
| 2009-11 | 0.48 | 0.84 | 1.28 | 1.90 | | 2.23 | 2.92 | 3.40 | 4.24 | 4.31 |
| 2009-12 | 0.43 | 0.86 | 1.36 | 1.99 | | 2.34 | 3.07 | 3.59 | 4.40 | 4.49 |
| 2010-01 | 0.42 | 0.85 | 1.37 | 2.00 | TIPS-30 | 2.48 | 3.21 | 3.73 | 4.50 | 4.60 |
| 2010-02 | 0.42 | 0.90 | 1.42 | 2.03 | 2.16 | 2.36 | 3.12 | 3.69 | 4.48 | 4.62 |
| 2010-03 | 0.56 | 1.08 | 1.51 | 1.98 | 2.15 | 2.43 | 3.16 | 3.73 | 4.49 | 4.64 |
| 2010-04 | 0.62 | 1.10 | 1.50 | 1.90 | 2.05 | 2.58 | 3.28 | 3.85 | 4.53 | 4.69 |
| 2010-05 | 0.41 | 0.86 | 1.31 | 1.72 | 1.83 | 2.18 | 2.86 | 3.42 | 4.11 | 4.29 |
| 2010-06 | 0.34 | 0.76 | 1.26 | 1.69 | 1.77 | 2.00 | 2.66 | 3.20 | 3.95 | 4.13 |
| 2010-07 | 0.34 | 0.73 | 1.24 | 1.80 | 1.87 | 1.76 | 2.43 | 3.01 | 3.80 | 3.99 |
| 2010-08 | 0.13 | 0.51 | 1.02 | 1.65 | 1.76 | 1.47 | 2.10 | 2.70 | 3.52 | 3.80 |
| 2010-09 | 0.13 | 0.46 | 0.91 | 1.58 | 1.66 | 1.41 | 2.05 | 2.65 | 3.47 | 3.77 |
| 2010-10 | -0.32 | 0.02 | 0.53 | 1.32 | 1.44 | 1.18 | 1.85 | 2.54 | 3.52 | 3.87 |
| 2010-11 | -0.21 | 0.17 | 0.67 | 1.44 | 1.61 | 1.35 | 2.02 | 2.76 | 3.82 | 4.19 |
| 2010-12 | 0.21 | 0.65 | 1.04 | 1.67 | 1.89 | 1.93 | 2.66 | 3.29 | 4.17 | 4.42 |
| 2011-01 | 0.06 | 0.62 | 1.06 | 1.70 | 1.97 | 1.99 | 2.72 | 3.39 | 4.28 | 4.52 |
| 2011-02 | 0.25 | 0.84 | 1.24 | 1.85 | 2.13 | 2.26 | 2.96 | 3.58 | 4.42 | 4.65 |
| 2011-03 | -0.09 | 0.54 | 0.96 | 1.58 | 1.89 | 2.11 | 2.80 | 3.41 | 4.27 | 4.51 |
| 2011-04 | -0.14 | 0.49 | 0.86 | 1.48 | 1.79 | 2.17 | 2.84 | 3.46 | 4.28 | 4.50 |
| 2011-05 | -0.34 | 0.29 | 0.78 | 1.47 | 1.77 | 1.84 | 2.51 | 3.17 | 4.01 | 4.29 |
| 2011-06 | -0.38 | 0.21 | 0.76 | 1.53 | 1.78 | 1.58 | 2.29 | 3.00 | 3.91 | 4.23 |
| 2011-07 | -0.49 | 0.09 | 0.62 | 1.36 | 1.62 | 1.54 | 2.28 | 3.00 | 3.95 | 4.27 |
| 2011-08 | -0.75 | -0.36 | 0.14 | 0.81 | 1.10 | 1.02 | 1.63 | 2.30 | 3.24 | 3.65 |
| 2011-09 | -0.72 | -0.39 | 0.08 | 0.69 | 1.02 | 0.90 | 1.42 | 1.98 | 2.83 | 3.18 |
| 2011-10 | -0.63 | -0.28 | 0.19 | 0.72 | 0.99 | 1.06 | 1.62 | 2.15 | 2.87 | 3.13 |
| 2011-11 | -0.85 | -0.46 | 0.00 | 0.55 | 0.78 | 0.91 | 1.45 | 2.01 | 2.72 | 3.02 |
| 2011-12 | -0.78 | -0.44 | -0.03 | 0.56 | 0.78 | 0.89 | 1.43 | 1.98 | 2.67 | 2.98 |
| 2012-01 | -0.92 | -0.55 | -0.11 | 0.51 | 0.74 | 0.84 | 1.38 | 1.97 | 2.70 | 3.03 |
| 2012-02 | -1.11 | -0.69 | -0.25 | 0.45 | 0.72 | 0.83 | 1.37 | 1.97 | 2.75 | 3.11 |
| 2012-03 | -1.03 | -0.57 | -0.14 | 0.56 | 0.87 | 1.02 | 1.56 | 2.17 | 2.94 | 3.28 |
| **2012-04** | **-1.06** | **-0.65** | **-0.21** | **0.50** | **0.79** | **0.89** | **1.43** | **2.05** | **2.82** | **3.18** |
| **2012-05** | **-1.12** | **-0.79** | **-0.34** | **0.44** | **0.68** | **0.76** | **1.21** | **1.80** | **2.53** | **2.93** |
| **2012-06** | **-1.05** | **-0.82** | **-0.50** | **0.10** | **0.50** | **0.71** | **1.08** | **1.62** | **2.31** | **2.70** |
| 2012-07 | -1.15 | -0.92 | -0.60 | -0.01 | 0.39 | 0.62 | 0.98 | 1.53 | 2.22 | 2.59 |
| 2012-08 | -1.19 | -0.94 | -0.59 | 0.06 | 0.47 | 0.71 | 1.14 | 1.68 | 2.40 | 2.77 |
| 2012-09 | -1.47 | -1.17 | -0.71 | 0.02 | 0.44 | 0.67 | 1.12 | 1.72 | 2.49 | 2.88 |
| **2012-10** | **-1.47** | **-1.18** | **-0.75** | **-0.01** | **0.41** | **0.71** | **1.15** | **1.75** | **2.51** | **2.90** |
| **2012-11** | **-1.38** | **-1.13** | **-0.77** | **-0.06** | **0.35** | **0.67** | **1.08** | **1.65** | **2.39** | **2.80** |
| **2012-12** | **-1.40** | **-1.13** | **-0.76** | **0.00** | **0.33** | **0.70** | **1.13** | **1.72** | **2.47** | **2.88** |
| 2013-01 | -1.39 | -1.04 | -0.61 | 0.20 | 0.48 | 0.81 | 1.30 | 1.91 | 2.68 | 3.08 |
| 2013-02 | -1.39 | -0.94 | -0.57 | 0.19 | 0.57 | 0.85 | 1.35 | 1.98 | 2.78 | 3.17 |
| 2013-03 | -1.43 | -0.97 | -0.59 | 0.19 | 0.62 | 0.82 | 1.32 | 1.96 | 2.78 | 3.16 |
| **2013-04** | **-1.38** | **-0.97** | **-0.65** | **0.07** | **0.48** | **0.71** | **1.15** | **1.76** | **2.55** | **2.93** |
| **2013-05** | **-1.14** | **-0.69** | **-0.36** | **0.35** | **0.72** | **0.84** | **1.31** | **1.93** | **2.73** | **3.11** |
| **2013-06** | **-0.59** | **-0.21** | **0.25** | **0.98** | **1.21** | **1.20** | **1.71** | **2.30** | **3.07** | **3.40** |
| 2013-07 | -0.45 | 0.02 | 0.46 | 1.09 | 1.34 | 1.40 | 1.99 | 2.58 | 3.31 | 3.61 |
| 2013-08 | -0.33 | 0.15 | 0.55 | 1.16 | 1.44 | 1.52 | 2.15 | 2.74 | 3.49 | 3.76 |
| 2013-09 | -0.17 | 0.34 | 0.66 | 1.22 | 1.50 | 1.60 | 2.22 | 2.81 | 3.53 | 3.79 |
| **2013-10** | **-0.41** | **0.11** | **0.43** | **1.05** | **1.37** | **1.37** | **1.99** | **2.62** | **3.38** | **3.68** |
| **2013-11** | **-0.38** | **0.18** | **0.55** | **1.20** | **1.51** | **1.37** | **2.07** | **2.72** | **3.50** | **3.80** |
| **2013-12** | **-0.09** | **0.47** | **0.74** | **1.32** | **1.61** | **1.58** | **2.29** | **2.90** | **3.63** | **3.89** |
| 2014-01 | -0.09 | 0.45 | 0.63 | 1.17 | 1.44 | 1.65 | 2.29 | 2.86 | 3.52 | 3.77 |
| 2014-02 | -0.26 | 0.30 | 0.55 | 1.12 | 1.40 | 1.52 | 2.15 | 2.71 | 3.38 | 3.66 |
| 2014-03 | -0.14 | 0.37 | 0.56 | 1.05 | 1.33 | 1.64 | 2.23 | 2.72 | 3.35 | 3.62 |
| **2014-04** | **-0.11** | **0.38** | **0.54** | **0.98** | **1.23** | **1.70** | **2.27** | **2.71** | **3.27** | **3.52** |
| **2014-05** | **-0.34** | **0.21** | **0.37** | **0.82** | **1.08** | **1.59** | **2.12** | **2.56** | **3.12** | **3.39** |
| **2014-06** | **-0.29** | **0.23** | **0.37** | **0.84** | **1.11** | **1.68** | **2.19** | **2.60** | **3.15** | **3.42** |
| 2014-07 | -0.27 | 0.18 | 0.28 | 0.72 | 0.98 | 1.70 | 2.17 | 2.54 | 3.07 | 3.33 |
| 2014-08 | -0.21 | 0.15 | 0.22 | 0.64 | 0.90 | 1.63 | 2.08 | 2.42 | 2.94 | 3.20 |
| 2014-09 | 0.10 | 0.38 | 0.46 | 0.81 | 1.05 | 1.77 | 2.22 | 2.53 | 3.01 | 3.26 |
| **2014-10** | **0.06** | **0.32** | **0.38** | **0.74** | **0.96** | **1.55** | **1.98** | **2.30** | **2.77** | **3.04** |
| **2014-11** | **0.14** | **0.37** | **0.45** | **0.77** | **0.99** | **1.62** | **2.03** | **2.33** | **2.76** | **3.04** |
| **2014-12** | **0.37** | **0.47** | **0.51** | **0.73** | **0.89** | **1.64** | **1.98** | **2.21** | **2.55** | **2.83** |
| 2015-01 | 0.17 | 0.24 | 0.27 | 0.50 | 0.66 | 1.37 | 1.67 | 1.88 | 2.20 | 2.46 |
| 2015-02 | 0.11 | 0.22 | 0.26 | 0.52 | 0.73 | 1.47 | 1.79 | 1.98 | 2.34 | 2.57 |
| 2015-03 | 0.04 | 0.23 | 0.28 | 0.55 | 0.73 | 1.52 | 1.84 | 2.04 | 2.41 | 2.63 |
| **2015-04** | **-0.26** | **-0.01** | **0.08** | **0.42** | **0.65** | **1.35** | **1.69** | **1.94** | **2.33** | **2.59** |
| **2015-05** | **-0.10** | **0.27** | **0.33** | **0.70** | **0.96** | **1.54** | **1.93** | **2.20** | **2.69** | **2.96** |
| **2015-06** | **0.05** | **0.39** | **0.50** | **0.89** | **1.13** | **1.68** | **2.10** | **2.36** | **2.85** | **3.11** |
| 2015-07 | 0.14 | 0.42 | 0.50 | 0.87 | 1.11 | 1.63 | 2.04 | 2.32 | 2.77 | 3.07 |
| 2015-08 | 0.31 | 0.49 | 0.56 | 0.87 | 1.08 | 1.54 | 1.91 | 2.17 | 2.55 | 2.86 |
| 2015-09 | 0.33 | 0.52 | 0.65 | 1.01 | 1.24 | 1.49 | 1.88 | 2.17 | 2.62 | 2.95 |
| **2015-10** | **0.21** | **0.39** | **0.57** | **0.98** | **1.22** | **1.39** | **1.76** | **2.07** | **2.50** | **2.89** |
| **2015-11** | **0.40** | **0.55** | **0.69** | **1.03** | **1.25** | **1.67** | **2.02** | **2.26** | **2.69** | **3.03** |
| **2015-12** | **0.46** | **0.59** | **0.73** | **1.06** | **1.26** | **1.70** | **2.04** | **2.24** | **2.61** | **2.97** |
| 2016-01 | 0.33 | 0.49 | 0.67 | 1.05 | 1.26 | 1.52 | 1.85 | 2.09 | 2.49 | 2.86 |
| 2016-02 | 0.14 | 0.30 | 0.47 | 0.85 | 1.09 | 1.22 | 1.53 | 1.78 | 2.20 | 2.62 |
| 2016-03 | -0.03 | 0.16 | 0.34 | 0.73 | 0.99 | 1.38 | 1.68 | 1.89 | 2.28 | 2.68 |
| **2016-04** | **-0.22** | **-0.03** | **0.19** | **0.60** | **0.86** | **1.26** | **1.57** | **1.81** | **2.21** | **2.62** |
| **2016-05** | **-0.22** | **-0.04** | **0.21** | **0.64** | **0.86** | **1.30** | **1.60** | **1.81** | **2.22** | **2.63** |
| **2016-06** | **-0.27** | **-0.07** | **0.17** | **0.63** | **0.82** | **1.17** | **1.44** | **1.64** | **2.02** | **2.45** |
| 2016-07 | -0.32 | -0.16 | 0.04 | 0.42 | 0.61 | 1.07 | 1.33 | 1.50 | 1.82 | 2.23 |
| 2016-08 | -0.17 | -0.06 | 0.09 | 0.43 | 0.62 | 1.13 | 1.40 | 1.56 | 1.89 | 2.26 |
| 2016-09 | -0.17 | -0.05 | 0.12 | 0.47 | 0.64 | 1.18 | 1.46 | 1.63 | 2.02 | 2.35 |
| **2016-10** | **-0.26** | **-0.10** | **0.10** | **0.49** | **0.69** | **1.27** | **1.56** | **1.76** | **2.17** | **2.50** |
| **2016-11** | **-0.07** | **0.11** | **0.32** | **0.69** | **0.86** | **1.60** | **1.93** | **2.14** | **2.54** | **2.86** |
| **2016-12** | **0.15** | **0.30** | **0.56** | **0.89** | **1.04** | **1.96** | **2.29** | **2.49** | **2.84** | **3.11** |
| 2017-01 | 0.03 | 0.27 | 0.42 | 0.74 | 0.92 | 1.92 | 2.23 | 2.43 | 2.75 | 3.02 |
| 2017-02 | 0.01 | 0.29 | 0.40 | 0.73 | 0.93 | 1.90 | 2.22 | 2.42 | 2.76 | 3.03 |
| 2017-03 | 0.18 | 0.42 | 0.49 | 0.79 | 0.99 | 2.01 | 2.30 | 2.48 | 2.83 | 3.08 |
| **2017-04** | **0.08** | **0.28** | **0.39** | **0.72** | **0.91** | **1.82** | **2.10** | **2.30** | **2.67** | **2.94** |
| **2017-05** | **0.09** | **0.29** | **0.47** | **0.80** | **0.99** | **1.84** | **2.11** | **2.30** | **2.70** | **2.96** |
| **2017-06** | **0.14** | **0.32** | **0.46** | **0.75** | **0.93** | **1.77** | **2.01** | **2.19** | **2.54** | **2.80** |
| 2017-07 | 0.23 | 0.42 | 0.55 | 0.84 | 1.01 | 1.87 | 2.13 | 2.32 | 2.65 | 2.88 |
| 2017-08 | 0.16 | 0.35 | 0.43 | 0.74 | 0.93 | 1.78 | 2.03 | 2.21 | 2.55 | 2.80 |
| 2017-09 | 0.12 | 0.31 | 0.37 | 0.67 | 0.87 | 1.80 | 2.03 | 2.20 | 2.53 | 2.78 |
| **2017-10** | **0.25** | **0.42** | **0.50** | **0.77** | **0.94** | **1.98** | **2.20** | **2.36** | **2.65** | **2.88** |
| **2017-11** | **0.30** | **0.43** | **0.50** | **0.72** | **0.87** | **2.05** | **2.23** | **2.35** | **2.60** | **2.80** |
| **2017-12** | **0.42** | **0.48** | **0.50** | **0.68** | **0.80** | **2.18** | **2.32** | **2.40** | **2.60** | **2.77** |

Staff Accessed, Feb. 15, 2023: http://federalreserve.gov/releases/h15/data.htm
https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

**Annual**

| Series | Year | Inflation Indexed | H.15 ID |
|---|---|---|---|
| TIPS-05a | 5 | Inflation Indexed | RIFLGFCY05_XII_N.A |
| TIPS-07a | 7 | | RIFLGFCY07_XII_N.A |
| TIPS-10a | 10 | | RIFLGFCY10_XII_N.A |
| TIPS-20a | 20 | | RIFLGFCY20_XII_N.A |
| TIPS-30a | 30 | | RIFLGFCY30_XII_N.A |

**Annual**

| Series | Year | H.15 ID |
|---|---|---|
| UST-05a | 5 | RIFLGFCY05_N.A |
| UST-07a | 7 | RIFLGFCY07_N.A |
| UST-10a | 10 | RIFLGFCY10_N.A |
| UST-20a | 20 | RIFLGFCY20_N.A |
| UST-30a | 30 | RIFLGFCY30_N.A |

| Year | TIPS-05a | TIPS-07a | TIPS-10a | TIPS-20a | TIPS-30a | UST-05a | UST-07a | UST-10a | UST-20a | UST-30a |
|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 1.27 | 1.73 | 2.06 | | | 2.97 | 3.52 | 4.01 | 4.96 | |
| 2004 | 1.04 | 1.45 | 1.83 | 2.14 | | 3.43 | 3.87 | 4.27 | 5.04 | |
| 2005 | 1.50 | 1.63 | 1.81 | 1.97 | | 4.05 | 4.15 | 4.29 | 4.64 | |
| 2006 | 2.28 | 2.29 | 2.31 | 2.31 | | 4.75 | 4.76 | 4.80 | 5.00 | 4.91 |
| 2007 | 2.15 | 2.25 | 2.29 | 2.36 | | 4.43 | 4.51 | 4.63 | 4.91 | 4.84 |
| 2008 | 1.30 | 1.63 | 1.77 | 2.18 | | 2.80 | 3.17 | 3.66 | 4.36 | 4.28 |
| 2009 | 1.06 | 1.32 | 1.66 | 2.21 | | 2.20 | 2.82 | 3.26 | 4.11 | 4.08 |
| 2010 | 0.26 | 0.68 | 1.15 | 1.73 | 1.82 | 1.93 | 2.62 | 3.22 | 4.03 | 4.25 |
| 2011 | -0.41 | 0.09 | 0.55 | 1.19 | 1.47 | 1.52 | 2.16 | 2.78 | 3.62 | 3.91 |
| 2012 | -1.19 | -0.87 | -0.48 | 0.22 | 0.56 | 0.76 | 1.22 | 1.80 | 2.54 | 2.92 |
| 2013 | 0.76 | -0.29 | 0.07 | 0.75 | 1.07 | 1.17 | 1.74 | 2.35 | 3.12 | 3.45 |
| 2014 | -0.09 | 0.32 | 0.44 | 0.86 | 1.11 | 1.64 | 2.14 | 2.54 | 3.07 | 3.34 |
| 2015 | 0.15 | 0.36 | 0.45 | 0.78 | 1.00 | 1.53 | 1.89 | 2.14 | 2.55 | 2.84 |
| 2016 | -0.01 | 0.07 | 0.27 | 0.65 | 0.86 | 1.33 | 1.63 | 1.84 | 2.22 | 2.59 |
| 2017 | 0.17 | 0.36 | 0.46 | 0.75 | 0.92 | 1.91 | 2.16 | 2.33 | 2.65 | 2.89 |
| 2018 | 0.78 | 0.82 | 0.83 | 0.93 | 1.01 | 2.75 | 2.85 | 2.91 | 3.02 | 3.11 |
| 2019 | 0.35 | 0.37 | 0.40 | 0.60 | 0.78 | 1.95 | 2.05 | 2.14 | 2.40 | 2.58 |
| 2020 | -0.79 | -0.71 | -0.60 | -0.31 | -0.11 | 0.53 | 0.72 | 0.89 | 1.35 | 1.56 |
| 2021 | -1.69 | -1.26 | -0.91 | -0.43 | -0.2 | 0.86 | 1.20 | 1.45 | 1.98 | 2.06 |
| 2022 | 0.22 | 0.33 | 0.43 | 0.64 | 0.76 | 3.00 | 3.01 | 2.95 | 3.30 | 3.11 |
| 2023 | 1.80 | 1.73 | 1.68 | 1.73 | 1.8 | 4.06 | 4.03 | 3.96 | 4.26 | 4.09 |

CASE: UE 426
WITNESS: MATT MULDOON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 109

# Value Line (VL)
# Electric Utilities

# March 25, 2024

**INDUSTRY TIMELINESS: 71 (of 93)**

**All major electric utilities located in the eastern region of the United States are reviewed in this Issue; western-based electrics, in Issue 11; and the remaining industry participants, in Issue 5. Since our last review of the Electric Utility (East) group three months ago, electric utility stocks covered in The Value Line Investment Survey fell 12.8% in value on average, compared to the 9.2% decline in the S&P 500.**

**On a 12-month basis, the Value Line Utility Index has fallen 19.8% versus a 1.9% drop in the Value Line Arithmetic Index. This underperformance is in stark contrast to the first two-thirds of last year when the defensive nature of utilities was sought after. The sharp rise in interest rates over the past several months, with the 10-year Treasury yield recently tagging 5.0%, a level not seen since August of 2007, has really pressured rate-sensitive equities. This is because Treasurys provide a competitive investment vehicle for income-oriented investors and compare favorably to the 4.3% median dividend on electric utility stocks. A rebound in this group ought to be in play when recession fears resurface and investors start to anticipate lower interest rates.**

**Total annual return prospects through 2026-2028 for electrics is near the high end of the range witnessed over the past year. The median level for the industry is presently about 11% after we began reducing our Target Price Range for most of these stocks in order to better reflect the evolving interest rate environment. Although there is a generally reduced risk level in owning utilities, given that they are regulated monopolies, we typically look for at least 10%-11% long-term total annual return potential before recommending a specific equity to utility investors. That level is in line with the broader market's returns over the long haul.**

**Utility Portfolio Considerations**

Given that utilities have significantly sold off of late, one might ask if this group is undervalued on a longer-term basis as opposed to simply being oversold. We'd conclude that electrics are indeed undervalued if we were confident the 10-year Treasury yield would remain in the 2002 to 2022 range of about 0.5% to 5.5%. Looking further back in time, however, and considering a higher range of interest rates might be in play going forward, we'd arrive at a much different answer.

In the 1990s, the 10-year yield was 8.0% at mid-decade and as high as 9.1% early on. The floor for the 10-year yield over the course of the 1990s was 4.3%. While the higher end of that range certainly does not appear to be in our immediate future, the long-term interest rate chart is no longer characterized by a series of lower highs and lower lows. The breakout above 3.2% that took place in September of 2022, and the substantial ground gained since, are indicative of a change in the declining secular trend.

Our conclusion on valuations is that electric utilities have a good chance for a strong rally on the anticipation of a cyclical decline in rates over the intermediate term. But over the long haul, we expect relative valuations to fall. Only in recent years have utility stocks regularly traded above a market price-to-earnings (P/E) ratio. As a point of reference, *Consolidated Edison*, a long-term industry bellwether, sported an average annual relative P/E that ranged between .60 and .80 during the 1990s. During the 2002-2022 stretch, the range was .73 to 1.18, with a market multiple averaged over the past seven full years (2016-2022). Interest rates are certainly not the only factor determining valuations, but it is a significant driving force.

Utility investors can help their cause by being disciplined buyers. Sticking to purchase candidates that possess regulatory environments rated average or better would be ideal. Those with near real-time pricing adjustments that minimize regulatory lag should be sought. A decent or improving balance sheet ought to be a consideration, as well. Solid local economic strength and population growth in a utility's service area is also a big plus.

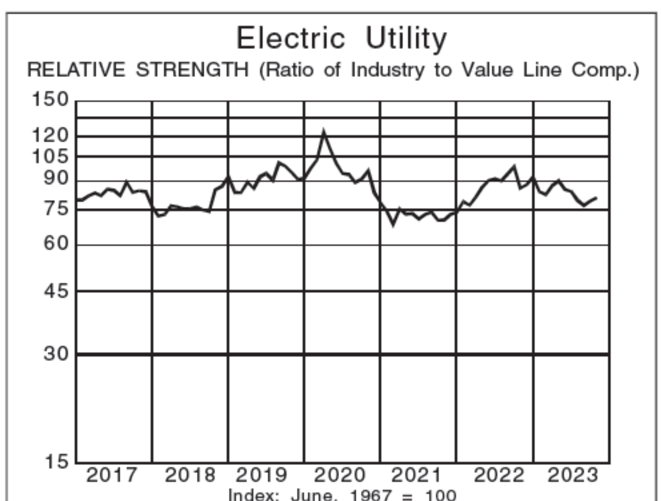
**Conclusion**

The recent macroeconomic backdrop is a significant challenge for most electrics. The main difficulties are wage inflation, a rising cost of capital due to higher interest rates, and stubbornly elevated commodity energy and raw material prices. These issues have been magnified for companies attempting to raise funds for expensive and complicated renewables projects, particularly in offshore wind generation.

Due to how regulatory mechanisms work in this industry, some of these higher expenses can rapidly be passed on to customers, but it varies widely by state. Many costs must instead go through a filed rate case to be reviewed by a regulatory panel, which can be an onerous and lengthy process. This "regulatory lag" can accumulate over time, causing some utilities to perennially under-earn their authorized return on equity. This is a prescription for below-average (relative to the industry median) earnings and dividend growth.

While this industry appears homogeneous, individual electrics vary widely. Regulatory climate and the overall health of the underlying regional and local economies within a utility's service area are big difference-makers. States committing to aggressive clean energy transitions will generate a lot of invested capital opportunities for utilities in those territories. This should also be a key difference maker. As always, utility investors need to be highly selective.

*Anthony J. Glennon*



**All major Electric Utilities located in the Central region of the United States reported third-quarter 2023 financial results and are reviewed in this Issue.**

**Electric Utility (Central) stocks covered in *The Value Line Investment Survey* stayed relatively flat in price on average, versus a slight increase in the S&P 500 since our last review three months ago.**

**Utilities have continued to underperform the broader market averages as of late largely due to the challenging operating backdrop, including the rise in interest rates over the past year. However, a rebound may be in play as the recent U.S. inflation data report, which was better-than-expected, raised the likelihood that the Federal Reserve will put an end to its rate hikes. Total return prospects through 2026-2028 for many of these stocks is near the high-end of the 2023 range, and a number of the electrics remain trading at double-digit discounts to historical valuations.**

**Interest Rates' Effect On Potential Rebound**

Many equities covered in the Utility (Central) Industry increased considerably in value after the Consumer Price Index for October came in flat, which led to the 10-year Treasury yield falling below 4.5%. Note, the rise in interest rates over the past year sent the 10-year Treasury yield above 5% in October, a level not seen since 2007. Investors seem to be enthused with the inflation data and anticipation of lower interest rates is growing. Indeed, the share-price performance of utility stocks has an inverse relationship with the interest rate environment, and we think a rebound in this group is likely to occur when the Fed puts an end to its aggressive rate hikes. As always, investors should keep an eye out for future rate-setting meetings by the central bank.

**The Challenging Macroeconomic Environment**

Most electrics face elevated energy and raw material prices, wage inflation, and rising interest rates. Inflationary pressure continues to negatively impact energy and raw material prices, operating and maintenance costs, as well as fuel and wage prices. Too, the interest rate environment is increasing borrowing costs, which is especially significant for utilities as they usually have low returns on total capital and rely on heavy debt borrowings. While regulatory mechanisms should help pass some of these higher expenses to customers, the regulatory process can take a long time, and lead to a utility to under-earn its return on equity (ROE).

**High Quality, Disciplined Investors**

We recommend investors look for utilities with a solid regulatory environment, balance sheet strength, and stable top- and bottom-line growth among other factors. Indeed, stocks with pending rate cases nearing approval, and real-time pricing adjustments are ideal to minimize regulatory lag. Regulatory lag can be detrimental to a utility's earnings and dividend growth as it causes them to under earn their ROE. Due to the challenging macroeconomic backdrop, investors need to be more selective and disciplined than usual. Accordingly, accounts should consider purchasing equities with strong Financial Strength grades and improving balance sheets. We also recommend specific utility stocks with more than 10% long-term annual total return potential. Including the reduced risk of electrics, this growth is about in-line with the broader market average. Electrics may be undervalued in the intermediate-term as there is a high probability of a decline in rates over that interim. While interest rates are a significant factor in our valuations, there are a number of other forces, as mentioned, that investors should look for in order to be high quality, disciplined buyers.

**INDUSTRY TIMELINESS: 51 (of 93)**

**Dividend Hikes**

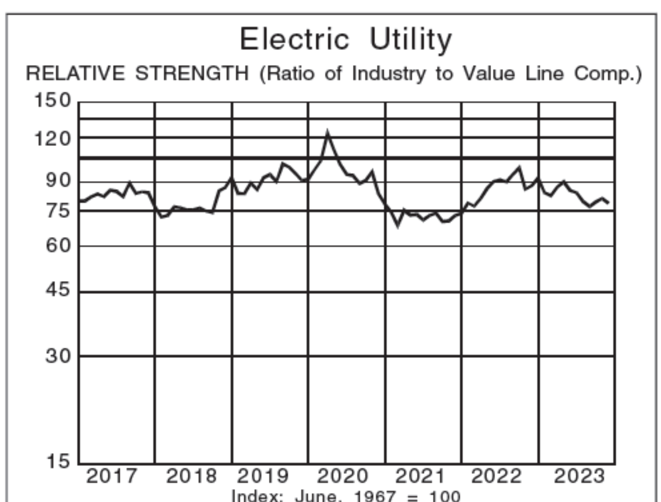
The dividend remains the most notable feature for many electrics, making it very suitable for income-oriented accounts. The industry-wide yield average of 3.6% sits far above The Value Line median. Too, a number of utilities have a proven track record of commitment and many continue to raise their payouts. Indeed, *Fortis* increased its quarterly disbursement by $0.025 a share (4.4%), which is the 50th consecutive year of dividend hikes for the company. *WEC Energy* is also expected to raise its quarterly dividend by $0.053 a share (6%), marking 21 consecutive years of dividend hikes.

**Conclusion**

The rising interest rate climate and challenging macroeconomic environment continues to negatively impact utilities and the group's stock performance. However, the recent decrease in the 10-year Treasury yield has improved the sector's prospects and investor hopes that the Federal Reserve will put an end to rate hikes.

While short- and long-term capital appreciation potential for most electric stocks is not especially appealing, we recommend looking for equities with at least 10% long-term annual return potential. We use this above-industry-average, and not the broader *Value Line* median measure due to the reduced risk of utilities. Meanwhile, the dividend yield remains the standout feature of this group. Regulatory mechanisms tend to also improve prospects for many utilities as they help pass on higher expenses to customers, but regulatory lag is still a hurdle for most electrics.

*Zachary J. Hodgkinson*



**All major electric utilities located in the western region of the United States are reviewed in this Issue; eastern-based electrics, in Issue 1; and the remaining industry participants, in Issue 5. Since our last review of the Electric Utility (West) group three months ago, electric utility stocks covered in the *Value Line Investment Survey* dropped 12.8% in value on average, compared to a 1.7% decline in the S&P 500.**

**On a 12-month basis, the *Value Line Utility Index* has fallen 9.2% versus a 12.1% rise in the *Value Line Arithmetic Index*. This underperformance is in stark contrast to the first two-thirds of 2022 when the defensive nature of utilities was sought after. The sharp rise in interest rates, over the past several months with the 10-year Treasury yield recently surpassing 4.8%, a level not seen since August of 2007, has really hurt these stocks, as Treasurys provide a competitive investment vehicle for income-oriented investors and compare favorably to the recent 4.4% median dividend yield for electric utilities. A sharp turnaround in these stocks should be in play when recession fears resurface and/or the Federal Reserve begins to cut rates.**

**Total annual return prospects through 2026-2028 for electrics look as high as we've seen them over the past year. The median level for the group is presently 10.8% after we began reducing our Target Price Range on most of these stocks to better reflect the evolving interest rate environment. Although there is a generally reduced risk level in owning utilities, given that they're regulated monopolies, we like to see at least 10%-11% long-term total annual return potential before recommending a specific equity to utility investors. That level is in line with historical returns for the broader market.**

**Utility Portfolio Considerations**

Given that this group has really sold off strongly of late, one might wonder if the sector could be termed "undervalued" on a long-term basis. Our answer would be yes if we were confident the 10-year Treasury yield would remain in the 2002 to 2022 range of about 0.5% to 5.5%. If we look back further in history, however, and consider a higher range of interest rates might be in play going forward, than we'd arrive at a very different answer.

In the 1990s, the 10-year yield was as high as 9.1% early on in the decade and 8.0% at mid-decade, while the floor for that yield over the course of the 1990s was 4.3%. While the higher end of the range for that decade certainly does not appear to be in our immediate future, the long-term interest rate chart is no longer characterized by a series of lower highs and lower lows. The breakout above 3.2% that took place in September of 2022, and the ground gained since then, is certainly indicative of a change in the long-term trend.

Our conclusion on valuations is that the group has a good chance of a strong rally on a cyclical decline in rates associated with economic weakness over the intermediate term. But longer term, relative valuations will likely fall. Only in recent years have utility stocks traded above a market price-to-earnings (P/E) ratio.

We think utility investors can help their cause by being disciplined buyers. The midpoint of the annual total return projections based on the 3- to 5-year Target Price Range should generally be at about 11% or better. It would also be a good practice to emphasize utilities with higher-than-average dividend growth prospects. We'd put the industry median at about 4.5% for that metric.

**INDUSTRY TIMELINESS: 92 (of 93)**

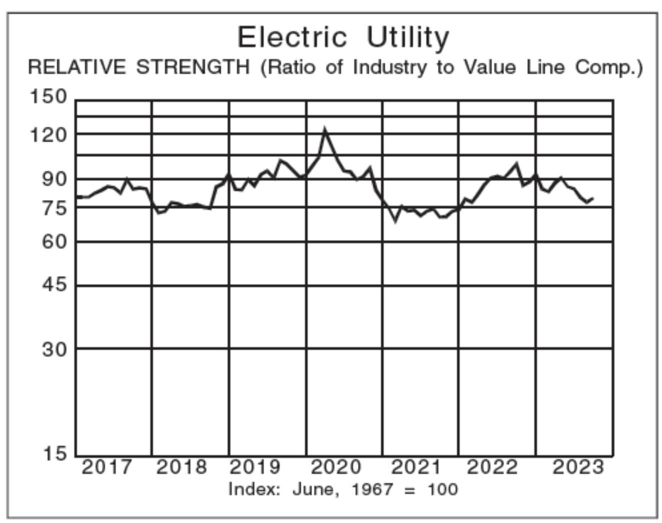
**Topical Considerations**

The main challenges electrics are facing include higher interest rates and upward trending wages, materials, fuel, and purchased power. Due to how the regulatory mechanisms work in this industry, some costs can rapidly be passed on to consumers, such as natural gas prices. Many cannot be and must go through a filed-rate-case process with regulators. The regulatory lag before recoupment may be as short as one year, but in some instances can drag on for a few years. Some companies are fortunate to have a very minimal lag on a reasonable percentage of outlays, as a result of the approved use of nearly real-time pricing adjustments.

High purchased power costs during peak load periods out West have been exacerbated by the shuttering of reliable and inexpensive coal generation. The impact is at times problematic because those open market purchases are not necessarily an automatic and quick pass through to consumers. This situation is also an opportunity, as it increasingly makes sense for renewable generating capacity to be utility owned.

Finally, with *PG&E Corp.* back within our regular coverage, and *Edison Int'l* facing some new wildfire lawsuits, a discussion on bankruptcy risk in California from wildfires is appropriate. (Regarding the wildfire lawsuits impacting *Hawaiian Electric*, and to a lesser degree, *Xcel Energy*, we'd refer subscribers to the respective company reports.) The California Wildfire Fund was established in 2019 as a form of insurance for the state's three major electric utilities (subsidiaries *PG&E*, *Edison Int'l*, and *Sempra Energy*), funded by the companies and their customer base up to $21 billion. The fund doesn't cover claims on fires that took place prior to its formation, while individual claims are paid out over and above the first $1 billion a company incurs. The fund is meant to cover catastrophic losses. With this extra layer of protection above regular insurance carried, bankruptcy risk for the aforementioned California utilities is likely very low.

*Anthony J. Glennon*



# ALLETE NYSE-ALE

RECENT PRICE 55.43 | P/E RATIO 14.4 (Trailing: 12.9, Median: 19.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 4.9% | VALUE LINE

TIMELINESS 2 Raised 11/17/23
SAFETY 2 New 10/1/04
TECHNICAL 3 Raised 12/1/23
BETA .95 (1.00 = Market)

**18-Month Target Price Range**
Low-High: $45-$85 | Midpoint (% to Mid): $65 (15%)

**2026-28 PROJECTIONS**

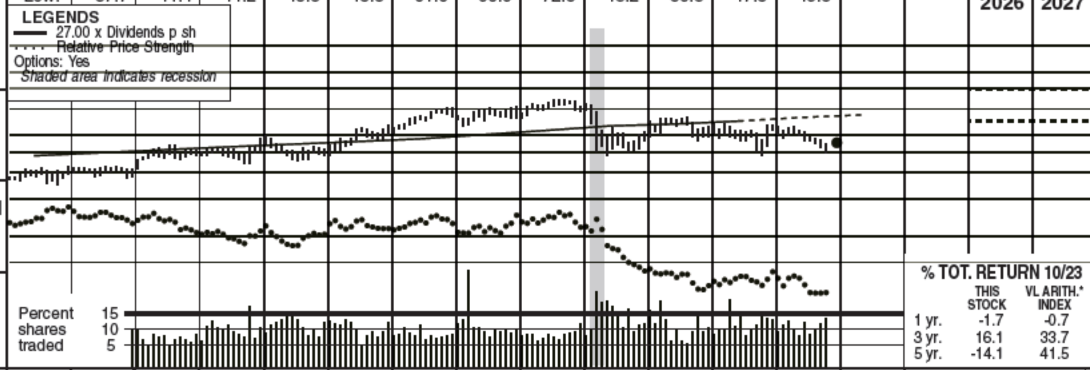
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 100 | (+80%) | 19% |
| Low | 70 | (+25%) | 10% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 153 | 137 | 159 |
| to Sell | 131 | 130 | 123 |
| Hld's(000) | 43870 | 43928 | 43650 |

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 42.7 | 54.1 | 58.0 | 59.7 | 66.9 | 81.2 | 82.8 | 88.6 | 84.7 | 73.1 | 68.6 | 66.7 |
| Low: | 37.7 | 41.4 | 44.2 | 45.3 | 48.3 | 61.6 | 66.6 | 72.5 | 48.2 | 56.8 | 47.8 | 49.3 |

LEGENDS
— 27.00 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession




Target Price Range 2026 | 2027 | 2028

**% TOT. RETURN 10/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -1.7 | -0.7 |
| 3 yr. | 16.1 | 33.7 |
| 5 yr. | -14.1 | 41.5 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 28.04 | *30.15* | *28.80* | Revenues per sh | *31.15* |
| 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 | 7.70 | *9.05* | *8.75* | "Cash Flow" per sh | *9.50* |
| 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 | 3.38 | *4.35* | *4.05* | Earnings per sh A | *5.00* |
| 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 | *2.71* | *2.79* | Div'd Decl'd per sh B ■ † | *3.00* |
| 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 | 3.64 | *5.95* | *5.95* | Cap'l Spending per sh | *7.25* |
| 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 | 47.06 | *49.10* | *51.25* | Book Value per sh C | *54.00* |
| 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 | 56.01 | *58.00* | *59.00* | Common Shs Outst'g D | *61.00* |
| 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 | 18.1 | *Bold figures are* | | Avg Ann'l P/E Ratio | *17.0* |
| .79 | .84 | 1.07 | 1.02 | .92 | 1.01 | 1.05 | .91 | .76 | .98 | 1.16 | 1.20 | 1.32 | .94 | 1.11 | 1.05 | *Value Line* | | Relative P/E Ratio | *.95* |
| 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% | 4.4% | *estimates* | | Avg Ann'l Div'd Yield | *3.7%* |

**CAPITAL STRUCTURE as of 9/30/23**
Total Debt $1805.5 mill. Due in 5 Yrs $390.7 mill.
LT Debt $1686.1 mill. LT Interest $65.9 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $5.1 mill.

Pension Assets-12/22 $745.7 mill. Oblig $911.7 mill.

Pfd Stock None

Common Stock 57,477,405 shs.

MARKET CAP: $3.2 billion (Mid Cap)

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1018.4 | 1136.8 | 1486.4 | 1339.7 | 1419.3 | 1498.6 | 1240.5 | 1169.1 | 1419.2 | 1570.7 | *1750* | *1700* | Revenues ($mill) | *1900* |
| 104.7 | 124.8 | 163.4 | 155.3 | 159.2 | 174.1 | 172.4 | 174.2 | 169.2 | 189.3 | *250* | *240* | Net Profit ($mill) | *305* |
| 21.5% | 22.6% | 19.4% | 11.3% | 14.8% | -- | -- | -- | NMF | NMF | *NMF* | *NMF* | Income Tax Rate | *NMF* |
| 4.4% | 6.3% | 2.0% | 1.4% | .8% | .7% | 1.3% | 1.1% | 1.5% | 1.4% | *2.0%* | *2.0%* | AFUDC % to Net Profit | *1.0%* |
| 44.6% | 44.2% | 46.3% | 42.0% | 41.0% | 39.9% | 38.6% | 41.0% | 42.2% | 40.8% | *39.5%* | *39.5%* | Long-Term Debt Ratio | *40.5%* |
| 55.4% | 55.8% | 53.7% | 58.0% | 59.0% | 60.1% | 61.4% | 59.0% | 57.8% | 59.6% | *60.5%* | *60.5%* | Common Equity Ratio | *59.5%* |
| 2425.9 | 2882.2 | 3388.9 | 3263.4 | 3507.4 | 3584.3 | 3632.8 | 3887.8 | 4176.3 | 4457.5 | *4700* | *4900* | Total Capital ($mill) | *5550* |
| 2576.5 | 3286.4 | 3669.1 | 3741.2 | 3822.4 | 3904.4 | 4377.0 | 4840.8 | 5100.2 | 5004.0 | *5300* | *5450* | Net Plant ($mill) | *5675* |
| 5.3% | 5.2% | 5.8% | 5.8% | 5.5% | 5.8% | 5.6% | 5.3% | 4.8% | 5.6% | *5.5%* | *5.5%* | Return on Total Cap'l | *6.0%* |
| 7.8% | 7.8% | 9.0% | 8.2% | 7.7% | 8.1% | 7.7% | 7.6% | 7.0% | 7.5% | *8.0%* | *8.0%* | Return on Shr. Equity | *9.0%* |
| 7.8% | 7.8% | 9.0% | 8.2% | 7.7% | 8.1% | 7.7% | 7.6% | 7.0% | 7.5% | *8.0%* | *8.0%* | Return on Com Equity E | *9.0%* |
| 2.2% | 2.5% | 3.6% | 2.8% | 2.4% | 2.7% | 2.3% | 2.0% | 1.5% | 2.5% | *2.5%* | *2.5%* | Retained to Com Eq | *3.5%* |
| 72% | 67% | 60% | 66% | 68% | 66% | 70% | 74% | 78% | 76% | *70%* | *69%* | All Div'ds to Net Prof | *60%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -12.0 | +11.5 | +4.7 |
| 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) F | 1588 | 1557 | 1556 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (avg.) | NA | NA | NA |
| Fixed Charge Cov. (%) | 230 | 219 | 220 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -- | -3.0% | *3.0%* |
| "Cash Flow" | 4.5% | 2.0% | *4.5%* |
| Earnings | 3.0% | .5% | *6.0%* |
| Dividends | 3.5% | 3.5% | *3.5%* |
| Book Value | 4.5% | 3.0% | *3.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 311.6 | 243.2 | 293.9 | 320.4 | 1169.1 |
| 2021 | 339.2 | 335.6 | 345.4 | 399.0 | 1419.2 |
| 2022 | 383.5 | 373.1 | 388.3 | 425.8 | 1570.7 |
| 2023 | 564.9 | 533.4 | 378.8 | *272.9* | *1750* |
| 2024 | *425* | *400* | *445* | *430* | *1700* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1.28 | .39 | .78 | .90 | 3.35 |
| 2021 | .99 | .53 | .53 | 1.18 | 3.23 |
| 2022 | 1.24 | .67 | .59 | .90 | 3.38 |
| 2023 | 1.02 | .90 | 1.49 | *.94* | *4.35* |
| 2024 | *1.35* | *.65* | *.90* | *1.15* | *4.05* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .5875 | .5875 | .5875 | .5875 | 2.35 |
| 2020 | .6175 | .6175 | .6175 | .6175 | 2.47 |
| 2021 | .63 | .63 | .63 | .63 | 2.52 |
| 2022 | .65 | .65 | .65 | .65 | 2.60 |
| 2023 | .6775 | .6775 | .6775 | .6775 | |

**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, 17%. 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. '22 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 primary utility subsidiary has filed a general rate case.** Minnesota Power requested an increase of $89 million, based on a 10.3% return on equity and a 53% common-equity ratio. The utility is asking for an interim rate hike of $64 million, subject to refund, to take effect in January 2024. ALLETE expects final rates to be implemented by late 2025. The proposed hikes will help the utility's transition to an improved, clean renewable energy grid, and its goal of 100% carbon-free energy by 2040. Minnesota Power was also recently awarded $65 million in government grants for its high-voltage direct current modernization project, which will replace aging infrastructure and modernize the terminal stations from North Dakota to Minnesota. The project is expected to begin next year, pending regulatory approval, and cost approximately $800-$900 million.

**ALLETE posted third-quarter earnings of $1.49 per share on net income of $85.9 million, a $52.2 million increase year over year.** Interim rates at Minnesota Power, along with a favorable arbitration award involving a subsidiary of ALLETE Clean Energy were the main drivers to the strong showing in the September period. Management raised its full-year 2023 profit guidance range to $4.30-$4.40 per share from its previous spread of $3.55-$3.85 a share. Accordingly, we have also bumped up our EPS call for this year by $0.65, to $4.35.

**We look for a dividend increase in the first quarter of 2024.** This is the usual timing of the board's action. We estimate that the directors will boost the quarterly dividend by about $0.02 a share. ALLETE remains committed to its long-term targets of annual increases in line with earnings growth (5%-7%) and a payout ratio of 60%-70%. The hike will likely be below this profit growth range because of the utility's high payout ratio.

**The stock is timely, and has an above-average dividend yield, even for a utility.** Total return potential over the next 18 months and 3- to 5-year span is attractive in comparison to most of its peers. Too, ALLETE has a high score for Price Stability and is ranked Above Average (2) for Safety.

*Zachary J. Hodgkinson* *December 8, 2023*

(A) Diluted EPS. Excl. nonrec. gains (loss): '15, (46¢); '17, 25¢; '19, 26¢; '19 EPS don't sum due to rounding. Next earnings report due late Feb. (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 '22: $9.60/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 | 35 |
| Earnings Predictability | 90 |

# ALLIANT ENERGY NDQ-LNT

RECENT PRICE 49.96 | P/E RATIO 16.8 (Trailing: 18.2 / Median: 21.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 4 Lowered 10/27/23
SAFETY 2 Raised 9/28/07
TECHNICAL 3 Raised 12/1/23
BETA .90 (1.00 = Market)

**18-Month Target Price Range**
Low-High: $41-$76 | Midpoint (% to Mid): $59 (15%)

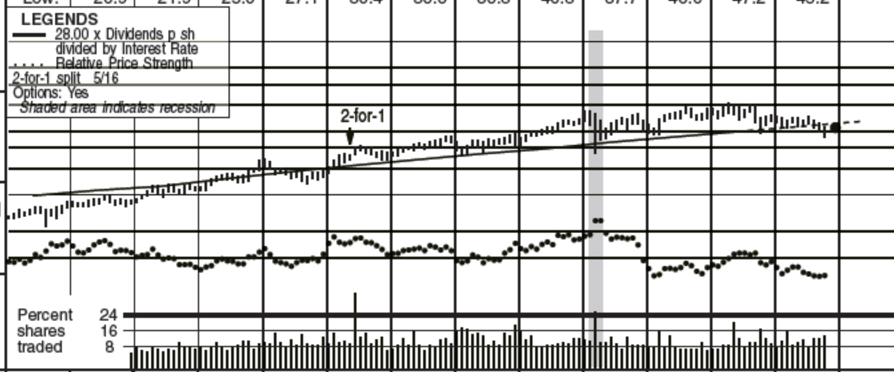
**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 80 | (+60%) | 15% |
| Low | 60 | (+20%) | 8% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 329 | 303 | 270 |
| to Sell | 252 | 259 | 267 |
| Hld's(000) | 192231 | 193788 | 196380 |

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 23.8 | 27.1 | 34.9 | 35.4 | 41.0 | 45.6 | 46.6 | 55.4 | 60.3 | 62.3 | 65.4 | 56.3 |
| Low: | 20.9 | 21.9 | 25.0 | 27.1 | 30.4 | 36.6 | 36.8 | 40.8 | 37.7 | 46.0 | 47.2 | 45.2 |




Target Price Range 2026 | 2027 | 2028

**% TOT. RETURN 10/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -3.2 | -0.7 |
| 3 yr. | -3.1 | 33.7 |
| 5 yr. | 31.1 | 41.5 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 16.74 | *16.05* | *16.55* | Revenues per sh | *16.95* |
| 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 | 5.40 | *5.50* | *5.75* | "Cash Flow" per sh | *6.45* |
| 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 | 2.73 | *2.85* | *3.10* | Earnings per sh A | *3.80* |
| .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* | *1.92* | Div'd Decl'd per sh B ■ † | *2.29* |
| 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 | 5.91 | *5.80* | *5.80* | Cap'l Spending per sh | *5.40* |
| 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 | 24.99 | *26.55* | *27.80* | Book Value per sh C | *31.90* |
| 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 | 251.14 | *255.80* | *256.00* | Common Shs Outst'g D | *257.00* |
| 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 | 21.4 | *Bold figures are Value Line estimates* | | Avg Ann'l P/E Ratio | *18.0* |
| .80 | .81 | .93 | .80 | .91 | .92 | .86 | .87 | .91 | 1.17 | 1.04 | 1.03 | 1.13 | 1.09 | 1.15 | 1.24 | | | Relative P/E Ratio | *1.00* |
| 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% | 2.9% | | | Avg Ann'l Div'd Yield | *3.7%* |

**CAPITAL STRUCTURE as of 9/30/23**
Total Debt $9339 mill. Due in 5 Yrs $2117 mill.
LT Debt $8429 mill. LT Interest $285 mill.
(LT interest earned: 3.5x)

**Leases, Uncapitalized** Annual rentals $3 mill.

**Pension Assets-12/22** $706 mill. Oblig $875 mill.

**Pfd Stock** None

**Common Stock** 252,719,087 shs.

**MARKET CAP: $12.6 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3276.8 | 3350.3 | 3253.6 | 3320.0 | 3382.2 | 3534.5 | 3647.7 | 3416.0 | 3669.0 | 4205.0 | *4100* | *4240* | Revenues ($mill) | *4350* |
| 382.1 | 395.7 | 390.9 | 384.0 | 466.1 | 522.3 | 567.4 | 624.0 | 674.0 | 686.0 | *715* | *800* | Net Profit ($mill) | *975* |
| 12.4% | 10.1% | 15.3% | 13.4% | 12.5% | 8.4% | 10.8% | - - | 10.8% | 3.1% | *1.0%* | *2.0%* | Income Tax Rate | *2.0%* |
| 8.1% | 8.8% | 9.4% | 16.3% | 10.7% | 14.5% | 16.3% | 8.8% | 3.7% | 8.7% | *4.0%* | *4.0%* | AFUDC % to Net Profit | *4.0%* |
| 46.1% | 49.7% | 47.3% | 51.5% | 47.8% | 52.3% | 50.6% | 53.5% | 52.9% | 55.0% | *53.5%* | *52.5%* | Long-Term Debt Ratio | *52.0%* |
| 50.8% | 47.5% | 50.0% | 46.1% | 49.8% | 45.7% | 47.6% | 44.9% | 47.1% | 45.0% | *46.5%* | *47.5%* | Common Equity Ratio | *48.0%* |
| 6461.0 | 7257.2 | 7446.3 | 8377.6 | 8392.8 | 10032 | 10938 | 12657 | 12725 | 13944 | *14665* | *15035* | Total Capital ($mill) | *17070* |
| 7147.3 | 6442.0 | 8970.2 | 9809.9 | 10798 | 12462 | 13527 | 14336 | 14987 | 16247 | *17050* | *17090* | Net Plant ($mill) | *19180* |
| 7.0% | 6.5% | 6.3% | 5.6% | 6.7% | 6.3% | 6.3% | 5.9% | 6.3% | 6.1% | *6.5%* | *6.5%* | Return on Total Cap'l | *7.0%* |
| 11.0% | 10.8% | 10.0% | 9.5% | 10.6% | 10.9% | 10.5% | 10.6% | 11.3% | 10.9% | *10.5%* | *11.0%* | Return on Shr. Equity | *12.0%* |
| 11.3% | 11.2% | 10.2% | 9.7% | 10.9% | 11.2% | 10.7% | 10.8% | 11.0% | 10.9% | *10.5%* | *11.0%* | Return on Com Equity E | *12.0%* |
| 4.9% | 4.6% | 3.6% | 2.8% | 4.0% | 4.4% | 4.2% | 4.2% | 4.3% | 4.1% | *4.0%* | *4.5%* | Retained to Com Eq | *4.5%* |
| 57% | 60% | 66% | 72% | 64% | 62% | 61% | 62% | 62% | 62% | *62%* | *62%* | All Div'ds to Net Prof | *60%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -2.3 | +3.7 | -.7 |
| Avg. Indust. Use (MWH) | 11134 | 11696 | 11494 |
| Avg. Indust. Revs. per KWH (¢) | 7.55 | 7.64 | 8.39 |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 5496 | 5486 | 5629 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +.6 | +.8 | +.7 |
| Fixed Charge Cov. (%) | 251 | 259 | NA |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | - - | .5% | *2.0%* |
| "Cash Flow" | 6.5% | 7.5% | *3.5%* |
| Earnings | 6.0% | 8.0% | *6.5%* |
| Dividends | 6.5% | 6.5% | *6.0%* |
| Book Value | 6.0% | 7.0% | *5.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 916 | 763 | 920 | 817 | 3416 |
| 2021 | 901 | 817 | 1024 | 927 | 3669 |
| 2022 | 1068 | 943 | 1135 | 1059 | 4205 |
| 2023 | 1077 | 912 | 1077 | *1034* | *4100* |
| 2024 | *1080* | *950* | *1145* | *1065* | *4240* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .72 | .54 | .94 | .26 | 2.47 |
| 2021 | .68 | .57 | 1.02 | .35 | 2.63 |
| 2022 | .77 | .63 | .90 | .43 | 2.73 |
| 2023 | .65 | .64 | 1.02 | *.54* | *2.85* |
| 2024 | *.71* | *.70* | *1.10* | *.59* | *3.10* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .355 | .355 | .355 | .355 | 1.42 |
| 2020 | .38 | .38 | .38 | .38 | 1.52 |
| 2021 | .4025 | .4025 | .4025 | .4025 | 1.61 |
| 2022 | .4275 | .4275 | .4275 | .4275 | 1.71 |
| 2023 | .4525 | .4525 | .4525 | .4525 | |

**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 985,000 customers and gas to 425,000 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. '22 reported deprec. rates: 2.9%-6.1%. Has 3,300 employees. Chairman, President & CEO: John O. Larsen. Inc.: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718-2148. Tel.: 608-458-3311. Internet: www.alliantenergy.com.

**Alliant Energy has got its next CEO.** Indeed, the Wisconsin-based electric and gas utility announced that, effective January 1st, Lisa Barton will assume the role of chief executive, replacing John Larsen, who is stepping down after leading the company for what will be four-and-a-half years. An industry veteran who previously held leadership positions at American Electric Power, Ms. Barton joined Alliant earlier this year, heading both utility subsidiaries and filling the position of Chief Operating Officer. Mr. Larsen, meanwhile, will retain his chairmanship of the company's board of directors.

**We still look for earnings to rise just over 4%, to $2.85 a share, this year.** On the plus side, Alliant should benefit from lower operating costs and from the recovery of certain construction costs. However, heating and cooling demand is likely to be lower, coinciding with unseasonably mild weather during much of the year.

**Alliant has earmarked $4.15 billion for renewable-energy and battery-storage projects between this year and 2027.** Importantly, going green will greatly reduce the utility's reliance on fossil fuels, the price of which can fluctuate significantly. At the same time, Alliant stands to earn sizable tax credits, which it can monetize and use to further lower service costs.

**Residential power demand may increase at a fairly modest clip over the next decade or two.** A recent study by the Weldon Cooper Center for Public Service at the University of Virginia ranked Wisconsin 39th among the 50 states for likely population growth between 2020 and 2040. Iowa, meanwhile, was just a bit better, at 28th. That said, word that Alliant has recently seen an uptick in economic development interest augurs well not only for commercial activity across the utility company's service area but also for the Midwest as a destination for job seekers.

**Alliant shares are ranked 4 (Below Average) for relative year-ahead price performance.** While the utility company boasts a fairly attractive dividend (current yield: 3.6%), long-term total return potential doesn't stand out.

*Nils C. Van Liew* *December 8, 2023*

(A) Diluted EPS. Excl. nonrecurring losses: '11, 1¢; '12, 8¢. '20 & '21 EPS don't sum due to rounding. Next earnings report due late Feb. (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: $1,980 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 |

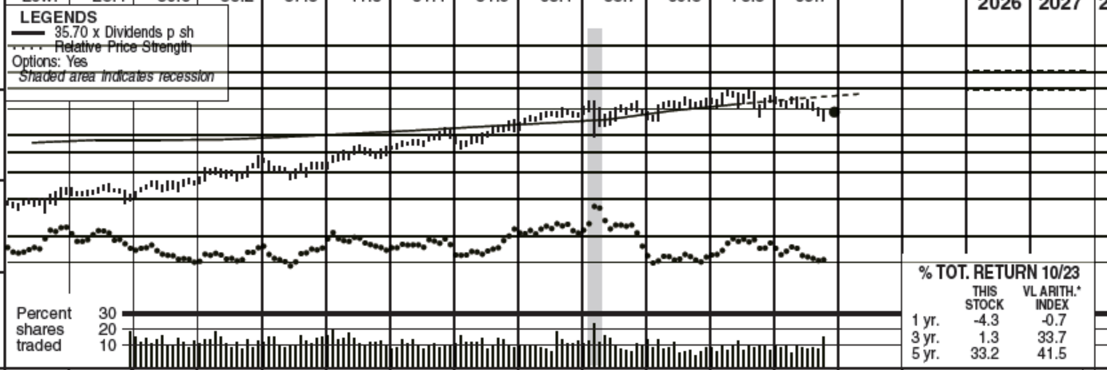
# AMEREN NYSE-AEE

RECENT PRICE 77.46 | P/E RATIO 17.0 (Trailing: 17.6 Median: 20.0) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 3 Raised 12/8/23
SAFETY 1 Raised 9/10/21
TECHNICAL 3 Raised 12/1/23
BETA .90 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 35.3 | 37.3 | 48.1 | 46.8 | 54.1 | 64.9 | 70.9 | 80.9 | 87.7 | 90.8 | 99.2 | 91.2 |
| Low: | 28.4 | 30.6 | 35.2 | 37.3 | 41.5 | 51.4 | 51.9 | 63.1 | 58.7 | 69.8 | 73.3 | 69.7 |

Target Price Range 2026 | 2027 | 2028




**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $68-$120 | $94 (20%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 120 | (+55%) | 14% |
| Low | 100 | (+30%) | 10% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 326 | 296 | 289 |
| to Sell | 270 | 268 | 287 |
| Hld's(000) | 206602 | 205221 | 204708 |

**% TOT. RETURN 10/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -4.3 | -0.7 |
| 3 yr. | 1.3 | 33.7 |
| 5 yr. | 33.2 | 41.5 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 30.37 | *29.95* | *31.60* | Revenues per sh | *32.65* |
| 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 | 9.59 | *9.50* | *10.05* | "Cash Flow" per sh | *12.20* |
| 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 | 4.14 | *4.40* | *4.70* | Earnings per sh A | *5.50* |
| 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* | *2.65* | Div'd Decl'd per sh B ■ | *3.30* |
| 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 | 12.79 | *12.90* | *12.55* | Cap'l Spending per sh | *13.00* |
| 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 | 40.11 | *40.20* | *42.90* | Book Value per sh C | *55.00* |
| 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 | 262.00 | *267.00* | *269.00* | Common Shs Outst'g D | *285.00* |
| 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 | 21.5 | *Bold figures are* | | Avg Ann'l P/E Ratio | *20.0* |
| .92 | .85 | .62 | .62 | .75 | .85 | .93 | .88 | .88 | .96 | 1.04 | .99 | 1.18 | 1.14 | 1.16 | 1.24 | *Value Line* | | Relative P/E Ratio | *1.10* |
| 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% | 2.7% | *estimates* | | Avg Ann'l Div'd Yield | *3.0%* |

**CAPITAL STRUCTURE as of 9/30/23**
Total Debt $16018 mill. Due in 5 Yrs $2789 mill.
LT Debt $13829 mill. LT Interest $450 mill.
(LT interest earned: 3.8x)
Pension Assets-12/22 $5745 mill.
Oblig $5457 mill.
Pfd Stock $129 mill. Pfd Div'd $5 mill.
807,595 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 262,945,048 shs.
as of 10/31/23
MARKET CAP: $20.4 billion (Large Cap)

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5838.0 | 6053.0 | 6098.0 | 6076.0 | 6177.0 | 6291.0 | 5910.0 | 5794.0 | 6394.0 | 7957.0 | *8000* | *8500* | Revenues ($mill) | *9300* |
| 518.0 | 593.0 | 585.0 | 659.0 | 683.0 | 821.0 | 834.0 | 877.0 | 995.0 | 1074.0 | *1190* | *1275* | Net Profit ($mill) | *1570* |
| 37.5% | 38.9% | 38.3% | 36.7% | 38.2% | 22.4% | 17.9% | 15.0% | 13.6% | 14.0% | *12.0%* | *12.0%* | Income Tax Rate | *12.0%* |
| 7.1% | 5.7% | 5.1% | 4.1% | 5.6% | 6.9% | 5.8% | 5.5% | 6.0% | 5.0% | *6.0%* | *5.0%* | AFUDC % to Net Profit | *4.0%* |
| 45.2% | 47.2% | 49.3% | 47.7% | 49.2% | 50.3% | 52.1% | 55.0% | 56.1% | 56.6% | *55.5%* | *53.5%* | Long-Term Debt Ratio | *51.0%* |
| 53.7% | 51.7% | 49.7% | 51.3% | 49.8% | 48.8% | 47.1% | 44.3% | 43.3% | 43.4% | *44.0%* | *46.0%* | Common Equity Ratio | *48.5%* |
| 12190 | 12975 | 13968 | 13840 | 14420 | 15632 | 17116 | 20158 | 22391 | 24193 | *24950* | *25750* | Total Capital ($mill) | *29500* |
| 16205 | 17424 | 18799 | 20113 | 21466 | 22810 | 24376 | 26807 | 29261 | 31262 | *33050* | *35000* | Net Plant ($mill) | *38400* |
| 5.6% | 5.8% | 5.3% | 6.0% | 6.0% | 6.4% | 6.0% | 5.3% | 5.3% | 5.4% | *5.0%* | *5.0%* | Return on Total Cap'l | *6.0%* |
| 7.7% | 8.7% | 8.3% | 9.1% | 9.3% | 10.6% | 10.2% | 9.7% | 10.1% | 10.2% | *11.0%* | *11.0%* | Return on Shr. Equity | *10.0%* |
| 7.8% | 8.7% | 8.3% | 9.2% | 9.4% | 10.7% | 10.3% | 9.7% | 10.2% | 10.2% | *11.0%* | *11.0%* | Return on Com Equity E | *10.0%* |
| 1.9% | 2.9% | 2.5% | 3.3% | 3.4% | 4.8% | 4.4% | 4.2% | 4.4% | 4.4% | *5.0%* | *5.0%* | Retained to Com Eq | *4.0%* |
| 76% | 67% | 70% | 64% | 64% | 56% | 57% | 57% | 57% | 57% | *57%* | *56%* | All Div'ds to Net Prof | *60%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % 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 '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -1.5% | .5% | *4.0%* |
| "Cash Flow" | 4.0% | 6.5% | *5.5%* |
| Earnings | 4.0% | 8.0% | *6.5%* |
| Dividends | 3.5% | 5.0% | *6.5%* |
| Book Value | 2.0% | 5.5% | *6.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1440 | 1398 | 1628 | 1328 | 5794 |
| 2021 | 1566 | 1472 | 1811 | 1545 | 6394 |
| 2022 | 1879 | 1726 | 2306 | 2046 | 7957 |
| 2023 | 2062 | 1760 | 2060 | *2118* | *8000* |
| 2024 | *2120* | *1800* | *2450* | *2130* | *8500* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .59 | .98 | 1.47 | .46 | 3.50 |
| 2021 | .91 | .80 | 1.65 | .48 | 3.84 |
| 2022 | .97 | .80 | 1.74 | .63 | 4.14 |
| 2023 | 1.00 | .90 | 1.87 | *.63* | *4.40* |
| 2024 | *1.03* | *.90* | *2.00* | *.77* | *4.70* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .475 | .475 | .475 | .495 | 1.92 |
| 2020 | .495 | .495 | .495 | .515 | 2.00 |
| 2021 | .55 | .55 | .55 | .55 | 2.20 |
| 2022 | .59 | .59 | .59 | .59 | 2.36 |
| 2023 | .63 | .63 | .63 | | |

**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. Has approximately 9,250 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 posted solid results for the September quarter.** Earnings per share of $1.87 were $0.04 higher than our estimate and $0.13 above the year-ago tally. Most of the outperformance was due to increased investments in infrastructure across all business segments and lower tax expenses. Too, earnings at Ameren Missouri, the largest segment, continue to benefit from higher electric service rates, and we look for this to remain a main catalyst to the bottom line in the next couple of years.

**The utility's guidance has improved a bit.** Due to the aforementioned tailwinds and strong bottom-line performances of late, management narrowed its 2023 earnings estimate to a range of $4.30 to $4.45 per share. This compares to the initial guidance range of $4.25 to $4.45 per share. The company also updated its five-year plan, which includes a 6% to 8% compounded annual growth rate for earnings from 2023 through 2027. Our 2023 and 2024 bottom-line projections are staying put at $4.40 and $4.70 per share, respectively. Profit growth should be primarily driven by increased infrastructure investment and strong rate base growth.

**Ameren remains active on the regulatory front.** There was a constructive settlement of the Ameren Missouri Electric rate review, and new rates recently went into effect. The agreement calls for a 2% increase in residential customer rates, compounded annually since April 2017. AEE also has a rate case ongoing for its Illinois electric segment, and received a lower-than-expected proposed order from the commission. In December, the company filed briefs detailing concerns with the return on equity in the proposed electric order. A final order is expected in mid-December.

**This issue is best suited for conservative income-oriented investors.** The dividend yield of 3.3% is about average for a utility, which is one of the highest dividend-paying industries in the market. Meanwhile, capital appreciation potential over the 18-month and 3- to 5-year time frames is solid compared to most of its peers. Lastly, these shares are ranked to track the broader market averages in the coming year.

*Zachary J. Hodgkinson December 8, 2023*

(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 mid-February. (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%.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 80 |
| Earnings Predictability | 100 |

# AMERICAN ELEC. PWR. NDQ-AEP

| RECENT PRICE | 78.54 | P/E RATIO | 13.8 (Trailing: 16.3) (Median: 18.0) | RELATIVE P/E RATIO | 0.85 | DIV'D YLD | 4.5% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

TIMELINESS 3 Raised 11/24/23
SAFETY 1 Raised 3/17/17
TECHNICAL 4 Raised 12/1/23
BETA .80 (1.00 = Market)

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $67-$123 | $95 (20%) |

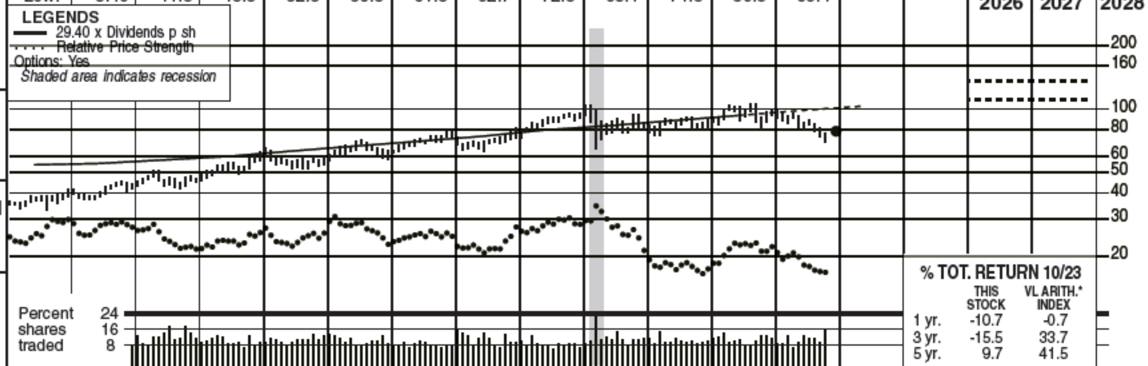
**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 135 | (+70%) | *17%* |
| Low | 110 | (+40%) | *12%* |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 707 | 635 | 596 |
| to Sell | 496 | 532 | 572 |
| Hld's(000) | 390225 | 381232 | 386016 |

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 45.4 | 51.6 | 63.2 | 65.4 | 71.3 | 78.1 | 81.1 | 96.2 | 105.0 | 91.5 | 105.6 | 98.3 |
| Low: | 37.0 | 41.8 | 45.8 | 52.3 | 56.8 | 61.8 | 62.7 | 72.3 | 65.1 | 74.8 | 80.3 | 69.4 |




**% TOT. RETURN 10/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -10.7 | -0.7 |
| 3 yr. | -15.5 | 33.7 |
| 5 yr. | 9.7 | 41.5 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 38.20 | *37.30* | *38.75* | Revenues per sh | *40.90* |
| 6.80 | 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 | 10.72 | *11.00* | *11.65* | "Cash Flow" per sh | *14.75* |
| 2.86 | 2.99 | 2.97 | 2.60 | 3.13 | 2.98 | 3.18 | 3.34 | 3.59 | 4.23 | 3.62 | 3.90 | 4.08 | 4.42 | 4.96 | 5.09 | *5.25* | *5.60* | Earnings per sh A | *6.80* |
| 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* | *3.52* | Div'd Decl'd per sh B ■ † | *4.16* |
| 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 | 13.18 | *15.35* | *14.15* | Cap'l Spending per sh | *14.00* |
| 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 | 46.60 | *52.60* | *55.05* | Book Value per sh C | *62.55* |
| 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 | 513.87 | *523.00* | *530.00* | Common Shs Outst'g D | *550.00* |
| 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 | 21.1 | *Bold figures are* | | Avg Ann'l P/E Ratio | *18.0* |
| .87 | .79 | .67 | .85 | .75 | .88 | .81 | .84 | .80 | .80 | .97 | .97 | 1.14 | 1.01 | .92 | 1.23 | *Value Line* | | Relative P/E Ratio | *1.00* |
| 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% | 3.3% | *estimates* | | Avg Ann'l Div'd Yield | *3.3%* |

**CAPITAL STRUCTURE as of 9/30/23**
Total Debt $42220 mill. Due in 5 Yrs $12886 mill.
LT Debt $36716 mill. LT Interest $1400 mill.

**Leases, Uncapitalized** Annual rentals $119.6 mill.

**Pfd Stock** None

**Common Stock** 525,875,633 shs.

**MARKET CAP: $41.3 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15357 | 17020 | 16453 | 16380 | 15425 | 16196 | 15561 | 14919 | 16792 | 19640 | *19500* | *20550* | Revenues ($mill) | *22500* |
| 1549.0 | 1634.0 | 1763.4 | 2073.6 | 1783.2 | 1923.8 | 2019.0 | 2200.1 | 2488.1 | 2307.2 | *2765* | *2990* | Net Profit ($mill) | *3740* |
| 36.2% | 37.8% | 35.1% | 26.8% | 33.7% | 5.8% | .7% | 1.9% | 4.6% | NMF | *21.0%* | *21.0%* | Income Tax Rate | *21.0%* |
| 7.3% | 9.0% | 11.0% | 8.0% | 8.0% | 10.7% | 12.7% | 9.7% | 7.8% | 7.0% | *7.0%* | *7.0%* | AFUDC % to Net Profit | *5.0%* |
| 51.1% | 49.0% | 49.8% | 50.0% | 51.5% | 53.2% | 56.1% | 58.5% | 58.3% | 58.5% | *58.0%* | *58.0%* | Long-Term Debt Ratio | *57.5%* |
| 48.9% | 51.0% | 50.2% | 50.0% | 48.5% | 46.8% | 43.9% | 41.5% | 41.7% | 42.0% | *42.0%* | *42.0%* | Common Equity Ratio | *42.5%* |
| 32913 | 33001 | 35633 | 34775 | 37707 | 40677 | 44759 | 49537 | 53734 | 57520 | *62950* | *68900* | Total Capital ($mill) | *75900* |
| 40997 | 44117 | 46133 | 45639 | 50262 | 55099 | 60138 | 63902 | 66001 | 71283 | *74600* | *78000* | Net Plant ($mill) | *87300* |
| 6.0% | 6.3% | 6.1% | 7.2% | 5.9% | 5.9% | 5.6% | 5.6% | 5.6% | 4.0% | *4.5%* | *4.5%* | Return on Total Cap'l | *5.0%* |
| 9.6% | 9.7% | 9.9% | 11.9% | 9.8% | 10.1% | 10.3% | 10.7% | 11.1% | 9.7% | *10.0%* | *10.0%* | Return on Shr. Equity | *11.0%* |
| 9.6% | 9.7% | 9.9% | 11.9% | 9.8% | 10.1% | 10.3% | 10.7% | 11.1% | 9.7% | *10.0%* | *10.0%* | Return on Com Equity | *11.0%* |
| 3.7% | 3.8% | 3.9% | 5.5% | 3.2% | 3.5% | 3.4% | 3.8% | 4.3% | 2.9% | *4.0%* | *4.0%* | Retained to Com Eq | *4.5%* |
| 62% | 61% | 60% | 54% | 67% | 65% | 67% | 65% | 61% | 70% | *63%* | *63%* | All Div'ds to Net Prof | *61%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | - - | +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) | +1.0 | NA | NA |
| Fixed Charge Cov. (%) | 243 | 272 | 285 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | .5% | -.5% | *3.0%* |
| "Cash Flow" | 5.0% | 5.5% | *5.5%* |
| Earnings | 5.0% | 4.0% | *6.5%* |
| Dividends | 5.0% | 5.0% | *5.5%* |
| Book Value | 3.5% | 3.5% | *6.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) E Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 3747 | 3494 | 4066 | 3610 | 14918 |
| 2021 | 4281 | 3826 | 4623 | 4061 | 16792 |
| 2022 | 4593 | 4640 | 5526 | 4881 | 19640 |
| 2023 | 4690 | 4373 | 5342 | *5095* | *19500* |
| 2024 | *4820* | *4750* | *5375* | *5605* | *20550* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1.00 | 1.05 | 1.50 | .87 | 4.42 |
| 2021 | 1.15 | 1.15 | 1.59 | 1.07 | 4.96 |
| 2022 | 1.22 | 1.20 | 1.62 | 1.05 | 5.09 |
| 2023 | 1.11 | 1.13 | 1.77 | *1.24* | *5.25* |
| 2024 | *1.35* | *1.35* | *1.75* | *1.15* | *5.60* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .67 | .67 | .67 | .70 | 2.71 |
| 2020 | .70 | .70 | .70 | .74 | 2.84 |
| 2021 | .74 | .74 | .74 | .78 | 3.00 |
| 2022 | .78 | .78 | .78 | .83 | 3.17 |
| 2023 | .83 | .83 | .83 | .88 | |

**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. '22 reported depreciation rates (utility): 2.6%-12.5%. Has 16,700 employees. President, Executive Chairman & Chief Executive Officer: Julie Sloat. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

**We think that American Electric Power will likely post solid earnings growth in 2023 and 2024.** The company should continue to benefit from rate relief, increased investment in its transmission business, and volume growth over the next few years, despite challenging economic conditions which have led to usage decline of late. Third-quarter earnings per share came in at $1.77, above Wall Street's and our expectations due to rate increases, load growth, and higher transmission revenue. As a result, management narrowed its 2023 bottom-line outlook to a range of $5.24-$5.34 per share, and reaffirmed a long-term annual earnings growth target of 6%-7%. We are sticking with our 2023 and 2024 EPS estimates of $5.25 and $5.60, respectively.

**The company remains active on the regulatory front.** Units in Indiana and Michigan requested hikes in the third quarter, based on a 10.5% return on equity (ROE). The utility expects new rates to go into effect by next year. In Ohio, AEP reached an agreement with the Public Utilities Commission of Ohio to invest more than $1.5 billion in the electric grid over the next five years. If approved, the average residential customer would see an average annual increase of about $1.50 per month through 2028. Kentucky Power is also making progress in its June 2023 rate base application, which asks for a 9.9% ROE and a request for the securitization of $471 million of regulatory assets. A final order is expected by the end of this year, and interim rates will likely go into effect in January 2024.

**The board of directors raised the dividend, effective with the December payment.** This is the typical timing of hikes for AEP. The increase was $0.05 a share (6%) quarterly, in line with the company's 6%-7% operating earnings growth range and within the utility's target for a payout ratio of 60%-70%.

**These shares are ranked 3 (Average) for Timeliness.** Nonetheless, this stock is best suited for risk-averse income-oriented investors. Indeed, the above average dividend yield of 4.5% remains this issue's most notable feature. Meanwhile, total return potential over the 18-month and 3- to 5-year time frames is solid for a utility.

*Zachary J. Hodgkinson December 8, 2023*

(A) Diluted EPS. Excl. nonrec. gains (losses): '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¢); '22, (58¢); '23, (34¢). Next earnings report due late February. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '22: $52.5 million (D) In mill. (E) Rev. may not sum due to rounding.

| Company's Financial Strength | A+ |
|---|---|
| Stock's Price Stability | 100 |
| Price Growth Persistence | 55 |
| Earnings Predictability | 95 |

# AVANGRID, INC. NYSE-AGR

| RECENT PRICE | P/E RATIO | | RELATIVE P/E RATIO | DIV'D YLD |
|---|---|---|---|---|
| 29.16 | 12.2 | Trailing: 19.3; Median: NMF | 0.81 | 6.0% |

VALUE LINE

| | |
|---|---|
| TIMELINESS | 3 Raised 11/3/23 |
| SAFETY | 3 Lowered 11/10/23 |
| TECHNICAL | 3 Raised 10/6/23 |
| BETA | .85 (1.00 = Market) |

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $26-$52 | $39 (35%) |

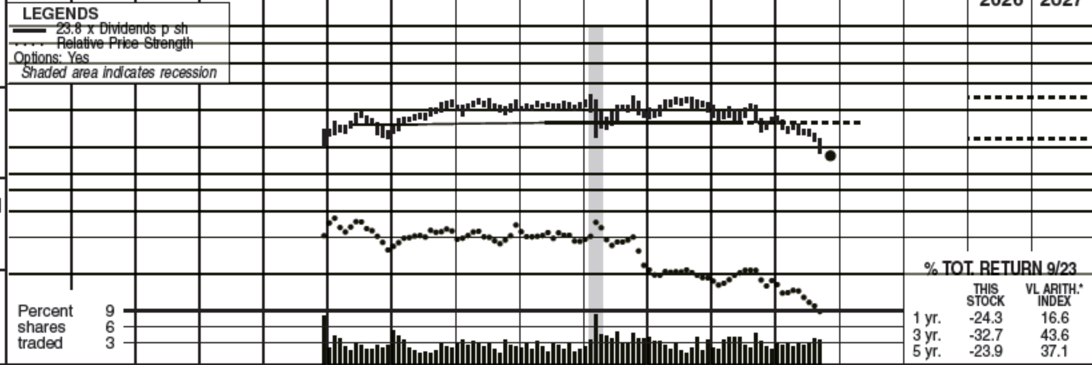
**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 55 | (+90%) | *21%* |
| Low | 35 | (+20%) | *10%* |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 190 | 161 | 146 |
| to Sell | 125 | 141 | 132 |
| Hld's(000) | 48560 | 50224 | 50434 |

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| High: | 38.9 | 46.7 | 53.5 | 54.6 | 52.9 | 57.2 | 55.6 | 51.7 | 44.8 |
| Low: | 32.4 | 35.4 | 37.4 | 45.2 | 47.4 | 35.6 | 44.0 | 37.6 | 27.5 |




**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -24.3 | 16.6 |
| 3 yr. | -32.7 | 43.6 |
| 5 yr. | -23.9 | 37.1 |

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 incorportated in 1997 in New York under the name NGE Resources, Inc. AVANGRID began trading on the NYSE on December 17, 2015.

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -- | -- | 14.14 | 19.48 | 19.30 | 20.96 | 20.51 | 20.45 | 18.04 | 20.49 | *21.60* | *22.50* | Revenues per sh | *25.20* |
| -- | -- | 3.44 | 4.74 | 4.49 | 4.89 | 5.41 | 5.22 | 4.64 | 5.14 | *4.95* | *5.35* | "Cash Flow" per sh | *6.35* |
| -- | -- | 1.05 | 1.98 | 1.67 | 1.92 | 2.17 | 2.02 | 2.18 | 2.32 | *2.10* | *2.35* | Earnings per sh A | *2.80* |
| -- | -- | -- | 1.73 | 1.73 | 1.74 | 1.76 | 1.76 | 1.76 | 1.76 | *1.76* | *1.76* | Div'd Decl'd per sh B ■ | *1.88* |
| -- | -- | 3.50 | 5.52 | 7.82 | 5.78 | 8.87 | 9.00 | 7.70 | 6.52 | *8.65* | *9.05* | Cap'l Spending per sh | *9.55* |
| -- | -- | 48.74 | 48.90 | 48.79 | 48.88 | 49.31 | 49.21 | 49.35 | 50.13 | *50.45* | *51.05* | Book Value per sh C | *53.35* |
| -- | -- | 308.86 | 308.99 | 309.01 | 309.01 | 309.01 | 309.08 | 386.57 | 386.63 | *387.00* | *387.00* | Common Shs Outst'g D | *387.00* |
| -- | -- | 33.5 | 20.5 | 27.3 | 26.1 | 23.1 | 23.6 | 23.2 | 19.6 | *Bold figures are* | | Avg Ann'l P/E Ratio | *16.0* |
| -- | -- | 1.69 | 1.08 | 1.37 | 1.41 | 1.23 | 1.21 | 1.25 | 1.14 | *Value Line* | | Relative P/E Ratio | *.90* |
| -- | -- | -- | 4.3% | 3.8% | 3.5% | 3.5% | 3.7% | 3.5% | 3.9% | *estimates* | | Avg Ann'l Div'd Yield | *4.2%* |
| -- | -- | 4367.0 | 6018.0 | 5963.0 | 6478.0 | 6338.0 | 6320.0 | 6974.0 | 7923.0 | *8350* | *8700* | Revenues ($mill) | *9750* |
| -- | -- | 267.0 | 611.0 | 516.0 | 595.0 | 673.0 | 625.0 | 780.0 | 901.0 | *810* | *910* | Net Profit ($mill) | *1085* |
| -- | -- | 11.3% | 37.4% | 32.4% | 22.1% | 17.0% | 7.2% | 6.2% | 3.2% | *7.0%* | *7.0%* | Income Tax Rate | *7.0%* |
| -- | -- | 12.7% | 7.5% | 12.4% | 9.4% | 15.0% | 17.1% | 15.5% | 12.9% | *17.0%* | *15.0%* | AFUDC % to Net Profit | *13.0%* |
| -- | -- | 23.1% | 23.0% | 25.6% | 26.2% | 30.6% | 40.8% | 29.3% | 29.8% | *31.5%* | *32.0%* | Long-Term Debt Ratio | *38.0%* |
| -- | -- | 76.9% | 77.0% | 74.4% | 73.8% | 69.4% | 59.2% | 70.7% | 70.2% | *68.5%* | *68.0%* | Common Equity Ratio | *62.0%* |
| -- | -- | 19583 | 19619 | 20273 | 20472 | 21953 | 25687 | 26998 | 27603 | *28525* | *29025* | Total Capital ($mill) | *33400* |
| -- | -- | 20711 | 21548 | 22669 | 23459 | 25218 | 26751 | 28866 | 30994 | *33225* | *35575* | Net Plant ($mill) | *42700* |
| -- | -- | 2.1% | 3.8% | 3.1% | 3.5% | 3.7% | 3.0% | 3.4% | 3.9% | *3.5%* | *3.5%* | Return on Total Cap'l | *4.0%* |
| -- | -- | 1.8% | 4.0% | 3.4% | 3.9% | 4.4% | 4.1% | 4.1% | 4.6% | *4.0%* | *4.5%* | Return on Shr. Equity | *5.5%* |
| -- | -- | 1.8% | 4.0% | 3.4% | 3.9% | 4.4% | 4.1% | 4.1% | 4.6% | *4.0%* | *4.5%* | Return on Com Equity E | *5.5%* |
| -- | -- | 1.8% | 1.4% | NMF | .4% | .8% | .5% | .9% | 1.1% | *.5%* | *1.0%* | Retained to Com Eq | *1.5%* |
| -- | -- | -- | 66% | 104% | 90% | 81% | 87% | 79% | 76% | *84%* | *75%* | All Div'ds to Net Prof | *67%* |

**CAPITAL STRUCTURE as of 9/30/23**
**Total Debt** $10932 mill. **Due in 5 Yrs** $3275 mill.
**LT Debt** $9919 mill. **LT Interest** $350 mill.
Incl. $87 mill. finance leases.
(Total Interest coverage: 3.3x)
**Leases, Uncapitalized** Annual rentals $29 mill.

**Pension Assets-12/22** $2151 mill. **Oblig** $2451 mill.

**Pfd Stock** None

**Common Stock** 386,770,915 shs.
as of 10/25/23
**MARKET CAP: $11.3 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (MWH) | -1.7 | +1.8 | +.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, Summer (Mw) | NA | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +.9 | +.1 | +1.6 |
| Fixed Charge Cov. (%) | 237 | 270 | 247 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -- | 2.0% | 4.0% |
| "Cash Flow" | -- | 3.5% | 4.0% |
| Earnings | -- | 7.0% | 4.5% |
| Dividends | -- | 9.0% | 1.0% |
| Book Value | -- | .5% | 1.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1789 | 1392 | 1470 | 1669 | 6320 |
| 2021 | 1966 | 1477 | 1598 | 1933 | 6974 |
| 2022 | 2133 | 1794 | 1838 | 2158 | 7923 |
| 2023 | 2466 | 1587 | 1974 | *2323* | *8350* |
| 2024 | *2525* | *1825* | *2050* | *2300* | *8700* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .76 | .32 | .32 | .62 | 2.02 |
| 2021 | 1.14 | .35 | .34 | .44 | 2.18 |
| 2022 | 1.16 | .46 | .31 | .39 | 2.32 |
| 2023 | .64 | .21 | .27 | *.98* | *2.10* |
| 2024 | *.69* | *.45* | *.55* | *.66* | *2.35* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .44 | .44 | .44 | .44 | 1.76 |
| 2020 | .44 | .44 | .44 | .44 | 1.76 |
| 2021 | .44 | .44 | .44 | .44 | 1.76 |
| 2022 | .44 | .44 | .44 | .44 | 1.76 |
| 2023 | .44 | .44 | .44 | .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 and solar power generation, with 9.2 GW of capacity and 1.7 GW under construction. Renewables segment accounted for about 17% of net profits for trailing 12 months. Power/fuel costs: 31% of rev. '22 reported depr. rate: 2.6%. Iberdrola owns 81.5% of stock. Employs 7,579. Board Chair: Ignacio Sanchez Galan. CEO: Pedro Azagra Blazquez. Inc.: New York. Address: 180 Marsh Hill Road, Orange, CT 06477. Tel.: 207-629-1200. Web: www.avangrid.com.

**AVANGRID received a constructive outcome in two electric rate cases.** In New York, the company's rate base (i.e., the dollar value of assets a utility is allowed to earn an economic return on) has been approved to expand by nearly 40%, from $6.6 billion in 2022 to $9.2 billion in 2026. The rise reflects investments needed to increase reliability/resiliency and accelerate the state's clean energy initiatives. Higher prices will be based on a 9.2% allowable return on equity (ROE), up from 8.8% previously. New delivery rates will be collected from November 1st, but will reflect the higher level back to May 1st. Fourth-quarter profits are thus expected to be outsized due to eight months worth of the price increase and from a mitigation of past uncollectibles. In Maine, the utility commission approved a safety, reliability and resiliency plan that will lift the state rate base by over $380 million over the next two years, to nearly $1.3 billion. Our understanding is that the ROE in Maine is unchanged at 9.25%.
**The company is appealing an unfavorable Connecticut rate decision.** AVANGRID had asked for an 8% hike over three years, with an increase of $91 million to cover rising operating costs in the first year of the schedule. In August, the company was granted an increase of $16.8 million for year one. If AVANGRID cannot get relief through Connecticut's court system, it will be saddled with an 8.63% ROE in that state (one of the lowest levels in the U.S.), down from 9.1% previously.
**Concluding the acquisition of PNM Resources is a priority.** AVANGRID agreed to purchase the parent of electric utilities in New Mexico and Texas for $4.3 billion. The merger was blocked by regulators in New Mexico. The decision was appealed to that state's supreme court, which has been slow to make a decision.
**AVANGRID has significantly underperformed our utility index in 2023.** The market has turned sour on electric utilities in general, and the added finance and project risks associated with renewable energy (particularly offshore wind generation) has come under additional scrutiny. AGR's 6.0% yield may make a purchase here worth the risk for well diversified utility investors.
*Anthony J. Glennon* *November 10, 2023*

(A) Diluted egs. Excl. nonrecur. gain/(loss): '16, 6¢; '17, (44¢); '19, 9¢; '20, (14¢); '21, (21¢); '22, (5¢); 1Q-3Q '23, (12¢);. Qtly. EPS may not sum to full-year due to rounding. Next egs. report due late Jan. (B) Div'ds paid in early Jan., Apr., July and Oct. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '22: $5,721 mill., $14.80/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in NY in '23: 9.2%; in CT in '23: 8.63% elec.; in CT in '19: 9.3% gas; in ME in '22: 9.25%. Regulatory Climate: Below Average.

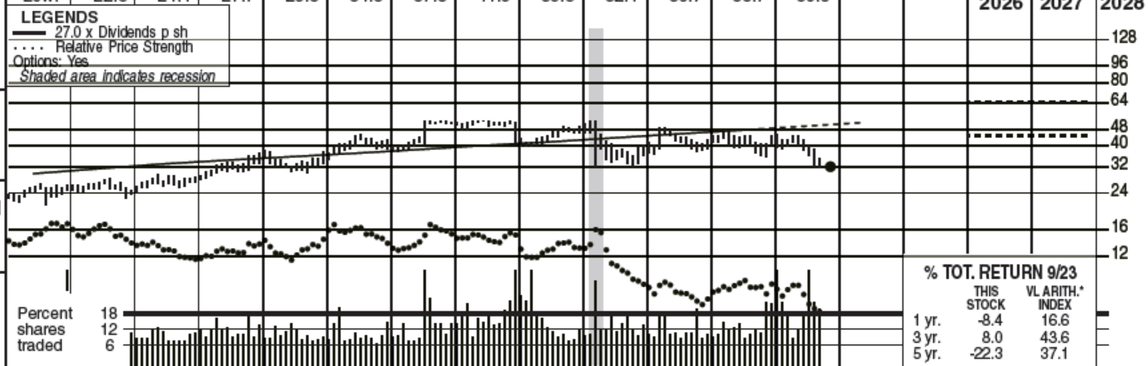
| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 85 |
| Price Growth Persistence | 40 |
| Earnings Predictability | 80 |

# AVISTA CORP. NYSE-AVA

| RECENT PRICE | P/E RATIO | | RELATIVE P/E RATIO | DIV'D YLD | |
|---|---|---|---|---|---|
| 32.04 | 13.8 | (Trailing: 16.6) (Median: 19.0) | 0.86 | 5.7% | VALUE LINE |

| | | |
|---|---|---|
| TIMELINESS | 2 | Raised 10/13/23 |
| SAFETY | 2 | Raised 5/7/10 |
| TECHNICAL | 4 | Raised 10/13/23 |
| BETA .90 (1.00 = Market) | | |

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 28.0 | 29.3 | 37.4 | 38.3 | 45.2 | 52.8 | 52.9 | 49.5 | 53.0 | 49.1 | 46.9 | 45.3 |
| Low: | 22.8 | 24.1 | 27.7 | 29.8 | 34.3 | 37.8 | 41.9 | 39.8 | 32.1 | 36.7 | 35.7 | 30.5 |




**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $28-$54 | $41 (30%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 65 | (+105%) | 23% |
| Low | 45 | (+40%) | 13% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 153 | 122 | 109 |
| to Sell | 125 | 134 | 133 |
| Hld's(000) | 66349 | 67752 | 67636 |

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -8.4 | 16.6 |
| 3 yr. | 8.0 | 43.6 |
| 5 yr. | -22.3 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 22.82 | *22.10* | *22.15* | Revenues per sh | *23.45* |
| 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 | 4.40 | *5.10* | *5.50* | "Cash Flow" per sh | *6.60* |
| .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 | 2.12 | *2.30* | *2.50* | Earnings per sh A | *2.90* |
| .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 | *1.84* | *1.92* | Div'd Decl'd per sh B ■ | *2.20* |
| 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 | 6.03 | *6.00* | *6.35* | Cap'l Spending per sh | *6.75* |
| 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 | 31.15 | *31.85* | *33.00* | Book Value per sh C | *37.00* |
| 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 | 74.95 | *77.00* | *78.50* | Common Shs Outst'g D | *85.00* |
| 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 | 20.0 | *Bold figures are* | | Avg Ann'l P/E Ratio | *19.0* |
| 1.64 | .90 | .76 | .81 | .88 | 1.23 | .82 | .91 | .89 | .99 | 1.18 | 1.32 | .80 | 1.09 | 1.09 | 1.16 | *Value Line* | | Relative P/E Ratio | *1.05* |
| 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% | 4.2% | *estimates* | | Avg Ann'l Div'd Yield | *4.0%* |

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1618.5 | 1472.6 | 1484.8 | 1442.5 | 1445.9 | 1396.9 | 1345.6 | 1321.9 | 1438.9 | 1710.2 | *1700* | *1740* | Revenues ($mill) | *1995* |
| 111.1 | 114.2 | 118.1 | 137.2 | 126.1 | 136.4 | 197.0 | 129.5 | 147.3 | 155.2 | *175* | *195* | Net Profit ($mill) | *255* |
| 36.0% | 37.6% | 36.3% | 36.3% | 36.5% | 16.0% | 13.8% | 5.2% | 7.5% | 15.0% | *15.0%* | *15.0%* | Income Tax Rate | *15.0%* |
| 8.8% | 11.1% | 10.1% | 8.1% | 7.9% | 7.7% | 5.5% | 8.5% | 7.5% | 2.4% | *5.0%* | *5.0%* | AFUDC % to Net Profit | *5.0%* |
| 51.4% | 51.0% | 50.0% | 51.2% | 47.2% | 50.5% | 49.4% | 50.4% | 47.5% | 50.4% | *50.5%* | *50.5%* | Long-Term Debt Ratio | *49.5%* |
| 48.6% | 49.0% | 50.0% | 48.8% | 52.8% | 49.5% | 50.6% | 49.6% | 52.5% | 49.6% | *49.5%* | *49.5%* | Common Equity Ratio | *50.5%* |
| 2669.7 | 3027.3 | 3060.3 | 3379.0 | 3273.2 | 3580.3 | 3834.6 | 4089.8 | 4104.7 | 4709.7 | *5000* | *5250* | Total Capital ($mill) | *6100* |
| 3202.4 | 3620.0 | 3898.6 | 4147.5 | 4398.8 | 4648.9 | 4797.0 | 4991.6 | 5225.5 | 5444.7 | *5650* | *5900* | Net Plant ($mill) | *6375* |
| 5.4% | 4.9% | 5.1% | 5.3% | 5.0% | 4.8% | 6.2% | 4.2% | 4.7% | 4.6% | *5.0%* | *5.0%* | Return on Total Cap'l | *5.0%* |
| 8.6% | 7.7% | 7.7% | 8.3% | 7.3% | 7.7% | 10.2% | 6.4% | 6.8% | 6.6% | *7.5%* | *7.5%* | Return on Shr. Equity | *7.5%* |
| 8.6% | 7.7% | 7.7% | 8.3% | 7.3% | 7.7% | 10.2% | 6.4% | 6.8% | 6.6% | *7.5%* | *7.5%* | Return on Com Equity E | *7.5%* |
| 2.9% | 2.4% | 2.3% | 3.0% | 1.9% | 2.2% | 4.9% | .9% | 1.4% | 1.1% | *2.0%* | *2.0%* | Retained to Com Eq | *2.0%* |
| 66% | 69% | 70% | 64% | 73% | 72% | 52% | 85% | 80% | 83% | *80%* | *77%* | All Div'ds to Net Prof | *76%* |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $2791.5 mill. **Due in 5 Yrs** $30.0 mill.
**LT Debt** $2530.0 mill. **LT Interest** $140.0 mill.
Incl. $51.5 mill. debt to affiliated trusts; $42.5 mill. finance leases.
(LT interest earned: 2.1x)
**Leases, Uncapitalized** Annual rentals $10.3 mill.
**Pension Assets-12/22** $540.7 mill. **Oblig** $557.7 mill.
**Pfd Stock** None

**Common Stock** 75,763,513 shs. as of 7/28/23
**MARKET CAP: $2.4 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -2.4 | +4.3 | +3.1 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 6.38 | 6.41 | 6.62 |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 1721 | 1889 | 1810 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +1.8 | +1.4 | -1.0 |
| Fixed Charge Cov. (%) | 222 | 216 | 175 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -2.5% | -2.0% | *2.0%* |
| "Cash Flow" | 3.0% | -0.5% | *3.5%* |
| Earnings | 2.5% | 0.5% | *6.0%* |
| Dividends | 4.5% | 4.0% | *4.5%* |
| Book Value | 4.0% | 3.5% | *3.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 390.2 | 278.6 | 272.6 | 380.5 | 1321.9 |
| 2021 | 412.9 | 298.2 | 296.0 | 431.8 | 1438.9 |
| 2022 | 462.7 | 378.6 | 359.4 | 509.5 | 1710.2 |
| 2023 | 474.6 | 379.9 | *335* | *510.5* | *1700* |
| 2024 | *485* | *390* | *345* | *520* | *1740* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .72 | .26 | .07 | .85 | 1.90 |
| 2021 | .98 | .20 | .20 | .71 | 2.10 |
| 2022 | .99 | .16 | d.08 | 1.05 | 2.12 |
| 2023 | .73 | .23 | *.15* | *1.19* | *2.30* |
| 2024 | *.75* | *.25* | *.25* | *1.25* | *2.50* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .3875 | .3875 | .3875 | .3875 | 1.55 |
| 2020 | .405 | .405 | .405 | .405 | 1.62 |
| 2021 | .4225 | .4225 | .4225 | .4225 | 1.69 |
| 2022 | .44 | .44 | .44 | .44 | 1.76 |
| 2023 | .46 | .46 | .46 | | |

**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: 411,000 electric, 377,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 38%; commercial, 30%; industrial, 10%; wholesale, 17%; other, 5%. Generating sources: gas & coal, 31%; hydro, 31%; purch., 38%. Fuel costs: 35% of revs. '22 reported depr. rate (Avista Utilities): 3.6%. Has 1,767 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's earnings target for 2023 remains at $2.30 a share.** As always, when dealing with utility stocks, we caution our subscribers to look at the full-year numbers and not get caught up in the sequential figures. These businesses post choppy quarterly results and AVA is no different. That said, leadership has stated it looks for annual gains in the range of 5% to 7%, and our current outlook is just above that spread. This year, tax credits tied to earlier rate cases are being returned to customers. With that, we anticipate lower showings in the second and third quarters, with roughly 50% of annual utility earnings recognized in the final stanza of the year. Too, costs under the Energy Recovery Mechanism in Washington are apt to be higher than expected in 2023 due to poor hydro conditions.

**The pressure points on utility stocks in general are mounting.** AVA shares have fallen about 15% in price since our late July coverage. For starters, higher interest rates make the yield on these selections less attractive. Additionally, each media report that states a recession can be avoided sends members of the investment community looking for riskier propositions. And, all of this is happening at a time when the Maui wildfires have everyone asking questions about the legal liabilities of utility companies.

**Avista has some positives going for it.** Pertaining to electric and natural gas general rate cases, the company received approval from the Idaho Public Utilities Commission for the multiparty settlement agreement filed in mid-June. Annual base electric revenues increased 8% on September 1, 2023. On the natural gas side of the coin, a boost of 2.7% kicked in on the same day. The settlement includes a 9.4% return on equity with a common equity ratio of 50% and a rate of return on the rate base of 7.19%. Clean energy moves should also pay off. A wind generation pact in Montana is promising, and hydro agreements will lift AVA's generating capabilities from non-emitting resources.

**At north of 5.5%, this timely utility's yield exceeds the industry average.** Too, the recent downturn in the quotation has enhanced capital appreciation potential out to 2026-2028.

*Erik M. Manning* *October 20, 2023*

(A) Diluted EPS. Excl. nonrec. gain (loss): '14, 9¢; '17, (16¢); gains on discont. ops.: '14, $1.17; '15, 8¢. EPS may not sum due to rounding. Next earnings report due early November.
(B) Div'ds paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. In '22: $911.2 mill., $12.16/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., '22: 7.1%. Regulatory Climate: WA, Below Avg.; ID, Above Avg.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 75 |
| Price Growth Persistence | 45 |
| Earnings Predictability | 65 |

# BLACK HILLS CORP. NYSE-BKH

| RECENT PRICE | P/E RATIO | RELATIVE P/E RATIO | DIV'D YLD | |
|---|---|---|---|---|
| 49.27 | 13.0 (Trailing: 13.2, Median: 18.0) | 0.81 | 5.3% | VALUE LINE |

TIMELINESS 5 Lowered 10/6/23

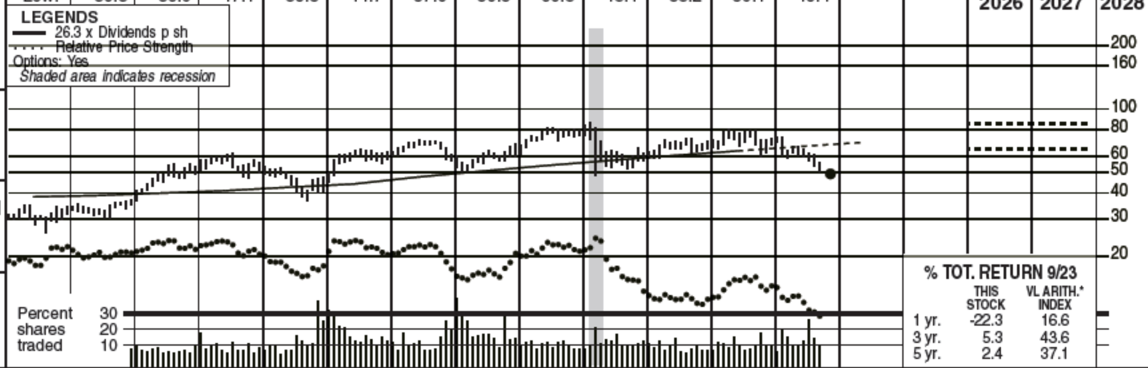
SAFETY 2 Raised 5/1/15

TECHNICAL 3 Lowered 8/4/23

BETA 1.00 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 37.0 | 55.1 | 62.1 | 53.4 | 64.6 | 72.0 | 68.2 | 82.0 | 87.1 | 72.8 | 80.9 | 74.0 |
| Low: | 30.3 | 36.9 | 47.1 | 36.8 | 44.7 | 57.0 | 50.5 | 60.8 | 48.1 | 58.2 | 59.1 | 46.4 |

LEGENDS
— 26.3 x Dividends p sh
···· Relative Price Strength
Options: Yes
Shaded area indicates recession




## 18-Month Target Price Range

| Low-High | Midpoint (% to Mid) |
|---|---|
| $46-$86 | $66 (35%) |

## 2026-28 PROJECTIONS

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 85 | (+75%) | 18% |
| Low | 65 | (+30%) | 12% |

## Institutional Decisions

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 148 | 150 | 164 |
| to Sell | 143 | 156 | 136 |
| Hld's(000) | 59331 | 57740 | 58479 |

## % TOT. RETURN 9/23

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -22.3 | 16.6 |
| 3 yr. | 5.3 | 43.6 |
| 5 yr. | 2.4 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 38.60 | 38.50 | 39.15 | Revenues per sh | 40.85 |
| 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 | 7.75 | 8.00 | "Cash Flow" per sh | 9.25 |
| 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 | 3.97 | 3.75 | 3.90 | Earnings per sh A | 4.50 |
| 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 | 2.65 | Div'd Decl'd per sh B ■ | 3.01 |
| 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 | 9.14 | 9.30 | 9.50 | Cap'l Spending per sh | 9.25 |
| 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 | 45.31 | 46.75 | 48.70 | Book Value per sh C | 55.00 |
| 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 | 66.10 | 67.50 | 69.00 | Common Shs Outst'g D | 71.00 |
| 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 | 18.1 | Bold figures are | | Avg Ann'l P/E Ratio | 16.5 |
| .80 | NMF | .66 | 1.15 | 1.95 | 1.09 | 1.02 | 1.00 | .81 | 1.17 | .98 | .91 | 1.13 | .87 | .96 | 1.04 | Value Line | | Relative P/E Ratio | .90 |
| 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% | 3.4% | estimates | | Avg Ann'l Div'd Yield | 4.1% |

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1275.9 | 1393.6 | 1304.6 | 1573.0 | 1680.3 | 1754.3 | 1734.9 | 1696.9 | 1949.1 | 2551.8 | 2600 | 2700 | Revenues ($mill) | 2900 |
| 115.8 | 128.8 | 128.3 | 140.3 | 186.5 | 192.5 | 214.5 | 232.9 | 236.7 | 258.4 | 250 | 265 | Net Profit ($mill) | 320 |
| 34.7% | 33.7% | 35.8% | 25.1% | 28.7% | 19.2% | 13.0% | 12.2% | 2.8% | 8.5% | 8.5% | 8.5% | Income Tax Rate | 8.5% |
| 2.4% | 2.4% | 2.7% | 5.3% | 2.7% | 1.4% | 3.3% | 2.5% | 2.0% | 2.4% | 2.5% | 2.5% | AFUDC % to Net Profit | 2.5% |
| 51.6% | 47.9% | 56.0% | 66.5% | 64.5% | 57.5% | 57.1% | 57.9% | 59.7% | 54.6% | 54.5% | 54.5% | Long-Term Debt Ratio | 54.0% |
| 48.4% | 52.1% | 44.0% | 33.5% | 35.5% | 42.5% | 42.9% | 42.1% | 40.3% | 45.4% | 45.5% | 45.5% | Common Equity Ratio | 46.0% |
| 2704.7 | 2643.6 | 3332.7 | 4825.8 | 4818.4 | 5132.4 | 5502.2 | 6089.5 | 6914.0 | 6602.3 | 6950 | 7350 | Total Capital ($mill) | 8425 |
| 2990.3 | 3239.4 | 3259.1 | 4469.0 | 4541.4 | 4854.9 | 5503.2 | 6019.7 | 6449.2 | 6797.9 | 7125 | 7525 | Net Plant ($mill) | 8525 |
| 5.5% | 6.1% | 4.9% | 4.0% | 5.2% | 5.0% | 4.9% | 5.0% | 4.5% | 5.1% | 4.5% | 4.5% | Return on Total Cap'l | 5.0% |
| 8.9% | 9.4% | 8.8% | 8.7% | 10.9% | 8.8% | 9.1% | 9.1% | 8.5% | 8.6% | 8.0% | 8.0% | Return on Shr. Equity | 8.0% |
| 8.9% | 9.4% | 8.8% | 8.7% | 10.9% | 8.8% | 9.1% | 9.1% | 8.5% | 8.6% | 8.0% | 8.0% | Return on Com Equity E | 8.0% |
| 3.7% | 4.3% | 3.8% | 3.3% | 5.3% | 3.9% | 3.8% | 3.8% | 3.3% | 3.4% | 2.5% | 2.5% | Retained to Com Eq | 2.5% |
| 58% | 54% | 57% | 62% | 52% | 55% | 58% | 58% | 61% | 61% | 67% | 68% | All Div'ds to Net Prof | 67% |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $4480.7 mill. **Due in 5 Yrs** $1835.0 mill.
**LT Debt** $3955.7 mill. **LT Interest** $200.0 mill.
(Total Interest Coverage: 2.6x)
**Leases, Uncapitalized** Annual rentals $2.4 mill.

**Pension Assets-12/22** $323.1 mill. **Oblig** $358.4 mill.

**Pfd Stock** None

**Common Stock** 67,110,952 shs. as of 7/31/23

**MARKET CAP: $3.3 billion (Mid Cap)**

## ELECTRIC OPERATING STATISTICS

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -.7 | +1.5 | +3.5 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Yearend (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 1050 | 1078 | 1107 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +.9 | +1.0 | +1.0 |
| Fixed Charge Cov. (%) | 285 | 259 | 281 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 1.0% | 2.0% | 3.5% |
| "Cash Flow" | 4.5% | 3.5% | 3.5% |
| Earnings | 9.5% | 5.5% | 3.0% |
| Dividends | 4.5% | 6.0% | 4.5% |
| Book Value | 4.5% | 7.5% | 4.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 537.0 | 326.9 | 346.6 | 486.4 | 1696.9 |
| 2021 | 633.4 | 372.6 | 380.6 | 562.5 | 1949.1 |
| 2022 | 823.6 | 474.2 | 462.6 | 791.4 | 2551.8 |
| 2023 | 921.2 | 411.3 | 465 | 802.5 | 2600 |
| 2024 | 930 | 475 | 480 | 815 | 2700 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1.59 | .33 | .58 | 1.23 | 3.73 |
| 2021 | 1.54 | .40 | .70 | 1.11 | 3.74 |
| 2022 | 1.82 | .52 | .54 | 1.11 | 3.97 |
| 2023 | 1.73 | .35 | .52 | 1.15 | 3.75 |
| 2024 | 1.77 | .43 | .55 | 1.15 | 3.90 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .505 | .505 | .505 | .535 | 2.05 |
| 2020 | .535 | .535 | .535 | .565 | 2.17 |
| 2021 | .565 | .565 | .565 | .595 | 2.29 |
| 2022 | .595 | .595 | .595 | .625 | 2.41 |
| 2023 | .625 | .625 | .625 | | |

**BUSINESS:** Black Hills Corporation is a holding company for Black Hills Energy, which serves 220,431 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, 35%; commercial, 39%; industrial, 23%; other, 3%. Generating sources: coal, 35%; gas, 19%; wind, 11%; purchased, 35%. Fuel costs: 38% of revs. '22 deprec. rate: 3.2%. Has 2,982 employees. Chairman: Steven R. Mills. President & CEO: Linn Evans. Inc.: SD. Address: 7001 Mount Rushmore Rd., P.O. Box 1400, Rapid City, SD 57709-1400. Telephone: 605-721-1700. Internet: www.blackhillscorp.com.

**Black Hills' stock price has continued to slide deeper into negative territory this year.** The shares are down 31% in 2023, versus the 17% average decline for all electric utilities covered by *Value Line*. While many interest-rate sensitive issues are suffering as the 10-year Treasury yield continues to press higher, BKH's troubles extend back to the third quarter of last year, which marked the start of four-consecutive weak quarterly year-to-year comparisons. The stock's decline picked up momentum in February when leadership broke the news to investors that it was cutting its long-term earnings growth projections, to 4%-6% from 5%-7%. Inflation has been cited as the root cause. Some electrics are better able to deal with today's difficult macro environment of elevated commodity/labor costs and higher interest rates without suffering from extreme regulatory lag. It depends largely on what pricing mechanisms a utility has at its disposal to pass on higher costs to consumers in a timely fashion. Black Hills is suffering from regulatory lag and has either recently filed rate cases or is preparing to do so in its various service areas.

**The company is focused on adding renewable power sources in its electric grid territories.** Colorado has initiatives in place requiring that 80% of the state's electricity comes from non-emitting sources within seven years. Accordingly, Black Hills is investing in a combination of solar cells, wind power, and battery storage totalling 520 megawatts by 2030. Half will be utility owned, with the remainder under long-term supply agreements to the company. South Dakota and Wyoming are less aggressive in their energy transitions. Still, Black Hills has received the green light to expand renewables by 120 mw through 2026 in those states. These investments should provide an economic rate of retuen to the company.

**This equity is untimely.** That can be said for the stocks of most of Black Hills' peers. The rise in Treasury rates to levels not seen since 2007 has the group reeling. This issue may be less speculative now than it may seem. It's already cut its outlook to realistic levels while many peers may have to. BKH's 5.3% yield is a percentage point above its industry median.

*Anthony J. Glennon* *October 20, 2023*

(A) Diluted EPS. Excl. nonrec. gains/(losses): '15, ($3.54); '16, ($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¢). Qtly. EPS may not sum to full year due to rounding. Next egs. report due early Nov. (B) Div'ds paid in early March, June, Sept., and Dec. ■ Div'd reinv. plan avail. (C) Incl. deferred chgs. In '22: $1.75 bill., $26.45/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in SD in '15: none specified; in CO in '17: 9.37%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 85 |
| Price Growth Persistence | 45 |
| Earnings Predictability | 95 |

# CENTERPOINT EN'RGY NYSE-CNP

| RECENT PRICE | P/E RATIO | (Trailing: 22.4) (Median: 19.0) | RELATIVE P/E RATIO | DIV'D YLD | VALUE LINE |
|---|---|---|---|---|---|
| 27.95 | 15.8 | | 0.98 | 2.9% | |

TIMELINESS 2 Raised 11/10/23
SAFETY 3 Lowered 12/18/15
TECHNICAL 3 Raised 11/24/23
BETA 1.15 (1.00 = Market)

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $22-$41 | $32 (15%) |

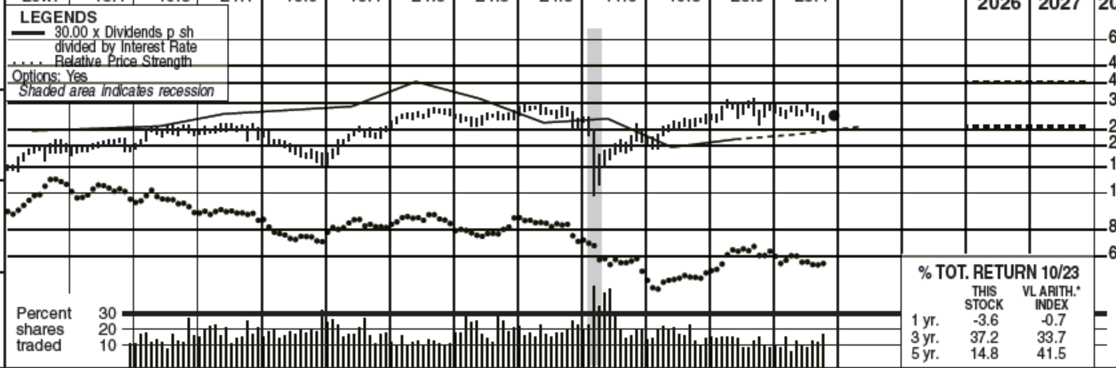
**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 40 | (+45%) | 12% |
| Low | 25 | (-10%) | 1% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 330 | 269 | 257 |
| to Sell | 232 | 269 | 272 |
| Hld's(000) | 574926 | 567918 | 562002 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 21.8 | 25.7 | 25.8 | 23.7 | 25.0 | 30.5 | 29.6 | 31.4 | 27.5 | 28.4 | 33.5 | 31.5 |
| Low: | 18.1 | 19.3 | 21.1 | 16.0 | 16.4 | 24.5 | 24.8 | 24.3 | 11.6 | 19.3 | 25.0 | 25.4 |




**% TOT. RETURN 10/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -3.6 | -0.7 |
| 3 yr. | 37.2 | 33.7 |
| 5 yr. | 14.8 | 41.5 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 14.81 | *14.55* | *14.80* | Revenues per sh | *16.75* |
| 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 | 3.65 | *3.70* | *3.95* | "Cash Flow" per sh | *4.75* |
| 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 | 1.59 | *1.73* | *1.87* | Earnings per sh A | *2.10* |
| .68 | .73 | .76 | .78 | .79 | .81 | .83 | .95 | .99 | 1.03 | 1.35 | 1.12 | .86 | .90 | .66 | .72 | *.76* | *.83* | Div'd Decl'd per sh B ■ | *.95* |
| 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 | 7.02 | *6.65* | *7.05* | Cap'l Spending per sh | *9.00* |
| 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 | 14.68 | *17.25* | *19.05* | Book Value per sh C | *21.50* |
| 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 | 629.54 | *631.50* | *632.00* | Common Shs Outst'g D | *634.00* |
| 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 | 18.7 | *Bold figures are* | | Avg Ann'l P/E Ratio | *16.0* |
| .80 | .68 | .79 | .88 | .92 | .94 | 1.05 | .89 | .91 | 1.15 | .90 | 2.00 | 1.04 | .82 | 1.41 | 1.08 | *Value Line* | | Relative P/E Ratio | *.90* |
| 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% | 2.4% | *estimates* | | Avg Ann'l Div'd Yield | *2.9%* |

**CAPITAL STRUCTURE as of 9/30/23**
**Total Debt** $18263 mill. **Due in 5 Yrs** $6698 mill.
**LT Debt** $16838 mill. **LT Interest** $600 mill.
Incl. $170 mill. securitized transition & system restoration bonds.
(LT interest earned: 2.4x)
**Leases, Uncapitalized** Annual rentals $5 mill.
**Pension Assets-12/22** $1212 mill. **Oblig** $1553 mill.
**Pfd Stock** None

**Common Stock** 631,223,560 shs. **as of 10/18/23**
**MARKET CAP: $17.6 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8106.0 | 9226.0 | 7386.0 | 7528.0 | 9614.0 | 10589 | 12301 | 7418.0 | 8352.0 | 9321.0 | *9200* | *9350* | Revenues ($mill) | *10600* |
| 536.0 | 611.0 | 465.0 | 432.0 | 679.0 | 368.0 | 871.0 | 863.0 | 668.0 | 1057.0 | *1150* | *1190* | Net Profit ($mill) | *1345* |
| 31.4% | 31.0% | 35.1% | 37.0% | 36.1% | 28.4% | 14.9% | 13.4% | 14.1% | 25.4% | *25.0%* | *25.0%* | Income Tax Rate | *25.0%* |
| 3.5% | 4.1% | 4.7% | 3.5% | 2.9% | 5.4% | 6.7% | 6.0% | 9.3% | 6.0% | *5.0%* | *5.0%* | AFUDC % to Net Profit | *4.0%* |
| 64.4% | 63.8% | 69.5% | 68.5% | 63.6% | 51.9% | 63.0% | 58.0% | 62.3% | 59.6% | *60.5%* | *58.0%* | Long-Term Debt Ratio | *57.5%* |
| 35.6% | 36.2% | 30.5% | 31.5% | 36.4% | 37.5% | 29.1% | 29.9% | 34.5% | 37.1% | *39.5%* | *42.0%* | Common Equity Ratio | *42.5%* |
| 12146 | 12557 | 11362 | 10992 | 12883 | 16740 | 22603 | 19869 | 24973 | 24878 | *27725* | *28850* | Total Capital ($mill) | *32000* |
| 9593.0 | 10502 | 11537 | 12307 | 13057 | 14044 | 20945 | 22362 | 23484 | 27143 | *30100* | *33250* | Net Plant ($mill) | *40400* |
| 6.3% | 6.7% | 6.1% | 5.8% | 6.8% | 3.4% | 5.1% | 5.6% | 3.8% | 5.3% | *5.0%* | *5.0%* | Return on Total Cap'l | *5.0%* |
| 12.4% | 13.4% | 13.4% | 12.5% | 14.5% | 4.6% | 10.4% | 10.3% | 7.1% | 10.5% | *10.5%* | *10.0%* | Return on Shr. Equity | *10.0%* |
| 12.4% | 13.4% | 13.4% | 12.5% | 14.5% | 5.3% | 11.5% | 11.6% | 6.7% | 10.9% | *10.0%* | *10.0%* | Return on Com Equity E | *10.0%* |
| 4.2% | 4.5% | 1.1% | NMF | 4.7% | NMF | 2.7% | 5.0% | 2.2% | 6.1% | *5.5%* | *5.5%* | Retained to Com Eq | *5.5%* |
| 66% | 67% | 92% | 103% | 68% | NMF | 80% | 66% | 72% | 46% | *46%* | *44%* | All Div'ds to Net Prof | *45%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +6.7 | +1.8 | +2.0 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | NA | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (avg.) | +7.9 | +2.5 | +2.0 |
| Fixed Charge Cov. (%) | 152 | 135 | 252 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -3.5% | -6.0% | *3.0%* |
| "Cash Flow" | -.5% | -2.0% | *6.0%* |
| Earnings | .5% | 1.0% | *8.5%* |
| Dividends | -.5% | -7.5% | *4.0%* |
| Book Value | 3.5% | 8.0% | *8.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 2167 | 1575 | 1622 | 2054 | 7418 |
| 2021 | 2547 | 1742 | 1749 | 2314 | 8352 |
| 2022 | 2763 | 1944 | 1903 | 2711 | 9321 |
| 2023 | 2779 | 1875 | 1860 | *2686* | *9200* |
| 2024 | *2700* | *1900* | *2050* | *2700* | *9350* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .56 | .17 | .29 | .27 | 1.29 |
| 2021 | .41 | .29 | .21 | .03 | .94 |
| 2022 | .82 | .28 | .30 | .19 | 1.59 |
| 2023 | .49 | .17 | .40 | *.67* | *1.73* |
| 2024 | *.50* | *.20* | *.50* | *.67* | *1.87* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .2875 | .2875 | .2875 | .2875 | 1.15 |
| 2020 | .29 | .15 | .15 | .15 | .74 |
| 2021 | .16 | .16 | .16 | .17 | .65 |
| 2022 | .17 | .17 | .18 | .18 | .70 |
| 2023 | .18 | .19 | .19 | .20 | |

**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 151,000 customers, and gas utilities with 4.27 million customers in Texas, Minnesota, Louisiana, Mississippi, Indiana, and Ohio. Acquired Vectren 2/19. Sold nonutility operations in '20. Sold its stake in Energy Transfer LP in '21 and '22. Electric revenue breakdown not available. Fuel costs: 33% of revenues. '22 depreciation rate: 3.8%. Has 8,986 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 had a mixed third quarter.** The top line declined 2% year over year, to $1.86 billion. However, the bottom line rose 33% over the previous-year tally, to $0.40 per share thanks to ongoing cost controls.

**Share earnings for 2023 and 2024 will likely increase at an upper-single-digit pace.** The company has been controlling operation and maintenance expenses, as evidenced by the third quarter per-share profit. Additionally, benefits from rate relief and new customer wins should further support the bottom line. All things considered, we estimate 2023 share earnings will rise about 9% year over year, to $1.73. Meanwhile, we look for 2024 per-share profit to grow around 8%, to $1.87.

**The utility company is making progress on four different rate cases.** The Texas gas rate case was expected to be filed by November 1st, with a proposed 9.64% return on equity (ROE). Minnesota Gas based on a 9.39% ROE, and Indiana Electric, with a proposed 10.4% ROE, are on track for filings in November and December, respectively. Finally, the Houston Electric rate case filing is scheduled for the second quarter of 2024, based on a 9.4% ROE and a 42.5% equity ratio.

**The 10-year capital plan was increased by another $500 million to $43.9 billion.** The program started in 2021 and is about 10% higher than the original $40 billion target.

**The board of directors raised the quarterly dividend by a cent per share or 5.3%, effective with the December payment.** The company has been consistent with dividend hikes after a cut in 2020 amid the pandemic.

**CenterPoint Energy will soon have a new chief executive officer (CEO).** David J. Lesar is to be succeeded by Jason P. Wells. Upon succession on January 5, 2024, Mr. Wells will assume the President and CEO roles.

**Shares of CenterPoint are ranked 2 (Above Average) for relative year ahead price performance.** The equity also has about-average capital gains prospects over the next 18 months. Also, the stock has subpar long-term capital appreciation potential. The dividend yield is low for a utility, as well.

*Emma Jalees* *December 8, 2023*

(A) GAAP Dil. EPS 2022 & onwards. 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 egs. report due early Feb. (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 '22: $6.82/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., '22: 8.27%. Regulatory Climate: TX, Avg.; IN, Above Avg.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 75 |
| Price Growth Persistence | 40 |
| Earnings Predictability | 55 |

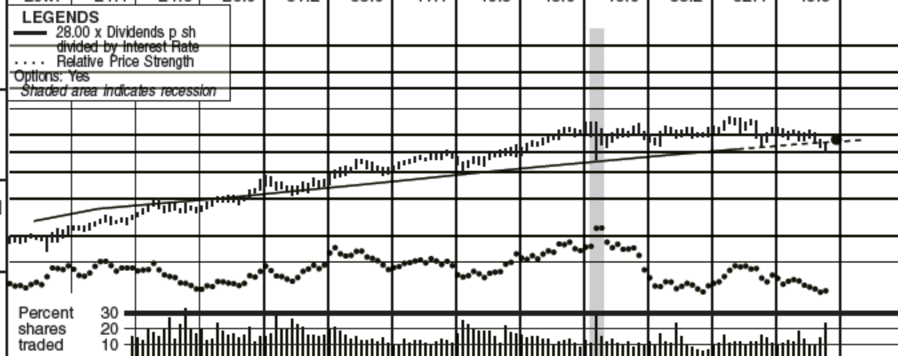
# CMS ENERGY CORP. NYSE-CMS

| RECENT PRICE | P/E RATIO | | RELATIVE P/E RATIO | DIV'D YLD | |
|---|---|---|---|---|---|
| 57.33 | 18.3 | (Trailing: 22.6) (Median: 21.0) | 1.13 | 3.4% | VALUE LINE |

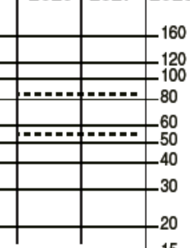
**TIMELINESS** 4 Lowered 11/24/23
**SAFETY** 3 Lowered 12/8/23
**TECHNICAL** 4 Raised 11/24/23
**BETA** .85 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 25.0 | 30.0 | 36.9 | 38.7 | 46.3 | 50.8 | 53.8 | 65.3 | 69.2 | 65.8 | 73.8 | 65.7 |
| Low: | 21.1 | 24.6 | 26.0 | 31.2 | 35.0 | 41.1 | 40.5 | 48.0 | 46.0 | 53.2 | 52.4 | 49.9 |

**LEGENDS**
— 28.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



**Target Price Range**
2026 | 2027 | 2028




**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $47-$90 | $69 (20%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 85 | (+50%) | 13% |
| Low | 55 | (-5%) | 3% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 339 | 303 | 297 |
| to Sell | 264 | 252 | 262 |
| Hld's(000) | 276172 | 274530 | 284222 |

Percent shares traded 30 20 10

**% TOT. RETURN 10/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -1.6 | -0.7 |
| 3 yr. | -6.3 | 33.7 |
| 5 yr. | 25.7 | 41.5 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 29.51 | **29.10** | **30.15** | Revenues per sh | **31.25** |
| 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 | 6.69 | **7.15** | **7.65** | "Cash Flow" per sh | **8.25** |
| .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 | 2.84 | **3.05** | **3.30** | 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 | **1.95** | **2.04** | Div'd Decl'd per sh B ■ | **2.30** |
| 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 | 8.15 | **8.00** | **9.50** | Cap'l Spending per sh | **9.75** |
| 9.46 | 10.88 | 11.42 | 11.19 | 11.92 | 12.09 | 12.98 | 13.34 | 14.21 | 15.23 | 15.77 | 16.78 | 17.68 | 19.02 | 22.11 | 23.32 | **25.35** | **27.30** | Book Value per sh C | **27.75** |
| 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 | 291.27 | **292.00** | **295.00** | Common Shs Outst'g D | **300.00** |
| 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 | 22.9 | *Bold figures are* | | Avg Ann'l P/E Ratio | **19.0** |
| 1.42 | .66 | .91 | .80 | .85 | .96 | .92 | .91 | .92 | 1.10 | 1.07 | 1.10 | 1.29 | 1.20 | 1.28 | 1.32 | *Value Line* | | Relative P/E Ratio | **1.05** |
| 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% | 2.8% | *estimates* | | Avg Ann'l Div'd Yield | **3.3%** |

**CAPITAL STRUCTURE as of 9/30/23**
**Total Debt** $15157 mill. **Due in 5 Yrs** $2300 mill.
**LT Debt** $14177 mill. **LT Interest** $600 mill.
Incl. $63 mill. finance leases.
(LT interest earned: 2.4x)
**Leases, Uncapitalized** Annual rentals $5 mill.
**Pension Assets-12/22** $3599 mill.
**Oblig** $3070 mill.
**Pfd Stock** $224 mill. **Pfd Div'd** $10 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** 291,763,567 shs.
**as of 10/9/23**
**MARKET CAP: $16.7 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6566.0 | 7179.0 | 6456.0 | 6399.0 | 6583.0 | 6873.0 | 6845.0 | 6680.0 | 7329.0 | 8596.0 | **8500** | **8900** | Revenues ($mill) | **9350** |
| 454.0 | 479.0 | 525.0 | 553.0 | 610.0 | 659.0 | 682.0 | 757.0 | 751.0 | 833.0 | **895** | **980** | Net Profit ($mill) | **1120** |
| 39.9% | 34.3% | 34.0% | 33.1% | 31.2% | 14.9% | 17.7% | 15.0% | 11.5% | 10.3% | **15.0%** | **15.0%** | Income Tax Rate | **15.0%** |
| 2.0% | 2.3% | 2.7% | 3.1% | 1.1% | 1.4% | 2.1% | 1.1% | 1.5% | 1.4% | **2.0%** | **2.0%** | AFUDC % to Net Profit | **1.0%** |
| 67.5% | 68.7% | 68.3% | 67.1% | 67.3% | 69.0% | 70.4% | 71.2% | 64.5% | 65.3% | **65.0%** | **64.0%** | Long-Term Debt Ratio | **63.5%** |
| 32.2% | 31.0% | 31.4% | 32.6% | 32.4% | 30.7% | 29.4% | 28.6% | 34.2% | 33.6% | **34.0%** | **35.0%** | Common Equity Ratio | **35.5%** |
| 10730 | 11846 | 12534 | 13040 | 13692 | 15476 | 17082 | 19223 | 18760 | 20205 | **21825** | **23025** | Total Capital ($mill) | **23300** |
| 12246 | 13412 | 14705 | 15715 | 16761 | 18126 | 18926 | 21039 | 22352 | 22713 | **23850** | **25350** | Net Plant ($mill) | **28500** |
| 6.0% | 5.7% | 5.7% | 5.8% | 5.9% | 5.6% | 5.3% | 5.2% | 5.3% | 5.4% | **5.5%** | **5.5%** | Return on Total Cap'l | **6.0%** |
| 13.0% | 12.9% | 13.2% | 12.9% | 13.6% | 13.8% | 13.5% | 13.7% | 11.3% | 11.9% | **12.0%** | **12.0%** | Return on Shr. Equity | **13.0%** |
| 13.1% | 13.0% | 13.3% | 13.0% | 13.7% | 13.8% | 13.6% | 13.7% | 11.6% | 12.1% | **12.0%** | **12.0%** | Return on Com Equity E | **13.5%** |
| 5.2% | 5.0% | 5.2% | 4.8% | 5.2% | 5.3% | 4.9% | 5.3% | 3.8% | 4.3% | **4.5%** | **4.5%** | Retained to Com Eq | **5.0%** |
| 60% | 62% | 61% | 63% | 62% | 62% | 64% | 62% | 68% | 65% | **65%** | **62%** | All Div'ds to Net Prof | **62%** |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -3.1 | +2.4 | +3.0 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 8.14 | 8.46 | 8.78 |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 8215 | 7951 | 8061 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +1.0 | +1.0 | +1.0 |
| Fixed Charge Cov. (%) | 240 | 223 | 226 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | .5% | 2.5% | 3.0% |
| "Cash Flow" | 5.5% | 5.5% | 4.0% |
| Earnings | 6.5% | 6.0% | 5.5% |
| Dividends | 8.0% | 7.0% | 5.0% |
| Book Value | 6.0% | 7.5% | 4.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1864 | 1443 | 1575 | 1798 | 6680 |
| 2021 | 2013 | 1558 | 1725 | 2033 | 7329 |
| 2022 | 2374 | 1920 | 2024 | 2278 | 8596 |
| 2023 | 2284 | 1555 | 1673 | **2988** | **8500** |
| 2024 | **2335** | **2100** | **2200** | **2265** | **8900** |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .85 | .48 | .76 | .55 | 2.64 |
| 2021 | 1.09 | .55 | .54 | .40 | 2.58 |
| 2022 | 1.20 | .50 | .56 | .58 | 2.84 |
| 2023 | .69 | .67 | .60 | **1.09** | **3.05** |
| 2024 | **.75** | **.70** | **.75** | **1.10** | **3.30** |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .3825 | .3825 | .3825 | .3825 | 1.53 |
| 2020 | .4075 | .4075 | .4075 | .4075 | 1.63 |
| 2021 | .435 | .435 | .435 | .435 | 1.74 |
| 2022 | .46 | .46 | .46 | .46 | 1.84 |
| 2023 | .4875 | .4875 | .4875 | .4875 | |

**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 1,836 megawatts of nonregulated generating capacity. Sold EnerBank in '21. Electric revenue breakdown: residential, 46%; commercial, 32%; industrial, 15%; other, 7%. Generating sources: coal, 29%; gas, 19%; renewables, 6%; purchased, 47%. Fuel costs: 34% of revenues. '22 depreciation rates: 3.7% electric, 2.9% gas, 8.9% other. Has 8,560 full-time employees. Chairman: John G. Russell. President & CEO: Garrick Rochow. Inc.: Michigan. Address: One Energy Plaza, Jackson, Michigan 49201. Telephone: 517-788-0550. Internet: www.cmsenergy.com.

**CMS Energy registered mixed third-quarter results.** The top line plummeted 17% year over year, to $1.67 billion. Still, the bottom line rose 7% over the year-ago period, to $0.60 per share thanks to lower operating expenses. Management reaffirmed the 2023 full-year adjusted share-earnings forecast range of $3.06-$3.12. Plus, CMS initiated its full-year 2024 projection at $3.27 to $3.33 per share.

**Regarding the Consumers subsidiary, electric rate case considerations are ongoing.** To recall, the unit filed an application with the Michigan Public Service Commission (MPSC) seeking a rate increase of $216 million, but revised in September to $169 million due to the deferment of some capital expenditures. Still, the company has maintained its position for a 10.25% return on equity (ROE) and a 51.5% equity ratio.

**Meanwhile, gas rate proceedings made progress.** In August, the commission approved a previously filed settlement agreement asking for a $95 million increase based on a 9.9% ROE. The rate was effective on October 1st. The company is planning to pursue the next gas rate case in December.

**The company has an electric reliability roadmap, which should form the basis for future electric rate cases.** The utility has identified about $3 billion of additional investment opportunities for the next five years, on top of the prior $4 billion plan ($7 billion in total). Some actions include doubling investment in vegetation management to shorten trim cycles, requesting approval of up to 400 miles of annual undergrounding beginning in 2027, replacing more than 20,000 poles annually, and automating grids. If the MPSC agrees with these capital investments, the Consumers division will have an easier time negotiating its future electric rate cases. We note that utilities do not operate like regular businesses. These companies are incentivized to invest in capital infrastructures, allowing them to seek rate increases.

**CMS shares, though untimely, have good 18-month capital gains potential.** Still, the stock lacks investment appeal over the 3- to 5-year period. The dividend yield is subpar by utility standards.

*Emma Jalees* *December 8, 2023*

(A) Diluted EPS. Excl. nonrec. gains (losses): '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); '17, (53¢); gains (losses) on disc. ops.: '07, (40¢); '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢; '21, $2.08; '22, 1¢. Next earnings report due early Feb. (B) Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '22: $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 | 60 |
| Earnings Predictability | 90 |

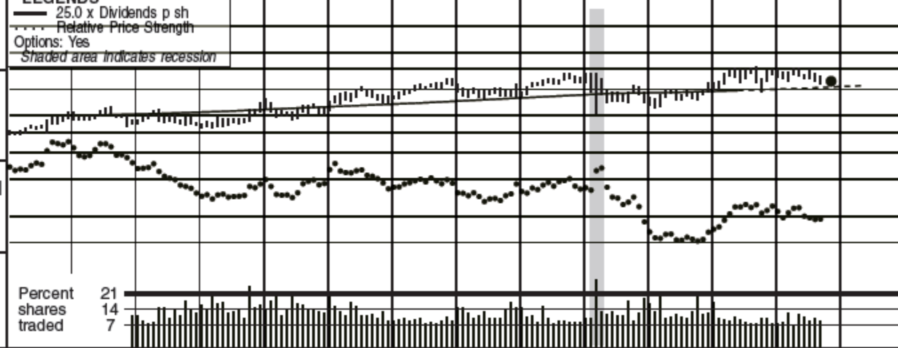
# CON. EDISON NYSE-ED

RECENT PRICE 87.48 | P/E RATIO 17.6 (Trailing: 17.9, Median: 18.0) | RELATIVE P/E RATIO 1.17 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 2 Raised 10/13/23
SAFETY 1 New 7/27/90
TECHNICAL 4 Lowered 10/20/23
BETA .75 (1.00 = Market)

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 66.0 | 64.0 | 68.9 | 72.3 | 81.9 | 89.7 | 84.9 | 95.0 | 95.1 | 85.6 | 102.2 | 100.9 |
| Low: | 53.6 | 54.2 | 52.2 | 56.9 | 63.5 | 72.1 | 71.1 | 73.3 | 62.0 | 65.6 | 78.1 | 80.5 |

LEGENDS
— 25.0 x Dividends p sh
···· Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2026 | 2027 | 2028: 160, 120, 100, 80, 60, 50, 40, 30, 20, 15

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $76-$126 | $101 (15%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 105 | (+20%) | 8% |
| Low | 85 | (-5%) | 3% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 532 | 477 | 476 |
| to Sell | 366 | 411 | 461 |
| Hld's(000) | 239865 | 235681 | 224094 |

Percent shares traded: 21, 14, 7

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | 3.3 | 16.6 |
| 3 yr. | 22.9 | 43.6 |
| 5 yr. | 33.9 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 38.63 | 44.15 | *44.35* | *46.25* | Revenues per sh | *52.15* |
| 5.77 | 5.99 | 5.86 | 6.24 | 6.61 | 7.15 | 7.45 | 7.30 | 7.93 | 7.89 | 8.41 | 8.92 | 9.39 | 9.70 | 10.06 | 10.36 | *11.45* | *12.05* | "Cash Flow" per sh | *14.00* |
| 3.48 | 3.36 | 3.14 | 3.47 | 3.57 | 3.86 | 3.93 | 3.62 | 4.05 | 3.94 | 4.10 | 4.55 | 4.37 | 4.17 | 4.38 | 4.55 | *4.90* | *5.20* | Earnings per sh A | *6.15* |
| 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* | *3.34* | Div'd Decl'd per sh B ■ | *3.86* |
| 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 | 11.17 | 11.74 | *15.80* | *14.50* | Cap'l Spending per sh | *16.00* |
| 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 | 56.60 | 58.28 | *58.75* | *60.65* | Book Value per sh C | *67.25* |
| 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 | 353.98 | 354.96 | *345.00* | *345.00* | Common Shs Outst'g D | *345.00* |
| 13.8 | 12.3 | 12.5 | 13.3 | 15.1 | 15.4 | 14.7 | 15.9 | 15.6 | 18.8 | 19.8 | 17.1 | 19.7 | 19.0 | 17.2 | 20.3 | *Bold figures are* | | Avg Ann'l P/E Ratio | *15.5* |
| .73 | .74 | .83 | .85 | .95 | .98 | .83 | .84 | .79 | .99 | 1.00 | .92 | 1.05 | .98 | .93 | 1.18 | *Value Line* | | Relative P/E Ratio | *.85* |
| 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% | 3.4% | *estimates* | | Avg Ann'l Div'd Yield | *4.0%* |

**CAPITAL STRUCTURE as of 6/30/23**
Total Debt $23250 mill. Due in 5 Yrs $1579 mill.
LT Debt $20648 mill. LT Interest $1099 mill.
(Total Interest Coverage: 2.8x)

**Leases, Uncapitalized** Annual rentals $64 mill.

**Pension Assets-12/22** $14979 mill. **Oblig** $12113 mill.

**Pfd Stock** None

**Common Stock** 344,923,585 shs. as of 7/31/23

**MARKET CAP: $30.2 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12381 | 12919 | 12554 | 12075 | 12033 | 12337 | 12574 | 12246 | 13676 | 15670 | *15300* | *15950* | Revenues ($mill) | *18000* |
| 1157.0 | 1066.0 | 1193.0 | 1189.0 | 1266.0 | 1424.0 | 1438.0 | 1399.0 | 1528.0 | 1620.0 | *1720* | *1805* | Net Profit ($mill) | *2130* |
| 31.8% | 34.0% | 33.6% | 35.3% | 36.6% | 20.1% | 17.5% | 12.9% | 16.2% | 15.4% | *18.0%* | *18.0%* | Income Tax Rate | *18.0%* |
| .5% | .3% | .7% | 1.3% | 1.5% | 1.5% | 1.9% | 2.2% | 2.1% | 3.4% | *4.0%* | *4.0%* | AFUDC % to Net Profit | *4.0%* |
| 46.1% | 48.0% | 47.9% | 50.8% | 48.9% | 51.1% | 50.7% | 52.0% | 53.0% | 49.3% | *48.5%* | *48.0%* | Long-Term Debt Ratio | *51.0%* |
| 53.9% | 52.0% | 52.1% | 49.2% | 51.1% | 48.9% | 49.3% | 48.0% | 47.0% | 50.7% | *51.5%* | *52.0%* | Common Equity Ratio | *49.0%* |
| 22735 | 24207 | 25058 | 29033 | 30149 | 34221 | 36549 | 39229 | 42641 | 40834 | *39425* | *40075* | Total Capital ($mill) | *47400* |
| 28436 | 29827 | 32209 | 35216 | 37600 | 41749 | 43889 | 46555 | 48596 | 46766 | *50000* | *52650* | Net Plant ($mill) | *60900* |
| 6.4% | 5.6% | 6.0% | 5.3% | 5.4% | 5.3% | 5.1% | 4.7% | 4.7% | 5.2% | *5.5%* | *5.5%* | Return on Total Cap'l | *5.5%* |
| 9.4% | 8.5% | 9.1% | 8.3% | 8.2% | 8.5% | 8.0% | 7.4% | 7.6% | 7.8% | *8.5%* | *8.5%* | Return on Shr. Equity | *9.0%* |
| 9.4% | 8.5% | 9.1% | 8.3% | 8.2% | 8.5% | 8.0% | 7.4% | 7.6% | 7.8% | *8.5%* | *8.5%* | Return on Com Equity E | *9.0%* |
| 3.6% | 2.6% | 3.5% | 3.0% | 3.0% | 3.5% | 2.9% | 2.2% | 2.5% | 2.6% | *3.0%* | *3.0%* | Retained to Com Eq | *3.5%* |
| 62% | 69% | 61% | 64% | 63% | 59% | 64% | 70% | 67% | 67% | *66%* | *64%* | All Div'ds to Net Prof | *63%* |

**CECONY ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Electric Sales (GWH) | -6.5 | -.5 | 3.3 |
| Annual Residential Use (GWH) | 11107 | 11344 | 11875 |
| Annual Comm./Ind. Use (GWH) | 9280 | 9250 | 10522 |
| Annual Retail Choice (GWH) | 22000 | 21549 | 21116 |
| Annual Govt. & Other Use (GWH) | 9184 | 9185 | 9507 |
| % Change Customers (yr-end) | NA | NA | NA |
| Peak Load, Summer (Mw) | 13170 | 13517 | 12424 |
| ConEd Fixed Charge Cov. (%) | 325 | 352 | 240 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -1.0% | -.5% | *4.5%* |
| "Cash Flow" | 4.0% | 4.5% | *5.5%* |
| Earnings | 2.0% | 1.5% | *6.0%* |
| Dividends | 2.5% | 3.0% | *3.5%* |
| Book Value | 4.0% | 4.0% | *3.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 3234 | 2719 | 3333 | 2960 | 12246 |
| 2021 | 3677 | 2971 | 3613 | 3415 | 13676 |
| 2022 | 4060 | 3415 | 4165 | 4031 | 15670 |
| 2023 | 4403 | 2944 | *4050* | *3903* | *15300* |
| 2024 | *4500* | *3150* | *4250* | *4050* | *15950* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1.35 | .60 | 1.48 | .74 | 4.17 |
| 2021 | 1.44 | .53 | 1.41 | 1.00 | 4.38 |
| 2022 | 1.47 | .64 | 1.63 | .81 | 4.55 |
| 2023 | 1.83 | .61 | *1.63* | *.83* | *4.90* |
| 2024 | *1.85* | *.65* | *1.75* | *.95* | *5.20* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .74 | .74 | .74 | .74 | 2.96 |
| 2020 | .765 | .765 | .765 | .765 | 3.06 |
| 2021 | .775 | .775 | .775 | .775 | 3.10 |
| 2022 | .79 | .79 | .79 | .79 | 3.16 |
| 2023 | .81 | .81 | .81 | | |

**BUSINESS:** Consolidated Edison, Inc. (ConEd) is a holding company for Consolidated Edison Company of New York (CECONY), which sells electricity, gas, and steam in most of NY city and Westchester County. ConEd also owns Orange and Rockland Utilities (O&R), which operates in New York and New Jersey. ConEd has 3.9 mill. electric, 1.2 mill. gas customers. Expected to close on the sale of its portfolio of renewable generation for $6.8 bill. by mid-2022. It entered into midstream gas joint venture 6/16; sold it 7/21. Purchases most of its power. Fuel costs: 26% of revenues. '22 reported deprec. rates: 3.0%-3.5%. Employs 14,319. Chrmn, President & CEO: Timothy Cawley. Inc.: NY. Addr.: 4 Irving Place, New York, NY 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

**Consolidated Edison looks on pace for a solid earnings gain this year.** Annual electric and gas delivery prices rose $442 million and $217 million, respectively, starting in August. The increase was based on a favorable rate decision handed down by the New York State Public Service Commission, which raised the regulated return on equity (ROE) for the holding company's larger of its two utilities, Consolidated Edison Company of New York (CECONY), from 8.8% to 9.25%. Milder weather and higher interest expense likely masked much of the rate hike's impact in the third quarter, however. (September-period financial results were due out just after our press cycle.)

**Ongoing rate relief and the benefits of New York's aggressive "green" energy initiatives should keep profits rising.** Next August, additional delivery price increases of $518 million for electric and $173 million for gas take effect. Further, in August of 2025, electric and gas rates are slated to rise for the third-consecutive year, by $382 million and $122 million, respectively. CECONY also filed for a rate increase of $141 million nine months ago for its steam service, effective from the start of this month, with most of the benefit falling to 2024. All told, ConEd ought to see a few years of 6%-plus bottom-line gains. Notably, there are nearly $12 billion in recently approved new capital investments through 2026-2028, directed at reliability, safety, and clean energy objectives. This ups the odds that the next rate case, a few years from now, will be constructive, as well.

**ConEd shares are ranked to outperform the broader market averages over the coming six to 12 months.** Earnings growth is accelerating, and the company has simplified its business model by shedding generating assets that were not under the regulatory pricing umbrella. The capital from those divestitures has paved the way for the company to fully benefit from New York's clean-energy push without having to dilute its shareholders any time soon from equity offerings. This low-risk standard utility format has drawn investors in. ConEd has outperformed our median electric utility coverage by eight percentage points this year.

*Anthony J. Glennon* *November 10, 2023*

(A) Diluted EPS. Excl. nonrec. gains/losses: '13, d32¢; '14, 9¢; '16, 18¢; '17, 84¢; '18, d13¢; '19, d29¢; '20, d89¢; '21, d53¢; '22, 11¢; 1Q-2Q '23, $2.29. Excl. gain on disc. ops.: '08, $1.01. Next egs. report due mid-Feb. Qtly. figures may not sum to full year due to rounding. (B) Div'ds paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan available. (C) Incl. intang. In '22: $12.35/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '23: 9.25%; O&R in '22: 9.2%. Regulatory Climate: Below Average.

| | |
|---|---|
| Company's Financial Strength | A+ |
| Stock's Price Stability | 90 |
| Price Growth Persistence | 45 |
| Earnings Predictability | 100 |

# DOMINION ENERGY NYSE-D

RECENT PRICE 40.00 | P/E RATIO 12.3 (Trailing: 10.8 / Median: 21.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 6.7% | VALUE LINE

TIMELINESS 4 Lowered 7/7/23

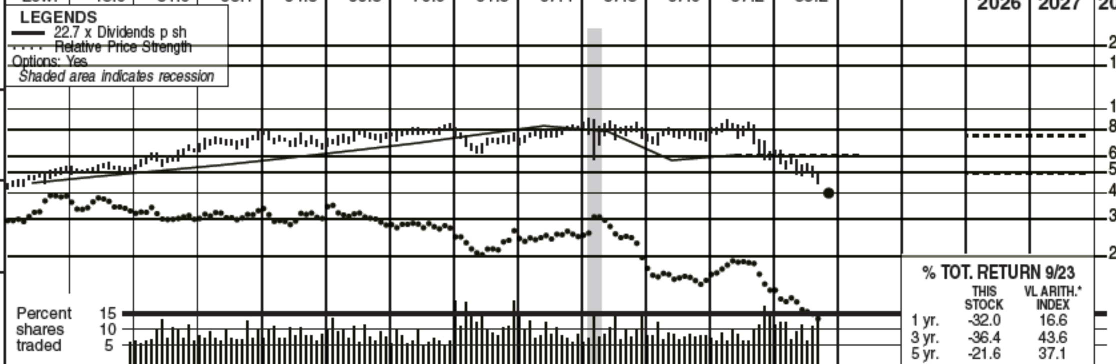
SAFETY 3 Lowered 9/29/23

TECHNICAL 3 Raised 11/3/23

BETA .85 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 55.6 | 68.0 | 80.9 | 79.9 | 79.0 | 85.3 | 81.7 | 83.9 | 90.9 | 81.1 | 88.8 | 63.9 |
| Low: | 48.9 | 51.9 | 63.1 | 64.5 | 66.3 | 70.9 | 61.5 | 67.4 | 57.8 | 67.9 | 57.2 | 39.2 |

LEGENDS
— 22.7 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession




Target Price Range 2026 | 2027 | 2028

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $36-$74 | $55 (40%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 75 | (+90%) | 21% |
| Low | 50 | (+25%) | 12% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 660 | 623 | 562 |
| to Sell | 740 | 624 | 625 |
| Hld's(000) | 588391 | 588585 | 595361 |

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -32.0 | 16.6 |
| 3 yr. | -36.4 | 43.6 |
| 5 yr. | -21.6 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 27.16 | 27.94 | 25.26 | 26.16 | 25.23 | 22.73 | 22.58 | 21.26 | 19.60 | 18.69 | 19.51 | 19.63 | 19.78 | 17.58 | 17.24 | 20.57 | **20.20** | **18.20** | Revenues per sh | **20.00** |
| 5.08 | 5.07 | 4.82 | 5.10 | 5.04 | 5.24 | 5.47 | 5.71 | 5.99 | 6.32 | 6.89 | 7.24 | 7.65 | 7.17 | 7.27 | 7.81 | **6.85** | **7.00** | "Cash Flow" per sh | **7.85** |
| 2.13 | 3.04 | 2.64 | 2.89 | 2.76 | 2.75 | 3.09 | 3.05 | 3.20 | 3.44 | 3.53 | 4.05 | 4.24 | 3.54 | 3.86 | 4.11 | **3.15** | **3.35** | Earnings per sh A | **4.00** |
| 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 | **2.67** | **2.67** | Div'd Decl'd per sh B ■ | **2.75** |
| 6.88 | 6.10 | 6.41 | 5.89 | 6.41 | 7.20 | 7.06 | 9.14 | 9.35 | 9.69 | 8.53 | 6.25 | 5.94 | 7.47 | 7.36 | 9.09 | **12.25** | **12.55** | Cap'l Spending per sh | **10.00** |
| 16.30 | 17.28 | 18.67 | 20.65 | 20.08 | 18.35 | 20.04 | 19.75 | 21.25 | 23.26 | 26.58 | 29.53 | 35.33 | 29.44 | 31.51 | 31.26 | **32.10** | **33.25** | Book Value per sh C | **39.20** |
| 577.00 | 583.00 | 599.00 | 581.00 | 570.00 | 576.00 | 581.00 | 585.00 | 596.00 | 628.00 | 645.00 | 681.00 | 838.00 | 806.00 | 810.00 | 835.00 | **842.00** | **851.00** | Common Shs Outst'g D | **900.00** |
| 20.6 | 13.8 | 12.7 | 14.3 | 17.3 | 18.9 | 19.2 | 23.0 | 22.1 | 21.3 | 22.2 | 17.5 | 18.2 | 22.6 | 19.5 | 18.7 | *Bold figures are* | *Value Line estimates* | Avg Ann'l P/E Ratio | **15.5** |
| 1.09 | .83 | .85 | .91 | 1.09 | 1.20 | 1.08 | 1.21 | 1.11 | 1.12 | 1.12 | .95 | .97 | 1.16 | 1.05 | 1.09 | | | Relative P/E Ratio | **.85** |
| 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% | 3.5% | | | Avg Ann'l Div'd Yield | **4.4%** |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $48597 mill. **Due in 5 Yrs** $4900 mill.
**LT Debt** $39223 mill. **LT Interest** $2265 mill.
(Total Interest coverage: 3.0x)
**Leases, Uncapitalized** Annual rentals $44 mill.

**Pension Assets-12/22** $8694 mill. **Oblig** $8066 mill.
**Pfd Stock** $1783 mill. **Pfd Divd** $93 mill.

**Common Stock** 836,772,913 shs.
as of 7/28/23

**MARKET CAP: $33.5 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13120 | 12436 | 11683 | 11737 | 12586 | 13366 | 16572 | 14172 | 13964 | 17174 | **17000** | **15500** | Revenues ($mill) | **18000** |
| 1806.0 | 1793.0 | 1899.0 | 2123.0 | 2244.0 | 2651.0 | 3447.0 | 3006.0 | 3191.0 | 3505.0 | **2745** | **2940** | Net Profit ($mill) | **3715** |
| 33.0% | 28.1% | 32.0% | 22.8% | 27.2% | 17.3% | 20.3% | 12.2% | 13.7% | 16.3% | **16.0%** | **16.0%** | Income Tax Rate | **17.0%** |
| 3.7% | 4.5% | 5.3% | 7.5% | 10.5% | 5.1% | 2.6% | 3.4% | 3.7% | 3.2% | **5.0%** | **5.0%** | AFUDC % to Net Profit | **4.5%** |
| 61.9% | 65.4% | 65.1% | 67.4% | 64.4% | 60.8% | 51.4% | 56.5% | 56.4% | 58.3% | **58.5%** | **56.0%** | Long-Term Debt Ratio | **56.0%** |
| 37.3% | 34.6% | 34.9% | 32.6% | 35.6% | 39.2% | 45.0% | 39.5% | 38.5% | 39.1% | **39.0%** | **41.0%** | Common Equity Ratio | **42.0%** |
| 31229 | 33360 | 36280 | 44836 | 48090 | 51251 | 65818 | 60074 | 66344 | 66795 | **69075** | **68675** | Total Capital ($mill) | **84400** |
| 32628 | 36270 | 41554 | 49964 | 53758 | 54560 | 69082 | 57848 | 59774 | 63460 | **70625** | **78225** | Net Plant ($mill) | **94100** |
| 7.3% | 6.6% | 6.5% | 6.0% | 5.9% | 6.5% | 6.4% | 6.2% | 5.9% | 6.0% | **5.0%** | **5.5%** | Return on Total Cap'l | **5.5%** |
| 15.2% | 15.5% | 15.0% | 14.5% | 13.1% | 13.2% | 10.8% | 11.5% | 11.0% | 12.6% | **9.5%** | **10.0%** | Return on Shr. Equity | **10.0%** |
| 15.4% | 15.4% | 15.0% | 14.5% | 13.1% | 13.2% | 11.6% | 12.4% | 12.2% | 13.1% | **10.0%** | **10.0%** | Return on Com Equity E | **10.5%** |
| 4.2% | 3.3% | 2.9% | 2.7% | 1.8% | 2.3% | 1.5% | .3% | 4.3% | 4.6% | **1.5%** | **2.0%** | Retained to Com Eq | **3.0%** |
| 73% | 79% | 81% | 81% | 86% | 82% | 87% | 98% | 66% | 66% | **85%** | **80%** | All Div'ds to Net Prof | **69%** |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (MWH) | -2.2 | +.8 | +2.0 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | NA | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | NA | NA | NA |
| Fixed Charge Cov. (%) | 235 | 227 | 272 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -3.0% | -1.0% | *1.5%* |
| "Cash Flow" | 4.0% | 3.0% | *1.0%* |
| Earnings | 3.0% | 2.5% | *.5%* |
| Dividends | 4.0% | .5% | *1.5%* |
| Book Value | 4.5% | 5.5% | *4.0%* |

**QUARTERLY REVENUES ($ mill.)**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 3938 | 3106 | 3607 | 3521 | 14172 |
| 2021 | 3870 | 3038 | 3176 | 3880 | 13964 |
| 2022 | 4279 | 3596 | 4386 | 4913 | 17174 |
| 2023 | 5252 | 3794 | *4210* | *3744* | *17000* |
| 2024 | *3800* | *3700* | *4250* | *3750* | *15500* |

**EARNINGS PER SHARE A**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .92 | .73 | 1.08 | .81 | 3.54 |
| 2021 | 1.09 | .76 | 1.11 | .90 | 3.86 |
| 2022 | 1.18 | .77 | 1.11 | 1.06 | 4.11 |
| 2023 | .99 | .53 | *.80* | *.83* | *3.15* |
| 2024 | *1.02* | *.60* | *.85* | *.88* | *3.35* |

**QUARTERLY DIVIDENDS PAID B ■**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .9175 | .9175 | .9175 | .9175 | 3.67 |
| 2020 | .94 | .94 | .94 | .63 | 3.45 |
| 2021 | .63 | .63 | .63 | .63 | 2.52 |
| 2022 | .6675 | .6675 | .6675 | .6675 | 2.67 |
| 2023 | .6675 | .6675 | .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 3.5 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, 47%; commercial, 34%; industrial, 8%; other, 11%. Generating sources: gas, 36%; nuclear, 28%; coal, 8%; other, 5%; purchased, 23%. Power/fuel costs: 31% of revs. '22 reported deprec. rates: 1.9%-3.9%. Employs 17,100. Chrmn., Pres. & 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 is nearing the conclusion of its strategic business review.** Announced a year ago, it was described by leadership as a complete analysis, including a look at alternatives to the current business mix and capital allocation. Thus far, the one solace that has come out of the process for existing investors is that the company has publicly committed to maintaining the current dividend level, although the rising payout ratio is potentially problematic. No full-year earnings targets are being provided until the process is complete. We cut our 2023 estimate by $0.45 per share due to seasonally-mild weather, rising interest expense, the loss of income from discontinued operations, and timing issues for the recoupment of certain costs. (Third-quarter results were due out just after our press cycle.) We've also scaled back our 2024 share-earnings target by $0.40 based on further expected divestitures of income-generating assets.

**Dominion stock has been battered by the near-term loss of earnings power.** Over the past year, the shares underperformed the *Value Line Utility Index* by 26 percentage points. The sharp rise in interest rates during a time that the company was getting increasingly leveraged to take on new projects, particularly its huge wind farm off the coast of Virginia, has been problematic. In July, Dominion agreed to sell its interest in the Cove Point liquefied natural gas operation in Maryland for $3.3 billion in after-tax proceeds. In September, the company agreed to sell three natural gas utilities for $9.4 billion in cash and $4.6 billion in assumed debt to Enbridge (NYSE: ENB). These nonstrategic asset sales should shore up the balance sheet and allow the company to maintain an investment-grade credit rating.

**This equity is untimely.** Dominion is nearing the end of its transformation, and is expected to reveal its conclusions and new projections shortly. Long-term earnings growth of 5%-7% per annum, albeit from a lower base in 2024, may still be feasible. The key Virginia service area is experiencing accelerating load growth, from 2%-3% in years past to 5%, on migration and rising data-center demand. The 6.7% yield is appealing, but not without risks.

*Anthony J. Glennon* *November 10, 2023*

(A) Diluted egs. Excl. nonrec. gains/(losses): '08, 12¢; '09, (47¢); '10, $2.13; '11, (31¢); '12, ($2.18); '14, (81¢); '17, $1.19; '18, (31¢); '19, ($2.62); '20, ($1.72); '21, (67¢); '22, ($3.03); 2Q '23, 33¢; gain/(losses) from disc. ops.: '10, (26¢); '12, (4¢); '13, (16¢); '20, ($2.39); '21, 79¢; '22, 1¢. Next egs. report due mid-Feb. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '22: $20.78/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%. Reg. Clim.: Avg.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 30 |
| Earnings Predictability | 100 |

# DTE ENERGY CO. NYSE-DTE

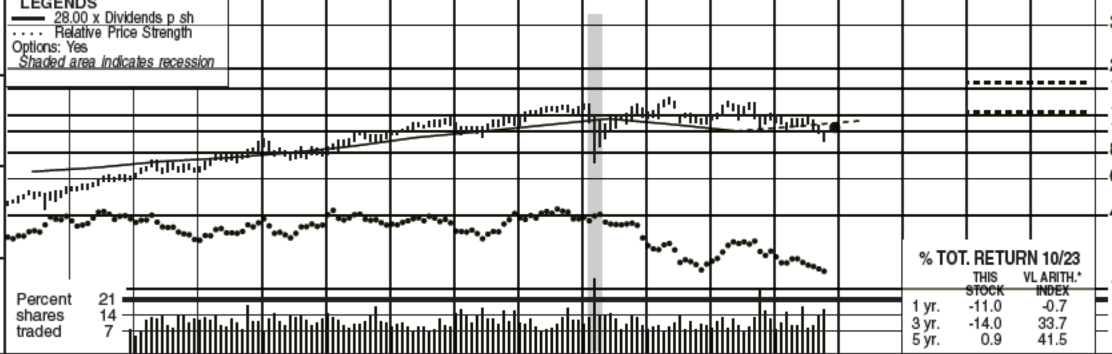
RECENT PRICE 104.86 | P/E RATIO 14.2 (Trailing: 20.7; Median: 18.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 5 Lowered 11/24/23
SAFETY 2 Raised 12/21/12
TECHNICAL 4 Raised 11/3/23
BETA 1.00 (1.00 = Market)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 62.6 | 73.3 | 90.8 | 92.3 | 100.4 | 116.7 | 121.0 | 134.4 | 135.7 | 145.4 | 140.2 | 121.3 | |
| Low: | 52.5 | 60.3 | 64.8 | 73.2 | 78.0 | 96.6 | 94.3 | 107.3 | 71.2 | 108.2 | 100.6 | 90.1 | |

Target Price Range 2026 | 2027 | 2028

LEGENDS
—— 28.00 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $82-$152 | $117 (10%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 170 | (+60%) | 16% |
| Low | 125 | (+20%) | 8% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 399 | 313 | 334 |
| to Sell | 260 | 325 | 284 |
| Hld's(000) | 153190 | 154100 | 154545 |

Percent shares traded 21 14 7

**% TOT. RETURN 10/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -11.0 | -0.7 |
| 3 yr. | -14.0 | 33.7 |
| 5 yr. | 0.9 | 41.5 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 93.48 | *82.75* | *90.00* | Revenues per sh | *97.10* |
| 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 | 12.65 | *13.60* | *14.50* | "Cash Flow" per sh | *17.05* |
| 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 | 5.52 | *5.75* | *6.70* | Earnings per sh A | *8.30* |
| 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 | 3.54 | *3.81* | *4.05* | Div'd Decl'd per sh B ■ | *4.65* |
| 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 | 16.42 | *17.05* | *17.50* | Cap'l Spending per sh | *18.50* |
| 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 | 46.35 | *52.95* | *54.25* | Book Value per sh C | *60.75* |
| 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 | 205.69 | *205.50* | *205.50* | Common Shs Outst'g D | *206.00* |
| 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 | 22.4 | *Bold figures are* | | Avg Ann'l P/E Ratio | *18.0* |
| .97 | .89 | .69 | .78 | .85 | .95 | 1.01 | .78 | .91 | 1.00 | .94 | .94 | 1.06 | .84 | 1.62 | 1.30 | *Value Line* | | Relative P/E Ratio | *1.00* |
| 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% | 3.4% | *estimates* | | Avg Ann'l Div'd Yield | *3.5%* |

**CAPITAL STRUCTURE as of 9/30/23**
**Total Debt** $19136 mill. **Due in 5 Yrs** $6481 mill.
**LT Debt** $18542 mill. **LT Interest** $514 mill.
Incl. $209 mill. securitization bonds. Incl. $19 mill. finance leases.
(LT interest earned: 1.7x)
**Leases, Uncapitalized** Annual rentals $16 mill.

**Pension Assets-12/22** $5507 mill. **Oblig** $5857 mill.

**Pfd Stock** None
**Common Stock** 206,258,727 shs.

**MARKET CAP: $21.6 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9661.0 | 12301 | 10337 | 10630 | 12607 | 14212 | 12669 | 12177 | 14964 | 19228 | *17000* | *18500* | Revenues ($mill) | *20000* |
| 661.0 | 905.0 | 796.0 | 868.0 | 1029.0 | 1120.0 | 1169.0 | 1368.0 | 796.0 | 1135.4 | *1180* | *1375* | Net Profit ($mill) | *1710* |
| 27.5% | 28.5% | 25.6% | 24.5% | 21.8% | 8.1% | 11.5% | 10.9% | - - | 2.6% | *5.0%* | *5.0%* | Income Tax Rate | *5.0%* |
| 3.5% | 4.1% | 4.3% | 3.6% | 3.5% | 3.8% | 3.3% | 3.4% | 4.9% | 4.0% | *3.0%* | *3.0%* | AFUDC % to Net Profit | *3.0%* |
| 47.7% | 50.0% | 50.2% | 55.6% | 56.2% | 54.2% | 57.7% | 60.5% | 62.5% | 63.0% | *61.5%* | *61.5%* | Long-Term Debt Ratio | *61.0%* |
| 52.3% | 50.0% | 49.8% | 44.4% | 43.8% | 45.8% | 42.3% | 39.5% | 37.5% | 37.0% | *38.5%* | *38.5%* | Common Equity Ratio | *39.0%* |
| 15135 | 16670 | 17607 | 20280 | 21697 | 22371 | 27607 | 31426 | 23236 | 25158 | *28250* | *29000* | Total Capital ($mill) | *32200* |
| 15800 | 16820 | 18034 | 19730 | 20721 | 21650 | 25317 | 27969 | 26944 | 28767 | *31050* | *31500* | Net Plant ($mill) | *36600* |
| 5.7% | 6.6% | 5.7% | 5.3% | 5.9% | 6.1% | 5.3% | 5.4% | 4.7% | 4.4% | *5.0%* | *5.0%* | Return on Total Cap'l | *6.0%* |
| 8.3% | 10.9% | 9.1% | 9.6% | 10.8% | 10.9% | 10.0% | 11.0% | 9.1% | 13.0% | *11.5%* | *11.5%* | Return on Shr. Equity | *12.5%* |
| 8.3% | 10.9% | 9.1% | 9.6% | 10.8% | 10.9% | 10.0% | 11.0% | 9.1% | 13.0% | *11.5%* | *11.5%* | Return on Com Equity E | *12.5%* |
| 2.7% | 5.2% | 3.4% | 3.7% | 4.6% | 4.9% | 4.1% | 4.9% | .1% | 2.0% | *4.5%* | *4.5%* | Retained to Com Eq | *4.5%* |
| 67% | 52% | 63% | 61% | 58% | 55% | 59% | 56% | 99% | 76% | *60%* | *60%* | All Div'ds to Net Prof | *62%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -3.4 | +2.1 | -1.4 |
| 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. (%) | 268 | 233 | 264 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 3.0% | 2.5% | *5.0%* |
| "Cash Flow" | 3.0% | 4.5% | *4.5%* |
| Earnings | 4.0% | 2.5% | *4.5%* |
| Dividends | 5.5% | 5.5% | *3.0%* |
| Book Value | 3.0% | 1.5% | *1.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 3022 | 2583 | 3284 | 3288 | 12177 |
| 2021 | 3581 | 3021 | 3715 | 4647 | 14964 |
| 2022 | 4577 | 4924 | 5251 | 4476 | 19228 |
| 2023 | 3779 | 2684 | 2888 | *7649* | *17000* |
| 2024 | *4575* | *4550* | *4850* | *4525* | *18500* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1.76 | 1.44 | 2.46 | 1.42 | 7.08 |
| 2021 | 1.65 | .60 | .30 | 1.55 | 4.10 |
| 2022 | 2.03 | .19 | 1.99 | 1.31 | 5.52 |
| 2023 | 1.33 | .99 | 1.44 | *1.99* | *5.75* |
| 2024 | *2.30* | *1.20* | *1.90* | *1.30* | *6.70* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 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 | .885 | .885 | .885 | 3.54 |
| 2023 | .9525 | .9525 | .9525 | | |

**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. '22 reported deprec. rates: 4.2% electric, 2.9% gas. Has 10,600 employees. Chairman, President & CEO: Jerry Norcia. Incorporated: Michigan. Address: One Energy Plaza, Detroit, Michigan 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

**DTE Energy's electric utility subsidiary has a general rate case pending.** DTE Electric is seeking an increase of $622 million, nearly 60% larger than its initial 2022 request of which Michigan regulators approved less than 10% of. We continue to think the Michigan Public Service Commission will likely give the utility an unfavorable ruling, given the aforementioned rate case decision in November 2022. An order was expected when this report went to press, and DTE awaits a decision in hopes of getting a better understanding of its financial potential in 2024.

**DTE Energy faced various challenges in the third quarter.** September-period sales plunged 45% over the year-ago period, to $2.888 billion, as DTE has faced $370 million of unprecedented headwinds this year, including unfavorable weather, low rate orders, and storm activity. Earnings of $1.44 per share came in well shy of our $2.15 forecast. Accordingly, management lowered its full-year 2024 earnings guidance midpoint from $6.25 per share to $5.75. We shaved $0.35 from our EPS call, to $5.75, to reflect unprecedented headwinds and worse-than-expected financial performances of late.

**Top- and bottom-line growth should get back on track next year.** While the unprecedented headwinds of unfavorable weather, low rate orders, and storm activity will likely continue in 2024, DTE has offset $270 million of challenges so far this year and is in a better position to deal with these obstacles in the long term. The utility should also be able to get some rate relief, but we await the final order from Michigan regulators before reflecting the rate increase in our presentation. As a result, we are maintaining our 2024 top- and bottom-line estimates of $18.5 billion and $6.70 a share, respectively. We look for solid results over the next few years, as DTE Energy is well-positioned for the long term and should be able to pass on the higher costs associated with the challenging macroeconmic environment to the consumer, through rate cases and infrastructure mechanisms.

**This equity has a dividend yield that is about average, by utility standards.** Meanwhile, the Timeliness rank resides at 5 (Lowest).

*Zachary J. Hodgkinson* *December 8, 2023*

(A) Diluted EPS. Excl. nonrec. gains (loss): '07, $1.96; '08, 50¢; '11, 51¢; '15, (39¢); '17, 59¢; gains (losses) on discontinued operations: '07, $1.20; '08, 13¢; '12, (33¢); '21, 57¢. Next earnings report due late February. (B) Div'ds paid mid-Jan., Apr., July & Oct. ■ Div'd reinvestment plan available. (C) Incl. intang. In '22: $29.20/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on common equity 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 | 50 |
| Earnings Predictability | 65 |

# DUKE ENERGY NYSE-DUK

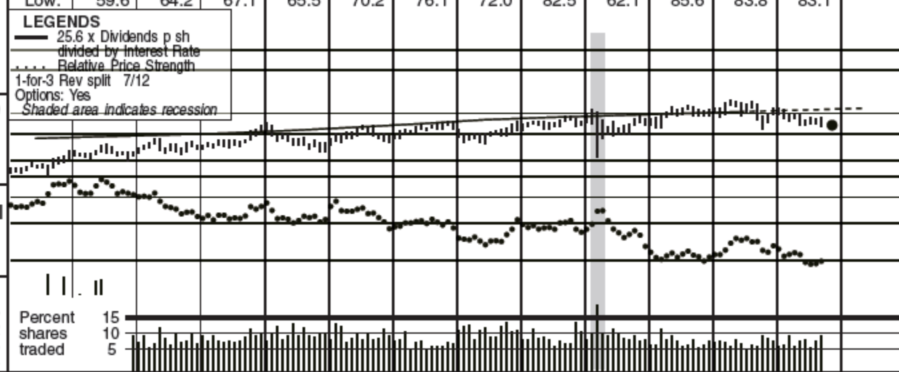
RECENT PRICE 87.90 | P/E RATIO 14.3 (Trailing: 17.6 / Median: 18.0) | RELATIVE P/E RATIO 0.95 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 4 Lowered 8/18/23
SAFETY 2 New 6/1/07
TECHNICAL 3 Raised 11/3/23
BETA .85 (1.00 = Market)

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 71.1 | 75.5 | 87.3 | 90.0 | 87.8 | 91.8 | 91.4 | 97.4 | 103.8 | 108.4 | 116.3 | 106.4 |
| Low: | 59.6 | 64.2 | 67.1 | 65.5 | 70.2 | 76.1 | 72.0 | 82.5 | 62.1 | 85.6 | 83.8 | 83.1 |

LEGENDS
— 25.6 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
1-for-3 Rev split 7/12
Options: Yes
Shaded area indicates recession

**Target Price Range** 2026 | 2027 | 2028



**18-Month Target Price Range**
Low-High Midpoint (% to Mid)
$74-$131 $103 (15%)

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 135 | (+55%) | 15% |
| Low | 100 | (+15%) | 7% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 947 | 891 | 852 |
| to Sell | 673 | 731 | 753 |
| Hld's(000) | 499614 | 493832 | 495714 |

Percent shares traded 15 10 5

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -1.0 | 16.6 |
| 3 yr. | 12.3 | 43.6 |
| 5 yr. | 34.1 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 32.64 | 37.36 | **38.50** | **38.95** | Revenues per sh | **40.90** |
| 8.11 | 7.34 | 7.58 | 8.49 | 8.68 | 6.80 | 8.56 | 9.11 | 9.40 | 9.20 | 10.01 | 11.05 | 12.12 | 12.04 | 12.60 | 12.91 | **13.25** | **13.55** | "Cash Flow" per sh | **14.60** |
| 3.60 | 3.03 | 3.39 | 4.02 | 4.14 | 3.71 | 3.98 | 4.13 | 4.10 | 3.71 | 4.22 | 4.72 | 5.06 | 5.12 | 5.24 | 5.27 | **5.60** | **6.00** | 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** | **4.14** | Div'd Decl'd per sh B ■ | **4.30** |
| 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 | 12.63 | 14.76 | **16.75** | **17.60** | Cap'l Spending per sh | **16.75** |
| 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 | 61.55 | 61.51 | **64.50** | **66.25** | Book Value per sh C | **70.00** |
| 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 | 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 | 17.0 | 17.7 | 17.1 | 18.9 | 19.6 | *Bold figures are* | | Avg Ann'l P/E Ratio | **17.0** |
| .85 | 1.04 | .89 | .81 | .87 | 1.11 | .98 | .94 | .92 | 1.12 | 1.00 | .92 | .94 | .88 | 1.02 | 1.14 | *Value Line* | | Relative P/E Ratio | **.95** |
| 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% | 3.9% | *estimates* | | Avg Ann'l Div'd Yield | **3.9%** |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $74523 mill. **Due in 5 Yrs** $19536 mill.
**LT Debt** $69914 mill. **LT Interest** $2206 mill.
Incl. $915 mill. finance leases.
(LT interest earned: 2.7x)
**Leases, Uncapitalized** Annual rentals $225 mill.
**Pension Assets-12/21** $9235 mill.
Oblig $8207 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** 770,707,545 shs. as of 7/31/23
**MARKET CAP: $67.7 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 24598 | 23925 | 23459 | 22743 | 23565 | 24521 | 25079 | 23868 | 25097 | 28768 | **29650** | **30000** | Revenues ($mill) | **31500** |
| 2813.0 | 2934.0 | 2854.0 | 2560.0 | 2963.0 | 3339.0 | 3747.0 | 3878.0 | 4133.0 | 4104.1 | **4310** | **4620** | Net Profit ($mill) | **5390** |
| 32.6% | 30.6% | 32.2% | 31.0% | 30.4% | 14.1% | 12.7% | .3% | 5.1% | 7.4% | **9.0%** | **9.0%** | Income Tax Rate | **9.0%** |
| 8.8% | 7.2% | 9.2% | 11.7% | 12.3% | 11.4% | 8.0% | 6.9% | 5.9% | 8.1% | **7.0%** | **7.0%** | AFUDC % to Net Profit | **7.0%** |
| 48.0% | 47.7% | 48.6% | 52.6% | 54.0% | 53.8% | 54.0% | 53.7% | 55.1% | 56.1% | **58.5%** | **58.5%** | Long-Term Debt Ratio | **61.0%** |
| 52.0% | 52.3% | 51.4% | 47.4% | 46.0% | 46.2% | 44.1% | 44.4% | 43.1% | 42.5% | **40.0%** | **40.0%** | Common Equity Ratio | **37.5%** |
| 79482 | 78088 | 77222 | 86609 | 90774 | 94940 | 101807 | 103589 | 109744 | 115235 | **124525** | **124525** | Total Capital ($mill) | **144100** |
| 69490 | 70046 | 75709 | 82520 | 86391 | 91694 | 102127 | 106782 | 111408 | 111748 | **124375** | **124375** | Net Plant ($mill) | **141100** |
| 4.6% | 4.8% | 4.8% | 4.0% | 4.3% | 4.6% | 4.7% | 4.8% | 4.8% | 4.5% | **4.5%** | **4.5%** | Return on Total Cap'l | **4.5%** |
| 6.8% | 7.2% | 7.2% | 6.2% | 7.1% | 7.6% | 8.0% | 8.1% | 8.4% | 8.5% | **9.0%** | **9.0%** | Return on Shr. Equity | **9.0%** |
| 6.8% | 7.2% | 7.2% | 6.2% | 7.1% | 7.6% | 8.3% | 8.2% | 8.5% | 8.5% | **9.0%** | **9.0%** | Return on Com Equity E | **9.0%** |
| 1.5% | 1.7% | 1.5% | .6% | 1.2% | 2.0% | 2.4% | 2.3% | 1.9% | 2.5% | **2.5%** | **2.5%** | Retained to Com Eq | **3.0%** |
| 78% | 76% | 79% | 91% | 83% | 74% | 71% | 73% | 78% | 76% | **73%** | **73%** | All Div'ds to Net Prof | **68%** |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -2.3 | +2.0 | 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.) | NA | NA | NA |
| Fixed Charge Cov. (%) | 183 | 209 | 285 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | .5% | -.5% | 2.5% |
| "Cash Flow" | 4.0% | 5.0% | 5.0% |
| Earnings | 3.0% | 4.5% | 5.0% |
| 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 |
|---|---|---|---|---|---|
| 2020 | 5949 | 5421 | 6721 | 5777 | 23868 |
| 2021 | 6150 | 5758 | 6951 | 6238 | 25097 |
| 2022 | 7132 | 6685 | 7968 | 6983 | 28768 |
| 2023 | 7276 | 6578 | *8150* | *7646* | *29650* |
| 2024 | *7350* | *6650* | *8250* | *7750* | *30000* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1.14 | 1.08 | 1.87 | 1.03 | 5.12 |
| 2021 | 1.26 | 1.15 | 1.88 | .94 | 5.24 |
| 2022 | 1.30 | 1.14 | 1.78 | 1.11 | 5.27 |
| 2023 | 1.20 | .91 | *1.98* | *1.51* | *5.60* |
| 2024 | *1.35* | *1.30* | *2.05* | *1.30* | *6.00* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .9275 | .9275 | .945 | .945 | 3.75 |
| 2020 | .945 | .945 | .965 | .965 | 3.82 |
| 2021 | .965 | .965 | .985 | .985 | 3.90 |
| 2022 | .985 | .985 | 1.005 | 1.005 | 3.98 |
| 2023 | 1.005 | 1.005 | 1.0250 | | |

**BUSINESS:** Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, and 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, 32%; nuclear, 30%; coal, 18%; other, 1%; purchased, 19%. Fuel costs: 28% of revs. '22 reported deprec. rate: 3.6%. Has 27,600 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 continues to make progress in its rate cases.** The North Carolina Utilities Commission approved new rates in that state that were implemented on October 1st. The utility reached a settlement calling for increases of $234 million (5.8%) in 2023, $126 million (3.2%) in 2024, and $138 million (3.4%) in 2025. In Kentucky, the utility's electric rate case hearing has reached a conclusion, and an order by the Kentucky Public Service Commission is expected in late November. Duke also partnered with Amazon to place a two-megawatt solar plant on top of an Amazon fulfillment center in north Kentucky, which is the largest rooftop solar site in that state. This should benefit the utility's long-term clean energy transition goals.

**Rate relief is a main reason for the profit growth we expect in 2023 and 2024.** We think the utility should continue to benefit from a number of pending rate cases, as well as strong electric volume growth over the next few years. Accordingly, management reaffirmed its long-term annual earnings growth rate of 5%-7% through 2027. While the utility is taking advantage of rate relief, we have cut our 2023 profit projection by $0.05 a share, to reflect weaker-than-expected second-quarter earnings due to mild weather and increased interest expenses. We look for 2023 and 2024 bottom-line totals of $5.60 and $6.00 per share, right around management's annual target of 5%-7% growth.

**These shares have dropped nearly 10% in value since our August report, alongside many of its peers in the utilities industry.** Utility stocks have been under selling pressure due to increased competition in the bond market caused by rising Treasury yields. Duke shares have closely tracked the S&P Utility Index (XLU) over the past year, and both are down more than 15% over that interim.

**Income-oriented investors may be drawn to this issue.** The stock has an above-average dividend yield for a utility. Too, Duke has a proven track record of strong management and the stock price has outperformed its peer group over the past five to 10 years. At this level, however, appreciation potential to 2026-2028 is nothing to write home about.

*Zachary J. Hodgkinson November 10, 2023*

(A) Dil. EPS. Excl. net nonrec. losses: '12, 64¢; '13, 22¢; '14, 59¢; '15, 5¢; '16, 60¢; '18, 96; '20, $3.40; '21, 30¢; net nonrec gain: '17, 14¢. 2021 EPS may not sum to annual due to rounding. Next egs. due early Nov. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd re-inv. plan avail. (C) Incl. intang. In '22: $41.34/sh. (D) In mill., (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '21 in NC: 9.6%; 9.5%; in '20 in FL: 9.5%-11.5%; in '20 in IN: 9.7%. in '19 in SC:9.5%; Reg. Clim.: NC, SC Avg.; OH, IN Above Avg.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 45 |
| Earnings Predictability | 100 |

# EDISON INTERNAT'L NYSE-EIX

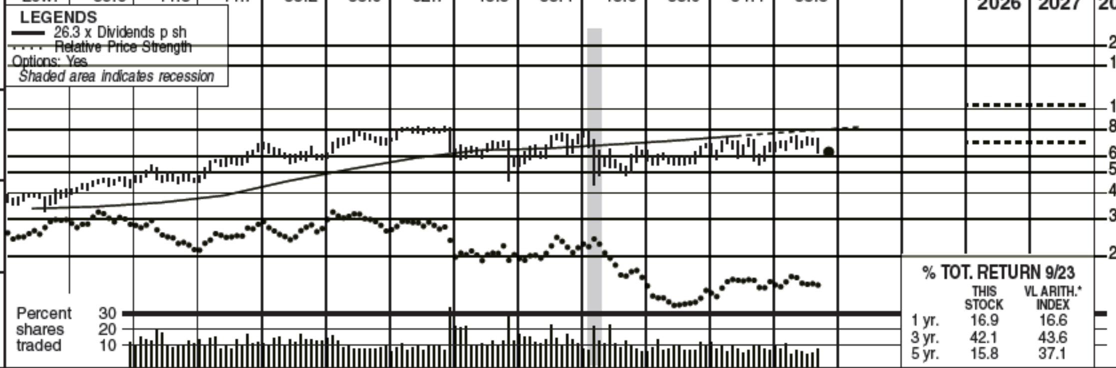
RECENT PRICE 62.53 | P/E RATIO 13.0 (Trailing: 13.2 Median: 14.0) | RELATIVE P/E RATIO 0.81 | DIV'D YLD 5.0% | VALUE LINE

TIMELINESS 3 Lowered 7/7/23
SAFETY 3 Lowered 11/23/18
TECHNICAL 2 Lowered 10/20/23
BETA 1.00 (1.00 = Market)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 48.0 | 54.2 | 68.7 | 69.6 | 78.7 | 83.4 | 71.0 | 76.4 | 78.9 | 68.6 | 73.3 | 74.9 | |
| Low: | 39.6 | 44.3 | 44.7 | 55.2 | 58.0 | 62.7 | 45.5 | 53.4 | 43.6 | 53.9 | 54.4 | 58.8 | |

Target Price Range 2026 | 2027 | 2028

LEGENDS
— 26.3 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $49-$85 | $67 (5%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 105 | (+70%) | 17% |
| Low | 70 | (+10%) | 8% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 382 | 371 | 369 |
| to Sell | 254 | 274 | 304 |
| Hld's(000) | 343385 | 343456 | 340122 |

Percent shares traded 30 20 10

% TOT. RETURN 9/23

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | 16.9 | 16.6 |
| 3 yr. | 42.1 | 43.6 |
| 5 yr. | 15.8 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 40.25 | 43.31 | 37.98 | 38.09 | 39.16 | 36.41 | 38.61 | 41.17 | 35.37 | 36.43 | 37.81 | 38.85 | 34.11 | 35.83 | 39.18 | 45.05 | 45.20 | 46.65 | Revenues per sh | 50.00 |
| 7.60 | 8.08 | 7.96 | 8.41 | 9.03 | 9.63 | 8.80 | 9.95 | 10.35 | 10.43 | 11.03 | 4.69 | 9.81 | 10.69 | 11.16 | 12.07 | 12.40 | 13.00 | "Cash Flow" per sh | 14.50 |
| 3.32 | 3.68 | 3.24 | 3.35 | 3.23 | 4.55 | 3.78 | 4.33 | 4.15 | 3.94 | 4.51 | d1.26 | 4.70 | 4.52 | 4.59 | 4.63 | 4.75 | 5.10 | Earnings per sh A | 6.00 |
| 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 | 2.99 | 3.14 | Div'd Decl'd per sh B ■ | 3.66 |
| 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 | 15.12 | 15.25 | 15.75 | Cap'l Spending per sh | 17.00 |
| 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 | 35.70 | 35.25 | 35.00 | Book Value per sh C | 42.25 |
| 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 | 382.21 | 384.00 | 386.00 | Common Shs Outst'g D | 390.00 |
| 16.0 | 12.4 | 9.7 | 10.3 | 11.8 | 9.7 | 12.7 | 13.0 | 14.8 | 17.9 | 17.2 | -- | 14.1 | 13.3 | 12.9 | 14.0 | Bold figures are | | Avg Ann'l P/E Ratio | 14.5 |
| .85 | .75 | .65 | .66 | .74 | .62 | .71 | .68 | .75 | .94 | .87 | -- | .75 | .68 | .70 | .81 | Value Line | | Relative P/E Ratio | .80 |
| 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% | 4.4% | estimates | | Avg Ann'l Div'd Yield | 4.2% |

**CAPITAL STRUCTURE as of 6/30/23**
Total Debt $33480 mill. Due in 5 Yrs $9685 mill.
LT Debt $29430 mill. LT Interest $1400 mill.
(Total Interest Coverage: 2.9x)
Leases, Uncapitalized Annual rentals $542 mill.

Pension Assets-12/22 $3462 mill.
Oblig $3524 mill.

Pfd Stock $3879 mill. Pfd Div'd $212 mill.

Common Stock 383,288,769 shs.
as of 7/20/23
MARKET CAP: $24.0 billion (Large Cap)

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12581 | 13413 | 11524 | 11869 | 12320 | 12657 | 12347 | 13578 | 14905 | 17220 | 17350 | 18000 | Revenues ($mill) | 19500 |
| 1344.0 | 1539.0 | 1480.0 | 1422.0 | 1603.0 | d290.0 | 1716.0 | 1818.0 | 1907.0 | 1977.0 | 2030 | 2170 | Net Profit ($mill) | 2550 |
| 25.2% | 22.4% | 6.6% | 11.1% | 5.0% | -- | 1.2% | 5.0% | 18.0% | 12.5% | 13.0% | 13.0% | Income Tax Rate | 13.0% |
| 7.8% | 5.8% | 8.0% | 6.8% | 7.2% | -- | 9.6% | 9.6% | 8.8% | 9.6% | 9.0% | 9.0% | AFUDC % to Net Profit | 8.0% |
| 45.7% | 44.1% | 45.0% | 41.8% | 45.6% | 53.6% | 53.5% | 55.2% | 57.6% | 60.7% | 63.5% | 65.5% | Long-Term Debt Ratio | 66.5% |
| 46.2% | 47.2% | 46.7% | 49.2% | 45.8% | 38.3% | 39.9% | 39.5% | 33.2% | 30.6% | 28.5% | 27.0% | Common Equity Ratio | 27.0% |
| 21516 | 23216 | 24352 | 24362 | 25506 | 27284 | 33360 | 35581 | 41959 | 44547 | 47425 | 50475 | Total Capital ($mill) | 60325 |
| 30455 | 32981 | 35085 | 37000 | 39050 | 41348 | 44285 | 47839 | 50700 | 53486 | 56375 | 59400 | Net Plant ($mill) | 69175 |
| 7.3% | 7.7% | 7.1% | 6.9% | 7.3% | .1% | 6.4% | 6.3% | 5.6% | 5.7% | 5.5% | 5.5% | Return on Total Cap'l | 5.5% |
| 11.5% | 11.9% | 11.1% | 10.0% | 11.6% | NMF | 11.1% | 11.4% | 10.7% | 11.3% | 11.5% | 12.5% | Return on Shr. Equity | 12.5% |
| 12.5% | 13.0% | 12.0% | 10.8% | 12.7% | NMF | 12.0% | 12.0% | 12.5% | 12.9% | 13.5% | 14.5% | Return on Com Equity E | 14.0% |
| 8.1% | 8.8% | 7.2% | 5.6% | 6.6% | NMF | 5.9% | 5.4% | 5.4% | 5.2% | 5.0% | 5.5% | Retained to Com Eq | 5.5% |
| 40% | 37% | 44% | 53% | 52% | NMF | 54% | 58% | 61% | 64% | 67% | 65% | All Div'ds to Net Prof | 64% |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +.7 | -3.9 | +2.6 |
| Avg. Indust. Use (MWH) | 589 | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 23133 | 21190 | 24345 |
| Annual Load Factor (%) | 46.7 | 52.7 | 45.8 |
| % Change Customers (yr-end) | +.6 | +.3 | +.8 |
| Fixed Charge Cov. (%) | NMF | 113 | 135 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 0.5% | 2.0% | 4.0% |
| "Cash Flow" | 2.5% | 1.5% | 4.0% |
| Earnings | 2.0% | 1.5% | 4.5% |
| Dividends | 7.5% | 6.5% | 5.0% |
| Book Value | 1.5% | 0.5% | 2.5% |

**QUARTERLY REVENUES ($ mill.)**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 2790 | 2987 | 4644 | 3157 | 13578 |
| 2021 | 2960 | 3315 | 5299 | 3331 | 14905 |
| 2022 | 3968 | 4008 | 5228 | 4016 | 17220 |
| 2023 | 3966 | 3964 | 5350 | 4070 | 17350 |
| 2024 | 4100 | 4250 | 5475 | 4175 | 18000 |

**EARNINGS PER SHARE A**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .63 | 1.00 | 1.67 | 1.19 | 4.52 |
| 2021 | .79 | .94 | 1.69 | 1.16 | 4.59 |
| 2022 | 1.07 | .94 | 1.48 | 1.15 | 4.63 |
| 2023 | 1.09 | 1.01 | 1.49 | 1.16 | 4.75 |
| 2024 | 1.14 | 1.06 | 1.63 | 1.27 | 5.10 |

**QUARTERLY DIVIDENDS PAID B ■**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .6125 | .6125 | .6125 | .6125 | 2.45 |
| 2020 | .6375 | .6375 | .6375 | .6375 | 2.55 |
| 2021 | .6625 | .6625 | .6625 | .6625 | 2.65 |
| 2022 | .70 | .70 | .70 | .70 | 2.80 |
| 2023 | .7375 | .7375 | .7375 | | |

**BUSINESS:** Edison International is a holding company for Southern California Edison Company (SoCal Edison), 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, 40%; commercial, 42%; industrial, 3%; other, 15%. Generating sources: nuclear, 9%; gas, 7%; hydroelectric, 4%; purchased, 80%. Power costs: 37% of revs. '22 reported depr. rate: 3.8%. Employs 13,385. Chairman: William P. Sullivan. President & 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 is on target for a solid 2023 campaign and operational momentum through next year.** The utility posted good first-half profit comparisons that should enable it to surpass the midpoint of this year's internal share-earnings projection of $4.55 to $4.85. The escalation mechanism set forth in the 2021 General Rate Case (GRC) decision that allows the company to bill for certain types of expenses, thereby circumventing regulatory lag, is a big plus. Higher interest expense remains problematic, but there are enough tailwinds to more than offset the challenging rate environment. Load growth in California is brisk at around 3% due in part to the ongoing shift to electric vehicles and heavy equipment. Leadership remains confident in its expectation of 5%-7% profit growth through at least 2025, with a path to $7 per share by 2028. The state's aggressive green energy initiatives and ongoing fire mitigation work should deliver economic returns on invested capital. As always, rate relief by way of the regulatory umbrella will be a key factor. In that vein, the company filed its latest GRC a few months ago.

**Although Edison has worked to lower its wildfire risks, they're still problematic.** Orange County recently filed a lawsuit alleging EIX's utility, SoCal Edison, acted negligently in maintaining and operating its equipment, causing two wildfires that burned thousands of acres. The blazes in question took place in October, 2020 and May, 2022. Dollar amounts sought weren't given. In recent years, EIX has paid out billions of dollars in lawsuit settlements associated with the role its power lines played in the disastrous late 2017 to 2018 forest fires in the Golden State. While we now exclude the charges from our earnings presentation (beginning from 2019), to better highlight the progress that EIX is making in its core operations, one can see the impact on the balance sheet via the rising debt as a percentage of total capital in the financial array.

**These shares are neutrally ranked for year-ahead relative performance.** Despite the many good things taking place in EIX's service area, wildfire risks, though likely less catastrophic now than in the past, are still financially material.

*Anthony J. Glennon* *October 20, 2023*

(A) Adjusted (non-GAAP) EPS from 2019 on. Excl. gains/(losses): nonrecur's ; '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); '18, (14¢); '19, (92¢); '20, ($2.54); '21, ($2.59); '22, ($3.02); 1Q '23, (28¢); disc. ops.: '13, 11¢; '14, 57¢; '15, 11¢; '18, 10¢. Qtly. EPS may not sum due to rounding. Next egs. report due early Nov. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '22: $2.49/sh. (D) In mill. (E) Rate base: net orig. cost. Rate all'd on com. eq. in '20: 10.3%; Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 80 |
| Price Growth Persistence | 35 |
| Earnings Predictability | 10 |

# ENTERGY CORP. NYSE-ETR

RECENT PRICE 101.63 | P/E RATIO 15.7 (Trailing: 14.6 Median: 14.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Raised 9/8/23
SAFETY 2 Raised 12/13/19
TECHNICAL 4 Lowered 12/8/23
BETA .95 (1.00 = Market)

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $80-$145 | $113 (10%) |

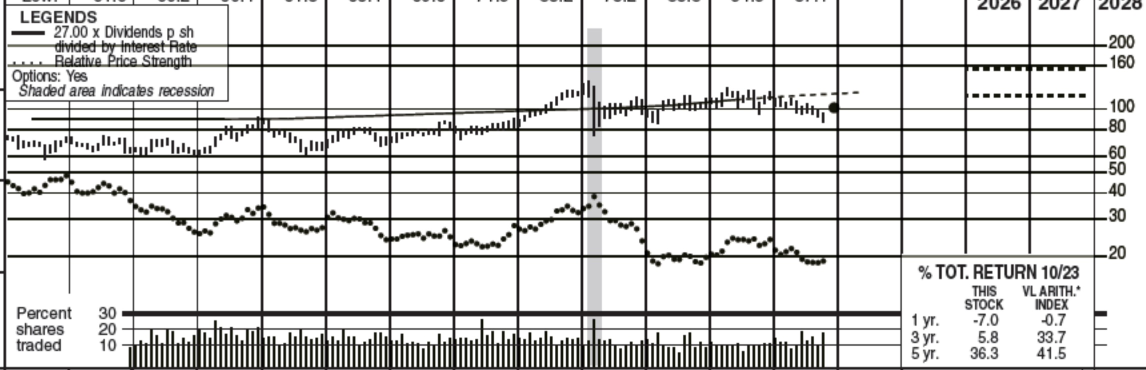
**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 155 | (+55%) | 15% |
| Low | 115 | (+15%) | 7% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 377 | 367 | 405 |
| to Sell | 274 | 287 | 270 |
| Hld's(000) | 186530 | 184354 | 181973 |

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 74.5 | 72.6 | 92.0 | 90.3 | 82.1 | 87.9 | 90.8 | 122.1 | 135.5 | 115.0 | 126.8 | 111.9 |
| Low: | 61.6 | 60.2 | 60.4 | 61.3 | 65.4 | 69.6 | 71.9 | 83.2 | 75.2 | 85.8 | 94.9 | 87.1 |




**% TOT. RETURN 10/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -7.0 | -0.7 |
| 3 yr. | 5.8 | 33.7 |
| 5 yr. | 36.3 | 41.5 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 65.18 | 57.15 | 57.80 | Revenues per sh | 65.20 |
| 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 | 15.51 | 18.20 | 17.45 | "Cash Flow" per sh | 19.90 |
| 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 | 5.37 | 7.25 | 6.45 | Earnings per sh A | 7.50 |
| 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 | 4.10 | 4.34 | 4.56 | Div'd Decl'd per sh B ■ † | 5.00 |
| 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 | 25.04 | 23.00 | 19.00 | Cap'l Spending per sh | 19.75 |
| 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 | 61.40 | 63.10 | 65.50 | Book Value per sh C | 73.90 |
| 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 | 211.18 | 214.00 | 218.00 | Common Shs Outst'g D | 230.00 |
| 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 | 21.1 | Bold figures are Value Line estimates | | Avg Ann'l P/E Ratio | 18.0 |
| 1.02 | 1.00 | .80 | .74 | .57 | .71 | .74 | .68 | .63 | .57 | .75 | .75 | .88 | .79 | .81 | 1.22 | | | Relative P/E Ratio | 1.00 |
| 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% | 3.6% | | | Avg Ann'l Div'd Yield | 3.7% |

**CAPITAL STRUCTURE as of 9/30/23**
**Total Debt** $27534 mill. **Due in 5 Yrs** $11117 mill.
**LT Debt** $24659 mill. **LT Interest** $824.0 mill.
Incl. $54.7 mill. of securitization bonds.
(LT interest earned: 2.8x)
**Leases, Uncapitalized** Annual rentals $62.1 mill.
**Pension Assets-12/22** $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** 211,473,074 shs. **as of 10/31/23**
**MARKET CAP: $21.5 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11391 | 12495 | 11513 | 10846 | 11074 | 11009 | 10879 | 10114 | 11743 | 13764 | 12225 | 12600 | Revenues ($mill) | 15000 |
| 904.5 | 1060.0 | 1061.2 | 1249.8 | 950.7 | 1092.1 | 1258.2 | 1406.7 | 1402.8 | 1103.2 | 1550 | 1405 | Net Profit ($mill) | 1725 |
| 26.7% | 37.8% | 2.2% | 11.3% | 1.8% | -- | -- | -- | 16.1% | 16.1% | 23.0% | 23.0% | Income Tax Rate | 23.0% |
| 10.1% | 9.3% | 7.4% | 8.1% | 14.7% | 17.5% | 16.7% | 12.2% | 7.1% | 2.5% | 10.0% | 8.0% | AFUDC % to Net Profit | 10.0% |
| 55.1% | 54.9% | 57.8% | 63.6% | 63.6% | 63.2% | 62.0% | 65.5% | 67.6% | 64.2% | 64.5% | 64.5% | Long-Term Debt Ratio | 64.5% |
| 43.6% | 43.8% | 40.8% | 35.5% | 35.5% | 35.9% | 37.1% | 33.7% | 31.7% | 35.2% | 35.5% | 35.5% | Common Equity Ratio | 35.5% |
| 22109 | 22842 | 22714 | 22777 | 22528 | 24602 | 27557 | 32386 | 36733 | 36810 | 38780 | 41065 | Total Capital ($mill) | 48910 |
| 27882 | 28723 | 27824 | 27921 | 29664 | 31974 | 35183 | 38853 | 42244 | 42477 | 45025 | 47730 | Net Plant ($mill) | 56845 |
| 5.4% | 6.0% | 6.0% | 6.9% | 5.7% | 5.8% | 5.9% | 5.6% | 4.9% | 4.3% | 5.0% | 4.5% | Return on Total Cap'l | 4.5% |
| 9.1% | 10.3% | 11.1% | 15.1% | 11.6% | 12.0% | 12.0% | 12.6% | 11.8% | 8.4% | 11.5% | 9.5% | Return on Shr. Equity | 10.0% |
| 9.2% | 10.4% | 11.2% | 15.2% | 11.7% | 12.2% | 12.1% | 12.7% | 11.9% | 8.4% | 11.5% | 9.5% | Return on Com Equity E | 10.0% |
| 3.0% | 4.4% | 4.8% | 7.7% | 3.9% | 4.9% | 5.2% | 5.9% | 5.2% | 1.9% | 4.5% | 3.0% | Retained to Com Eq | 3.5% |
| 68% | 58% | 58% | 50% | 68% | 61% | 58% | 55% | 57% | 78% | 60% | 71% | All Div'ds to Net Prof | 77% |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -4.1 | +3.2 | +1.1 |
| Avg. Indust. Use (MWH) | 1017 | 1015 | 1018 |
| Avg. Indust. Revs. per KWH(¢) | 4.95 | 5.91 | 7.08 |
| Capacity at Peak (Mw) | 25665 | NA | NA |
| Peak Load, Summer (Mw) | 21340 | NA | NA |
| Annual Load Factor (%) | 62 | NA | NA |
| % Change Customers (yr-end) | +1.0 | +1.0 | +1.0 |
| Fixed Charge Cov. (%) | 202 | 243 | 209 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -.5% | -1.5% | 2.0% |
| "Cash Flow" | .5% | -.5% | 1.5% |
| Earnings | -.5% | 1.5% | .5% |
| Dividends | 1.5% | 2.5% | 4.0% |
| Book Value | 1.5% | 4.0% | 4.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 2427 | 2413 | 2904 | 2370 | 10114 |
| 2021 | 2845 | 2822 | 3353 | 2723 | 11743 |
| 2022 | 2878 | 3395 | 4219 | 3273 | 13764 |
| 2023 | 2981 | 2846 | 3596 | 2802 | 12225 |
| 2024 | 2900 | 3300 | 3300 | 3100 | 12600 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .59 | 1.79 | 2.59 | 1.93 | 6.90 |
| 2021 | 1.66 | 1.30 | 2.63 | 1.28 | 6.87 |
| 2022 | 1.36 | .78 | 2.74 | .51 | 5.37 |
| 2023 | 1.47 | 1.84 | 3.14 | .80 | 7.25 |
| 2024 | 1.50 | 1.05 | 2.95 | .95 | 6.45 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 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 | 1.01 | 1.01 | 1.07 | 4.10 |
| 2023 | 1.07 | 1.07 | 1.07 | 1.13 | |

**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. Is selling its last nonutility nuclear unit (shut down 5/22). Electric revenue breakdown: residential, 37%; commercial, 24%; industrial, 27%; other, 12%. Generating sources: gas, 68%; nuclear, 22%; coal, 9%; hydro and solar, 1%. Fuel costs: 32% of revenues. '22 reported depreciation rate: 2.7%. Has 11,707 employees. Chairman & CEO: Leo P. Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

**Entergy recorded improved third-quarter bottom-line results.** Revenues fell to around $3.6 billion as electricity prices significantly declined due to lower fuel prices year over year. However, the company benefited from much warmer temperatures through its coverage areas, while population growth also helped. These factors led to a significant increase in gross profits, and the company has made investments in improving its infrastructure, allowing for a decline in maintenance expenses. Though interest costs rose due to higher interest rates, a profit of $3.14 per share was recorded during the recent quarter. We expect solid fourth-quarter earnings to occur at Entergy, as it should benefit from a few positive rate adjustments, including a new one in the Louisiana area, which began in September. Overall, we look for the bottom line to reach $7.25 per share this year.

**We expect decent growth in the years ahead.** The company should benefit from several rate cases across its coverage areas in the past few quarters, and we expect more to be filed, helping the top line grow. Still, some headwinds will likely exist in the near term, including cooler weather compared to this summer and the slowdown of some industrial activities that require Entergy's power to occur. Meanwhile, the energy provider has agreed to sell its gas distribution business for $484 million. This deal will likely close in the third quarter of 2025, subject to regulatory approvals. Over the long haul, Entergy is well positioned to benefit from growing populations in the southern U.S. along with reshoring of industrial and manufacturing processes. Another plus is capital projects, including several solar facilities in the years ahead. Overall, we project earnings will recede to $6.45 per share in 2024 before recovering to $7.50 by 2026-2028.

**The board hiked the quarterly payout by 6% to $1.13 per share.** What's more, we estimate the payout will grow at a solid clip in the years ahead.

**Shares of Entergy are neutrally ranked for Timeliness.** Also this stock has below-average 3- to 5-year appreciation potential. The dividend yield is attractive, however.

*John E. Seibert III* *December 8, 2023*

(A) Diluted EPS. GAAP starting in 2022. 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 February. (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 '22: $23.64/sh. (D) In mill. (E) Rate base: Net original cost. Allowed ROE (blended): 9.71%; earned on avg. com. eq., '22: 8.5%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 90 |
| Price Growth Persistence | 45 |
| Earnings Predictability | 75 |

# EVERGY, INC. NYSE-EVRG

RECENT PRICE 50.72 | P/E RATIO 12.3 (Trailing: 17.1 Median: NMF) | RELATIVE P/E RATIO 0.76 | DIV'D YLD 5.1% | VALUE LINE

TIMELINESS 3 Raised 11/3/23

SAFETY 2 New 9/14/18

TECHNICAL 4 Lowered 12/8/23

BETA .95 (1.00 = Market)

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $43-$79 | $61 (20%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 100 | (+95%) | 22% |
| Low | 70 | (+40%) | 12% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 358 | 310 | 298 |
| to Sell | 268 | 284 | 272 |
| Hld's(000) | 191450 | 194561 | 192350 |

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| High: | 61.1 | 67.8 | 76.6 | 69.4 | 73.1 | 65.4 |
| Low: | 50.9 | 54.6 | 42.0 | 51.9 | 54.1 | 46.9 |

LEGENDS
.... Relative Price Strength
Options: Yes
Shaded area indicates recession


Target Price Range 2026 | 2027 | 2028

% TOT. RETURN 10/23

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -16.2 | -0.7 |
| 3 yr. | -0.4 | 33.7 |
| 5 yr. | 4.8 | 41.5 |

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.

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -- | -- | -- | -- | -- | 16.75 | 22.71 | 21.66 | 24.36 | 25.49 | *25.15* | *26.10* | Revenues per sh | *28.25* |
| -- | -- | -- | -- | -- | 4.89 | 7.18 | 7.06 | 8.18 | 7.34 | *7.90* | *8.20* | "Cash Flow" per sh | *9.20* |
| -- | -- | -- | -- | -- | 2.50 | 2.79 | 2.72 | 3.83 | 3.26 | *3.60* | *3.85* | Earnings per sh A | *4.85* |
| -- | -- | -- | -- | -- | 1.74 | 1.93 | 2.05 | 2.18 | 2.33 | *2.48* | *2.61* | Div'd Decl'd per sh B ■ | *3.05* |
| -- | -- | -- | -- | -- | 4.19 | 5.34 | 6.88 | 8.60 | 9.41 | *9.20* | *9.25* | Cap'l Spending per sh | *9.50* |
| -- | -- | -- | -- | -- | 39.28 | 37.82 | 38.50 | 40.32 | 41.86 | *42.70* | *44.10* | Book Value per sh C | *47.50* |
| -- | -- | -- | -- | -- | 255.33 | 226.64 | 226.84 | 229.30 | 229.90 | *230.00* | *230.00* | Common Shs Outst'g D | *230.00* |
| -- | -- | -- | -- | -- | 22.7 | 21.8 | 21.7 | 16.2 | 19.9 | *Bold figures are* | | Avg Ann'l P/E Ratio | *17.5* |
| -- | -- | -- | -- | -- | 1.23 | 1.16 | 1.11 | .88 | 1.15 | *Value Line* | | Relative P/E Ratio | *.95* |
| -- | -- | -- | -- | -- | 3.1% | 3.2% | 3.5% | 3.5% | 4.0% | *estimates* | | Avg Ann'l Div'd Yield | *3.7%* |
| -- | -- | -- | -- | -- | 4275.9 | 5147.8 | 4913.4 | 5586.7 | 5859.1 | *5780* | *6000* | Revenues ($mill) | *6500* |
| -- | -- | -- | -- | -- | 535.8 | 669.9 | 618.3 | 879.7 | 752.7 | *830* | *885* | Net Profit ($mill) | *1115* |
| -- | -- | -- | -- | -- | 9.8% | 12.6% | 14.1% | 11.7% | 5.8% | *9.0%* | *9.0%* | Income Tax Rate | *9.0%* |
| -- | -- | -- | -- | -- | 2.5% | 2.5% | 5.5% | 5.0% | 5.1% | *6.0%* | *6.0%* | AFUDC % to Net Profit | *5.0%* |
| -- | -- | -- | -- | -- | 40.0% | 50.6% | 51.3% | 50.1% | 50.0% | *51.5%* | *51.5%* | Long-Term Debt Ratio | *53.5%* |
| -- | -- | -- | -- | -- | 60.0% | 49.4% | 48.7% | 49.9% | 48.0% | *48.5%* | *48.5%* | Common Equity Ratio | *46.5%* |
| -- | -- | -- | -- | -- | 16716 | 17337 | 17924 | 18542 | 19668 | *20175* | *21250* | Total Capital ($mill) | *23400* |
| -- | -- | -- | -- | -- | 18952 | 19346 | 20106 | 21150 | 22137 | *23150* | *24200* | Net Plant ($mill) | *26300* |
| -- | -- | -- | -- | -- | 4.0% | 4.8% | 4.5% | 5.7% | 6.9% | *5.5%* | *5.5%* | Return on Total Cap'l | *6.0%* |
| -- | -- | -- | -- | -- | 5.3% | 7.8% | 7.1% | 9.5% | 8.1% | *9.0%* | *9.0%* | Return on Shr. Equity | *10.0%* |
| -- | -- | -- | -- | -- | 5.3% | 7.8% | 7.1% | 9.5% | 8.1% | *9.0%* | *9.0%* | Return on Com Equity E | *10.0%* |
| -- | -- | -- | -- | -- | .6% | 2.4% | 1.8% | 4.1% | 3.1% | *3.0%* | *3.0%* | Retained to Com Eq | *3.5%* |
| -- | -- | -- | -- | -- | 89% | 69% | 75% | 57% | 73% | *69%* | *68%* | All Div'ds to Net Prof | *63%* |

**CAPITAL STRUCTURE as of 9/30/23**
**Total Debt** $10187 mill. **Due in 5 Yrs** $4388 mill.
**LT Debt** $9298 mill. **LT Interest** $306 mill.
Incl. $40.9 mill. finance leases.
(LT interest earned: 3.8x)

**Leases, Uncapitalized** Annual rentals $18.8 mill.

**Pension Assets-12/22** $1714.7 mill.
**Oblig** $2561.7 mill.

**Pfd Stock** None

**Common Stock** 229,720,757 shs.
**MARKET CAP: $11.7 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -3.9 | +3.1 | +6.7 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 7.14 | 6.94 | 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. (%) | 286 | 350 | 382 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| 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 |
|---|---|---|---|---|---|
| 2020 | 1116 | 1184 | 1517 | 1094 | 4913.4 |
| 2021 | 1611 | 1236 | 1616 | 1122 | 5586.7 |
| 2022 | 1223 | 1446 | 1909 | 1281 | 5859.1 |
| 2023 | 1297 | 1354 | 1669 | *1460* | *5780* |
| 2024 | *1250* | *1500* | *1950* | *1300* | *6000* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .31 | .59 | 1.60 | .22 | 2.72 |
| 2021 | .84 | .81 | 1.95 | .23 | 3.83 |
| 2022 | .53 | .84 | 1.86 | .03 | 3.26 |
| 2023 | .62 | .78 | 1.53 | *.67* | *3.60* |
| 2024 | *.65* | *.80* | *2.00* | *.40* | *3.85* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .475 | .475 | .475 | .505 | 1.93 |
| 2020 | .505 | .505 | .505 | .535 | 2.05 |
| 2021 | .535 | .535 | .535 | .5725 | 2.18 |
| 2022 | .5725 | .5725 | .5725 | .6125 | 2.33 |
| 2023 | .6125 | .6125 | .6125 | .6425 | |

**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, 32%; commercial, 27%; industrial, 15%; wholesale, 13%; other, 13%. Generating sources: coal, 54%; nuclear, 17%; purchased, 29%. Fuel costs: 28% of revenues. '22 reported deprec. rate: 3%. Has 4,900 employees. Chairman: Mark A. Ruelle. 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.

**We look for Evergy's earnings prospects to improve in 2023 and 2024.** Increased income from the company's transmission system, as well as rate relief in Missouri and Kansas, should remain key factors over the next few years. Indeed, higher transmission margin due to ongoing investments to improve its transmission infrastructure contributed $0.04 per share to third period profits and should continue to benefit earnings moving forward. Our full-year 2023 earnings estimate is at the midpoint of Evergy's updated guidance range of $3.55-$3.65 per share. Too, the utility is now targeting a long-term annual earnings per share growth target of 4%-6%, based on the midpoint of its original 2023 profit guidance of $3.65 per share.

**Evergy received a disappointing regulatory ruling in Kansas.** The negotiated unanimous settlement, which is currently pending approval by the Kansas Corporation Commission, fell short of the utility's expectations. Under the settlement agreement, Kansas Central will receive a net revenue increase of $74 million (3.5%) compared to the subsidiary's initial request of $204 million (9.8%). Too, Kansas Metro, which requested a hike of $14 million (2%), is set to receive a net revenue decrease of $32.9 million (-4.5%). The ruling, if approved, will hurt the company's forward plan by approximately $0.15 a share and go into effect by December 21st, 2023. Evergy plans to continue filing rate cases in Kansas and Missouri every two years.

**The board of directors raised the dividend, effective with the December payment.** The increase was $0.12 a share (5%) annually. The utility's target for the payout ratio is a range of 60%-70%. The yield of 5.1% now sits comfortably above the utility average, which is one of the highest dividend-paying industries in the market.

**This stock is best suited for income-oriented investors.** What's more, 18-month and 3- to 5-year capital appreciation potential remains attractive for a utility. Indeed, we look for the stock to trade within a range of $70-$100 out to 2026-2028. Meanwhile, the Timeliness rank sits at just 3 (Average).

*Zachary J. Hodgkinson December 8, 2023*

(A) Diluted earnings. Next earnings report due mid Feb. (B) Dividends paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. (C) Incl. intangibles. (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, '22: 9.8%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 90 |
| Price Growth Persistence | 35 |
| Earnings Predictability | 85 |

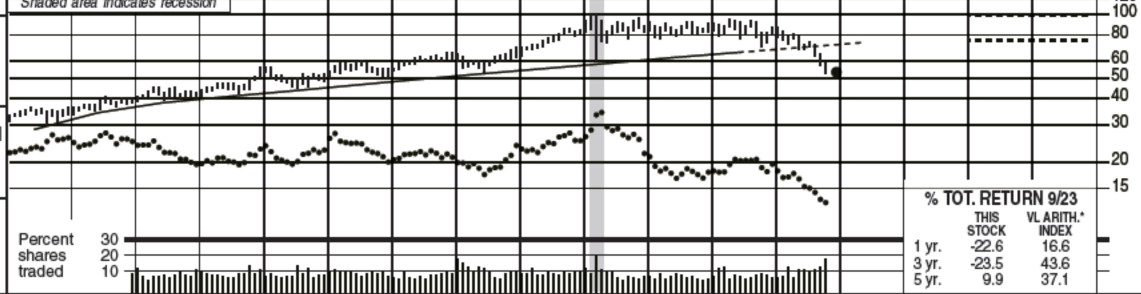
# EVERSOURCE ENERGY NYSE-ES

RECENT PRICE 53.39 | P/E RATIO 12.2 (Trailing: 12.3; Median: 19.0) | RELATIVE P/E RATIO 0.81 | DIV'D YLD 5.3% | VALUE LINE

TIMELINESS 3 Raised 10/20/23
SAFETY 2 Lowered 5/12/23
TECHNICAL 4 Lowered 11/10/23
BETA .90 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 40.9 | 45.7 | 56.7 | 56.8 | 60.4 | 66.1 | 70.5 | 86.6 | 99.4 | 92.7 | 94.6 | 86.8 |
| Low: | 33.5 | 38.6 | 41.3 | 44.6 | 50.0 | 54.1 | 52.8 | 63.1 | 60.7 | 76.6 | 70.5 | 52.2 |

LEGENDS
— 25.6 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2026 | 2027 | 2028

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $57-$111 | $84 (55%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 100 | (+85%) | *20%* |
| Low | 75 | (+40%) | *13%* |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 444 | 399 | 379 |
| to Sell | 316 | 351 | 375 |
| Hld's(000) | 279271 | 295013 | 283976 |

Percent shares traded 30 20 10

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -22.6 | 16.6 |
| 3 yr. | -23.5 | 43.6 |
| 5 yr. | 9.9 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 28.64 | 35.27 | *37.00* | *38.75* | Revenues per sh | *43.05* |
| 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 | 6.99 | 7.74 | 8.79 | *9.05* | *9.30* | "Cash Flow" per sh | *10.70* |
| 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 | 3.64 | 3.86 | 4.09 | *4.35* | *4.60* | Earnings per sh A | *5.55* |
| .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 | 2.55 | *2.70* | *2.86* | Div'd Decl'd per sh B ■ | *3.42* |
| 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 | 9.22 | 9.88 | *11.50* | *11.25* | Cap'l Spending per sh | *10.50* |
| 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 | 42.39 | 44.41 | *45.45* | *47.65* | Book Value per sh C | *54.50* |
| 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 | 344.40 | 348.44 | *351.50* | *355.00* | Common Shs Outst'g D | *360.00* |
| 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 | 23.7 | 22.2 | 20.9 | *Bold figures are* | | Avg Ann'l P/E Ratio | *16.0* |
| .99 | .82 | .80 | .85 | .97 | 1.27 | .95 | .94 | .91 | .98 | .98 | 1.01 | 1.18 | 1.22 | 1.20 | 1.21 | *Value Line* | | Relative P/E Ratio | *.90* |
| 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% | 3.0% | *estimates* | | Avg Ann'l Div'd Yield | *3.9%* |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $24822 mill. **Due in 5 Yrs** $8012.9 mill.
**LT Debt** $22161 mill. **LT Interest** $687.0 mill.
(Total Interest coverage: 3.7x)

**Leases, Uncapitalized** Annual rentals $10.3 mill.

**Pension Assets-12/22** $5806.4 mill.
**Oblig** $5220.1 mill.
**Pfd Stock** $155.6 mill. **Pfd Div'd** $7.6 mill.

**Common Stock** 349,085,815 shs.
**as of 7/31/23**
**MARKET CAP: $18.6 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7301.2 | 7741.9 | 7954.8 | 7639.1 | 7752.0 | 8448.2 | 8526.5 | 8904.4 | 9863.1 | 12289 | *13000* | *13750* | Revenues ($mill) | *15500* |
| 793.7 | 827.1 | 886.0 | 949.8 | 995.5 | 1040.5 | 1121.0 | 1244.8 | 1337.7 | 1427.4 | *1535* | *1640* | Net Profit ($mill) | *2015* |
| 35.0% | 36.2% | 37.9% | 36.9% | 36.8% | 21.7% | 19.7% | 22.2% | 21.9% | 24.3% | *24.0%* | *24.0%* | Income Tax Rate | *24.0%* |
| 1.4% | 2.4% | 2.9% | 3.9% | 4.7% | 6.1% | 6.3% | 5.3% | 4.2% | 4.8% | *5.0%* | *5.0%* | AFUDC % to Net Profit | *5.0%* |
| 44.3% | 45.9% | 45.6% | 44.8% | 51.2% | 52.4% | 52.8% | 52.4% | 54.2% | 56.3% | *57.0%* | *57.0%* | Long-Term Debt Ratio | *56.5%* |
| 54.8% | 53.2% | 53.6% | 54.4% | 48.2% | 46.9% | 46.6% | 47.1% | 45.3% | 43.3% | *42.5%* | *42.5%* | Common Equity Ratio | *43.0%* |
| 17544 | 18738 | 19313 | 19697 | 23018 | 24474 | 27097 | 29842 | 32233 | 35763 | *37600* | *39600* | Total Capital ($mill) | *45600* |
| 17576 | 18647 | 19892 | 21351 | 23617 | 25610 | 27585 | 30883 | 33378 | 36113 | *38725* | *41200* | Net Plant ($mill) | *48000* |
| 5.5% | 5.3% | 5.5% | 5.8% | 5.2% | 5.2% | 5.1% | 5.1% | 5.1% | 5.0% | *5.0%* | *5.0%* | Return on Total Cap'l | *5.5%* |
| 8.1% | 8.2% | 8.4% | 8.7% | 8.9% | 8.9% | 8.8% | 8.8% | 9.1% | 9.1% | *9.5%* | *9.5%* | Return on Shr. Equity | *10.0%* |
| 8.2% | 8.2% | 8.5% | 8.8% | 8.9% | 9.0% | 8.8% | 8.8% | 9.1% | 9.2% | *9.5%* | *9.5%* | Return on Com Equity E | *10.0%* |
| 3.4% | 3.5% | 3.4% | 3.5% | 3.5% | 3.4% | 3.6% | 3.5% | 3.6% | 3.6% | *3.5%* | *3.5%* | Retained to Com Eq | *4.0%* |
| 59% | 58% | 61% | 60% | 61% | 62% | 60% | 60% | 61% | 61% | *62%* | *62%* | All Div'ds to Net Prof | *62%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -2.7 | +1.6 | +.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) | NA | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +.8 | +.6 | NA |
| Fixed Charge Cov. (%) | 352 | 355 | 317 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 2.0% | 4.0% | *6.0%* |
| "Cash Flow" | 5.0% | 7.5% | *5.5%* |
| Earnings | 6.5% | 5.5% | *6.0%* |
| Dividends | 7.5% | 6.0% | *6.0%* |
| Book Value | 5.5% | 4.5% | *4.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 2374 | 1953 | 2344 | 2234 | 8904 |
| 2021 | 2826 | 2123 | 2433 | 2482 | 9863 |
| 2022 | 3471 | 2573 | 3216 | 3030 | 12289 |
| 2023 | 3796 | 2629 | *3375* | *3200* | *13000* |
| 2024 | *3950* | *2850* | *3550* | *3400* | *13750* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1.02 | .76 | 1.01 | .85 | 3.64 |
| 2021 | 1.15 | .79 | 1.02 | .91 | 3.86 |
| 2022 | 1.30 | .86 | 1.01 | .92 | 4.09 |
| 2023 | 1.41 | 1.00 | *1.00* | *.94* | *4.35* |
| 2024 | *1.45* | *1.00* | *1.10* | *1.05* | *4.60* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .535 | .535 | .535 | .535 | 2.14 |
| 2020 | .5675 | .5675 | .5675 | .5675 | 2.27 |
| 2021 | .6025 | .6025 | .6025 | .6025 | 2.41 |
| 2022 | .6375 | .6375 | .6375 | .6375 | 2.55 |
| 2023 | .675 | .675 | .675 | | |

**BUSINESS:** Eversource Energy (formerly Northeast Utilities) is the parent of 12 regulated utilities with 4.4 million electric, natural gas, and water customers. Supplies power to most of Connecticut and gas to part of CT; 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, 53%; commercial/indus'l/other, 47%. Fuel costs: 41% of revs. '22 reported depr. rate: 3.6%. Employs 9,626. Chrmn.: James J. Judge. Pres. & CEO: Joseph R. Nolan, Jr. Inc.: MA. Addr.: 300 Cadwell Drive, Springfield, MA 01104. Telephone: 413-785-5871. Internet: www.eversource.com.

**Eversource Energy stock has been among the worst performers in the electric utilities space, largely due to its involvement in offshore wind generation.** The shares are down about 36% in value this year, 20 percentage points worse than the peer-group median. The company concluded a strategic review and decided to divest its risky offshore wind assets, which on paper no longer look as profitable as they once did (due to rising financing and development costs). In September, Eversource sold its stake in undeveloped offshore leased areas to its joint-venture partner Orsted for $625 million. The three projects under development will continue to receive funding as the company negotiates the details of a sale with multiple parties. A $331 million nonrecurring impairment charge was booked in the second quarter to account for a likely loss on the exit of these assets. The company's total offshore wind investment after accounting for the impairment charge is approximately $2.1 billion as of mid-year 2023. Investors are fearful of more bad news such as further impairment charges.

**Eversource looks poised for solid intermediate-term earnings gains.** In Massachusetts, higher electric delivery charges went into effect at the start of this year, with $64 million to be phased in through the end of this year, and additional increases based on inflation, maintenance, and transmission & distribution (T&D) project spending in place thereafter. Although the company's authorized return on equity (ROE) for its electric rate base was cut to 9.8% from 10% in Massachusetts, the nearly real-time formulaic pricing adjustments received ought to go a long way towards reducing regulatory lag and delivering a reliable stream of revenue growth.

**This equity is trading at an appealing valuation relative to peers.** ES stock's underperformance versus the industry median translates to $6 billion of market capitalization lost, whereas the entire offshore wind investment was $2.4 billion at mid-year with $625 million recouped from the leased area sale. Further impairment charges may be on the way, implying a poor sales price for remaining wind assets, but Eversource's plunge looks overdone.

*Anthony J. Glennon* *November 10, 2023*

(A) Diluted EPS. Excl. nonrecur. gain/(losses): '08, (19¢); '10, 9¢; '19, (64¢); '20, (9¢); '21, (32¢); '22, (4¢). 1Q-2Q '23, (96¢). Next egs. report due mid-Feb. Quarterly figures may not sum to full year due to rounding. (B) Div'ds paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '22: $25.16/sh. (D) In mill. (E) Rate allowed on com. eq. in MA: (elec.) '22, 9.8%; (gas) '20, 9.7%-9.9%; in CT: (elec.) '18, 9.25%; (gas) '18, 9.3%; in NH: '21, 9.3%; Regulatory Climate: CT, Below Avg.; NH, Avg.; MA, Above Avg.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 85 |
| Price Growth Persistence | 65 |
| Earnings Predictability | 100 |

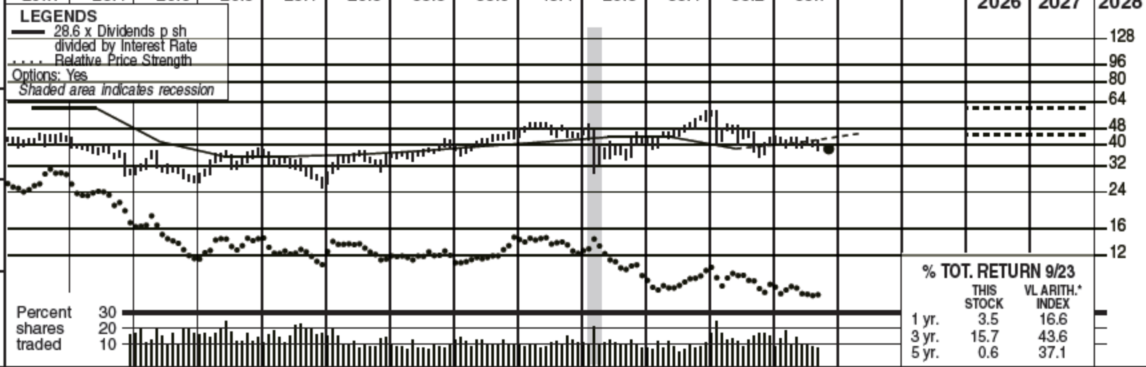
# EXELON CORP. NDQ-EXC

RECENT PRICE 38.45 | P/E RATIO 15.4 (Trailing: 16.8, Median: 14.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS – Suspended 2/4/22
SAFETY 2 Raised 8/13/21
TECHNICAL – Suspended 2/4/22
BETA NMF (1.00 = Market)

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 43.7 | 37.8 | 38.9 | 38.3 | 37.7 | 42.7 | 47.4 | 51.2 | 50.5 | 58.0 | 58.2 | 44.4 |
| Low: | 28.4 | 26.6 | 26.5 | 25.1 | 26.3 | 33.3 | 35.6 | 43.4 | 29.3 | 38.4 | 35.2 | 35.7 |

Target Price Range 2026 | 2027 | 2028




**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $32-$51 | $42 (10%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 60 | (+55%) | 15% |
| Low | 45 | (+15%) | 8% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 494 | 474 | 438 |
| to Sell | 421 | 378 | 411 |
| Hld's(000) | 816073 | 809770 | 812887 |

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | 3.5 | 16.6 |
| 3 yr. | 15.7 | 43.6 |
| 5 yr. | 0.6 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 37.13 | 19.19 | 19.80 | 20.20 | Revenues per sh | 21.50 |
| 7.43 | 7.64 | 8.25 | 8.32 | 7.23 | 6.61 | 6.72 | 6.61 | 6.80 | 7.88 | 8.37 | 9.29 | 9.17 | 9.65 | 10.56 | 6.07 | 6.75 | 7.00 | "Cash Flow" per sh | 7.50 |
| 4.03 | 4.10 | 4.29 | 3.87 | 3.75 | 1.92 | 2.31 | 2.10 | 2.54 | 2.68 | 2.78 | 3.12 | 3.22 | 3.22 | 2.82 | 2.26 | 2.40 | 2.50 | Earnings per sh A | 3.00 |
| 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 | 1.44 | 1.60 | Div'd Decl'd per sh B ■ | 1.80 |
| 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 | 8.15 | 7.19 | 6.80 | 6.80 | Cap'l Spending per sh | 7.00 |
| 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 | 35.13 | 24.89 | 25.20 | 25.20 | Book Value per sh C | 28.75 |
| 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 | 979.00 | 994.00 | 995.00 | 1000.00 | Common Shs Outst'g D | 1000.0 |
| 18.2 | 18.0 | 11.5 | 11.0 | 11.3 | 19.1 | 13.4 | 16.0 | 12.6 | 12.5 | 13.4 | 13.3 | 14.7 | 12.4 | 16.6 | 19.9 | Bold figures are | | Avg Ann'l P/E Ratio | 17.5 |
| .97 | 1.08 | .77 | .70 | .71 | 1.22 | .75 | .84 | .63 | .66 | .67 | .72 | .78 | .64 | .90 | 1.15 | Value Line | | Relative P/E Ratio | .95 |
| 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% | 3.2% | estimates | | Avg Ann'l Div'd Yield | 3.5% |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $42233 mill. **Due in 5 Yrs** $12334 mill.
**LT Debt** $39492 mill. **LT Interest** $1450 mill.
Includes $390 mill. nonrecourse transition bonds.
(Interest coverage: 2.7x)
**Leases, Uncapitalized** Annual rentals $156 mill.

**Pension Assets-12/22** $20827 mill. **Oblig** $23846 mill.

**Pfd Stock** None

**Common Stock** 995,219,195 shs. as of 6/30/23
**MARKET CAP: $38.3 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 24888 | 27429 | 29447 | 31360 | 33531 | 35985 | 34438 | 33039 | 36347 | 19078 | 19700 | 20200 | Revenues ($mill) | 21500 |
| 1999.0 | 1826.0 | 2282.0 | 2488.0 | 2636.0 | 3026.0 | 3139.0 | 3149.0 | 2764.0 | 2246.4 | 2400 | 2500 | Net Profit ($mill) | 3000 |
| 36.5% | 27.2% | 32.2% | 38.5% | 34.2% | 11.1% | 19.4% | 17.4% | 16.1% | 14.5% | 15.0% | 15.0% | Income Tax Rate | 15.0% |
| 4.5% | 5.5% | 5.4% | 8.3% | 6.5% | 4.6% | 5.0% | 5.5% | 7.4% | 7.0% | 6.0% | 5.0% | AFUDC % to Net Profit | 5.0% |
| 44.4% | 46.7% | 48.3% | 55.5% | 52.2% | 52.8% | 49.6% | 52.1% | 50.9% | 59.9% | 61.0% | 61.0% | Long-Term Debt Ratio | 64.5% |
| 55.2% | 52.8% | 51.3% | 44.5% | 47.8% | 47.2% | 50.4% | 47.9% | 49.1% | 40.2% | 39.0% | 39.0% | Common Equity Ratio | 35.5% |
| 41196 | 42811 | 50272 | 58053 | 62422 | 65229 | 63943 | 68068 | 70107 | 58836 | 64125 | 64125 | Total Capital ($mill) | 81000 |
| 47330 | 52087 | 57439 | 71555 | 74202 | 76707 | 80233 | 82584 | 84219 | 69076 | 69175 | 69175 | Net Plant ($mill) | 77600 |
| 5.9% | 5.3% | 5.5% | 5.5% | 5.3% | 5.7% | 6.0% | 5.7% | 5.0% | 5.0% | 5.0% | 5.0% | Return on Total Cap'l | 5.0% |
| 8.7% | 8.0% | 8.8% | 9.6% | 8.8% | 9.8% | 9.7% | 9.7% | 8.0% | 9.5% | 9.5% | 10.0% | Return on Shr. Equity | 10.0% |
| 8.7% | 8.0% | 8.8% | 9.6% | 8.8% | 9.8% | 9.7% | 9.7% | 8.0% | 9.5% | 9.5% | 10.0% | Return on Com Equity E | 10.0% |
| 3.2% | 3.3% | 4.5% | 5.1% | 4.7% | 5.5% | 5.4% | 5.1% | 3.7% | 4.0% | 4.0% | 4.0% | Retained to Com Eq | 4.0% |
| 63% | 59% | 49% | 47% | 47% | 44% | 45% | 47% | 54% | 60% | 60% | 60% | All Div'ds to Net Prof | 60% |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % 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 (Mw) | NA | NA | NA |
| Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +.7 | +.6 | NA |
| Fixed Charge Cov. (%) | 211 | 237 | 325 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 2.5% | 1.0% | NMF |
| "Cash Flow" | 3.0% | 5.5% | NMF |
| Earnings | -.5% | 2.5% | NMF |
| Dividends | -3.0% | 4.0% | NMF |
| Book Value | 4.5% | 3.5% | NMF |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 8747 | 7322 | 8853 | 8117 | 33039 |
| 2021 | 9890 | 7915 | 8910 | 9632 | 36347 |
| 2022 | 5327 | 4239 | 4845 | 4667 | 19078 |
| 2023 | 5563 | 4818 | 4900 | 4419 | 19700 |
| 2024 | 5300 | 4850 | 5500 | 4550 | 20200 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .87 | .55 | 1.04 | .76 | 3.22 |
| 2021 | d.06 | .89 | 1.09 | .90 | 2.82 |
| 2022 | .64 | .44 | .75 | .43 | 2.26 |
| 2023 | .70 | .41 | .79 | .50 | 2.40 |
| 2024 | .70 | .50 | .80 | .50 | 2.50 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .3625 | .3625 | .3625 | .3625 | 1.45 |
| 2020 | .3825 | .3825 | .3825 | .3825 | 1.53 |
| 2021 | .3825 | .3825 | .3825 | .3825 | 1.53 |
| 2022 | .3375 | .3375 | .3375 | .3375 | 1.35 |
| 2023 | .360 | .360 | .360 | | |

**BUSINESS:** Exelon Corporation is a holding company for Commonwealth Edison (ComEd), PECO Energy, Baltimore Gas and Electric (BGE), Pepco, Delmarva Power (DPL), & Atlantic City Electric (ACE). Has 9.1 mill. elec., 1.3 mill. gas customers. Spun off Constellation Energy (nonregulated generating & energy-marketing ops.) 2/22. Acq'd Constellation Energy 3/12; Pepco Holdings 3/16. Elec. rev. breakdown: residntl., 54%; small commercl. & indstrl., 16%; large commercl. & indstrl., 17%; other, 13%. Fuel costs: 48% of revs. '22 deprec. rates: 2.8%-8.7% elec., 2.1% gas. Has 18,700 empls. Chrmn.: John F. Young. CEO: Calvin Butler. Inc.: PA. Addr.: 10 S.Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

**Exelon's Commonwealth Edison (ComEd) unit reached a deal with Constellation Energy to power its Illinois facilities with 100% hourly-matched carbon-free nuclear energy.** ComEd will become the first U.S. publicly-traded utility to supply its facilities with 100% clean energy produced in the same time and area it is consumed. We think the deal will benefit the utility's long-term clean energy transition targets, including its goal of 100% clean energy by 2050, while also reducing carbon emissions and the use of fossil fuels hourly. What's more, the U.S. Department of Energy recently awarded Exelon and Constellation Energy up to $1 billion in federal grants to accelerate the development of hydrogen hubs.

**We look for moderate profit growth over the next few years.** Exelon should continue to take advantage of additional revenues from regulatory mechanisms, rate relief, and higher distribution rates as an entirely regulated utility. As a result, our 2023 estimate is on the high end of Exelon's updated targeted range of $2.30-$2.42 per share. (The company was set to report third-quarter results shortly after this report went to press.) We look for solid second-half financial results, as earnings should remain less volatile moving forward due to the recent spinoff of its non-regulated power-generating assets.

**These shares have dropped 10% in value since our August review, along with many of its peers in the utilities industry.** Rising Treasury yields and increased competition in the bond market have put utility stocks under selling pressure, of late. Indeed, the S&P Utility Index (XLU) is down more than 15% the past year to date, marking the sector's largest annual loss on record.

**This issue may be suitable for conservative, income-oriented accounts.** The stock has an average dividend yield for a utility. Exelon is also ranked 2 (Above Average) for Safety, has a strong financial position, and is generally considered to be a solid addition to a well-rounded portfolio. However, even with the aforementioned share price drop, both 18-month and 3- to 5-year capital appreciation potential are nothing to write home about.

*Zachary J. Hodgkinson November 10, 2023*

(A) Dil. egs. Excl. nonrec. gain (loss): '09, (20¢); '12, (50¢); '13, (31¢); '14, (22¢); '16, ($1.46); '17, $1.19; '18, ($1.05); '19, (21¢); '20, ($1.21); '21, ($1.08); disc. ops. gain (loss): '07, 2¢; '08, 3¢. Next egs. report: Feb. (B) Div'ds paid in early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. deferred charges. In '22: $15.20/sh. (D) In mill. (E) Rate allowed on common equity in IL in '15: 9.25%; in MD in '16: 9.75% elec., 9.65% gas; Regulatory Climate: PA, NJ: Average; IL, MD: Below Avg.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | NMF |
| Price Growth Persistence | NMF |
| Earnings Predictability | NMF |

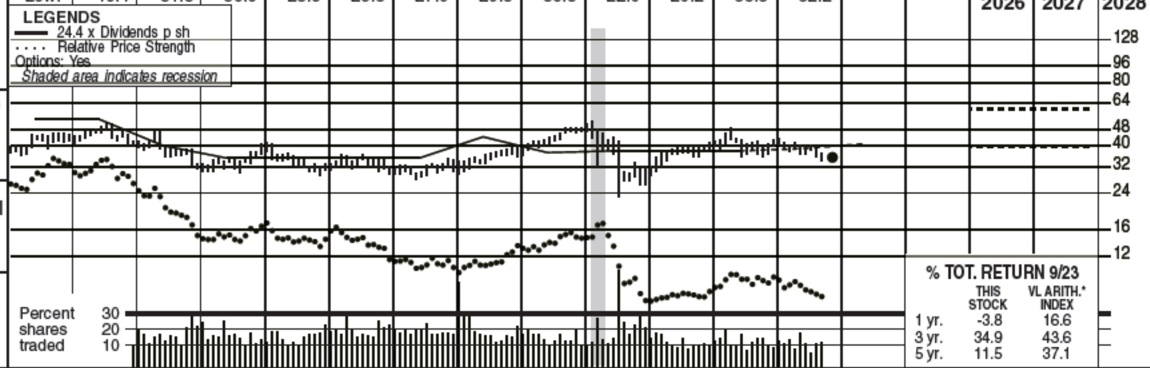
# FIRSTENERGY NYSE-FE

RECENT PRICE 35.40 | P/E RATIO 13.4 (Trailing: 14.4 Median: 13.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 3 Raised 11/10/23
SAFETY 3 Lowered 7/31/20
TECHNICAL 4 Lowered 10/20/23
BETA .85 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 51.1 | 46.8 | 40.8 | 41.7 | 36.6 | 35.2 | 39.9 | 49.1 | 52.5 | 41.8 | 48.8 | 43.3 |
| Low: | 40.4 | 31.3 | 30.0 | 28.9 | 29.3 | 27.9 | 29.3 | 36.3 | 22.9 | 29.2 | 35.3 | 32.2 |

LEGENDS
— 24.4 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession




**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $30-$54 | $42 (20%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 60 | (+70%) | 17% |
| Low | 40 | (+15%) | 7% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 379 | 342 | 301 |
| to Sell | 271 | 289 | 334 |
| Hld's(000) | 462656 | 463591 | 472563 |

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -3.8 | 16.6 |
| 3 yr. | 34.9 | 43.6 |
| 5 yr. | 11.5 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 19.52 | 21.78 | **22.65** | **23.75** | Revenues per sh | **26.50** |
| 8.34 | 9.04 | 8.80 | 8.50 | 5.75 | 6.05 | 6.30 | 6.26 | 7.04 | 7.04 | 6.54 | 5.19 | 4.80 | 4.59 | 5.41 | 4.71 | **4.70** | **4.95** | "Cash Flow" per sh | **5.80** |
| 4.22 | 4.38 | 3.32 | 3.25 | 1.88 | 2.13 | 2.97 | 2.56 | 2.71 | 2.63 | 2.73 | 2.59 | 2.56 | 2.39 | 2.60 | 2.41 | **2.55** | **2.70** | Earnings per sh A | **3.20** |
| 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 | **1.60** | **1.69** | Div'd Decl'd per sh B ■ | **2.02** |
| 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 | 4.29 | 4.82 | **5.90** | **6.05** | Cap'l Spending per sh | **6.50** |
| 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 | 15.21 | 17.77 | **18.80** | **19.90** | Book Value per sh C | **23.50** |
| 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 | 570.26 | 572.13 | **574.50** | **577.00** | Common Shs Outst'g D | **585.00** |
| 15.6 | 15.6 | 13.0 | 11.7 | 22.4 | 21.1 | 13.1 | 13.2 | 12.6 | 12.7 | 11.4 | 13.6 | 17.1 | 15.7 | 14.1 | 17.0 | *Bold figures are* | | Avg Ann'l P/E Ratio | **15.5** |
| .83 | .94 | .87 | .74 | 1.41 | 1.34 | .74 | .69 | .63 | .67 | .57 | .73 | .91 | .81 | .76 | .99 | *Value Line* | | Relative P/E Ratio | **.85** |
| 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% | 3.8% | *estimates* | | Avg Ann'l Div'd Yield | **4.1%** |

**CAPITAL STRUCTURE as of 9/30/23**
**Total Debt** $24454 mill. **Due in 5 Yrs** $6699 mill.
**LT Debt** $22882 mill. **LT Interest** $1025 mill.
Incl. $23 mill. finance leases.
(Total Interest coverage: 2.8x)
**Leases, Uncapitalized** Annual rentals $56 mill.

**Pension Assets-12/22** $6693 mill. **Oblig** $8828 mill.

**Pfd Stock** None

**Common Stock** 573,814,823 shs.

**MARKET CAP: $20.3 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 14903 | 15049 | 15029 | 14562 | 14022 | 11261 | 11035 | 10790 | 11132 | 12459 | **13000** | **13700** | Revenues ($mill) | **15500** |
| 1245.0 | 1074.0 | 1144.0 | 1118.0 | 1213.0 | 1346.0 | 1380.0 | 1296.0 | 1419.0 | 1377.0 | **1475** | **1560** | Net Profit ($mill) | **1880** |
| 36.1% | 28.4% | 35.8% | 37.4% | 37.2% | 28.5% | 19.8% | 13.6% | 20.6% | 48.1% | **17.5%** | **19.0%** | Income Tax Rate | **21.0%** |
| 6.0% | 11.0% | 10.2% | 9.2% | 6.5% | 4.8% | 5.1% | 5.9% | 5.3% | 6.1% | **6.0%** | **6.0%** | AFUDC % to Net Profit | **6.0%** |
| 55.5% | 60.7% | 60.7% | 74.5% | 84.3% | 72.3% | 73.8% | 75.4% | 71.9% | 67.6% | **67.0%** | **66.0%** | Long-Term Debt Ratio | **61.5%** |
| 44.5% | 39.3% | 39.3% | 25.5% | 15.7% | 27.4% | 26.2% | 24.6% | 28.1% | 32.4% | **33.0%** | **34.0%** | Common Equity Ratio | **38.5%** |
| 28523 | 31596 | 31613 | 24433 | 25040 | 24565 | 26593 | 29368 | 30923 | 31369 | **32875** | **33550** | Total Capital ($mill) | **35900** |
| 33252 | 35783 | 37214 | 29387 | 28879 | 29911 | 31650 | 33294 | 34744 | 36285 | **38525** | **39650** | Net Plant ($mill) | **46600** |
| 6.0% | 5.0% | 5.3% | 6.6% | 7.0% | 7.4% | 6.8% | 6.0% | 6.2% | 5.9% | **6.0%** | **6.0%** | Return on Total Cap'l | **6.5%** |
| 9.8% | 8.6% | 9.2% | 17.9% | 30.9% | 19.8% | 19.8% | 17.9% | 16.4% | 13.5% | **13.5%** | **13.5%** | Return on Shr. Equity E | **13.5%** |
| 9.8% | 8.6% | 9.2% | 17.9% | 30.9% | 18.9% | 19.7% | 17.9% | 16.4% | 13.5% | **13.5%** | **13.5%** | Return on Com Equity E | **13.5%** |
| 2.6% | 3.8% | 4.3% | 8.1% | 14.6% | 8.4% | 8.1% | 6.2% | 6.6% | 4.8% | **5.0%** | **5.0%** | Retained to Com Eq | **5.0%** |
| 74% | 56% | 53% | 55% | 53% | 58% | 59% | 65% | 60% | 65% | **63%** | **63%** | All Div'ds to Net Prof | **63%** |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (MWH) | -4.0 | +2.4 | +1.5 |
| Residential Use (MWH) | 54978 | 55624 | 55995 |
| Commercial Use (MWH) | 34811 | 35599 | 36317 |
| Industrial Use (MWH) | 52034 | 54027 | 55169 |
| Tot. Electric Deliv'd (MWH) | 141823 | 145250 | 147481 |
| Peak Load Summer (Mw) | NA | NA | NA |
| % Change Customers (yr-end) | +.6 | +.4 | +.4 |
| Fixed Charge Cov. (%) | 203 | 171 | 291 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -6.5% | -9.5% | 4.5% |
| "Cash Flow" | -3.0% | -6.5% | 3.0% |
| Earnings | - - | -1.5% | 4.5% |
| Dividends | -3.5% | 1.5% | 4.5% |
| Book Value | -6.5% | -2.5% | 7.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 2709 | 2522 | 3022 | 2537 | 10790 |
| 2021 | 2726 | 2622 | 3124 | 2660 | 11132 |
| 2022 | 2989 | 2818 | 3475 | 3177 | 12459 |
| 2023 | 3231 | 3006 | 3487 | **3276** | **13000** |
| 2024 | **3350** | **3125** | **3725** | **3500** | **13700** |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .66 | .57 | .84 | .32 | 2.39 |
| 2021 | .69 | .59 | .82 | .51 | 2.60 |
| 2022 | .60 | .53 | .79 | .50 | 2.41 |
| 2023 | .60 | .47 | .88 | **.60** | **2.55** |
| 2024 | **.65** | **.52** | **.91** | **.62** | **2.70** |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .38 | .38 | .38 | .38 | 1.52 |
| 2020 | .39 | .39 | .39 | .39 | 1.56 |
| 2021 | .39 | .39 | .39 | .39 | 1.56 |
| 2022 | .39 | .39 | .39 | .39 | 1.56 |
| 2023 | .39 | .39 | .39 | .41 | |

**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 6.214 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown: residential, 57.2%; commercial, industrial & other, 42.8%. Purchases most of its power. Power costs: 36.9% of revenues. 2022 reported depreciation rate: 2.7%. Has 12,335 employees. Chair: John W. Somerhalder II. President and CEO: Brian X. Tierney. Incorporated: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Telephone: 800-736-3402. Internet: www.firstenergycorp.com.

**In time, FirstEnergy's Safety rank and Financial Strength grade are likely to improve.** In 2021, the company settled its bribery charges with federal prosecutors and Ohio regulators. After this year, payments of $45 million in 2024 and $25 million in 2025, both excluded from our adjusted (non-GAAP) earnings presentation, should be all that remain. New leadership continues to cooperate with federal prosecutors as the DPA (i.e., deferred prosecution agreement) concludes next July. Equity injections of $1 billion were received in late 2021, followed by the mid-2022 sale of a minority interest in the company's long-range transmission assets for $2.38 billion. Fitch restored FirstEnergy's credit rating to investment grade last year and further upgrades should eventually follow in 2024, as the DPA concludes and the company completes the sale of another minority interest for $3.5 billion (expected closing date in early 2024). Notably, FirstEnergy will retain nearly 70% of its overall transmission portfolio (relative to where it was prior to 2022).

**The company appears on target for healthy annual earnings gains this year and next.** Following a solid third-quarter showing, management updated its 2023 operating earnings projection, narrowing the range to $2.49-$2.59 per share from $2.44-$2.64. Seasonally mild weather and pension contributions, due to last year's weak stock and bond markets, were once again headwinds. The company was able to significantly lower operating and maintenance expense, however, by leveraging the flexibility and strengths of its vast Mid-Atlantic to Midwest service area. Next year, FirstEnergy should benefit more from rate relief. A favorable outcome was recently concluded in the Maryland rate case, while settlement talks are still underway in West Virginia and New Jersey. Base rate cases will likely be filed in Ohio and Pennsylvania next year.

**FirstEnergy's board increased the quarterly dividend 5%.** The payout target was lifted to 60%-70% of income earlier this year. Yearly increases, commensurate with annual earnings gains of 6% (from this year's base), are likely to follow. The yield is 40 basis points above the industry median, while some risks are subsiding.

*Anthony J. Glennon* *November 10, 2023*

(A) Dil. EPS. Excl. nonrec. loss: '13, $2.07; '14, $2.05; '15, $1.34; '16, $17.12; '17, $6.61; '18, $1.26; '19, 89¢; '20, 54¢; '21, 33¢; '22, $1.70; '23, 28¢; gains from disc. ops.: '18, 66¢; '20, 14¢; '21, 8¢. Qtrly. EPS don't sum due to chg. in shs. Next egs. report due Jan. (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 '22: $9.88/sh. (D) In mill. (E) High ROE from large writeoffs. Rate base: Depr. orig. cost. Rates all'd on com. eq.: 9.6-11.7%; Reg.: 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 | 100 |

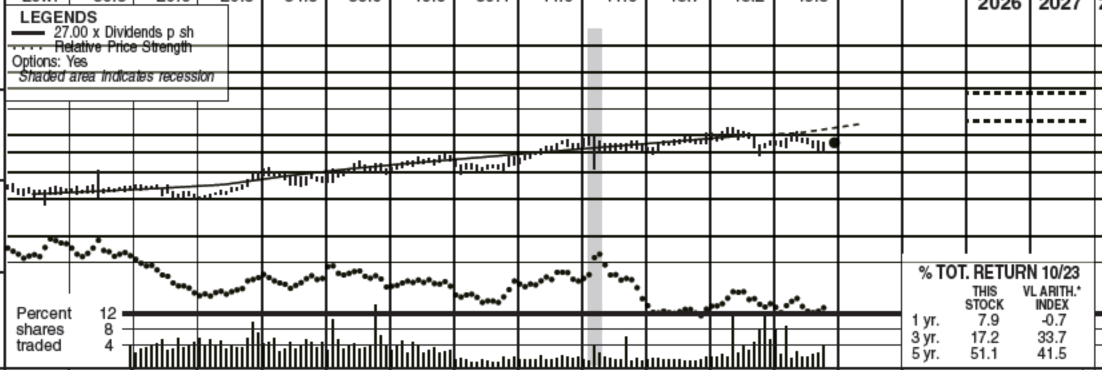
# FORTIS INC. TSE-FTS.TO A

RECENT PRICE 55.50 | P/E RATIO 19.6 (Trailing: 18.0 Median: 20.0) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 3 Raised 10/20/23
SAFETY 2 Raised 7/17/15
TECHNICAL 3 Raised 12/1/23
BETA .70 (1.00 = Market)

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 40.7 | 35.1 | 40.5 | 42.1 | 45.1 | 48.7 | 47.4 | 56.9 | 59.3 | 61.6 | 65.4 | 62.1 |
| Low: | 30.5 | 29.6 | 29.8 | 34.5 | 36.0 | 40.6 | 39.4 | 44.0 | 41.6 | 48.7 | 48.2 | 49.8 |

LEGENDS
27.00 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession



**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $48-$78 | $63 (15%) |

Target Price Range 2026 | 2027 | 2028

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 95 | (+70%) | 17% |
| Low | 70 | (+25%) | 10% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 134 | 129 | 120 |
| to Sell | 123 | 119 | 107 |
| Hld's(000) | 240882 | 241164 | 244100 |

Percent shares traded 12 8 4

**% TOT. RETURN 10/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | 7.9 | -0.7 |
| 3 yr. | 17.2 | 33.7 |
| 5 yr. | 51.1 | 41.5 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 22.90 | *22.50* | *23.25* | Revenues per sh | *25.10* |
| 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 | 6.24 | *6.40* | *6.60* | "Cash Flow" per sh | *7.50* |
| 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 | 2.78 | *2.90* | *3.10* | Earnings per sh B | *3.75* |
| .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 | 2.17 | *2.29* | *2.53* | Div'd Decl'd per sh C ■ | *2.80* |
| 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 | 7.02 | *7.85* | *8.25* | Cap'l Spending per sh | *8.25* |
| 16.72 | 18.00 | 18.57 | 18.95 | 20.53 | 20.84 | 22.39 | 24.90 | 28.63 | 32.32 | 31.77 | 34.80 | 36.49 | 36.58 | 37.21 | 36.44 | *39.25* | *40.50* | Book Value per sh D | *46.00* |
| 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 | 482.15 | *489.00* | *495.00* | Common Shs Outst'g E | *510.00* |
| 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 | 21.1 | Bold figures are | | Avg Ann'l P/E Ratio | *21.5* |
| 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 | 1.15 | 1.22 | Value Line | | Relative P/E Ratio | *1.20* |
| 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% | 4.1% | estimates | | Avg Ann'l Div'd Yield | *3.7%* |

**CAPITAL STRUCTURE as of 9/30/23**
**Total Debt** $30123 mill. **Due in 5 Yrs** $7732 mill.
**LT Debt** $27170 mill. **LT Interest** $945 mill.
Incl. $340 mill. finance leases.
(LT interest earned: 2.4x)
**Leases, Uncapitalized** Annual rentals $8 mill.

**Pension Assets-12/22** $3722 mill. **Oblig** $3922 mill.
**Pfd Stock** $1623 mill. **Pfd Div'd** $65 mill.

**Common Stock** 488,500,000 shs.

**MARKET CAP: $27.1 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4047.0 | 5401.0 | 6727.0 | 6838.0 | 8301.0 | 8390.0 | 8783.0 | 8935.0 | 9448.0 | 11043.0 | *11000* | *11500* | Revenues ($mill) | *12800* |
| 390.0 | 374.0 | 672.0 | 660.0 | 1174.0 | 1136.0 | 1238.0 | 1274.0 | 1294.0 | 1340.4 | *1420* | *1535* | Net Profit ($mill) | *1910* |
| 7.4% | 14.6% | 21.3% | 16.9% | 25.8% | 13.4% | 12.5% | 14.3% | 14.3% | 16.0% | *14.5%* | *14.5%* | Income Tax Rate | *14.5%* |
| 5.9% | 7.2% | 7.4% | 10.0% | 9.5% | 8.4% | 9.2% | 9.3% | 9.0% | 9.0% | *8.0%* | *8.0%* | AFUDC % to Net Profit | *7.0%* |
| 53.5% | 54.8% | 53.3% | 59.3% | 58.4% | 58.8% | 54.2% | 55.6% | 55.5% | 55.0% | *53.5%* | *53%* | Long-Term Debt Ratio | *51.5%* |
| 37.0% | 35.7% | 38.1% | 36.2% | 37.1% | 37.2% | 41.8% | 40.5% | 40.8% | 41.5% | *43.0%* | *43.5%* | Common Equity Ratio | *45.0%* |
| 12892 | 19235 | 21151 | 35874 | 36108 | 40082 | 40445 | 42141 | 43328 | 44922 | *46275* | *48050* | Total Capital ($mill) | *51900* |
| 12267 | 17816 | 19595 | 29337 | 29668 | 32654 | 33988 | 35998 | 37816 | 41663 | *42250* | *43500* | Net Plant ($mill) | *48600* |
| 4.6% | 3.4% | 4.5% | 2.8% | 4.5% | 4.1% | 4.4% | 4.3% | 4.2% | 2.4% | *4.5%* | *4.5%* | Return on Total Cap'l | *5.0%* |
| 6.5% | 4.3% | 6.8% | 4.5% | 7.8% | 6.9% | 6.7% | 6.8% | 6.7% | 4.4% | *7.0%* | *7.0%* | Return on Shr. Equity | *7.5%* |
| 7.0% | 4.5% | 7.4% | 4.5% | 8.3% | 7.2% | 6.9% | 7.1% | 7.0% | 4.4% | *7.0%* | *7.0%* | Return on Com Equity F | *7.5%* |
| 3.2% | 1.7% | 4.5% | 2.1% | 5.2% | 4.1% | 4.0% | 2.5% | 3.5% | 3.5% | *3.5%* | *3.5%* | Retained to Com Eq | *4.0%* |
| 61% | 68% | 46% | 59% | 41% | 46% | 45% | 67% | 52% | 78% | *81%* | *82%* | All Div'ds to Net Prof G | *75%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % 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. (%) | 207 | 211 | 215 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | - - | -.5% | *3.5%* |
| "Cash Flow" | 3.5% | 3.5% | *5.0%* |
| Earnings | 4.5% | 3.5% | *5.0%* |
| Dividends | 5.5% | 5.5% | *6.0%* |
| Book Value | 6.5% | 3.5% | *4.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 2391 | 2077 | 2121 | 2346 | 8935 |
| 2021 | 2539 | 2130 | 2196 | 2583 | 9448 |
| 2022 | 2835 | 2487 | 2553 | 3168 | 11043 |
| 2023 | 3319 | 2594 | 2719 | *2368* | *11000* |
| 2024 | *3000* | *2500* | *2550* | *3450* | *11500* |

| Cal-endar | EARNINGS PER SHARE B Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .67 | .59 | .63 | .71 | 2.60 |
| 2021 | .76 | .54 | .62 | .69 | 2.61 |
| 2022 | .74 | .59 | .68 | .77 | 2.78 |
| 2023 | .90 | .61 | .81 | *.58* | *2.90* |
| 2024 | *.80* | *.65* | *.80* | *.85* | *3.10* |

| Cal-endar | QUARTERLY DIVIDENDS PAID C ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .45 | .45 | .45 | .4775 | 1.83 |
| 2020 | .4775 | .4775 | .4775 | .505 | 1.94 |
| 2021 | .505 | .505 | .505 | .535 | 2.05 |
| 2022 | .535 | .535 | .535 | .565 | 2.17 |
| 2023 | .565 | .565 | .565 | .590 | |

**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. '22 reported deprec. rate: 2.6%. Has 9,100 employees. Chairman: Jo Mark Zurel. 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.

**Fortis' earnings will likely advance modestly in the next few years.** The company unveiled a new $25 billion five-year capital plan, which is expected to rise to over $49 billion in 2028 due to rate base increases. The Inflation Reduction Act should also benefit earnings growth and help the transition to clean energy over that interim, as nearly 30% of the plan is allocated to cleaner energy investment focused on improving the grid and fuel solutions. Meanwhile, the utility has a number of ongoing rate cases and recent regulatory outcomes that will likely boost Fortis' annual earning power. In Arizona, Tucson Electric Power's $100 million hike request, based on a return on equity (ROE) of 9.55% and a common-equity ratio of 54%, was approved and new customer rates were implemented in September. Too, the British Columbia Utilities Commission approved an allowed ROE of 9.65% for both Fortis' utilities; Fortis BC Energy and Fortis BC Electric.

**Our 2023 and 2024 bottom-line projections are staying put at $2.90 a share and $3.10, respectively.** Fortis has a proven track record of strong financial performances of late, and we look for this to persist over the next few years. Rate base increases will probably continue to be the main driver of growth over that interim. The company's capital plan, supported by the Inflation Reduction Act, should also lead to solid long-term rate base and earnings growth. Indeed, Fortis expects a five-year annual rate base increase of 6.3%.

**The board of directors raised the dividend, effective with the December payment.** The increase was $0.025 a share quarterly, marking 50 years of consecutive dividend hikes. Fortis announced its annual dividend growth target range of 4%-6% through 2028, which we believe is very attainable.

**These shares will likely appeal to income-oriented investors as the dividend remains this issue's most notable feature.** Indeed, the yield of 4.3% sits comfortably above the utility average, which is one of the highest dividend-paying industries. Too, total return potential for the 18-month and 3- to 5-year time frames is solid compared to most of its peers.

*Zachary J. Hodgkinson December 8, 2023*

(A) Also trades on NYSE (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 early Feb. (C) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. (2% disc.). (D) Incl. intang. In '22: $34.05/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 | 55 |
| Earnings Predictability | 95 |

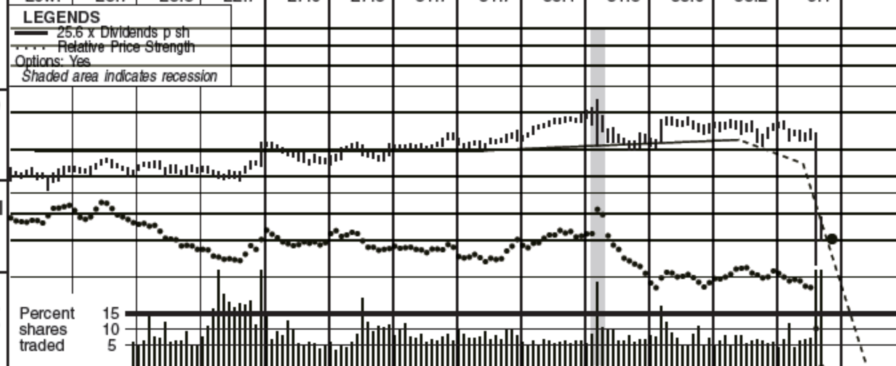
# HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE 12.11 | P/E RATIO 6.9 (Trailing: 5.8 Median: 19.0) | RELATIVE P/E RATIO 0.43 | DIV'D YLD Nil | VALUE LINE

TIMELINESS — Suspended 8/25/23
SAFETY 5 Lowered 9/15/23
TECHNICAL — Suspended 8/25/23
BETA .95 (1.00 = Market)

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 29.2 | 28.3 | 35.0 | 34.9 | 35.0 | 38.7 | 39.3 | 47.6 | 55.2 | 46.0 | 44.7 | 43.7 |
| Low: | 23.7 | 23.8 | 22.7 | 27.0 | 27.3 | 31.7 | 31.7 | 35.1 | 31.8 | 33.0 | 33.2 | 9.1 |

LEGENDS
— 25.6 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession




Target Price Range 2026 | 2027 | 2028

**18-Month Target Price Range**
Low-High Midpoint (% to Mid)
$11-$40 $26 (110%)

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 14 | (+15%) | 4% |
| Low | 8 | (-35%) | -9% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 163 | 143 | 130 |
| to Sell | 132 | 148 | 151 |
| Hld's(000) | 60941 | 58685 | 58926 |

% TOT. RETURN 9/23

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -62.4 | 16.6 |
| 3 yr. | -58.1 | 43.6 |
| 5 yr. | -58.5 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 34.18 | *34.10* | *34.70* | Revenues per sh | *35.65* |
| 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 | 4.90 | *4.55* | *4.75* | "Cash Flow" per sh | *4.20* |
| 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 | 2.20 | *1.80* | *1.90* | Earnings per sh A | *1.00* |
| 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 | *1.08* | *Nil* | Div'd Decl'd per sh B | *Nil* |
| 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 | 3.14 | *3.45* | *3.50* | Cap'l Spending per sh | *3.75* |
| 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 | 20.12 | *20.95* | *22.75* | Book Value per sh C | *25.95* |
| 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 | 109.47 | *110.00* | *111.00* | Common Shs Outst'g D | *115.00* |
| 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 | 18.5 | *Bold figures are* | | Avg Ann'l P/E Ratio | *11.0* |
| 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 | .98 | 1.07 | *Value Line* | | Relative P/E Ratio | *.60* |
| 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% | 3.4% | *estimates* | | Avg Ann'l Div'd Yield | *Nil* |
| | | | | | | 3238.5 | 3239.5 | 2603.0 | 2380.7 | 2555.6 | 2860.8 | 2874.6 | 2579.8 | 2850.4 | 3742.0 | *3750* | *3850* | Revenues ($mill) | *4100* |
| | | | | | | 163.4 | 170.2 | 161.8 | 250.1 | 180.6 | 203.7 | 219.8 | 199.7 | 248.1 | 243.0 | *200* | *210* | Net Profit ($mill) | *115* |
| | | | | | | 34.0% | 35.0% | 36.5% | 33.1% | 34.7% | 20.0% | 19.0% | 17.0% | 20.2% | 20.1% | *19.0%* | *19.0%* | Income Tax Rate | *19.0%* |
| | | | | | | 4.8% | 5.5% | 5.8% | 4.6% | 9.6% | 7.7% | 7.5% | 5.9% | 5.2% | 5.8% | *8.5%* | *7.0%* | AFUDC % to Net Profit | *15.0%* |
| | | | | | | 44.0% | 45.2% | 43.5% | 41.6% | 43.4% | 47.5% | 44.6% | 46.5% | 46.4% | 50.3% | *50.5%* | *48.5%* | Long-Term Debt Ratio | *47.0%* |
| | | | | | | 55.0% | 53.8% | 55.5% | 57.5% | 55.7% | 51.7% | 54.6% | 52.7% | 52.8% | 49.0% | *49.0%* | *50.0%* | Common Equity Ratio | *52.5%* |
| | | | | | | 3142.9 | 3332.3 | 3473.5 | 3595.1 | 3765.5 | 4182.3 | 4176.9 | 4435.9 | 4524.1 | 4498.5 | *4700* | *4900* | Total Capital ($mill) | *5700* |
| | | | | | | 3858.9 | 4148.8 | 4377.7 | 4603.5 | 5025.9 | 4830.1 | 5109.6 | 5265.7 | 5392.1 | 5687.0 | *5775* | *5850* | Net Plant ($mill) | *6050* |
| | | | | | | 6.4% | 6.2% | 5.7% | 7.9% | 5.8% | 5.9% | 6.3% | 5.5% | 6.4% | 6.4% | *5.5%* | *5.5%* | Return on Total Cap'l | *3.0%* |
| | | | | | | 9.3% | 9.3% | 8.2% | 11.9% | 8.5% | 9.3% | 9.5% | 8.4% | 10.2% | 10.9% | *8.5%* | *8.5%* | Return on Shr. Equity | *4.0%* |
| | | | | | | 9.4% | 9.4% | 8.3% | 12.0% | 8.5% | 9.3% | 9.6% | 8.5% | 10.3% | 10.9% | *8.5%* | *8.5%* | Return on Com Equity E | *4.0%* |
| | | | | | | 3.7% | 2.3% | 1.5% | 6.3% | 2.1% | 3.1% | 3.4% | 2.3% | 4.1% | 4.0% | *3.5%* | *8.5%* | Retained to Com Eq | *4.0%* |
| | | | | | | 61% | 75% | 83% | 48% | 76% | 67% | 64% | 73% | 61% | 64% | *60%* | *1%* | All Div'ds to Net Prof F | *2%* |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $2741.8 mill. **Due in 5 Yrs** $545.0 mill.
**LT Debt** $2695.6 mill. **LT Interest** $117.3 mill.
Incl. $123.2 mill. finance leases.
(Total Interest Coverage: 3.6x)
**Leases, Uncapitalized** Annual rentals $11.2 mill.

**Pension Assets-12/22** $1806.4 mill.
**Oblig** $1856.4 mill.
**Pfd Stock** $34.3 mill. **Pfd Div'd** $1.9 mill.

**Common Stock** 109,611,599 shs.
as of 7/18/23
**MARKET CAP: $1.3 billion (Small Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | NA | NA | NA |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 24.21 | 26.88 | 36.75 |
| Capacity at Yearend (Mw) | 2254 | 2278 | 2100 |
| Peak Load, Winter (Mw) | 1471 | 1471 | 1467 |
| Annual Load Factor (%) | 66.2 | 67.2 | 68.2 |
| % Change Customers (yr-end) | +.6 | +.5 | -.2 |
| Fixed Charge Cov. (%) | 337 | 393 | 356 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -1.5% | 4.0% | *4.0%* |
| "Cash Flow" | 4.5% | 5.0% | *-2.0%* |
| Earnings | 4.0% | 3.0% | *-11.5%* |
| Dividends | 1.0% | 2.0% | *NMF* |
| Book Value | 3.0% | 2.5% | *3.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 677.2 | 609.0 | 641.4 | 652.2 | 2579.8 |
| 2021 | 642.9 | 680.3 | 756.9 | 770.3 | 2850.4 |
| 2022 | 785.1 | 895.6 | 1042 | 1019 | 3742.0 |
| 2023 | 928.2 | 895.7 | *960* | *966.1* | *3750* |
| 2024 | *940* | *910* | *1000* | *1000* | *3850* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .31 | .45 | .59 | .46 | 1.81 |
| 2021 | .59 | .58 | .58 | .50 | 2.25 |
| 2022 | .63 | .48 | .57 | .52 | 2.20 |
| 2023 | .50 | .50 | *.40* | *.40* | *1.80* |
| 2024 | *.45* | *.45* | *.50* | *.50* | *1.90* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .32 | .32 | .32 | .32 | 1.28 |
| 2020 | .33 | .33 | .33 | .33 | 1.32 |
| 2021 | .34 | .34 | .34 | .34 | 1.36 |
| 2022 | .35 | .35 | .35 | .35 | 1.40 |
| 2023 | .36 | .36 | .36 | -- | 1.08 |

**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 469,668 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Elec. rev. breakdown: residential, 44%; commercial, 19%; industrial, 37%; other, less than 1%. Generating sources: oil, 52%; purchased, 48%. Fuel costs: 50%+ of revs. '22 reported deprec. rate: 3.3%. Has 3,756 employees. Chairman: Tom Fargo. Pres. & CEO: Scott Seu. Inc.: HI. Address: 1001 Bishop St., Suite 2900, Honolulu, HI 96808-0730. Telephone: 808-543-5662. Internet: www.hei.com.

**Hawaiian Electric Industries' (HEI) share price has cratered due to its role in the Maui wildfires.** On August 8th, winds associated with Hurricane Dora downed power lines that started an early morning fire near the town of Lahaina. According to HEI, fire officials who responded to the scene declared that particular fire "one hundred percent contained and extinguished," and then left. HEI has also stated that the fires that began hours later, resulting in at least 115 deaths and a few billion dollars of property damage, must be from a different source than its equipment because the utility deenergized its system after the initial downed wires. Meanwhile, Maui County filed a lawsuit against HEI, claiming the utility acted negligently by not preemptively cutting power despite a warning from the National Weather Service of high winds. The suit alleges HEI's failure to maintain its system led to energized, downed power lines causing the fires. HEI has also been hit with a class action suit on the behalf of shareholders, alleging that negligence led to the stock's woes.

**HEI suspended its dividend to conserve cash due to the financial constraints associated with its ongoing legal issues.** The company has also drawn down most of its $375 million revolving credit facility. S&P Global Ratings downgraded HEI and all of its rated subsidiaries to B- (junk status), citing the company's likely inconsistent access to capital in the aftermath of the Maui blaze.

**Our projections are based on a likely drawn-out legal process that eventually leads to a settlement.** While it's possible HEI can have its day in court and emerge victorious, we doubt that outcome is realistic. Even if the company's version of events is true, downed poles later that day likely contributed to failed evacuation attempts. We've priced in settlement figures of about $200 million annually starting sometime after 2024. It's an amount the company can stay viable at in terms of maintaining the power grid. This assumption leaves nothing worthwhile for shareholders here.

**The Timeliness rank for this issue has been suspended, as the news cycle is the dominant factor driving the stock.**

*Anthony J. Glennon* *October 20, 2023*

(A) Diluted EPS. Excl. nonrec. losses: '07, 9¢; '12, 25¢; '17, 12¢. Qrtly. EPS don't sum due to rounding. Next earnings report due early Nov. (B) Quarterly dividends not declared prior to 8/21/23 have been suspended. (C) Incl. deferred cahrges. In '22: $272.4 mill., $2.49/sh. (D) In mill. (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%; Regulatory Climate: Below Average. (F) Includes preferred dividends.

| | |
|---|---|
| Company's Financial Strength | C+ |
| Stock's Price Stability | 40 |
| Price Growth Persistence | 55 |
| Earnings Predictability | 85 |

# IDACORP, INC. NYSE-IDA

RECENT PRICE 96.28 | P/E RATIO 18.4 (Trailing: 17.9; Median: 20.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 3.4% | VALUE LINE

**TIMELINESS** 4 Lowered 8/18/23
**SAFETY** 1 Raised 1/22/21
**TECHNICAL** 5 Lowered 9/29/23
**BETA** .85 (1.00 = Market)

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $83-$137 | $110 (15%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 125 | (+30%) | *10%* |
| Low | 105 | (+10%) | *6%* |

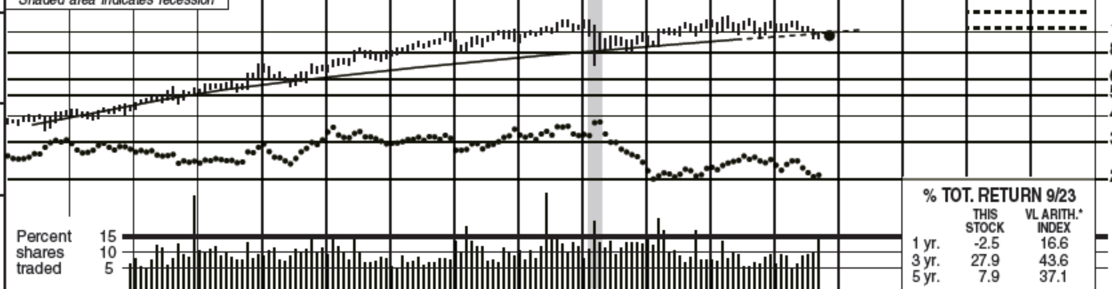
**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 187 | 174 | 168 |
| to Sell | 162 | 153 | 170 |
| Hld's(000) | 41351 | 41405 | 42011 |

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 45.7 | 54.7 | 70.1 | 70.5 | 83.4 | 100.0 | 102.4 | 114.0 | 113.6 | 113.8 | 118.9 | 113.0 |
| Low: | 38.2 | 43.1 | 50.2 | 55.4 | 65.0 | 77.5 | 79.6 | 89.3 | 69.1 | 85.3 | 93.5 | 88.1 |

LEGENDS
— 30.3 x Dividends p sh
.... Relative Price Strength
Options: Yes
*Shaded area indicates recession*

Target Price Range 2026 | 2027 | 2028




**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -2.5 | 16.6 |
| 3 yr. | 27.9 | 43.6 |
| 5 yr. | 7.9 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 32.51 | ***32.85*** | ***34.00*** | Revenues per sh | ***36.50*** |
| 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 | 8.55 | ***8.80*** | ***9.30*** | "Cash Flow" per sh | ***10.60*** |
| 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 | 5.11 | ***5.15*** | ***5.40*** | Earnings per sh A | ***6.10*** |
| 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 | 3.04 | ***3.20*** | ***3.40*** | Div'd Decl'd per sh B ■ † | ***4.15*** |
| 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 | 8.56 | ***14.00*** | ***16.00*** | Cap'l Spending per sh | ***11.00*** |
| 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 | 55.52 | ***56.85*** | ***59.25*** | Book Value per sh C | ***66.00*** |
| 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 | 50.56 | ***51.00*** | ***51.50*** | Common Shs Outst'g D | ***53.00*** |
| 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 | 21.0 | *Bold figures are* | *Value Line* | Avg Ann'l P/E Ratio | ***19.0*** |
| .97 | .84 | .68 | .75 | .72 | .79 | .75 | .77 | .82 | 1.00 | 1.04 | 1.11 | 1.19 | 1.02 | 1.12 | 1.21 | *estimates* | | Relative P/E Ratio | ***1.05*** |
| 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% | 2.8% | | | Avg Ann'l Div'd Yield | ***3.6%*** |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $2605.6 mill. **Due in 5 Yrs** $335.0 mill.
**LT Debt** $2482.4 mill. **LT Interest** $110.0 mill.
(Total Interest Coverage: 4.0x)

**Pension Assets-12/22** $839.7 mill. **Oblig** $953.8 mill.

**Pfd Stock** None

**Common Stock** 50,614,789 shs. as of 7/28/23

**MARKET CAP: $4.9 billion (Mid Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1246.2 | 1282.5 | 1270.3 | 1262.0 | 1349.5 | 1370.8 | 1346.4 | 1350.7 | 1458.1 | 1644.0 | ***1675*** | ***1750*** | Revenues ($mill) | ***1935*** |
| 182.4 | 193.5 | 194.7 | 198.3 | 212.4 | 226.8 | 232.9 | 237.4 | 245.6 | 259.0 | ***265*** | ***280*** | Net Profit ($mill) | ***335*** |
| 28.3% | 8.0% | 19.0% | 15.5% | 18.6% | 7.1% | 9.5% | 10.8% | 13.1% | 12.7% | ***13.0%*** | ***13.0%*** | Income Tax Rate | ***13.0%*** |
| 12.3% | 13.6% | 16.3% | 16.3% | 13.9% | 15.2% | 16.2% | 17.3% | 17.7% | 19.8% | ***15.0%*** | ***15.0%*** | AFUDC % to Net Profit | ***16.0%*** |
| 46.6% | 45.3% | 45.6% | 44.8% | 43.7% | 43.6% | 41.3% | 43.9% | 42.8% | 43.9% | ***46.5%*** | ***47.0%*** | Long-Term Debt Ratio | ***50.0%*** |
| 53.4% | 54.7% | 54.4% | 55.2% | 56.3% | 56.4% | 58.7% | 56.1% | 57.2% | 56.1% | ***53.5%*** | ***53.0%*** | Common Equity Ratio | ***50.0%*** |
| 3465.9 | 3567.6 | 3783.3 | 3898.5 | 3997.5 | 4205.1 | 4201.3 | 4560.4 | 4669.1 | 5001.4 | ***5425*** | ***5790*** | Total Capital ($mill) | ***7000*** |
| 3665.0 | 3833.5 | 3992.4 | 4172.0 | 4283.9 | 4395.7 | 4531.5 | 4709.5 | 4901.8 | 5173.0 | ***5650*** | ***6000*** | Net Plant ($mill) | ***7000*** |
| 6.4% | 6.6% | 6.2% | 6.1% | 6.3% | 6.4% | 6.5% | 6.1% | 6.2% | 6.1% | ***6.0%*** | ***6.0%*** | Return on Total Cap'l | ***5.5%*** |
| 9.9% | 9.9% | 9.5% | 9.2% | 9.4% | 9.6% | 9.4% | 9.3% | 9.2% | 9.2% | ***9.0%*** | ***9.0%*** | Return on Shr. Equity | ***9.5%*** |
| 9.9% | 9.9% | 9.5% | 9.2% | 9.4% | 9.6% | 9.4% | 9.3% | 9.2% | 9.2% | ***9.0%*** | ***9.0%*** | Return on Com Equity E | ***9.5%*** |
| 5.6% | 5.4% | 4.8% | 4.3% | 4.4% | 4.4% | 4.2% | 3.9% | 3.7% | 3.7% | ***3.5%*** | ***3.5%*** | Retained to Com Eq | ***3.5%*** |
| 43% | 46% | 50% | 53% | 53% | 54% | 56% | 58% | 60% | 60% | ***62%*** | ***63%*** | All Div'ds to Net Prof | ***68%*** |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +2.0 | +3.9 | +7.3 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 3392 | 3751 | 3568 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +2.7 | +2.8 | +2.4 |
| Fixed Charge Cov. (%) | 313 | 334 | 419 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 3.5% | 2.5% | *3.5%* |
| "Cash Flow" | 4.0% | 3.5% | *4.0%* |
| Earnings | 4.0% | 4.0% | *4.0%* |
| Dividends | 8.5% | 6.5% | *6.5%* |
| Book Value | 5.0% | 4.5% | *3.5%* |

| Cal-endar | QUARTERLY REVENUES($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 291.0 | 318.8 | 425.3 | 315.6 | 1350.7 |
| 2021 | 316.1 | 360.1 | 446.9 | 335.0 | 1458.1 |
| 2022 | 344.3 | 358.7 | 518.0 | 422.9 | 1644.0 |
| 2023 | 429.7 | 413.8 | ***410*** | ***421.5*** | ***1675*** |
| 2024 | ***445*** | ***430*** | ***425*** | ***450*** | ***1750*** |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .74 | 1.19 | 2.02 | .74 | 4.69 |
| 2021 | .89 | 1.38 | 1.93 | .65 | 4.85 |
| 2022 | .91 | 1.27 | 2.10 | .83 | 5.11 |
| 2023 | 1.11 | 1.35 | ***1.95*** | ***.74*** | ***5.15*** |
| 2024 | ***1.20*** | ***1.40*** | ***2.05*** | ***.75*** | ***5.40*** |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .63 | .63 | .63 | .67 | 2.56 |
| 2020 | .67 | .67 | .67 | .71 | 2.72 |
| 2021 | .71 | .71 | .71 | .75 | 2.88 |
| 2022 | .75 | .75 | .75 | .79 | 3.04 |
| 2023 | .79 | .79 | .79 | .83 | |

**BUSINESS:** IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 618,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.4 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 38%; commercial, 27%; industrial, 22%; irrigation, 12%; other, 1%. Generating sources: hydro, 29%; coal, 20%; gas, 13%; purchased, 39%. Fuel costs: 40% of revenues. '22 reported depreciation rate: 3.0%. Has 2,077 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.

**IDACORP's string of annual earnings gains could be in jeopardy.** Customer growth fueled impressive showings in the first half of this year, and favorable adjustments tied to grid modernization and expansion pitched in, as well. Leadership has repeated its earnings outlook of $4.95 to $5.15 per share, and stated that Idaho Power will use approximately $15 million of additional tax credits available under its Idaho earnings support regulatory mechanism in 2023. As far as our estimate, we are holding tight at $5.15 a share, which would represent earnings growth of about three-quarters of a percentage point. Of course, this would extend the annual growth streak to 16 years, but we do have some concerns. Most notably, a rising debt burden that has been facilitating both clean-energy maneuvers and huge infrastructure buildouts. The added interest expense could chip away at the small margin of growth we foresee right now.

**Our $5.40-a-share earnings estimate for 2024 factors in some higher rates.** The company's last filing of a general rate case was just over 12 years ago (in 2011). All the while, the population in its service area has jumped considerably, and customer growth has been the byproduct of this wave. Idaho, in particular, is past due for an increase in electric delivery rates. Management is poised to follow suit in the state of Oregon, though little information on the timing front has been provided as this report heads to press. The $5.40 figure represents 5% year-over-year growth, roughly in line with in-house expectations.

**IDACORP's top-quality stock is not all that appealing at this juncture.** Despite a 10% drop in price over the last 90 days, IDA's stock is an untimely choice (4: Below Average). Also, capital appreciation potential three to five years hence is below the *Value Line* median. The lower price has pumped up the yield a bit, and a 5% increase to $0.83 a quarter starting with the November payout was a welcome sign, but there are better options available within our utilities coverage. Make no mistake, the company's impressive finances and track record warrant the stock a premium valuation versus its peers. We simply think our subscribers should await a more favorable entry point.

*Erik M. Manning* *October 20, 2023*

(A) Diluted EPS. Earnings may not sum due to rounding. Next earnings report due early November. (B) Dividends historically paid in late February, May, August, and November. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '22: $1421.9 mill., $28.12/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on common equity in '12: 10% (imputed); Regulatory Climate: Above Average.

| | |
|---|---|
| Company's Financial Strength | A+ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 70 |
| Earnings Predictability | 100 |

# NEXTERA ENERGY NYSE-NEE

RECENT PRICE 57.20 | P/E RATIO 17.4 (Trailing: 18.0, Median: 23.0) | RELATIVE P/E RATIO 1.16 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Raised 10/13/23
SAFETY 2 Lowered 10/13/23
TECHNICAL 4 Lowered 11/10/23
BETA .95 (1.00 = Market)

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $50-$116 | $83 (45%) |

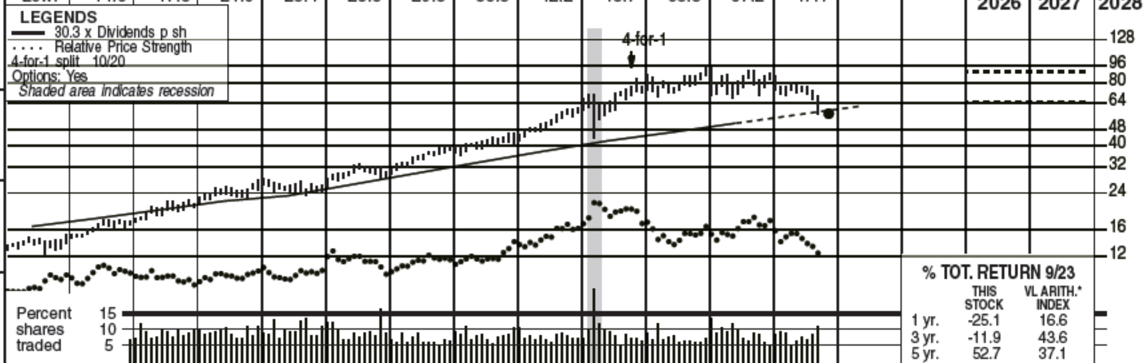
**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 90 | (+55%) | 15% |
| Low | 65 | (+15%) | 7% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 1244 | 1124 | 1166 |
| to Sell | 926 | 1029 | 974 |
| Hld's(000) | 1566738 | 1589194 | 1563720 |

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 18.1 | 22.4 | 27.7 | 28.2 | 33.0 | 39.8 | 46.1 | 61.3 | 83.3 | 93.7 | 93.6 | 86.5 |
| Low: | 14.6 | 17.5 | 21.0 | 23.4 | 25.5 | 29.3 | 36.3 | 42.2 | 43.7 | 68.3 | 67.2 | 47.1 |




**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -25.1 | 16.6 |
| 3 yr. | -11.9 | 43.6 |
| 5 yr. | 52.7 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 10.55 | **13.65** | **14.30** | Revenues per sh | **18.00** |
| 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 | 4.52 | 4.70 | 5.30 | **5.65** | **5.95** | "Cash Flow" per sh | **7.25** |
| .82 | 1.02 | .99 | 1.19 | 1.21 | 1.14 | 1.21 | 1.40 | 1.52 | 1.45 | 1.63 | 1.67 | 1.94 | 2.31 | 2.55 | 2.90 | **3.20** | **3.40** | Earnings per sh A | **4.40** |
| .41 | .45 | .47 | .50 | .55 | .60 | .66 | .73 | .77 | .87 | .98 | 1.11 | 1.25 | 1.40 | 1.54 | 1.70 | **1.87** | **2.06** | Div'd Decl'd per sh B ■ † | **2.65** |
| 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 | 8.19 | 9.70 | **9.50** | **9.50** | Cap'l Spending per sh | **9.75** |
| 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 | 19.74 | **22.30** | **23.60** | Book Value per sh C | **30.00** |
| 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 | 1987.0 | **2025.0** | **2025.0** | Common Shs Outst'g D | **2050.0** |
| 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 | 28.9 | 31.3 | 27.8 | *Bold figures are* | | Avg Ann'l P/E Ratio | **18.0** |
| 1.00 | .87 | .89 | .69 | .72 | .92 | .93 | .91 | .85 | 1.09 | 1.09 | 1.34 | 1.43 | 1.48 | 1.69 | 1.62 | *Value Line* | | Relative P/E Ratio | **1.00** |
| 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% | 2.1% | *estimates* | | Avg Ann'l Div'd Yield | **3.3%** |

**CAPITAL STRUCTURE as of 6/30/23**
Total Debt $72173 mill. Due in 5 Yrs $29730 mill.
LT Debt $60982 mill. LT Interest $1568 mill.

(Total Interest coverage: 4.4x)

Pension Assets-12/22 $4543 mill. Oblig $2711 mill.

Pfd Stock None

Common Stock 2,023,713,997 shs.

MARKET CAP: $116 billion (Large Cap)

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15136 | 17021 | 17486 | 16155 | 17195 | 16727 | 19204 | 17997 | 17069 | 20956 | **27600** | **29000** | Revenues ($mill) | **37000** |
| 2062.0 | 2465.0 | 2752.0 | 2693.0 | 3074.0 | 3200.0 | 3769.0 | 4552.0 | 5021.0 | 5742.0 | **6475** | **6895** | Net Profit ($mill) | **9035** |
| 26.9% | 32.3% | 30.8% | 29.3% | 24.4% | 28.6% | 11.7% | 13.0% | 15.0% | 18.2% | **18.0%** | **18.0%** | Income Tax Rate | **18.0%** |
| 7.0% | 6.7% | 6.9% | 8.2% | 6.7% | 6.6% | 4.1% | 4.6% | 6.3% | 4.3% | **4.0%** | **4.0%** | AFUDC % to Net Profit | **4.0%** |
| 57.1% | 55.0% | 54.2% | 53.3% | 52.7% | 44.0% | 50.4% | 53.5% | 57.8% | 58.5% | **57.0%** | **59.0%** | Long-Term Debt Ratio | **60.0%** |
| 42.9% | 45.0% | 45.8% | 46.7% | 47.3% | 56.0% | 49.6% | 46.5% | 42.2% | 41.5% | **43.0%** | **41.0%** | Common Equity Ratio | **40.0%** |
| 42009 | 44283 | 49255 | 52159 | 59671 | 60926 | 74548 | 78457 | 88162 | 94485 | **105000** | **116700** | Total Capital ($mill) | **153100** |
| 52720 | 55705 | 61386 | 66912 | 72416 | 70334 | 82010 | 91803 | 99348 | 111059 | **125300** | **139350** | Net Plant ($mill) | **180100** |
| 6.2% | 7.0% | 6.8% | 6.3% | 6.3% | 6.3% | 6.0% | 6.8% | 6.6% | 6.9% | **7.0%** | **6.5%** | Return on Total Cap'l | **6.5%** |
| 11.4% | 12.4% | 12.2% | 11.1% | 10.9% | 9.4% | 10.2% | 12.5% | 13.5% | 14.6% | **14.0%** | **14.5%** | Return on Shr. Equity | **14.5%** |
| 11.4% | 12.4% | 12.2% | 11.1% | 10.9% | 9.4% | 10.2% | 12.5% | 13.5% | 14.6% | **14.0%** | **14.5%** | Return on Com Equity E | **14.5%** |
| 5.2% | 6.0% | 6.1% | 4.4% | 4.4% | 3.2% | 3.7% | 5.0% | 5.4% | 6.1% | **6.0%** | **5.5%** | Retained to Com Eq | **5.5%** |
| 54% | 51% | 50% | 60% | 60% | 66% | 64% | 60% | 60% | 58% | **59%** | **61%** | All Div'ds to Net Prof | **60%** |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | NA | NA | +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, Summer (Mw) | NA | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +1.5 | +1.5 | +1.5 |
| Fixed Charge Cov. (%) | 301 | 284 | 370 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 0.5% | 1.0% | *9.5%* |
| "Cash Flow" | 7.5% | 9.0% | *7.5%* |
| Earnings | 8.0% | 11.0% | *9.5%* |
| Dividends | 11.0% | 12.0% | *9.5%* |
| Book Value | 8.0% | 7.5% | *8.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 4613 | 4204 | 4785 | 4395 | 17997 |
| 2021 | 3726 | 3927 | 4370 | 5046 | 17069 |
| 2022 | 2890 | 5183 | 6719 | 6164 | 20956 |
| 2023 | 6716 | 7349 | 7172 | *6363* | *27600* |
| 2024 | *6775* | *7625* | *7800* | *6800* | *29000* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .59 | .65 | .67 | .40 | 2.31 |
| 2021 | .67 | .71 | .75 | .41 | 2.55 |
| 2022 | .74 | .81 | .85 | .51 | 2.90 |
| 2023 | .84 | .88 | .94 | *.54* | *3.20* |
| 2024 | *.88* | *.93* | *.99* | *.60* | *3.40* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .3125 | .3125 | .3125 | .3125 | 1.25 |
| 2020 | .35 | .35 | .35 | .35 | 1.40 |
| 2021 | .385 | .385 | .385 | .385 | 1.54 |
| 2022 | .425 | .425 | .425 | .425 | 1.70 |
| 2023 | .4675 | .4675 | .4675 | | |

**BUSINESS:** NextEra Energy, Inc. is a holding company for Florida Power & Light Co. (FP&L), which provides electricity to roughly 5.8 million customers in eastern, southern, & northwestern Florida. NextEra Energy Resources is a nonregulated power generator with nuclear, gas, & renewables. Has 54% stake in NextEra Energy Partners. Acquired Gulf Power 1/19; Florida City Gas 7/18. Revenue.: residential, about 55%; commercial/industrial/other, 45%. Generating sources: gas, 71%; nuclear, 21%; solar/other, 7%; purchased, 1%. Fuel costs: 30.5% of revenues. '22 depreciation rate: 3.4%. Employs 15,300. Chairman, President and CEO: John W. Ketchum. Inc.: Florida. Address: 700 Universe Blvd., Juno Beach, FL 33408. Tel.: 561-694-4000. Internet: www.nexteraenergy.com.

**NextEra Energy shares have been among the worst performers within the electric utility group.** NEE stock is down about double the nearly 16% year-to-date median decline of its industry. In recent years, this company has been valued at a significant premium, in terms of a higher-than-average price-to-earnings (P/E) multiple and low dividend yield, to its peers. The top valuation within the group was justified given the double-digit rate of growth for earnings and dividends over the past five years. Lately, however, it has been the stocks of companies in the electric utility industry with the strongest ties to renewable energy, and growth that's fueled by consistently expanding the capital base via debt and equity injections, which have suffered the most. It didn't help that the NEE's 54%-owned subsidiary, NextEra Energy Partners, cut its distribution growth targets in half, citing higher interest rates and a lower equity valuation as a limiting factor to the renewables projects it can pursue. Logically, investors questioned what a higher cost of capital meant for the parent company.

**Management remains confident in NextEra's ability to achieve the upper end of its targeted earnings growth range of 6%-8% to late decade.** We still think that this is feasible given the company's solid balance sheet, interest rate hedges over the next few years, superior fundamentals at Florida Power & Light (FP&L), and NextEra's renewable-energy expertise. Florida's population gains, at triple the national average, low unemployment, and high labor participation rate lead to plenty of transmission & distribution work. This, along with reliability and hardiness projects in the hurricane-susceptible state, should keep load growth and regulatory capital (the rate base) rising at healthy levels. FP&L also has the okay from regulators to expand solar capacity within the rate base from 5% of power generation to 35% in years to come.

**We've reduced our 3- to 5-year Target Price Range by about $25 at the midpoint.** This isn't because we doubt the company's ability to grow at the pace it has targeted. In the face of higher interest rates, it's doubtful utilities will regularly trade much above a market P/E multiple.

*Anthony J. Glennon* *November 10, 2023*

(A) Diluted EPS. Excl. nonrecurring gains/(losses): '11, (6¢); '13, (20¢); '16, 12¢; '17, $1.22¢; '18, $1.80; '20, (83¢); '21, (74¢); '22, (80¢); 1Q-3Q '23, 36¢; disc. ops.: '13, 11¢. EPS may not some to full yr. due to rounding. Next egs. report due late Jan. (B) Div'ds paid in mid-Mar., mid-June, mid-Sept., & mid-Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '22: $6.38/sh. (D) In mill., adj. for stock split. (E) Rate all'd on com. eq. in '22 (FPL): 9.8%-11.8%; Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 85 |
| Price Growth Persistence | 95 |
| Earnings Predictability | 85 |

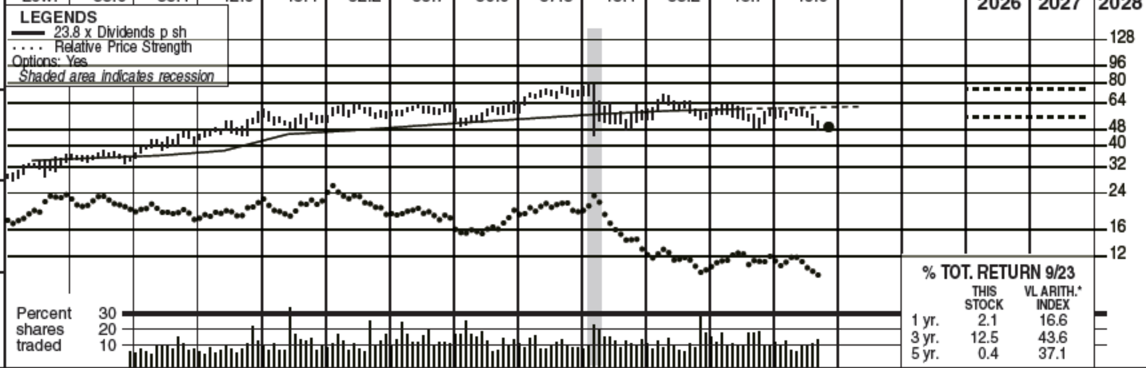
# NORTHWESTERN NDQ-NWE

RECENT PRICE 49.39 | P/E RATIO 14.3 (Trailing: 16.2 / Median: 17.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 5.2% | VALUE LINE

TIMELINESS 4 Raised 10/13/23
SAFETY 2 Raised 7/27/18
TECHNICAL 5 Lowered 10/20/23
BETA .95 (1.00 = Market)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 38.0 | 47.2 | 58.7 | 59.7 | 63.8 | 64.5 | 65.7 | 76.7 | 80.5 | 70.8 | 63.1 | 61.2 | |
| Low: | 33.0 | 35.1 | 42.6 | 48.4 | 52.2 | 55.7 | 50.0 | 57.3 | 45.1 | 53.2 | 48.7 | 46.0 | |

LEGENDS
— 23.8 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2026 | 2027 | 2028
128 / 96 / 80 / 64 / 48 / 40 / 32 / 24 / 16 / 12

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $48-$74 | $61 (25%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 75 | (+50%) | 15% |
| Low | 55 | (+10%) | 8% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 169 | 135 | 157 |
| to Sell | 115 | 123 | 113 |
| Hld's(000) | 57154 | 58097 | 58238 |

Percent shares traded 30 / 20 / 10

% TOT. RETURN 9/23

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | 2.1 | 16.6 |
| 3 yr. | 12.5 | 43.6 |
| 5 yr. | 0.4 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 24.74 | **24.20** | **25.80** | Revenues per sh | **28.25** |
| 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 | 6.86 | 6.92 | 6.46 | **6.80** | **7.20** | "Cash Flow" per sh | **8.35** |
| 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 | 3.21 | 3.50 | 3.29 | **3.45** | **3.60** | Earnings per sh A | **4.15** |
| 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 | 2.48 | 2.52 | **2.56** | **2.60** | Div'd Decl'd per sh B ■ † | **2.76** |
| 3.00 | 3.47 | 5.26 | 6.30 | 5.20 | 5.89 | 5.95 | 5.76 | 5.89 | 5.96 | 5.60 | 5.64 | 6.26 | 8.02 | 8.03 | 8.62 | **8.50** | **7.75** | Cap'l Spending per sh | **7.00** |
| 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 | 44.61 | **47.50** | **48.50** | Book Value per sh C | **52.30** |
| 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 | 59.74 | **62.00** | **62.00** | Common Shs Outst'g D | **62.00** |
| 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 | 18.6 | 17.4 | 17.3 | *Bold figures are* | | Avg Ann'l P/E Ratio | **15.5** |
| 1.15 | .84 | .77 | .82 | .79 | 1.00 | .95 | .85 | .93 | .90 | .90 | .91 | 1.06 | .96 | .94 | .99 | *Value Line* | | Relative P/E Ratio | **.85** |
| 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% | 4.4% | *estimates* | | Avg Ann'l Div'd Yield | **4.3%** |
| | | | | | | 1154.5 | 1204.9 | 1214.3 | 1257.2 | 1305.7 | 1198.1 | 1257.9 | 1198.7 | 1372.3 | 1477.8 | **1500** | **1600** | Revenues ($mill) | **1750** |
| | | | | | | 94.0 | 120.7 | 138.4 | 164.2 | 162.7 | 171.1 | 179.3 | 162.6 | 181.6 | 185.5 | **210** | **225** | Net Profit ($mill) | **255** |
| | | | | | | 13.2% | - - | 13.7% | - - | 7.6% | - - | 1.6% | - - | .9% | - - | **3.0%** | **6.0%** | Income Tax Rate | **12.0%** |
| | | | | | | 8.7% | 8.9% | 9.8% | 4.3% | 5.2% | 3.4% | 4.6% | 6.0% | 14.9% | 18.5% | **14.0%** | **13.0%** | AFUDC % to Net Profit | **12.0%** |
| | | | | | | 53.5% | 53.4% | 53.1% | 52.0% | 50.2% | 52.2% | 52.5% | 52.8% | 52.2% | 48.2% | **47.5%** | **46.5%** | Long-Term Debt Ratio | **48.0%** |
| | | | | | | 46.5% | 46.6% | 46.9% | 48.0% | 49.8% | 47.8% | 47.5% | 47.2% | 47.8% | 51.8% | **52.5%** | **53.5%** | Common Equity Ratio | **52.0%** |
| | | | | | | 2215.7 | 3168.0 | 3408.6 | 3493.9 | 3614.5 | 4064.6 | 4289.8 | 4409.1 | 4893.1 | 5148.3 | **5625** | **5625** | Total Capital ($mill) | **6200** |
| | | | | | | 2690.1 | 3758.0 | 4059.5 | 4214.9 | 4358.3 | 4521.3 | 4700.9 | 4952.9 | 5247.2 | 5657.5 | **6000** | **6250** | Net Plant ($mill) | **6725** |
| | | | | | | 5.5% | 4.8% | 5.2% | 5.9% | 5.6% | 5.2% | 5.2% | 4.6% | 4.6% | 4.5% | **4.5%** | **5.0%** | Return on Total Cap'l | **5.0%** |
| | | | | | | 9.1% | 8.2% | 8.6% | 9.8% | 9.0% | 8.8% | 8.8% | 7.8% | 7.8% | 7.0% | **7.0%** | **7.5%** | Return on Shr. Equity | **8.0%** |
| | | | | | | 9.1% | 8.2% | 8.6% | 9.8% | 9.0% | 8.8% | 8.8% | 7.8% | 7.8% | 7.0% | **7.0%** | **7.5%** | Return on Com Equity E | **8.0%** |
| | | | | | | 3.5% | 3.8% | 3.0% | 4.1% | 3.4% | 3.2% | 3.1% | 2.0% | 2.3% | 1.7% | **2.0%** | **2.0%** | Retained to Com Eq | **2.5%** |
| | | | | | | 61% | 54% | 65% | 58% | 62% | 64% | 64% | 74% | 71% | 76% | **74%** | **72%** | All Div'ds to Net Prof | **67%** |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $2668.5 mill. **Due in 5 Yrs** $1111.4 mill.
**LT Debt** $2565.4 mill. **LT Interest** $102.0 mill.
Incl. $7.2 mill. finance leases.
(Total Interest Coverage: 2.5x)

**Pension Assets-12/22** $441.5 mill. **Oblig** $521.8 mill.

**Pfd Stock** None

**Common Stock** 60,041,809 shs. as of 7/21/23

**MARKET CAP: $3.0 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -4.4 | +.7 | +3.7 |
| Avg. Indust. Use (MWH) | 33526 | 31792 | 34079 |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Winter (Mw) | NA | NA | 2073 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +1.2 | +1.6 | +1.5 |
| Fixed Charge Cov. (%) | 247 | 245 | 219 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -2.0% | -1.0% | 2.5% |
| "Cash Flow" | 3.0% | 1.0% | 3.5% |
| Earnings | 3.5% | 1.0% | 3.5% |
| Dividends | 5.5% | 4.0% | 2.0% |
| Book Value | 6.0% | 4.5% | 3.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 335.3 | 269.4 | 280.6 | 313.4 | 1198.7 |
| 2021 | 400.8 | 298.2 | 326.0 | 347.3 | 1372.3 |
| 2022 | 394.5 | 323.0 | 335.1 | 425.2 | 1477.8 |
| 2023 | 454.5 | **290.5** | **325** | **430** | **1500** |
| 2024 | **455** | **340** | **365** | **440** | **1600** |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1.00 | .43 | .58 | 1.21 | 3.21 |
| 2021 | 1.24 | .59 | .70 | .97 | 3.50 |
| 2022 | 1.08 | .58 | .47 | 1.16 | 3.29 |
| 2023 | 1.10 | .32 | **.88** | **1.15** | **3.45** |
| 2024 | **1.10** | **.50** | **.85** | **1.15** | **3.60** |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .575 | .575 | .575 | .575 | 2.30 |
| 2020 | .60 | .60 | .60 | .60 | 2.40 |
| 2021 | .62 | .62 | .62 | .62 | 2.48 |
| 2022 | .63 | .63 | .63 | .63 | 2.52 |
| 2023 | .64 | .64 | .64 | | |

**BUSINESS:** NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 463,000 electric customers in Montana and South Dakota and 301,000 gas customers in Montana, South Dakota, and Nebraska. Electric revenue breakdown: residential, 45%; commercial, 46%; industrial, 5%; other, 4%. Generating sources: coal, 28%; hydro, 26%; wind, 6%; natural gas, 6%; purchased power, 34%. Fuel costs: 33% of revenues. 2022 reported depreciation rate: 2.8%. Has approximately 1,500 employees. Board Chair: Dana J. Dykhouse. President and CEO: Brian B. Bird. Incorporated: DE. Address: 3010 West 69th Street, Sioux Falls, SD 57108. Telephone: 605-978-2900. Internet: www.northwesternenergy.com.

**Regulators are dragging their feet on approving NorthWestern's settlement agreement for new electric and natural gas rates.** To recap: in early April, the utility worked out an acceptable consensus with the Montana Consumer Counsel, the Montana Large Customer Group, and Walmart, Inc. The settlement has been submitted to the Montana Public Service Commission (MPSC) for the regulatory body's consideration. The MPSC has already granted interim rate hikes, starting from last October, to allow the company to begin the recoupment of some elevated spending. The agreed to base rates would increase annual electric and natural gas revenues by $67.4 million and $14.1 million, respectively. Those levels are predicated on the same authorized returns on equity, namely 9.65% for electric and 9.55% for gas, that were last agreed upon in 2015 and 2017. If the MPSC signs off on the agreement, the utility will have gotten about two-thirds of what it originally filed for in its general rate case. Importantly, NorthWestern would also receive pricing mechanisms geared towards reducing regulatory lag.

**Rate-base expansion should drive growth.** (The rate base is the dollar value of assets for which a utility is allowed to earn a regulated return on.) In June, NorthWestern completed an $83 million, 58-megawatt gas-fired power plant in South Dakota, with the potential for added capacity later. A $275 million, 175-mw gas generation facility in Montana was due to be operational later this year, but was delayed due to environmental permitting troubles. Now cleared, it is expected to come on line in 2024. The company may also add 220 mw of coal-fired generation, assuming it can get regulatory body approval, by doubling its stake in an existing plant at very favorable terms.

**NorthWestern stock, however, is an untimely selection for year-ahead relative price performance.** Rapidly rising yields on Treasury securities has pressured this equity and the stock's of most of the company's peers. We've scaled back our 3- to 5-year Target Price Range for the shares of many utilities, including NWE, on the prospect that the rise in interest rates is more than just a cyclical increase.

*Anthony J. Glennon* *October 20, 2023*

(A) Diluted egs. Excl. nonrec. gains/(losses): '12, 40¢; '15, 27¢; '18, 52¢; '19, 45¢; '20, (15¢); '21, 10¢; '22, (4¢); 1Q-2Q '23, (5¢). Qtly EPS may not sum to full yr. due to rounding. Next egs. report due early Nov. (B) Div'ds paid late Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shrhldr. invest. plan avail. (C) Incl. def'd charges. In '22: $17.98/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%. Reg. Climate: Below Avg.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 90 |
| Price Growth Persistence | 30 |
| Earnings Predictability | 95 |

# OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 34.93 | P/E RATIO 16.5 (Trailing: 20.0 Median: 18.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 4.8% | VALUE LINE

**TIMELINESS** 2 Raised 12/1/23

**SAFETY** 2 Lowered 12/18/15

**TECHNICAL** 3 Raised 12/1/23

**BETA** 1.05 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 30.1 | 40.0 | 39.3 | 36.5 | 34.2 | 37.4 | 41.8 | 45.8 | 46.4 | 38.6 | 42.9 | 40.4 |
| Low: | 25.1 | 27.7 | 32.8 | 24.2 | 23.4 | 32.6 | 29.6 | 38.0 | 23.0 | 29.2 | 33.3 | 31.3 |

**18-Month Target Price Range**

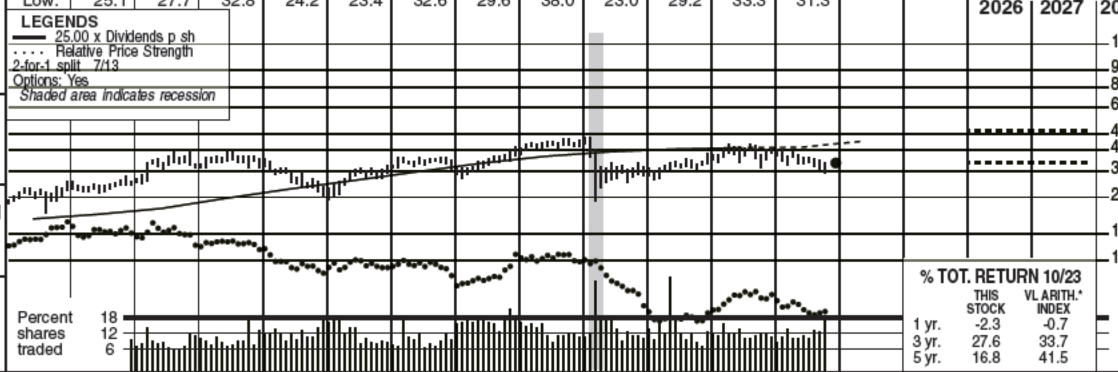
| Low-High | Midpoint (% to Mid) |
|---|---|
| $27-$48 | $38 (5%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 50 | (+45%) | 13% |
| Low | 35 | (Nil) | 5% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 262 | 183 | 174 |
| to Sell | 155 | 211 | 216 |
| Hld's(000) | 139192 | 139715 | 134247 |




**% TOT. RETURN 10/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -2.3 | -0.7 |
| 3 yr. | 27.6 | 33.7 |
| 5 yr. | 16.8 | 41.5 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 16.86 | *17.00* | *17.50* | Revenues per sh | *19.00* |
| 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 | 4.56 | *4.60* | *4.65* | "Cash Flow" per sh | *6.25* |
| 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 | 2.25 | *2.05* | *2.15* | Earnings per sh A | *3.15* |
| .68 | .70 | .71 | .73 | .76 | .80 | .85 | .95 | 1.05 | 1.16 | 1.27 | 1.40 | 1.51 | 1.58 | 1.63 | 1.64 | *1.66* | *1.78* | Div'd Decl'd per sh B ■ | *1.85* |
| 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 | 5.25 | *4.75* | *4.75* | Cap'l Spending per sh | *4.75* |
| 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 | 21.95 | *22.25* | *23.10* | Book Value per sh C | *26.00* |
| 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 | 200.20 | *200.20* | *200.20* | Common Shs Outst'g D | *200.20* |
| 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 | 17.2 | *Bold figures are* | | Avg Ann'l P/E Ratio | *14.0* |
| .73 | .75 | .72 | .85 | .90 | .97 | .99 | .96 | .89 | .93 | .92 | .89 | 1.01 | .83 | .77 | 1.00 | *Value Line* | | Relative P/E Ratio | *.80* |
| 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% | 4.5% | *estimates* | | Avg Ann'l Div'd Yield | *4.4%* |

**CAPITAL STRUCTURE as of 9/30/23**
**Total Debt** $4751.1 mill. **Due in 5 Yrs** $1731.5 mill.
**LT Debt** $4339.7 mill. **LT Interest** $158.7 mill.
(LT interest earned: 4.3x)

**Leases, Uncapitalized** Annual rentals $5.7 mill.

**Pension Assets-12/22** $486.0 mill. **Oblig** $502.9 mill.

**Pfd Stock** None

**Common Stock** 200,287,364 shs.

**MARKET CAP: $7.0 billion (Mid Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2867.7 | 2453.1 | 2196.9 | 2259.2 | 2261.1 | 2270.3 | 2231.6 | 2122.3 | 3653.7 | 3375.7 | *3400* | *3500* | Revenues ($mill) | *3800* |
| 387.6 | 395.8 | 337.6 | 338.2 | 384.3 | 425.5 | 449.6 | 415.9 | 472.5 | 452.5 | *410* | *430* | Net Profit ($mill) | *630* |
| 24.9% | 30.4% | 29.2% | 30.5% | 32.5% | 14.5% | 7.4% | 13.2% | 11.5% | 12.0% | *12.0%* | *12.0%* | Income Tax Rate | *12.0%* |
| 2.6% | 1.7% | 3.7% | 6.4% | 15.0% | 8.3% | 1.6% | 1.6% | 2.2% | 2.0% | *2.0%* | *2.0%* | AFUDC % to Net Profit | *2.0%* |
| 43.1% | 45.9% | 44.3% | 41.1% | 41.7% | 42.0% | 43.6% | 49.0% | 52.6% | 49.8% | *52.0%* | *52.0%* | Long-Term Debt Ratio | *50.0%* |
| 56.9% | 54.1% | 55.7% | 58.9% | 58.3% | 58.0% | 56.4% | 51.0% | 47.4% | 52.4% | *48.0%* | *48.0%* | Common Equity Ratio | *50.0%* |
| 5337.2 | 5999.7 | 5971.6 | 5849.6 | 6600.7 | 6902.0 | 7334.7 | 7126.2 | 8552.7 | 8962.0 | *9400* | *9750* | Total Capital ($mill) | *10400* |
| 6672.8 | 6979.9 | 7322.4 | 7696.2 | 8339.9 | 8643.8 | 9044.6 | 9374.6 | 9832.9 | 10546.8 | *10830* | *11000* | Net Plant ($mill) | *12075* |
| 8.6% | 7.8% | 6.9% | 7.0% | 7.0% | 7.3% | 7.1% | 6.9% | 6.4% | 5.9% | *6.5%* | *6.5%* | Return on Total Cap'l | *7.5%* |
| 12.8% | 12.2% | 10.2% | 9.8% | 10.0% | 10.6% | 10.9% | 11.5% | 11.6% | 11.0% | *12.0%* | *12.0%* | Return on Shr. Equity | *13.0%* |
| 12.8% | 12.2% | 10.2% | 9.8% | 10.0% | 10.6% | 10.9% | 11.5% | 11.6% | 11.0% | *12.0%* | *12.0%* | Return on Com Equity E | *13.0%* |
| 7.3% | 6.5% | 4.0% | 3.3% | 3.5% | 3.8% | 3.6% | 2.8% | 3.6% | 3.0% | *4.5%* | *4.5%* | Retained to Com Eq | *5.5%* |
| 43% | 47% | 61% | 67% | 64% | 64% | 67% | 76% | 69% | 73% | *81%* | *81%* | All Div'ds to Net Prof | *57%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -4.9 | +2.6 | +8.3 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 4.40 | 7.68 | NA |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 6437 | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +1.1 | +1.4 | NA |
| Fixed Charge Cov. (%) | 326 | 336 | 335 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -3.0% | 5.0% | *5.5%* |
| "Cash Flow" | 2.5% | 5.0% | *7.0%* |
| Earnings | 3.0% | 4.5% | *6.5%* |
| Dividends | 7.5% | 6.5% | *3.0%* |
| Book Value | 4.0% | 1.5% | *5.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 431.3 | 503.5 | 702.1 | 485.4 | 2122.3 |
| 2021 | 1630.0 | 577.4 | 864.4 | 581.3 | 3653.7 |
| 2022 | 589.3 | 803.7 | 1270.0 | 711.9 | 3375.7 |
| 2023 | 557.2 | 605.0 | 945.4 | *1292.4* | *3400* |
| 2024 | *630* | *750* | *1300* | *820* | *3500* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .23 | .51 | 1.04 | .30 | 2.08 |
| 2021 | .26 | .56 | 1.26 | .28 | 2.36 |
| 2022 | .33 | .36 | 1.31 | .25 | 2.25 |
| 2023 | .19 | .44 | 1.20 | *.22* | *2.05* |
| 2024 | *.35* | *.30* | *1.25* | *.25* | *2.15* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .365 | .365 | .365 | .388 | 1.48 |
| 2020 | .3875 | .3875 | .3875 | .4025 | 1.57 |
| 2021 | .4025 | .4025 | .4025 | .41 | 1.62 |
| 2022 | .41 | .41 | .41 | .4141 | 1.64 |
| 2023 | .4141 | .4141 | .4141 | .4182 | |

**BUSINESS:** OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 879,000 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. '22 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 reached an uncontested settlement to replace two aging power generation units at the Horseshoe Lake Power Plant, and is awaiting the final order from the Oklahoma Corporation Commission.** The Horseshoe Lake Project, which will replace the oldest units in the utility's generation fleet, is expected to cost approximately $331 million and increase the average residential customer's bill by $2.20 per month. The hike will likely go into effect in late 2026. The company also plans to file a rate review in Oklahoma by the end of the year, and expects a constructive regulatory outcome.

**We have raised our 2023 earnings estimate by $0.05 a share.** The company is benefiting from its transformation to a fully focused electric utility, as well as rate relief. As a result of the strong performances of late, OGE raised and narrowed its full-year 2023 profit guidance range to $2.02-$2.07 a share from the previous range of $1.93-$2.07 per share. The company looks for earnings growth to continue through 2024 and beyond as tailwinds at the electric company should help it to surpass long-term interest cost increases. We think OGE is well-positioned for the next few years due to rate relief, and the company's improved prospects as a pure play electric utility. The Inflation Reduction Act should also provide assistance to the bottom line through an otherwise challenging macroeconomic environment over that interim. Our 2024 earnings estimate is staying put at $2.15 a share.

**The board of directors has raised the dividend, effective with the October payment.** The increase was modest, at $0.0041 a share quarterly (1% higher). This issue offers a very attractive dividend, and the yield of 4.8% now sits comfortably above the utility average, which is one of the highest dividend-paying industries in the market.

**This stock was recently upgraded one notch in our Timeliness Ranking System to 2 (Above Average).** These shares should also appeal to income-oriented investors as the dividend remains this issue's most notable feature. Meanwhile, total return potential is unspectacular for the 18-month and 3- to 5-year time spans.

*Zachary J. Hodgkinson* *December 8, 2023*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '15, (33¢); '17, $1.18; '19, (8¢); '20, ($2.95); '21, $1.32; '22, $1.06; gain on discont. ops.: '19 & '21 EPS don't sum due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '22: $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 | 35 |
| Earnings Predictability | 95 |

# OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE 75.42 | P/E RATIO 18.5 (Trailing: 11.4 Median: 20.0) | RELATIVE P/E RATIO 1.14 | DIV'D YLD 2.3% | VALUE LINE

TIMELINESS 2 Raised 11/10/23
SAFETY 2 Raised 6/17/16
TECHNICAL 1 Raised 11/10/23
BETA .90 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 25.3 | 31.9 | 32.7 | 33.4 | 42.6 | 48.7 | 51.9 | 57.7 | 56.9 | 71.7 | 82.5 | 92.7 |
| Low: | 20.7 | 25.2 | 26.5 | 24.8 | 25.8 | 35.7 | 39.0 | 45.9 | 31.0 | 39.4 | 52.6 | 57.3 |

Target Price Range 2026 | 2027 | 2028

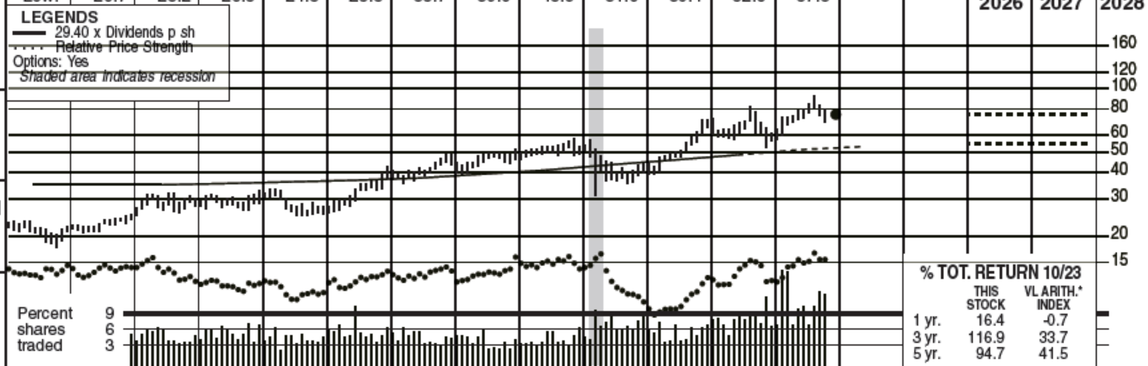
**18-Month Target Price Range**
Low-High: $35-$93 — Midpoint (% to Mid): $64 (-15%)

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 75 | (Nil) | 3% |
| Low | 55 | (-25%) | -4% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 117 | 135 | 108 |
| to Sell | 133 | 108 | 115 |
| Hld's(000) | 20465 | 25614 | 25238 |




**% TOT. RETURN 10/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | 16.4 | -0.7 |
| 3 yr. | 116.9 | 33.7 |
| 5 yr. | 94.7 | 41.5 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 41.50 | 37.06 | 29.03 | 31.08 | 29.86 | 23.76 | 24.63 | 21.48 | 20.60 | 20.42 | 21.47 | 23.10 | 22.90 | 21.46 | 28.80 | 35.08 | *32.35* | *29.75* | Revenues per sh | *31.20* |
| 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 | 8.77 | *7.95* | *6.45* | "Cash Flow" per sh | *6.00* |
| 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 | 6.78 | *6.40* | *4.00* | Earnings per sh A | *3.65* |
| 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* | *1.81* | Div'd Decl'd per sh B ■ | *2.20* |
| 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 | 4.11 | *5.90* | *6.00* | Cap'l Spending per sh | *6.25* |
| 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 | 29.24 | *29.80* | *31.15* | Book Value per sh C | *34.25* |
| 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 | 41.63 | *41.70* | *42.00* | Common Shs Outst'g D | *42.50* |
| 19.0 | 30.1 | 31.2 | NMF | 47.5 | 21.7 | 21.1 | 18.8 | 18.2 | 20.2 | 22.1 | 22.2 | 23.5 | 18.3 | 12.3 | 9.5 | *Bold figures are* | | Avg Ann'l P/E Ratio | *17.5* |
| 1.01 | 1.81 | 2.08 | NMF | 2.98 | 1.38 | 1.19 | .99 | .92 | 1.06 | 1.11 | 1.20 | 1.25 | .94 | .66 | .55 | *Value Line* | | Relative P/E Ratio | *.95* |
| 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% | 2.5% | *estimates* | | Avg Ann'l Div'd Yield | *3.4%* |

**CAPITAL STRUCTURE as of 9/30/23**
Total Debt $824.0 mill. Due in 5 Yrs $207.8 mill.
LT Debt $824.0 mill. LT Interest $31.6 mill.
(LT interest earned: 9.7x)

Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-12/22 $387.2 mill. Oblig $416.7 mill.

Pfd Stock None

Common Stock 41,710,521 shs. as of 10/27/23

MARKET CAP: $3.1 billion (Mid Cap)

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 893.3 | 799.3 | 779.8 | 803.5 | 849.4 | 916.4 | 919.5 | 890.1 | 1196.8 | 1460.2 | *1350* | *1250* | Revenues ($mill) | *1325* |
| 50.2 | 56.9 | 58.6 | 62.0 | 73.9 | 82.3 | 86.8 | 95.9 | 176.8 | 282.3 | *265* | *170* | Net Profit ($mill) | *155* |
| 21.3% | 22.5% | 27.0% | 24.5% | 25.5% | 15.0% | 16.7% | 17.4% | 16.9% | 20.5% | *20.0%* | *20.0%* | Income Tax Rate | *20.0%* |
| 5.6% | 3.9% | 3.5% | 2.2% | 2.3% | 4.1% | 4.9% | 6.4% | .8% | .9% | *3.0%* | *3.5%* | AFUDC % to Net Profit | *4.0%* |
| 42.1% | 46.5% | 42.4% | 43.0% | 41.3% | 44.7% | 46.9% | 41.8% | 42.6% | 40.0% | *41.5%* | *41.5%* | Long-Term Debt Ratio | *42.5%* |
| 57.9% | 53.5% | 57.6% | 57.0% | 58.7% | 55.3% | 53.1% | 58.2% | 57.4% | 58.3% | *58.5%* | *58.5%* | Common Equity Ratio | *57.5%* |
| 924.4 | 1071.3 | 1051.0 | 1175.4 | 1187.3 | 1318.9 | 1471.1 | 1495.4 | 1724.8 | 2041.1 | *2140* | *2250* | Total Capital ($mill) | *2525* |
| 1167.0 | 1268.5 | 1387.8 | 1477.2 | 1539.6 | 1581.1 | 1753.8 | 2049.3 | 2124.6 | 2212.7 | *2355* | *2475* | Net Plant ($mill) | *2700* |
| 6.8% | 6.7% | 6.8% | 6.5% | 7.3% | 7.3% | 7.0% | 7.4% | 11.1% | 12.0% | *9.0%* | *8.5%* | Return on Total Cap'l | *7.5%* |
| 9.4% | 9.9% | 9.7% | 9.3% | 10.6% | 11.3% | 11.1% | 11.0% | 17.8% | 18.0% | *13.5%* | *13.0%* | Return on Shr. Equity E | *11.5%* |
| 9.3% | 9.9% | 9.7% | 9.3% | 10.6% | 11.3% | 11.1% | 11.0% | 17.8% | 18.0% | *13.5%* | *13.0%* | Return on Com Equity | *11.5%* |
| 1.2% | 2.2% | 2.0% | 2.1% | 3.3% | 4.0% | 4.0% | 4.1% | 11.3% | 12.4% | *7.5%* | *7.0%* | Retained to Com Eq | *5.0%* |
| 87% | 78% | 79% | 78% | 69% | 65% | 64% | 63% | 37% | 24% | *44%* | *52%* | All Div'ds to Net Prof | *60%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -3.9 | +.3 | +16.8 |
| 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. (%) | 405 | 651 | 653 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -1.0% | 4.0% | *5.0%* |
| "Cash Flow" | 7.5% | 9.5% | *5.5%* |
| Earnings | 18.0% | 14.5% | *4.5%* |
| Dividends | 2.5% | 4.0% | *7.0%* |
| Book Value | 3.5% | 6.0% | *8.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 234.7 | 192.8 | 235.8 | 226.8 | 890.1 |
| 2021 | 261.7 | 285.6 | 316.3 | 333.2 | 1196.8 |
| 2022 | 374.9 | 400.0 | 383.9 | 301.4 | 1460.2 |
| 2023 | 339.1 | 337.7 | 358.1 | *315.1* | *1350* |
| 2024 | *320* | *330* | *310* | *290* | *1250* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .60 | .42 | .87 | .45 | 2.34 |
| 2021 | .73 | 1.01 | 1.26 | 1.23 | 4.23 |
| 2022 | 1.72 | 2.05 | 2.01 | 1.00 | 6.78 |
| 2023 | 1.49 | 1.95 | 2.19 | *.77* | *6.40* |
| 2024 | *1.00* | *1.10* | *1.20* | *.70* | *4.00* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .35 | .35 | .35 | .35 | 1.40 |
| 2020 | .37 | .37 | .37 | .37 | 1.48 |
| 2021 | .39 | .39 | .39 | .39 | 1.56 |
| 2022 | .4125 | .4125 | .4125 | .4125 | 1.65 |
| 2023 | .4375 | .4375 | .4375 | .4375 | |

**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 (72% of '22 operating income). '22 deprec. rate: 3.0%. 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 has raised its 2023 earnings guidance for the second-consecutive quarter.** The company is benefiting from strong financial performances within the Manufacturing and Plastics segments, as well as from updated PVC pipe pricing expectations and a reduction in corporate costs. Accordingly, the utility raised its 2023 profit guidance upon reporting September-period results. Earnings of $2.19 per share were far above our call of $1.40. Management now looks for the bottom line to be in a range of $6.76-$6.96 per share, up from the previous guidance range of $5.70-$6.00 a share. The Plastics segment is largely responsible for management's updated outlook as the prices and margins of PVC pipe are receding at a slower rate than previously expected. Meanwhile, the company now looks for its Electric division to produce profit growth of 6% compared to the 2022 tally, and is increasing the Manufacturing segment earnings forecast due to higher sales volumes and margin improvement in the third quarter.

**We have raised our 2023 earnings estimate by $0.70, to $6.40 a share, and boosted our 2024 estimate by $0.50, to $4.00 per share.** The utility's improved prospects, along with elevated PVC pipe pricing, which remains higher-than-anticipated, will likely boost the company's earning power over the next few years. Rate relief should also improve the bottom line in that interim.

**Otter Tail Power filed a rate case in North Dakota.** The utility requested a hike of approximately $17 million (8.4%), based on a return on equity of 10.6% and a common-equity ratio of 53.5%. This was Otter Tail's first rate case in the state of North Dakota since 2016, and is driven by operating cost increases. An order is expected in late 2024, while interim rates are set to be implemented at the start of the new year.

**The stock's dividend yield is below average for a utility.** Meanwhile, capital appreciation potential over the intermediate- and long-term time frames is unattractive. Indeed, the current quotation remains within and above our 18-month and 3- to 5-year Target Price Ranges, respectively.

*Zachary J. Hodgkinson* *December 8, 2023*

(A) Dil. EPS. Excl. nonrec. gains (loss): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from disc. ops.: '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢; '15, 2¢; '16, 1¢; '17, 1¢. '19 EPS may not sum due to rounding. Next earnings report due mid-Feb. (B) Div'ds histor. pd. in early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '22: $4.10/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%.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 55 |
| Price Growth Persistence | 80 |
| Earnings Predictability | 70 |

# PORTLAND GENERAL NYSE-POR

| RECENT PRICE | 41.13 | P/E RATIO | 15.2 (Trailing: 15.9 / Median: 18.0) | RELATIVE P/E RATIO | 0.95 | DIV'D YLD | 4.8% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

**TIMELINESS** 5 Lowered 8/11/23
**SAFETY** 2 Raised 10/22/21
**TECHNICAL** 4 Lowered 9/15/23
**BETA** .90 (1.00 = Market)

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $37-$63 | $50 (20%) |

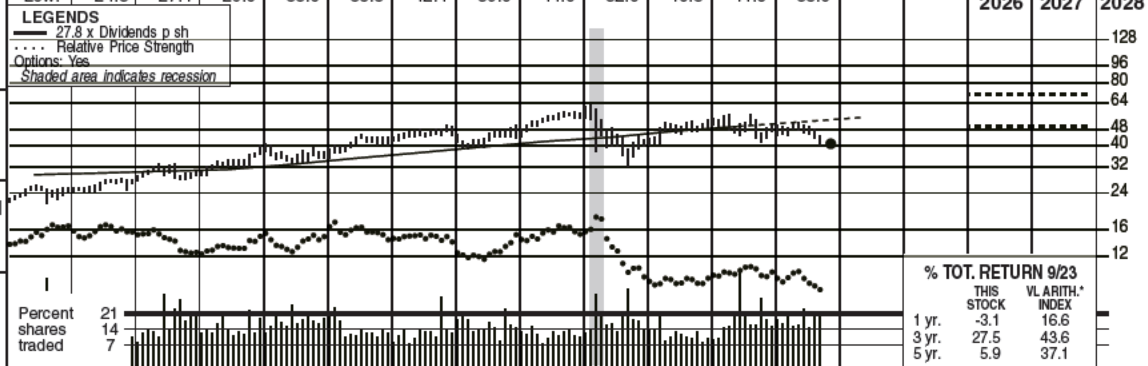
**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 70 | (+70%) | 18% |
| Low | 50 | (+20%) | 10% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 207 | 184 | 189 |
| to Sell | 157 | 173 | 170 |
| Hld's(000) | 98285 | 101190 | 103597 |

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 28.1 | 33.3 | 40.3 | 41.0 | 45.2 | 50.1 | 50.4 | 58.4 | 63.1 | 53.1 | 57.0 | 51.6 |
| Low: | 24.3 | 27.4 | 29.0 | 33.0 | 35.3 | 42.4 | 39.0 | 44.0 | 32.0 | 40.8 | 41.6 | 38.0 |




**Target Price Range**

| 2026 | 2027 | 2028 |
|---|---|---|

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -3.1 | 16.6 |
| 3 yr. | 27.5 | 43.6 |
| 5 yr. | 5.9 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 29.65 | *28.15* | *29.40* | Revenues per sh | *32.35* |
| 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 | 7.83 | 7.25 | 7.41 | *7.00* | *7.75* | "Cash Flow" per sh | *9.30* |
| 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 | 2.75 | 2.72 | 2.74 | *2.70* | *3.00* | Earnings per sh A | *3.65* |
| .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 | 1.79 | *1.88* | *1.98* | Div'd Decl'd per sh B ■ † | *2.36* |
| 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 | 8.58 | *12.00* | *10.75* | Cap'l Spending per sh | *11.00* |
| 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 | 31.13 | *33.95* | *35.00* | Book Value per sh C | *38.70* |
| 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 | 89.28 | *101.50* | *102.00* | Common Shs Outst'g D | *102.00* |
| 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 | 16.6 | 17.7 | 18.2 | *Bold figures are* | | Avg Ann'l P/E Ratio | *16.5* |
| .63 | .98 | .96 | .76 | .78 | .89 | .95 | .81 | .89 | 1.00 | 1.01 | .99 | 1.19 | .85 | .96 | 1.06 | *Value Line* | | Relative P/E Ratio | *.90* |
| 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% | 3.6% | *estimates* | | Avg Ann'l Div'd Yield | *3.9%* |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $3938 mill. **Due in 5 Yrs** $520 mill.
**LT Debt** $3778 mill. **LT Interest** $155 mill.
Incl. $292 mill. finance leases.
(Total Interest Coverage: 2.7x)
**Leases, Uncapitalized** Annual rentals $4 mill.
**Pension Assets-12/22** $547 mill.
**Oblig** $695 mill.

**Pfd Stock** None

**Common Stock** 101,094,514 shs.
as of 7/20/23

**MARKET CAP: $4.2 billion (Mid Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1810.0 | 1900.0 | 1898.0 | 1923.0 | 2009.0 | 1991.0 | 2123.0 | 2145.0 | 2396.0 | 2647.0 | *2855* | *3000* | Revenues ($mill) | *3300* |
| 137.0 | 175.0 | 172.0 | 193.0 | 204.0 | 212.0 | 214.0 | 247.0 | 244.0 | 245.0 | *255* | *305* | Net Profit ($mill) | *375* |
| 23.2% | 26.0% | 20.7% | 20.6% | 25.3% | 7.4% | 11.2% | 12.4% | 8.6% | 15.2% | *17.5%* | *17.5%* | Income Tax Rate | *17.5%* |
| 14.6% | 33.7% | 19.8% | 16.6% | 8.8% | 8.0% | 7.0% | 9.7% | 10.2% | 8.6% | *10.0%* | *9.0%* | AFUDC % to Net Profit | *8.5%* |
| 51.3% | 52.7% | 47.8% | 48.4% | 50.1% | 46.5% | 51.3% | 53.6% | 56.8% | 57.0% | *54.5%* | *53.5%* | Long-Term Debt Ratio | *54.5%* |
| 48.7% | 47.3% | 52.2% | 51.6% | 49.9% | 53.5% | 48.7% | 46.4% | 43.2% | 43.0% | *45.5%* | *46.5%* | Common Equity Ratio | *45.5%* |
| 3735.0 | 4037.0 | 4329.0 | 4544.0 | 4842.0 | 4684.0 | 5323.0 | 5628.0 | 6265.0 | 6459.0 | *7550* | *7700* | Total Capital ($mill) | *8650* |
| 4880.0 | 5679.0 | 6012.0 | 6434.0 | 6741.0 | 6887.0 | 7161.0 | 7539.0 | 8005.0 | 8465.0 | *9250* | *9850* | Net Plant ($mill) | *10900* |
| 5.1% | 5.8% | 5.4% | 5.6% | 5.5% | 5.8% | 5.1% | 5.6% | 4.9% | 4.9% | *4.5%* | *5.0%* | Return on Total Cap'l | *5.5%* |
| 7.5% | 9.2% | 7.6% | 8.2% | 8.4% | 8.5% | 8.3% | 9.5% | 9.0% | 8.8% | *7.5%* | *8.5%* | Return on Shr. Equity | *9.5%* |
| 7.5% | 9.2% | 7.6% | 8.2% | 8.4% | 8.5% | 8.3% | 9.5% | 9.0% | 8.8% | *7.5%* | *8.5%* | Return on Com Equity E | *9.5%* |
| 2.9% | 4.6% | 3.3% | 3.5% | 3.6% | 3.5% | 3.1% | 4.1% | 3.5% | 3.1% | *2.5%* | *3.0%* | Retained to Com Eq | *3.5%* |
| 61% | 50% | 56% | 57% | 58% | 59% | 63% | 57% | 61% | 64% | *70%* | *66%* | All Div'ds to Net Prof | *64%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +.4 | +5.1 | +3.4 |
| Avg. Indust. Use (MWH) | 18472 | 20002 | 22097 |
| Avg. Indust. Revs. per KWH (¢) | 4.99 | 5.22 | 5.23 |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 3771 | 4447 | 4255 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +1.5 | +.6 | +1.1 |
| Fixed Charge Cov. (%) | 275 | 261 | 254 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 1.0% | 4.0% | *3.0%* |
| "Cash Flow" | 4.0% | 5.5% | *3.5%* |
| Earnings | 4.0% | 5.0% | *5.0%* |
| Dividends | 5.0% | 6.0% | *5.5%* |
| Book Value | 3.0% | 3.0% | *4.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 573 | 469 | 547 | 556 | 2145 |
| 2021 | 609 | 537 | 642 | 608 | 2396 |
| 2022 | 626 | 591 | 743 | 687 | 2647 |
| 2023 | 687 | 648 | *790* | *730* | *2855* |
| 2024 | *740* | *660* | *825* | *775* | *3000* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .91 | .43 | .84 | .57 | 2.75 |
| 2021 | 1.07 | .36 | .56 | .73 | 2.72 |
| 2022 | .67 | .72 | .65 | .70 | 2.74 |
| 2023 | .80 | .44 | *.76* | *.70* | *2.70* |
| 2024 | *.80* | *.65* | *.80* | *.75* | *3.00* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .3625 | .3625 | .385 | .385 | 1.50 |
| 2020 | .385 | .385 | .385 | .4075 | 1.56 |
| 2021 | .4075 | .4075 | .43 | .43 | 1.68 |
| 2022 | .43 | .43 | .4525 | .4525 | 1.77 |
| 2023 | .4525 | .4525 | .475 | | |

**BUSINESS:** Portland General Electric Company (PGE) provides electricity to 926,000 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, 52%; commercial, 33%; industrial, 14%; other, 1%. Generating sources: gas, 32%; wind, 15%; coal, 4%; hydro, 7%; purchased, 41%. Fuel costs: 37% of revenues. '22 reported depreciation rate: 3.4%. Has 2,873 full-time employees. Chairman: Jack E. Davis. President and CEO: 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's annual share earnings should be up nicely in 2024 following this year's flat to down result.** For full-year 2023, leadership is still targeting profits of $2.60 to $2.75 per share. Weather extremes helped lift 2022's electric usage up 3.4% in the utility's service area, making for a difficult comparison this year, and purchased power costs were unusually high in the second quarter. Moreover, major investments in generating capacity and battery storage are driving up financing costs. Capital expenditures will likely rise from $766 million in 2022 to $1.23 billion this year and $1.1 billion in 2024. Rate relief should lift earnings next year. The utility filed for a 14% price increase with its Oregon regulators, in part to recoup higher purchased power costs. The request also addresses reliability and resiliency work, capital investments, and rising operating and financing costs. Our estimates assume a reasonably good outcome with higer electric rates in place on January 1st. Leadership called the progress made in negotiations "constructive and collaborative," thus far.

**Oregon's aggressive "green" energy initiatives should drive bottom-line growth.** PGE will add at least 375 to 500 megawatts of nonemitting annual power generation in the intermediate term, plus significant battery storage capacity. The company is partnering with NextEra Energy (NEE) to construct a 311-mw wind energy facility. PGE will own two-thirds of the venture and is to receive NEE's share of the power generation via a long-term purchase agreement. Project completion is targeted for December. Regulatory backing for the pursuit of more of these types of renewable generation projects should expand the rate base (the dollar value of assets a utility is allowed to earn an economic return on) for many years to come. This, plus load growth from a vibrant tech-based local economy, should enable PGE to achieve its long-term 5%-7% earnings and dividend growth targets.

**These shares, however, are untimely.** Similar to other interest-rate sensitive issues, POR's stock price has been under pressure of late. Annual total return prospects are higher than the industry median.

*Anthony J. Glennon* *October 20, 2023*

(A) Diluted earnings. Excl. nonrecurring gains/(losses): '13, (42¢); '17, (19¢); '20, ($1.03); '22, (14¢). Next earnings report due October 27th.
(B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available.
(C) Incl. deferred charges. In '21: $473 mill., $5.30/sh. (D) In mill.
(E) Rate base: Net original cost. Rate allowed on common equity in '22: 9.5%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 60 |
| Earnings Predictability | 95 |

# PINNACLE WEST NYSE-PNW

| RECENT PRICE | P/E RATIO | | RELATIVE P/E RATIO | DIV'D YLD | |
|---|---|---|---|---|---|
| 73.04 | 17.1 | (Trailing: 20.4 Median: 17.0) | 1.07 | 4.8% | VALUE LINE |

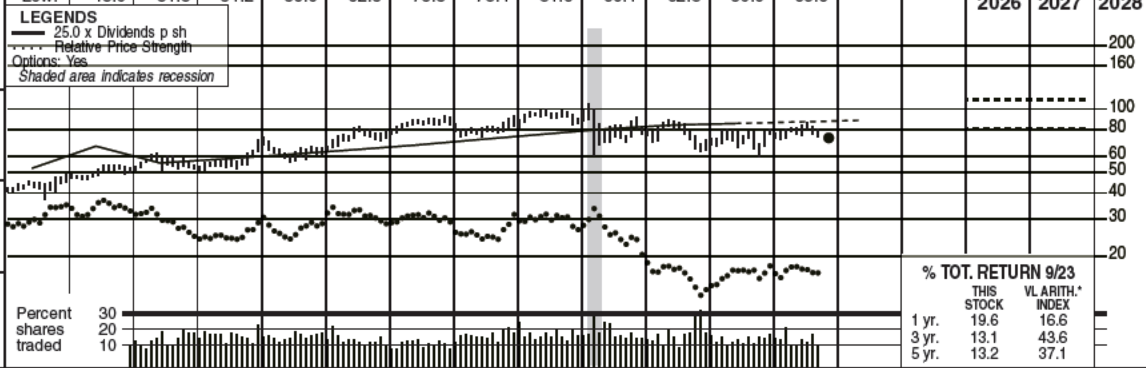
| | | |
|---|---|---|
| TIMELINESS | 5 | Lowered 10/13/23 |
| SAFETY | 2 | Lowered 10/22/21 |
| TECHNICAL | 3 | Lowered 10/20/23 |

BETA .95 (1.00 = Market)

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 54.7 | 61.9 | 71.1 | 73.3 | 82.8 | 92.5 | 92.6 | 99.8 | 105.5 | 88.5 | 80.6 | 86.0 |
| Low: | 45.9 | 51.5 | 51.2 | 56.0 | 62.5 | 75.8 | 73.4 | 81.6 | 60.1 | 62.8 | 59.0 | 69.6 |

Target Price Range 2026 | 2027 | 2028

LEGENDS
— 25.0 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession




**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $68-$107 | $88 (20%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 110 | (+50%) | 14% |
| Low | 80 | (+10%) | 7% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 299 | 243 | 201 |
| to Sell | 175 | 222 | 237 |
| Hld's(000) | 97877 | 98017 | 97185 |

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | 19.6 | 16.6 |
| 3 yr. | 13.1 | 43.6 |
| 5 yr. | 13.2 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 38.21 | **40.75** | **40.05** | Revenues per sh | **41.65** |
| 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 | 13.44 | **13.30** | **13.30** | "Cash Flow" per sh | **15.00** |
| 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 | 4.26 | **4.20** | **4.50** | Earnings per sh A | **5.70** |
| 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 | 3.42 | **3.48** | **3.54** | Div'd Decl'd per sh B ■ | **3.75** |
| 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 | 15.09 | **14.50** | **15.00** | Cap'l Spending per sh | **15.00** |
| 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 | 53.45 | **54.10** | **56.75** | Book Value per sh C | **62.00** |
| 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 | 113.17 | **113.50** | **118.00** | Common Shs Outst'g D | **120.00** |
| 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 | 17.1 | *Bold figures are* | | Avg Ann'l P/E Ratio | **16.5** |
| .79 | .97 | .91 | .80 | .92 | .91 | .86 | .84 | .81 | .98 | .97 | .96 | 1.03 | .86 | .76 | .99 | *Value Line* | | Relative P/E Ratio | **.90** |
| 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% | 4.7% | *estimates* | | Avg Ann'l Div'd Yield | **4.0%** |

**CAPITAL STRUCTURE as of 6/30/23**
Total Debt $8788.6 mill. Due in 5 Yrs $2100.7 mill.
LT Debt $8164.3 mill. LT Interest $395.0 mill.
(Total Interest Coverage: 2.8x)

Leases, Uncapitalized Annual rentals $18.1 mill.

Pension Assets-12/22 $2829.5 mill.
Oblig $2809.5 mill.

Pfd Stock None

Common Stock 113,312,203 shs.
as of 7/28/23
MARKET CAP: $8.3 billion (Mid Cap)

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3454.6 | 3491.6 | 3495.4 | 3498.7 | 3565.3 | 3691.2 | 3471.2 | 3587.0 | 3803.8 | 4324.4 | **4625** | **4725** | Revenues ($mill) | **5000** |
| 406.1 | 397.6 | 437.3 | 442.0 | 497.8 | 511.0 | 538.3 | 550.6 | 618.7 | 483.6 | **475** | **525** | Net Profit ($mill) | **685** |
| 34.4% | 34.2% | 34.3% | 33.9% | 32.5% | 20.2% | -- | 12.1% | 14.8% | 13.0% | **11.0%** | **12.0%** | Income Tax Rate | **14.0%** |
| 10.0% | 11.6% | 11.8% | 14.1% | 13.9% | 15.2% | 9.3% | 9.5% | 10.1% | 15.2% | **14.0%** | **13.0%** | AFUDC % to Net Profit | **12.0%** |
| 40.0% | 41.0% | 43.0% | 45.6% | 48.9% | 47.0% | 47.1% | 52.8% | 53.9% | 56.1% | **56.0%** | **52.5%** | Long-Term Debt Ratio | **56.0%** |
| 60.0% | 59.0% | 57.0% | 54.4% | 51.1% | 53.0% | 52.9% | 47.2% | 46.1% | 43.9% | **44.0%** | **47.5%** | Common Equity Ratio | **44.0%** |
| 6990.9 | 7398.7 | 8046.3 | 8825.4 | 9796.4 | 9861.1 | 10263 | 11948 | 12820 | 13790 | **13950** | **14100** | Total Capital ($mill) | **16900** |
| 10889 | 11194 | 11809 | 12714 | 13445 | 14030 | 14523 | 15159 | 15987 | 16854 | **17475** | **18200** | Net Plant ($mill) | **20200** |
| 7.1% | 6.4% | 6.4% | 6.0% | 6.1% | 6.2% | 6.3% | 5.5% | 5.8% | 4.5% | **4.5%** | **5.0%** | Return on Total Cap'l | **5.0%** |
| 9.7% | 9.1% | 9.5% | 9.2% | 9.9% | 9.8% | 9.9% | 9.8% | 10.5% | 8.0% | **7.5%** | **8.0%** | Return on Shr. Equity | **9.5%** |
| 9.7% | 9.1% | 9.5% | 9.2% | 9.9% | 9.8% | 9.9% | 9.8% | 10.5% | 8.0% | **7.5%** | **8.0%** | Return on Com Equity E | **9.5%** |
| 4.1% | 3.5% | 3.9% | 3.5% | 4.2% | 3.9% | 3.8% | 3.5% | 4.2% | 1.7% | **1.5%** | **1.5%** | Retained to Com Eq | **3.0%** |
| 58% | 62% | 59% | 62% | 58% | 60% | 61% | 64% | 60% | 78% | **83%** | **78%** | All Div'ds to Net Prof | **66%** |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +5.0 | -.1 | +4.4 |
| Avg. Indust. Use (MWH) | 766 | 808 | 849 |
| Avg. Indust. Revs. per KWH (¢) | 7.62 | 8.11 | 9.20 |
| Capacity at Peak (Mw) | 9094 | 8726 | 8612 |
| Peak Load, Summer (Mw) | 7660 | 7580 | 7587 |
| Annual Load Factor (%) | 45.5 | 45.9 | 48.1 |
| % Change Customers (yr-end) | +2.3 | +2.2 | +2.1 |
| Fixed Charge Cov. (%) | 318 | 317 | 226 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 1.5% | 2.0% | *3.0%* |
| "Cash Flow" | 5.0% | 5.5% | *3.5%* |
| Earnings | 4.5% | 3.5% | *2.5%* |
| Dividends | 4.0% | 5.5% | *2.0%* |
| Book Value | 4.0% | 4.0% | *3.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 661.9 | 929.6 | 1254.5 | 741.0 | 3587.0 |
| 2021 | 696.5 | 1000.2 | 1308.2 | 798.9 | 3803.8 |
| 2022 | 783.5 | 1061.7 | 1469.9 | 1009.3 | 4324.4 |
| 2023 | 945.0 | *1121.7* | *1510* | *1048.3* | *4625* |
| 2024 | *965* | *1135* | *1540* | *1085* | *4725* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .27 | 1.71 | 3.07 | d.17 | 4.87 |
| 2021 | .32 | 1.91 | 3.00 | .24 | 5.47 |
| 2022 | .15 | 1.45 | 2.88 | d.21 | 4.26 |
| 2023 | d.03 | *.94* | *3.30* | *d.01* | *4.20* |
| 2024 | *.05* | *1.35* | *3.11* | *d.01* | *4.50* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .737 | .738 | .738 | .782 | 3.00 |
| 2020 | .783 | .783 | .783 | .83 | 3.18 |
| 2021 | .83 | .83 | .83 | .85 | 3.34 |
| 2022 | .85 | .85 | .85 | .85 | 3.40 |
| 2023 | .865 | .865 | .865 | | |

**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, 47%; commercial/industrial, 41%; other, 12%. Generating sources: gas, 25%; nuclear, 24%; coal, 20%; renewables, 12%; purchased, 19%. Fuel costs: 38% of revenues. '22 reported deprec. rate: 3.03%. Has 5,861 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 should see a resumption of annual earnings growth in 2024.** After a weak start to this year due to higher operating and maintenance expense and mild weather, a heat wave took hold in July and the company benefited from a court ruling that allowed for the inclusion within its rate base of money spent to clean up emissions at a coal plant. The judiciary appeal win resulted in a surcharge on customers bills beginning July 1st. Higher electric demand from the heat wave, plus the surcharge, prompted management to raise this year's earnings projection from $3.95-$4.15 per share to $4.10-$4.30. Relative to last year, this year's bottom line is suffering from higher retirement contributions, prompted by last year's decline in equity and bond markets, and higher interest expense. Full-year profits should be up next year given the likelihood of higher electric rates.

**A pending general rate case could help restore some of the earnings power lost last year.** Rate relief is due at the start of 2024, but how much? From early 2022, the company has been operating under revised regulatory parameters that cut its allowed return on equity (ROE) from 10% to a nationwide low of 8.7%. The change effectively reduced the utility's annual earning power by about $1.00 per share. Pinnacle is requesting its ROE be restored near the former level. The company is also seeking an expansion in the use of automatic pricing mechanisms to cut regulatory lag in the recoupment of investments it's planning to make in support of Arizona's clean-energy objectives. A decision from a revamped state regulatory commission, which has a few new members and a different chairperson because of term limits, is due by year's end. A March appeals court decision has restored some of the company's former ROE, now at 8.9%, as the bench ruled that the regulatory commission overstepped its bounds by penalizing the utility for "poor customer service."

**These shares, however, are untimely.** PNW is down 11% over the past three months, in concert with its industry peers and other interest rate sensitive stocks. The dividend yield, 45 basis points above the industry median, may be a draw.

*Anthony J. Glennon* *October 20, 2023*

(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¢). '20 and '22 qtly. EPS don't sum due to rounding. Next egs. report due early Nov. (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/other intangibles. In '22: $17.54/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on common equity in '23: 8.9%. Regulatory Climate: Below Average.

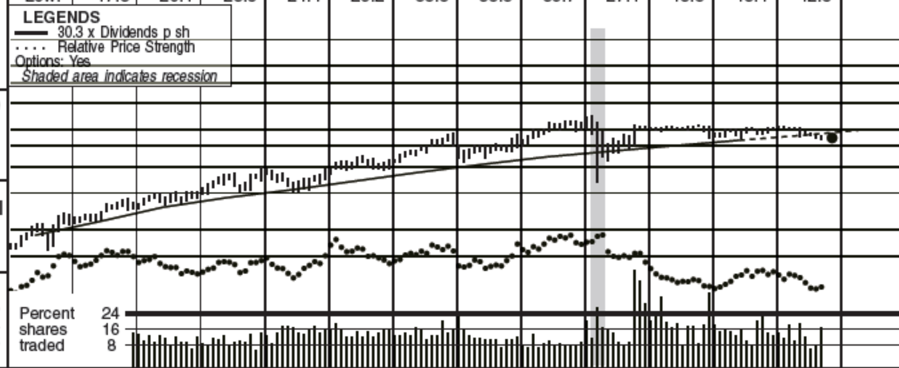
| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 85 |
| Price Growth Persistence | 45 |
| Earnings Predictability | 90 |

# PNM RESOURCES NYSE-PNM

| RECENT PRICE | 43.85 | P/E RATIO | 16.2 (Trailing: 16.2; Median: 19.0) | RELATIVE P/E RATIO | 1.01 | DIV'D YLD | 3.6% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

TIMELINESS — Suspended 1/20/23
SAFETY 2 Raised 4/23/21
TECHNICAL — Suspended 1/20/23
BETA .90 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 22.5 | 24.5 | 31.6 | 31.2 | 36.2 | 46.0 | 45.3 | 53.0 | 56.1 | 50.1 | 49.3 | 49.6 |
| Low: | 17.3 | 20.1 | 23.5 | 24.4 | 29.2 | 33.3 | 33.8 | 39.7 | 27.1 | 43.8 | 43.4 | 42.8 |




Target Price Range: 2026 | 2027 | 2028

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $42-$59 | $51 (15%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 60 | (+35%) | 11% |
| Low | 45 | (+5%) | 4% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 171 | 141 | 134 |
| to Sell | 110 | 131 | 146 |
| Hld's(000) | 75195 | 75599 | 78139 |

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | 0.6 | 16.6 |
| 3 yr. | 17.6 | 43.6 |
| 5 yr. | 29.0 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 26.21 | *27.55* | *29.70* | Revenues per sh | *32.20* |
| 2.54 | 1.76 | 2.32 | 2.67 | 3.18 | 3.39 | 3.52 | 4.09 | 4.28 | 4.51 | 5.30 | 5.47 | 5.95 | 5.80 | 6.19 | 6.67 | *6.75* | *7.05* | "Cash Flow" per sh | *8.35* |
| .76 | .11 | .58 | .87 | 1.08 | 1.31 | 1.41 | 1.45 | 1.48 | 1.46 | 1.92 | 2.00 | 2.16 | 2.28 | 2.45 | 2.69 | *2.70* | *2.85* | Earnings per sh A | *3.35* |
| .91 | .61 | .50 | .50 | .50 | .58 | .68 | .76 | .82 | .90 | .99 | 1.09 | 1.18 | 1.25 | 1.33 | 1.41 | *1.49* | *1.59* | Div'd Decl'd per sh B ■ † | *1.90* |
| 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 | 10.63 | *10.75* | *9.30* | Cap'l Spending per sh | *9.00* |
| 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 | 25.54 | *26.65* | *27.80* | Book Value per sh C | *31.95* |
| 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 | 85.83 | *88.00* | *90.00* | Common Shs Outst'g D | *90.00* |
| 35.6 | NMF | 18.1 | 14.0 | 14.5 | 15.0 | 16.1 | 18.7 | 18.7 | 22.4 | 20.4 | 19.4 | 22.2 | 19.6 | 19.9 | 17.4 | *Bold figures are* | | Avg Ann'l P/E Ratio | *15.5* |
| 1.89 | NMF | 1.21 | .89 | .91 | .95 | .90 | .98 | .94 | 1.18 | 1.03 | 1.05 | 1.18 | 1.01 | 1.08 | 1.01 | *Value Line* | | Relative P/E Ratio | *.85* |
| 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% | 2.7% | 3.0% | *estimates* | | Avg Ann'l Div'd Yield | *3.7%* |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $4676.4 mill. **Due in 5 Yrs** $2262.1 mill.
**LT Debt** $3927.6 mill. **LT Interest** $163.0 mill.
(Total Interest Coverage: 3.0x)

**Leases, Uncapitalized** Annual rentals $19.0 mill.

**Pension Assets-12/22** $454.0 mill. **Oblig** $545.6 mill.
**Pfd Stock** $11.5 mill. **Pfd Div'd** $.5 mill.

**Common Stock** 85,834,874 shs. **as of 7/28/23**
**MARKET CAP: $3.8 billion (Mid Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1387.9 | 1435.9 | 1439.1 | 1363.0 | 1445.0 | 1436.6 | 1457.6 | 1523.0 | 1779.9 | 2249.6 | *2425* | *2675* | Revenues ($mill) | *2900* |
| 114.0 | 116.8 | 118.8 | 117.4 | 154.4 | 160.6 | 173.1 | 183.4 | 211.6 | 232.0 | *235* | *255* | Net Profit ($mill) | *305* |
| 31.6% | 34.8% | 36.9% | 32.4% | 33.0% | 12.9% | 8.1% | 9.5% | 13.4% | 14.6% | *15.0%* | *16.0%* | Income Tax Rate | *19.0%* |
| 1.3% | 10.7% | 17.0% | 11.0% | 11.9% | 12.1% | 9.8% | 8.9% | 8.6% | 9.0% | *9.0%* | *8.0%* | AFUDC % to Net Profit | *9.0%* |
| 50.0% | 47.8% | 54.1% | 55.7% | 56.1% | 61.1% | 59.8% | 56.9% | 61.8% | 63.9% | *63.0%* | *62.0%* | Long-Term Debt Ratio | *62.5%* |
| 49.7% | 51.9% | 45.5% | 44.0% | 43.6% | 38.6% | 39.9% | 42.9% | 38.0% | 36.0% | *37.0%* | *37.5%* | Common Equity Ratio | *37.0%* |
| 3344.0 | 3437.1 | 3633.3 | 3806.8 | 3887.5 | 4370.0 | 4207.7 | 4780.6 | 5698.6 | 6096.1 | *6350* | *6650* | Total Capital ($mill) | *7725* |
| 3933.9 | 4270.0 | 4535.4 | 4904.7 | 4980.2 | 5234.6 | 5466.0 | 5965.1 | 6752.9 | 6972.8 | *7560* | *8020* | Net Plant ($mill) | *9125* |
| 5.2% | 5.1% | 4.8% | 4.7% | 5.3% | 5.0% | 5.5% | 4.9% | 4.6% | 4.9% | *4.5%* | *4.5%* | Return on Total Cap'l | *5.0%* |
| 6.8% | 6.5% | 7.1% | 7.0% | 9.0% | 9.4% | 10.2% | 8.9% | 9.7% | 10.5% | *10.0%* | *10.0%* | Return on Shr. Equity | *10.5%* |
| 6.8% | 6.5% | 7.1% | 7.0% | 9.1% | 9.5% | 10.3% | 8.9% | 9.7% | 10.6% | *10.0%* | *10.0%* | Return on Com Equity E | *10.5%* |
| 3.8% | 3.2% | 3.3% | 2.8% | 4.5% | 4.5% | 4.8% | 4.1% | 4.6% | 5.1% | *4.5%* | *4.5%* | Retained to Com Eq | *4.5%* |
| 45% | 51% | 54% | 61% | 51% | 53% | 54% | 54% | 53% | 52% | *55%* | *56%* | All Div'ds to Net Prof | *56%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % 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) | 1974 | 1968 | 2139 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | 1.1% | 1.2% | 1.0% |
| Fixed Charge Cov. (%) | 257 | 317 | 289 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 1.0% | 4.0% | *6.0%* |
| "Cash Flow" | 7.5% | 6.0% | *5.0%* |
| Earnings | 8.5% | 9.0% | *5.0%* |
| Dividends | 9.5% | 8.0% | *6.0%* |
| Book Value | 2.5% | 3.5% | *4.0%* |

| Calendar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 333.6 | 357.6 | 472.5 | 359.3 | 1523.0 |
| 2021 | 364.7 | 426.5 | 554.6 | 434.1 | 1779.9 |
| 2022 | 444.1 | 499.7 | 729.9 | 575.9 | 2249.6 |
| 2023 | 544.1 | 477.2 | *780* | *623.7* | *2425* |
| 2024 | *595* | *600* | *825* | *655* | *2675* |

| Calendar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .18 | .55 | 1.40 | .15 | 2.28 |
| 2021 | .32 | .55 | 1.37 | .21 | 2.45 |
| 2022 | .50 | .57 | 1.46 | .15 | 2.69 |
| 2023 | .55 | .55 | *1.33* | *.27* | *2.70* |
| 2024 | *.55* | *.60* | *1.40* | *.30* | *2.85* |

| Calendar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .29 | .29 | .29 | .29 | 1.16 |
| 2020 | .3075 | .3075 | .3075 | .3075 | 1.23 |
| 2021 | .3275 | .3275 | .3275 | .3275 | 1.31 |
| 2022 | .3475 | .3475 | .3475 | .3475 | 1.39 |
| 2023 | .3675 | .3675 | .3675 | | |

**BUSINESS:** PNM Resources, Inc. is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves 544,000 customers in north central New Mexico, including Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to 268,000 customers in Texas. Electric revenue breakdown: residential, 30%; commercial, 26%; industrial, 5%; other, 39%. Generating sources not available. Fuel costs: 44% of revenues. '22 reported depreciation rates: 2.6%-7.8%. Has 1,537 employees. Chairman and CEO: Patricia Vincent-Collawn. Incorporated: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, New Mexico 87102-3289. Telephone: 505-241-2700. Internet: www.pnmresources.com.

**The buyout of PNM Resources continues to drag on.** AVANGRID and PNM remain committed to a deal and have extended their agreement through the end of this year with an option for a three-month extension. To recap, shareholders are to receive $50.30 per share in an all-cash deal. The New Mexico Public Regulation Commission (NMPRC) voted against the merger in late 2021, citing concerns over AVANGRID's track record as a utility in the Northeast, a legal investigation of its parent company, Iberdrola of Spain, and potentially higher electric rates. Of these charges, we suspect it was the latter one that was the main stumbling block.

**In March, the companies and the agency that was the main obstacle to the deal agreed to negotiate a conclusion, but the courts are also involved.** The NMPRC, with newly appointed members, has agreed to a "rehearing and reconsideration to be made in a timely fashion," indicating its willingness to renegotiate the terms of a merger deal. But a joint motion filed with the New Mexico Supreme Court to dismiss a judiciary appeal the companies had made early last year and remand the case back to the NMPRC was denied in May. That decision was appealed and the justices heard oral arguments in mid-September on why they should move the decision back to the regulatory commission. The bench's decision on the latest appeal is expected by year's end.

**This issue's Timeliness rank is suspended, given that the buyout continues to be the dominant factor.** PNM shares were pricing in high odds the deal would go through earlier this year when it seemed likely the revamped NMPRC would reconsider the case. The court proceedings and appeal process has muddied the waters, however. At the recent price, there is 16% upside (including dividends) to the $50.30 buyout level and probably 10%-20% downside now that the peer group is trading at a much higher dividend yield than it had been earlier this year. These targets are on a 6-month basis. Existing shareholders should ride the process out. Odds slightly favor the merger gets done, but new commitments would be fairly speculative given roughly equal upside potential and downside risk.

*Anthony J. Glennon* *October 20, 2023*

(A) Dil. EPS. Excl. nonrec. gain/(loss): '08, ($3.77); '10, ($1.36); '11, 88¢; '13, (16¢); '15, ($1.28); '17, (92¢); '18, (93¢); '19, ($1.19); '20, (13¢); '21, (18¢); '22, (72¢). '23, 6¢. Excl. disc. op. gains: '08, 42¢; '09, 78¢. Next egs. report due early Nov. (B) Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinv. plan avail. (C) Incl. def. charges/other intang. In '22: $14.94/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in NM in '18: 9.575%; in TX in '11: 10.125%; Regulatory Climate: NM, Below Average.; TX, Average.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 80 |
| Earnings Predictability | 95 |

# PPL CORPORATION NYSE-PPL

RECENT PRICE 24.39 | P/E RATIO 15.2 (Trailing: 16.7 / Median: 14.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Raised 11/10/23
SAFETY 3 Lowered 3/18/22
TECHNICAL 4 Lowered 11/10/23
BETA 1.05 (1.00 = Market)

**18-Month Target Price Range**
Low-High: $20-$40 | Midpoint (% to Mid): $30 (25%)

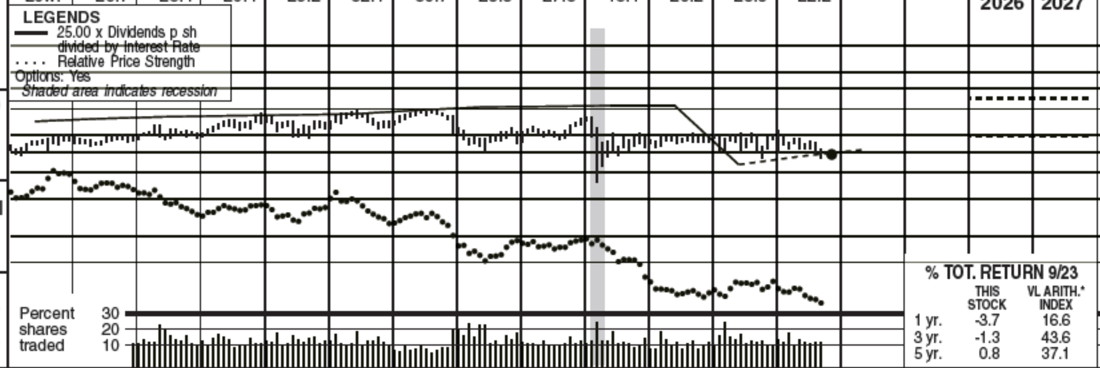
**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 45 | (+85%) | 19% |
| Low | 30 | (+25%) | 9% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 370 | 376 | 321 |
| to Sell | 358 | 339 | 385 |
| Hld's(000) | 529592 | 550878 | 541827 |

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 30.2 | 33.6 | 38.1 | 36.7 | 39.9 | 40.2 | 32.5 | 36.3 | 36.8 | 30.7 | 31.0 | 31.7 |
| Low: | 26.7 | 28.4 | 29.4 | 29.2 | 32.1 | 30.7 | 25.3 | 27.8 | 18.1 | 26.2 | 23.5 | 22.2 |




Target Price Range 2026 | 2027 | 2028

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -3.7 | 16.6 |
| 3 yr. | -1.3 | 43.6 |
| 5 yr. | 0.8 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 7.87 | 10.73 | *10.55* | *10.80* | Revenues per sh | *11.50* |
| 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 | 2.07 | 3.09 | *3.20* | *3.30* | "Cash Flow" per sh | *3.70* |
| 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 | .53 | 1.41 | *1.55* | *1.70* | Earnings per sh A | *2.10* |
| 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 | .88 | *.95* | *1.03* | Div'd Decl'd per sh B ■ | *1.26* |
| 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 | 2.68 | 2.93 | *3.25* | *3.65* | Cap'l Spending per sh | *4.00* |
| 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 | 18.67 | 18.89 | *19.50* | *20.15* | Book Value per sh C | *22.45* |
| 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 | 735.11 | 736.49 | *737.00* | *737.00* | Common Shs Outst'g D | *738.00* |
| 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 | 20.0 | *Bold figures are* | | Avg Ann'l P/E Ratio | *17.0* |
| .92 | 1.06 | 1.71 | .76 | .66 | .69 | .72 | .74 | .70 | .67 | .89 | .61 | .71 | .71 | NMF | 1.16 | *Value Line* | | Relative P/E Ratio | *.95* |
| 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% | 3.1% | *estimates* | | Avg Ann'l Div'd Yield | *3.4%* |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $14815 mill. **Due in 5 Yrs** $3613 mill.
**LT Debt** $14481 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: 3.5x)

**Leases, Uncapitalized** Annual rentals $24 mill.
**Pension Assets-12/22** $3149 mill. **Oblig** $3333 mill.

**Pfd Stock** None
**Common Stock** 737,088,540 shs. as of 7/31/23
**MARKET CAP: $18.0 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11860 | 11499 | 7669.0 | 7517.0 | 7447.0 | 7785.0 | 7769.0 | 7607.0 | 5783.0 | 7902.0 | *7770* | *7970* | Revenues ($mill) | *8500* |
| 1541.0 | 1583.0 | 1603.0 | 1902.0 | 1449.0 | 1827.0 | 1746.0 | 1571.0 | 401.0 | 1041.0 | *1180* | *1255* | Net Profit ($mill) | *1550* |
| 23.1% | 33.0% | 22.5% | 25.4% | 24.2% | 20.0% | 19.0% | 20.3% | 23.0% | 19.2% | *21.0%* | *21.0%* | Income Tax Rate | *21.0%* |
| 3.7% | 2.8% | 1.6% | 1.6% | 1.9% | 2.0% | 1.9% | 1.8% | 6.0% | .7% | *2.0%* | *2.0%* | AFUDC % to Net Profit | *2.0%* |
| 62.3% | 58.0% | 65.2% | 64.3% | 64.8% | 63.3% | 61.5% | 61.7% | 43.7% | 48.1% | *47.5%* | *46.5%* | Long-Term Debt Ratio | *44.0%* |
| 37.7% | 42.0% | 34.8% | 35.7% | 35.2% | 36.7% | 38.5% | 38.3% | 56.3% | 51.9% | *52.5%* | *53.5%* | Common Equity Ratio | *56.0%* |
| 33058 | 32484 | 28482 | 27707 | 30608 | 31726 | 33712 | 34926 | 24389 | 26804 | *27270* | *27735* | Total Capital ($mill) | *29675* |
| 33087 | 34597 | 30382 | 30074 | 33092 | 34458 | 36482 | 38892 | 25470 | 30238 | *31050* | *31900* | Net Plant ($mill) | *34900* |
| 6.2% | 6.5% | 7.1% | 8.4% | 6.2% | 7.2% | 6.6% | 5.9% | 2.6% | 4.9% | *5.5%* | *5.5%* | Return on Total Cap'l | *6.5%* |
| 12.4% | 11.6% | 16.2% | 19.2% | 13.5% | 15.7% | 13.4% | 11.7% | 2.9% | 7.5% | *8.0%* | *8.5%* | Return on Shr. Equity | *9.5%* |
| 12.4% | 11.6% | 16.2% | 19.2% | 13.5% | 15.7% | 13.4% | 11.7% | 2.9% | 7.5% | *8.0%* | *8.5%* | Return on Com Equity E | *9.5%* |
| 5.3% | 4.5% | 6.0% | 8.8% | 3.5% | 6.0% | 4.3% | 2.2% | NMF | 1.8% | *3.5%* | *3.5%* | Retained to Com Eq | *3.5%* |
| 57% | 61% | 63% | 54% | 74% | 62% | 68% | 81% | NMF | 76% | *67%* | *61%* | All Div'ds to Net Prof | *60%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -5.2 | +3.0 | +1.5 |
| 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) | NA | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | NA | NA | NA |
| Fixed Charge Cov. (%) | 278 | 154 | 348 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -7.5% | -3.0% | *3.5%* |
| "Cash Flow" | -3.5% | -5.0% | *3.5%* |
| Earnings | -6.0% | -11.5% | *8.0%* |
| Dividends | - - | -2.0% | *-1.5%* |
| Book Value | - - | 4.0% | *3.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 2054 | 1739 | 1885 | 1929 | 7607.0 |
| 2021 | 1498 | 1288 | 1512 | 1485 | 5783.0 |
| 2022 | 1782 | 1696 | 2134 | 2290 | 7902.0 |
| 2023 | 2415 | 1823 | *1740* | *1722* | *7700* |
| 2024 | *2470* | *1870* | *1785* | *1845* | *7970* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .72 | .45 | .50 | .38 | 2.04 |
| 2021 | .26 | d.20 | .27 | .19 | .53 |
| 2022 | .41 | .30 | .41 | .28 | 1.41 |
| 2023 | .48 | .29 | *.45* | *.33* | *1.55* |
| 2024 | *.49* | *.33* | *.47* | *.41* | *1.70* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .41 | .4125 | .4125 | .4125 | 1.65 |
| 2020 | .4125 | .415 | .415 | .415 | 1.66 |
| 2021 | .415 | .415 | .415 | .415 | 1.66 |
| 2022 | .415 | .20 | .225 | .225 | 1.07 |
| 2023 | .225 | .24 | .24 | | |

**BUSINESS:** PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Electric Utilities, which distributes electricity to 1.4 mill. customers in eastern & central Pennsylvannia. Acquired Kentucky Utilities and Louisville Gas and Electric (1.3 mill. customers) 11/10. Acq'd Narragansett Electric (770,000 customers, renamed Rhode Island Energy) 5/22. Spun off power-generating sub. in '15. Sold electric distribution sub. in U.K. in '21. Electric rev. breakdown: res'l, 46%; comm'l, 21%; ind'l, 10%; other, 23%. Fuel costs: 33% of revs. '22 reported deprec. rate: 3.2%. Has 6,527 employees. Chairman: William H. Spence. President & CEO: Vincent Sorgi. Inc.: PA. Address: Two North Ninth St., Allentown, PA 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

**We have lowered our 2023 share-earnings estimate for PPL Corp. by a nickel.** At $1.55, our new call represents an increase of roughly 10% over the adjusted $1.41 that the Pennsylvania-based electric and gas utility tallied in 2022. Previously, we thought earnings would rise closer to 13% on the year.

**Our less positive near-term stance partly reflects lower-assumed revenue within PPL's legacy footprint (excluding any contribution from Narragansett Electric, which was acquired in May, 2022).** Notably, the total number of degree days—a key indicator of underlying heating and cooling demand—were down by more than 20% in Kentucky during the June quarter and off in excess of 35% in Pennsylvania over the same span. What's more, extended periods of rainy summer weather across the Northeast and South suggest that comparisons remained unfavorable in the third quarter.

**PPL was recently ahead of schedule in its cost-cutting efforts.** Indeed, as of June 30th, the utility was reportedly further along in its plan to cut operating and maintenance (O&M) expense by between $50 million and $60 million this year. The news is particularly encouraging, given a spike in storm events that probably limited the window for network upgrades.

**Management recently affirmed its positive intermediate-term outlook.** If leadership has it right, both earnings and dividends will increase 6%–8% annually through at least 2026. An expanded rate base ought to help. So, too, should $115 million to $125 million in additional O&M spending cuts.

**Kentucky regulators were slated to weigh in on PPL's CPCN (Certificate of Public Convenience and Necessity) filing shortly after we went to press.** As we understand it, a favorable ruling will clear the way for PPL's KU and LG&E subsidiaries to replace four coal-fired power plants with clean-burning natural gas units and solar arrays backed up by battery storage.

**Shares of PPL are ranked 3 (Average) for relative year-ahead price performance.** At the recent quotation, we think that buy-and-hold investors seeking utility exposure will do pretty well here.

*Nils C. Van Liew* *November 10, 2023*

(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 & '21 EPS don't sum due to rounding. Next egs. rept. due mid-Feb. (B) Div'ds paid in early Jan., April, July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $3.12/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., '21: 2.8%. Reg. Clim.: Avg.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 75 |
| Price Growth Persistence | 15 |
| Earnings Predictability | 50 |

# P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE 60.16 | P/E RATIO 16.9 (Trailing: 16.8 Median: 16.0) | RELATIVE P/E RATIO 1.13 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Raised 5/12/23
SAFETY 1 Raised 11/23/12
TECHNICAL 4 Raised 11/3/23
BETA .90 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 34.1 | 37.0 | 43.8 | 44.4 | 47.4 | 53.3 | 56.7 | 63.9 | 62.2 | 67.1 | 75.6 | 65.5 |
| Low: | 28.9 | 29.7 | 31.3 | 36.8 | 37.8 | 41.7 | 46.2 | 50.0 | 34.8 | 53.8 | 52.5 | 53.7 |

Target Price Range 2026 | 2027 | 2028

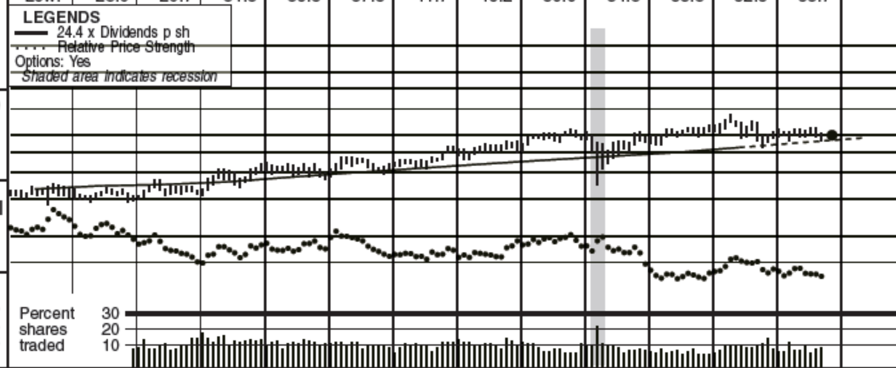
**18-Month Target Price Range**
Low-High Midpoint (% to Mid)
$48-$81 $65 (5%)

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 75 | (+25%) | 9% |
| Low | 60 | (Nil) | 4% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 438 | 442 | 395 |
| to Sell | 377 | 347 | 396 |
| Hld's(000) | 361159 | 354960 | 362902 |




% TOT. RETURN 9/23

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | 5.1 | 16.6 |
| 3 yr. | 14.9 | 43.6 |
| 5 yr. | 26.7 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 19.29 | 19.72 | *23.80* | *24.40* | Revenues per sh | *26.00* |
| 4.36 | 4.68 | 4.98 | 5.27 | 5.36 | 4.87 | 5.17 | 5.82 | 5.75 | 5.07 | 5.30 | 5.81 | 6.14 | 6.37 | 6.46 | 6.08 | *6.20* | *6.55* | "Cash Flow" per sh | *7.70* |
| 2.59 | 2.90 | 3.08 | 3.07 | 3.11 | 2.44 | 2.45 | 2.99 | 2.91 | 2.83 | 2.82 | 3.12 | 3.28 | 3.43 | 3.65 | 3.47 | *3.50* | *3.70* | Earnings per sh A | *4.40* |
| 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* | *2.40* | Div'd Decl'd per sh B ■† | *2.82* |
| 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 | 5.39 | 5.81 | *7.20* | *7.20* | Cap'l Spending per sh | *7.25* |
| 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 | 28.65 | 27.62 | *28.70* | *30.00* | Book Value per sh C | *34.75* |
| 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 | 504.00 | 497.00 | *500.00* | *500.00* | Common Shs Outst'g D | *500.00* |
| 16.5 | 13.6 | 10.0 | 10.4 | 10.4 | 12.8 | 13.5 | 12.6 | 14.1 | 15.3 | 16.3 | 16.6 | 18.0 | 15.7 | 16.8 | 18.5 | *Bold figures are* | | Avg Ann'l P/E Ratio | *15.5* |
| .88 | .82 | .67 | .66 | .65 | .81 | .76 | .66 | .71 | .80 | .82 | .90 | .96 | .81 | .91 | 1.08 | *Value Line* | | Relative P/E Ratio | *.85* |
| 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% | 3.3% | 3.4% | *estimates* | | Avg Ann'l Div'd Yield | *4.1%* |

**CAPITAL STRUCTURE as of 9/30/23**
**Total Debt** $19734 mill. **Due in 5 Yrs** $7225 mill.
**LT Debt** $17039 mill. **LT Interest** $630 mill.
(Total Interest coverage: 3.4x)

**Leases, Uncapitalized** Annual rentals $35 mill.

**Pension Assets-12/22** $4911 mill. **Oblig** $5628 mill.

**Pfd Stock** None

**Common Stock** 498,314,302 shs. as of 10/17/23
**MARKET CAP: $30.0 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9968.0 | 10886 | 10415 | 9198.0 | 9161.0 | 9696.0 | 10076 | 9603.0 | 9722.0 | 9800.0 | *11900* | *12200* | Revenues ($mill) | *13000* |
| 1243.0 | 1518.0 | 1476.0 | 1436.0 | 1431.0 | 1582.0 | 1666.0 | 1741.0 | 1853.0 | 1739.0 | *1730* | *1860* | Net Profit ($mill) | *2210* |
| 39.5% | 38.2% | 37.4% | 31.7% | 37.3% | 23.7% | 32.2% | 14.3% | 19.5% | 13.7% | *20.0%* | *20.0%* | Income Tax Rate | *20.0%* |
| 4.6% | 4.5% | 6.2% | 8.4% | 10.6% | 8.7% | 6.5% | 7.0% | 5.5% | 5.1% | *8.0%* | *8.0%* | AFUDC % to Net Profit | *7.0%* |
| 40.4% | 40.4% | 40.3% | 45.3% | 46.6% | 47.8% | 47.7% | 47.6% | 51.3% | 54.6% | *54.0%* | *53.5%* | Long-Term Debt Ratio | *54.0%* |
| 59.6% | 59.6% | 59.7% | 54.7% | 53.4% | 52.2% | 52.3% | 52.4% | 48.7% | 45.4% | *46.0%* | *46.5%* | Common Equity Ratio | *46.0%* |
| 19470 | 20446 | 21900 | 24025 | 25915 | 27545 | 28832 | 30480 | 29657 | 30224 | *31200* | *32200* | Total Capital ($mill) | *37600* |
| 21645 | 23589 | 26539 | 29286 | 31797 | 34363 | 35844 | 37585 | 34366 | 35942 | *38250* | *40475* | Net Plant ($mill) | *46700* |
| 7.5% | 8.4% | 7.6% | 6.8% | 6.4% | 6.7% | 6.7% | 6.6% | 7.1% | 6.7% | *6.5%* | *6.5%* | Return on Total Cap'l | *7.0%* |
| 10.7% | 12.5% | 11.3% | 10.9% | 10.3% | 11.0% | 11.0% | 10.9% | 12.8% | 12.7% | *12.0%* | *12.5%* | Return on Shr. Equity | *12.5%* |
| 10.7% | 12.5% | 11.3% | 10.9% | 10.3% | 11.0% | 11.0% | 10.9% | 12.8% | 12.7% | *12.0%* | *12.5%* | Return on Com Equity E | *12.5%* |
| 4.4% | 6.3% | 5.3% | 4.6% | 4.1% | 4.7% | 4.7% | 4.7% | 5.7% | 4.8% | *4.5%* | *4.5%* | Retained to Com Eq | *4.5%* |
| 59% | 49% | 53% | 58% | 61% | 58% | 57% | 57% | 56% | 62% | *65%* | *64%* | All Div'ds to Net Prof | *64%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -2.5 | +1.3 | +1.6 |
| 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) | 9905 | 10064 | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (avg.) | +.9 | +.9 | +.9 |
| Fixed Charge Cov. (%) | 298 | 273 | 298 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | -1.0% | .5% | *4.5%* |
| "Cash Flow" | 2.0% | 3.0% | *3.5%* |
| Earnings | 2.0% | 4.5% | *4.0%* |
| Dividends | 4.0% | 4.5% | *5.5%* |
| Book Value | 4.0% | 2.0% | *2.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 2781 | 2050 | 2370 | 2402 | 9603 |
| 2021 | 2889 | 1874 | 1903 | 3056 | 9722 |
| 2022 | 2313 | 2076 | 2272 | 3139 | 9800 |
| 2023 | 3755 | 2421 | 2456 | *3268* | *11900* |
| 2024 | *3850* | *2475* | *2525* | *3350* | *12200* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1.03 | .79 | .96 | .65 | 3.43 |
| 2021 | 1.28 | .70 | .98 | .69 | 3.65 |
| 2022 | 1.33 | .64 | .86 | .64 | 3.47 |
| 2023 | 1.39 | .70 | .85 | *.56* | *3.50* |
| 2024 | *1.40* | *.75* | *.85* | *.70* | *3.70* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■† Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .47 | .47 | .47 | .47 | 1.88 |
| 2020 | .49 | .49 | .49 | .49 | 1.96 |
| 2021 | .51 | .51 | .51 | .51 | 2.04 |
| 2022 | .54 | .54 | .54 | .54 | 2.16 |
| 2023 | .57 | .57 | .57 | | |

**BUSINESS:** Public Service Enterprise Group Inc. 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 NJ, and PSEG Power LLC, a nonregulated power generator with nuclear plants in the Northeast (sold its fossil-fuel generation, 2/22). In mid-2022, announced intent to divest offshore wind assets. Percentage of electric sales: Commercial (57%); Residential (34%); Industrial (9%). Fuel costs: 41% of revenues. '22 reported depreciation rates (utility): 1.9%-2.6%. Has 12,525 employees. Executive Chair: Dr. Ralph Izzo. Chair, Pres. & CEO: Ralph A. LaRossa. 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 (PSEG) will likely see a small profit gain this year.** Despite better-than-expected third-quarter earnings, leadership reaffirmed its bottom-line target for full-year 2023 of $3.40-$3.50 per share. The completion of certain maintenance work often shifts from quarter to quarter, so utilities, especially the larger ones, can manage earnings to a degree. In aggregate, PSEG's 2023 campaign is benefiting from growth in transmission and distribution margins resulting from ongoing investment in infrastructure replacement and clean energy programs. Still, milder-than-typical weather, rising interest expense and higher retirement contributions are weighing on the bottom line.

**Earnings are likely to exhibit a more-pronounced upwards trajectory in 2024.** Utility revenue is rising due to regulatory pricing mechanisms that allow for near-contemporaneous returns on capital used for certain grid improvements. This year's mild weather sets up easier comparisons in 2024. Plus, interest expense and pension contributions may moderate.

**New Jersey's "green" energy initiatives ought to keep profits on the rise through late decade.** Last year's Inflation Reduction Act, to a large degree a backdoor clean-energy bill, is also supportive, providing years of subsidies for nuclear power, deemed a "nonemitting" energy source. This played out well for PSEG's hand, with the company deciding to hold onto its five-unit nuclear generating fleet. Those assets provide a steady stream of cash flow that will help fund rising investments needed to meet New Jersey's aggressive carbon-free goals. PSEG's $15 billion to $18 billion five-year capital spending program should expand the company's rate base at a 6% to 7.5% clip per annum on average. Through regulatory pricing mechanisms, based on a 9.6% allowable return on equity, the aforementioned level of investment ought to translate to 5%-7% long-term profit growth.

**This top-quality equity, however, does not stand out at the recent quotation.** Total return prospects to 2026-2028 are below the electric utility median of 11%. PSEG's 3.9% dividend yield is below the peer-group median of 4.3%.

*Anthony J. Glennon* *November 10, 2023*

(A) Diluted EPS. Excl. nonrec. gains/(losses): '08, (96¢); '09, 6¢; '11, (34¢); '12, 7¢; '15, 39¢; '16, ($1.08); '17, 28¢ (net); '18, (29¢); '19, 5¢; '20, 33¢; '21, ($4.94); '22, ($1.41); Q1-Q3 '23, $1.09; disc. ops.: '07, 3¢; '08, 40¢; '10, 1¢; '11, 19¢. Next egs. report due early February. (B) Div'ds historically paid in late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '22: $8.90/sh. (D) In mill., adj. for '08 split. (E) Rate base: Net original cost. Rate allowed on common equity in '18: 9.6%; Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | A+ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 70 |
| Earnings Predictability | 95 |

# SEMPRA ENERGY NYSE-SRE

RECENT PRICE 68.50 | P/E RATIO 14.9 (Trailing: 15.0; Median: 20.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 3.6% | VALUE LINE

**TIMELINESS** 5 Lowered 9/15/23
**SAFETY** 2 Raised 7/29/16
**TECHNICAL** 5 Lowered 10/20/23
**BETA** 1.00 (1.00 = Market)

**18-Month Target Price Range**
Low-High: $64-$131 Midpoint (% to Mid): $98 (40%)

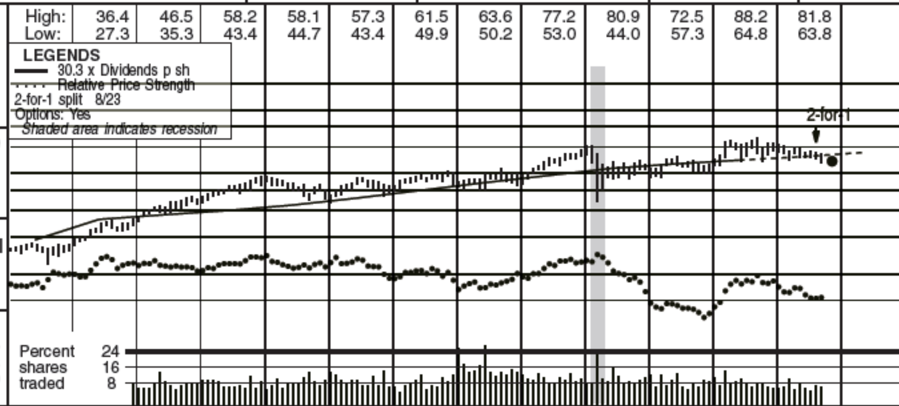
**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 105 | (+55%) | 14% |
| Low | 75 | (+10%) | 6% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 518 | 436 | 446 |
| to Sell | 364 | 425 | 389 |
| Hld's(000) | 547374 | 538994 | 539812 |

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 36.4 | 46.5 | 58.2 | 58.1 | 57.3 | 61.5 | 63.6 | 77.2 | 80.9 | 72.5 | 88.2 | 81.8 |
| Low: | 27.3 | 35.3 | 43.4 | 44.7 | 43.4 | 49.9 | 50.2 | 53.0 | 44.0 | 57.3 | 64.8 | 63.8 |




Target Price Range 2026 | 2027 | 2028

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -6.3 | 16.6 |
| 3 yr. | 26.5 | 43.6 |
| 5 yr. | 40.4 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 21.89 | 22.11 | 16.44 | 18.72 | 20.91 | 19.90 | 21.59 | 22.40 | 20.60 | 20.35 | 22.29 | 21.34 | 18.56 | 19.71 | 20.28 | 22.97 | *27.55* | *28.15* | Revenues per sh | *30.15* |
| 3.47 | 3.70 | 3.97 | 3.88 | 4.29 | 4.46 | 4.43 | 4.70 | 5.16 | 4.75 | 5.29 | 5.53 | 5.57 | 6.61 | 7.09 | 7.85 | *7.95* | *8.50* | "Cash Flow" per sh | *10.45* |
| 2.13 | 2.22 | 2.39 | 2.01 | 2.24 | 2.18 | 2.11 | 2.32 | 2.62 | 2.12 | 2.32 | 2.74 | 2.99 | 3.69 | 4.22 | 4.61 | *4.50* | *4.80* | Earnings per sh A | *6.00* |
| .62 | .69 | .78 | .78 | .96 | 1.20 | 1.26 | 1.32 | 1.40 | 1.51 | 1.65 | 1.79 | 1.94 | 2.09 | 2.20 | 2.29 | *2.38* | *2.50* | Div'd Decl'd per sh B ■ | *3.05* |
| 3.85 | 4.24 | 3.88 | 4.29 | 5.93 | 6.10 | 5.26 | 6.34 | 6.36 | 8.42 | 7.86 | 6.91 | 6.36 | 8.10 | 7.91 | 8.52 | *8.55* | *8.55* | Cap'l Spending per sh | *9.00* |
| 15.94 | 16.38 | 18.27 | 18.77 | 20.50 | 21.21 | 22.51 | 22.99 | 23.78 | 25.89 | 25.20 | 27.18 | 30.29 | 35.06 | 39.59 | 41.72 | *43.75* | *46.05* | Book Value per sh C | *54.30* |
| 522.43 | 486.65 | 493.02 | 480.89 | 479.87 | 484.74 | 488.92 | 492.66 | 496.60 | 500.31 | 502.72 | 547.54 | 583.43 | 576.94 | 633.84 | 628.67 | *630.00* | *630.00* | Common Shs Outst'g D | *630.00* |
| 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 | 17.5 | 15.4 | 16.8 | *Bold figures are* | | Avg Ann'l P/E Ratio | *15.0* |
| .74 | .71 | .67 | .80 | .74 | .95 | 1.11 | 1.15 | .99 | 1.28 | 1.22 | 1.10 | 1.20 | .90 | .83 | .97 | *Value Line* | | Relative P/E Ratio | *.85* |
| 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% | 3.0% | *estimates* | | Avg Ann'l Div'd Yield | *3.4%* |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $30033 mill. **Due in 5 Yrs** $6475 mill.
**LT Debt** $27521 mill. **LT Interest** $1215 mill.
Incl. $1343 mill. finance leases.
(Total Interest Coverage: 3.3x)

**Leases, Uncapitalized** Annual rentals $53 mill.
**Pension Assets-12/22** $2390 mill. **Oblig** $2806 mill.
**Pfd Stock** $889 mill. **Pfd Div'd** $45 mill.
900,000 shs. 4.875%, cumulative.
**Common Stock** 629,307,130 shs.
**as of 7/31/23**
**MARKET CAP: $43.1 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10557 | 11035 | 10231 | 10183 | 11207 | 11687 | 10829 | 11370 | 12857 | 14439 | *17350* | *17750* | Revenues ($mill) | *19000* |
| 1060.0 | 1162.0 | 1314.0 | 1065.0 | 1169.0 | 1607.0 | 1825.0 | 2316.0 | 2701.0 | 2960.0 | *2885* | *3080* | Net Profit ($mill) | *3835* |
| 26.5% | 19.7% | 19.2% | 14.4% | 24.5% | 20.1% | 17.9% | 18.0% | 25.5% | 20.1% | *19.0%* | *19.0%* | Income Tax Rate | *19.0%* |
| 11.2% | 14.4% | 15.3% | 22.2% | 21.9% | 12.6% | 10.0% | 8.7% | 8.0% | 8.6% | *9.0%* | *9.0%* | AFUDC % to Net Profit | *8.5%* |
| 50.5% | 51.7% | 52.6% | 52.7% | 56.4% | 55.7% | 51.0% | 48.2% | 44.8% | 47.5% | *49.0%* | *49.0%* | Long-Term Debt Ratio | *47.5%* |
| 49.4% | 48.2% | 47.3% | 47.3% | 43.5% | 38.4% | 43.4% | 44.8% | 53.3% | 50.7% | *49.0%* | *49.5%* | Common Equity Ratio | *51.0%* |
| 22281 | 23513 | 24963 | 27400 | 29135 | 38769 | 40734 | 45174 | 47069 | 51683 | *56025* | *58900* | Total Capital ($mill) | *67100* |
| 25460 | 25902 | 28039 | 32931 | 36503 | 36796 | 36452 | 40003 | 43894 | 47782 | *51000* | *54050* | Net Plant ($mill) | *62200* |
| 6.0% | 6.1% | 6.4% | 5.0% | 5.1% | 5.1% | 5.5% | 6.1% | 6.6% | 6.8% | *6.0%* | *6.0%* | Return on Total Cap'l | *6.5%* |
| 9.6% | 10.2% | 11.1% | 8.2% | 9.2% | 9.4% | 9.1% | 9.9% | 10.4% | 10.9% | *10.0%* | *10.5%* | Return on Shr. Equity | *11.0%* |
| 9.6% | 10.3% | 11.1% | 8.2% | 9.2% | 10.0% | 9.5% | 10.6% | 10.5% | 11.1% | *10.5%* | *10.5%* | Return on Com Equity E | *11.0%* |
| 4.1% | 5.0% | 5.8% | 2.9% | 3.3% | 4.1% | 3.9% | 4.8% | 5.2% | 5.7% | *5.0%* | *5.0%* | Retained to Com Eq | *5.5%* |
| 58% | 52% | 48% | 65% | 65% | 62% | 62% | 58% | 52% | 50% | *54%* | *53%* | All Div'ds to Net Prof | *51%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -.4 | -3.7 | +2.8 |
| 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 | +.9 | +.5 |
| Fixed Charge Cov. (%) | 178 | 201 | 232 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 0.5% | - - | *6.0%* |
| "Cash Flow" | 5.5% | 7.0% | *6.5%* |
| Earnings | 7.0% | 12.0% | *6.5%* |
| Dividends | 8.5% | 7.5% | *5.5%* |
| Book Value | 7.0% | 9.0% | *6.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 3029 | 2526 | 2644 | 3171 | 11370 |
| 2021 | 3259 | 2741 | 3013 | 3844 | 12857 |
| 2022 | 3820 | 3547 | 3617 | 3455 | 14439 |
| 2023 | 6560 | 3335 | *3650* | *3805* | *17350* |
| 2024 | *6125* | *3750* | *3825* | *4050* | *17750* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1.27 | .79 | .66 | .94 | 3.69 |
| 2021 | 1.48 | .82 | .85 | 1.08 | 4.22 |
| 2022 | 1.46 | .99 | .99 | 1.18 | 4.61 |
| 2023 | 1.46 | .94 | *.97* | *1.13* | *4.50* |
| 2024 | *1.55* | *1.00* | *1.05* | *1.20* | *4.80* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .448 | .484 | .484 | .484 | 1.90 |
| 2020 | .484 | .523 | .523 | .523 | 2.05 |
| 2021 | .523 | .55 | .55 | .55 | 2.17 |
| 2022 | .55 | .573 | .573 | .573 | 2.27 |
| 2023 | .573 | .595 | .595 | .595 | |

**BUSINESS:** Sempra Energy is a holding company for San Diego Gas & Electric (SDG&E), which sells electricity & gas mainly in San Diego County, and Southern California Gas (SoCalGas), which distributes gas to most of Southern California. Owns 80% of Oncor (acquired 3/18), which distributes electricity in TX. Customers: 5.2 mill. electric, 7.0 mill. gas. Electric revenue breakdown: N/A. Purchases 76% of its power; the rest is gas. The Sempra Infrastrucure subsidiary (SI) is active in LNG exportation and other energy endeavors. Sold SA utilities in 2020. Power costs: 24.5% of revenue. '22 reported deprec. rates: 2.6%-7.0%. Employs 15,785. Chr., Pres. & CEO: Jeffrey W. Martin. Inc.: CA. Addr.: 488 8th Ave., San Diego, CA 92101. Tel.: 619-696-2000. Internet: www.sempra.com.

**Sempra Energy's earnings should resume a growth trajectory in 2024 after this year's likely decline.** Leadership affirmed its respective share-earnings targets of $4.30-$4.60 and $4.55-$4.90 for 2023 and 2024. Quarterly comparisons will be difficult through the end of this year, as 2022's heat wave in southern California drove electricity usage up 2.8%. Regulatory lag is a key issue for this year in particular. Significant investments in grid modernization and the related financing costs await recoupment. While Sempra received a favorable regulatory outcome, based on a 9.7% allowable return on equity, at its 80%-owned transmission and distribution subsidiary in Texas a few months ago, the company is overdue for rate relief in California. A regulatory decision is expected in the second quarter of next year for San Diego Gas & Electric and SoCalGas. Higher rates should be retroactive to the start of 2024.

**Leadership's projected 6%-8% long-term earnings growth target is feasible.** Load growth in southern California has been running at about 3% annually, driven by economic activity and shifts to vehicles and the like that are recharged from the grid. Meanwhile, Sempra's service area in Texas is among the fastest growing in terms of transmission and distribution work, due to the rapid pace of the state's population growth and healthy economic activity. Lastly, the economics of the liquefied natural gas (LNG) export operation looks attractive. Sempra Infrastucture (SI) has put together a project that will export 13 million tonnes per annum of LNG from Texas to Europe and Asia starting in 2027. We estimate a bump in Sempra's annual earnings power by $0.25-$0.50 per share, with an opportunity to replicate the gains through additional project phases. Notably, SI has comparable LNG expansions taking place at its Baja California site in Mexico.

**This equity, however, is untimely.** The rise in the 10-year Treasury yield to levels not seen since 2007 has pressured the stock prices of rate-sensitive industries and prompted us to reduce our 2026-2028 Target Price Ranges for Sempra and most utility peers. The jump in rates looks as if it's more than just cyclical in nature.

*Anthony J. Glennon* *October 20, 2023*

(A) Diluted egs. Excl. nonrec. gains/(losses): '09, (13¢); '10, (52¢); '11, 58¢; '12, (44¢); '13, (11¢); '15, 7¢; '16, 61¢; '17, ($1.81); '18, ($1.03); '19, 8¢; '20, (40¢); '21, ($2.21); '22, (82¢); '23, 9¢. Disc. ops.: '19, 58¢; '20, $3.15. Qtly. EPS may not sum due to rounding. Next egs. report due early Nov. (B) Div'ds paid mid-Jan., Apr., July, Oct. ■ Div. reinv. avail. (C) Incl. intang. In '22: $7.21/sh. (D) In mill., adj. for 8/23 stk. split. (E) Rate base: Net orig. cost. Rate allowed on com. eq.: SDG&E '22: 9.95%; SoCalGas in '22: 9.8%. Reg. Climate: Avg.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 90 |
| Price Growth Persistence | 50 |
| Earnings Predictability | 95 |

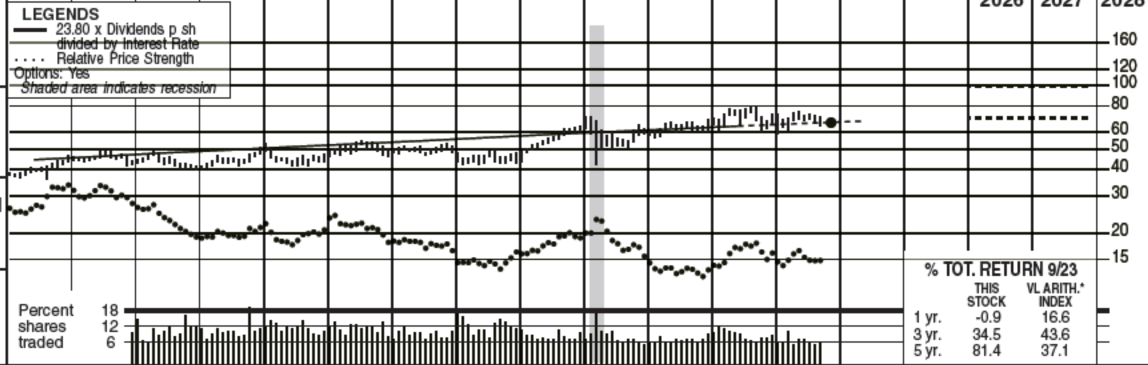
# SOUTHERN COMPANY NYSE-SO

RECENT PRICE 66.79 | P/E RATIO 15.8 (Trailing: 21.2; Median: 17.0) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 4.2% | VALUE LINE

**TIMELINESS** 4 Lowered 8/4/23
**SAFETY** 2 Lowered 2/21/14
**TECHNICAL** 4 Lowered 11/10/23
**BETA** .90 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 48.6 | 48.7 | 51.3 | 53.2 | 54.6 | 53.5 | 49.4 | 64.3 | 71.1 | 68.9 | 80.6 | 75.8 |
| Low: | 41.8 | 40.0 | 40.3 | 41.4 | 46.0 | 46.7 | 42.4 | 43.3 | 42.0 | 56.7 | 60.7 | 58.8 |

LEGENDS
— 23.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2026 | 2027 | 2028

**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $61-$100 | $81 (20%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 100 | (+50%) | *14%* |
| Low | 70 | (+5%) | *5%* |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 911 | 843 | 773 |
| to Sell | 594 | 622 | 703 |
| Hld's(000) | 693302 | 697201 | 688021 |

Percent shares traded 18 12 6

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -0.9 | 16.6 |
| 3 yr. | 34.5 | 43.6 |
| 5 yr. | 81.4 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 21.80 | 26.89 | *25.70* | *27.10* | Revenues per sh | *28.90* |
| 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 | 7.34 | *7.55* | *8.00* | "Cash Flow" per sh | *9.25* |
| 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 | 3.42 | 3.61 | *3.60* | *4.00* | Earnings per sh A | *5.15* |
| 1.60 | 1.66 | 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* | *2.86* | Div'd Decl'd per sh B ■ | *3.10* |
| 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 | 6.83 | 7.58 | *7.85* | *7.85* | Cap'l Spending per sh | *7.50* |
| 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 | 26.30 | 27.93 | *28.00* | *29.90* | Book Value per sh C | *32.25* |
| 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 | 1060.0 | 1089.0 | *1070.0* | *1070.0* | Common Shs Outst'g D | *1070.0* |
| 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 | 18.4 | 19.6 | *Bold figures are* | | Avg Ann'l P/E Ratio | *16.5* |
| .85 | .97 | .90 | .95 | .99 | 1.08 | .91 | .84 | .80 | .93 | .78 | .82 | .94 | .92 | 1.00 | 1.14 | *Value Line* | | Relative P/E Ratio | *.90* |
| 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% | 4.1% | *estimates* | | Avg Ann'l Div'd Yield | *3.6%* |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $55134 mill. **Due in 5 Yrs** $15427 mill.
**LT Debt** $50495 mill. **LT Interest** $1754 mill.
Incl. $215 mill. finance leases.
(LT interest earned: 3.3x)
**Leases, Uncapitalized** Annual rentals $307 mill.
**Pension Assets-12/22** $17225 mill. **Oblig** $16382 mill.
**Pfd Stock** $242 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** 1,090,546,579 shs.
**MARKET CAP: $72.8 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 17087 | 18467 | 17489 | 19896 | 23031 | 23495 | 21419 | 20375 | 23113 | 29279 | *27500* | *29000* | Revenues ($mill) | *30900* |
| 2439.0 | 2567.0 | 2647.0 | 2757.0 | 3269.0 | 3096.0 | 3354.0 | 3481.0 | 3670.0 | 3931.3 | *3850* | *4280* | Net Profit ($mill) | *5510* |
| 34.8% | 33.8% | 33.4% | 28.5% | 25.2% | 21.3% | 15.9% | 14.3% | 16.3% | 18.8% | *15.0%* | *15.0%* | Income Tax Rate | *15.0%* |
| 11.6% | 13.9% | 13.2% | 11.9% | 7.6% | 6.8% | 6.0% | 6.6% | 7.7% | 8.0% | *8.0%* | *8.0%* | AFUDC % to Net Profit | *6.0%* |
| 51.5% | 49.5% | 52.8% | 61.5% | 64.5% | 62.0% | 60.1% | 61.5% | 64.0% | 63.0% | *64.0%* | *64.0%* | Long-Term Debt Ratio | *63.0%* |
| 45.8% | 47.3% | 44.0% | 35.7% | 35.0% | 37.6% | 39.5% | 38.1% | 35.6% | 36.5% | *36.0%* | *36.0%* | Common Equity Ratio | *37.0%* |
| 41483 | 42142 | 46788 | 69359 | 68953 | 65750 | 69594 | 73336 | 78285 | 80558 | *83500* | *85000* | Total Capital ($mill) | *93500* |
| 51208 | 54868 | 61114 | 78446 | 79872 | 80797 | 83080 | 87634 | 91108 | 94570 | *99350* | *100000* | Net Plant ($mill) | *110000* |
| 6.8% | 7.1% | 6.6% | 4.9% | 5.9% | 5.9% | 6.0% | 5.9% | 5.8% | 5.5% | *5.5%* | *5.5%* | Return on Total Cap'l | *6.5%* |
| 12.1% | 12.1% | 12.0% | 10.3% | 13.3% | 12.4% | 12.1% | 12.3% | 13.0% | 12.5% | *13.0%* | *13.0%* | Return on Shr. Equity | *14.5%* |
| 12.5% | 12.5% | 12.6% | 11.0% | 13.4% | 12.5% | 12.1% | 12.4% | 13.1% | 13.0% | *13.0%* | *13.0%* | Return on Com Equity E | *14.5%* |
| 3.2% | 3.2% | 3.1% | 2.5% | 3.9% | 2.6% | 2.8% | 2.8% | 3.1% | 3.0% | *3.5%* | *3.5%* | Retained to Com Eq | *5.0%* |
| 75% | 75% | 76% | 78% | 72% | 79% | 77% | 78% | 76% | 78% | *77%* | *77%* | All Div'ds to Net Prof | *67%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -8.5 | -5.3 | +2.0 |
| Avg. Indust. Use (MWH) | 2947 | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 6.03 | NA | NA |
| Capacity at Yearend (Mw) | 41940 | NA | NA |
| Peak Load, Summer (Mw) | 34209 | NA | NA |
| Annual Load Factor (%) | 60.3 | NA | NA |
| % Change Customers (yr-end) | -8.9 | +1.3 | +1.5 |
| Fixed Charge Cov. (%) | 281 | 270 | 275 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | - - | .5% | *6.0%* |
| "Cash Flow" | 4.0% | 4.5% | *5.0%* |
| Earnings | 3.0% | 3.0% | *6.5%* |
| Dividends | 3.5% | 3.5% | *3.5%* |
| Book Value | 3.0% | 2.5% | *3.5%* |

| Cal-endar | QUARTERLY REVENUES (mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 5018 | 4620 | 5620 | 5117 | 20375 |
| 2021 | 5910 | 5198 | 6238 | 5767 | 23113 |
| 2022 | 6648 | 7206 | 8378 | 7047 | 29279 |
| 2023 | 6480 | 5748 | *8000* | *7272* | *27500* |
| 2024 | *6800* | *7200* | *8000* | *7000* | *29000* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .81 | .75 | 1.18 | .51 | 3.25 |
| 2021 | 1.09 | .67 | 1.22 | .44 | 3.42 |
| 2022 | .97 | 1.07 | 1.31 | .26 | 3.61 |
| 2023 | .79 | .79 | *1.32* | *.70* | *3.60* |
| 2024 | *1.20* | *1.00* | *1.30* | *.50* | *4.00* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .60 | .62 | .62 | .62 | 2.46 |
| 2020 | .62 | .64 | .64 | .64 | 2.54 |
| 2021 | .64 | .66 | .66 | .66 | 2.62 |
| 2022 | .66 | .68 | .68 | .68 | 2.70 |
| 2023 | .68 | .70 | .70 | | |

**BUSINESS:** The Southern Company, through its subsidiaries, supplies electricity to 4.4 mill. customers in GA, AL, and MS. Also has a competitive generation business. Acq'd AGL Resources (renamed Southern Company Gas, 4.4 mill. customers in GA, NJ, IL, VA, & TN) 7/16. Sold Gulf Power 1/19. Electric revenue breakdown: residential, 37%; commercial, 30%; industrial, 19%; other, 14%. Generating sources: gas, 44%; coal, 20%; nuclear, 16%; other, 11%; purchased, 9%. Fuel costs: 29% of revenues. '22 reported deprec. rates (utility): 2.7%-3.6%. Has 27,300 employees. President and CEO: Chris Womack. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-0747. Internet: www.southerncompany.com.

**Southern Company's Georgia Power subsidiary continues to face challenges in its nuclear construction project.** Indeed, Georgia Power agreed to pay $413 million to resolve a legal dispute regarding a cost-sharing agreement with Oglethorpe Power over Plant Vogtle units 3 and 4. The utility expects to record a $114 million after-tax charge in the third quarter due to the settlement. Meanwhile, Georgia Power recently found a motor fault in one of its reactor coolant pumps at the site of Vogtle unit 4. The company is currently in the process of replacing the pump, and now expects unit 4 to be in-service by the first quarter of 2024. Once again, additional project delays and cost increases are likely to occur, and construction timing will greatly impact our full-year estimates. We remain optimistic that the project, once completed, will benefit the company's transition towards cleaner energy, as well as improve its long-term dividend and earnings growth prospects.

**We have lowered our 2023 EPS estimate by $0.05.** At $3.60, our new call represents a slight decline from the $3.61 a share that the utility earned last year due to worse-than-expected second quarter financials and construction delays. (Third-period results were expected to be released shortly after this Issue went to press.) While the Vogtle nuclear station continues to experience delays, we think Southern should benefit from rate relief, higher retail pricing, and increased usage of electricity throughout the next couple of years. As a result, our 2024 bottom-line estimate is staying put at $4.00 per share, in-line with management's long-term annual earnings-per-share growth target of 5%-7%.

**Shares of Southern Company have declined 10% in value since our August report, along with many of its peers.** Utility stocks have been among the worst-performing sectors of late due to rising Treasury yields. Indeed, the S&P Utility Index (XLU) is down more than 15% over the past 12 months, marking the sector's largest annual loss on record.

**Income-oriented accounts may be drawn to this untimely issue.** Indeed, the stock's dividend yield of 4.2% remains its most notable feature.

*Zachary J. Hodgkinson November 10, 2023*

(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 in mid-Feb. (B) Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '22: $19.85/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., '21: 12.8%. Regulatory Climate: GA, AL Above Average; MS, FL Average.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 45 |
| Earnings Predictability | 95 |

# WEC ENERGY GROUP NYSE-WEC

| RECENT PRICE | 82.22 | P/E RATIO | 16.1 (Trailing: 19.0, Median: 21.0) | RELATIVE P/E RATIO | 0.99 | DIV'D YLD | 3.8% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

**TIMELINESS** 4 Lowered 12/1/23
**SAFETY** 1 Raised 3/23/12
**TECHNICAL** 3 Raised 11/24/23
**BETA** .85 (1.00 = Market)

**18-Month Target Price Range**
**Low-High** **Midpoint (% to Mid)**
$71-$126 $99 (20%)

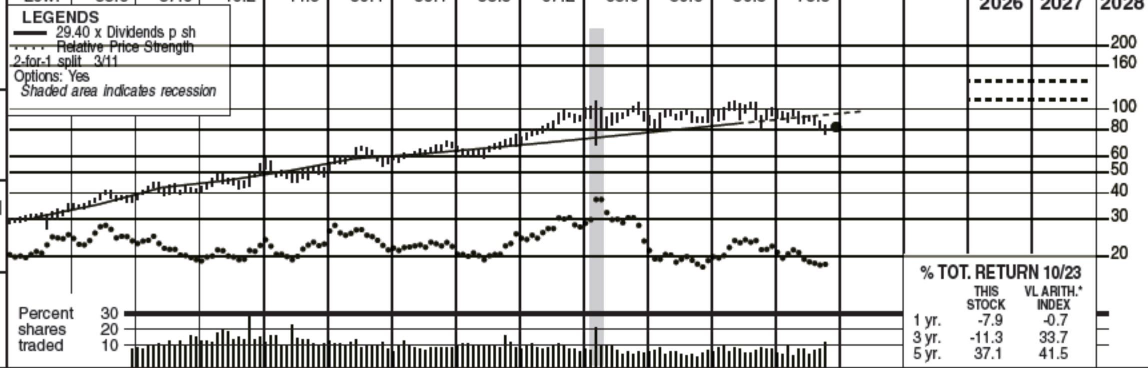
**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 135 | (+65%) | *16%* |
| Low | 110 | (+35%) | *11%* |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 477 | 430 | 428 |
| to Sell | 408 | 414 | 426 |
| Hld's(000) | 240294 | 237652 | 239348 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 41.5 | 45.0 | 55.4 | 58.0 | 66.1 | 70.1 | 75.5 | 98.2 | 109.5 | 99.9 | 108.4 | 99.3 |
| Low: | 33.6 | 37.0 | 40.2 | 44.9 | 50.4 | 56.1 | 58.5 | 67.2 | 68.0 | 80.6 | 80.8 | 75.5 |




**% TOT. RETURN 10/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -7.9 | -0.7 |
| 3 yr. | -11.3 | 33.7 |
| 5 yr. | 37.1 | 41.5 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 30.43 | *29.70* | *30.90* | Revenues per sh | *34.10* |
| 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 | 8.01 | *8.60* | *9.05* | "Cash Flow" per sh | *10.65* |
| 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 | 4.46 | *4.60* | *4.90* | Earnings per sh A | *5.90* |
| .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 | *3.12* | *3.33* | Div'd Decl'd per sh B ■ | *3.80* |
| 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 | 7.34 | *9.30* | *9.30* | Cap'l Spending per sh | *9.25* |
| 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 | 36.76 | *37.35* | *37.90* | Book Value per sh C | *42.00* |
| 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* | *315.43* | Common Shs Outst'g D | *315.43* |
| 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 | 21.9 | *Bold figures are* | | Avg Ann'l P/E Ratio | *20.5* |
| .88 | .89 | .89 | .89 | .89 | 1.01 | .93 | .93 | 1.07 | 1.04 | 1.01 | 1.06 | 1.25 | 1.28 | 1.21 | 1.27 | *Value Line* | | Relative P/E Ratio | *1.15* |
| 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% | 3.4% | *estimates* | | Avg Ann'l Div'd Yield | *3.4%* |
| | | | | | | 4519.0 | 4997.1 | 5926.1 | 7472.3 | 7648.5 | 7679.5 | 7523.1 | 7241.7 | 8316.0 | 9597.4 | *9375* | *9750* | Revenues ($mill) | *10750* |
| | | | | | | 578.6 | 589.5 | 640.3 | 940.2 | 998.2 | 1060.5 | 1134.2 | 1201.1 | 1301.5 | 1406.8 | *1450* | *1545* | Net Profit ($mill) | *1860* |
| | | | | | | 36.9% | 38.0% | 40.4% | 37.6% | 37.2% | 13.8% | 9.9% | 15.9% | 13.4% | 18.6% | *19.0%* | *19.0%* | Income Tax Rate | *19.0%* |
| | | | | | | 4.5% | 1.3% | 4.5% | 3.8% | 1.6% | 2.1% | 1.8% | 2.4% | 1.9% | 2.1% | *2.0%* | *2.0%* | AFUDC % to Net Profit | *2.0%* |
| | | | | | | 50.6% | 48.5% | 51.2% | 50.5% | 48.0% | 50.4% | 52.5% | 52.8% | 55.3% | 54.7% | *55.0%* | *55.0%* | Long-Term Debt Ratio | *55.5%* |
| | | | | | | 49.1% | 51.2% | 48.6% | 49.3% | 51.9% | 49.4% | 47.4% | 47.1% | 44.6% | 44.4% | *44.5%* | *44.5%* | Common Equity Ratio | *44.5%* |
| | | | | | | 8626.6 | 8636.5 | 17809 | 18118 | 18238 | 19813 | 21355 | 22228 | 24467 | 25368 | *26375* | *2700* | Total Capital ($mill) | *29800* |
| | | | | | | 10907 | 11258 | 19190 | 19916 | 21347 | 22001 | 23620 | 25707 | 26982 | 29114 | *30500* | *3100* | Net Plant ($mill) | *35100* |
| | | | | | | 8.1% | 8.1% | 4.5% | 6.3% | 6.6% | 6.5% | 6.5% | 6.5% | 6.3% | 6.4% | *6.5%* | *6.5%* | Return on Total Cap'l | *7.0%* |
| | | | | | | 13.6% | 13.2% | 7.4% | 10.5% | 10.5% | 10.8% | 11.2% | 11.4% | 11.9% | 12.0% | *12.5%* | *12.5%* | Return on Shr. Equity | *13.0%* |
| | | | | | | 13.6% | 13.3% | 7.4% | 10.5% | 10.5% | 10.8% | 11.2% | 11.5% | 11.9% | 12.5% | *12.5%* | *12.5%* | Return on Com Equity E | *13.0%* |
| | | | | | | 5.9% | 5.3% | 2.1% | 3.5% | 3.6% | 3.7% | 3.8% | 3.8% | 4.1% | 4.0% | *4.5%* | *4.0%* | Retained to Com Eq | *4.0%* |
| | | | | | | 57% | 60% | 71% | 67% | 66% | 66% | 66% | 67% | 66% | 65% | *68%* | *68%* | All Div'ds to Net Prof | *64%* |

**CAPITAL STRUCTURE as of 9/30/23**
**Total Debt** $18218.7 mill. **Due in 5 Yrs** $4611 mill.
**LT Debt** $15956.5 mill. **LT Interest** $452.7 mill.
Incl. $12.1 mill. finance leases.
(LT interest earned: 4.4x)
**Leases, Uncapitalized** Annual rentals $6.8 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.

**MARKET CAP: $25.9 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % 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 '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 3.0% | 2.0% | *5.0%* |
| "Cash Flow" | 7.0% | 7.5% | *6.5%* |
| Earnings | 6.5% | 7.0% | *6.0%* |
| Dividends | 10.0% | 6.5% | *7.0%* |
| Book Value | 7.0% | 3.5% | *4.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 2108 | 1548 | 1651 | 1933 | 7241.7 |
| 2021 | 2691 | 1676 | 1746 | 2201 | 8316.0 |
| 2022 | 2908 | 2127 | 2003 | 2558 | 9597.4 |
| 2023 | 2888 | 1830 | 1957 | *2700* | *9375* |
| 2024 | *2750* | *2250* | *2200* | *2550* | *9750* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 1.43 | .76 | .84 | .76 | 3.79 |
| 2021 | 1.61 | .87 | .92 | .71 | 4.11 |
| 2022 | 1.79 | .91 | .96 | .80 | 4.46 |
| 2023 | 1.61 | .92 | 1.00 | *1.07* | *4.60* |
| 2024 | *1.90* | *1.00* | *1.15* | *.85* | *4.90* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .5900 | .5900 | .5900 | .5900 | 2.36 |
| 2020 | .6325 | .6325 | .6325 | .6325 | 2.53 |
| 2021 | .6775 | .6775 | .6775 | .6775 | 2.71 |
| 2022 | .7275 | .7275 | .7275 | .7275 | 2.91 |
| 2023 | .7800 | .7800 | .7800 | .7800 | |

**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. '22 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 Group is about to finish another year of solid performance.** The company has posted consistent earnings growth over the past few years, and this will likely happen again in 2023 and beyond. The utility continues to benefit from increases in electric and gas volume, as well as rate relief. Indeed, WEC has made substantial headway on the rate-case front of late, and rate base growth contributed $0.13 a share to September-period profits. The Michigan Public Service Commission recently approved a 9.1% overall rate increase for 2024 for Michigan Gas Utilities. Too, the Minnesota Commission approved a settlement to grant Minnesota Energy Resources a 7.1% increase in base rates. The company is also making progress in its pending rate case in Illinois for Peoples Gas and North Shore Gas, and expected a favorable ruling by the end of November (as we went to press).

**We are maintaining our 2024 earnings-per-share estimate of $4.90.** This would represent 6.5% earnings growth, within WEC Energy's annual goal of 6%-7%. The same factors that should help boost profits this year should remain present in 2024. The company will also likely benefit from the aforementioned recently approved and pending rate cases.

**We expect a dividend increase in early 2024.** We estimate the board of directors will raise the quarterly disbursement by $0.053 a share (7%). The company likely announced a dividend hike in December, shortly after this Issue went to press. This would mark 21 consecutive years of increases. WEC Energy is targeting a payout ratio of 65%-70% of earnings, and expects dividend growth will continue to be in line with share-earnings growth.

**WEC Energy shares may appeal to conservative, income-oriented investors.** This untimely stock holds strong Price Stability and Earnings Predictability scores, as well as a top notch Safety rank. The dividend yield of 3.8% sits above the utility average, which is one of the highest yielding industries under our coverage. Too, total return potential for the next 18-months and 3- to 5-years is attractive compared to most of its peers. However, the stock is ranked to trail the broader market averages in the year ahead.

*Zachary J. Hodgkinson December 8, 2023*

(A) Diluted EPS. Excl. gain on discontinued ops.: '11, 6¢; nonrecurring gain: '17, 65¢. Next earnings report due early Feb. (B) Div'ds paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '22: $20.05/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%-10.2%; 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 | 70 |
| Earnings Predictability | 100 |

# XCEL ENERGY NDQ-XEL

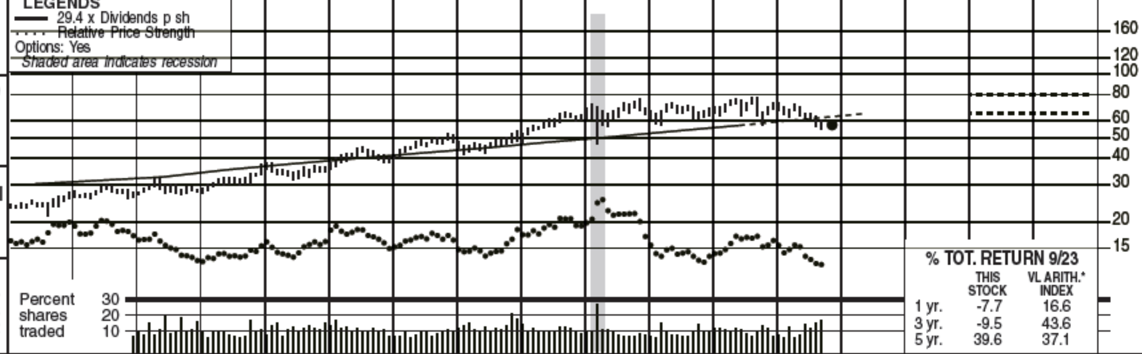
RECENT PRICE 57.65 | P/E RATIO 17.0 (Trailing: 18.3 Median: 20.0) | RELATIVE P/E RATIO 1.06 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Lowered 8/11/23
SAFETY 1 Raised 5/1/15
TECHNICAL 4 Lowered 10/6/23
BETA .85 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 29.9 | 31.8 | 37.6 | 38.3 | 45.4 | 52.2 | 54.1 | 66.1 | 76.4 | 72.9 | 77.7 | 73.0 |
| Low: | 25.8 | 26.8 | 27.3 | 31.8 | 35.2 | 40.0 | 41.5 | 47.7 | 46.6 | 57.2 | 56.9 | 53.7 |

LEGENDS
— 29.4 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2026 | 2027 | 2028



**18-Month Target Price Range**

| Low-High | Midpoint (% to Mid) |
|---|---|
| $49-$93 | $71 (25%) |

**2026-28 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 80 | (+40%) | 12% |
| Low | 65 | (+15%) | 7% |

**Institutional Decisions**

| | 4Q2022 | 1Q2023 | 2Q2023 |
|---|---|---|---|
| to Buy | 485 | 448 | 426 |
| to Sell | 362 | 377 | 422 |
| Hld's(000) | 427005 | 433290 | 432509 |

Percent shares traded 30 20 10

**% TOT. RETURN 9/23**

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | -7.7 | 16.6 |
| 3 yr. | -9.5 | 43.6 |
| 5 yr. | 39.6 | 37.1 |

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | © VALUE LINE PUB. LLC | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 27.86 | *27.35* | *28.75* | Revenues per sh | *30.35* |
| 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 | 7.81 | *8.25* | *8.65* | "Cash Flow" per sh | *10.10* |
| 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 | 3.17 | *3.35* | *3.55* | Earnings per sh A | *4.25* |
| .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* | *2.22* | Div'd Decl'd per sh B ■ † | *2.66* |
| 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 | 8.44 | *9.00* | *9.25* | Cap'l Spending per sh | *9.50* |
| 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 | 30.34 | *31.50* | *33.15* | Book Value per sh C | *38.25* |
| 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 | 549.58 | *551.60* | *553.00* | Common Shs Outst'g D | *560.00* |
| 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 | 22.2 | Bold figures are | | Avg Ann'l P/E Ratio | *17.5* |
| .89 | .82 | .85 | .90 | .89 | .94 | .84 | .81 | .83 | .97 | 1.02 | 1.02 | 1.19 | 1.23 | 1.22 | 1.29 | Value Line | | Relative P/E Ratio | *.95* |
| 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% | 2.8% | estimates | | Avg Ann'l Div'd Yield | *3.6%* |

**CAPITAL STRUCTURE as of 6/30/23**
**Total Debt** $25610 mill. **Due in 5 Yrs** $3808 mill.
**LT Debt** $24015 mill. **LT Interest** $869 mill.
Incl. $228 mill. finance leases.
(Total Interest Coverage: 2.8x)

**Leases, Uncapitalized** Annual rentals $264 mill.
**Pension Assets-12/22** $2685 mill. **Oblig** $2871 mill.

**Pfd Stock** None

**Common Stock** 551,532,742 shs. as of 7/25/23
**MARKET CAP: $31.8 billion (Large Cap)**

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | | 26-28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10915 | 11686 | 11024 | 11107 | 11404 | 11537 | 11529 | 11526 | 13431 | 15310 | *15100* | *15900* | Revenues ($mill) | *17000* |
| 948.2 | 1021.3 | 1063.6 | 1123.4 | 1171.0 | 1261.0 | 1372.0 | 1473.0 | 1597.0 | 1736.0 | *1725* | *1960* | Net Profit ($mill) | *2385* |
| 33.8% | 33.9% | 35.8% | 34.1% | 30.7% | 12.6% | 8.5% | - - | - - | - - | *NMF* | *NMF* | Income Tax Rate | *NMF* |
| 13.4% | 12.5% | 7.7% | 7.8% | 9.4% | 12.4% | 8.3% | 10.7% | 6.2% | 5.9% | *6.0%* | *6.0%* | AFUDC % to Net Profit | *6.0%* |
| 53.3% | 53.0% | 54.1% | 56.3% | 55.9% | 56.4% | 56.8% | 57.4% | 58.2% | 57.8% | *58.0%* | *58.0%* | Long-Term Debt Ratio | *58.0%* |
| 46.7% | 47.0% | 45.9% | 43.7% | 44.1% | 43.6% | 43.2% | 42.6% | 41.8% | 42.2% | *42.0%* | *42.0%* | Common Equity Ratio | *42.0%* |
| 20477 | 21714 | 23092 | 25216 | 25975 | 28025 | 30646 | 34220 | 37391 | 39488 | *41750* | *44075* | Total Capital ($mill) | *50900* |
| 26122 | 28757 | 31206 | 32842 | 34329 | 36944 | 39483 | 42950 | 45457 | 48253 | *50525* | *52850* | Net Plant ($mill) | *59700* |
| 6.0% | 6.0% | 5.8% | 5.7% | 5.8% | 5.7% | 5.6% | 5.4% | 5.3% | 5.5% | *5.5%* | *5.5%* | Return on Total Cap'l | *6.0%* |
| 9.9% | 10.0% | 10.0% | 10.2% | 10.2% | 10.3% | 10.4% | 10.1% | 10.2% | 10.4% | *10.5%* | *10.5%* | Return on Shr. Equity | *11.0%* |
| 9.9% | 10.0% | 10.0% | 10.2% | 10.2% | 10.3% | 10.4% | 10.1% | 10.2% | 10.4% | *10.5%* | *10.5%* | Return on Com Equity E | *11.0%* |
| 4.5% | 4.5% | 4.3% | 4.0% | 3.9% | 4.3% | 4.4% | 4.2% | 4.2% | 4.3% | *4.0%* | *4.0%* | Retained to Com Eq | *4.0%* |
| 54% | 55% | 57% | 61% | 62% | 58% | 58% | 58% | 59% | 58% | *62%* | *62%* | All Div'ds to Net Prof | *62%* |

**ELECTRIC OPERATING STATISTICS**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -2.3 | +1.4 | +1.2 |
| Resid'l Revs. per KWH (¢) | 12.12 | 12.94 | 13.41 |
| C & I Revs. per KWH (¢) | 7.86 | 8.73 | 9.02 |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 19665 | 19849 | 20346 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | NA | NA | NA |
| Fixed Charge Cov. (%) | 252 | 262 | 255 |

**BUSINESS:** Xcel Energy Inc. is the parent of Northern States Power Company (NSP), which supplies electricity to MN, WI, ND, SD & MI & gas to MN, WI, ND & MI; Public Service Company of Colorado (PSCo), which supplies electricity & gas to CO; & Southwestern Public Service Company (SPS), which supplies electricity to TX and NM. Customers: 3.8 mill. electric, 2.1 mill. gas. Electric revenues: resid'l, 29%; comm'l & ind'l, 48%; other, 23%. Purchases 33% of power, owns 67%. Total electric mix: wind, 33%; gas, 24%; coal, 23%, nuclear, 13%, solar/other, 7%. Fuel costs: 45% of revenues. '22 deprec. rate: 3.7%. Employs 11,982. President, CEO and Chrmn.: Robert Frenzel. Inc.: MN. Addr.: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Int.: www.xcelenergy.com.

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '20-'22 to '26-'28 |
|---|---|---|---|
| Revenues | 1.5% | 2.5% | *3.5%* |
| "Cash Flow" | 6.5% | 7.5% | *6.0%* |
| Earnings | 5.5% | 6.0% | *6.0%* |
| Dividends | 6.0% | 6.0% | *6.5%* |
| Book Value | 5.0% | 5.5% | *5.0%* |

**QUARTERLY REVENUES ($ mill.)**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | 2811 | 2586 | 3182 | 2947 | 11526 |
| 2021 | 3541 | 3068 | 3467 | 3355 | 13431 |
| 2022 | 3751 | 3424 | 4082 | 4053 | 15310 |
| 2023 | 4080 | 3022 | *4010* | *3988* | *15100* |
| 2024 | *4125* | *3500* | *4150* | *4125* | *15900* |

**EARNINGS PER SHARE A**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2020 | .56 | .54 | 1.14 | .54 | 2.79 |
| 2021 | .67 | .58 | 1.13 | .58 | 2.96 |
| 2022 | .70 | .60 | 1.18 | .69 | 3.17 |
| 2023 | .76 | .52 | *1.30* | *.77* | *3.35* |
| 2024 | *.80* | *.60* | *1.35* | *.80* | *3.55* |

**QUARTERLY DIVIDENDS PAID B ■ †**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2019 | .38 | .405 | .405 | .405 | 1.60 |
| 2020 | .405 | .43 | .43 | .43 | 1.70 |
| 2021 | .43 | .4575 | .4575 | .4575 | 1.80 |
| 2022 | .4575 | .4875 | .4875 | .4875 | 1.92 |
| 2023 | .4875 | .52 | .52 | .52 | |

**Xcel Energy should achieve this year's profit objectives.** During the first half of 2023, the company's share earnings were $0.02 below the prior year's $1.30. Mild second-quarter weather in the northern region was a factor, as was higher operating and maintenance (O&M) expense and interest charges. There was also less incremental regulatory recovery to offset rising costs than previously expected, given a dissapointing conclusion to the company's general rate case (GRC) in Minnesota (see below). Xcel has put a belt-tightening plan in place to reduce O&M costs by 3%, which should enable it to reach its 2023 profit target of $3.30-$3.40 a share.

**The company is appealing the low return on equity (ROE) handed down by Minnesota regulators.** As part of Xcel's GRC, commissioners heard testimony from the Minnesota Department of Commerce, which found that Xcel had been "flourishing" at its prior 9.06% ROE, but an increase to 9.25% was merited. Commissioners voted to set the rate at 9.25%, despite the conclusion of a state administrative law judge (ALJ) that a 9.87% ROE would be "reasonable" for Xcel, given the sharp rise in the cost of capital lately. Xcel has requested reconsideration. The case would go to an appeals court if regulators dismiss the appeal.

**Xcel has submitted a $15-billion resource plan consistent with the "green" energy transition of Colorado.** If approved, the investments the company will be making in renewables for that state will go a long ways towards supporting the company's long-term 5%-7% earnings growth goals. Clean energy plans in other state territories are also supportive.

**The company provided an update on the Colorado wildfire lawsuits it's been hit with.** (We covered this issue at great length in our July 21st review.) Notably, the investigation report, which concluded that sparks from an Xcel power line was the most likely source of ignition 80-110 feet away, also mentioned an underground coal fire could not be ruled out.

**Xcel stock is untimely.** Though tort law in Colorado is less onerous to defendents than California law, the aforementioned legal woes, plus headline risk, will likely drag on as an overhang to XEL shares.

*Anthony J. Glennon* *October 20, 2023*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '10, 5¢; '15, (16¢); '17, (5¢); gains (loss) on discontinued ops.: '09, (1¢); '10, 1¢. '20 EPS don't sum due to rounding.
Next earnings report due October 27th.
(B) Div'ds typically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available.
(C) Incl. intangibles. In '22: $2871 mill., $5.22/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on common equity (blended): 9.6%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | A+ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 95 |
| Earnings Predictability | 100 |

CASE: UE 426
WITNESS: MATT MULDOON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 110

# ROE: Financial News that Investors in Electric Utilities Are Seeing

**March 25, 2024**

S&P Global



# Major energy rate case decisions in the US

## January-December 2023

## Quarterly update on decided rate cases

Lisa Fontanella, **Research Director**
**Contributors: Brian Collins, Jim Davis, Russell Ernst, Lillian Federico, Monica Hlinka, Jason Lehmann, Dan Lowrey**
**Editor: Wyatt Scott**

**For detailed data**

Access the RRA's electric and gas rate case decisions as of Dec. 31, 2023, data tables.

Energy authorized returns on equity rose in 2023 as the pace of rate case activity reached record-high levels, with nearly 165 decisions issued by state public utility commissions, including 106 electric or gas equity return determinations.

**To learn more or to request a demo, visit spglobal.com/marketintelligence.**

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# Executive Summary

## Introduction

Energy authorized returns on equity rose in 2023 as the pace of rate case activity reached record-high levels.

As per calculations from Regulatory Research Associates, the average authorized return on equity (ROE) for electric utilities in cases decided during 2023 was 9.60%, compared to the 9.54% average for cases decided in 2022. There were 63 electric ROE determinations reflected in the calculations for 2023 versus 53 in 2022.

Despite the rise in 2023, the average authorized ROE for electric utilities in 2023 remains near historic lows and was the sixth-lowest annual average over the more than 40 years RRA has tracked rate case activity.

The average ROE authorized for gas utilities was 9.64% for cases decided during 2023 versus the 9.53% average observed in 2022. RRA's calculations relied on 43 gas rate case decisions that included an ROE determination during 2023 versus 33 in 2022. For gas utilities, the average authorized ROE in 2023 was the seventh-lowest annual average on record.

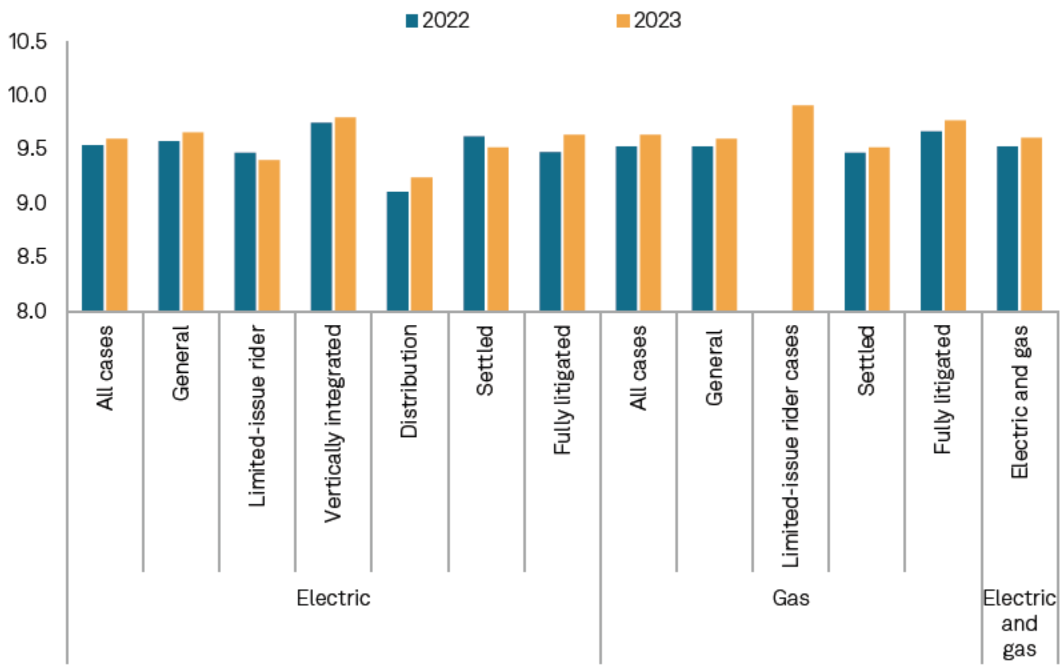
Rate case activity reached record-high levels in 2023, with nearly 165 decisions issued by state public utility commissions, including 106 electric or gas equity return determinations.

While the reasons for a rate case filing are numerous, the main driver continues to be the recovery of capital expenditures. Energy utilities are investing in infrastructure to modernize transmission and distribution systems, build new natural gas, solar and wind generation, and deploy new technologies to accommodate the expansion of electric vehicles, battery storage and advanced metering infrastructure that facilitate the transition toward decarbonization. Other reasons for rate filings include rising expenses, revised cost-of-capital parameters, the impact of broader economic and sector-wide forces on operations, the need to address rate treatment to be accorded generation facilities being retired prior to the end of their planned service lives due to the energy transition, recovery of storm and severe-weather related costs, and regulatory approval for alternative regulatory mechanisms.

## About this report

This quarterly report offers a detailed overview of electric and gas rate case decisions issued in the US during 2023 and select aggregated historical data. The information presented in this report utilizes the data compiled by Regulatory Research Associates for its rate case database, which is available on the S&P Capital IQ Pro platform. RRA endeavors to follow all "major" rate cases for investor-owned utilities nationwide, with "major" defined as a case in which the utility's request would result in a rate change of at least $5 million or in which the commission approves a rate change of at least $3 million. In addition to base rate cases, the rate case history database includes details regarding certain limited-issue rider proceedings, primarily those involving significant rate base additions recognized outside of a general rate case. In some of these cases, the rate change coverage criteria may not apply. Historical data in this report may not match earlier data provided in previous reports due to differences in presentation, including the treatment of withdrawn or dismissed cases and the addition of cases not previously included in RRA's coverage.

## Average authorized ROE (%)




| | 2022 | 2023 |
|---|---|---|
| **Electric averages** | | |
| All cases | 9.54 | 9.60 |
| General rate cases | 9.58 | 9.66 |
| Limited-issue rider cases | 9.47 | 9.40 |
| Vertically integrated cases | 9.75 | 9.80 |
| Distribution cases | 9.11 | 9.24 |
| Settled cases | 9.62 | 9.52 |
| Fully litigated cases | 9.48 | 9.64 |
| **Gas averages** | | |
| All cases | 9.53 | 9.64 |
| General rate cases | 9.53 | 9.60 |
| Limited-issue rider cases | | 9.91 |
| Settled cases | 9.47 | 9.52 |
| Fully litigated cases | 9.67 | 9.77 |
| **Composite electric and gas averages** | | |
| Electric and gas | 9.53 | 9.61 |
| **US Treasury** | | |
| 30-year bond yield | 3.11 | 4.09 |

Data compiled Jan. 26, 2024.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.

# The Take

The average authorized returns in 2023 edged modestly higher than the annual levels observed in 2022 as higher interest rates began to impact authorized ROEs. The effect of interest rate increases on authorized returns will likely be limited, however, given that regulators are slower to adjust ROEs upward than downward, and affordability concerns persist as regulators contend with customer rate increases stemming from significant but necessary capital investment in the energy transition during a period of high inflation.

In recent years, rate case activity for investor-owned electric and gas utilities in the US has been elevated, with state public utility commissions issuing almost 165 decisions in 2023. With higher interest rates, higher inflation and accelerating capital spending to address public policy goals, particularly the energy transition, RRA anticipates rate case filings will remain robust.

# Overview of electric and gas authorizations

The average electric and gas authorized returns on equity inched gently higher per averages calculated for 2023.

The average ROE authorized for electric utilities rose to 9.60% for rate cases decided in 2023 from the 9.54% average observed in 2022. There were 63 electric ROE determinations reflected in the calculations for 2023 versus 53 in full year 2022.

The average ROE authorized for gas utilities was 9.64% for cases decided in 2023, above the 9.53% average observed in 2022. There were 43 gas rate case decisions decided in 2023 versus 33 in full year 2022.

The electric data set includes several limited-issue rider cases. Historically, the ROEs authorized in limited-issue rider cases were meaningfully higher than those approved in general rate cases, driven primarily by incentives allowed in Virginia for certain types of generation investment. These premiums have largely expired. Excluding rider cases, the average authorized ROE for electric cases was 9.66% in 2023 versus 9.58% in full year 2022.

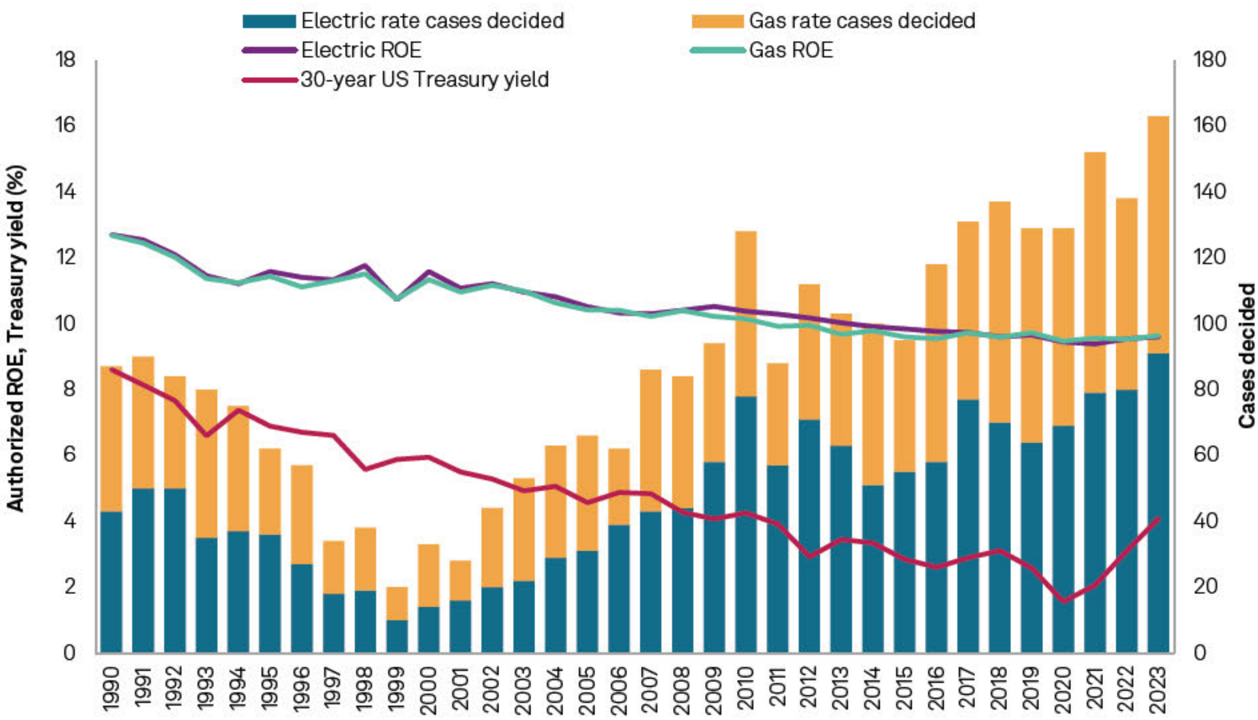
Excluding the six rider cases, the average authorized ROE for gas cases was 9.60% in 2023. There were no rider cases with a gas-authorized ROE in 2022. For the most part, limited-issue riders have a limited impact on average ROEs in the gas sector, as most of the gas riders rely on ROEs approved in a previous base rate case.

In 2023, the median ROE authorized in all electric utility rate cases was 9.50%, equal to that observed in 2022; for gas utilities, the metric was 9.64% in 2023 and 9.53% in full year 2022.

Historically, authorized returns have generally tracked the overall direction of interest rates, albeit with two important caveats to keep in mind — the magnitude of the change in authorized ROEs may not be as dramatic as that observed in interest rates, and changes in authorized ROEs may lag changes in interest rates, especially in the upward direction.

Interest rates — as measured by the 30-year US Treasury bond yield — fell almost steadily between 1990 and 2020, placing downward pressure on authorized ROEs. Between 1990 and 2020, Treasury yields fell more than 700 basis points, to 1.56% from 8.61%, while average authorized ROEs for electric and gas utilities combined fell less than 325 basis points, to 9.45% from 12.69%. The average authorized ROEs did not fall below 10% until 2011 for gas utilities and until 2014 for electric utilities. The calendar-year averages fell below 9.50% for the first time in 2020.

### Average electric, gas authorized ROEs; number of rate cases decided




Data compiled Jan. 26, 2024.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.


The decline in authorized ROEs has coincided with an upswing in rate case activity, with 100 or more cases adjudicated in 12 of the last 15 calendar years. This count includes electric and gas cases where no ROEs were specified, but it does not include withdrawn cases. At almost 165 cases decided, rate case activity in 2023 was the most robust observed in any year during the 1990–2023 period, with authorized increases totaling about $12 billion.

With interest rates and authorized ROEs declining at different rates between 1990 and 2020, the spread between authorized ROEs and the average yield on 30-year US Treasuries somewhat widened over this period — from a little over 400 basis points in 1990 to peaking at just under 800 basis points in 2020.

This occurrence is attributable primarily to the regulators' often-unstated understanding that the drop in interest rates caused by the Fed intervention was unusual. Consequently, regulators did not necessarily fully reflect the interest rate drop in newly authorized ROEs in some instances; in others, regulators acknowledged that the changing dynamics of the industry and instability in the overall economy presented increased risks for investors, justifying a higher premium over interest rates.

However, with the uptick in interest rates since 2020, the spread has begun to narrow, falling to around 550 basis points in 2023.

With the myriad factors putting upward pressure on customer bills, the spread may continue to narrow as regulators may become more reluctant to raise authorized returns.

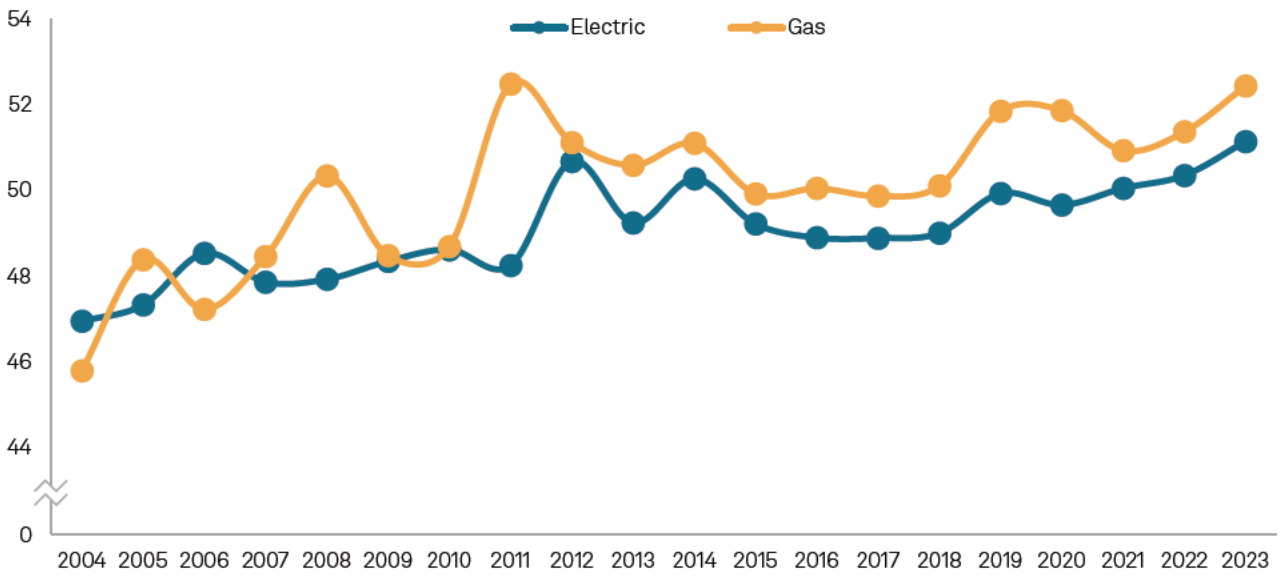
# Capital structure trends

The negative cash flow impact of federal tax changes that took effect in 2018 raised concerns regarding utility liquidity and credit metrics. In response, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than those observed in 2018 and 2017.

For full years 2023, 2022, 2021, 2020, and 2019, the average equity ratios authorized in electric utility cases were 51.15%, 50.36%, 50.06%, 49.67% and 49.94%, respectively. The average equity ratios authorized gas utilities for these years were 52.45%, 51.38%, 50.94%, 51.87% and 51.86%, respectively.

From a longer-term perspective, equity ratios have generally increased over the last several years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. Many commissions began approving more equity-rich capital structures in the wake of the 2008 financial crisis. For the bulk of the period since 2004, allowed equity ratios for gas utilities have been above those authorized for electric utilities.

**Average authorized equity ratio (%)**




Data compiled Jan. 26, 2024.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

# A more granular look at ROE trends

Thus far, the discussion has looked broadly at trends in authorized ROEs; the following sections provide a more granular view.

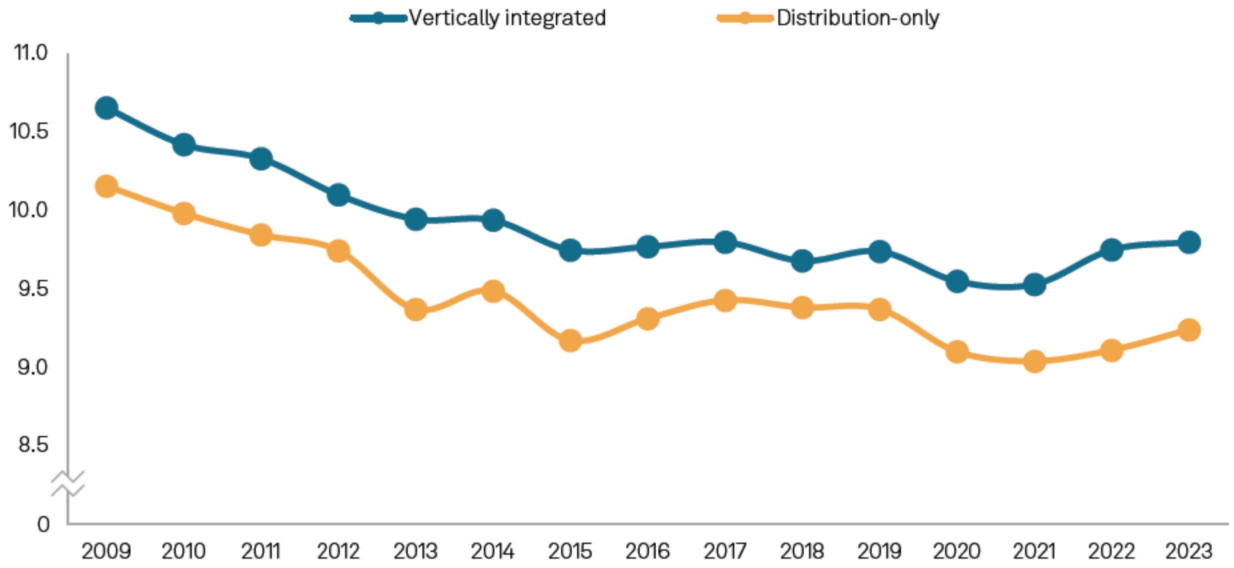
RRA has observed that there can be significant differences between average ROEs based on the types of proceedings/decisions in which these ROEs were established.

As a result of the electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for distribution operations.

RRA finds that the annual average authorized ROEs in vertically integrated cases involving generation have been about 30–65 basis points higher than in distribution-only cases, arguably reflecting the increased risk associated with the ownership and operation of generation assets.

The industry average ROE for vertically integrated electric utilities was 9.80% in 2023 versus the 9.75% average in 2022. For electric distribution-only cases, the industry average ROE was 9.24% in 2023 versus the 9.11% average in 2022.

**Average authorized electric ROEs (%)**

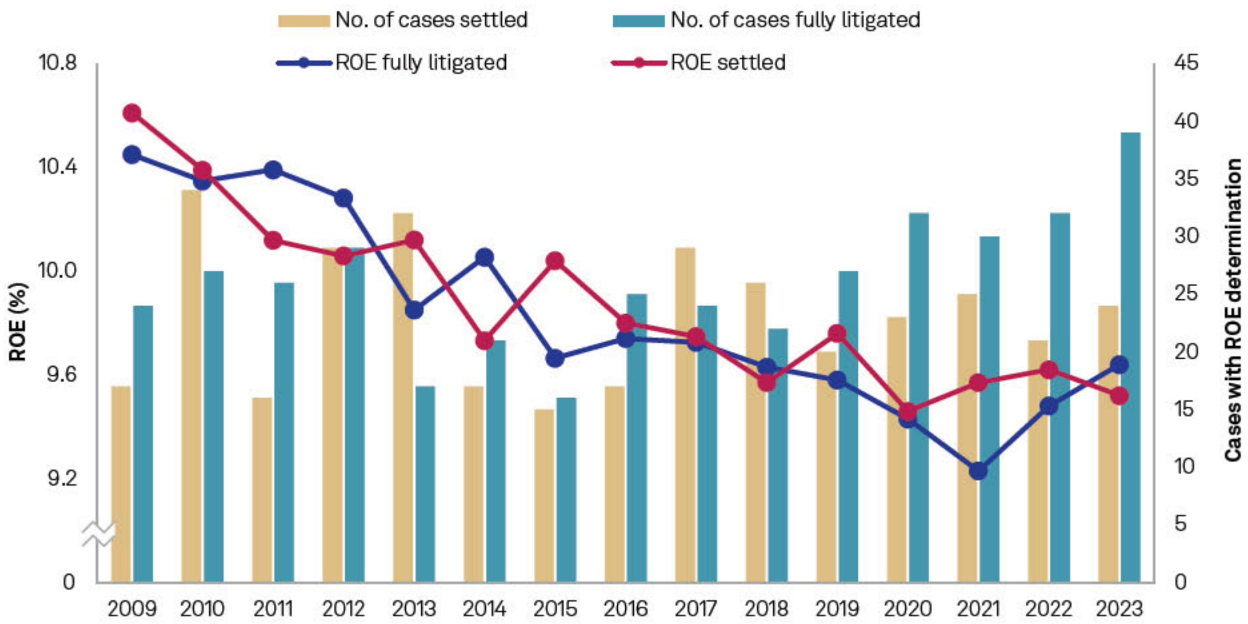



Data compiled Jan. 26, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.


Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are "black box" in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. Some states, however, preclude this type of treatment, and settlements must specify these values, if not the specific adjustments from which these values were derived.

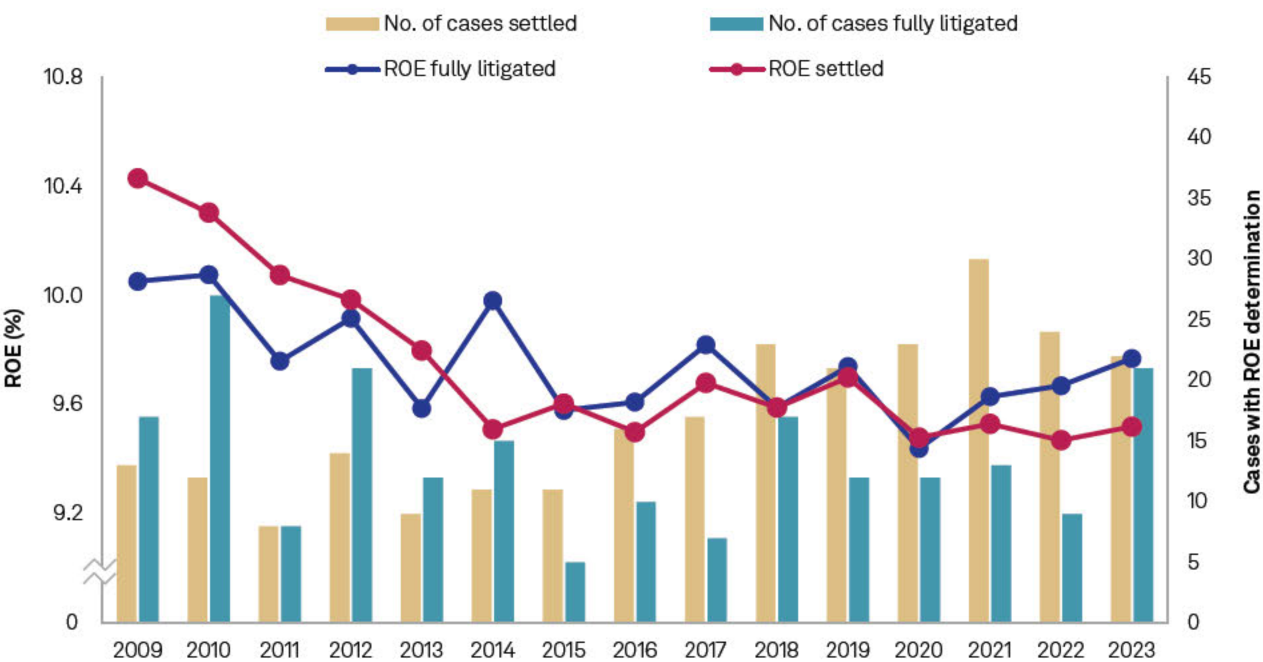
For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, while in others, it was higher for settled cases.

## Average authorized electric ROEs: settled vs. fully litigated cases




Data compiled Jan. 26, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.


## Average authorized gas ROEs: settled vs. fully litigated cases




Data compiled Jan. 26, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

The following discussion focuses on the corresponding tables available here.

**Table 1** shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and quarterly since 2019, followed by the number of observations in each period. **Table 2** indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and quarterly since 2021.

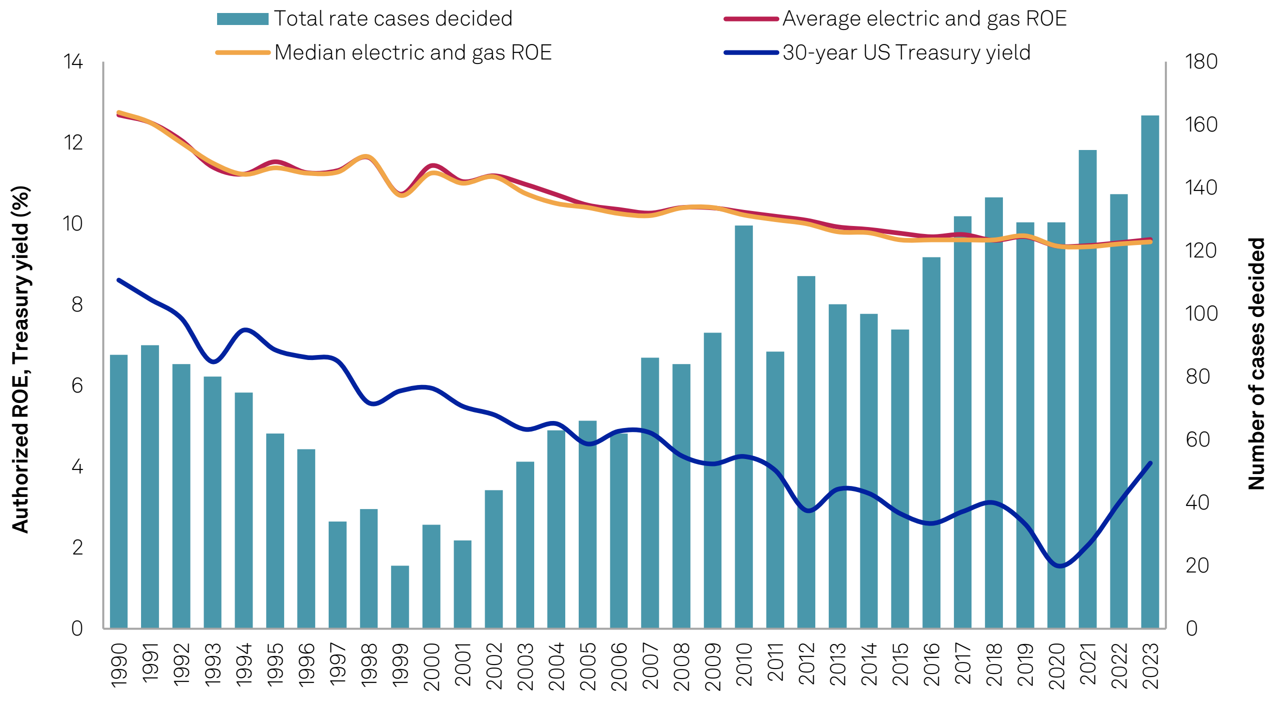
**Tables 3 and 4** provide comparisons since 2009 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

The individual electric and gas cases decided in 2023 are listed in **Table 5**, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time the decisions were rendered. This study does not reflect fuel adjustment clause rate changes.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases decided during the specified time periods and are not necessarily representative of the average currently authorized ROEs for utilities industrywide or the returns earned by the utilities.

**Table 6** and the graph below track the combined average and median equity return authorized for all electric and gas rate cases since 1990. As the table indicates, since 1990, authorized ROEs have generally trended downward, reflecting the significant decline in interest rates and capital costs over this time frame.

## Composite electric, gas average authorized ROEs; total number of rate cases




Data compiled Jan. 26, 2024.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.

# Further Reading

The Commissions

The rate case process: a conduit to enlightenment

Rate base: It's more complicated than it sounds

Frequently Asked Questions

Intro to Water Utilities — Current Trends and Growth Drivers

An Overview of FERC Regulation

FERC Regulatory Review

# About the Author(s)

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# About Regulatory Research Associates

Regulatory Research Associates, a group within S&P Global Commodity Insights, is the leading authority on utility securities and regulation. Understanding the financial and strategic impact of federal and state regulation is a key to success in the energy business. For over 40 years, Regulatory Research Associates has been the leading provider of independent research, expert analysis, proprietary data and consultation on utility securities and regulation. S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro.

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S&P Global

**RRA Regulatory Focus**

**Quarterly update on decided rate cases**

February 2023

# Major energy rate case decisions in the US — January-December 2022

## Quarterly update on decided rate cases

**Lisa Fontanella, Research Director**

**Contributors: Brian Collins, Jim Davis, Russell Ernst, Lillian Federico, Monica Hlinka, Jason Lehmann, Dan Lowrey**

**Editor: Majda Shabbir**

**For detailed data**

Access the Major Energy Rate Case Decisions – January – December 2022 and related data.

The average electric and gas authorized returns on equity authorized by state regulators during 2022 remain near all-time lows.

**To learn more or to request a demo, visit spglobal.com/marketintelligence.**

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# Executive Summary

## Introduction

The average authorized return on equity for electric utilities approved in cases decided during 2022 rebounded from 2021, which was the lowest annual average in RRA's rate case database comprising all major rate cases decided since 1980. Despite the rise, however, the average authorized ROE for electric utilities in 2022 remained near historic lows and was the third-lowest annual average on record.

For gas utilities, the average authorized ROE in 2022 fell to the second-lowest annual average on record.

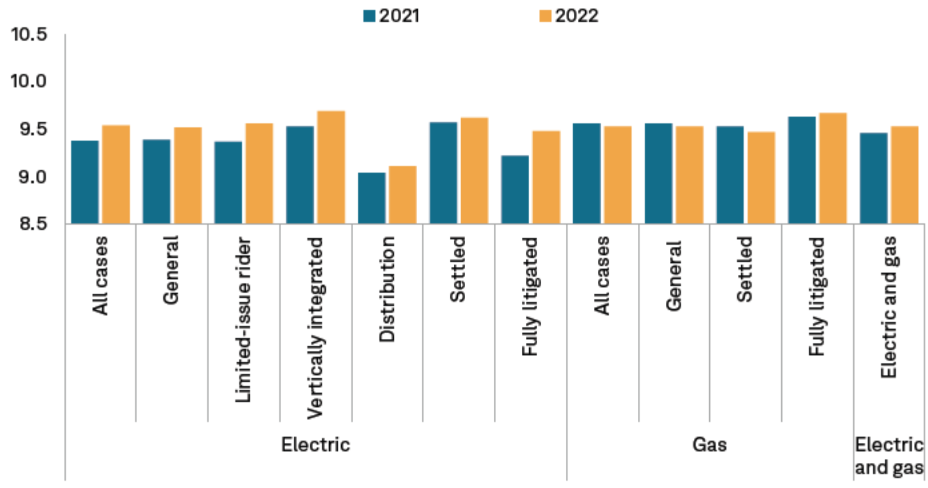
The average ROE authorized for electric utilities was 9.54% for rate cases decided in 2022 as compared to the 9.38% average for cases decided in 2021. There were 53 electric ROE determinations reflected in the calculations for 2022 versus 55 in 2021.

The average ROE authorized for gas utilities was 9.53% for cases decided during 2022 versus the 9.56% average observed in 2021. RRA's calculations relied on 33 gas rate case decisions that included an ROE determination during 2022 versus 43 in 2021.

Rate case activity remained elevated with about 136 decisions issued by state public utility commissions in 2022. This level of activity, however, is down from 2021 — a record year with 151 decisions rendered in electric and gas rate cases across the U.S.

While the reasons for a rate case filing are numerous, the main driver continues to be recovery of capital expenditures. Energy utilities are investing in infrastructure to modernize transmission and distribution systems; build new natural gas, solar and wind generation; and deploy new technologies to accommodate the expansion of electric vehicles, battery storage and advanced metering infrastructure that facilitate the transition toward decarbonization. Other reasons for rate filings include rising expenses, revised cost of capital parameters, the impact of broader economic and sector-wide forces on operations, the need to address rate treatment to be accorded generation facilities that are being retired prior to the end of their planned service lives due to the energy transition, recovery of storm and severe-weather related costs and regulatory approval for alternative regulatory mechanisms.

**Average authorized ROE (%)**




| | 2021 | 2022 |
|---|---|---|
| **Electric averages** | | |
| All cases | 9.38 | 9.54 |
| General rate cases | 9.39 | 9.52 |
| Limited-issue rider cases | 9.37 | 9.56 |
| Vertically integrated cases | 9.53 | 9.69 |
| Distribution cases | 9.04 | 9.11 |
| Settled cases | 9.57 | 9.62 |
| Fully litigated cases | 9.22 | 9.48 |
| **Gas averages** | | |
| All cases | 9.56 | 9.53 |
| General rate cases | 9.56 | 9.53 |
| Settled cases | 9.53 | 9.47 |
| Fully litigated cases | 9.63 | 9.67 |
| **Composite electric and gas averages** | | |
| Electric and gas | 9.46 | 9.53 |
| **US Treasury** | | |
| 30-year bond yield | 2.06 | 3.11 |

Data compiled Jan. 27, 2023.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury.

## About this report

This quarterly report offers a detailed overview of electric and gas rate case decisions issued in the U.S. during 2022 and select aggregated historical data. The information presented in this report utilizes the data compiled by Regulatory Research Associates for its rate case database, available on the S&P Capital IQ Pro platform. RRA endeavors to follow all "major" rate cases for investor-owned utilities nationwide, with "major" defined as a case in which the utility's request would result in a rate change of at least $5 million or in which the commission approves a rate change of at least $3 million. In addition to base rate cases, the rate case history database includes details regarding certain limited-issue rider proceedings, primarily those that involve significant rate base additions that are recognized outside of a general rate case. In some of these cases, the rate change coverage criteria may not apply. In an effort to align data presented in this report with data available in S&P Capital IQ Pro's online database, earlier historical data provided in previous reports may not match historical data in this report due to certain differences in presentation, including the treatment of cases that were withdrawn or dismissed, as well as the addition of cases that were not included previously as part of RRA's coverage.

# The Take

Averages calculated for 2022 show electric and gas authorized returns on equity remain near historic lows. Rate case activity for investor-owned electric and gas utilities in the U.S. remained elevated with about 136 decisions issued by state public utility commissions in 2022. This level of activity, however, is down from 2021, which was a record year with 151 decisions rendered in electric and gas rate cases across the U.S. With interest rates on the rise, RRA anticipates rate case filings will remain robust.

Authorized returns may edge slightly higher in 2023, as elevated levels of inflation have prompted the U.S. Federal Reserve to aggressively raise interest rates. The effect of interest rate increases on authorized returns is unlikely to be dramatic, however, as authorized returns tend to be stickier on the upside than on the downside.

In addition, affordability remains a concern, as regulators grapple with rate increases stemming from the recovery of pandemic-related costs and energy transition related expenses in the recent inflationary environment.

# Overview of electric and gas authorizations

Despite an increase in the average authorized ROE for electric utilities, authorized returns remain near all-time lows.

The average ROE authorized for electric utilities rose to 9.54% for rate cases decided in 2022 from the 9.38% average for cases decided in 2021. There were 53 electric ROE determinations reflected in the calculations for 2022 versus 55 in 2021.

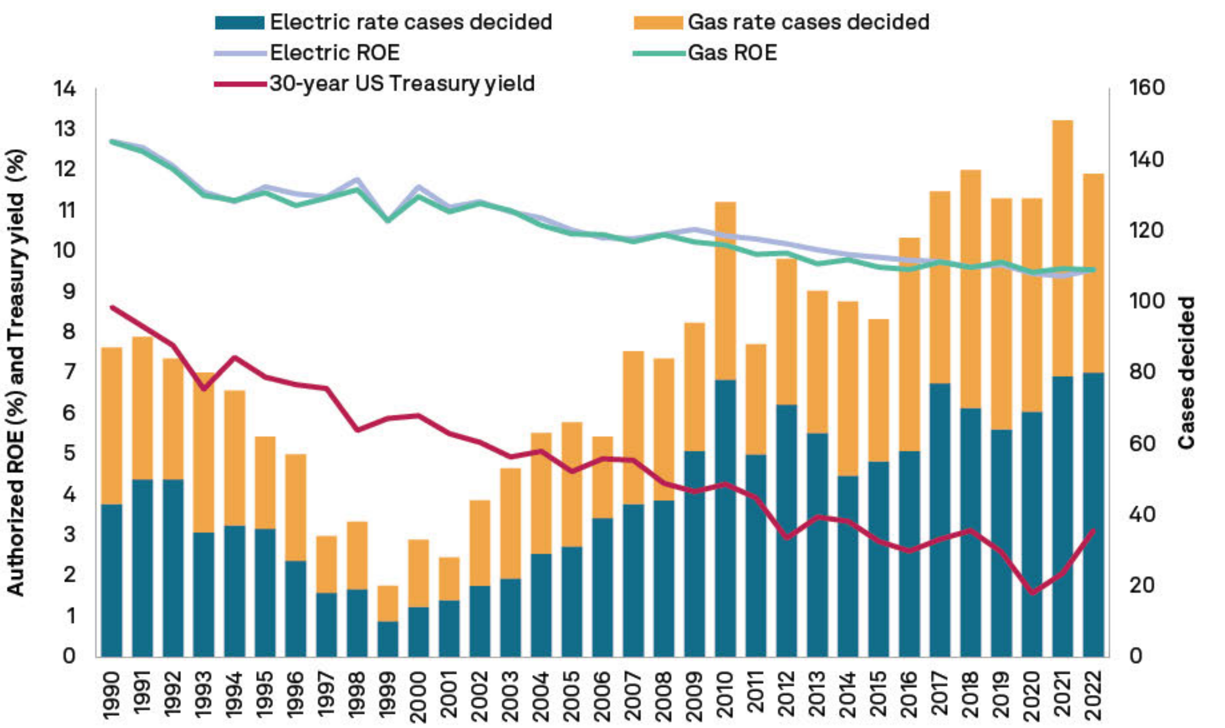
The average ROE authorized for gas utilities was 9.53% for cases decided in 2022, slightly lower than the 9.56% average observed in 2021. There were 33 gas rate case decisions that included an ROE determination during 2022 versus 43 in 2021.

The electric data set includes several limited-issue rider cases. Historically, the ROEs authorized in limited-issue rider cases were meaningfully higher than those approved in general rate cases, driven primarily by incentives allowed in Virginia for certain types of generation investment. These premiums have largely expired, however, resulting in narrowing the gap between the average ROE in the rider cases and general rate cases. Excluding rider cases, the average authorized ROE for electric cases was 9.52% in 2022 versus 9.39% in 2021. By contrast, limited issue riders have not had much impact on average ROEs in the gas sector, as most of the gas riders rely on ROEs approved in a previous base rate case.

In 2022, the median ROE authorized in all electric utility rate cases was 9.50% versus 9.38% in 2021; for gas utilities, the metric was 9.60% in both 2022 and 2021.

The ROE averages are near the lowest levels ever witnessed in the industry. The electric ROE average in 2022 and 2021 were weighed down by ROE determinations in Illinois and Vermont that were calculated utilizing a formulaic approach tied to U.S. Treasury bond yields. Excluding these ROE determinations, the average return authorized for electric utilities was 9.63% in 2022 and 9.48% in 2021.

## Average electric, gas authorized ROEs; number of rate cases decided




Data compiled Jan. 27, 2023.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury.

Looking longer-term, interest rates — as measured by the 30-year U.S. Treasury bond yield — fell almost steadily between 1990 and 2020, placing downward pressure on authorized ROEs, however, the decline in authorized ROEs was much less dramatic than that for Treasury yields. Between 1990 and 2020, Treasury yields fell more than 700 basis points, to 1.56% from 8.61%, while average authorized ROEs for electric and gas utilities combined fell less than 325 basis points, to 9.45% from 12.69%. The average authorized ROEs did not fall below 10% until 2011 for gas utilities and until 2014 for electric utilities. The calendar-year averages fell below 9.50% for the first time in 2020.

The decline in authorized ROEs has coincided with an upswing in rate case activity, with 100 or more cases adjudicated in 10 of the last 12 calendar years. This count includes electric and gas cases where no ROEs were specified but does not include withdrawn cases. At over 150 cases, rate case activity in 2021 was the most robust observed in any year during the 1990-2022 period. In 2022, 136 cases were decided.

Absent the pandemic, increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, storm and disaster recovery, cybersecurity, early plant retirement and employee benefits have contributed to an active rate case agenda over the last decade.

Due to the COVID-19 pandemic and the challenging economic landscape, many utilities and state commissions sought to limit the immediate impact of rate hikes during 2020 by pushing rate changes into a future period or agreeing to forgo rate hikes and using accounting mechanisms, such as the accelerated recovery of excess accumulated deferred tax liabilities, to mitigate requested increases.

Amid the current high inflationary environment and ongoing economic uncertainties, however, the pace of rate case activity in the U.S. is robust, with about 90 electric and gas rate cases currently pending.

With interest rates and authorized ROEs declining at different rates between 1990 and 2020, the gap between authorized ROEs and interest rates somewhat widened over this period — from a little over 400 basis points in 1990 to a little under 800 basis points in 2020.

This phenomenon is largely attributable to the regulators' often-unstated understanding that the drop in interest rates caused by the Fed intervention was unusual. Consequently, regulators did not necessarily fully reflect the interest rate drop in newly authorized ROEs in some instances; in others, regulators acknowledged that the changing dynamics of the industry and instability in the overall economy presented increased risks for investors, justifying a higher premium over interest rates.

With authorized ROEs flatlining in the past couple of years, the margin between Treasury yields has narrowed to below 650 basis points. Nevertheless, allowed returns may begin to edge slightly higher going forward, as the Fed continues to raise interest rates as part of an aggressive effort to combat multi-decade high inflation rates. The effect of interest rate increases on authorized returns is unlikely to be dramatic, however, as authorized returns tend to be stickier on the upside than on the downside.

In addition, affordability concerns are likely to continue, as regulators grapple with rate increases stemming from the recovery of pandemic-related costs and stranded costs related to the energy transition. These considerations will be further complicated by the overall state of the economy, higher natural gas prices and the significant level of planned capital spending expected in the industry, particularly to fund the energy transition.

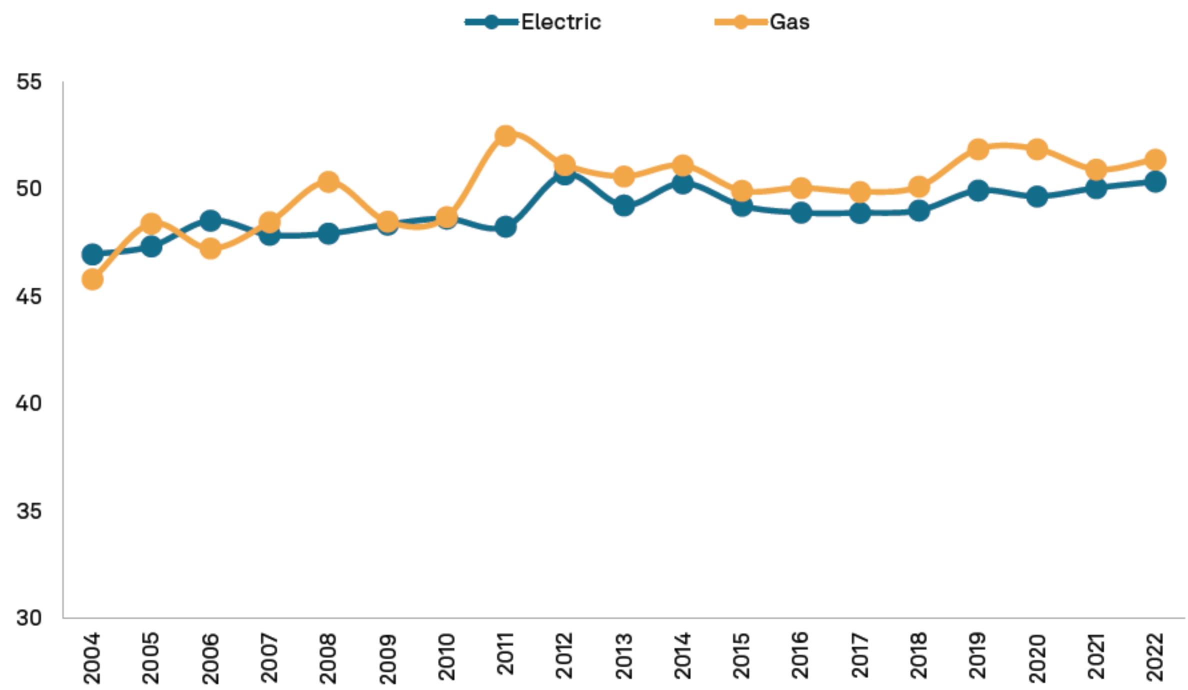
## Capital structure trends

The negative cash flow impact of federal tax changes that took effect in 2018 raised concerns regarding utility liquidity and credit metrics. In response, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than the levels observed in 2018 and 2017.

For 2022, 2021, 2020, 2019, 2018 and 2017, the average equity ratios authorized in electric utility cases were 50.36%, 50.06%, 49.67%, 49.94%, 49.02% and 48.90%, respectively. The average equity ratios authorized gas utilities were 51.38%, 50.92%, 51.87%, 51.86%, 50.12% and 49.88%, respectively.

Taking a longer-term view, equity ratios have generally increased over the last several years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. Many commissions began approving more equity-rich capital structures in the wake of the 2008 financial crisis. For the bulk of the period since 2004, allowed equity ratios for gas utilities have been above those authorized for electric utilities.

### Average authorized equity ratio (%)




Data compiled Jan. 27, 2023.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.


## A more granular look at ROE trends

The discussion thus far has looked broadly at trends in authorized ROEs; the sections that follow provide a more granular view.

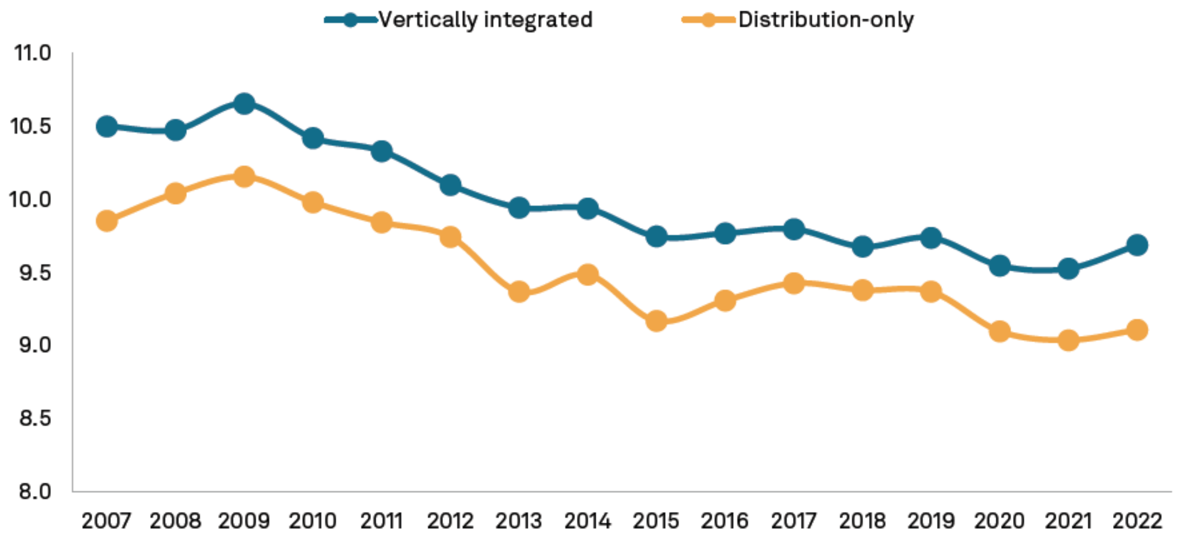
RRA has observed that there can be significant differences between average ROEs based upon the types of proceedings/decisions in which these ROEs were established.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for distribution operations.

RRA finds that the annual average authorized ROEs in vertically integrated cases involving generation have been about 30 to 65 basis points higher than in distribution-only cases, arguably reflecting the increased risk associated with ownership and operation of generation assets.

The industry average ROE for vertically integrated electric utilities was 9.69% in cases decided in 2022 versus the 9.53% average in 2021. For electric distribution-only cases, the industry average ROE was 9.11% in 2022 versus 9.04% in 2021.

**Average authorized electric ROEs (%)**

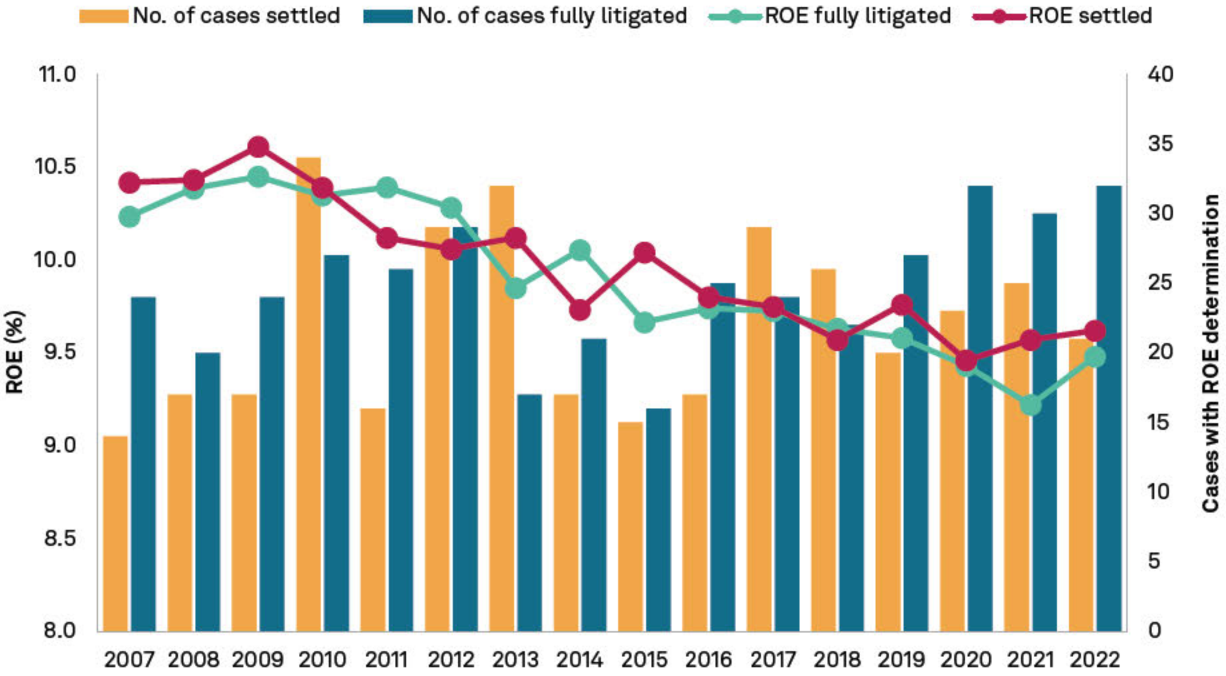



Data compiled Jan. 27, 2023.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.


Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are "black box" in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. Some states, however, preclude this type of treatment, and settlements must specify these values if not the specific adjustments from which these values were derived.

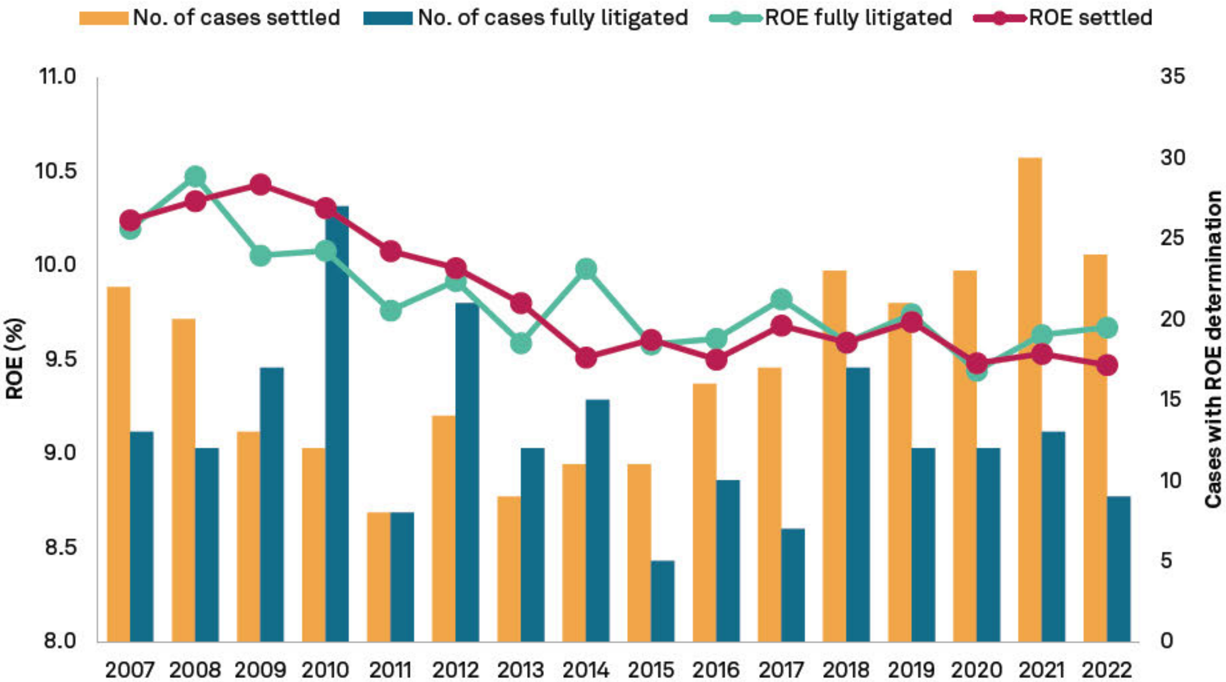
For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, while in others, it was higher for settled cases.

## Average authorized electric ROEs: settled vs. fully litigated cases




Data compiled Jan. 27, 2023.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.


## Average authorized gas ROEs — settled vs. fully litigated cases




Data compiled Jan. 27, 2023.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

The following discussion focuses on the corresponding tables available here.

**Table 1** shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and by quarter since 2017, followed by the number of observations in each period. **Table 2** indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and by quarter since 2020.

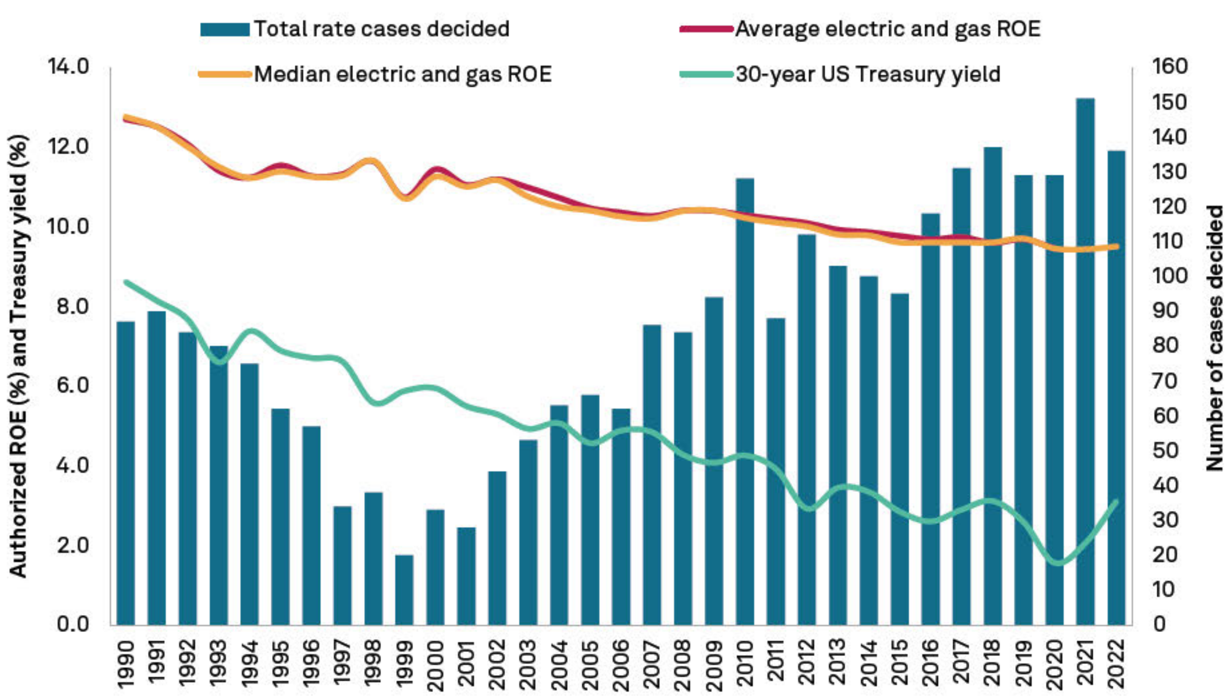
**Tables 3 and 4** provide comparisons since 2007 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

The individual electric and gas cases decided in 2022 are listed in **Table 5**, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time the decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases decided during the specified time periods and are not necessarily representative of either the average currently authorized ROEs for utilities industrywide or the returns actually earned by the utilities.

**Table 6** and the graph below track the combined average and median equity return authorized for all electric and gas rate cases since 1990. As the table indicates, since 1990, authorized ROEs have generally trended downward, reflecting the significant decline in interest rates and capital costs that has occurred over this time frame.

## Composite electric, gas average authorized ROEs; total number of rate cases




Data compiled Jan. 27, 2023.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

# Further Reading

The rate case process: a conduit to enlightenment

Rate base: How would you rate your knowledge of this utility industry fundamental?

An Overview of FERC Regulation

Frequently Asked Questions

Adjustment Clauses — a State by State Overview

Adjustment Clauses — Data tables

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Utility Asset Securitization in the U.S.

FERC Regulatory Review

Utility Capital Expenditures Update — Energy and water utility capex plans on-track for record breaking 2022

FERC and Electric ROEs — 2022 Update: Recently concluded cases

FERC and Electric ROEs — 2022 Update: Pending cases

See it in charts: Energy research, December 2022.

# About Regulatory Research Associates

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RRA Regulatory Focus
**Major Rate Case Decisions**
February 10, 2022

# Major Energy Rate Case Decisions – January – December 2021

## Quarterly update on decided rate cases

Lisa Fontanella Research Director

The average electric authorized return on equity continued its steady decline in 2021, hitting an all-time low. For gas utilities, the average authorized return on equity increased in 2021.

**For detailed data**

Access RRA's electric and gas rate cases as of year-end 2021 data tables.

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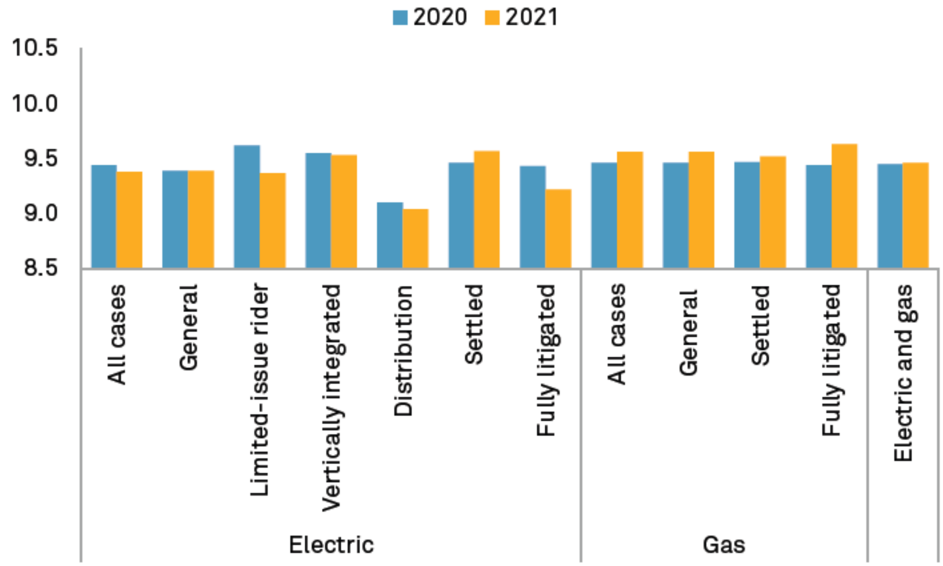
# Executive Summary

## Introduction

Amid ongoing virus challenges, 2021 was a record year in terms of rate case activity. Rate case activity neared all-time highs, with almost 150 decisions issued by state public utility commissions in 2021, the highest level since the early 1980s. The average ROE authorized for electric utilities fell to 9.38% for rate cases decided in 2021 from the 9.44% average for cases decided in 2020. The average ROE authorized for gas utilities was 9.56% for cases decided during 2021, up from the 9.46% observed in 2020.

While the reasons for a rate case filing are numerous, the main driver of new filings continues to be capital expenditures. Energy utilities are investing in infrastructure to modernize transmission and distribution systems, build new natural gas, solar and wind generation, and deploy new technologies to accommodate the expansion of electric vehicles, battery storage and advanced metering infrastructure that facilitate the transition toward decarbonization. Among other reasons for rate filings are changes in expenses and cost of capital, and the impact of broader economic and sector-wide forces.

## Average authorized return on equity (%)




| Electric averages | 2020 | 2021 |
|---|---|---|
| All cases | 9.44 | 9.38 |
| General rate cases | 9.39 | 9.39 |
| Limited-issue rider cases | 9.62 | 9.37 |
| Vertically integrated cases | 9.55 | 9.53 |
| Distribution cases | 9.10 | 9.04 |
| Settled cases | 9.46 | 9.57 |
| Fully litigated cases | 9.43 | 9.22 |
| **Gas averages** | | |
| All cases | 9.46 | 9.56 |
| General rate cases | 9.46 | 9.56 |
| Settled cases | 9.47 | 9.52 |
| Fully litigated cases | 9.44 | 9.63 |
| **Composite electric and gas averages** | | |
| Electric and gas | 9.45 | 9.46 |
| **U.S. Treasury** | | |
| 30-year bond yield | 1.56 | 2.06 |

Data compiled Jan. 26, 2022.
Sources: Regulatory Research Associates, a group within S&P Global Market Intelligence; U.S. Department of the Treasury

## About this report

This report, which is updated quarterly, offers a detailed overview of completed electric and gas rate case decisions in the U.S. The information presented in this report utilizes the data compiled by RRA for its rate case database, available on the S&P Capital IQ Pro platform. RRA endeavors to follow all "major" rate cases for investor-owned utilities nationwide, with "major" defined as a case in which the utility's request would result in a rate change of at least $5 million or in which the commission approves a rate change of at least $3 million. In addition to base rate cases, the rate case history database includes details regarding certain limited-issue rider proceedings, primarily those that involve significant rate base additions that are recognized outside of a general rate case. In some of these cases, the rate change coverage criteria may not apply.

# The Take

Rate case activity for investor-owned electric and gas utilities in the U.S. neared all-time highs in 2021, with about 150 rate cases decided, the highest level since the 1980s. The average authorized return on equity for electric utilities approved in cases decided during 2021 was the lowest annual average in RRA's rate case database, which includes all major rate cases decided since 1980. For gas utilities, the average authorized ROE remained close to the lowest-ever levels.

Interest rates, including long-term U.S. Treasury bond yields that are used to represent the risk-free rate in utility ratemaking, have remained historically low, exerting downward pressure on authorized ROEs over the past several years. The average ROE authorized for electric utilities fell to 9.38% for rate cases decided in 2021 from the 9.44% average for cases decided in 2020. The average ROE authorized for gas utilities was 9.56% for cases decided during 2021, up from the 9.46% observed in 2020.

Authorized returns may edge higher in 2022, as the U.S. Federal Reserve is poised to embark on a course of interest rate hikes beginning in March, as part of its efforts to extinguish soaring inflation.

State regulatory support and the authorization of adequate returns to ensure ongoing capital attraction in the utility sector will be instrumental, as the industry shifts away from fossil fuels to renewables and storage and invests in strengthening the nation's power grid against climate and other risks.

# Overview of electric and gas authorizations

The average authorized return on equity for electric utilities approved in cases decided during 2021 was the lowest annual average in RRA's rate case database, which includes all major rate cases decided since 1980. For gas utilities, the average authorized ROE remained close to historical lows.

The average ROE authorized for electric utilities fell to 9.38% for rate cases decided in 2021 from the 9.44% average for cases decided in 2020. There were 54 electric ROE determinations reflected in the calculations for 2021 versus 55 in 2020.

The average ROE authorized for gas utilities was 9.56% for cases decided during 2021, up from the 9.46% observed in 2020. There were 42 gas cases that included an ROE determination in 2021 versus 34 gas cases in 2020.

The electric ROE average in 2021 was weighed down by three ROE determinations in Illinois and Vermont that were calculated utilizing a formulaic approach tied to U.S. Treasury bond yields. Excluding these three ROE determinations, the average return authorized for electrics in 2021 was 9.48%.

In addition, the electric data set includes several limited-issue rider cases. There is, however, little difference between the ROE averages including rider cases and those excluding rider cases in 2021; historically, the annual average authorized ROEs in electric cases that involve 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. However, these premiums were approved for limited durations and have since begun to expire. As a result, the gap between the average ROE observed in the rider cases and that observed in 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 the rider cases, the average authorized ROE was 9.39% in electric general rate cases decided in 2021, equal to that observed in 2020.

In 2021, the median ROE authorized in all electric utility rate cases was 9.39%, versus 9.45% in 2020; for gas utilities, this metric was 9.60% in 2021, versus 9.42% in 2020.

The 2020 and 2021 calendar-year results reflect the impact of interest rate cuts by the Federal Reserve and the regulatory reaction to the COVID-19 pandemic-induced recession.

From a longer-term perspective, interest rates, as measured by the 30-year U.S. Treasury bond yield, fell almost steadily from the early 1980s until 2015 or so, placing downward pressure on authorized ROEs. Even though the decline in authorized ROEs was less dramatic in the period since 1990, average authorized ROEs fell below 10% for gas utilities in 2011 and for electric utilities in 2014. The calendar-year averages hovered between 9.5% and 9.8% through 2019, falling below 9.5% for the first time in 2020.

These declines in ROE have been occurring at the same time that rate case activity has been on an upswing. There have been 100 or more cases adjudicated in ten of the last 12 calendar years. This count includes electric and gas cases where no ROEs were specified; however, withdrawn cases are not included. Rate case activity in 2021, at 150 cases, was the most robust observed in any year during the 1990-2021 period. In 2019 and 2020 there were about 130 cases decided in each year.

Absent the pandemic, increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, storm and disaster recovery, cybersecurity and employee benefits have contributed to an active rate case agenda over the last decade.

Due to COVID-19 and the challenging economic landscape, during 2020 many utilities and state commissions found creative ways to limit the immediate impact of rate hikes by pushing rate changes into a future period or agreeing to forgo rate hikes and using accounting mechanisms, such as the accelerated recovery of excess accumulated deferred tax liabilities, to mitigate requested increases. In 2021, utilities were back before the state commissions seeking the highest combined increase in electric and gas rates since RRA began tracking cases.

Currently, there are almost 90 electric and gas rate cases pending, implying that 2022 will be another active year for rat case decisions, even if it does not match the 2021 case total.

Rising interest rates over the past several years also likely contributed to the increased rate case activity. After holding rates near zero for several years, the Federal Reserve began raising the federal funds rate in 2015. Before the pandemic hit, the Fed, after more than a decade without a cut, lowered rates three times in 2019, due to signs of a slowing economy.

## Major Energy Rate Case Decisions

Additionally, when the coronavirus outbreak shut down the U.S. economy in March 2020, the Fed took swift action, cutting the federal funds rate to near zero and beginning to purchase Treasury and mortgage-backed securities to provide additional economic stimulus.

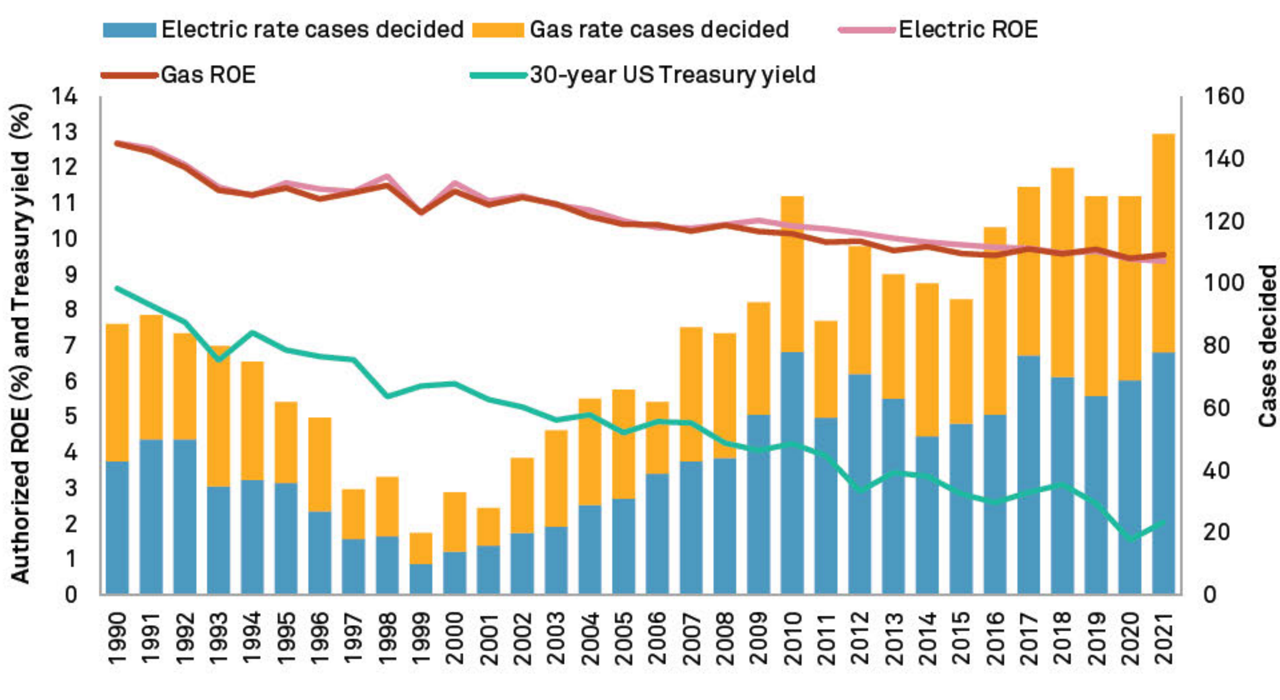
Amid increasing concerns over inflation, the Fed is expected to begin increasing the federal funds rate in March.

While changes in the federal funds rate do not move in lockstep with longer-term treasuries, and authorized ROEs do not move in lockstep with interest rates, the expectation is that as interest rates change, authorized ROEs would also change in a similar fashion. However, several factors impact the timing and magnitude of such a shift. For example, normal regulatory lag, i.e., the amount of time it takes for a utility to put together a rate case filing and tender it to the commission and then for the commission to process the case, would without any other influences delay a change in average authorized ROEs relative to interest rates.

It is also worth noting that while both interest rates and authorized ROEs have generally been declining since 1990, the gap between authorized ROEs and interest rates widened somewhat over this period, largely as a result of regulators' often-unstated understanding that the drop in interest rates caused by Federal Reserve intervention was unusual. Consequently, regulators did not necessarily fully reflect the interest rate drop in newly authorized ROEs in some instances; in others, regulators acknowledged that the changing dynamics of the industry and instability in the overall economy presented increased risks for investors, justifying a higher premium over interest rates.

In more recent periods, with the focus on affordability and the need to maintain universal service as the pandemic drags on, regulators have been more apt to further lower authorized ROEs to mitigate the level of bill increases. These concerns are likely to continue, as regulators begin to grapple with rate increases that result from the recovery of pandemic-related costs and stranded costs related to the energy transition. These considerations could be further impacted by the pace of the economic recovery, rising natural gas prices and the significant level of planned capital spending expected in the industry, particularly to fund the energy transition.

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




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

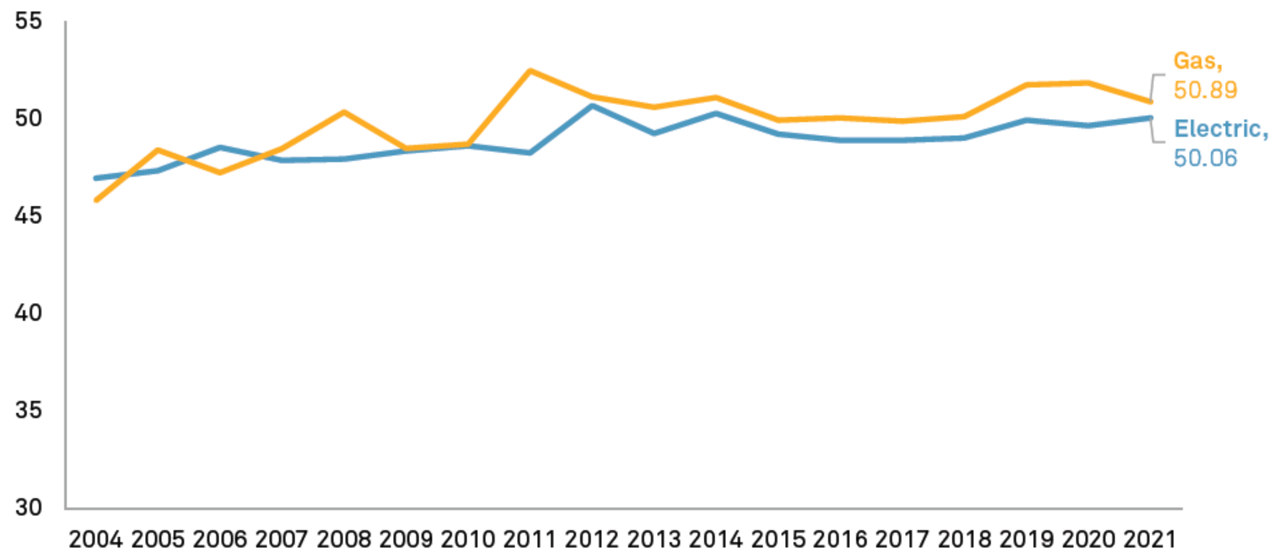
# Capital structure trends

The negative cash flow impact of federal tax changes that took effect in 2018 raised concerns regarding utility liquidity and credit metrics. In response, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than the levels observed in 2018 and 2017.

Over the last five years, 2021, 2020, 2019, 2018 and 2017, the average equity ratios authorized in electric utility cases were 50.06%, 49.66%, 49.94%, 49.02% and 48.90%, respectively. The average equity ratios authorized gas utilities were 50.89%, 51.86%, 51.75%, 50.12% and 49.88%, respectively.

Taking a longer-term view, equity ratios have generally increased over the last several years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. Many commissions began approving more equity-rich capital structures in the wake of the 2008 financial crisis. For the bulk of the period since 2004, allowed equity ratios for gas utilities have been above those authorized for electrics.

## Average authorized capital structures (%)




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

# A more granular look at ROE trends

The discussion thus far has looked broadly at trends in authorized ROEs; the sections that follow provide a more granular view.

RRA has observed that there can be significant differences between average ROEs based upon the types of proceedings/decisions in which these ROEs were established.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for delivery operations.

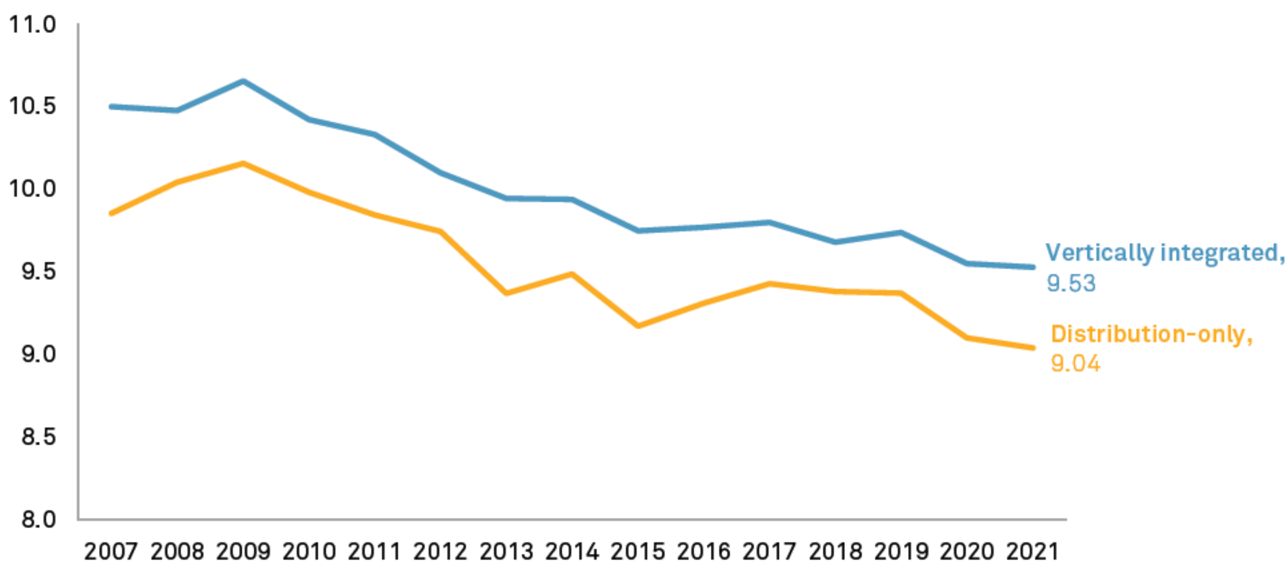
Comparing electric vertically integrated cases versus delivery-only proceedings over the past several years, RRA finds that the annual average authorized ROEs in vertically integrated cases typically are about 30 to 65 basis points higher than in delivery-only cases, arguably reflecting the increased risk associated with ownership and operation of generation assets.

The industry average ROE for vertically integrated electric utilities was 9.53% in cases decided in 2021, versus the 9.55% average posted in 2020. For electric distribution-only cases, the industry average ROE was 9.04% in 2021, versus 9.10% in 2020.

Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are "black box" in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. However, some states preclude this type of treatment, and settlements must specify these values, if not the specific adjustments from which these values were derived.

For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, in others, it was higher for settled cases, and in a handful of years, the authorized ROE was similar for both fully litigated and settled cases.

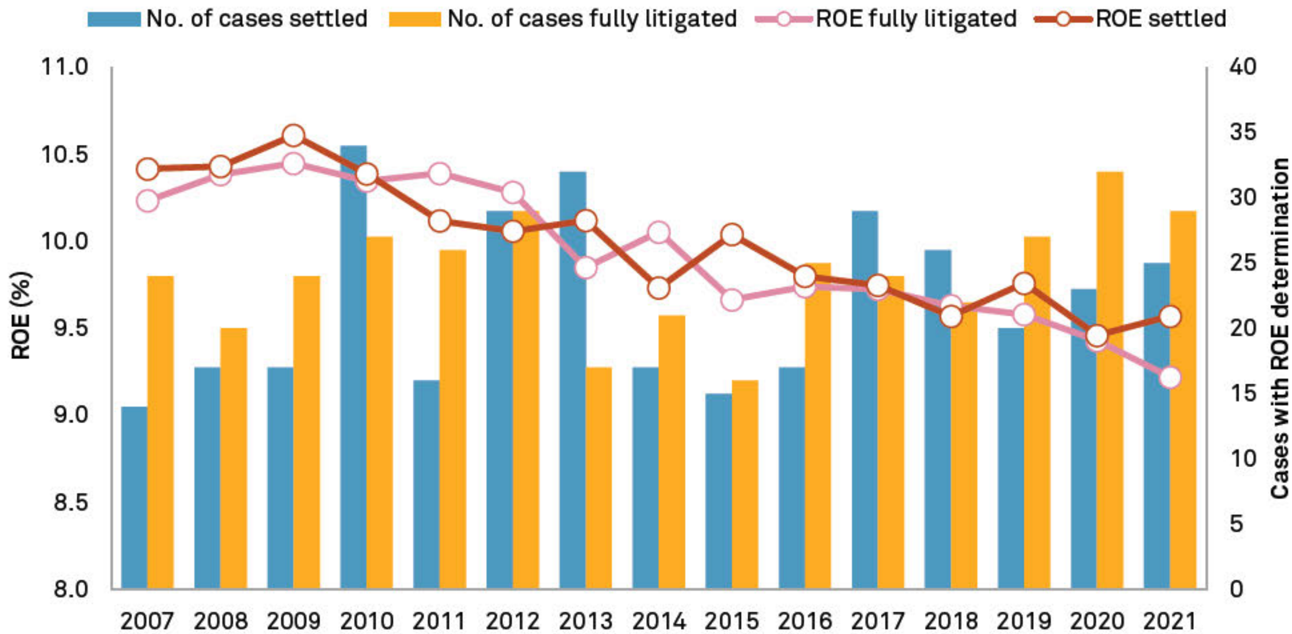
## Average authorized electric ROEs (%)




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

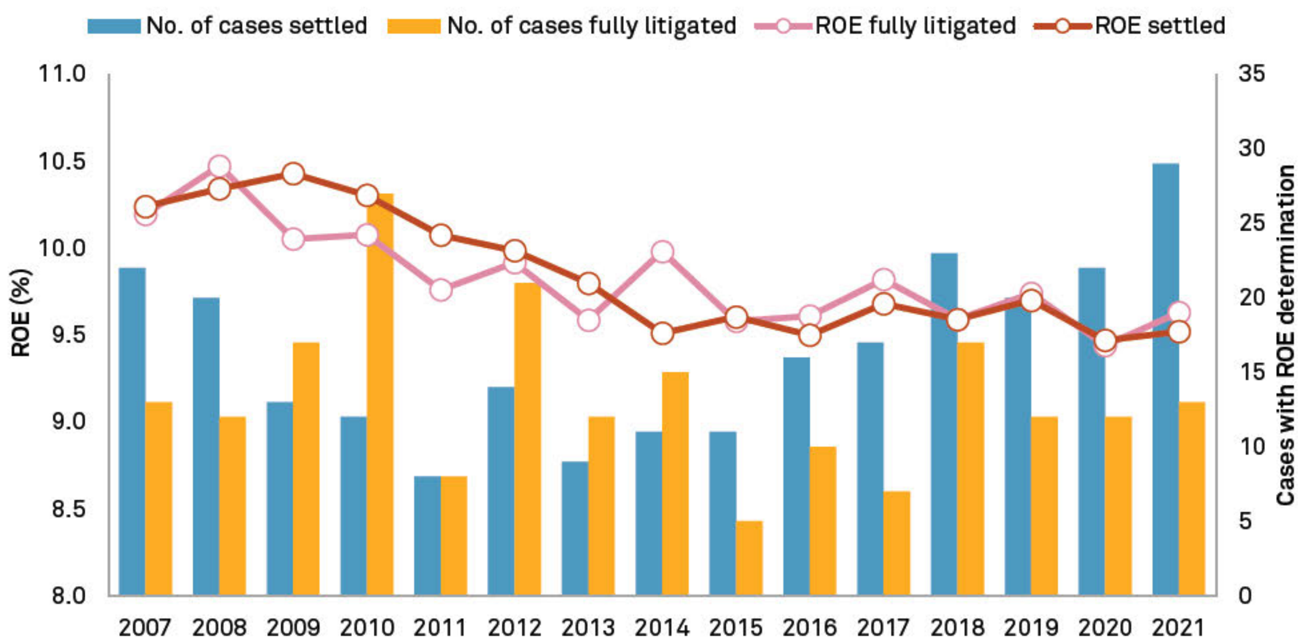
## Major Energy Rate Case Decisions

### Average authorized electric ROEs: settled vs. fully litigated cases




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

### Average authorized gas ROEs: settled vs. fully litigated cases




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

## Major Energy Rate Case Decisions

The following discussion focuses on the corresponding tables available here.

**Table 1** shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and by quarter since 2017, followed by the number of observations in each period. **Table 2** indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and by quarter for the past three years.

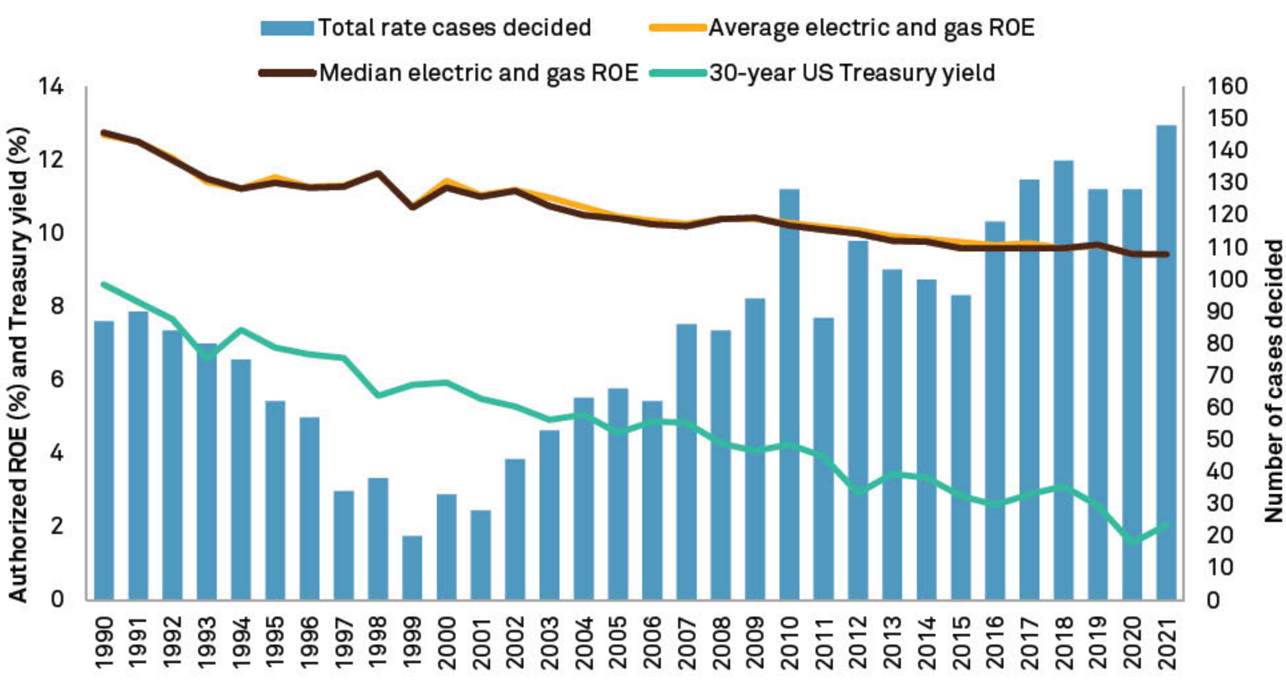
**Tables 3** and **4** provide comparisons since 2007 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

The individual electric and gas cases decided in 2021 are listed in **Table 5**, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time the decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases decided during the specified time periods and are not necessarily representative of either the average currently authorized ROEs for utilities industrywide or the returns actually earned by the utilities.

**Table 6** and the graph below track the combined average and median equity return authorized for all electric and gas rate cases since 1990. As the table indicates, since 1990, authorized ROEs have generally trended downward, reflecting the significant decline in interest rates and capital costs that has occurred over this time frame.

### Composite electric and gas authorized ROEs and number of rate cases




Data compiled Jan. 26, 2022.
Sources: Regulatory Research Associates, a group within S&P Global Market Intelligence; U.S. Department of the Treasury

# Further Reading

The rate case process: a conduit to enlightenment

Rate base: How would you rate your knowledge of this utility industry fundamental?

The Commissions

State Regulatory Evaluations — Energy Sept. 3, 2021

A variety of stranded cost recovery, abatement strategies emerging in US energy transition.

Energy utility capex plans on-track for record-breaking 2021 and 2022

The Big Picture: 2022 Electric, Natural Gas and Water Utilities Outlook

State Regulatory Evaluations — Energy

Major Utility Cases in Progress in the U.S.

Major utility cases in progress — Pending significant non-rate case activity

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# About Regulatory Research Associates

Regulatory Research Associates, a group within S&P Global Market Intelligence, is the leading authority on utility securities and regulation. Understanding the financial and strategic impact of federal and state regulation is a key to success in the energy business. For nearly 40 years, Regulatory Research Associates has been the leading provider of independent research, expert analysis, proprietary data and consultation on utility securities and regulation.

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## The Citizens' Utility Board Asked the Oregon Public Utility Commission to Dismiss Portland General Electric's Rate Request for 2025

by Pete Danko – Portland Business Journal – Mar. 15, 2024


In what it called an "unprecedented appeal" to regulators, **Oregon's residential ratepayer advocate** on Thursday formally **asked** the **P**ublic **U**tility **C**ommission to **dismiss** **P**ortland **G**eneral **E**lectric's **latest proposed rate increase**.

PGE late last month requested a 7.4% overall average rate increase in 2025, 7.2% for the residential customers that the Citizens' Utility Board represents.  It would come on the heels of an 18% overall increase that hit PGE residential customers in January, with a smaller but not yet set rate boost for wildfire mitigation costs still due to kick in this April.

Rates also rose in 2023, and the new PGE request would push PGE prices some 40% above where they stood in 2022, according to CUB.

**Something 'never done before'.**

"We're asking the Commission to do something they have never done before," **Bob Jenks**, **CUB**'s executive director, **said** in a news release.  "We are seeing historically high bills for many PGE customers, and we **need regulators** to **do something bold and unprecedented**.  Now is the time to flip the script and show our utilities that consumer protections come before profits."

A PGE representative, responding to a request for comment, emailed that "PGE is and will continue to be fully engaged in the public Rate Review process administered by the Oregon Public Utility Commission."

**If not a dismissal**, **CUB asked the PUC** to "**segregate**" **several issues from PGE's request**, **including PGE's ask for** an **increase** in its **return on equity** — its profit margin, in essence — **from 9.5% to 9.75%**. **CUB said many of those issues** were **fought** over **in last year's PGE general rate case**.

"The **Company seeks** to re**-litigate many** of the **contentious issues** that were collaboratively resolved and determined to result in just and **reasonable** rates mere weeks earlier," it said in the PUC filing.

**CUB said** it was **supported in** its **motion by Lewis & Clark Law School's Green Energy Institute and** the Alliance of **W**estern **E**nergy **C**onsumers, which represents big energy users.

Rates are ultimately set by the three-person, governor-appointed PUC after a 10-month process that includes regulatory staff analysis and stakeholder and public input.

**PGE's Battery Investments**

With rates already on the rise, PGE executives earlier last month had told investment analysts that the company would look to file a narrowly focused general rate case, mostly to pay for new battery energy storage systems it expects to bring online next year.

But CUB saw the request that came less than two weeks later as far from narrow. Out of a $202 million revenue requirement boost, just $17.3 million was directly attributable to the battery systems.

PGE says associated substation costs also need to be paid for, along with other transmission and distribution system upgrades that it says will improve reliability and help it meet growing load.

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## Consumer Group asks Oregon Regulators to Dismiss New PGE Rate Hike Request

by Gosia Wozniacka - Oregonian – Mar. 15, 2024

A state nonprofit group that advocates for utility customers is asking Oregon regulators to dismiss Portland General Electric's newest rate increase proposal.

In a motion filed Thursday, the Oregon **C**itizens' **U**tility **B**oard **asked** the **P**ublic **U**tility **C**ommission to **throw out PGE's 7.4% increase request**. If approved by the commission, the increase would take effect in January 2025.

The **C**itzens' **U**tility **B**oard, which was **created via** a **1984 ballot measure**, said in a statement that it has never taken such an action before and is doing so now "in the face of record bills for PGE customers."

The board points out that PGE's residential customers have seen a 30% increase in power bills over the past two years. Their rates went up 12% in January 2023 and by 18% this past January.

Customers are reeling from record-high bills that resulted from this year's rate increase and the ice storm in January and many won't be able to handle yet another increase, said Bob Jenks, the board's executive director.

Jenks said the utility's latest request for 2025 will likely grow to cover other costs such as wildfire mitigation or winter storm recovery.

"We're asking the Commission to do something they have never done before," Jenks said. "We are seeing historically high bills for many PGE customers, and we need regulators to do something bold and unprecedented."

The **P**ublic **U**tility **C**ommission regulates investor-owned electric and other utilities. Commission spokesperson **Kandi Young said** the **Commission's normal practice** would be to seek written replies from its staff and other parties and then issue a written ruling after reviewing responses. **But** Oregon **CUB's petition asks** the **Commission instead** to **decide** the **motion at** a **public meeting**.

"The Commission is considering CUB's request for a change to the standard process, and will advise parties when written responses are due," Young told The Oregonian/OregonLive via email.

PGE declined to comment on the petition and said it would continue to focus on its rate increase proposal.

"PGE is and will continue to be fully engaged in the public Rate Review process administered by the Oregon Public Utility Commission," the utility's spokesperson, Drew Hanson, said in an email.

PGE's 7.4% rate increase request is tied to clean energy needs – specifically, battery storage projects, PGE said previously.

In its petition, the Citizens' Utility Board told regulators that its review of the request found that the new Constable **Battery Storage** project, which is what's included in PGE's rate increase proposal, will cost only $17.3 million, or 8.5% of the total $202 million revenue demand.

The rest, said **Jenks**, will go toward higher profits for shareholders and shifting financial risk to customers, among other things – issues the **commission already ruled** on and rejected in **December for** the **increase that went into effect this year**.

**If** the **P**ublic **U**tilities **C**ommission **will not dismiss PGE's entire rate increase case**, the **C**itizens' **U**tility **B**oard **asks** that it **limit** the **scope** of what PGE can request, including **removing all** of the **items** that the **commission previously ruled against**.

# Is Oregon Utility Regulation Part of the Problem?

by Bob Jenks – Oregon CUB – Jan. 25, 2024

Is Oregon Utility Regulation Part of the Problem? | Latest News | News | Oregon CUB

As utility bills in Oregon continue to rise in 2024, CUB is asking tough questions from state regulators. Currently, utility regulators spend a lot of time looking at many requests from utilities to raise rates. This analysis can take up to 10 months in many cases. But overall affordability to customers is not part of the equation for regulators.

We need to look at utility bills holistically – before we see rates skyrocket. Our current system means that customer advocates, decision-makers, and customers do not have a clear picture of what to expect from utility bills. And an even harder time knowing when rates will go up dramatically.

## Exposing Flaws in Oregon's System of Utility Regulation

From December 2022 to January 2024, Portland General Electric (PGE) customers have seen bills go up by 30%. This large increase in 13 months shows real and significant flaws in Oregon's system of regulation utilities.

Our current structure leads regulation to focus on each individual line item, but not on the overall affordability of rates. There are several parts to this problem:

- Utilities have an incentive to spend money.
- Utilities can request dozens of rate increases a year.
- **Regulator looks at individual utility projects**, **not total rates**.
- Costs can be updated even after they are approved by regulators.
- Utilities work to keep information confidential from the public.

Electric utilities are typically the ones who see the most frequent requests for rate increases. PGE is not the only utility that has had large bill increases in the past few years. Pacific Power customers saw bills increase by 21% at the start of 2023 and by 11% on January 1, 2024.

Increasingly, gas utilities are also asking for more from customers more often. Alongside the big spikes in the cost of methane, NW Natural gas rates have increased by 32.7% since September 2022.

**Utilities have an incentive to spend money**

Utilities make a profit from making capital investments. This ability to profit from a new power plant, laying new lines, or other projects is protected by Oregon law. While many investments are necessary to maintain a reliable system, too many investments can cause rates to be unaffordable.

To justify a capital expense, a utility normally has to show that the investment was expected to bring benefits to the system and to customers. But affordability to customers is not part of the equation for regulators.

**Example: Wildfire Mitigation**

After the 2020 Labor Day fires, it became clear that utilities needed to invest money in wildfire mitigation. Oregon's utilities are now spending hundreds of millions of dollars to mitigate potential wildfires. Since a wildfire caused by a utility line can cause significant harm, it would be hard to argue that this is not a prudent and necessary investment.

For utilities, wildfire mitigation was an opportunity to spend money and increase profits. Did they ask whether this was affordable for customers? Did they look at other investments to see if there were costs that could be avoided or delayed?

Read More: **Protecting Oregon Customers from Wildfire Risk and Cost Increases**

**Regulation Looks at Individual Investments, Not Total Rates**

Under Oregon law, regulators at the Public Utility Commission are supposed to establish fair and reasonable rates. What regulators do not consider is how these costs affect customers overall.

When a utility asks regulators if it can charge customers more money, it brings a list of investments and expenses. Regulators go down the list, examining each cost to see if it is reasonable and justifiable. They ask questions like: Will this cost provide a benefit to the energy system? Will this investment be able to be used for its expected lifetime?

What **regulators do not ask**: How much will approving this cost increase customer bills? **What other costs is** the **utility asking for that will increase bills**? Can customers afford this large of an overall increase?

**Investments.**

When a utility makes an investment, it is motivated by profit first and meeting basic standards of providing service second. What is not considered is how an investment will impact the people they are charging.

While adding many new upgrades to the utility's system may help the system, when combined their cost may be beyond the reach of most customers when they are added to the bill. With neither utilities nor regulators considering whether families can afford total energy bills, a lot of pressure falls on advocates like CUB.

**Single-Issue Rate-Making Makes Controlling Costs More Difficult**

**Holistic Utility Regulation:** Under traditional regulation, regulators consider utilities' investments, the overall cost of providing service, profits, and more. For a long time, the holistic model was the standard for utility regulation. Over the past couple of decades, utilities have increasingly asked for surcharges outside of this process.

**Single Issue Regulation (Surcharges):** In the case of single-issue rate-making, regulators typically only look at the utility costs and surcharge requests related to a single issue. One recent example of a single-issue surcharge is the Wildfire Mitigation cases mentioned above. PGE and Pacific Power both asked to add a surcharge to cover costs related to wildfire prevention. Other examples of single-issue requests include surcharges to cover costs associated with the 2021 ice storm and pilot programs for electric vehicle investments.

Right now, electric utilities are the ones most likely to use the surcharge method to raise rates. But gas utilities are also able to use this tactic. Across the country, energy utilities are using single-issue regulation more and more often to get more and more money from customers

**Costs are Updated After Regulators Review Them**

In some of these mechanisms, PGE will file a proposal but is allowed to update the proposal. In the case of power costs, the final update is after the Commission actually issues its final order in the case. This means the Commission is expected to make a decision without knowing the rate that is established.

**Lack of Transparency on Rate Impacts**

In order to protect trade secrets, utilities are allowed to designate some information as **confidential**. But utilities abuse this process. When PGE updates its power cost forecasts in power cost cases, it designates the expected price increase as confidential. CUB cannot think of any reason why a forecasted rate increase could ever be considered confidential. But it does make it difficult to inform the public about what their rates will be, and it makes public discussion of future rate hikes more difficult.

**Enough is Enough.**

**PGE's rates** have **increased** by **30% in** the **last 13 months**. But no one has reviewed the overall rate level and asked the question: Are rates fair and reasonable?

**Using the Tools in Regulators' Toolbelts**

Regulators at the Public Utility Commission have tools that they can use to lower the impact to customers.

**Directing Utilities to Adjust Expenses**

**First**, the Commission can order a utility to propose and implement other measures to reduce **rate shock**. The regulators could tell the utility to **delay certain expenses**. They could also direct utilities to take other **cost-cutting measures**, reducing the need for a rate increase altogether.

**Delaying Increases**

**Second**, when regulators approve a rate increase, they can order the utility to delay some of that increase until sometime in the future. By **delaying increases**, electric customers in particular can avoid a large increase during winter when energy usage is the highest.

In the case of PGE's 2024 increase, regulators asked the utility to delay an additional 2% increase until the spring. In 2023, Pacific Power delayed the rollout of its 21% increase until the spring, lessening the impact of the winter heating season.

By delaying increases, regulators can help protect customers from surprisingly high bills during the winter months. This could be the difference between a household being able to keep the heat on or facing disconnection.

**Tying Customer Costs to Allowable Profits**

**Third**, regulators can add incentives to keep costs low by **lowering allowable profit margins** if the cost to customers is not controlled.

**CUB is Pushing for Policy Changes**

State utility regulators are required to set some costs, such as utility profits, at a reasonable level. However, the **P**ublic **U**tility **C**ommission **can set** the **rate at** the **lowest level** that is **considered reasonable**. For example, the **Commission might determine** that a **reasonable profit margin is anything between 9.0% and 10.0%**. Under normal circumstances, the Commission might set that margin at the midpoint or 9.5%.

But **to mitigate a large rate increase**, the **Commission can set** the **profit margin at** the **lowest point** which is **reasonable or 9.0%.** Lowering profits will lower the rate increase for customers. This is an important tool because it tells utilities that if they cannot control their costs, it will reduce their profit margins.

CUB advocates are hard at work this year to create lasting change to protect customers from more bill increases. In 2024, we are facing multiple requests from utilities to increase rates again. Oregonians from Newport to Ontario could be impacted.

**Reduce the Number of Increases**

A big policy issue for CUB this year is to **reduce** the **number of rate requests** that **utilities** are **asking for each year**. We have been pushing back against the rising tide of surcharges facing Oregon energy customers.

In the PGE case, CUB continued to fight for a more holistic approach to utility regulation and won on several issues we raised. Now, PGE is consolidating some of their requests and has dropped others. This is good for customers' ability to know what to expect from bills down the line.

Read more: **Are Utility Customers Being Nickled and Dimed? - CUB Blog**

**Pushing for New Policy: Avoid Large Bill Spikes in the Winter**

Regulators did the right thing in delaying even more increases for PGE customers this winter. Now, CUB is calling on the Public Utility Commission to make spreading high rate increases a standard practice to prevent disastrous winter bills for Oregonians.

While CUB has negotiated delays in winter increases with utilities, this is the first time in recent memory that the Commission has made such a request. Without this delay, customers could have seen a higher bill increase in January, a month that typically brings the highest energy bills of the year.

**Stay Up to Date on Oregon Utility Issues**

CUB will continue to advocate for people in Oregon on major utility issues. **Sign up for the CUB email list** for the latest updates, action alerts, and news on policies that affect the utilities your home relies on.

**Donate to CUB**

To keep up with CUB, like us on **Facebook** and follow us on **Twitter!**

## It’s Been 30 Years Since Food Ate Up This Much of Your Income

by Jesse Newman and Heather Haddon – WSJ – Feb 26, 2024

Ongoing high costs lead food manufacturers and restaurants to keep prices elevated.

The last time Americans spent this much of their money on food, George H.W. Bush was in office, “Terminator 2: Judgment Day” was in theaters and C+C Music Factory was rocking the Billboard charts.

Eating continues to cost more, even as overall inflation has eased from the blistering pace consumers endured throughout much of 2022 and 2023. Prices at restaurants and other eateries were up 5.1% last month compared with January 2023, while grocery costs increased 1.2% during the same period, Labor Department data show.

Relief isn’t likely to arrive soon. Restaurant and food company executives said they are still grappling with rising labor costs and some ingredients, such as cocoa, that are only getting more expensive. Consumers, they said, will find ways to cope.

“If you look **historically after periods** of **inflation**, there’s really **no period** you could point to **where** [**food**] **prices go back down**,” said Steve Cahillane, chief executive of snack giant Kellanova , in an interview. “They **tend to be sticky**.”

Companies are set to pay more for staffing, after 22 states in January lifted the minimum wage for hourly workers.

In **1991**, **U.S. consumers spent 11.4%** of their **disposable personal income on food**, according to data from the U.S. Agriculture Department. At the time, households were still dealing with steep food-price increases following an inflationary period during the 1970s.

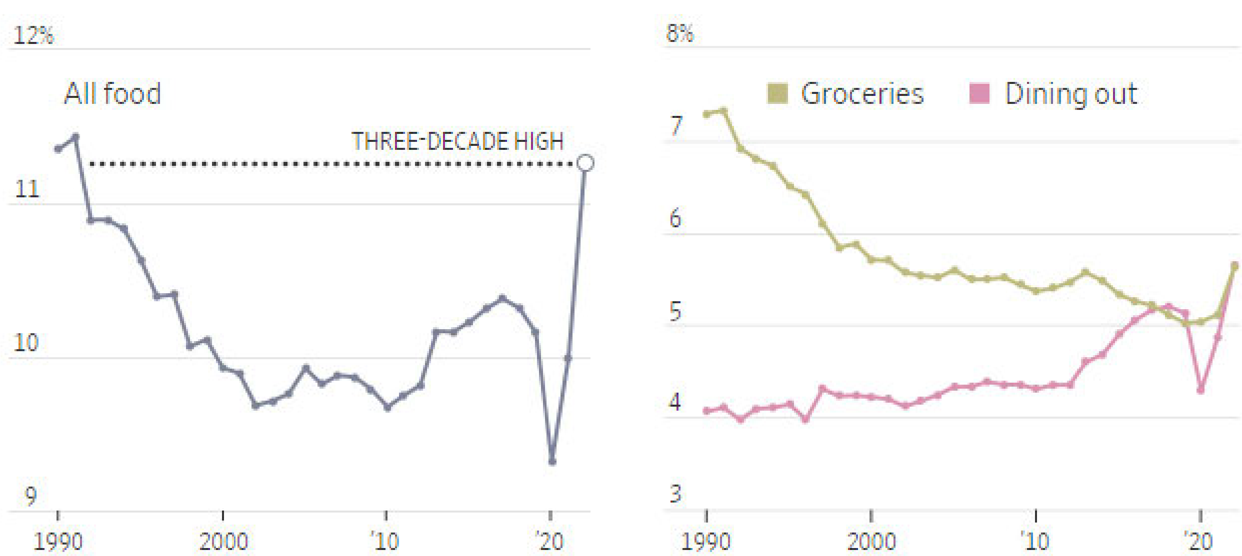
More than three decades later, food spending has reattained that level, USDA data shows. In **2022**, **consumers spent 11.3%** of their **disposable income on food**, according to the most recent USDA data available.

Many diners have said they are going out less frequently or skipping appetizers, while buying cheaper store brands more frequently at supermarkets and seeking out promotions or deals offered via apps. That is starting to chip away at some sales for food makers and restaurant operators.

Food companies said they are feeling pinched themselves. While commodities such as corn, wheat, coffee beans and chicken have gotten cheaper, prices for sugar, beef and french fries are still high or rising. Companies across the U.S. economy have also raised prices beyond covering their own higher expenses, lifting profits for industries including retail, biotech and manufacturing.

Food inflation has raised the ire of President Biden, who took to Instagram during the Super Bowl to blast food makers that he said were providing less bang for consumers' buck – putting fewer chips in each bag or shrinking the size of ice-cream containers.

**Food spending's share of disposable income**




Source: Agriculture Department

"The American public is tired of being played for suckers," Biden said. "I've had enough of what they call **shrinkflation**. It's a rip-off."

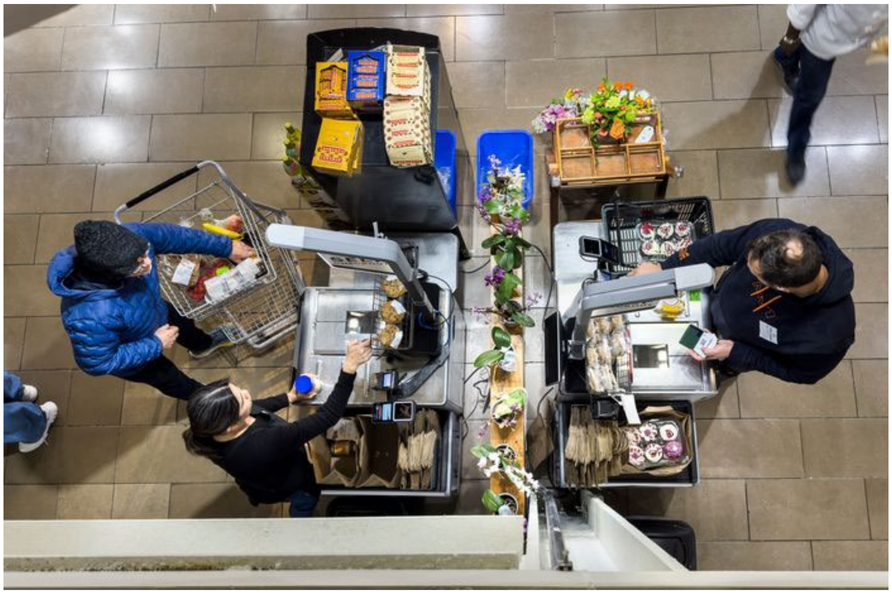
David Chavern, CEO of the Consumer Brands Association, which represents major food manufacturers, said the industry offers many choices at different price points. "We hope to work with the president on real solutions that benefit consumers," he said.

In suburban Chicago, Lisa Wister said her food bills are rising faster than her family's income, leading them to make their own granola from scratch and pack their own snacks for the movies. "Everything is a negotiation, an analysis about our budget," said Wister, an occupational therapist. "It's exhausting."

Denny's, Wendy's and other restaurant chains told investors this month that their guest counts fell last year compared with 2022 levels as consumers, in particular those with lower incomes, feel the financial pinch. Big food makers including Hershey and Kraft Heinz have reported that their sales volumes declined as prices rose for their products, with several reporting a hit to profits in the latest fiscal year – and others an increase.

Oreo maker Mondelez said in January it would continue raising prices on some of its products this year, largely because of cocoa prices, which earlier in February surged past a 46-year record. Hershey said this month it expects more expensive cocoa to cut into the company's profit this year. Kraft Heinz said inflation is moderating but that its costs are still higher, driven in part by pricier tomatoes and sugar.

Companies are set to pay more for staffing, after 22 states in January lifted the minimum wage for hourly workers. Hiring skilled workers like mechanics to replace employees who retired during the pandemic is particularly expensive, said Henk Hartong, CEO of Brynwood Partners, which owns 17 food and beverage plants that make Pillsbury cake mixes and other products.



Many people say they are buying cheaper store brands more frequently at supermarkets.

Restaurant chains said they are trying to operate more efficiently to help defray wage increases, but they also expect to raise prices.

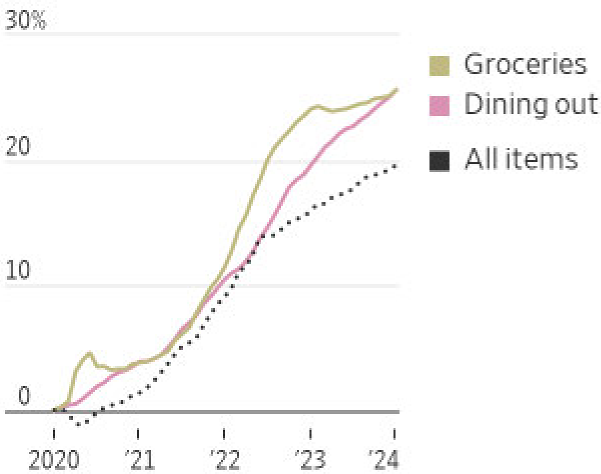
"It's a really fast move and a high percent increase," Chipotle Mexican Grill CEO Brian Niccol said in an interview, referring to California's 25% minimum wage increase for fast-food workers employed by large chains, set to take effect in April. "Pricing is going to be part of the puzzle."

Some restaurant and food companies, including Kraft Heinz, Mondelez International and Olive Garden owner Darden Restaurants , are projecting higher earnings this year. Signs of a consumer-spending slowdown has led others to temper their outlooks, with same-store sales projection for 2024 and frozen-foods maker Conagra reducing its per-share earnings forecast.

Investors have cooled on food stocks. An S&P 500 subindex of restaurant stocks has risen 10% in the past 12 months through Wednesday's close, while the broader index gained about 25%. An S&P subindex tracking packaged food and meat companies fell roughly 8% over that period.

When Anna Zabinski and her husband eat out these days, she said, they ask themselves whether a side of macaroni and cheese is worth the extra $1.99, and often go for refills instead of ordering more expensive large-size drinks.

Change in prices since January 2020




Note: Based on seasonally adjusted consumer-price index.
Source: Labor Department

Zabinski, a professor from Normal, Ill., said they'll sometimes split a $20 steak and side dish at Texas Roadhouse or a large sandwich from Jimmy John's. Nonetheless, she said, "our daily and monthly expenditures still seem higher than even two years ago."

Food manufacturers and restaurants have been offering more deals on some items. J.M. Smucker and Conagra have reduced prices on coffee and margarine, passing through lower costs for coffee beans and edible oils. McDonald's and Wendy's said they would offer deals this year aimed at consumers seeking relief from rising prices.

Gary Pilnick, chief executive of WK Kellogg, said the company has been working to market cereals such as Frosted Flakes and Froot Loops to pressured consumers. An ad campaign launched in 2022, for example, encouraged consumers to eat cereal for dinner, pitching it as an easy, inexpensive alternative that, combined with milk and fruit, costs less than $1 per serving. "Give chicken the night off," the campaign's tagline says.

**Although** it is **rare for food prices to retreat**, it is **also unusual for prices** to **skyrocket as much as** they have in **recent years**, said TD Cowen analyst Robert Moskow. He said he expects grocery prices to decline for a period this year as food makers come under pressure from consumers and retailers.

Kraft Heinz said it is focused on providing affordable options for families, and that while its costs rose 3% in 2023, it raised prices by 1%. WK Kellogg said that before raising prices, the company tries to combat higher costs through greater productivity.

Kellanova said it is working to keep prices as low as possible. Cahillane declined to comment on pricing for his company's products this year but said that the maker of Pringles and Pop-Tarts hasn't raised prices to pad its profit.

Cahillane said that as consumers become accustomed to seeing higher prices on supermarket shelves, they will adjust.

"Just like a gallon of gas, it becomes the new price and people get begrudgingly used to it," he said.

## PNM Takes 'Deep Breath' after Avangrid Deal Fails, Eyes Solo Strategy for Now

by Garrett Hering
Standard and Poor's Global Market Intelligence – Feb. 6, 2024

**PNM** Resources Inc. is refocusing on its future as a growing but independent utility enterprise after its proposed **$8.3 billion combination with Avangrid** Inc. **collapsed** in **January**. At least for now.

"While we were disappointed with the outcome, we have continued to advance our stand-alone business strategy to invest in the infrastructure needed to meet customer needs, enable the clean energy transition and diversify our rate base," PNM Resources CEO Patricia Vincent-Collawn said Feb. 6 on the company's fourth-quarter 2023 earnings call with investment analysts.

That strategy includes accelerating its earnings and dividend growth and rolling out a five-year, $6.1 billion investment plan for regulated utility arms Public Service Co. of New Mexico and Texas-New Mexico Power Co., including transmission and distribution system expansion and a build-out of utility-owned battery storage.

"PNM hit a new system peak in 2022 and in 2023 after not seeing one in nearly a decade," Don Tarry, the company's president and COO, said on the call. "Clean energy mandates in New Mexico over the next 20 years will require additional transmission resources to integrate a growing amount of intermittent renewable resources on the system."

As PNM works through a "deep-breath phase" following the failure of its planned acquisition by Avangrid, executives and the company's board still believe that a larger-scale company could benefit from "cheaper capital" as well as access to "materials, supplies [and] employee opportunities," Vincent-Collawn added.

However, the CEO said the company would need to see a change in philosophy at the **New Mexico P**ublic **R**egulation **C**ommission, which **rejected** the **merger** in **2021**. A subsequent **May 2023 decision** by the **New Mexico Supreme Court** to **deny PNM** and **Avangrid** a **request** to **remand** the **case back to state regulators** foreshadowed the termination of the deal.

"When the board talks about it, that's what we're balancing," the CEO said.

### Earnings beat, revenue miss

On the call, PNM unveiled its consolidated earnings guidance for 2024 of $2.65 to $2.75 per diluted share. The company boosted its earnings-per-share growth target to 6%-7% per year between 2024 and 2028, up from a prior 5% growth target.

For 2023, PNM posted earnings of $2.82 per diluted share, up from $2.69 per share a year earlier and beating the S&P Capital IQ consensus estimate of $2.78 per share. PNM's adjusted earnings of 18 cents per share in the fourth quarter of the year beat consensus by about 29%.

On a GAAP basis, the utility reported a loss of $50.2 million for the quarter, partially attributed to rate credits associated with the San Juan Generating Station settlement and disallowances in a recent rate case decision.

The company generated $1.94 billion in revenues in 2023, down from $2.25 billion a year before and missing the consensus estimate by 7.6%. The company's fourth-quarter revenue of $412.1 million was about 24% below consensus.

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## No Surprise from the Fed

by Dante DeAntonio, Director – Moody's Analytics – Mar. 21, 2024

An **upbeat**, if still **cautious**, tone characterized the March meeting of the **Fed**eral Open Market Committee. The **fed funds rate target**, as anticipated, was kept **unchanged**, despite higher-than-expected consumer price inflation reports in recent months. However, reflecting recent communications, the **Fed**eral Reserve **dampened expectations** about the FOMC's urgency to **rush to rate cuts**.

The **committee's latest Summary of Economic Projections suggests** that **2024 will see 75 basis points' worth of cuts to** the **fed funds rate**, **unchanged from** the most recent Summary of Economic **Projections from December**. This reflects policymakers' continued confidence that policy tightening has worked and inflation will eventually return to target. However, the committee reiterated that it will not be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably toward 2%

Notably, though, policymakers are now more upbeat about a soft landing than they were in December. The FOMC's GDP forecast for 2024 was revised upward from 1.4% to 2.1%. Subsequently, the Fed predicts 2% growth for 2025 and 2026, up slightly from December without comparable changes to inflation and unemployment projections.

Inflation has receded meaningfully in the U.S. without the corresponding increase in joblessness historically observed when restrictive policy is needed to bring down inflation. However, early inflation readings in January and February came in higher than expected, owing to a large degree to sticky shelter inflation. As Fed Chair Jerome Powell reiterated, the Fed will need to see a few more reports to convince itself that inflation is on a sustainable trend back to target. This renders a May cut unlikely, given a limited number of outstanding inflation reports before then.

The labor market is still threatening to stall progress on inflation. Wage growth is a sizable margin above the level the Fed estimates as compatible with its inflation target. January and February payroll hiring accelerated from late 2023, and at 3.9%, the unemployment rate signals the U.S. labor market is unlikely to have come fully into balance

Our latest baseline forecast puts the first interest rate cut in June. In total, we expect a 75-basis point reduction by the end of 2024. We expect policy is loosened gradually and that the Fed's main policy rate remains restrictive through mid-2026.

**CHIPS Act Awards Ramp Up**

Federal subsidies to boost semiconductor production in the U.S. are accelerating. In December, U.S. Commerce Secretary Gina Raimondo said she expects to make around a dozen semiconductor chips funding awards within the next year under the CHIPS Act of 2022, some of them multibillion-dollar announcements. This prediction is coming true.

On Tuesday, the White House announced the biggest award yet, approximately $8.5 billion in direct subsidies to Intel along with up to $11 billion in loans. The company had previously announced that it expects to spend upward of $100 billion on U.S. facilities and research programs in Arizona, Ohio, New Mexico and Oregon. Two new facilities just outside Columbus OH will be part of a complex that could ultimately be among the largest chipmaking centers in the world.

Initial CHIPS Act payouts were slow in coming and relatively small. Now the pace is accelerating. On February 19, the Commerce Department announced a large award of $1.5 billion to GlobalFoundries to subsidize three projects. The bulk of the award is for construction of a new plant on the company's Malta NY site, which will make chips for applications in automotive, aerospace, defense and artificial intelligence.

A smaller part of the award is for expansion of the company's existing Malta facility by adding new technologies already in use in GlobalFoundries' Singapore and Germany facilities, which supply the auto industry. The third project is to upgrade and expand capacity in the company's facility in Essex Junction VT, creating the first U.S. facility for high-volume production of gallium nitride semiconductors used in electric vehicles, power grids, data centers, and 5G and 6G smartphones.

The GlobalFoundries award is significant because the company is the only U.S.-based "pure-play" foundry. In other words, it makes chips based on users' specifications, making it a competitor to Taiwan-based TSMC, albeit much smaller. Although GlobalFoundries is U.S.-based, it also has facilities in Europe and opened one in Singapore in September

The incentives to the company improve the prospects for domestic chip security in two ways: First, the better cost1effectiveness encourages the company to locate its next plant domestically. Second, as a competitor to TSMC, the company can potentially compete to supply some of TSMC's biggest U.S. customers, notably Apple and Nvidia.

## Oregon Loses Jobs for the First Time Since 2021

Mike Rogoway – Oregonian –

**Oregon**'s spectacular rebound from the pandemic recession may be coming to an end.

In January, the state posted a **net loss in jobs compared** to a **year earlier** – the first time that has happened since 2021. And the **unemployment rate climbed above 4%** for the first time in more than a year.

This isn't a recession. Far from it.

Wages continue climbing and Oregon's labor market remains tight, by historical standards. Employers say it's still very hard to find workers.

Still, it's clear that the robust growth that got underway three years ago, in the wake of COVID-19, is at last winding down.

The **state had 1.97 million jobs in January**, according to the latest seasonally adjusted data from the Oregon Employment Department. That's about **5,000 fewer** jobs **than** it had a **year earlier**.

It's a **tiny decline overall, 0.2% on** an **annual basis**. **But** it's a **sharp contrast** to the **prior three years**, when Oregon was adding several thousand jobs each month as the state roared back from the pandemic.

The slowdown isn't a big surprise. **Oregon's workforce had regained** all the **jobs** it **lost to** the **pandemic by** the **start of last year** and, with the **state's population stagnant**, Oregon simply doesn't have more people to fill job openings.

Oregon's slight decline in employment compares to 1.9% job growth nationally over the last 12 months. Employment department economist Gail Krumenauer notes in a new report that Oregon's slowdowns came mostly in the latter part of the year.

Manufacturing was among Oregon's weakest sectors last year, according to Krumenauer, declining by 3.4%. The state's factories began shedding jobs in 2022 and continued their downward trajectory through most of last year.

Blame the semiconductor industry for much of that decline. Chipmakers pulled back last year from three years of outstanding growth. Economists are expecting better results over the next few years as factory upgrades get underway at Intel and other large Oregon chip factories.

In 2023, Oregon also shed jobs in retail – a sector that never fully recovered from the pandemic – and posted declines in categories that include building maintenance and call centers.

Oregon's biggest gains, Krumenauer found, were in health care, local government and hospitality jobs. Construction, which had appeared to be a standout sector last year, actually grew little over the past 18 months, according to newly revised state data.

State economists expect Oregon will resume adding jobs this year, growing by almost 16,000 positions over the next year. Krumenauer notes that works out to about 1% annual growth, anemic by recent standards but suggestive of a state economy that is solid, though no longer spectacular.

CASE: UE 426
WITNESS: Itayi Chipanera

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 200

# OPENING TESTIMONY

## Revenue Requirement Detail, Income Taxes, Regulatory Commission Fees, Kilowatt Hour Taxes, Valmy Plant Revenue Requirement, Utility Plant in Service, Oregon Jurisdiction Allocation, Cash Working Capital

**March 25, 2024**

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

A. My name is Itayi Chipanera. I am a Senior Financial Analyst employed in the Accounting and Finance Section of the Rates, Safety, and Utility Performance (RSUP) Program 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/201.

**Q. What is the purpose of your testimony?**

A. I am the summary revenue requirement witness for this docket. I provide a summary of all the adjustments proposed by Staff to Idaho Power Company's (Idaho Power or Company) requested Test Year expense, rate base, and the consequent revenue requirement effect. I also discuss my own review of Test Year expense for income taxes, Oregon Commission regulatory fees, kilowatt hour taxes and corporate activity taxes. Additionally, I discuss the Company's filing regarding the revenue requirement for the Valmy plant decommissioning.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

Introduction ........................................................ 3
Summary Of Revenue Requirement ........................................................ 4
Issue 1. Income Taxes ........................................................ 8
issue 2. Oregon Regulatory Commission Fees ........................................................ 10
issue 3. KiloWatt Hour Taxes ........................................................ 13
issue 4. Valmy Plant Revenue Requirement ........................................................ 16
issue 5. Utility Plant In Service ........................................................ 18
Issue 6. Oregon Jurisdictional Allocation ........................................................ 21
Issue 7. Cash Working Capital ........................................................ 25
Other Topics Reviewed ........................................................ 26
Conclusion ........................................................ 27

**Q. Did you prepare exhibits for this docket?**

A. Yes. In addition to my witness qualifications statement, I prepared the following exhibits:

Exhibit Staff/202 ........................................................ Corporate Activity Taxes
Exhibit Staff/203 ........................................................ Oregon Regulatory Fees
Exhibit Staff/204 ................................................................ Kilowatt Hour Taxes
Exhibit Staff/205 ..................................................... Company Data Responses

## INTRODUCTION

**Q. What is the revenue requirement increase proposed by Idaho Power Company in this docket?**

A. Idaho Power proposes an overall increase of $10.695 million, which would be a base rate increase of 19.28 percent.[1] The requested increase results in total Oregon retail sale revenues of $66.153 million for the Test Year.

**Q. What is the adjustment in revenue requirement recommended by Staff?**

A. Staff proposes to reduce the Company's requested revenue requirement increase from $10.695 million to $5.747 million, a reduction of $4.948 million.

**Q. What adjustments are you proposing to the Company's revenue requirement?**

A. I am proposing to adjust the Company's Test Year expense for Oregon regulatory commission (OPUC) fees, kilowatt hour taxes, and Oregon corporate activity taxes.

**Q. Are additional adjustments for the rest of the issues proposed by other Staff?**

A. Yes. The Company's filing is complex, and a thorough review involves multiple Staff members looking at different issues. Individual Staff are reviewing additions to different categories of utility plant, operating expenses, and revenues.

1 Idaho Power/1202, Noe/1.

## SUMMARY OF REVENUE REQUIREMENT

**Q. What factors did Idaho Power identify in its initial filing as the drivers of the requested rate increase?**

A. The Company cited new investments in generation, transmission, and distribution facilities and rising inflation on operating and maintenance expenses as the main drivers of the requested increase. The Company states that it has invested $3.3 billion into its system since its last rate case in Oregon.[2]

**Q. When was the Company's last general rate case in Oregon?**

A. The Company's last rate case, UE 233, was filed in July 2011 with approved rates going into effect on March 1, 2012.[3]

**Q. According to the Company, how has the Company's Oregon jurisdictional rate base changed since its last filing?**

A. The Company's Oregon jurisdictional rate base has increased from $121.854 million in UE 233 to $188.948 million in UE 426, an increase of $67.094 million.

**Q. According to the Company, how has the Company's Oregon jurisdictional total operating expenses levels changed since its last filing?**

A. The Company filed to recover total operating expenses of $40.690 million in UE 233, and it is requesting to recover $53.219 million in the current filing.

**Q. What is the Company's proposed cost of capital?**

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2 Idaho Power/100, Grow/2.

3 *In the Matter of Idaho Power Company, Request for a Rate Revision,* UE 233, Order No. 12-055, Entered 2/23/2012, page 1.

A. The Company's filing proposes a rate of return of 7.807 percent with a capital structure of 51 percent equity and 49 percent debt, a 5.104 percent cost of debt, and 10.4 percent return on equity.

**Q. Did you review the Company's cost of capital proposal?**

A. No. The Company's Cost of Capital (CoC) proposal is reviewed by Staff witness Matt Muldoon in Staff/100 and Rose Pileggi in Staff/1200.

**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.[4]

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 each of the different classes of customers impose on the utility's system.

**Q. Have the parties agreed to adjust any components of the $10.695 million proposed increase?**

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[4] *Pacific Power* and *Light*, UE 116, Order No. 01-787, pp.5-6 (September 7, 2001).

A. No. The parties have not yet agreed to adjust any components of the overall increase.

**Q. Is Staff working to address the concern raised at the Commission's March 14, 2014, Public Comments Hearing, asking that Staff share more detail on how the Company is spending money and where Staff recommends the Commission reduce the amounts the Company is asking for?**

A. Yes. Staff is working diligently to analyze the components of the Company's requested increase and proposes adjustments to lower the impact of this rate increase on Oregon utility customers of Idaho Power.

**Q. Please provide a table summarizing Staff's proposed adjustments.**

A. Figure 1 on the following page provides a table summary of Staff's proposed adjustments. The table shows Staff's testimony exhibit numbers, the names of the Staff sponsoring the testimony, a description of the adjustments, the amount of the adjustments to Test Year revenues, expenses or rate base, and the revenue requirement effect. Full support and explanations of the proposed adjustments can be found in the respective Staff members' testimony.

## Figure 1

**IDAHO POWER COMPANY**
**STAFF ISSUE SUMMARY**
**Test Year Ended December 31, 2024**
**($000)**

| Testimony | Issue | Staff | Proposed Staff Adjustments | Revenue | Expense | Rate Base | Staff Revenue Requirement Effect |
|---|---|---|---|---|---|---|---|
| **Total Incremental Revenue Requirement on the Company's Filed General Rate Case** | | | | | | | $10,695 |
| 100 | S-0 | Matt Muldoon | Return on Equity (ROE @ 9.3% - Mid Level) | | | | (1,463.84) |
| 100 | S-1 | Rose Pileggi | Cost of Debt (Including Interest Synchronization) | - | - | - | $139 |
| 500 | S-2 | Russ Beitzel | Benefits | - | (147.50) | - | (151.26) |
| 200 | S-3 | Itayi Chipanera | Corporate Activity Taxes | - | (63.81) | - | (65.44) |
| 200 | S-4 | Itayi Chipanera | Regulatory Commission Fees | - | (77.23) | - | (79.20) |
| 200 | S-5 | Itayi Chipanera | KiloWatt Hour Taxes | - | (75.28) | - | (77.20) |
| 900 | S-6 | Luz Mondragon | Miscellaneous Customer Service and Informational Expenses | - | (0.89) | - | (0.91) |
| 900 | S-7 | Luz Mondragon | Operations Supervision | - | (0.85) | - | (0.87) |
| 900 | S-8 | Luz Mondragon | Operation Supervision and Engineering | - | (40.18) | - | (41.20) |
| 900 | S-9 | Luz Mondragon | Wildfire Mitigation Distribution | - | (1,059.00) | - | (1,086.02) |
| 1000 | S-10 | Mitch Moore | Board of Directors Compensation | - | (109.00) | - | (111.78) |
| 1000 | S-11 | Mitch Moore | Board of Directors Travel/Meals | - | (5.00) | - | (5.13) |
| 1000 | S-12 | Mitch Moore | Materials And Supplies | - | - | (666.00) | (60.36) |
| 1300 | S-13 | Paul Rossow | Miscellaneous Customer Service | - | (0.89) | - | (0.91) |
| 1300 | S-14 | Paul Rossow | Meals and Entertainment | - | (20.69) | - | (21.21) |
| 1300 | S-15 | Paul Rossow | Memberships | - | (1.74) | - | (1.79) |
| 600 | S-16 | Bret Farrell | Uncollectible Accounts | - | (314.00) | - | (322.01) |
| 1100 | S-17 | Ming Peng | Depreciation Expense | - | 1,128.65 | - | 1,157.45 |
| 1100 | S-18 | Ming Peng | Accumulated Depreciation | - | - | (1,128.65) | (102.28) |
| 800 | S-19 | Charles Lockwood | Advertising | - | (1.55) | - | (1.59) |
| 1600 | S-20 | Charles Lockwood\Anna Kim | Low Income Weatherization Manager Disallowance | - | (10.56) | - | (10.83) |
| 1700 | S-21 | Steph Yamada | Wage and Salaries Operation and Maintenance (O&M) | - | - | (119.70) | (10.85) |
| 1700 | S-22 | Steph Yamada | Wage and Salaries Capital Adjustment | - | (226.61) | - | (232.39) |
| 1200 | S-23 | Rose Pileggi | Production Plant - Manager Disallowance | - | - | (555.37) | (50.33) |
| 1600 | S-24 | Charles Lockwood\Anna Kim | Energy Efficiency Disallowance | - | (75.45) | - | (77.37) |
| 200 | S-25 | Itayi Chipanera | Cash Working Capital | - | - | (168.49) | (15.27) |
| 1500 | S-26 | Brett Stevens | Jurisdiction Allocation Adjustment | - | (2,198.40) | - | (2,254.50) |
| Total Staff Proposed Adjustments (Base Rates) | | | | | | | **(4,948)** |
| Staff-Calculated Revenue Requirements Change (Base Rates): | | | | | | | **5,747** |

## ISSUE 1. INCOME TAXES

**Q. Please summarize the Company's filing related to state income taxes.**

A. The Company is liable for state income taxes on Oregon revenues in Idaho and Oregon with an immaterial percentage payable to other states. The portion of total state income taxes payable to the Oregon jurisdiction is 4.55 percent.[5] The amount of estimated Oregon state income taxes includes corporate activity taxes.[6] The table below summarizes the company's Test Year state income taxes.

**Figure 2**

| Jurisdiction/Tax ($ 000) | | Test Year State Income Taxes |
|---|---|---|
| Oregon Tax @ 6.6% | $ | 7.123 |
| Oregon Corporate Activity Tax | $ | 334.389 |
| Idaho @ 5.8% | $ | (809.205) |
| Other States | $ | 2.725 |
| **Total State Income Taxes** | **$** | **(464.968)** |

**Q. Please summarize the Company's filing related to federal income taxes.**

A. The Company calculates Test Year federal income taxes of ($4.049) million.[7] The federal tax calculation includes a tax credit of $4.692 million.[8]

**Q. Does the Company's filing include accumulated deferred income taxes (ADIT)?**

A. Yes. The Company's filing includes an Oregon jurisdictional amount of $16.743 million.

**Q. How did the Company estimate accumulated deferred income taxes for the Test Year?**

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5 Idaho Power/1202, Noe/22, at line 779.
6 Idaho Power/1202, Noe/22, at line 788.
7 Idaho Power/1202, Noe/21, at line 761.
8 Idaho Power/1202, Noe/21, at line 759.

A. Idaho Power estimated Test Year accumulated deferred income taxes by averaging the year-end 2022 and year-end 2023 ADIT balances on a system wide basis. Idaho Power then determined the Oregon-allocated share of the system wide estimate.

**Q. Is Staff proposing any adjustments to state income tax, federal income tax, or ADIT?**

A. Yes. Staff is proposing an adjustment to Test Year expense for the Oregon corporate activity tax. Idaho Power included corporate activity taxes with state income taxes, therefore an adjustment to corporate activity taxes affects the overall state income taxes.

**Q. Describe Staff's proposed adjustment to corporate activity taxes.**

A. The Company requested $334.389 thousand for corporate activity taxes based on $77.0 million of Oregon commercial activity. However, the Company's filed total retail, wholesale, and miscellaneous revenues for the Test Year sum to a total of $71.5 million. In addition to aligning the revenues used to estimate the Company's corporate activity taxes with revenues requested in the rest of the filing and incorporating Staff's proposed adjustments, the resulting total Oregon revenues are $65.806 million.[9] Staff estimated corporate activity taxes of $270.581 thousand using the adjusted Oregon revenues, resulting in a reduction of $68.807 thousand. Calculation details of Staff proposed corporate activity tax is provided in Staff/202.

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9 See, workpaper, UE 426 Staff Exhibit 200 Work Paper Revenue Requirement Model, Summary Sheet Tab

## ISSUE 2. OREGON REGULATORY COMMISSION FEES

**Q. What is the Oregon regulatory commission fee in this docket?**

A. The regulatory commission fee is composed of two fees, the Oregon Public Utility Commission fee (OPUC fee) and the Oregon Department of Energy, Energy Supplier Assessment (ODE ESA). The OPUC fee is a customer-funded fee whose purpose is to cover operating expenses of the Oregon Public Utility Commission. The Commission approves a rate used to collect OPUC fees and the rate is applied to a utility's revenues. The energy supplier assessment is levied on energy suppliers. Yearly energy supplier assessments are approved by the Oregon legislature and are capped at 0.375 percent of revenues.[10]

**Q. How much is the Company requesting for the fees in the 2024 Test Year and how does it compare to the 2022 Base Year?**

A. The Company is requesting $461.577 thousand in regulatory fees for the Test Year compared to $290.260 thousand in the Base Year, an increase of 59 percent.

**Q. What was the OPUC fee rate in effect at the time of the Company's filing?**

A. At the time of Idaho Power's filing the OPUC fee rate in effect was 0.43 percent.[11]

**Q. Did the Company use the OPUC fee rate to calculate its Test Year OPUC fees?**

A. No. The Company writes in its opening testimony that "regulatory commission fees were projected based on first projecting the 2023 Oregon PUC fee based on the actual 2023 fee. For the Oregon Department of Energy fee, Idaho Power's

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10 How We Are Funded, Oregon Department of Energy, published October 2023.

11 *In the Matter of The Imposition of Annual Regulatory Fees upon Public Utilities Operating within the State of Oregon*, Docket UM 1012, Order 23-057.

2023 estimate was based upon the prior year's tax rate applied to the actual Oregon gross operating revenue then adding or subtracting the difference between the 2023 forecast and the 2022 actuals to determine the 2024 Test Year amount.[12]

**Q. Has the OPUC fee rate changed since the Company's filing?**

A. Yes. The Commission approved a new rate of 0.45 percent in Order No. 24-054 entered on February 22, 2024.[13]

**Q. What is Staff's proposed adjustment to OPUC fees and ODE ESA?**

A. Staff proposes to adjust the OPUC fees by applying the current effective rate of 0.45 percent. Rather than rely on a single year rate to estimate the ODE ESA assessment, Staff is proposing to use a five-year average rate. In Exhibit Staff/203, Staff calculates a five-year average ODE ESA rate of 0.131 percent, which when applied to the Company's Oregon retail sales produces an ODE ESA assessment of $86.660 thousand. Applying the new OPUC fee rate to the Company's retail sales produces $297.688 of OPUC fees. As shown in Exhibit Staff/203, Staff's total estimated regulatory commission fee is $384,349, a proposed reduction of $77.228 thousand to the Company's filed amount.

**Q. Why is Staff's estimate of regulatory Commission fees more reasonable than Idaho Power's?**

A. Staff's estimate of OPUC fees applies the current approved OPUC fee rate. According to the Oregon Department of Energy, the average ODE ESA rate to be

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12 Idaho Power/1002, Larkin/22
13 Id., Order No. 24-054.

assessed for the 2023 to 2025 biennial is 0.106 percent.[14] Staff used the Company's five-year history to estimate an ODE ESA rate of 0.131 percent, which is more in line with the average rate for all utilities in Oregon. The Company's methodology produces a combined OPUC and ODE ESA regulatory commission fee rate of 0.7 percent relative to the Company's Test Year retail sales. The OPUC fee was fixed at 0.43 percent at the time of the filing, therefore the Company's Test Year regulatory commission fees amount implies an ODE ESA rate of 0.27 percent, which is more than double the 0.131 percent Staff estimated.

[14] How We Are Funded, Oregon Department of Energy, published October 2023.

## ISSUE 3. KILOWATT HOUR TAXES

**Q. What is the kilowatt hour tax?**

A. The kilowatt hour tax is a State of Idaho tax that applies to hydro generated electricity. Certain activities such as irrigation and manufacturing are exempt from this tax.[15]

**Q. What is the Company's request for kilowatt hour taxes and how do they compare to the base year?**

A. Idaho Power is requesting system wide $3.274 million in kilowatt hour taxes for Test Year 2024 compared to a Base Year amount of $1.163 million, which is an increase of $2.111 million or 181.5 percent.

**Q. Describe how the kilowatt hour tax is assessed by the Idaho State Tax Commission.**

A. The Idaho Tax Commission requires Idaho Power to report kilowatt hours generated from hydroelectricity, total kilowatt hours sold to customers, and kilowatts sold for industrial and irrigation use. A ratio of hydroelectric kilowatts relative to total kilowatt hours is then calculated. The calculated ratio is then multiplied by kilowatts used for irrigation and industrial use to get a net exemption. The net exemption kilowatt hours are subtracted from hydroelectric kilowatts to derive net taxable kilowatt hours. The net taxable kilowatt hours are then multiplied by a tax rate of 0.005.[16]

**Q. What method did Idaho Power use to determine the kilowatt hour tax amount included in the Test Year?**

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15 Kilowatt Hour Tax | Idaho State Tax Commission.
16 Idaho Tax Commission, Form 48.

A. Idaho Power estimated kilowatt hours taxes by "first projecting 2023 kWh taxes based on normalized hydro conditions and normalized consumption then adding or subtracting the difference between the 2023 forecast and the 2022 actuals to determine the 2024 Test Year amount."[17]

**Q. Describe how Staff reviewed the reasonableness of Idaho Power's kilowatt hour tax Test Year amount.**

A. Staff issued a data request to the Company asking for data that is necessary to assess historical kilowatt hour tax levels relative to Oregon retail sales. In Exhibit Staff/204, Staff estimates system wide Test Year kilowatt hour taxes of $1.503 million using a three-year average ratio of kilowatt hours taxes relative to Oregon retail sales. On an Oregon allocated basis, Staff's estimate is $63.888 thousand compared to the Company's request of $139.170 thousand. Using this estimate Staff proposes a reduction of $75.282 thousand to kilowatt hour taxes.[18]

**Q. Why is Staff's estimate of kilowatt taxes more reasonable than Idaho Power's?**

A. The Company's proposed growth to kilowatt hour taxes exceeds the Company's hydroelectric kilowatt hour generation growth by a large margin. The Company is proposing to increase kilowatt hour taxes by 181.5 percent from the Base Year to the Test Year, or an annual compound growth rate of 67.8 percent. Based on data provided to Staff in data request DR 299, the Company's hydroelectric generation

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17 Idaho Power /1002, Larkin/22

18 Staff used the Company's filed allocation factor; a comprehensive allocation adjustment is proposed in Staff/1500, by Staff witness Brett Stevens.

grew by an annual compound growth rate of 5.1 percent from 2021 to 2023. Staff's proposed Test Year kilowatt hour tax amount produces an annual growth rate of 14 percent, which is much smaller than the company's proposal of 67.8 percent and closer to the growth in the Company's hydroelectric generation.

## ISSUE 4. VALMY PLANT REVENUE REQUIREMENT

**Q. What is the regulatory history regarding the decommissioning of the Valmy plant?**

A. In Order No. 17-235, the Commission approved Idaho Power's request to accelerate depreciation recovery for Unit 1 and Unit 2 of the Valmy plant, shortening the depreciation schedule from 2031 for Unit 1 and 2035 for Unit 2 to 2025 for both units.[19] The Commission also ordered that the incremental recovery for the Valmy plant should be through base rates rather than through a separate schedule.[20] An incremental levelized revenue requirement of $1.057 million per year was approved.

**Q. Did the Company request any subsequent updates to the Valmy revenue requirement?**

A. Yes. In UE 345, the Company requested an increase to the incremental levelized revenue requirement to reflect its planned accelerated exit from Valmy Unit 1 by year-end 2019. Order No. 18-99 approved the Company's request to increase the incremental revenue requirement of $2.499 million. In UE 363, Idaho Power requested to remove $3.17 million of Unit 1 levelized revenue requirements having ceased Unit 1 operations at the end of 2019.[21]

**Q. Summarize the Company Valmy revenue requirements updates since the initial approval.**

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19 *In the Matter of Idaho Power Company, Request to Increase Rates for Electric Service to Recover Costs Associated with Valmy Power Plant,* UE 316, Order No. 17-235, page 1.
20 Order No. 17-235, page 5.
21 *In the Matter of Idaho Power Company, Application for Authority to Decrease Rates for Electric Service for Costs Associated with the North Valmy Power Plant*, UE 363, Order No. 19-341, page 1 to 2.

A. Figure 3 below shows the changes to the Valmy revenue requirements from the initial order through updates approved in Order No. 18-99 and Order No. 19-341. The figure shows the remaining levelized Valmy revenue requirement for Unit 2 is $1.168 million, this amount includes $80.33 thousand of decommissioning costs.

**Figure 3**

| **Valmy Revenue Requirement Changes ($000)** | | |
|---|---|---|
| Revenue Requirement in Base Rates at Initial Application | $ | 781.8 |
| Incremental Revenue Requirement (Order 17-235) | $ | 1,056.8 |
| Increment Revenue Requirement (Order 18-99) | $ | 2,498.9 |
| Revenue Reduction Exit from Unit 1 (Order 19-341) | $ | (3,169.5) |
| Revenue Requirement After Updates | $ | 1,168.0 |

**Q. How much revenue requirement is the Company requesting for the Valmy plant in this docket?**

A. The Company is requesting $1.168 million. This amount has not changed since Order No. 19-341.

**Q. Does the Company explain why there are no proposed changes to the Valmy revenue requirement?**

A. Yes. The Company says in exhibit Idaho Power/200 that it is not requesting “any incremental recovery in this case as a rate increase mitigation measure”.[22]

**Q. Is Staff proposing any adjustments to the Valmy revenue requirement?**

A. No.

[22] Idaho Power/200, Tatum/4, at line 24.

## ISSUE 5. UTILITY PLANT IN SERVICE

**Q. Please discuss Staff's overall approach to review plant additions.**

A. To determine the inclusion of new capital investment in rate base, a utility must make two showings. "First, it must show that the investment is presently used for providing utility service. Second it must show that the investments were prudently made, based on the information that it knew or should have known at the time."[23]

**Q. What is the Oregon law requiring utility plant to be presently used before it may be included in rates?**

A. ORS 757.355 requires utility plant to be presently used for providing utility service to customers and creates what is generally referred to as a "used and useful" standard, requiring the property to be placed into service prior to the effective date of the rates. ORS 757.355 provides:

> (1) Except as provided in subsection (2) of this section, 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.
>
> (2) The Public Utility Commission may allow rates for a water utility that include the costs of a specific capital improvement if the water utility is required to use the additional revenues solely for the purpose of completing the capital improvement. [1979 c.3 §2; 2003 c.202 §2]

**Q. Please discuss the Commission's standard of review for prudence.**

A. The purpose of the prudence review has been succinctly stated by the Commission in prior rate cases:

> [We] take this opportunity to clarify the prudence standard in ratemaking. Parties have raised questions about how the

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[23] See e.g., *In the Matter of PacifiCorp, dba Pacific Power's, Request for a General Rate Revision,* UE 246, Order No. 12-493 (December 12, 2020)

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 modern 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.[24]

**Q. Please explain Staff's application of the used and useful standard to review Idaho Power's new plant since its last general rate case filing.**

A. The application of the used and useful standard supports the inclusion in rate base of only capital investment in facilities that will be used and useful in providing utility services to customers. Staff issued data request DR 201 asking the Company to demonstrate the need for distribution plant additions more than $100 thousand for

[24] Order No. 12-493, page 25.

the Oregon jurisdiction since UE 233. In response to data request DR 201, the Company identified 14 plant additions that were added to meet compliance standards,11 projects that were added to meet customer needs, 11 projects that were added to enhance reliability, and 38 projects that were added for routine replacement of equipment reaching the end of its useful life.[25] Similarly, Staff issued data request DR 199 asking the Company to list transmission plant additions more than $3.0 million since UE 233 and provide a justification need for each project and when it was placed into service.[26] Staff also reviewed the timing of in-service dates for two projects that are expected to be put in service in 2024.

**Q. Please explain Staff's procedure to review for prudence to Idaho Power's plant additions.**

A. The Company added $3.3 billion in plant additions to its system in eleven years. Due to the volume of the projects and time constraints, Staff decided to sample a list of projects to review for prudence. The sample selected for prudence review included projects with the largest actual to budget variance and included the two largest projects located in the Oregon situs. Staff met with the Company to discuss the sample projects and found no evidence that support lack of prudence.

**Q. Is Staff proposing adjustments to utility plant in service?**

A. Other than those adjustments offered by Staff witness Pileggi, no.

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[25] Idaho Power response to DR 202.
[26] Idaho Power response to DR 199.

## ISSUE 6. OREGON JURISDICTIONAL ALLOCATION

**Q. Please explain the methodology used by Idaho Power Corporation to separate costs by jurisdiction and calculate the Oregon jurisdiction revenue requirement.**

A. Idaho Power uses a multi-step process to perform the jurisdictional allocation. The costs are first examined and assigned to a function such as transmission. The functional groups are then classified into one of the following categories for allocation, unless directly assigned (Distribution Plant is directly allocated based on situs):

1. Demand-related,
2. Energy-related,
3. Customer-related, and
4. Related Plant Accounts.

The average of the twelve monthly coincident peak demands were used to allocate the demand-related costs. The energy-related costs were allocated based on normalized jurisdictional kilowatt hours. The main customer-related costs were meter reading and customer accounting & billing which were allocated based on a review of actual costs.

The following are example allocations of the above process or have their own unique allocation:

- Operation and Maintenance expense related to Distribution Plant is allocated based on actual ratio of situs plant locations between Idaho and Oregon.

- Material and supplies are allocated by the respective related plant.
- Fuel inventory was allocated based on energy.
- Commission-ordered deferred investments were either directly assigned or allocated based on demand.
- Respective tax bases were developed, and taxes were calculated directly for each jurisdiction.

**Q. What did Staff do to analyze the issue?**

A. Staff reviewed the 1,000 plus line excel spreadsheet of the jurisdictional separation study as provided in SDR 119. Based on the review and simple tracing of the allocations in the excel spreadsheet, Staff determined that the allocation process as described by the Company was being followed.

**Q. Does Staff have any concerns with how Idaho Power allocated Distribution Plant additions to Oregon?**

A. Yes, during Staff's review and analysis, Staff questioned the Company on how the direct assignment process was working as it related to Distribution Plant additions. Staff questioned why there was an allocation of Distribution Plant if it is directly assigned based on situs. The Company stated that they were forecasting the 2023 Distribution Plant additions because the 2023 calendar year was not completed when they filed the rate case.[27] The 2023 forecast was based on the year-end 2022 historical situs ratio.

Staff believes that the growth in Distribution Plant at the total system level has been driven by growth in Idaho and not Oregon. Staff has requested that the

[27] Idaho Power response to DR 433.

Company provide Staff with the 2023 Distribution Plant additions by situs as recorded in the accounting system for 2023. The following ratio analysis[28] further supports the risk that the allocation of Distribution Plant additions to Oregon for 2023 could be overstated:

**Figure 4**

| SUMMARY FUNCTION | Total System Test Year 2024 | % of Total | JSS Test Year 2024 | % of JSS Total | JSS as % of Total System |
|---|---|---|---|---|---|
| Intangible Plant | 108,821,375 | 1.54% | 4,459,258 | 1.48% | 4.10% |
| Production Plant | 2,449,788,070 | 34.58% | 96,887,365 | 32.23% | 3.95% |
| Transmission Plant | 1,388,728,264 | 19.60% | 55,012,683 | 18.30% | 3.96% |
| Distribution Plant | 2,599,578,102 | 36.70% | 121,486,713 | 40.41% | 4.67% |
| General Plant | 537,154,111 | 7.58% | 22,809,672 | 7.59% | 4.25% |
| Total Electric Plant In Service | 7,084,069,922 | 100.00% | 300,655,691 | 100.00% | 4.24% |

In addition, Distribution O&M expenses were allocated based on the Distribution Plant ratio. The average allocation for Distribution O&M is 5.7 percent.[29] Idaho Power states that they currently cannot track cost by jurisdiction[30] and that the Company's method for jurisdictional allocation is a reasonable measure of cost causation.[31]

Concerns regarding the allocation factor grow when considering the population density differences between Oregon and Idaho. There are 19,913 Oregon customers in Idaho Power's service area, which is 3.2 percent of customers served by Idaho Power.[32] Staff has concerns about whether the amounts allocated to Oregon customers are really providing commensurate

28 Prepared using data provided in Idaho Power/1202, Noe/2, line 44 to line 50.
29 Calculated based on Idaho Power's response to SDR 58. Base year distribution Oregon allocated divided by Base Year distribution system wide. (1.675/29.314).
30 Idaho Power response to DR 413.
31 Idaho Power response to DR 255.
32 Idaho Power response to DR 183.

benefit. Given that separate states have different characteristics, it does not make sense to treat all O&M work as equal and spread the costs accordingly.

In UE 233, Staff had similar concerns and recommended that the Company separate costs and directly assign O&M costs. Staff gets the impression that, by avoiding taking the necessary steps to track O&M work by state as recommended, the allocation method has the potential for being unfair to Oregon customers.

**Q. Are you proposing any adjustments based on changes to Oregon jurisdictional allocations?**

A. No. Refer to Staff/1500, Opening Testimony by Staff witness Brett Stevens, for a Staff proposed adjustment based on changes to the jurisdictional allocations.

## ISSUE 7. CASH WORKING CAPITAL

**Q. Provide a summary of the Company's filed cash working capital.**

A. The Company included an Oregon allocated cash working capital amount of $1.685 million in rate base.

**Q. Did the Company prepare a lead/lag study to support its cash working capital request?**

A. No. The Company did not prepare a lead/lad study to support its cash working capital. The cash working capital proposed for the Test Year was estimated as four percent of the Company's filed operation and maintenance expenses. The Commission has approved the Company's approach to estimating cash working in UE 233.

**Q. Is Staff proposing an adjustment to cash working capital?**

A. Yes. Staff is proposing to reduce the overall level of the Company's level of operation and maintenance expenses therefore applying the four percent factor to the Staff's reduced expenses result in an adjustment of $170.47 thousand to the Test Year rate base.

## OTHER TOPICS REVIEWED

**Q. Did you review any topics where your analysis agreed with the Company's proposals?**

A. Yes. In addition to the issues discussed at length in this testimony, I also reviewed the Company's electric plant acquisition adjustment, escalations, property taxes, and franchise fees. My analysis was in alignment with the Company's treatment of these issues.

## CONCLUSION

**Q. Restate Staff's overall proposed adjustment and summarize your proposed adjustments.**

A. Staff is proposing an overall reduction of $4.948 million to the Company's revenue requirement request. Included with Staff's overall adjustments are my proposed adjustments summarized in Figure 5 below.

**Figure 5**

| Issue | Expense Adjustment | Rate Base |
|---|---|---|
| Corporate Activity Taxes | (63,807) | |
| Kilowatt Hour Taxes | (75,282) | |
| Regulatory Commission Fees | (77,228) | |
| Cash Working Capital | | (170,470) |
| **Total Adjustments** | **(216,318)** | **(170,470)** |

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: ITAYI CHIPANERA

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 201

## Witness Qualifications Statement
## Staff: Chipanera

## March 25, 2024

## WITNESS QUALIFICATIONS STATEMENT

**NAME:** Itayi Chipanera

**EMPLOYER:** Public Utility Commission of Oregon

**TITLE:** Senior Financial Analyst
Accounting and Finance Section

**ADDRESS:** 201 High Street SE. Suite 100
Salem, OR. 97301

**EDUCATION:** B.S., Economics
Idaho State University

M.S., Mathematics
University of Nevada – Reno

M.S., Accounting
Indiana University – Bloomington

**EXPERIENCE:** I have been employed by the OPUC in the Safety, Rates and Utility Performance Program since April of 2023. Prior to my employment with the OPUC I was employed in various finance roles in the insurance and banking industries including Advantis Credit Union where I was employed as a Senior Risk and Financial Analyst; City of Salem, Oregon, where I was a Finance Management Analyst; and SAIF Corporation where I was an Actuarial Research Analyst. I have worked as a revenue requirement summary witness on the following cases PGE UE 416, AVA UG 461, and current IPC UE 426.

CASE: UE 426
WITNESS: Itayi Chipanera

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 202

# Corporate Activity Taxes

# March 25, 2024

Staff Adjustment of Corporate Activity Taxes.

| Line | Company proposed<br>Test Year Oregon Corporate Activity Taxes | | Line | Staff proposed<br>Test Year Oregon Corporate Activity Taxes | |
|---|---|---|---|---|---|
| 1 | Total commercial activity | 83,000,000 | 1 | Total commercial activity | 71,805,704 |
| 2 | Total exclusions | 6,000,000 | 2 | Total exclusions | 6,000,000 |
| 3 | Oregon commercial Activity | 77,000,000 | 3 | Oregon commercial Activity | 65,805,704 |
| 4 | Cost inputs | 1,219,000,000 | 4 | Cost inputs | 1,219,000,000 |
| 5 | Labor costs | 284,000,000 | 5 | Labor costs | 284,000,000 |
| 6 | Multiply greater of line 4 or 5 by 35% | 426,650,000 | 6 | Multiply greater of line 4 or 5 by 35% | 426,650,000 |
| 7 | Apportionment % of subtraction | 4.0734% | 7 | Apportionment % of subtraction | 4.0734% |
| 8 | CAT subtraction | 17,379,161 | 8 | CAT subtraction | 17,379,161 |
| 9 | Commercial activity after subtraction | 59,620,839 | 9 | Commercial activity after subtraction | 48,426,543 |
| 10 | Subcontractor exclusion | - | 10 | Subcontractor exclusion | - |
| 11 | Taxable Oregon commercial activity | 59,620,839 | 11 | Taxable Oregon commercial activity | 48,426,543 |
| 12 | $1 million threshold | 1,000,000 | 12 | $1 million threshold | 1,000,000 |
| 13 | Taxable OR comm act > threshold | 58,620,839 | 13 | Taxable OR comm act > threshold | 47,426,543 |
| 14 | Multiply line 13 by .57 percent | 334,139 | 14 | Multiply line 13 by .57 percent | 270,331 |
| 15 | Base tax | 250 | 15 | Base tax | 250 |
| 16 | Total CAT | 334,389 | 16 | Total CAT | 270,581 |
| | | | | **Proposed Adjustment** | **(63,807)** |

CASE: UE 426
WITNESS: Itayi Chipanera

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 203

# Oregon Regulatory Fees

# March 25, 2024

# Staff Adjustment of Regulatory Commission Fees.

OPUC Fees

| | | | |
|---|---|---|---|
| (1) | 2024 Test Year Retail Retail Sales | $ | 66,152,949 |
| (2) | Updated OPUC Rate (Order 24-054) | | 0.45% |
| (3) | 2024 OPUC Fees | $ | 297,688 |

ODE, ESA

| | | 2018 | 2019 | 2020 | 2021 | 2022 | 2024 TY |
|---|---|---|---|---|---|---|---|
| (4) | Oregon Retail Sales | $ 55,160,426 | $ 51,990,825 | $ 51,171,193 | $ 53,968,480 | $ 60,209,245 | $ 66,152,949 |
| (5) | OR DOE Assessment | $ 75,484 | $ 71,975 | $ 66,191 | $ 72,146 | $ 70,163 | $ 86,660 |
| (6) | OR DOE Assessment Rate | 0.137% | 0.138% | 0.129% | 0.134% | 0.117% | |

| | |
|---|---|
| Oregon Deparment of Energy: Estimated Energy Supplier Assessment (ODE ESA) | 0.131% |

| | | |
|---|---|---|
| Total Staff Estimated Oregon Regulatory Fees (OPUC Fees + ODE ESA) | $ | 384,349 |
| Company Requested Amount | $ | 461,577 |
| Proposed Adjustment | $ | (77,228) |

CASE: UE 426
WITNESS: Itayi Chipanera

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 204

## Kilowatt Hour Taxes Cover

## March 25, 2024

# Staff Adjustment of Kilowatt Hour Taxes.

Staff KWH Tax Calculation

| | | 2020 | 2021 | 2022 | 2023 | 2024 (Staff Forecast) 4 Year Avg |
|---|---|---|---|---|---|---|
| 1 | Total adjusted KWH from Idaho hydroelectric power plants. | 3,950,333,114 | 3,091,332,088 | 2,961,140,884 | 3,590,621,502 | 3,398,356,897 |
| 2 | KWH sold to Idaho customers | 14,892,721,779 | 15,003,803,002 | 15,191,747,134 | 15,370,818,269 | 15,114,772,546 |
| 3 | Percentage of total adjusted KWH from Idaho hydroelectric power plants to KWH sold to Idaho customers. Divide Line 1 by Line 2 | 26.5% | 20.6% | 19.5% | 23.4% | 22.5% |
| 4 | Exmpetions for Irrigation and Industrial use | 1,193,465,165 | 971,001,881 | 915,776,832 | 1,074,011,657 | 1,038,563,884 |
| 5 | Net irrigation and industrial KWH exemption. (Line 3 * Line 4) | 316,569,733 | 200,061,896 | 178,501,142 | 250,889,008 | 233,507,367 |
| 6 | Net Taxable KWH | 3,633,763,381 | 2,891,270,192 | 2,782,639,742 | 3,339,732,494 | 3,164,849,530 |
| 7 | Estimated KWH Tax. Line 6 times (0.0005) | 1,816,882 | 1,445,635 | 1,391,320 | 1,669,866 | 1,582,425 |
| | Company Request (System Wide) | | | | | 3,273,507 |
| | Oregon Allocation Factor | | | | | 4.251% |
| | Company Request Oregon Allocation | | | | | 139,170 |
| | Staff Proposed KWH Tax Oregon Allocation | | | | | 67,275 |
| | Staff Proposed Adjustment | | | | | (71,895) |

CASE: UE 426
WITNESS: Itayi Chipanera

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 205

## Company Response to:
## Data Requests (DR)

## March 25, 2024

Idaho Power Company
UE 426
Idaho Power Response to OPUC Data
Request 183

***Request:***

Please provide the percentage of Idaho Power's customers that reside in

a. Oregon; and
b. Risk Zones in Oregon.

***Response:***

a. Idaho Power customers in Oregon account for 3.2 percent (19,913) of the Company's total customers across its service area.
b. Across the Company's entire service area, approximately 0.16 percent (982) of the Company's customers are located in wildfire risk zones in Oregon.

Idaho Power Company
UE 426
IPC Response to OPUC Data Request
201

***Request:***

Please provide a table by calendar year and FERC account for distribution plant additions for the Oregon and Idaho jurisdiction from UE 233 through the 2024 test year that are included in UE 426 rate base. Please provide the locations, both for Oregon and Idaho, of all distribution and substation investments for projects in excess of $100,000, total dollars of capital investment, type of facilities added, and date.

***Response:***

Please see Response to Staff’s Data Request No. 201 Attachment for the Excel file that includes a table by year and a table by FERC account of distribution plant additions by state location for project work orders greater than $100,000.

Idaho Power Company
UE 426
IPC Response to OPUC Data Request
202

***Request:***

Please provide the load growth, NERC compliance requirements and the associated distribution planning documents that demonstrate the need for the distribution plant additions for the Oregon jurisdiction from the test year in UE 233 through the UE 426 2024 test year.

***Response:***

Please see Response to Staff's Request No. 202 – Attachment for a list of the Oregon jurisdictional distribution plant projects in excess of $100,000. These projects fall into 5 major
categories:

1. Customer Required - Capital expenditures associated with requests from customers for specific service, capacity, or equipment. Customer pays for the project through facility charge or Contribution in Aid of Construction ("CIAC").

2. Compliance – Capital expenditures required due to a current compliance responsibility through the public utilities commissions ("PUC"), Standards of Conduct ("SOC"), Sarbanes-Oxley ("SOX"), Public Company Accounting Oversight Board, Critical Infrastructure Protection ("CIP"), Securities and Exchange Commission (SEC), Federal Energy Regulatory Commission ("FERC"), or other regulatory, legal, safety, contractual, or environmental mandates or requirements.

3. Growth – Capital expenditures for the electrical system resulting from an increase in the number of retail customers or the associated demand for power. Increases the capacity of the electrical system, relieves overload conditions, avoids operation outside of equipment or system design parameters. Also includes capital expenditures associated. with meter replacements. Based on Idaho Power's most current available data.

4. Reliability – Capital expenditures that will have a direct and measurable impact on the electric system reliability where failure is likely in the near future and failure would result in a significant negative impact to generation, transporting energy, or ability to serve large segments of customers. Includes reliability programs, technology and other projects designed to improve SAIFI and SAIDI ratings.

5. Routine Business/Infrastructure – Capital expenditures required for the replacement of equipment reaching the end of useful life. Reliability-related projects with lower magnitude of impact on company and customers. Additional equipment or facilities driven by employee growth or other drivers that are not directly attributable to an increase in the number of retail electric customers or the associated demand for power, including routine maintenance or ongoing maintenance to prevent failure, efficiency projects, technology and other prudent projects that don't fit in other Business Drivers.

There were no Oregon jurisdictional NERC compliance-related distribution plant projects in excess of $100,000. However, below summarizes the two Oregon jurisdictional growth projects related to load service. Note, Idaho Power does not have planning documents that demonstrate the need specific to the below projects however in each narrative the Company has detailed the results of the studies performed at the time that drove the need. In addition, as detailed in Idaho Power's 2021 Oregon Distribution System Plan, the Company leverages an asset replacement strategy to provide a comprehensive, long-range plan for managing the replacement of aging and/or condition-based transmission, distribution, and station assets.

<u>Project ID 27437388 – CWVY150002 - INCREASE STATION CAPACITY</u>

This project was driven by substation transformer capacity constraints at Cow Valley Substation ("CWVY").

When evaluating the transformer capacity at CWVY, the expected load on the CWVY T-061
transformer of 2.2 MW would exceed the planning capacity limit by 10.9 percent in the summer of 2016.

40°C (104°F) nameplate rating = 2.0 MVA
Planning capacity limit (98 percent of nameplate) = 1.96 MVA
Most recent peak, Summer 2015 = 2.19 MVA
Highest observed peak, Summer 2015 = 2.19 MVA
The average growth trend in this rural area was 0.5 percent annually.

The power factor on the transformer had been corrected to near unity.
No load transfer capability was available due to rural feeder layout.
Additional power factor correction would still have resulted in loading over the planning capacity limit.
Each of the three single phase transformers were anticipated to be overloaded. Phase C had the highest loading.

<u>Project ID 27517083 – NYSA190001 SYSTEM REINFORCEMENT NYSA14 OREGON CONSTRUCTION</u>

This load transfer project between the Nyssa-12 and Nyssa-14 feeders was needed to address capacity constraint issues on the Nyssa-12 feeder.

When evaluating the feeder capacity on Nyssa-12, the forecasted peak load of 11.6 MW would exceed the feeder's planning capacity of 10 MW by 11.6 percent in the summer of 2019.

Planning capacity limit = 10 MW
Adjusted 95th-percentile temperature event peak, Summer 2017 = 5.74 MW
The average growth trend in this rural area was 1.07 percent annually.

The addition of the 5.66 MW of large customer loads in the construction study/construction phases were included in the forecast
.

Idaho Power Company
UE 426
IPC Response to OPUC Data Request
255

***Request:***

Regarding Oregon allocation factors, for each Distribution O&M account (Non-Labor) (FERC 580-598) please explain:

a. The logic or reasoning behind allocating distribution costs to Oregon for work completed outside of Oregon.
b. The logic or reasoning behind why O&M distribution costs are not situs to the state where work was completed.
c. What factors are considered and included in the allocation base;
d. How is the allocation base spread or distributed;
e. How are Oregon allocation percentages calculated.

***Response:***

a. Distribution operation and maintenance ("O&M") is allocated in accordance with the corresponding jurisdictional spread of distribution plant, which is almost entirely assigned on a situs basis. Because the Company does not record O&M costs on a situs basis, the Company's method for jurisdictional allocation is a reasonable measure of cost causation.

b. Please see the Company's response to part a.

c. The factors considered for Distribution O&M are the directly assigned plant in service, which serves as the allocation basis for Distribution O&M allocation.

d. Distribution O&M is allocated over the corresponding distribution plant accounts, except for the Supervision and Engineering costs which are allocated over total Distribution plant.

e. The Oregon allocation percentages are calculated by dividing the Oregon total by System total for each account. These calculations can be found in the Excel version of Idaho Power/1202 provided with the Company's initial filing. The allocation of distribution O&M begins on Row 522 of this model.

Idaho Power Company
UE 426
IPC Response to OPUC Data Request
299

***Request:***

Please provide the following information from the filings with the Idaho State Tax Commission for the kWh Tax. The data should cover the years 2020, 2021 and 2022.

i. Kilowatt Hours generated from hydroelectric power plants. The Kilowatt Hours should reflect any adjustments that are necessary for the purpose of complying with the kWh Tax.
ii. Kilowatt Hours sold to customers as applicable to the kWh Tax.
iii. Kilowatt Hours exempt from the kWh Tax because of their use for irrigation and industrial use.
iv. The tax rate per kWh applicable for each of the years listed above.

***Response:***

Please see the attachment titled "Response to Staff Request No 299 – Attachment" for the requested information, for the years 2020 through 2022.

Idaho Power Company
UE 426
IPC Response to OPUC Data Request
413

***Request:***

If the Company is not tracking O&M and Wildfire costs separately, at the jurisdictional level, would the Company be willing to implement procedures to start tracking such costs for future years and to use in future general rate cases?

***Response:***

No, Idaho Power cannot track such costs by jurisdiction because invoicing is not state-specific and wildfire mitigation benefits all customers, not just those where the mitigation work occurs.

Idaho Power Company
UE 426
IPC Response to OPUC Data Request
433

***Request:***

Please provide the Total System actual plant additions for Distribution Plant by situs (Idaho, Oregon, and Joint) closed in the accounting system during calendar year 2023 that will be used to prepare the 2023 SEC Audited Financial Statements and the 2023 FERC Form 1 Financial Statements.

***Response:***

No, Idaho Power cannot track such costs by jurisdiction because invoicing is not state-specific
and wildfire mitigation benefits all customers, not just those where the mitigation work occurs

**Year-end 12/31/2023**

| | | Joint | |
|---|---|---|---|
| | Idaho | Oregon | Total |
| Account 360 | Allocation/Situs information is not yet available for Accounts 360-362. Will be supplemented when available. | | |
| Account 361 | | | |
| Account 362 | | | |
| Total | | | |

| | | Situs | |
|---|---|---|---|
| | Idaho | Oregon | Total |
| Account 360 | Allocation/Situs information is not yet available for Accounts 360-362. Will be supplemented when available. | | |
| Account 361 | | | |
| Account 362 | | | |
| Account 364 | $317,305,792 | $26,998,734 | $344,304,526 |
| Account 365 | $155,916,502 | $9,097,646 | $165,014,148 |
| Account 366 | $56,750,223 | $964,703 | $57,714,926 |
| Account 367 | $345,735,945 | $5,368,279 | $351,104,224 |
| Account 368 | $734,677,695 | $42,625,881 | $777,303,576 |
| Account 369 | $69,474,382 | $2,963,721 | $72,438,103 |
| Account 370 | $115,270,460 | $3,651,262 | $118,921,721 |
| Account 371 | $5,464,714 | $379,299 | $5,844,013 |
| Account 373 | $6,690,470 | $394,803 | $7,085,273 |
| Total | | | $1,899,730,510 |
| | | Total | $1,899,730,510 |

CASE: UE 426
WITNESS: Michelle Scala

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 300

## OPENING TESTIMONY
### Energy Justice

## March 25, 2024

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

A. My name is Michelle Scala. I am the Energy Justice Program Manager employed in the Strategy and Integration Division (SID) 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/301.

**Q. What is the purpose of your testimony?**

A. The purpose of Staff's testimony is to provide and validate energy justice considerations as they intersect with the proposals and potential impacts of Idaho Power Company's general rate case. I further elaborate on specific equity considerations in areas that have been identified as high-impact or high-priority energy justice issues; specifically, overall bill impacts & rate spread/rate design, and low-income bill discount & energy efficiency.

**Q. Did you prepare any exhibits for this docket?**

A. Yes. I prepared the following supporting exhibits:

Exhibit Staff/301. Witness Qualifications Statement

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

Issue 1. Energy Justice Overview .......................................................................... 3
Summary. Findings and Recommendations.................................................... 31

**Q. Could there be changes or updates to Staff's position and recommendations?**

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

## ISSUE 1. ENERGY JUSTICE OVERVIEW

**Q. Please briefly describe the primary role of energy justice in utility ratemaking.**

A. The primary role of energy justice in utility ratemaking is to advance the equitable distribution of energy system costs and benefits across all customer segments. It aims to address disproportionate impacts of rate structures and energy policies on environmental justice communities.[1] An energy justice informed review applies the concepts of equity, affordability, accessibility, and participation in the energy system against the utility general rate case filing and existing operations.

**Q. Please describe to what extent Idaho Power's proposal in UE 426 has considered energy justice.**

A. In Idaho Power Company's (Idaho Power, IPC, or Company) opening testimony, the Company demonstrates some awareness of affordability and social equity concerns through various exhibits and proposed measures. For example, in addition to referencing cost management strategies in the decade prior to this filed 2024 general rate revision,[2] Idaho Power has also included discussion on the measures taken to mitigate the overall rate increase and leverage new and existing customer assistance.[3] Further, specific proposals

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1 Per Oregon Revised Statute (ORS) 756.010(5), "Environmental justice communities" includes communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including but not limited to seniors, youth and persons with disabilities.

2 Idaho Power/100, Grow/2, 9-11.

3 Idaho Power/100, Grow/20-21.

put forward by the Company for consideration in this rate case evidence some inclusion of energy justice concepts and/or analysis. These include:

- A comparative analysis of current versus proposed residential customer bills, assuming all residential rate design and rate spread proposals are adopted (includes a proxied low-income customer segment overlay);[4] and
- A proposed new Schedule 63, Bill discount for Qualified Customers Program.[5]

**Q. Has Staff found the Company's existing actions and proposals sufficiently account for energy justice in this filing?**

A. No. While Staff appreciates Idaho Power's visible cognizance of energy justice concepts in its initial filing, Staff finds several of the Company's UE 426 proposals lack sufficient detail and analysis on the impacts to disproportionately burdened customer segments. Staff is concerned that in certain instances, failing to consider residential customer heterogeneity may result in effective rates that exacerbate existing disparities.

**Q. Please explain.**

A. Absent a thorough assessment of specific proposals impacting residential customers evidenced by a more robust set of customer segment analyses as well as a reasonable and documented measure of community engagement, Staff finds conclusions made by the Company regarding energy equity and low-income impacts unsupported. For example, while the

[4] Idaho Power/1300, Aschenbrenner/11-12; Idaho Power/1301, Aschenbrenner/1.
[5] Idaho Power/1300, Aschenbrenner/25-31.

Company has provided some segmented analysis relative to the distribution of residential customer bill impacts between total and low-income customer accounts,[6] this information is inclusive of all residential rate design proposals and fails to demonstrate the unique impacts of each change on the total and segmented populations.

Regarding the Company's low-income customer segment analysis methodology, Staff has concerns with 1) the lack of granularity relative to heterogeneity within the low-income segment (e.g., subsets across income brackets, housing type, and/or heating fuel); and 2) the validity of the Low-Income Home Energy Assistance Program (LIHEAP) participant data as a low-income segment.[7] Speaking to the lack of granularity, Staff has observed significant differences in energy burden across several customer variables within low-income households and is concerned that the total versus low-income segmentation does not sufficiently assess for disparate impacts. Assumptions of homogeneity, even within a layer of segmentation, can still misinform customer impact analysis. In a Data Request,[8] Staff requested the Company provide a customer segmented analysis using groups identified in the Company's Energy Burden Assessment, which included Malheur- Outlying Areas; Mobile Homeowners; Ontario- East, and Baker/Harney Outlying Areas. Table 1 depicts the Company's response.

6 Idaho Power/1300, Aschenbrenner/12, Lines 6-23, Figure 2.
7 The Company does not track income information for its customers and relied on customers identified as having received energy assistance through LIHEAP as a proxy for a low-income customer segment.
8 IPC's Response to Staff Data Request 443, Attachment A.

## Table 1. Residential Customer Segmented Rate Impacts

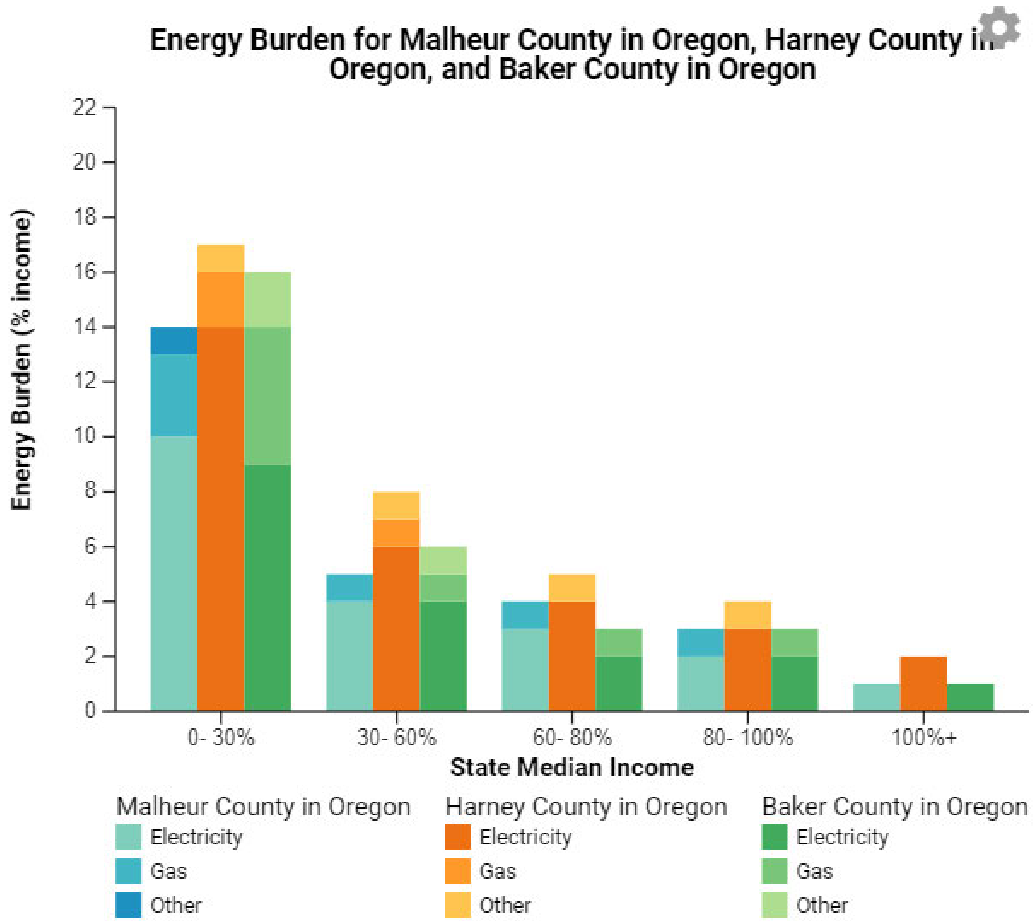
| IPC Proposed | Oct 15, 2024 Increase | Scenario if increase were $10.7 M* | | | |
|---|---|---|---|---|---|
| Residential Only | $10.7 Million* | New Residential Basic Charge $/Mo. | New Residential Avg. Bill $/Mo. ** | Increase $/Mo | % Increase |
| Malheur - Outlying Areas | | $15.00 | $217.74 | $39.41 | 22.10% |
| Mobile Home Owners | | $15.00 | $174.02 | $32.41 | 22.89% |
| Ontario - East | | $15.00 | $167.47 | $31.43 | 23.10% |
| Baker/Harney - Outlying Areas | | $15.00 | $164.43 | $30.82 | 23.06% |

* Oregon jurisdictional overall base rate revenue increase equates to 19.28 percent

** Includes the following Riders: Schedule 55 (APCU), Schedule 56 (PCAM), Schedule 91 (Energy Efficiency), Schedule 93 (Solar PV), and the proposed Schedule 64 (Bill Discount for Qualified Customers Cost Recovery Mechanism).

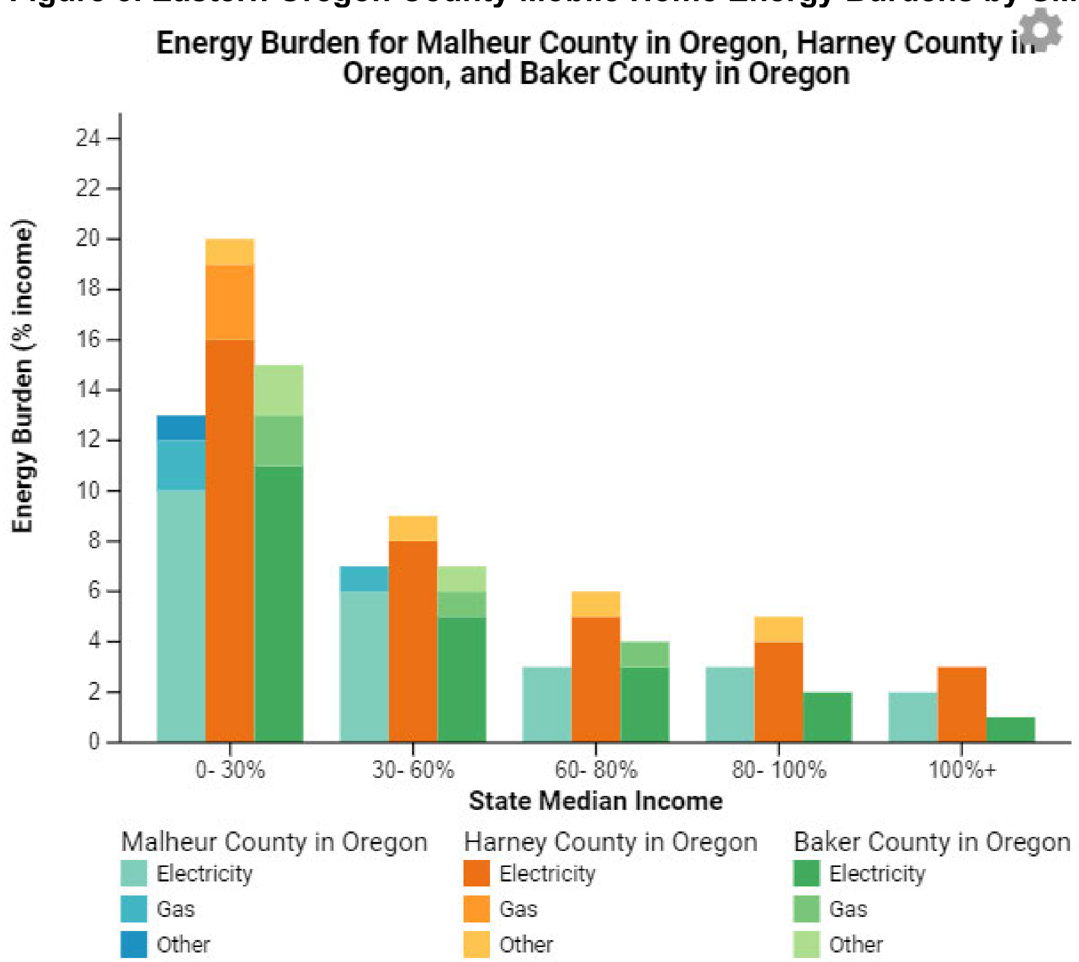
It is somewhat difficult to interpret these segmented rate impacts without additional context, and one may assume that from a percentage increase perspective, differences are minimal, while from a dollar increase perspective, Malheur County, outlying areas, face the largest increase. However, what would be observed from the Company's LINA, Ontario-East and Baker/Harney-Outlying areas face the highest energy burden while Mobile Homeowners are the most underserved. To this end, it seems necessary to apply an income bracket layer to the data in order to understand relative impacts to energy burden as a result of the Company's proposal. Using the US Department of Energy's Low-Income Energy Affordability Data Tool (LEAD), Staff reviewed energy burden for Oregon counties, Malheur, Harney, and Baker (Figure 2).

**Figure 2. Eastern Oregon County Energy Burdens by SMI**




According to this data set, energy burden more than doubled between household incomes at or below 30 percent SMI and between 30-60 percent SMI. In this same Figure 2, electrically heated homes also face disproportionately higher energy burdens than gas heated homes. From Staff's perspective, the LEAD data indicates heterogeneity across low-income brackets is significant. In another segment analysis, Staff found that a narrowed analysis of mobile homes meaningfully influenced average energy burden within certain counties and income subsets, but not others (Figure 3).

**Figure 3. Eastern Oregon County Mobile Home Energy Burdens by SMI**




To be clear, Staff is not intending that income-brackets and dwelling type fully achieve the desired layers of granularity, nor does Staff conclude that the LEAD data sets are necessarily the optimal source for low-income analysis. For example, Staff recognizes that the LEAD inputs include households not serviced by Idaho Power and lack billing data such as usage and monthly billed amount; however, Staff does intend to illustrate that there is reason for the Company to provide a more nuanced and comprehensive review of customer segments against each of its proposals if it is to argue that low-income households are not disproportionately impacted.

Regarding Staff's issue with the Company's proxied low-income segment, as derived using an account's history of LIHEAP, Staff is concerned this source is imprecise and potentially problematic if, in fact, not a reliable proxy for the low-income customer population. Based on the Company's filed Energy Burden Assessment or Low-Income Needs Assessment (LINA),[9] approximately 8,000 households have household incomes at or below 60 percent of the State Median Income (SMI) and thus are eligible to receive LIHEAP benefits. However, IPC's data shows only 1,319 customers with a history of LIHEAP. This is not a random sampling and leaves conclusions assigned to the low-income segment as a whole, vulnerable to bias from uniquely LIHEAP recipient customer characteristics.

**Q. What does Staff mean regarding a "reasonable and documented measure of community engagement"?**

A. Staff was unable to find any evidence that the Company had endeavored to discuss alternative rate design ideas with local communities. Doing so, via townhalls, targeted community outreach, or other forms of community engagement may have provided Idaho Power insights on its customers willingness and capacity to engage effectively with alternative rate designs. "Pre-work" that engages community and creates space for human-centered perspectives on the practical implications of the utility's rate proposal is a component of procedural equity that serves to advance energy justice in

[9] Staff/1601, Idaho Power's Low-Income Needs Assessment (Docket No. UM 2211).

ratemaking and equip the utility with a more informed proposal to bring before the Commission.

While this kind of pre-filing engagement is not presently required of utilities prior in a general rate case, it is a practice Staff has applied in a number of other dockets, including but not limited to Integrated Resource Planning, Clean Energy Plans, Energy Affordability Act Implementation (Docket No. UM 2211) programs, and more. Staff finds significant value in implementing process that allows for inclusive and transparent spaces to explore customer impacts and perspectives in advance of formal filings.

**Q. According to the Company, this sort of pre-filing engagement was conducted with Staff and other stakeholders in advance of the Schedule 63 Bill Discount Program Proposal, does Staff disagree?**

A. No. Staff agrees that the Company engaged with Staff and stakeholders in the UM 2211, House Bill (HB) 2475 Implementation Docket. In fact, Staff credits this early and frequent engagement in UM 2211 as reason the Schedule 63 proposal came to be (irrespective of the use of the rate case to advance the proposal). As is discussed by Mr. Farrell in Staff/600, Idaho Power was originally given exceptional runway to the implementation of HB 2475 after having raised concerns around the feasibility of providing such a program in its service territory.

However, after several rounds of customer surveys, community engagement, stakeholder comments, and an Energy Burden Assessment, the Company made a proactive shift in its initial position and advanced an interim bill discount proposal that aligned with several key design elements Staff had published the year prior. Here, granular analysis targeted at specific proposals or program design via the LINA, and robust community and stakeholder engagement played pivotal roles in the outcome of the Company's position on this issue. Staff finds this example supports its recommendation to issue the same "pre-work" guidance to all proposals that include significant changes to customer bills and/or rate designs.

**Q. Can you explain why the Company's existing Energy Burden Assessment does not appear to meet Staff's call for a "more robust set of customer segment analyses"?**

A. Yes. To clarify, Staff is grateful for Idaho Power's proactive initiative to pursue and complete a LINA following informal guidance discussed in UM 2211 engagement. A LINA is not currently required of regulated utilities, and yet where they have been completed, Staff has found the insights profoundly valuable. Relative to Staff's specific call for additional customer segment analyses, Staff remains open to the possibility that these can be done using the existing and/or updated LINA data sets applied in a more intentional manner to the Company's proposals. However, Staff has not found the Company to have done so in its initial filing and thus, finds the customer segment analyses lacking in this regard.

**Q. Please share what insights the Company's LINA does provide.**

A. Idaho Power's 2023 LINA provides a customer segmented overview of the energy burden faced by low-income households within its Oregon service territory. The assessment highlights key findings, offers insights into the socioeconomic and energy usage patterns of its customers, and provides guidance for addressing energy affordability and accessibility.

***Key findings include:***

**Socioeconomic Profile:** IPC's Oregon service territory included in the LINA consisted of approximately 12,800 occupied households, with a significant portion of the population living below the state median income level. At $48,000, the median household income in the IPC service area is notably lower than the state average of $66,000, indicating a higher prevalence of low-income households. Roughly 62 percent of residents would fall under the 60 percent of SMI metric for low-income status. Altogether, this indicates the policy challenges relative to reducing energy burden for “borderline” or fringe customers along the income distribution that face high energy burden while being marginally ineligible for most assistance programs. At the same time, this distribution also creates tighter limitations around cost recovery strategies for ratepayer funded direct assistance programs in order to avoid additionally burdening these customer segments.

**Energy Burden:** The average electricity energy burden for IPC customers is 4.2 percent, with a median of 3 percent. However of the 12,800 occupied households, 3,500 were deemed to have a high energy burden, defined as exceeding 6 percent of their income for electrically heated homes and 3 percent for non-electrically heated homes. The total energy assistance need for Idaho Power customers in Oregon is approximately $2.7M, of which, if fully and strategically applied, is the requisite total reduction that would bring all customer electricity bills below the high burden threshold. Idaho Power's energy charge in its residential retail rate is generally in line with other utilities in the region and below the national average of 16 cents/kWh. Therefore, the LINA suggests that low-incomes and high energy use, rather than rates, appear to be the most significant drivers of high energy burden in the area.

**Key Vulnerable Segments:** The assessment identifies specific customer segments facing significant energy burdens, including residents in Ontario-East, Malheur-Outlying areas, Mobile Homeowners, and communities in Baker/Harney-Outlying areas. These segments have been identified due to their high overall burden, low access to existing assistance programs, or their vulnerability as indicated by the Department of Energy's environmental justice screen. Per the LINA, these areas represent focus points for the Company to target its energy burden mitigation strategies. Mobile homes, for example represent a significant opportunity for targeted energy efficiency improvements; given the typically lower insulation levels and older infrastructure of mobile homes, energy efficiency upgrades can significantly reduce energy consumption and costs for these households. For rural communities where higher barriers to entry limit access to energy programs, the LINA recommends focusing on energy efficiency as a key strategy to reduce energy burden.

This is due to the potential for long term savings and the relative ease of implementing certain efficiency measures compared to the logistical challenges of delivering direct assistance in these regions.

**Q. Did the Company's LINA provide any guidance relative to addressing the issues and areas of concerns identified?**

A. Yes. From Staff's perspective and reading of the LINA, the most meaningful finding shared in the publication is the need to equally prioritize sustained energy burden reductions through energy efficiency and weatherization in a multi-prong approach with direct assistance. As noted in the list of key findings above, "low-incomes and high energy use, rather than rates, appear to be the most significant drivers of high energy burden in the area." To this end, Staff believes it appropriate that the Company's rate mitigation efforts and interim bill discount proposals include a meaningful energy efficiency component.

More generally, and less direct to this proceeding, Empower Dataworks also provided recommendations around targeted assistance programs; enhanced outreach and engagement; program evaluation and adaptation; and stakeholder Collaboration.

**Q. Does Staff agree with these recommendations?**

A. Yes. As noted above, Staff agrees with the LINA's finding and recommended strategy that targeted energy efficiency represents an essential component to prioritize in IPC energy burden mitigation proposals. The assessment describes and details how in most cases, Idaho Power's higher residential energy burden is largely driven by low-income, housing stock, and access to programs. The nature of these drivers supports the LINA and Staff's conclusions that energy efficiency must be, at least, equally prioritized alongside direct assistance programs.

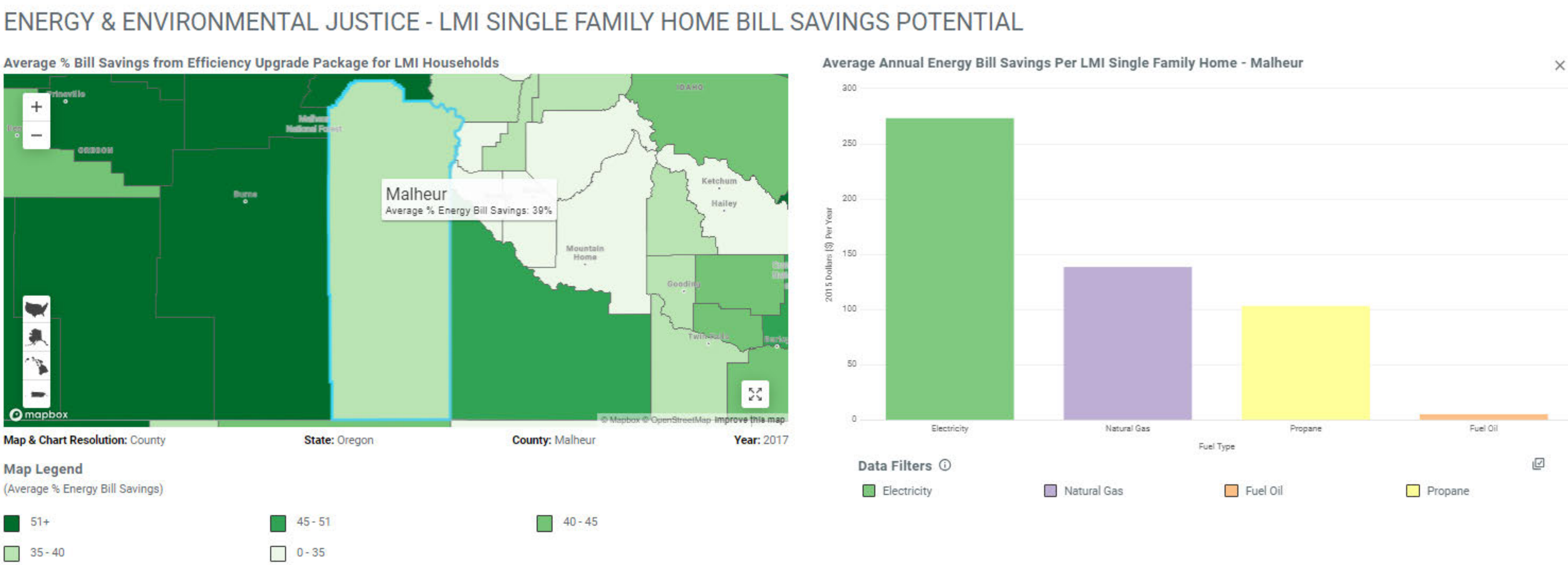
**Q. Please explain how this recommendation can be applied here.**

A. Staff is recommending that the Company be required to work with Staff and stakeholders to implement an energy efficiency component to it's Bill Discount Program and further, prioritize low-income energy efficiency and demand side management based on high energy burden and high potential customers as identified in the Company's LINA and any forthcoming customer segment analysis. Additional discussion on these recommendations are in this exhibits summary section as well as Staff/1600 and Staff/600.

**Q. Has Staff found the Company adopted these recommendations in its UE 426 filing?**

A. Not explicitly. Staff expected that based on feedback from stakeholder engagement in UM 2211, coupled with the LINA findings, energy efficiency would play a much more significant role in the Company's customer program proposals, including but not limited to Schedule 63. In a review of Low to Moderate Income (LMI) Single Family Home Bill Savings Potential relative to energy efficiency available from the US DOE's State and Local Planning for Energy (SLOPE) tool, Staff found evidence to support the meaningful impacts of targeted energy efficiency in counties serviced by Idaho Power (Figures 4; 5; and 6).

**Figure 4. Malheur County Average % Bill Savings from Efficiency Upgrade Package for LMI Households**



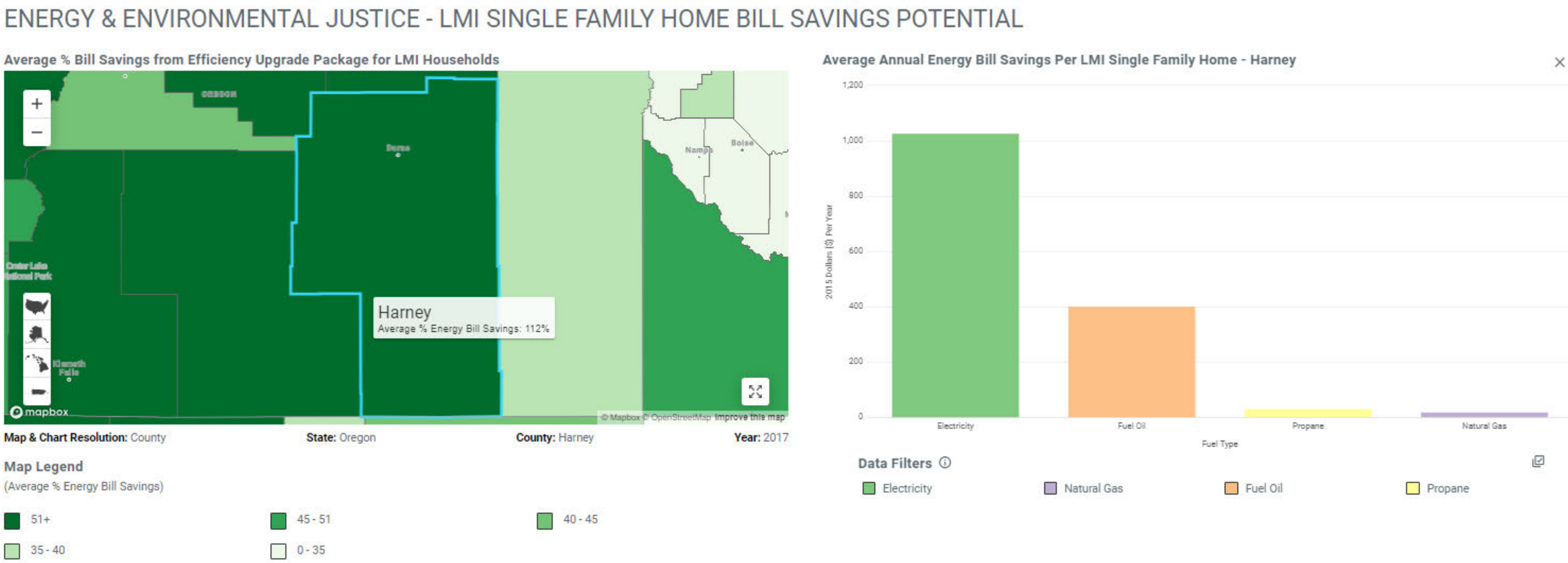

National Renewable Energy Laboratory. "LMI Single Family Home Bill Savings Potential," *State and Local Planning for Energy*, accessed 3/21/2024, https://maps.nrel.gov/slope.

LMI Single Family Home Bill Savings Potential Data Description

This layer displays the average energy bill savings realized by implementing a maximally cost-effective energy efficiency upgrade package for an average Low-to-Moderate Income (LMI) household. LMI households are defined as those that earn 0-80% of the Area Median Income (AMI). This data is provided at both the census tract and county levels.

Read more

**Figure 5. Harney County Average % Bill Savings from Efficiency Upgrade Package for LMI Households**

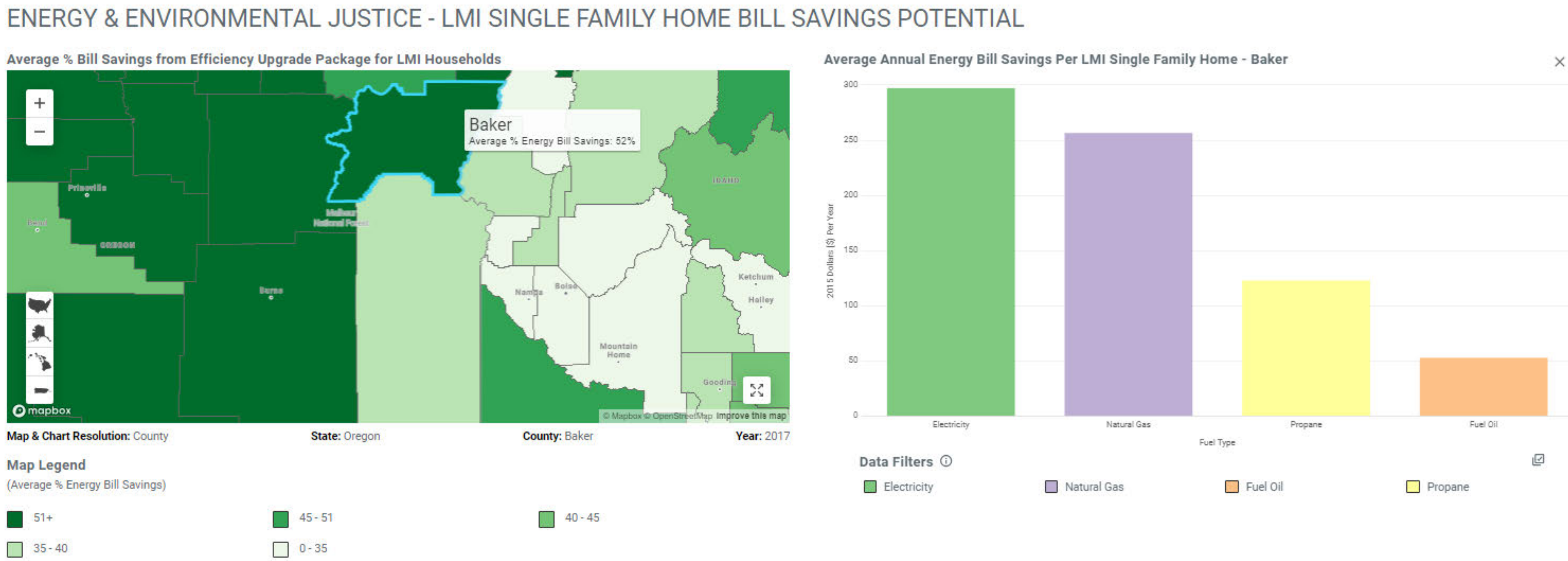



National Renewable Energy Laboratory. "LMI Single Family Home Bill Savings Potential," *State and Local Planning for Energy*, accessed 3/21/2024, https://maps.nrel.gov/slope.

LMI Single Family Home Bill Savings Potential Data Description

This layer displays the average energy bill savings realized by implementing a maximally cost-effective energy efficiency upgrade package for an average Low-to-Moderate Income (LMI) household. LMI households are defined as those that earn 0-80% of the Area Median Income (AMI). This data is provided at both the census tract and county levels.

**Figure 6. Baker County Average % Bill Savings from Efficiency Upgrade Package for LMI Households**




National Renewable Energy Laboratory. "LMI Single Family Home Bill Savings Potential," *State and Local Planning for Energy*, accessed 3/21/2024, https://maps.nrel.gov/slope.

LMI Single Family Home Bill Savings Potential Data Description

This layer displays the average energy bill savings realized by implementing a maximally cost-effective energy efficiency upgrade package for an average Low-to-Moderate Income (LMI) household. LMI households are defined as those that earn 0-80% of the Area Median Income (AMI). This data is provided at both the census tract and county levels.

As can be seen in each of the figures, Malheur, Harney, and Baker Counties show potential percent of bill savings from efficiency upgrades of 39 percent, 112 percent, and 52 percent respectively. In recognition of the data reviewed thus far as well as the cost recovery challenges the Company faces in implementing ratepayer funded direct assistance across an exceptionally small (approximately 14,000 residential customers) and financially burdened (approximately 62 percent of residential customers would fall under the State Median Income) service territory, Staff finds a targeted energy efficiency component to Idaho Power's energy burden mitigation strategy essential. In the same manner Idaho Power is given some measure of accommodation due to unique elements of its service territory compared to larger regulated Oregon electric utilities, this demonstrated and profound need for targeted energy efficiency should be exceptionally pursued. Staff discusses its concerns and recommendations regarding targeted energy efficiency deployment and the need to leverage the Company's Schedule 63 Bill Discount Program proposal with the UM 2211 process in Staff/1600 and Staff/600.

**Q. In addition to granular customer segmented analyses, procedural equity, and energy efficiency, which issues proposed by the Company in UE 426 does Staff believe have the biggest impact on energy burden and energy equity?**

A. Staff finds that the following issues deserve significant attention and perspective relative to energy justice principles and concepts:

- Magnitude of bill impact

- Schedule 63, Bill Discount Program
- Increase to service charge
- Alternative rate designs, including, seasonal rates and time-of-use rates
- Increase to reconnection charges

Staff also notes that while there are additional energy justice adjacent issues proposed in the rate case including the Company's decision to not pursue a bifurcation of the residential service charge (discussed in Staff/600), the purpose of this testimony is to elevate higher priority issues and areas where Staff's has identified high impact opportunities to advance a more equitable energy system for IPC customers.

**Q. Please elaborate on Staff's concerns relative to the magnitude of the impact.**

A. Recalling Table 1 in this exhibit, Staff shared that average dollar increases to customer bills across LINA customer segments ranged from a low $31.82 to a $39.41. The reported average increase across all residential customers is $32.37. Not only do these represent significant amounts to be *added* to existing bill amounts if the Company's proposals are adopted as filed, but they are average impacts and do not reveal the full extent to which some customers may be impacted. Put more specifically, these values assume an average monthly household usage of roughly 1,100 kWh. Customers using more than that measure, and customers with seasonal spikes can expect bill increases much larger than these averaged amounts.

Furthermore, customers facing disproportionate energy burdens logically have less financial capacity to absorb these increases and will face more dramatic practical implications relative to the increase, including increased risk for disconnection.  Staff implores that for rates to be judged as just and reasonable, social equity and affordability must be at the forefront of the conversation.  Staff recommends the Company utilize the LINA data set to understand thresholds of affordability within its service territory and evidence whether or not the overall rate impacts can be financially tolerated from an affordability standpoint.

While Staff appreciates the Company's effort to stage capital investments in a manner that might reduce some of the near-term rate pressure associated with this filing, Staff is concerned the measures taken are not enough and that the bill impacts are too great. Further, Staff would clarify that while the proposal does include income and energy burden qualified bill assistance, this is a limited measure, of which by the Company's own proposal, is only forecasting a 25 percent participation rate in the first program year.  Thus, not only does the program face concerns regarding the sufficiency in terms of the level of relief, but it is reasonable for parties to assume limited participation and therefore limited application as a rate mitigation tool in conjunction with this rate case.

Staff finds value in the possibility of exploring a more strategic and broadly applied measure to limit overall impact to customers' monthly bills.  At this stage, Staff does not have a proposal from which to achieve this type of rate pressure protection, however, Staff has proposed an adjustment to the overall UE 426 percentage of rate increase floors and ceilings across customer classes as detailed by Dr. Stevens in Staff/1700.

**Q. Please briefly describe Staff's concerns relative to the Schedule 63, Bill Discount Program.**

A. Staff's concerns regarding the Company's Bill Discount Program proposal are discussed and detailed by Mr. Farrell in Staff/600. In the interest of elevating specific priorities relative to energy justice, Staff's primary concerns center on three components of the proposal:

- Procedural Equity
- Level of Relief
- Lack of Energy Efficiency Component
- Cost Recovery Cap

Regarding procedural equity, as memorialized in comments submitted to the UE 426 docket by energy advocates and discussed in Staff/600, there were concerns expressed early and often regarding IPC's interest in including the proposal in a general rate case. The reason for this is the lack of accessibility currently attributed to the rate case review process and fears around the potential impacts a comprehensive issues negotiation might have on the final design. Staff endeavored to implement a temporary and experimental process to enhance procedural equity in this docket around the bill discount proposal and other priority energy justice issues via a Commissioner workshop. Staff has also committed to pursuing procedural equity throughout the docket by creating additional opportunities to receive non-intervenor and community input relative to Staff and other parties' consideration of these issues. Staff expects this to be an evolving process and is committed to reviewing these issues in a way that optimizes opportunities for procedural equity.

Regarding the level of relief, as discussed in this exhibit and Staff/600, energy burden among Idaho Power customers is among the highest in the state. Staff is concerned that the 60 percent maximum discount in addition to the higher barriers to entry afforded by the absence of autoenrollment and requirement of an energy burden metric evaluation may severely limit the program's efficacy at providing meaningful relief to customers.

Regarding the energy efficiency component, Staff details its concerns earlier in this testimony and in exhibits Staff/1600 and Staff/600.

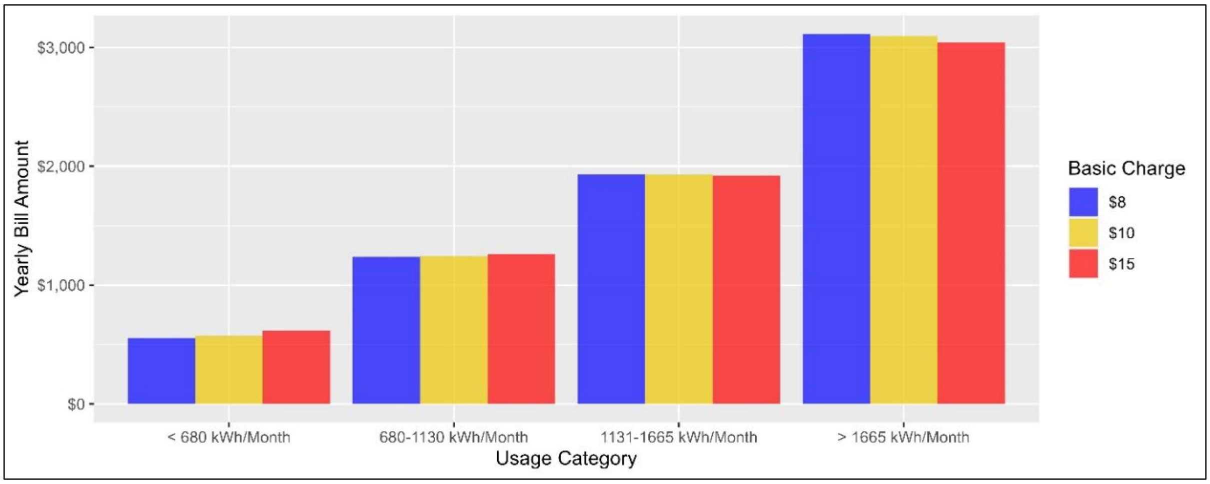
Regarding the cost recovery cap, as in previous proceedings, such as PGE's 2023 general rate revision, UE 416, Staff remains concerned that artificially low-cost recovery caps are incongruent with non-bypassibility language in the Energy Affordability Act, and shift significant cost recovery burden onto the residential customer class. Staff has proposed a higher effective cap in Staff/600 and wishes to monitor the spread, recovery, and volume of costs in whatever program is ultimately adopted to ensure that proportional rate impacts are considered in the cost recovery mechanism.

**Q. Please briefly describe Staff's concerns regarding IPC's proposal to increase the residential Service Charge from $8 to $15.**

A. IPC is proposing an increase to the residential Service Charge (fixed charge or basic charge) of $7.00. This proposal would raise the service charge by 87.5 percent. IPC argues that residential customers should pay their entire fixed cost of service (cost of metering and customer service) through the service charge. They also argue that the result of the lower basic charge is that residential customers who consume more energy end up subsidizing customers who consume less. Staff has not seen data indicating that this issue in isolation will have a disproportionate impact on lower income customers as a whole, however as noted earlier in this testimony, customer segmented analyses in proposal specific areas remains an area of need. That said, the discernable effect of this proposal at this time is that customers with higher usage will benefit from this proposal while lower usage customers will likely see higher bills.

Additionally, Staff is interested in understanding the potential practical effects of this change on customer engagement with energy efficiency. There are concerns that as this proposal increases the minimum bill a customer would pay (given the fixed nature of the service charge) the customer who cannot reduce this portion of the bill by adjusting usage or engaging with energy efficiency is less incented to participate. While the Company's testimony does endeavor to assure this change is more equitable and maintains price signals to promote efficiencies in tandem with its other proposals[10] Staff finds this to be another area where additional granularity and customer engagement would serve to benefit a review of the proposal.

**Figure 7. Yearly Bill by Basic Charge Amount
and Average Monthly Usage**




Helpful if text could be more legible – meaning is getting lost Matt

**Q. Please briefly describe Staff's concerns regarding IPC's alternative residential rate design proposals.**

A. Idaho Power is also proposing to introduce seasonal rates for its Oregon residential customers. These rates as proposed, would be higher in the summer and lower in the winter, albeit both an increase from the currently approved rates. The differential between seasons is approximately 7 percent. Staff has performed some limited analysis using the same, previously caveated, low-income customer segment proxy data using LIHEAP customers to assess the impacts of the seasonal proposal across some customer segmentation (Figures 8; 9; and 10).

10 Idaho Power/1300, Aschenbrenner/3.

**Figure 8. Seasonal Rate Impact - LIHEAP Customers**

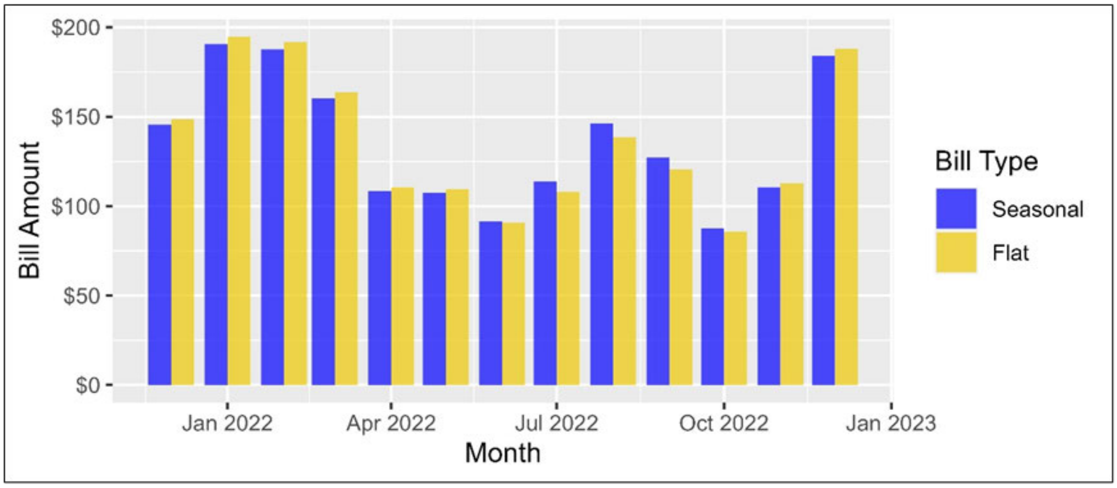



**Figure 9. Monthly Consumption by Month - LIHEAP Customers**

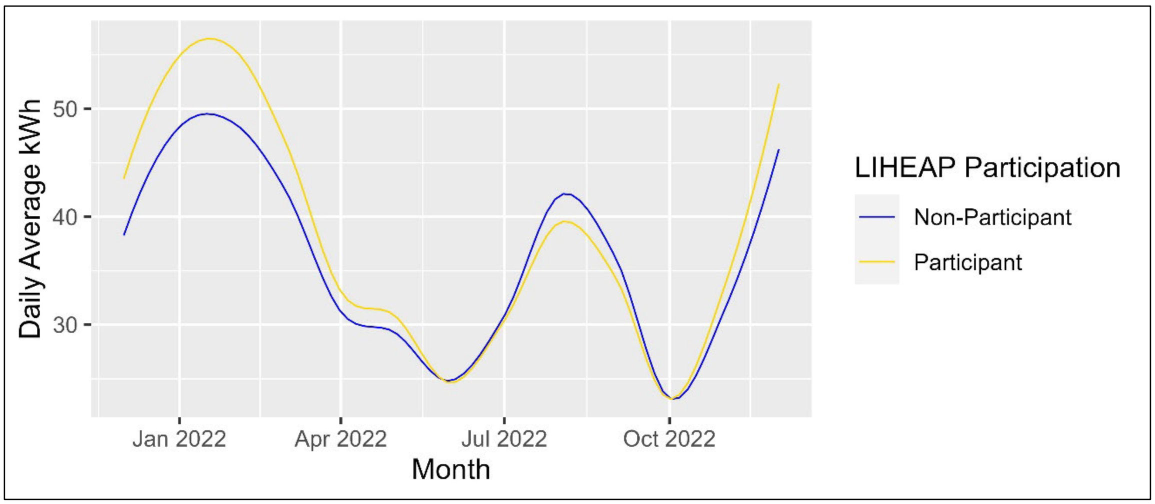
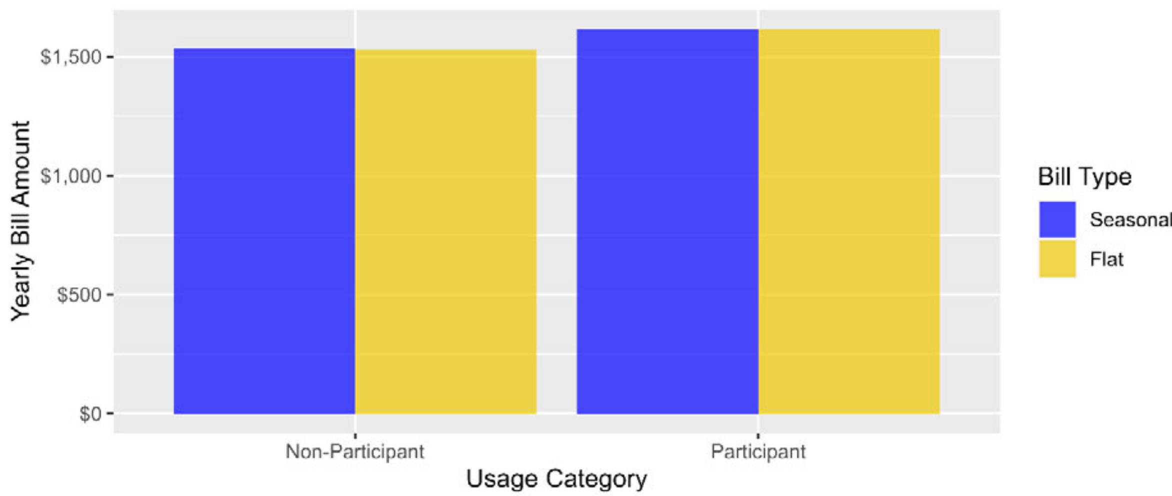


**Figure 10. Yearly Bill Impact of Seasonal Rates -LIHEAP Customers**




This proposal is designed to decrease the non-summer rates in a way that keeps the average residential customer's bill the same over the course of the years it would be without a differential between seasons. Based on the analysis above, and the observed assumption that low-income households tend to be more winter-peaking indicates a potential bill-impact benefit between November and May for LIHEAP participants and customers sharing similar load profiles. However, Staff notes that customer consumption patterns vary within the residential class across different income level segments that are not fully captured in these figures. In general, this type of variance means that the impact and burden of this change will vary based on factors like how efficient the customers' home is, whether they have access to air conditioning, and whether they have the ability to respond to price signals.

All of these factors can be impacted by income and other demographic factors. To this end, Staff is looking into whether cooling usage behaviors and access are equitable in the Company's service area and across customer segments. Absent equitable access, and in the event of energy limiting behaviors, a seasonal rate proposal may result in deeper long0term harms. From Staff's perspective, based on the available data, if the perceived benefit of IPC's seasonal rate proposal is contingent upon customer characteristics that reinforce energy inequity (e.g., limited access to air condition and energy efficiency for heating loads), then this proposal has the combined effect of exacerbating these issues further. Staff would recommend that the Company invest in targeting energy efficiency and the technology required for households to respond to price signals without effecting disproportionate burdens across already vulnerable customer segments before trying to implement a price signal. If customers do not have access to resources needed to respond without a behavior change or risk to energy security, then it is just a punitive policy. Additional discussion and recommendations are provided by Dr. Stevens in Staff/1700.

Staff also notes that the Company's seasonal rate proposal includes extending the summer rate season to include September, alongside existing June through August, to align with increased system demand and costs during these periods. Thus, a significant rationale for the efficacy of these rates is tied to cost causation and price signaling, but for the latter to function, one assumes a customer is able to flex their load in response.

Regarding Time-of-Use (TOU) rates, the Company's proposal relative to Schedule 5, the optional residential TOU rate, which would shorten the on-peak hours, and increase the rates, but maintain the on-peak and off-peak cost differential. Given the level of participation in this optional schedule, Staff finds this proposal to be less significant to energy justice concerns at this time. To the extent Schedule 5 becomes a more representative cohort of residential customers overtime, Staff encourages energy justice and equity be prioritized in consideration of the design and measures of efficacy. Staff discusses the TOU proposal in Staff/1700.

**Q. Please briefly describe Staff's concerns regarding the Company's proposal to increase residential reconnection charges.**

A. Staff provides in depth testimony addressing equity concerns as a result of Staff's position supporting Idaho Power's proposal to increase the residential reconnection charges in Mr. Shearer's testimony, Staff/1400 OAR Ch. 860, Div 21 Customer Protections. The Company's UE 426 proposal increasing reconnection charges is summarized in Table 2.

**Table 2. Service Connection Charges**

**Service Connection**:
Schedules 1, 5, 7, 9

| Monday Through Friday | Current Charge | Actual Cost | Proposed Charge |
|---|---|---|---|
| *7:30 a.m. to 6:00 p.m.* | $20.00 | $36.84 | **$30.00** |
| *6:01 p.m. to 9:00 p.m.** | $45.00 | $66.44 | **$70.00** |
| *9:01 p.m. to 7:29 a.m.*** | $80.00 | $117.63 | **$120.00** |

As shown, the increases, particularly in off-hour windows are significant in comparison to current charges and may present significant financial burdens to certain households. As is discussed in Staff/1400, while Staff's review of the proposal has concluded without opposition at this time, Staff endeavored to mitigate concerns around exacerbating known disparities relative to low-income households facing higher rates of disconnection, generally. Staff further endeavored to promote a more robust and comprehensive process for identifying income-eligible households to receive protections under the revised Division 21 rules, which include protections against certain types of disconnection and waived reconnection charges. Altogether, the intent of Staff's recommendations in this regard aligns with the concepts of equity and mitigating vulnerabilities in consideration of energy justice.

## SUMMARY FINDINGS AND RECOMMENDATIONS

**Q. Please summarize Staff's key recommendations to address energy justice in UE 426.**

A. The following summarizes Staff's recommendations relative to energy justice in the Company's filing, specifically as it relates to procedural equity, granular customer segment data, energy efficiency, the magnitude of the bill impact, Schedule 63, increase to the Service Charge, Alternative Rate Designs, and Customer Protections in conjunction with proposed changes to reconnection charges:

Procedural Equity:

Require IPC to engage with local communities and energy justice advocates through targeted outreach, or other forms of community engagement before filing rate proposals impacting residential customers.

Granular Customer Segment Data:

Require IPC to provide more detailed customer segment analyses, specifically in assessing the unique impacts of rate design and rate recovery proposals and dockets across different population segments, including low-income customers in rate recovery and rate design proposals moving forward. This includes adding layers of granularity, such as income brackets, housing types, and heating fuel, to better assess disparate impacts.

Demand Side Management:

Require IPC to prioritize and implement conservation efforts that leverage existing and upcoming programs and align with low-income customer needs for cost-effective energy burden reduction. To the extent that the Company plans to transition to more time-based residential rate designs, the Company should first invest in demand side management measures in the most energy burdened households so that the result will be behavior change, and associated system benefits, rather than punitive bill increases. Additional recommendations regarding the Company's demand side management programs are detailed in Staff/1600.

<u>Schedule 63 Bill Discount Program:</u>

Require the Company to continue engagement with both parties to the rate case and non-intervenors on a community and advocate informed program design that includes automatic enrollment of customers who are receiving LIHEAP, clarification regarding program outreach and eligibility practices, and buy-in relative to the level of relief, energy efficiency bundling, and cost recovery rate spread. These and Staff's recommendation for a kWh cap to target a $3,000 effective monthly cap for non-residential customers to provide a more proportional share of costs across customer classes are detailed in Staff/600.

<u>Increase to Service Charge:</u>

Reduce the proposed increase to the residential service charge from $7 to $2 for an effective service charge of $10 (Staff/1700). Further, encourage additional information and analysis on the effects of increases to the service charge on customer engagement with energy efficiency, particularly across residential customer segments.

Alternative Rate Designs:

Reject the adoption of seasonal rates in this proceeding but encourage continued consideration of the implementation of alternative rate designs across customer segments, ensuring they are equitable and do not disproportionately impact vulnerable customers. Require the Company to explore these types of designs with greater community involvement and in conjunction with the requisite detailed customer segment impact analyses. Recommendations regarding seasonal rates and TOU are detailed in Staff/1700.

Customer Protections (Div 21):

Require the Company to adopting more comprehensive measures to identify income-eligible households for Division 21 protections, as detailed in Staff/1400.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: Michelle Scala

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 301

## Witness Qualifications Statement

## March 25, 2024

# WITNESS QUALIFICATIONS STATEMENT

**NAME:** Michelle Scala

**EMPLOYER:** Public Utility Commission of Oregon

**TITLE:** Energy Justice Program Manager
Strategy and Integration Division

**ADDRESS:** 201 High Street SE. Suite 100
Salem, OR. 97301

**EDUCATION:** University of Hawaii, Manoa
Bachelor of Arts Economics

Bachelor of Arts Political Science
Concentration in Public Policy

**EXPERIENCE:** I have been employed by the Public Utility Commission of Oregon since July 2020 as a Senior Utility Analyst. I initially began work at the Commission in the then "Energy Rates, Finance and Audit Division" and transitioned to the Strategy and Integration Division upon its inception. In May of 2022, I was made Energy Justice Program Manager to the Utility Division where I lead energy equity work across utility rate, planning, and policy dockets. I have provided expert testimony as Commission Staff in general rate cases UE 394, UE 416, UG 433, and UG 435, UG 461 and have consulted on others. I have over ten years of experience in policy analysis and program evaluation for state and local governments and received a graduate certificate in Public Administration in 2024. My work prior to the Commission included serving as a Senior Fiscal Analyst at the Oregon Department of Human Services and Economist at the Oregon Employment Department. Before coming to Oregon, I was employed at the Hawaii State Legislature as the Senior Budget and Policy Analyst to the Senate Committee on Ways and Means.

CASE: UE 426
WITNESS: MELISSA NOTTINGHAM

# PUBLIC UTILITY COMMISSION OF OREGON

# STAFF EXHIBIT 400
## Public Comments

# Opening Testimony
## Public Comments

# March 25, 2024

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

A. My name is Melissa Nottingham. I am the Consumer Services and Please spell out Matt (RSPF) Manager. 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/401.

**Q. What is the purpose of your testimony?**

A. To provide the public comments submitted by consumers pertaining to UE 426 and a brief summary of issues and/or concerns identified, and where applicable, refer to the Staff testimony addressing related issues. Staff are viewing comments and will address them as practicable in Rebuttal Testimony.

**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, public comments received by the Commission are now made part of the Staff's Opening Testimony in a General Rate Case (GRC).

Please see Nottingham 402 for Comments received to date in this GRC. Staff will also publish Supplemental Opening Testimony on April 15, 2024, with incremental comments received including those received at Commission Public Comment Hearings on March 14, 2024 (virtual), and March 20, 2024, in person in Ontario, Oregon.

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 426 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.

## 1. Summary of Comments

**Q. How are public comments obtained by Staff?**

A. Comments may be submitted via an online form, an email, a letter, or a telephone call. All comments are submitted and published to the docket's webpage and is available for review at any time. Please see: Docket UE 426 IDAHO POWER REQUEST FOR A GENERAL RATE INCREASE.

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

A. Idaho Power's request for general rate increase has received four comments. Three of the commenters were concerned about the impact of higher rates and questioned how the Company spent the money already included in rates. One of the three expressed concern for the impact on communities with limited incomes and fewer economic opportunities. The other three comments questioned the Company's current spending on improving reliability, wholesale power to California, purchasing property, and dollars spent on habitat restoration projects.

**Q. What other issues were raised?**

**A.** One customer raised several issues concerning the following:

1. The conflict between the rate case and prior comments made by the Company to both the Public Utility Commission and the Energy Facility Siting Council on funds need to build the transmission line Boardman to Hemingway (B2H).

   Please note that the Company is not seeking cost recovery in and B2H is not addressed in this general rate case.

2. Monies collected for wildfire mitigation will fund protection for high fire risk areas in Idaho and not benefit Oregon customers.

   Please note that In Exhibit 900, Luz Mondragon, Senior Financial Analyst, reviews Wildfire Mitigation Costs

3. The Company's failure to consider the transmission corridor for B2H as creating a high fire risk area nor designating the area as a high fire risk area.

   Please note that the Company is not seeking cost recovery in and B2H is not addressed in this general rate case.

4. Concerns about why the company is requesting a higher ROE after assuring the Public Utility Commission and the Energy Facility Siting Council the Company has virtually no risks of defaulting or being unable to meet their obligations regarding the B2H transmission line, and as a result, the Company was not required to maintain a bond for site restoration as required by other developments in the state.

Please note that Staff's Manager of Accounting and Finance is reviewing the Company's Return on Equity, Overall Cost of Capital as informed by the Company's current credit ratings in Exhibit Staff 100.

**5.** The two counties serviced by Idaho Power in Oregon have declining numbers of residents and reduced energy consumption. The numbers are counter initiative to the Company's statement increased electrical consumption is a driver for the rate case.

Please note that In Exhibit 1500, Dr. Bret Stevens, Ph.D. analyzes the Company's load forecasting, class cost-of-service study, rate spread, rate design. and rate base.

**Q. Does this conclude your testimony?**

A. Yes.

## Witness Qualification Statement

**Name:** Melissa Nottingham

**Employer:** Public Utility Commission of Oregon

**Title:** Consumer Services and Residential Service Protection Fund (RSPF) Manager

**Address:** 201 High Street SE, Suite 400
Salem, Oregon 97301

**Education:** Bachelor of Arts in English, Arizona State University

**Experience:**

My employment at the Public Utility Commission began on May 1, 2022. During my tenure, I manage a team of 14 employees overseeing consumer complaints, the Oregon Lifeline Program, and the Telecommunication Devices Access Program. Part of my role includes sponsoring and participating in dockets related to Oregon Administrative Rules Division 21 and other consumer protection by regulated utilities in Oregon. I have provided testimony for UM 1908 and UM 2203, UE 416, and provided comments for AR 653, UM 2237, and ADV 1391.

Prior to my employment at the Public Utility Commission, I worked for PacifiCorp for 25 years. PacifiCorp is a multi-jurisdictional regulated electric utility. From 2010 until my departure in 2022, I was a Regulatory Manager. My responsibilities included ensuring regulatory compliance in six states including Oregon. I provided testimony in general rate cases in six states focusing on the company's Schedule 300 fees and any company tariff modifications. Other duties included: representing the company in formal customer complaints and small claims court, overseeing contracts for new service for loads more than 1 megawatt, sponsoring modifications to the company's rules, and participating in each state's administrative rule dockets.

| Docket Number | Docket Name | Company |
|---|---|---|
| UE 426 | IDAHO POWER REQUEST FOR A GENERAL RATE REVISION | IDAHO POWER COMPANY |

| Comment Number | Created Date | Email Received Date | Company Name | Comment Type | Source Type | First Name | Last Name | Email | Nearest City | Comment |
|---|---|---|---|---|---|---|---|---|---|---|
| UE 426-1 | 12/27/2023 12:32:52 AM | 10/4/2023 11:31:25 AM | IDAHO POWER COMPANY | General Comment | Email | | | | | Customer wanted to voice his comments as: I want to vote no to the Idaho Power increase, I don’t want any fixed rates and I don’t want any increases. I want Biden to pay for it because they said it was for infrastructure stuff, so charge him for it. I saw it on TV so I don’t want it. Just put my vote as no. Thank you |
| UE 426-2 | 1/12/2024 12:31:43 AM | 1/7/2024 3:50:22 AM | | General Comment | Email | | | ott.irene@frontier.com | | ott.irene@frontier.com<mailto:ott.irene@frontier.com>. Please include the attached public comments regarding Idaho Power's Request for a Rate Increase to their Oregon Customers. TO: Oregon Public Utilities Commission Date: 1/7/24 FROM: Irene Gilbert/ 2310 Adams Ave./La Grande, Oregon 97850 Email: ott.irene@frontier.com<mailto:ott.irene@frontier.com> Phone: 541-805-8446 Subject: Docket UE-426 Idaho Power Companies Request for General Rate Revision Filed December 15, 2023 Dear Commissioners: The following are significant concerns generated by a cursory review of the request for a Rate Increase for Oregon Electricity Customers: This request is not justified due to the fact that there are multiple discrepancies Between the previous statements made by the company representatives to the Public Utility Commission and the Energy Facility Siting Council and their request for this rate increase. In addition, there is a lack of information which identifies the utilization and benefits of the expenses to the Oregon customers being subjected to the requested rate increases. Basing the need for increased revenue on expenditures and increased needs of Idaho customers does not justify having Oregon customers pay for them. A large percentage of the future expenses being incurred by Idaho Power will result from their investment in the B2H transmission line. Idaho Power has provided conflicting information to the Oregon Department of Energy, the Energy Facility Siting Council and the PUC in previous and current submissions compared to that contained in their request for a rate increase. Objections to this rate increase includes, but are not limited to the following: 1. Oregon Counties subject to the rate increase will not benefit from costs incurred for Wildfire mitigation. Idaho Power describes a “robust” wildfire plan which focuses their expenses on the areas they have identified as highest risk .Most of the funding being spent and proposed to be spent will be directed to addressing wildfire risk in the State of Idaho. The requests from Counties in Oregon for staff and equipment needed to address the wildfire risk resulting from the Idaho Power development of the B2H transmission line were not implemented Wildfire risk in the five counties crossed by the transmission line were determined based upon a comparison of Eastern and Western United States. This resulted in no areas in Oregon containing the transmission Line being rated as “red” zones requiring “robust” mitigation. Only two areas were rated as “yellow” zones requiring a reduced level, and the rest supposedly had little wildfire risk. They failed to consider the site specific evaluations of the areas in the Counties being crossed by their transmission line indicating there are multiple “high risk”” areas which should require “robust mitigation.” 1. Arguments regarding the risks listed as necessitating a greater return on investment than larger utilities is inconsistent with the statements provided to the EFSC and ODOE and which continue to be their testimony in their currently proposed Amendments to the Site Certificate for the only development they are proposing in Oregon counties. Idaho Power continues to state that they are subject to virtually no risks of defaulting or being unable to meet their obligations regarding the B2H transmission line. Due to these assurances, they are not being required to maintain the bond for site restoration that is required of all other utility developments in the state. Their bond amount is currently set at $1.00. The entire risk of default on the part of Idaho Power due to financial problems or any other future events resulting in the company failing to restore their site have |

| Docket Number | | | Docket Name | | | | | | | Company |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | been transferred to their customers, Oregon citizens and landowners. 1. Arguments regarding the need for increased rates based upon increased Oregon customers or increased energy use are not supported by facts. Idaho Power’s customers all reside in Malheur or Baker Counties. According to the Oregon Department of Energy report to the legislature, for Oregon as a whole, during the past decade, the number of Oregon citizens has increased, however, the per household use of electricity has decreased resulting in virtually a flat usage for Oregon as a whole. Projections that Idaho Power will have an increase in the number of it’s Oregon customers are also not consistent with the Census reports which show that the number of people in Eastern Oregon has gone down. This is further supported by the Oregon Blue Book data compiled by the Population Research Center of Portland State University, between 2020 and 2022, the population of Malheur and Baker Counties have decreased. Basing their request for a rate increase on increases in population or energy user in another state does not support an increase in rates for Oregon customers. Customers in these financially disadvantaged counties of Eastern Ore |
| UE 426-3 | 2/5/2024 12:31:46 AM | 2/2/2024 2:39:45 PM | | General Comment | Email | | | Ellie.KNOLL@puc.oregon.gov | | From: david ayhens <dmayhens@hotmail.com> Sent: Friday, February 2, 2024 1:44 PM To: PUC PUCHearings * PUC <puc.hearings@puc.oregon.gov> Subject: IP general rate case dmayhens@hotmail.com<mailto:dmayhens@hotmail.com>. I have a grievance, there's a few things i would like for you to consider. first, Idaho Power has increased or rates several times one was to get to the national average, overseeing salmon and steel head which we pay for in the Columbia basin charge, and how can a power company purchase not 1 but 2 ranches in Oregon, in-addition they purchase recreational vehicle's, spendy drones, and I'm sure there's more. We continue to have crappie service with power outages. Also, I heard they sell power to California but we dont a kick back from it. it's time to stop the extras and control the companies from greed maybe its time to control the spending and be happy with what they have. Our standard average bill is over $200 when's enough. I 'm sure if you ask a lot more people would have more to say about. Sincerely, David Ayhens |
| UE 426-4 | 2/16/2024 1:37:39 PM | | IDAHO POWER COMPANY | Oppose Docket | Web | | | | NYSSA | Note: Letter typed verbatim by commission staff; enclosures not included, described below. (dr) Received Feb 06 2024 P.U.C. January 27, 2024 Oregon Public Utility Commission 201 High St. SE, Suite 100 Salem, OR 97301-3398 I call your attention to the Idaho Power proposed rate increase we received yesterday in our bill. This is ridiculous, and a real hardship to those of us on limited incomes in this poor area. Please see what you can do to stop this exorbitant request. I am writing also all of my state and federal representatives. Idaho Power has a monopoly in this area so we have no other source for our electricity. Sincerely, /s/ encl: 2 (IPC bill insert announcing the rate request) |

CASE: UE 426
WITNESS: RUSS BEITZEL

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 500

# OPENING TESTIMONY
# A&G EXPENSES, PENSIONS AND BENEFITS

**March 25, 2024**

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

A. My name is Russ Beitzel. I am Program Manager of the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (Commission or 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/501.

**Q. What is the purpose of your testimony?**

A. I present Staff's analysis in the general category of non-labor (NL) administrative and general (A&G) expenses, and Pension and Benefits (P&B).

**Q. Did you prepare any exhibits for this docket?**

A. Yes. I prepared the following supporting exhibits beyond my witness qualifications:

Exhibit Staff/502............................ IPC Responses to Staff Data Requests

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

Issue 1. A&G Expenses (Non-Labor).......................................................2
Issue 2. Pension and Benefits ....................................................................8
Summary..........................................................................................10

## ISSUE 1. A&G EXPENSES (NON-LABOR)

**Q. Please summarize Staff's adjustments for A&G expenses.**

A. Staff currently does not have a recommended adjustment to 2024 non-labor A&G. Staff's recommendations on each of the accounts reviewed herein, may change after reviewing other parties' testimonies filed in this docket and with additional information provided in outstanding data requests

**Q. What are A&G expenses?**

A. A&G expenses, sometimes labeled Operations and Maintenance (O&M), include human resources, accounting and finance, insurance, contract services and purchasing, corporate security, regulatory affairs, legal services, information technology (IT), research and development (R&D), employee benefits and incentives (P&B), support services, and regulatory fees that fall within the Federal Energy Regulatory Commission's (FERC) definition of A&G.[1]

Regarding non-labor A&G expenses, different Staff performed individual analysis on various subcomponents of A&G. In my testimony, I address the following A&G subcomponents: Office Supplies and Expenses (FERC 921), Outside Services Employed (FERC 923), Property Insurance (FERC 924), Injuries and Damage (FERC 925), Regulatory Commission Expense (FERC 928), Miscellaneous General Expenses (FERC 930), and Maintenance General Plant (FERC 935).

[1] Code of Federal Regulations (CFR), title 18, Chapter I, Subchapter C, Part 101 - Uniform System of Accounts (USOA) Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Accounts 920 – 935. Available at: https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101.

**Q. Please summarize the Company's overall request for A&G expenses.**

A. In the Company's filing, Idaho Power Company (IPC) reports actual A&G expenditures (inclusive of Labor costs) of $168.7 million in 2022 and a forecasted 2024 Test Year amount of $183.9 million. When these amounts are adjusted to remove the Idaho specific Employee P&B, the amounts are $151.5 million in 2022 and a forecasted 2024 Test Year amount of $ 148.7 million.

According to IPC, the primary drivers of the $2.8 million decline in Test Year A&G expenses (from 2022 actuals to the 2024 Test Year) are reductions to corporate and incentives expense of $16.3 million, offset by increases to other A&G expenses, most notably a $4.2 million increase to administration and general salaries and $6 million to injuries and damages.[2]

Without Labor included for Oregon only allocated expenses, Staff's calculation of IPC's A&G expenses related to FERC Accounts 920–935 shows actual expenses of $3.6 million in 2022 and a forecasted 2024 Test Year amount of $2.6 million. The reduction of $1 million will be discussed in more detail below.

**Q. What was the Company's approach to forecasting non-labor A&G expenses for the Test Year?**

A. The Company used inflation factors provided by Moody's Analytics to adjust from the Base Year to the Test Year for most of the accounts.[3] For those accounts with known adjustments, the Company factored in those adjustments.

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[2] See Idaho Power / 901, Jeppsen / 6.
[3] See Idaho Power / 1000, Larkin / 7.

**Q. Does Staff accept using escalators to increase Base Year expense to Test Year expense?**

A. Yes. In the absence of any known adjustments to either the Base Year or the Test Year, it is expected that inflation accounts, net of any productivity increases, for any increase. A basic question of whether the inflation rate used by the utility is appropriate always remains, however. In this case, Staff does not take issue with the escalation rate used by the Company. Staff has identified potential issues with some of Idaho Power's non-escalation adjustments to its 2022 Base Year expense.

**Q. How did Staff analyze A&G expenses?**

A. Staff analyzes the non-labor components of A&G by FERC account. To determine the reasonableness of the Company's Test Year forecast for non-labor A&G, Staff often relies on its analysis of actual A&G expense in previous years and compares Base Year actuals to the Company's forecasted Test Year expense. OAR 860-027-0045 specifies that IPC must adhere to the Uniform System of Accounts (USOA) adopted by FERC for accounting. Under USOA, expense for A&G is recorded in FERC Accounts 920–935.

To facilitate its review of the labor and non-labor components of A&G, Staff created Standard Data Requests (SDRs) that each utility must answer at the time it files a general rate case (GRC). SDR 057 requires the Company to provide all of its actual non-labor expenses and revenues, by FERC account, for the Base Year. SDR 058 requires the Company to provide forecasted summaries of expense for the Test Year, by FERC account. SDR 058 also requires the Company to provide all expenses and revenues, by FERC account, for the Base Year and the preceding two years. SDR 057 instructs that only non-labor expenses be reported, and SDR 058 instructs utilities to separately report labor and non-labor expenses.

**Q. How did Staff review IPC's non-labor A&G expenses at issue in Testimony?**

A. Staff relied on IPC's actual expenses recorded in the FERC accounts to review year-to-year changes in non-labor expenditures for major functional areas by FERC account. Staff issued 17 DRs in total and used the responses as part of the overall analysis.

**Q. What are Staff's conclusions related to the significant A&G FERC accounts?**

A. Staff's conclusions are noted below by FERC account and detail any proposed adjustments. For FERC Accounts 920 (A&G Salaries), 922 (A&G Transfer Credit), and 926 (P&B non-labor) the changes were immaterial. For FERC Accounts 921 (A&G Office Supplies), 923 (A&G Outside Services), 924 (A&G Property Insurance), 925 (A&G Injuries and Damages), 930 (Miscellaneous General Expense), and 935 (Maintenance of General Plant Expense), Staff reviewed the Company's proposals and they all are in-line with the Company's approach to escalate via inflation factors and are summarized in Table 1 below. The values provided below are Oregon-allocated amounts. Any additional Staff information is provided after Table 1.

| Table 1 | | | | | |
|---|---|---|---|---|---|
| | | | | | |
| Ferc Acct | Description | 2024 | 2022 | $ Change | % Change |
| 921 | Office Supplies | $ 680,115 | $ 637,452 | $ 42,663 | 7% |
| 923 | Outside Services | $ 400,687 | $ 374,825 | $ 25,863 | 7% |
| 924 | Property Insurance | $ 192,339 | $ 141,312 | $ 51,027 | 36% |
| 925 | Injuries and Damages | $ 529,941 | $ 274,417 | $255,524 | 93% |
| 930 | Misc. General Exp | $ 174,013 | $ 198,883 | $ (24,869) | -13% |
| 935 | Maint of General Plant | $ 304,302 | $ 284,695 | $ 19,606 | 7% |

**Q. What are Staff's conclusion regarding the expense categories for which Idaho Power adjusted the Base Year amounts?**

A. For FERC 925, Idaho Power adjusted its 2022 Base Year to include incremental costs incurred in 2023 related to managing wildfire risk. The Company obtained approval to defer incremental costs in 2023 related to Wildfire Mitigation and risk.[4] In its application to defer, the Company noted it anticipated incurring incremental costs related to Property Insurance in response to the Commission's orders requiring Wildfire Mitigation Planning and the need to implement current and best practices to reduce wildfire risk.[5] The Company expects these expenses to continue going forward, so made an adjustment to the 2022 Base Year amount to reflect a new normal level of expenses.

Staff does not have an adjustment to IPC's proposed increase in Property Insurance but has outstanding DRs related to the Company providing proof of actual 2023 WM expenses matching its predicted trend.

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4 *In the Matter of Idaho Power Company, Application for a Deferred Accounting of Costs Associated with Wildfire Mitigation Activities*, UM 2270, Order No. 24-010 (January 10, 2024).

5 Idaho Power Application for a Deferred Accounting of Costs Associated with Wildfire Mitigation Activities, UM 2270, December 29, 2022.

For FERC 925, the Company also made a significant upward adjustment to its Base Year expense for Injuries and Damages related to Wildfire Mitigation activities to obtain its Test Year expense.

Staff does not have an adjustment to the Test Year expense for Injuries and Damages, at this time, but has outstanding DRs related to the Company providing proof of actual 2023 WM expenses matching its predicted trend.

Finally, for FERC 930, the Company removed all General Advertising Expenses and had a reduction of Misc. General Expense. These two reductions were applied prior to adjusting for inflation, resulting in the noted decrease.[6]

**Q. What is Staff's conclusion regarding FERC Account 928, Regulatory Commission Expense?**

A. The Non-Labor increase of $15,000 from 2022 to 2024 in Regulatory Commission Expense is in line with the Company's approach to increase expense by the inflation rate.

Related to the $1 million reduction noted above, the Company removed an error from its 2022 financial records that allocated over $1 million of regulatory expenses to Oregon that belonged solely in Idaho. There is no amount related to this error in the Oregon allocation amounts for the Test Year.[7]

Staff has no adjustment to this account.

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[6] Staff/502 – IPC Response to Staff DR 126.
[7] Staff/502 – IPC Response to Staff DR 353.

## ISSUE 2. PENSION AND BENEFITS

**Q. Please summarize Staff's adjustments for P&B expense.**

A. Staff recommends an adjustment to 2024 P&B of $(148) thousand. This adjustment may change as a result of reviewing other parties' testimonies filed in this docket and with additional information provided in outstanding data requests.

**Q. Please summarize the Company's explanation of the P&B increase in the application.**

A. The Company proposed no change to the Oregon portion of the pension expense of $880 thousand.

For benefits, the Company originally stated that the amount was calculated using a three-year average of labor loadings for August year-to-date for 2022–2024, then applied that percentage to the actual 2023 labor loadings to estimate 2024 labor loadings.[8]

After receiving a DR from Staff, the Company provided updated information that included actual 2023 benefit costs and an escalation factor based on its known 2024 rates.[9] Staff's adjustment is based on using the new information in place of what was originally filed.

**Q. Does Staff accept this method?**

A. In this case, yes. The updated amounts fall within a range that is more appropriate for the category.

8 Staff/502, IPC Response to Staff DR 354
9 Staff/502, IPC Response to Staff DR 464, Attachment

**Q. Does Staff have concerns about the increase to benefits?**

A. No. The Company appears to be managing Benefit expenses appropriately.

**Q. What information has the Company provided related to benefits?**

A. Both in its testimony and in response to Staff DRs, the Company provided extensive information detailing its approach to determining appropriate benefits to offer, benchmarking strategy, retirement benefit strategy and internal benefits review presentations—all of which comprise its Total Rewards offering to employees.

Without reproducing dozens of pages of testimony and internal presentations, it is clear that the Company regularly reviews and benchmarks against its peers each benefit at the individual level (vacation time, pension, medical, etc.).

## SUMMARY

**Q. Please summarize your recommendations, identifying any adjustments you propose.**

A. Related to the Non-Labor A&G accounts, Staff proposes no adjustment at this time.

Related to P&B expenses, Staff proposes a reduction of $(148) thousand.

As noted earlier in my testimony, my recommendations may change based on further review and as informed by the testimonies offered by other parties.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: RUSS BEITZEL

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 501

## WITNESS QUALIFICATION STATEMENT

**March 25, 2024**

## WITNESS QUALIFICATIONS STATEMENT

NAME: Russell (Russ) Beitzel

EMPLOYER: Public Utility Commission of Oregon

TITLE: Program Manager
Rates and Telecommunications Section

ADDRESS: 201 High Street SE, Suite 100
Salem, OR. 97301

EDUCATION: Bachelor of Science in Accounting, Otterbein University

EXPERIENCE:

I have been employed with the Public Utility Commission of Oregon since 2018. I am currently the Program Manager of the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program. I have analyzed and addressed numerous issues including tariff changes, property sales, affiliated interest transactions, revenue requirement calculations, deferred tax calculations, rate spread, and rate design. I have also served as case manager on multiple water rate cases, and have provided testimony in UW 185, UW 182, UW 175, UW 177, UE 374, UG 388, and UE 416.

Additionally, I worked at Ashland, Inc. for twenty years as a manufacturing and corporate accountant and business analyst for a business unit with approximately one billion dollars in global annual sales. My accountant duties included product cost analysis, general ledger account analysis, SOX compliance, and internal and external audit compliance. My analyst duties included budgeting, forecasting, financial statement analysis, acquisition tracking, and division financial support for a global business unit.

CASE: UE 426
WITNESS: Russ Beitzel

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 502

## DR Responses

**March 25, 2024**

**TOPIC OR KEYWORD: O&M Expenses**

**STAFF'S DATA REQUEST NO. 353:**

Based on the response to staff DR 129, in the Company's attachment:

Related to the 2022 adjustment in Reg. Commission Expenses (FERC 928.303), please provide a narrative explanation for:

a. The negative adjustment; and
b. If any portion of the adjusted amount will be requested or automatically calculated to be added back later during the rate case in this or another account.
c. If the answer to b. is yes, please provide the amount and in which FERC account/cc.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 353:**

a. As described in the testimony of Ms. Jeppsen (Idaho Power/900 page 8), an adjustment of $1,381,742, reducing the 2022 Base year amount allocated to Oregon, was made due to an accounting error. The expenses had been recorded to 928.303 (Oregon Regulatory Expense) and should have been recorded to 928.203 (Idaho Regulatory Expense). Details for this adjustment were provided in Idaho Power/Jeppsen/901/ Workpaper 6 and in response to Staff's Data Request No. 263.

b. No, the $1,381,742 removed from 928.303 and moved to account 928.203 is direct assigned to Idaho and will not be added back in this rate case.

c. N/A

UE 426
Idaho Power Company's Response to
Staff's Data Request Nos. 125-132

**Topic or Keyword:**

**STAFF'S DATA REQUEST NO. 126:**

Using the data from SDR 58B found in the table below, please provide a narrative explanation for the three highlighted cells which show discrepancies between Staff's calculation using the growth rates provided in the application[1] and the Company's proposed amounts for Accounts 924, 925 and 930.

| | Using IP's growth rates in application | Company | Staff | Staff | Company |
|---|---|---|---|---|---|
| | 2024 IP - 2024 Staff | 2024 | 2024 2.7% | 2023 4.1% | 2022 |
| 920 | (0) | 344 | 344 | 335 | 321 |
| 921 | (1,389) | 680,115 | 681,504 | 663,587 | 637,452 |
| 922 | 0 | (1,431) | (1,431) | (1,393) | (1,338) |
| 923 | (41) | 400,687 | 400,728 | 390,193 | 374,825 |
| 924 | 41,261 | 192,339 | 151,078 | 147,106 | 141,312 |
| 925 | 236,560 | 529,941 | 293,381 | 285,668 | 274,417 |
| 926 | (781) | 86,961 | 87,743 | 85,436 | 82,071 |
| 928 | (2,818) | 277,849 | 280,667 | 273,288 | 262,525 |
| 930 | (38,613) | 174,013 | 212,627 | 207,037 | 198,883 |
| 935 | (68) | 304,302 | 304,370 | 296,368 | 284,695 |

**RESPONSE TO STAFF'S DATA REQUEST NO. 126:**

For account 924, the 2022 total Company actuals were $3,497,798. A Wildfire Mitigation Plan Adjustment of $955,737 (see 900/Jeppsen/7/Table 1 and Jeppsen Workpaper 12) brought 2022 total Company base to $4,453,536. This adjustment is needed to remove the effect of the authorized IPUC Wildfire Mitigation Plan deferrals in order to get to the appropriate level of system level costs. When adding the inflation adjustments for 2023 and 2024, the Total Company amount is $4,760,825. The Company used the allocation factor of 4.04% to arrive at the Total included in Filed Rate case for account 924 to $192,339.

For account 925, the 2022 total Company actuals were $6,393,766. A Wildfire Mitigation Plan Adjustment of $5,156,619 (see 900/Jeppsen/7/Table 1 and Jeppsen Workpaper 12) brought 2022 total Company base to $11,550,385. This adjustment is needed to remove the effect of the authorized IPUC Wildfire Mitigation Plan deferrals in order to get to the appropriate level of system level costs. When adding the inflation adjustments for 2023 and 2024, the Total Company amount is $12,026,066. The Company used the allocation factor of 4.29% to arrive at the Total included in Filed Rate case for account 925 to $529,941.

For account 930, the 2022 total Company actuals were $4,633,863. Reductions of $(476,066) (see 901/Jeppsen/6 – $(476,066) is representative of non-labor dollars) for General Advertising Expense adjustment and $(365,067) (see 901/Jeppsen/6) for Miscellaneous General Expenses brought 2022 total Company base to $3,792,730. When adding the inflation adjustments for 2023 and 2024, the Total Company amount is $4,054,424. The Company used the allocation factor of 4.29% to arrive at the Total included in Filed Rate case for account 930 to $174,013.

[1] See 1000/Larkin/7.

**TOPIC OR KEYWORD: O&M Expenses**

**STAFF'S DATA REQUEST NO. 354:**

Based on the response to staff DR 131, in the Company's attachment:

Please provide a narrative explanation for:

a. The increase from 2022 to 2024;
b. Why it's above the proposed rate case inflation factors; and
c. A revised spreadsheet, similar to the Company's response to Staff DR 132, showing detailed account information and description for the years previously provided.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 354:**

a. The $60.6M of operations and maintenance ("O&M") labor loadings (benefits and employer paid taxes) included in the 2024 Test Year is a function of forecasted O&M labor. Idaho Power calculated the projected 2024 O&M labor loadings by first calculating the average three-year historical 2020-2022 August year-to-date actual O&M labor costs as a percentage of the 3-year total actual O&M labor costs, which was determined to be 66.8%. This percentage was then applied to the actual August 2023 year-to-date O&M labor loadings to estimate the total 2024 O&M labor loading costs.

b. Please see response a. above.

c. Please see Response to Staff Request No. 354 – Attachment.

Response to Staff Request No. 464 - Attachment

| | | | | 4% * |
|---|---|---|---|---|
| **DCE** | **DCE** | **Actual 2022** | **Actual 2023** | **2024 Restated** |
| 500001 | 500001 Opr Pwr Prd Stm Gnr S&e-bridge | 69,804 | 86,504 | 89,965 |
| 500002 | 500002 Opr Pwr Prd Stm Gnr S&e-board | 29,326 | 37,948 | 39,466 |
| 500003 | 500003 Opr Pwr Prd Stm Gnr S&e-valmy | 43,634 | 41,997 | 43,676 |
| 506003 | 506003 Opr Pwr Prd Stm Gnr Msc-valmy | 794 | 3,094 | 3,217 |
| 535000 | 535000 Opr Pwr Prd Hyd Pwr Gnr S&e | 1,508,748 | 1,531,838 | 1,593,111 |
| 536000 | 536000 Opr Pwr Prd Hyd Pwr Gnr Wtr Fp | 55,526 | 54,106 | 56,270 |
| 536001 | 536001 Opr Pwr Prd Hyd Cloudseeding | 265,910 | 255,525 | 265,746 |
| 537000 | 537000 Opr Pwr Prd Hyd Pwr Gnr Hyd | 2,237,851 | 2,345,480 | 2,439,299 |
| 538000 | 538000 Opr Pwr Prd Hyd Pwr Gnr El Pl | 538,281 | 605,611 | 629,835 |
| 539000 | 539000 Opr Pwr Prd Hyd Pwr Gnr Misc | 1,233,806 | 1,352,676 | 1,406,783 |
| 541000 | 541000 Mnt Pwr Prd Hyd Pwr Gnr S&e | 31,195 | 61,556 | 64,018 |
| 542000 | 542000 Mnt Pwr Prd Hyd Pwr Gnr Strc | 215,469 | 213,911 | 222,467 |
| 543000 | 543000 Mnt Pwr Prd Hyd Pwr Gnr | 90,693 | 113,171 | 117,698 |
| 544000 | 544000 Mnt Pwr Prd Hyd Pwr Gnr El Pl | 625,447 | 630,776 | 656,007 |
| 545000 | 545000 Mnt Pwr Prd Hyd Pwr Gnr Msc Pl | 819,691 | 873,378 | 908,314 |
| 546000 | 546000 Opr Pwr Prd Othr Pwr Gnr S&e | 188,252 | 217,931 | 226,648 |
| 548000 | 548000 Opr Pwr Prd Othr Gnr | 933,628 | 1,046,354 | 1,088,209 |
| 549000 | 549000 Opr Pwr Prd Othr Gnr Msc | 124,506 | 175,924 | 182,961 |
| 552000 | 552000 Mnt Pwr Prd Othr Pwr Strc | 18,109 | 16,735 | 17,404 |
| 553000 | 553000 Mnt Pwr Prd Othr Pwr Gnr Gn&el | 20,429 | 14,981 | 15,580 |
| 554000 | 554000 Mnt Pwr Prd Oth Pwr Msc | 138,640 | 144,414 | 150,191 |
| 557000 | 557000 Opr Pwr Prd Oth Pwr Sp Oth Prd | 1,562,987 | 1,723,137 | 1,792,063 |
| 560000 | 560000 Opr Trns S&e | 833,919 | 826,050 | 859,092 |
| 561200 | 561200 Opr Trns-Load Dsptch-Monitor | 841,676 | 1,020,751 | 1,061,581 |
| 561300 | 561300 Opr Trns-Load Dsptch-Svc/Schd | 158,475 | 127,480 | 132,579 |
| 561700 | 561700 Opr Trns-Gen Intercnct Study | 46,903 | 85,430 | 88,848 |
| 562000 | 562000 Opr Trns Station Expenses | 684,314 | 676,308 | 703,360 |
| 563000 | 563000 Opr Trns Overhead Lines | 152,739 | 191,148 | 198,794 |
| 568000 | 568000 Mnt Trns S&e-mnt Trns S | 31,703 | 52,758 | 54,868 |
| 569100 | 569100 Mnt Trns Computer Hardware | 8,414 | 7,548 | 7,850 |
| 569200 | 569200 Mnt Trns Computer Software | 492,322 | 499,407 | 519,383 |
| 569300 | 569300 Mnt Trns-Comm Equipment | 1,918 | 1,715 | 1,783 |
| 570000 | 570000 Mnt Trns St Equp | 789,655 | 924,531 | 961,512 |
| 571000 | 571000 Maint Trans O/h Lines | 296,574 | 355,554 | 369,776 |
| 573000 | 573000 Mnt Trns Msc Pl-other | 1,256 | 367 | 382 |
| 580000 | 580000 Opr Dstr Super & Engineering | 1,068,704 | 1,194,915 | 1,242,711 |
| 581000 | 581000 Opr Dstr Load Dispatching | 1,697,873 | 1,923,903 | 2,000,860 |
| 582000 | 582000 Opr Dstr Station Expenses | 319,533 | 336,070 | 349,512 |
| 583000 | 583000 Opr Dstr Overhead Line Exp | 649,639 | 656,542 | 682,803 |
| 584000 | 584000 Opr Dstr Undgrnd Ln Exp | 255,746 | 320,124 | 332,929 |
| 585000 | 585000 Opr Dstr Str Lt & Sgnl | 7,909 | 784 | 815 |
| 586000 | 586000 Opr Dstr Mtr Exp | 1,235,455 | 1,475,619 | 1,534,643 |
| 587000 | 587000 Opr Dstr Cust Installation | 263,238 | 306,567 | 318,829 |
| 588000 | 588000 Opr Dstr Msc Exp | 1,043,906 | 1,102,435 | 1,146,533 |
| 590000 | 590000 Mnt Dstr S&e | 3,355 | 2,790 | 2,902 |
| 592000 | 592000 Mnt Dstr St Equp | 930,469 | 1,168,164 | 1,214,890 |
| 593000 | 593000 Mnt Dstr Overhead Lines | 1,817,077 | 1,956,566 | 2,034,829 |
| 594000 | 594000 Mnt Dstr Underground Lines | 121,793 | 128,335 | 133,468 |
| 595000 | 595000 Mnt Dstr Ln Trnsfmrs | 8,880 | 8,857 | 9,212 |
| 596000 | 596000 Mnt Dstr Street Light & Signal | 47,256 | 35,484 | 36,904 |

Response to Staff Request No. 464 - Attachment

| | | | | 4% * |
|---|---|---|---|---|
| **DCE** | **DCE** | **Actual 2022** | **Actual 2023** | **2024 Restated** |
| 597000 | 597000 Mnt Dstr Mtrs | 240,172 | 282,666 | 293,973 |
| 598000 | 598000 Mnt Dstr Msc-nt Grd Lt | 29,487 | 39,305 | 40,878 |
| 901000 | 901000 Opr Cust Acts & Srv Exp-sprvs | 255,345 | 278,718 | 289,867 |
| 902000 | 902000 Opr Cust Acts & Srv Mtr Rdng | 437,338 | 438,094 | 455,618 |
| 903000 | 903000 Opr Cust Records & Coll Exp | 3,362,331 | 3,576,362 | 3,719,417 |
| 907000 | 907000 Opr Cust Srv-supervision | 295,025 | 295,619 | 307,444 |
| 908000 | 908000 Opr Cust Srv-cust Assist Exp | 1,663,198 | 2,078,328 | 2,161,462 |
| 910000 | 910000 Opr Cust Srv & Info | 114,943 | 140,117 | 145,721 |
| 920000 | 920000 Opr Admin & General Salaries | 19,232,808 | 21,431,106 | 22,288,350 |
| 921000 | 921000 Opr A & G Office Supp & Exp | 277 | 2,941 | 3,059 |
| 921002 | 921002 Opr A&g - Airplane Clearing | 110,019 | 175,344 | 182,358 |
| 922999 | 922999 P/r Bene Trnsfrd-cr | -35,100,762 | -42,627,793 | -44,332,905 |
| 924000 | 924000 Opr A&g Prpty Ins-other | 138,412 | 154,786 | 160,977 |
| 925000 | 925000 Opr A&g Injrs & Dmgs | 49,796 | 53,060 | 55,183 |
| 926104 | 926104 Opr A&g Emp Pen & Ben-awrd/gft | 525,306 | 471,776 | 490,647 |
| 926110 | 926110 Opr A&g Emp Pen & Ben-lf Ins | -799,881 | -604,254 | -628,424 |
| 926111 | 926111 Opr A&g Emp Pen & Ben-ret Life | 78,655 | 213,296 | 221,828 |
| 926112 | 926112 Opr A&g-emp Pen & Ben-tuition | 79,422 | 62,325 | 64,817 |
| 926113 | 926113 Opr A&g-emp Pen & Ben-Med-Ibnr | 512,316 | 654,839 | 681,033 |
| 926114 | 926114 Opr A&g-emp Pen & Ben-Den-Ibnr | -23,544 | 4,732 | 4,921 |
| 926118 | 926118 OPR A&G EMP PEN & BEN-HSA EC | 1,837,808 | 1,883,064 | 1,958,387 |
| 926119 | 926119 OPR A&G EMP PEN & BEN-VISION | 184,427 | 294,813 | 306,605 |
| 926120 | 926120 Opr A&g Emp Pen & Ben-medical | 20,377,864 | 23,425,065 | 24,362,068 |
| 926122 | 926122 Opr A&g Emp Pen & Ben-ret Med | 498,123 | 1,729,559 | 1,798,741 |
| 926130 | 926130 Opr A&g Emp Pen & Ben-disablty | 445,989 | 984,212 | 1,023,581 |
| 926141 | 926141 Opr A&g Emp Pen & Benefits-esp | 8,780,167 | 9,832,639 | 10,225,945 |
| 926150 | 926150 Opr A&g Emp Pen & Ben-dental | 1,763,978 | 1,734,166 | 1,803,533 |
| 926151 | 926151 Opr A&g Emp Pen & Ben-ret Den | 219,327 | 472,730 | 491,639 |
| 926160 | 926160 Opr A&G Emp Pen & Ben-Fbap Adm | 20,906 | 20,402 | 21,218 |
| 926180 | 926180 Opr A&g Emp Pen & Ben-asst Pg | 124,235 | 128,689 | 133,836 |
| 926320 | 926320 Opr A&g Emp Pen & Ben-med Remb | -118,386 | -132,371 | -137,665 |
| 926350 | 926350 Opr A&g Emp Pen &ben-dent Remb | -9,183 | -10,384 | -10,799 |
| 930100 | 931000 Opr A&g Msc Gen Ex-rents | 4,732 | 4,529 | 4,710 |
| 930200 | 930200 Opr A&g Msc Gnrl Exp | 67,011 | 62,407 | 64,903 |
| 935000 | 935000 Mnt A&g General Plant | 367,477 | 439,716 | 457,305 |
| Total Benefits | | 50,328,567 | 54,923,850 | 57,120,804 |
| Percentage Increase | | | 9% | 4.0% |

*Actual 2024 GWA effective 12/23/23

CASE: UE 426
WITNESS: Bret Farrell

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 600

# OPENING TESTIMONY
## Uncollectible Expense, Other Operating Revenues, And Bill Discount Program

## March 25, 2024

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

A. My name is Bret Farrell. I am a Senior Utility and Energy Analyst 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 qualifications statement is found in Exhibit Staff/601.

**Q. What is the purpose of your testimony?**

A. I provide background, analysis, and recommendations regarding the Company's proposal for Uncollectible Expense, Other Operating Revenues, and Bill Discount Program.

**Q. Did you prepare any exhibits for this docket?**

A. Yes. I prepared the following supporting exhibits:

- Staff Exhibit 601 – Witness Qualifications
- Staff Exhibit 602 – IPC Response to Staff Data Request 274
- Staff Exhibit 603 – Staff Workpaper
- Staff Exhibit 604 – Staff Adjustment Workpaper

B. **How is your testimony organized?**

A. My testimony is organized as follows:

Issue 1. Uncollectible Expense ..... 3
Issue 2. Other Operating Revenues ..... 8
Issue 3. Bill Discount Program ..... 10
Issue 4. Other Issues ..... 26

**Q. Could there be changes or updates to Staff's position and recommendations?**

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

## ISSUE 1. UNCOLLECTIBLE EXPENSE

**Q. Please provide a summary of the Commission's historical treatment of uncollectible expense.**

A. It is a long-standing policy of Commission Staff to apply a three-year average methodology to determine the Test Year uncollectible expense for a utility's revenue requirement.[1] Commission Staff also examine other evidence to determine whether this approach results in a reasonable forecasted Test Year result. The amount included in a utility's revenue requirement for uncollectible expense is revenue sensitive because it depends on the amount of forecasted revenue. That is, the total uncollectible expense included in the revenue requirement is a function of the Test Year revenue and the uncollectible rate.

**Q. Describe the Company's proposal for Test Year uncollectible expense.**

A. The Company's 2024 Test Year forecast for uncollectible expense is $461,506, which is $274,672 higher than the 2022 uncollectible expense on an Oregon jurisdictional basis.[2]

**Q. Does the Company use the Staff three-year average methodology to derive its proposal for the Test Year uncollectible expense?**

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[1] *See, e.g., In the Matter of Avista Corporation*, Docket No. UG 246, Order No. 14-015 at 3 (January 21, 2014) and *In the Matter of Avista Corporation*, Docket No. 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*, Docket No. 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*, Docket No. 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).

[2] Idaho Power/1002, Larkin/13.

A. No. The Company states in testimony that the Test Year uncollectible expense is determined by first calculating the average three-year historical 2020-2022 August year-to-date actual Oregon net write-off costs as a percentage of the three-year total year actual Oregon net write-off costs, which was determined to be 58.6 percent. This percentage was then applied to the actual August 2023 year-to-date Oregon net write-off costs of $270,396 to estimate the total 2024 Oregon net write-off costs of $461,506.[3]

**Q. Please simply summarize the Company's proposed methodology.**

A. The Company's proposed methodology calculates each month's average uncollectible expense over the previous three years and based off these figures estimates that through August 2023 the Company has only collected 58.3 percent of the expected uncollectible expense for 2023 ($270,396). The remaining 41.4 percent ($191,110) is calculated based on the 2023 collections through August and added to the original 58.3 percent to estimate that the Company's Oregon allocated uncollectible expense for 2023 ($461,506). The total estimated uncollectible expense for 2023 using this methodology is then determined to be the Company's estimate for 2024 Test Year uncollectible expense.[4]

**Q. Does Staff agree with the Company's proposed methodology?**

A. No. Staff has several concerns with the Company's approach.

[3] Idaho Power/1002, Larkin/13.
[4] Staff/602, IPC Response to Staff Data Request 274.

First, Staff believes the Company's proposed methodology relies too heavily on data from one year, 2023, as a central component of their estimation methodology.[5] Additionally, Staff finds the Company's methodology of attempting to estimate the percentage of uncollectible expense collected by month to be overly complicated and unnecessary. Further, the Company fails to adequately justify the use of this methodology by providing any historical evidence to support the accuracy of their methodology.

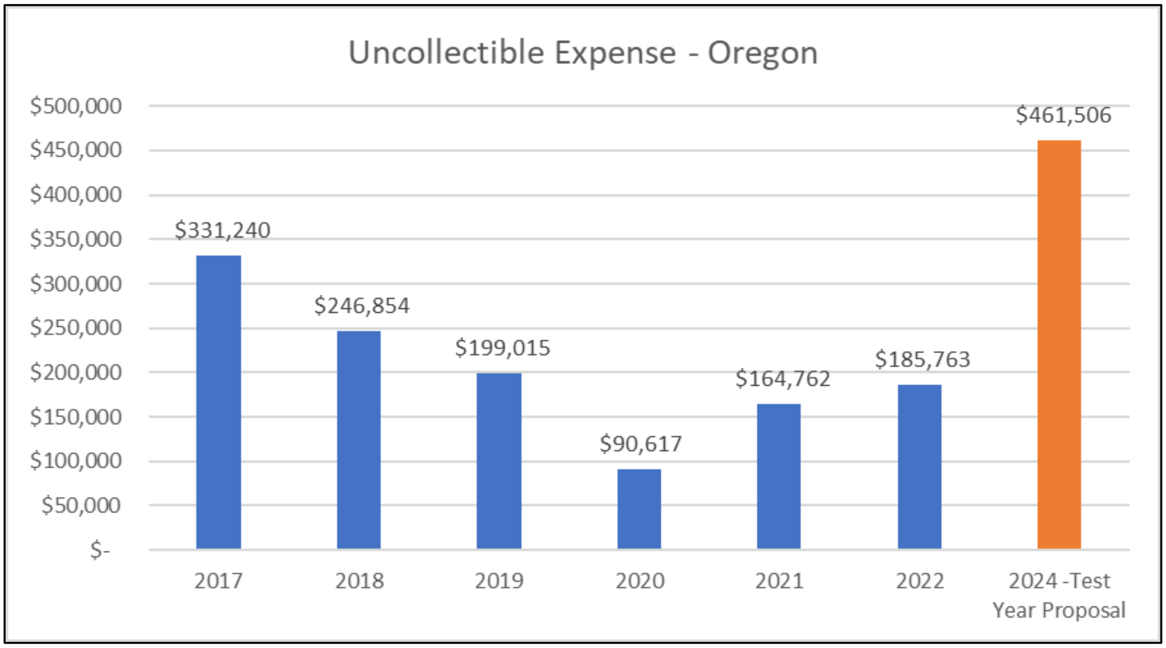
Finally, the Company's proposed 2024 test year uncollectible expense would be a 127 percent increase over the 2022 test year expense. Staff finds this to be an outsized increase in uncollectible expense based off the historic trend for the Oregon service territory (See Chart 1).[6]

**Q. Please explain why the Staff three-year average methodology is a more appropriate approach.**

A. A rolling-average methodology, such as the three-year average approach is meant to track the overall trend of the uncollectible rate while smoothing out year-over-year variances. By taking a rolling-average, underlying changes to the uncollectible rate are gradually incorporated into the test year forecast. This ensures that key variables influencing uncollectible expense are factored into the test-year forecast and that the effect of anomalous events are limited. The rolling-average also requires no complex modeling, no tenuous assumptions, and is relatively simple and straight-forward.

[5] Staff/602, IPC Response to Staff Data Request 274.
[6] Staff/603, Staff Workpaper.

**Chart 1**

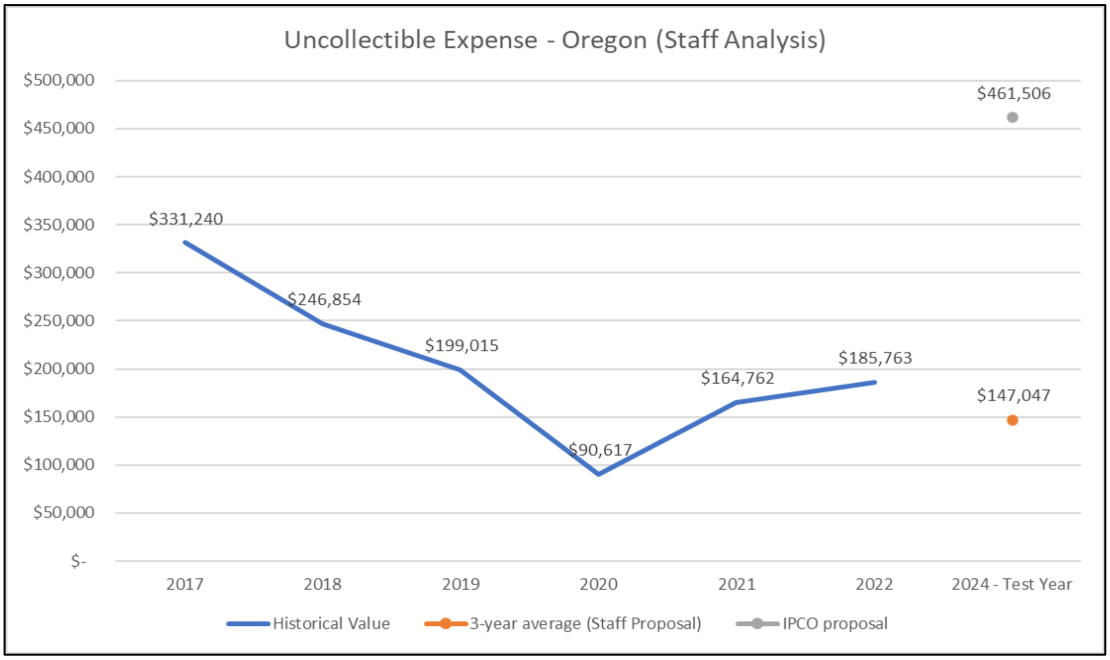



**Q. What is Staff's proposed adjustment for the Test Year uncollectible expense?**

A. Staff proposes using the three-year average of uncollectible expense between 2020-2022, which would be a value of $147,047 (see Chart 2).[7] Therefore, Staff proposes a decrease to the Company's Test Year uncollectible expense of $314,459.[8]

[7] Staff/603, Staff Workpaper.
[8] Staff/604, Staff Adjustment Workpaper.

**Chart 2**


Uncollectible Expense - Oregon (Staff Analysis)
$500,000
$450,000
$400,000
$350,000
$300,000
$250,000
$200,000
$150,000
$100,000
$50,000
$-
$461,506
$331,240
$246,854
$199,015
$185,763
$164,762
$147,047
$90,617
2017
2018
2019
2020
2021
2022
2024 - Test Year
Historical Value
3-year average (Staff Proposal)
IPCO proposal

## ISSUE 2. OTHER OPERATING REVENUES

**Q. Please summarize this issue.**

A. The Company forecasts revenue for the Test Year in various categories as a component of a general rate case. FERC accounting rules classify revenue into several different categories. In this testimony, Staff evaluates the Test Year Other Operating Revenues (FERC Accounts 451, 454, 456). Other Operating Revenues are a substantive component of a rate case in that the revenues function as an offset to expense and reduces the overall revenue requirement.

In this case, the Company proposes Test Year Other Operating Revenues of $80.9 million, which is a decrease of $4.4 million from the 2022 Base Year actuals.[9] The Company arrives at its Test Year forecast by using historic revenues to forecast 2024 revenues and making pro-forma adjustments. The Company also makes adjustments based on category specific information, such as the expiration of contracts.

**Q. How does the Company explain the reduction in Miscellaneous Operating Revenues in the Test Year?**

A. The Company cites two primary downward adjustments to its 2022 actuals:

- FERC Account 454: ($651,738) The Company forecasts decreases in facilities charges and water district payments and the termination of a contract for dark fiber rents.[10]

[9] Idaho Power/901, Jeppsen/1.
[10] Idaho Power/1000, Larkin/5.

- FERC Account 456: ($7,025,022) The Company forecasts a large decrease in wheeling revenues. The main driver of the Company's anticipated decrease to Other Long-Term firm revenues is the expiration of a 271 MW contract.[11]

**Q. Please explain Staff's analysis of this issue.**

A. Staff has reviewed the Company's historic revenue data, various methodologies around forecasting Other Operating Revenue categories, and the assumptions made by the Company in forecasting these revenues.

**Q. Has Staff finalized its review of this issue?**

A. No. Staff is still in the process of evaluating the accuracy and validity of the Company's Test Year forecast for certain other operating revenue categories. Staff is trying to ensure that the Test Year forecast aligns with expectations and reflects a realistic projection of future revenues.

**Q. Does Staff recommend an adjustment at this time?**

A. No. At this time, Staff has no adjustment to Other Operating Revenues.

[11] Idaho Power/1002, Larkin/10.

## ISSUE 3. BILL DISCOUNT PROGRAM

**Q. Please provide background information on investor-owned utility bill discount programs in Oregon.**

A. On January 1, 2022, HB 2475 became effective. The bill expanded language in ORS 757.230 to include additional factors the Commission may consider when establishing rate classifications, such as the "differential energy burdens on low-income customers and other economic, social equality or environmental justice factors that affect affordability for certain classes of utility customers." Commission HB 2475 implementation is currently focused on interim action to provide customers near-term relief under the new authority, which is to be followed by a longer-term investigation that will more comprehensively explore and establish the Commission's policies for differential rate and program design and administration. Since HB 2475 became effective, Staff has been engaged with each of Oregon's six investor-owned utilities to implement interim bill discount programs that address low-income energy burden.

**Q. Please provide a summary of the Commission's historical treatment of bill discount programs.**

A. Idaho Power is Oregon's last investor-owned utility to propose a bill discount program. The Commission has approved interim bill discount programs for each of Oregon's other investor-owned utilities in the following dockets:

- ADV 1365 – Portland General Electric,
- ADV 1412 – PacifiCorp,
- ADV 1390 – Northwest Natural,

- ADV 1409 – Cascade, and
- ADV 1410 – Avista.

Staff has previously asked utilities to file these programs as advice filings to provide for a more inclusive and accessible process from which parties can engage. Staff has found this venue and process to allow for greater coordination between Staff, stakeholders, and the Company and promote unanimous agreement on the program design before final approval.

**Q. Please summarize the Company's coordination efforts between Staff and stakeholders**

A. The Company states that it has engaged in discussion and workshops since late 2021 concerning HB 2475 implementation and bill discount program design as part of Docket No. UM 2114 and subsequently Docket No. UM 2211. Efforts by the Company have included hosting five virtual workshops, which highlighted concerns about service area economics and customer base and soliciting feedback on potential program design ideas. The Company has also engaged in informal discussions with Staff and stakeholders around program design challenges. Additionally, the Company held workshops that examined the results of their Energy Burden Assessment, which was conducted in March 2023.

**Q. Please summarize the Company's bill discount program proposal.**

A. The Company's Bill Discount Program is structured to offer residential customers ongoing monthly bill discounts determined by household income and estimated energy burden. Residential customers who demonstrate or self-declare that their gross household income, adjusted for household size, is at or below 60 percent of State Median Income (SMI), and whose estimated energy burden is calculated to be greater than six percent for electrically heated homes or three percent for non-electrically heated homes, will be provided a discount of up to 60 percent towards applicable charges. The Company is proposing a three-tier discount structure for customers with eligibility for each tier determined by their adjusted household income (see Table 1).[12]

**Table 1**

| | Adjusted Household Income | Discount Towards Eligible Charges |
|---|---|---|
| Tier 1 | Up to 20% SMI | 60% discount |
| Tier 2 | >20% up to 40% SMI | 25% discount |
| Tier 3 | >40% up to 60% SMI | 10% discount |

**Q. Please describe the Staff's review of the program proposal.**

A. In Docket No. UM 2211, Staff published a set of baseline criteria for evaluating utility bill discount proposals that incorporates feedback from utilities and other stakeholders. Staff provided this upfront, transparent information about its minimum evaluation criteria to facilitate timely and meaningful development of interim actions. Staff's approach to developing the baseline evaluation criteria was to first identify high level areas that would benefit from standardization and then reflect on feedback from prior stakeholder engagements and literature for

[12] Idaho Power/1300, Aschenbrenner/25.

practicable design elements that could be applied in interim designs. As intended, Staff's review of the Company's proposal was oriented around said baseline evaluation criteria. The five categories that Staff centers its review on are as follows:

- Eligibility,
- Level of relief,
- Tracking and accounting,
- Bundling, and
- Outreach and engagement.

**Q. Please describe the Company's proposal for Bill Discount Program eligibility.**

A. Eligibility for the Company's program is determined by a customer's gross household income adjusted for household size and the household's energy burden, which is estimated by the Company. A customer must demonstrate or self-declare that their income is at or below 60 percent SMI and additionally have an energy burden that is greater than six percent for electrically heated homes or three percent for non-electrically heated homes. A customer's energy burden will be calculated using a Company-created web-based portal that aggregates each requesting customer's annual electric bill for their declared primary residence (based on the location and/or customer's most recent 12 months' billings) and compares such amount against the household's customer-provided gross income, occupancy, and primary heating characteristics. The Company's proposal does not include automatic enrollment of customers receiving bill assistance funds from the Low-Income Home Energy Assistance Program (LIHEAP). Once eligibility is determined, the Company, a Community Action Partnership (CAP) agency, or Community Based Organization (CBO) will have the ability to enroll the customer in the bill discount program through the Company's web-based portal, where the eligible discount amount will be applied beginning with the customer's next billing cycle.[13]

**Q. Please describe Staff's review of the Company's eligibility proposal.**

A. Staff has two primary concerns with the Company's eligibility proposal. First, Staff believes low-barrier enrollment practices such as self-certification and automatic enrollment are important elements of a bill discount program. Automatic enrollment is beneficial as it ensures more vulnerable customers will receive the benefit of the program without the need for additional application processes, thereby reducing barriers to accessing the program. The Company in testimony states that at the request of stakeholders, automatic enrollment was removed from the program proposal. However, the guidance about enrollment in engagement was perceived, by Staff, as the need for the Company to target outreach amongst non-LIHEAP recipients and not to remove automatic enrollment. Therefore, Staff recommends that the Company incorporate automatic enrollment of customers receiving bill assistance funds from LIHEAP into the Company's Bill Discount Program.

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[13] Idaho Power/1300, Aschenbrenner/25.

Second, Staff is concerned with the Company's proposal for the calculation of a customer's energy burden. Staff would like the Company to expand on how customers who do not have 12 months of previous billing data would be treated under this eligibility requirement.

**Q. Please describe the Company's proposal for the Bill Discount Program's level of relief.**

A. The Company's proposed tiered discount amounts were informed by the Company's Energy Burden Assessment (EBA), which was conducted in March 2023 on the advice of Staff. The Company states that the results of the EBA were used to best inform the level of assistance and eligibility criteria that should be considered as part of the Company's Bill Discount Program proposal. The Company states that their tiered discount amounts are intended to reduce most participating customers' energy burden to at least six percent for electrically heated homes or three percent for non-electrically heated homes. The Company claims that for customers whose energy burdens are not able to be reduced to at least the threshold amounts solely by participating in the Company's Bill Discount Program, receipt of additional available bill assistance funds such as LIHEAP, coupled with the Company's Bill Discount Program, should make it possible for these customers to be able to achieve the targeted energy burden threshold amounts.[14]

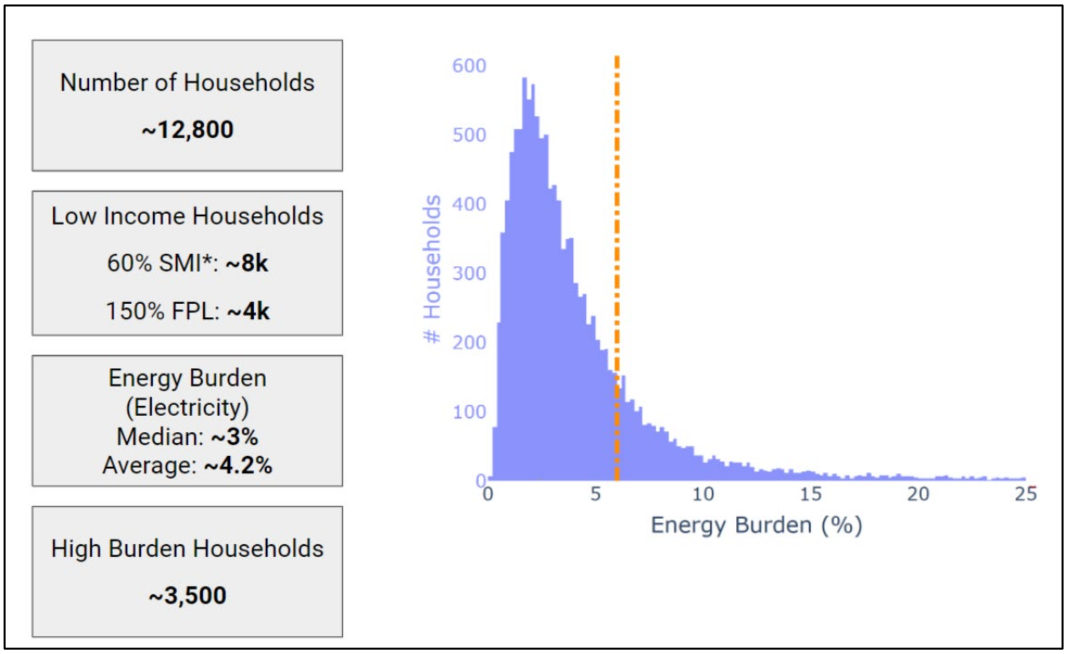
**Q. Please describe Staff's review of the Company's level of relief proposal.**

[14] Idaho Power/1300, Aschenbrenner/27.

A. Staff is generally supportive of the tiered discount approach taken by the Company; the same approach has been used by each of the other investor-owned utilities in Oregon. Staff is also appreciative of the Company's efforts to incorporate results from the EBA into their program design. In conversations with the Company and stakeholders, Staff has noted the difficulty in designing a program in the Company's service territory that addresses the needs of customers while not unduly burdening non-participating customers with program costs. The Company's service territory is somewhat more homogenous in terms of income levels, which can present challenges in designing a sustainable discount program. Staff is skeptical of the Company's claim that the receipt of additional bill assistance funds such as LIHEAP, paired with the bill discount program, would help a subset of customers to achieve the targeted energy burden threshold amounts. LIHEAP funding is capped, has high barriers to entry, and the Company provides no evidence that this outcome is possible; therefore Staff believes the Company should not rely on LIHEAP funding to achieve desired energy burden reduction goals.

Staff has endeavored to work with the Company to strike a balance between meaningful discounts and targeted energy burden relief without burdening more customers. However, Staff believes that due to the level of energy burden demonstrated in the Company's service territory it may be necessary to provide greater discount levels. The results of the Company's EBA found that 62 percent of residents in IPC's service territory would fall under 60 percent of the State Median Income and that of the 12,800 households identified in the EBA, 3,500 were deemed to have a high energy burden, meaning that annual electricity bills exceeded six percent of their income for electrically-heated homes and exceeded three percent of their income for non-electrically heated homes (see Chart 3).[15]

**Chart 3**




Based off the challenges posed by the Company's service territory, Staff would recommend greater discussion among stakeholder groups about whether the Company's current tier structure is appropriate.

**Q. Please describe the Company's proposal for the Bill Discount Program's tracking and accounting.**

A. The Company has agreed to report on a quarterly basis during the program's first year the following monthly statistics:

[15] See UM 2211, Idaho Power Company Low-Income Needs Assessment Information Session.

- Count of new participants and total participants, by zip code;
- Count of new participants and total participants, by discount tier;
- Participants' average discount amount, by discount tier;
- Participants' average bill pre- and post-discount, by discount tier;
- Average residential bill for non-participants;
- Count of participants in arrears, by age and discount tier;
- Total arrears of participants, by age and discount tier;
- Average arrears of participants, by age and discount tier; and
- Percent of participants that have received energy assistance, by discount tier.

The Company also intends to conduct a post-enrollment survey of participants within the first 12 months after a customer's enrollment in the Bill Discount Program along with a survey of CAP agencies and CBOs that are assisting with the enrollment of customers. The Company has stated that they are open to meeting with Staff and stakeholder to develop questions for these surveys.[16]

**Q. Please describe Staff's review of the Company's tracking and accounting proposal.**

A. Staff is appreciative of the Company's commitment to the collection and reporting of program related metrics. In Docket No. UM 2211, Staff intends to work with utilities and stakeholders to formalize metrics and reporting requirements that will allow for the evaluation of the bill discount programs and

[16] Idaho Power/1300, Aschenbrenner/29.

their effectiveness at reducing energy burden. To this end, Staff encourages the Company to remain committed to the reporting of energy burden related metrics. Staff is also appreciative of the Company's commitment to include Staff and stakeholders in the design of post-enrollment survey to ensure the greatest value of the results.

**Q. Please describe the Company's proposal for the Bill Discount Program's bundling.**

A. The Company discussed during its fifth HB 2475 workshop its willingness to consider bundling an arrearage management component as part of a future iteration of its Bill Discount Program, should there continue to be a desire or need to do so, as well as enhancing its weatherization program to address barriers to participation that may be unique to the Company's rural service area. The Company made no commitment to bundling of services with energy efficiency in this iteration of the Bill Discount Program.[17]

**Q. Please describe Staff's review of the Company's bundling proposal.**

A. Staff revised initial draft guidance related to energy efficiency (EE) bundling in interim programs in response to utility and CAP agency concerns that obligatory service bundles may be unfeasible from a capacity standpoint and create additional barriers from a participant standpoint. Staff's revisions recommended that utilities engage in information sharing with the Energy Trust of Oregon (ETO) and other EE/weatherization administering agencies; collaborate with said agencies on complementary services and cross referrals;

[17] Idaho Power/1300, Aschenbrenner/27.

and make EE/weatherization informational resources available to applicants. To the extent that these criteria do not oblige the Company to incorporate anything into the actual tariff, Staff simply reinforces its recommendation that utilities find ways to partner with ETO and EE/weatherization agencies and mitigate energy burden as effectively as possible (i.e. reducing energy needs + reducing the cost of energy). Given the extended period of time the Company has had to develop their program proposal, Staff is disappointed that the proposal does not include an EE component. The Company's EBA directly highlights the importance of EE measures in effectively reducing energy burden in the Company's service territory. Staff believes that energy efficiency measures are critical to the successful reduction of energy burden throughout Oregon and recommends that the Company develop a proposal that includes some EE component.

**Q. Please describe the Company's outreach and engagement efforts.**

A. Since 2021, the Company has been engaged in HB 2475 implementation discussions. The Company also held five virtual workshops where stakeholders were given the opportunity to provide feedback on the Company's potential program design. The Company has also committed to surveying participating customers and CAP agencies. As for customer outreach and engagement, the Company does not address in testimony how they intend to perform outreach or engage customers to make them aware of the existence of the program.[18]

[18] Idaho Power/1300, Aschenbrenner/26.

**Q. Please describe Staff's review of the Company's outreach and engagement efforts.**

A. Staff's expectations for outreach and engagement are that it be performed in a way that is transparent and informative; that the utility provide regularly scheduled monthly or quarterly discussions with partnering agencies and community representatives in a way that is mindful of stakeholder time; demonstrate meaningful engagement in advance of filing; and administer optional surveys to participating customers and CAP agencies at three, six, and 12 months from implementation. Staff believes that the Company has made a robust effort to solicit feedback from Staff and stakeholders but believes that the Company needs to be more accountable and transparent as to how this feedback is ultimately incorporated into the program design. As it pertains to customer outreach and engagement, the Company fails to address is testimony how they will perform outreach based on the different needs of their customers (mobile homes, multi-family, etc.). Staff recommends that the Company to more explicitly outline their efforts to make vulnerable customer groups aware of the existence of the bill discount program once it is in effect.

**Q. Is the Company planning on conducting post-enrollment income verification of participating customers?**

A. Yes, the Company intendeds to conduct post-enrollment verification via a three percent sample of participants that have not received LIHEAP within the previous two years. The frequency at which the Company conducts these post-enrollment income verifications is currently planned to be dependent upon whether there's an identified and meaningful discrepancy in enrollment statistics versus available demographic estimates (using United States Census Bureau data, etc.). The Company's proposal is for the program to be "risk-free", meaning customers who are unable to verify their income will not be required to pay back any discount amounts received. Customers who are unable to verify their income will however be removed from the program but will remain eligible for re-enrollment once satisfactory documentation has been provided to the Company.[19]

**Q. Please describe Staff's review of the Company's post-enrollment verification processes.**

A. Post-enrollment verification was not an issue directly linked to Staff's baseline evaluation criteria, but is an important consideration, nonetheless. Staff recognizes the importance of maintaining the integrity of the program by employing some verification of need and eligibility among participating customers. At the same time, Staff is sensitive to the additional burden and stress post-enrollment verification can put on customers, particularly those who are individuals or families with higher barriers. Additionally, since the implementation of the first bill discount programs stakeholders have provided feedback that a traditional audit is punitive and should be justified as a worthwhile model of verification before being implemented. The issue of post-enrollment verification will continue to be evaluated within Docket No. UM 2211. Staff encourages the Company to continue to work with Staff

[19] Idaho Power/1300, Aschenbrenner/30.

and stakeholders on the implementation of the post-enrollment verification processes to ensure households are not being unduly burdened.

**Q. Please describe the Company's cost-recovery mechanism proposal.**

A. The Company proposes to track for later recovery all exploratory, implementation, administration, and marketing costs of its proposed Bill Discount Program using the deferral authorized by Commission Order No. 23-055. Additionally, the Company is requesting authorization of a second deferral for all costs and revenues incurred to implement its proposed Bill Discount Program's rate mitigation measures. The Company's Schedule 64, as proposed, would provide for a two-way balancing account that would inform annual adjustments to customer rates based on a review of collections and payments from the account. The table below includes the proposed recovery rates contained in the Company's Schedule 64:

| Schedule | Monthly Adjustment Rate |
|---|---|
| Residential Rate Schedule (1 & 5) | $0.95 |
| Non-residential Rate Schedules | 0.0813¢, up to the Billing Period's first 2,460,024 kWhs |

The monthly adjustment rate for non-residential customers is an effective $2,000 monthly contribution cap.[20]

**Q. Please describe Staff's analysis of the Company's cost-recovery mechanism proposal.**

[20] Idaho Power/1300, Aschenbrenner/31-32.

A. Staff, along with stakeholders, raised concern over the Company's proposal to cap non-residential contributions to the bill discount program. A monthly cap for non-residential customers allows for large customers to bypass, to a certain extent, contributions towards the program. If a monthly contribution cap were to remain static as the size of the program grows, then this would exacerbate cost recovery inequities given the program's annual funding requirements would increase for all customers except those that are capped. Noting these issues, the Company has stated that it intends to provide notice within UM 2211 of the proposed Bill Discount Program being filed as part of this general rate case. This notification will allow all interested parties to offer feedback regarding the Company's proposed Bill Discount Program either independently or in conjunction with other changes proposed as part of this proceeding. In the review of this proposal, Staff asked the Company to analyze separate cost recovery mechanisms including a percentage of bill cost recovery for non-residential customers. At this time, Staff believes the Company's approach of a volumetric charge that targets a fixed monthly dollar cap is more appropriate given the challenges around implementing a percentage of bill mechanism. Staff, however, believes that the Company should revise the kWh cap to target a $3,000 effective cap for non-residential customers. A kWh cap which targets a $3,000 effective cap will alleviate short term concerns over the static nature of the mechanism and allow for a greater runway should the cap need to be changed in the future.

**Q. Please summarize Staff's review of the Company's Bill Discount Program proposal.**

A. Staff evaluated the Company's Bill Discount Program proposal through the lens of the baseline evaluation criteria put forth in Docket No. UM 2211. Based on this review and the baseline evaluation criteria, Staff has the following proposals for the Company before it can recommend approval of the program:

- Automatic enrollment of customers who are receiving LIHEAP.
- An explanation of how customers who do not have 12 months of previous billing data would be treated under the energy burden eligibility requirement.
- Greater discussion amongst stakeholder groups about the level of relief provided in the program to determine whether it is sufficient.
- An outline of how the Company intends to perform outreach and engagement of vulnerable groups to make them aware of the existence of the program.
- An outline of how the Company could incorporate energy efficiency initiatives into the program.
- A kWh cap that targets a $3,000 effective monthly cap for non-residential customers.

## ISSUE 4. OTHER ISSUES

**Q. Did Staff review any other issues proposed by the Company in this case?**

A. Yes. Staff reviewed the Company's proposal regarding the bifurcation of a residential service charge.

**Q. Please summarize the issue.**

A. A bifurcated service charge means single-family and multi-family dwellings would be charged different fees, which would more closely align with the actual costs associated with providing utility services to them. Under this approach, multi-family dwellings would be charged a lower service charge because it is less cost intensive for utilities to provide service to multi-family dwellings. The Company evaluated implementing a bifurcated residential service charge but concluded that due to the distribution of low-income customers living in single family dwellings along with the small overall benefit provided to customers, to not implement a bifurcated residential service charge.[21]

**Q. Please summarize Staff's review of the issue**

A. Staff reviewed the Company's testimony, Energy Burden Assessment, and Marginal Cost Study used to evaluate the practicality of the bifurcated service charge. Staff also issued a set of DRs asking for all analysis used to arrive at the Company's recommendation. Staff believes that due to the distribution of low-income customers in Idaho Power's Oregon service territory, a bifurcated single-family/multi-family service charge should not be pursued at this time. 90 percent of IPCOs low-income customers reside in single-family homes and

[21] Idaho Power/1300, Aschenbrenner/15.

therefore an increased single-family service charge would exacerbate the energy burden situation in the Company's service territory. Only eight percent of the Company's customers reside in multi-family housing, and despite a cost-based differential between single and multifamily dwellings of approximately 16 percent, Staff believes the costs and overall impact of implementing a bifurcated service charge outweigh the benefits.

**Q. Does Staff recommend any adjustments for this issue?**

A. No. Staff has no adjustments at this time.

**Q. Does this conclude your testimony?**

A. Yes.

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 601

## Witness Qualification Statement

**March 25, 2024**

## WITNESS QUALIFICATIONS STATEMENT

| | |
|---|---|
| NAME: | Bret Farrell |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Utility Analyst<br>Strategy Integration Division |
| ADDRESS: | 201 High Street SE. Suite 100<br>Salem, OR. 97301 |
| EDUCATION: | BA Economics, Illinois State University, Normal, IL<br><br>MS Applied Economics, Illinois State University, Normal, IL |
| EXPERIENCE: | I have been employed by the Oregon Public Utility Commission since April 2019. My responsibilities include research, statistical analysis, and recommendations on a range of regulatory issues.<br><br>I have provided testimony before the Commission in several general rates case proceedings and performed numerous analyses including economic, financial, and statistical with regard to public utilities. |

CASE: UE 426
WITNESS: BRET FARRELL

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 602

## IPC Response to Staff Data Request 274

## March 25, 2024

# IPC Response to Staff Data Request 274 is provided in Electronic Format

CASE: UE 426
WITNESS: BRET FARRELL

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 603

## Staff Workpaper

## March 25, 2024

# Staff Workpaper is provided in Electronic Format

CASE: UE 426
WITNESS: BRET FARRELL

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 604

## Staff Adjustment Workpaper

**March 25, 2024**

# Staff Adjustment Workpaper is provided in Electronic Format

CASE: UE 426
WITNESS: ANNA KIM

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 700

# OPENING TESTIMONY
## Jim Bridger Conversion

## March 25, 2024

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

A. My name is Anna Kim. I am the Energy Costs Section Manager employed in the Rates, Safety and Utility Performance Program 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/701.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to discuss the Jim Bridger unit conversions from coal to gas.

**Q. Did you prepare any exhibits for this docket?**

A. Yes. I prepared Exhibit Staff/701, my witness qualifications statement, and Exhibit Staff/702, a compilation of responses to data requests referenced in this testimony.

## ISSUE 1. JIM BRIDGER CONVERSION

**Q. What is the Jim Bridger conversion?**

A. Jim Bridger Unit 1 and Unit 2 are being converted from coal generation to gas generation.

**Q. Who owns and operates Jim Bridger?**

A. Idaho Power owns a third of the Jim Bridger facility. PacifiCorp owns the other two-thirds of this facility and is the operator.[1]

**Q. Have stakeholders and the Commission reviewed this decision in the past?**

A. Yes. These conversions were acknowledged as part of the Company's 2021 IRP Preferred Portfolio and action plan in LC 78.[2] These investments were also reviewed in PacifiCorp's 2021 IRP in LC 77 and as part of PacifiCorp's last General Rate Case UE 399.[3]

**Q. What is the current status of these unit conversions?**

A. As of January 26, 2024, Idaho Power reports that the project is on time and on budget.[4]

**Q. Are there any coal costs for Bridger Unit 1 or Unit 2 in the Test Year?**

A. No.[5]

**Q. Do you have any recommendations?**

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[1] Staff/702, Idaho Power response to Staff DR 236.
[2] Staff/702, Idaho Power response to Staff DR 145.
[3] UE 399, Opening Testimony Staff/300, Anderson/5-8.
[4] Staff/702, Idaho Power response to Staff DR 234.
[5] Staff/702, Idaho Power response to Staff DR 235.

A. No. Not at this time. Staff has not identified new concerns since Staff reviews in previous dockets.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: ANNA KIM

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 701

# Witness Qualifications Statement

# March 25, 2024

**WITNESS QUALIFICATIONS STATEMENT**

| | |
|---|---|
| NAME: | Anna Kim |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Energy Costs Section Manager<br>Rates, Safety and Utility Performance Program |
| ADDRESS: | 201 High Street SE. Suite 100<br>Salem, OR. 97301 |
| EDUCATION: | Master of Science, Economics<br>Portland State University,<br>Portland, OR<br><br>Master of Environmental<br>Studies, The Evergreen State<br>College, Olympia, WA<br><br>Bachelor of Arts, Environmental<br>Science, University of California,<br>Berkeley, CA |
| EXPERIENCE: | I have been employed by the Oregon Public Utility Commission (OPUC) since July 2018 in the Energy Resources and Planning Division. My responsibilities include providing advice on energy efficiency policy, pilot and program evaluation, and oversight of energy efficiency programs run through the Energy Trust of Oregon<br><br>Prior to working for the Commission, I worked for Seattle City Light as a power resource planner developing integrated resource plans. I also worked for five years as an evaluation consultant which involved evaluating energy efficiency and demand response pilots and programs and market research. |

CASE: UE 426
WITNESS: ANNA KIM

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 702

## Exhibits in Support
## Of Opening Testimony

**March 25, 2024**

**Topic or Keyword: Topic or Keyword: Jim Bridger Coal-fired power plant, Depreciation and Decommissioning at the end of 2025.**

**STAFF'S DATA REQUEST NO. 145:**

Has OPUC agreed to continue to accept the fossil fuel gas-fired power after Bridger's coal-fired power terminates in 2025?

**RESPONSE TO STAFF'S DATA REQUEST NO. 145:**

Yes. With Order No. 23-004, issued in Docket LC 78, the Commission acknowledged Idaho Power's 2021 Integrated Resource Plan ("IRP"), which included in the Preferred Portfolio the conversion of Units 1 and 2 from coal to natural gas by the summer of 2024.

**TOPIC OR KEYWORD: Bridger Gas Conversion**

**STAFF'S DATA REQUEST NO. 234:**

This is a standing data request. Please provide updates as available, at a minimum on a monthly basis. Please see Idaho Power/400 Adelman/6. Please provide project plans for Bridger Unit 1 conversion and Bridger Unit 2 conversion. Include major milestones and deliverables in the construction schedule, budgets for major components of the project cost, and actual costs to date.

a. Please describe the reason for any delays in the schedule.
b. Please describe the reason for any cost overruns or savings.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 234:**

Please see Response to Staff's Request No. 234 – Attachment for the natural gas installation project milestones for the work performed for the gas conversion of Bridger Units 1 and 2.

a. There have been no delays in the schedule to date.

b. Actual project costs are expected to be nearly equal to budgeted costs therefore Idaho Power does not anticipate any cost overruns or savings associated with the project.

**TOPIC OR KEYWORD: Bridger Gas Conversion**

**STAFF'S DATA REQUEST NO. 235:**

For Bridger Units 1 and 2 are there any coal costs including costs related to coal contracts reflected in the test year? If so, please identify the amounts, the accounts in which they will be found, and the rationale for their inclusion.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 235:**

There are no coal costs associated with Bridger Units 1 and 2 reflected in the test year. The Company's 2024 test year reflects the retirement of Unit 1 and 2 coal-related facilities as of year-end 2023 and no changes to the currently approved normalized level of net power supply expenses determined under the October Update of the 2023 Annual Power Cost Update with Order No. 23-184 in Docket UE 414.

**TOPIC OR KEYWORD: Bridger Gas Conversion**

**STAFF'S DATA REQUEST NO. 236:**

Please describe and provide documentation demonstrating the arrangement between Idaho Power and PacifiCorp about:

a. Overall Bridger facility management
b. Bridger Unit 1 and Unit 2 ownership structure
c. Bridger Unit 1 and Unit 2 conversion costs
d. Bridger Unit 1 and Unit 2 conversion project management
e. Operations and dispatch of Bridger 1 and 2 once the conversions are complete
f. Future retirement of the gas units for Bridger Unit 1 and Unit 2
g. Ownership and use of transmission for Bridger Unit 1 and Unit 2

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 236:**

a. – b. The Bridger plant consists of four jointly owned generating units. PacifiCorp has two-thirds ownership and is the operator of the facility. Idaho Power owns one-third of Bridger, or 706 megawatts ("MW") of net dependable capacity. Once the conversion projects are completed, two of the four units will be fueled by natural gas and two of the units will continue being fueled on coal. The ownership structure between the co-owners, and each owners' rights to capacity and output will remain unchanged with the conversion of Bridger Units 1 and 2 to gas in 2024.

c. Construction costs for the conversion of the existing coal combustion infrastructure to gas and gas receiving system are being shared between the owners by ownership share per the terms of the existing operating agreement. Idaho Power has included in the 2024 test year approximately $16.6 million in costs associated with the conversion of Units 1 and 2 to natural gas.

d. As the owner operator, PacifiCorp provides engineering and direct project management oversight of the project per the terms of the existing operating agreement. Idaho Power is actively involved in reviewing and approving expenses for the project.

e. – f. Revisions to the various Bridger agreements necessary for daily energy scheduling, fuel procurement and retirement of the Bridger plant are currently being negotiated between the owners. However, the Company does not anticipate any significant changes in the operation and dispatch of Units 1 and 2 in the future.

g. Transmission of energy from Bridger will continue after the conversion through the Borah West transmission path, 345-kilovolt ("kV"), 230-kV, and 138-kV transmission lines west of the Borah Substation near American Falls, Idaho. Idaho Power's one-third share of energy from Bridger flows west over this path. The Idaho-Wyoming path, or Bridger West, consists of three 345-kV transmission lines between Bridger and southeastern Idaho. The Company owns 800 MW of the 2,400 MW east-to-west capacity which effectively feeds into the Borah West path when power is moving east to west from Bridger.

CASE: UE 426
WITNESS: CHARLES LOCKWOOD

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 800

# OPENING TESTIMONY
## Advertising and Marketing Expense, Intervenor Funding, Covid Adjustments

## March 25, 2024

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

A. My name is Charles Lockwood. 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 qualifications statement is found in Exhibit Staff/801.

**Q. What is the purpose of your testimony?**

A. I provide background, analysis, and recommendations regarding the Company's 2024 Test Year expense for advertising and marketing, as well as the Company's adjustments for COVID-19 and intervenor funding.

**Q. Did you prepare any exhibits for this docket?**

A. Yes. I prepared the following supporting exhibits:

- Exhibit Staff/802, Idaho Power's Response to DR 212 Attachment A
- Exhibit Staff/803, Idaho Power's Response and Supplemental Response to DR 214
- Exhibit Staff/804, Idaho Power's Response to DR 486
- Exhibit Staff/805, Idaho Power's Response to DR 215 and 216

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

Issue 1. Advertising and Marketing ........ 3
Issue 2. Intervenor Funding and COVID-19 Adjustments ........ 14
Summary. ........ 15

**Q. Could there be changes or updates to Staff's position and recommendations?**

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

## ISSUE 1. ADVERTISING AND MARKETING

**Q. Does the Commission have a standard means of determining how advertising expenses are treated?**

A. Yes. OAR 860-026-0022 specifies how advertising expenses are treated in a utility rate case. The rule details five categories (A-E), each with a different standard for inclusion in rates.

Category "A" includes energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses.[1] Advertising expenses in this category are presumed reasonable when expenses are twelve and one-half hundredths of one percent (0.125 percent) or less of the gross retail operating revenues determined in that proceeding.[2]

Category "B" includes legally-mandated advertising expenses, which are assumed to be reasonable for rate-making purposes.[3]

Category "C" includes institutional advertising expenses, *promotional* advertising expenses, and any other advertising expenses not fitting into Category "A," "B," or "D".[4] Utilities must demonstrate these expenses are just and reasonable for inclusion in rates, as well as separately state the amount of advertising expenses in this category.

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[1] OAR 860-026-0022(2)(a).
[2] OAR 860-026-0022(3)(a).
[3] OAR 860-026-0022(2)(b).
[4] OAR 860-026-0022(2)(c).

Category "D" includes political advertising expenses and non-utility advertising expenses, which are presumed to be not just and reasonable for ratemaking purposes.[5]

Finally, Category "E" includes energy efficiency or conservation advertising expenses that relate to a Commission-approved program. Utilities must show these expenses are reasonable and recoverable in rates. With Commission approval, advertising expenses in Category "E" may be capitalized.[6]

**Q. Please describe the Company's Test Year expense for advertising.**

A. The Company proposes to include $178,262 in Category A and $303,341 in its Category C advertising in the 2024 Test Year as illustrated in Figure 1.[7] The Company has not proposed any expenses to be recovered in Categories B, D, or E in the 2024 Test Year.

**FIGURE 1. TOTAL ADVERTISING IN THE TEST YEAR**

| Category | Included in Rates? | 2024 Expenditures $ |
|---|---|---|
| A | YES | $178,262 |
| B | NO | $0 |
| C | YES | $303,341 |
| D | NO | $0 |
| E | NO | $0 |
| **TOTAL** | | **$481,603** |

5 OAR 860-026-0022(2)(d).
6 OAR 860-026-0022(2)(e).

**Q. Does Idaho Power include advertising expenses for any other category in its Test Year expense?**

A. Yes. Idaho Power has budgeted for other advertising during 2024. In total, the Company has budgeted approximately $2.1 million for its 2024 advertising budget, with $482 thousand of it being included as a Test Year expense to be added into rate base, as illustrated above. Idaho Power's forecasted advertising expenses not included as a Test Year expense include a $56,960 demand-side management Oregon Rider in FERC Account 254202, $1,073,743 demand-side management Idaho Rider in FERC Account 254201, and $472,923 general advertising in FERC Account 930100.

**Q. Please describe your analysis of the Company's proposed advertising expenses for Category A.**

A. First, Staff analyzed the Company's transactional data shown in the Company's responses to Standard Data Request Nos. 57 and 104, which inquired about Idaho Power's largest advertising expenditures in the Base Year. Staff confirmed the advertisements were entirely related to consumer safety, energy efficiency, conservation, and billing assistance. Staff also reviewed the largest vendors for the Company's Category A expenses and has confirmed the validity of their classification of as Category A expense. While this does not guarantee the credibility of the vendors in future agreements, this provides Staff with a measure of confidence that will be reassessed periodically. The largest Category A vendors are illustrated below, in Figure 2.[8]

**FIGURE 2. LARGEST CATEGORY A VENDORS IN 2022 BASE YEAR**

| Name | CATEGORY | Total $ |
|---|---|---|
| ONE SIXTEEN & WEST | A | $167,238 |
| ASSORTED NEWS PUBLICATIONS | A | $6,776 |
| EXPRESS PUBLISHING INC | A | $5,286 |
| Grand Total | | $179,299* |

* approximately 91% of total Category A Costs

Due to the scale of Idaho Power's advertising spending with One Sixteen & West, a full-service advertising agency located in Boise, Idaho, Staff analyzed the Company's transactions with this agency. Staff found the advertisements related entirely to safety concerns for customers surrounding wildfires, downed power lines, and overhead lines for the Company throughout all of 2022.[9]

**Q. How does the Company's advertising expenses compare to historical spending?**

A. Idaho Power's request for approximately $178 thousand budgeted for Category A expenses is an 18 percent increase from the approximately $150 thousand in Category A expenses the Company has spent on average over the last four

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8 Staff/802, Lockwood/1, Idaho Power's Response to DR 212 Attachment A (Category A) (electronic spreadsheet).

9 *Id.*

years.[10] The requested amount is presumed just and reasonable according to OAR 860-026-0022, as seen in Figure 3.

Staff's review found that while Idaho Power's 2024 Test Year Budget for Category A advertising is increasing, Staff has not identified any evidence to rebut the presumption that the amounts spent on Category A advertising are reasonable.

**FIGURE 3. 2024 TEST YEAR CATEGORY A ADVERTISING CALCULATION**

| | |
|---|---|
| **Category A Calculations:** | |
| Category A Expenses (Overall): | $178,262 |
| 2022 Idaho Power Retail Revenues: | $ 1,372,758,000 |
| *Factor per OAR: | 0.125% |
| Presumed Reasonable (Cat A) Costs: | $1,715,948 |
| Difference between Presumed and Proposed: | **$1,537,686** |
| Category A Expenses (Approx. Oregon-Allocation): | $9,390 |
| **Category A Calculations:** | |
| 2022 Idaho Power Oregon Retail Revenues: | $60,346,442 |
| *Factor per OAR: | 0.125% |
| Presumed Reasonable (Cat A) Costs: | $75,433 |
| Difference between Presumed and Proposed: | **$66,053** |
| *OAR 860-026-0022 Rule = 1/8 of 1% of sales is presumed reasonable. | |

**Q. Please describe how the Category A Test Year Expenses are allocated to Oregon ratepayers.**

A. Oregon customers are allocated approximately 4 to 5 percent of Category A expenses based on Idaho Power's recent allocation factors, with the actual

[10] Staff/802, Lockwood/1, Idaho Power's Response to DR 214 and Supplement Response (Category A) (electronic spreadsheet).

allocation percent varying based on the differing FERC accounts that comprise the Category A in totality.

**Q. What is your recommendation regarding the Category A Advertising expense?**

A. Idaho Power has not exceeded the 0.125 percent limit of Category A Advertising and all expenses appear to be prudent. Therefore, Staff has no adjustment.

**Q. Please describe your analysis of the Company's proposed advertising expenses for Category C.**

A. First, Staff analyzed the Company's transactional data shown in the Company's responses to Standard Data Request Nos. 57 and 104. Standard Data Request 57 asks for transaction summaries for all non-labor costs recorded in all FERC accounts in the Base Year and Standard Data Request 104 requires the utility to identify and describe all Category C advertising expense included in the Test Year. Staff also reviewed the information provided in Idaho Power's Response to DR 212, which asked for transactional line-item accounting detail for Category A, Category B, Category C, Category D, and Category E advertising expenditures from calendar year 2022 and calendar year 2023. Staff found several expenditures for which Staff requires further information as Staff cannot conclude that the Company has met its burden of proof without more evidence.

**Q. Please provide the standard for how the Commission reviews the Company's proposed advertising expenses for Category C.**

A. Category "C" includes institutional advertising expenses, promotional advertising expenses, and any other advertising expenses not fitting into Category "A," "B," or "D". Utilities must demonstrate these expenses are just and reasonable for inclusion in rates, as well as separately state the amount of advertising expenses in this category.[11]

**FIGURE 6. LARGEST CATEGORY C EXPENSES IN 2022 BASE YEAR**

| Name | CATEGORY | Total $ |
|---|---|---|
| BILL INSERTS | C | $150,740 |
| JOB ADVERTISEMENTS | C | $46,185 |
| Grand Total | | $196,925* |

* approximately 78% of total Category C Costs

**Q. Please explain further your analysis of the Category C expenses found in the 2022 Base Year.**

A. Upon review, Staff found the majority of the Category C expenses were being utilized for bill inserts and job advertisements. Staff finds that generally the usage of Category C expenses for job advertisements and bill inserts are just and reasonable for inclusion of rates.

Staff did further review of the bill inserts given expense for the inserts comprises a large portion of expenses for Category C, and found these costs are mainly due to Idaho Power's publication of Connections, the Company's monthly newsletter providing information on major Company projects as well as

[11] OAR 860-026-0022(2)(c).

safety information. Staff finds this is a just and reasonable usage of Category C expenses which should be included in rates.

**Q. Please describe the Category C expenses for which you are still conducting your investigation.**

A. Staff has concerns regarding the general advertisements, including social media advertisements, and sponsorships. Staff is particularly concerned regarding the allocation of Idaho sponsorships to Oregon ratepayers and the overarching content of the general advertisements which were not included in Category A or labelled as job advertising as seen in Figure 5.[12]

**FIGURE 6. STAFF'S CATEGORY C EXPENSE CONCERNS**

| Name | CATEGORY | Total $ |
|---|---|---|
| ADVERTISEMENT | C | $32,997 |
| SPONSORSHIPS | C | $10,500 |
| SOCIAL MEDIA ADVERTISING | C | $3,906 |
| Grand Total | | $47,403* |

* approximately 19% of total Category C Costs

**Q. What are the Idaho Power sponsorships for?**

A. Idaho Power spent approximately $10,500 on sponsorships for the Caldwell Night Rodeo, United Way of Treasure Valley, the College of Western Idaho Foundation, and the Ada County Highway District.[13] Staff sought more information in DR 486 from the Company regarding how the sponsorships are just and reasonable to be included in rates for Oregon customers. After

[12] Staff/803, Lockwood/1, Idaho Power's Response to DR 212 Attachment A (Category C) (electronic spreadsheet).
[13] Staff/803, Lockwood/1, Idaho Power's Response to DR 212 Attachment A (Category C) (electronic spreadsheet).

reviewing the sponsorships, Idaho Power agreed these entries should have been removed from the development of the 2024 Test Year.[14]

**Q. Does Staff have any further concerns about Idaho Power's Category C expenses?**

A. Yes. Idaho Power spent approximately $37 thousand on Category C expenses labelled as general advertisements and social media advertising. Staff understands that Idaho Power purchased advertisements for social media such as Facebook and LinkedIn, but the content of these advertisements is unclear. Therefore, Staff seeks additional information as to the nature of these advertisements and how they are deemed just and reasonable to be included inclusion in rates for Oregon customers.

**Q. What is your recommendation regarding the Category C Advertising expense?**

A. Currently Staff's recommendation is to remove the approximately $47 thousand, $37 thousand spent on general advertisements, social media advertising, and $10 thousand spent on sponsorships. The Company has not met its burden of proof to justify the inclusion of these expenses in testimony, workpapers, or responses to data requests. If the Company demonstrates the expenses are just and reasonable to be included in rates, Staff will revisit its recommendation. However, unless the Company provides evidence to meet the burden of proof, Staff recommends removal of these expenses from the Test Year.

[14] Staff/804, Lockwood/1 Idaho Power's Response to DR 486.

**Q. Did Staff have any additional inquiries into the Company's advertising expenses it wishes to share at this time?**

A. Yes. Staff sought further information through DRs regarding how the Company ensures its advertising is circulated to Oregon customers at the same level and quality as Idaho Customers, as well as information on advertising for low-income, bill discount, and energy efficiency programming.[15] Regarding the first inquiry, Idaho Power's radio and television advertising is placed into three primary designated marketing areas ("DMAs") across the Company's service area, including Treasure Valley, Magic Valley, and Pocatello/Idaho Falls. The Treasure Valley DMA reaches eastern Oregon as well. Digital advertising is placed in every zip code that Idaho Power serves in Idaho and Oregon.

Print ads in newspapers are placed in targeted areas with specific information of interest to those readers, such as wildfire safety messaging or rate change notifications. All customers receive general messaging via email and in their bills that includes helpful information like energy efficiency tips and programs, ways to pay their bill, and safety tips. Certain advertisements, particularly safety messaging and our customer newsletter, are provided in English and Spanish.

Regarding advertising for low-income, bill discount, and energy efficiency programming, Staff reviewed the transactional line-item accounting details for each and found that the Company has robust advertising intended to directly

[15] Staff/805, Lockwood/1-10, Idaho Power's Responses to DR 215 and 216.

promote energy efficiency and educate customers on available programming for low-income residents and those eligible for bill discounts.

## ISSUE 2. INTERVENOR FUNDING AND COVID-19 ADJUSTMENTS

**Q. Did Staff review any additional topics to be presented in this testimony?**

A. Yes. The Company made a series of adjustments to remove the impacts of intervenor funding and COVID-19 impacts that were recovered through individual rate adjustments in separate proceedings. Staff reviewed the Company's testimony, issued data requests to better understand the adjustments, reviewed the Company's responses, and verified the information with corresponding Commission orders and authorization. Staff did not identify the need for further adjustments.

## SUMMARY

**Q. Please summarize your recommendations, identifying any adjustments you propose.**

A. Staff currently proposes a singular adjustment in this testimony to remove approximately $47 thousand from Category C expenses from rates, until the Company provides further evidence as to the reasonableness of recovery in rates.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: Charles Lockwood

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 801

# Witness Qualifications Statement

# March 25, 2024

**WITNESS QUALIFICATIONS STATEMENT**

| | |
|---|---|
| NAME: | Charles Lockwood |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Utility Analyst<br>Utility Strategy and Integration Division |
| ADDRESS: | 201 High Street SE. Suite 100<br>Salem, OR. 97301 |
| EDUCATION: | University of Florida<br>Bachelor of Science in Environmental Science, 2019<br><br>University of Oregon<br>Juris Doctor, 2022<br>Concentrations in Green Business Law, Environmental and Natural Resources Law |
| EXPERIENCE: | Oregon Public Utility Commission<br>Administrative Hearings Division Law Clerk, 2021-2022<br><br>Oregon Public Utility Commission<br>Utility Analyst, 2022 - Present |

CASE: UE 426
WITNESS: CHARLES LOCKWOOD

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 802

## Exhibits in Support
## Of Opening Testimony

**March 25, 2024**

# IPC Response to Staff Data Request 212 is provided in Electronic Format

CASE: UE 426
WITNESS: CHARLES LOCKWOOD

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 803

## Exhibits in Support
## Of Opening Testimony

**March 25, 2024**

# IPC Response and Supplemental Reponse to Staff Data Request 214 is provided in Electronic Format

CASE: UE 426
WITNESS: CHARLES LOCKWOOD

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 804

## Exhibits in Support
## Of Opening Testimony

**March 25, 2024**

**TOPIC OR KEYWORD: Advertising**

**STAFF'S DATA REQUEST NO. 486:**

Please explain how the Company's sponsorships found in the Company's Category "C" expenditures, including the sponsorships for the Caldwell Night Rodeo, United Way of Treasure Valley, College of Western Idaho, and Ada Count Highway District are just and reasonable according to OAR 860-26-0022(3)(c).

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 486:**

After reviewing the line items discussed in this request, Idaho Power has determined that these entries (totaling $10,500 on a system basis in 2022) should have been removed from the development of the 2024 Test Year in the same manner as general advertising expense. This adjustment would reduce the Oregon jurisdictional 2024 Test Year expenses by $354.84.

CASE: UE 426
WITNESS: CHARLES LOCKWOOD

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 805

## Exhibits in Support
## Of Opening Testimony

**March 25, 2024**

**Topic or Keyword: Advertising and Marketing**

**STAFF’S DATA REQUEST NO. 215:**

Please describe the Company’s actions to ensure advertising is made equally available to all customers and circulated to Oregon consumers at the same level and quality as Idaho consumers.

**RESPONSE TO STAFF’S DATA REQUEST NO. 215:**

Traditional advertising, such as radio and television, is placed in the three primary designated marketing areas (“DMAs”) across the Company’s service area, including the Treasure Valley, Magic Valley, and Pocatello/Idaho Falls. The Treasure Valley DMA reaches eastern Oregon as well. Digital advertising is placed in every zip code Idaho Power serves in Idaho and Oregon. Print ads in newspapers are placed in targeted areas with specific information of interest to those readers, such as wildfire safety messaging or rate change notifications. All customers receive general messaging via email and in their bills that includes helpful information like energy efficiency tips and programs, ways to pay their bill, and safety tips. Certain advertisements, particularly safety messaging and our customer newsletter, are provided in English and Spanish.

**Topic or Keyword: Advertising and Marketing**

**STAFF'S DATA REQUEST NO. 216:**

In reference to the Company's response to DR 57A and DR 212, please provide transactional line-item accounting details regarding advertising for low-income, bill discount, and energy efficiency programming. Please be sure to include dates of the advertising, the type of advertising media, and the dollars spent per ad.

**RESPONSE TO STAFF'S DATA REQUEST NO. 216:**

See attachment 'Response to Staff Request No. 216 – Attachment'. In response to the request for dates of advertising, most of these materials ran with the coordinated campaign in May, June, October, and November of 2022 (marked as "EE Campaign" in the attachment). Other materials ran in the timeframe identified by the date column.

| Actuals | Description | Additional Description | Corp Comm Desc. | Month End Date |
|---|---|---|---|---|
| 4,341.20 | ONE SIXTEEN & WEST | INVOICE M11302022T SOW 1 | EE Campaign (TV, radio, and digital) | 2022-12-31 00:00:00.000 |
| 2,918.36 | ONE SIXTEEN & WEST | INVOICE 019480 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-12-31 00:00:00.000 |
| 2,897.74 | ONE SIXTEEN & WEST | INVOICE 19368 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 2,794.34 | ONE SIXTEEN & WEST | INVOICE 018812 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-08-31 00:00:00.000 |
| 2,794.34 | ONE SIXTEEN & WEST | INVOICE 018812 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-08-31 00:00:00.000 |
| 2,760.18 | ONE SIXTEEN & WEST | INVOICE 18695 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 2,212.53 | CREE-CX ACCRUALS Q4 2022 | 116 & WEST DEC MEDIA | EE Campaign (TV, radio, and digital) | 2022-12-31 00:00:00.000 |
| 2,198.99 | ONE SIXTEEN & WEST | INVOICE 19360 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 1,920.04 | ONE SIXTEEN & WEST | INVOICE 18689 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 1,871.07 | ONE SIXTEEN & WEST | INVOICE 18816 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-08-31 00:00:00.000 |
| 1,729.08 | OR ENERGY AUDIT BILL | | Bill insert | 2022-09-30 00:00:00.000 |
| 1,275.18 | ONE SIXTEEN & WEST | INVOICE 18696 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 1,224.15 | ONE SIXTEEN & WEST | SOW 1 MEDIA BUYING | EE Campaign (TV, radio, and digital) | 2022-12-31 00:00:00.000 |
| 1,191.06 | ONE SIXTEEN & WEST | INVOICE 19365 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 1,180.09 | ONE SIXTEEN & WEST | INVOICE 19369 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 905.83 | ONE SIXTEEN & WEST | INVOICE 019279 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-10-31 00:00:00.000 |
| 861.10 | ONE SIXTEEN & WEST | INVOICE 18817 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-08-31 00:00:00.000 |
| 726.47 | ONE SIXTEEN & WEST | INVOICE 18693 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 726.47 | ONE SIXTEEN & WEST | INVOICE 19438 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 685.00 | CREE CORRECTIONS YTD 2022 | INVOICE 113794670 LAMARCO | Billboards/bus wraps | 2022-12-31 00:00:00.000 |
| 647.60 | MCCLATCHY CO LLC, THE | INVOICE 133533 IDAHO STA | Print ad | 2022-09-30 00:00:00.000 |
| 552.88 | ONE SIXTEEN & WEST | INVOICE 18691 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 548.00 | LAMAR COMPANIES | INVOICE 113219827 LAMARCO | Electronic billboards | 2022-02-28 00:00:00.000 |
| 536.44 | MCCLATCHY CO LLC, THE | INVOICE 261550 EE GUIDES | Print ad | 2022-07-31 00:00:00.000 |
| 530.75 | ONE SIXTEEN & WEST | INVOICE 19482 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-12-31 00:00:00.000 |
| 520.94 | ONE SIXTEEN & WEST | INVOICE 018814 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-08-31 00:00:00.000 |
| 502.49 | ONE SIXTEEN & WEST | INVOICE 19362 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 500.15 | ONE SIXTEEN & WEST | INVOICE 18690 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 500.15 | ONE SIXTEEN & WEST | INVOICE 18999 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-09-30 00:00:00.000 |
| 486.18 | ONE SIXTEEN & WEST | INVOICE 19481 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-12-31 00:00:00.000 |
| 481.04 | MISC CORRECTIONS 1 | JUNE 2022 CONNECTION | Customer newsletter | 2022-06-30 00:00:00.000 |
| 442.23 | ONE SIXTEEN & WEST | INVOICE 019276 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-10-31 00:00:00.000 |

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| 425.00 | LEARFIELD COMMUNICATIONS LL | INVOICE 496-230466-474323 | ISU sports sponsorship | 2022-11-30 00:00:00.000 |
| 425.00 | LEARFIELD COMMUNICATIONS LL | INVOICE 496-230466-47432 | ISU sports sponsorship | 2022-11-30 00:00:00.000 |
| 425.00 | LEARFIELD COMMUNICATIONS LL | INVOICE 496-230466-47432 | ISU sports sponsorship | 2022-11-30 00:00:00.000 |
| 420.00 | BOISE STATE PUBLIC RADIO | INVOICE MC-1221029722 RAD | Radio | 2022-11-30 00:00:00.000 |
| 399.05 | ONE SIXTEEN & WEST | INVOICE 18946 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-08-31 00:00:00.000 |
| 378.23 | AUTOSORT | INVOICE 115994 OFFSITE PR | Printing charge | 2022-04-30 00:00:00.000 |
| 350.00 | ONE SIXTEEN & WEST | SOW 1 MEDIA BUYING | EE Campaign (TV, radio, and digital) | 2022-02-28 00:00:00.000 |
| 350.00 | ONE SIXTEEN & WEST | INVOICE 18281 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-03-31 00:00:00.000 |
| 350.00 | ONE SIXTEEN & WEST | INVOICE 18396 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-04-30 00:00:00.000 |
| 350.00 | ONE SIXTEEN & WEST | INVOICE 18525 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-05-31 00:00:00.000 |
| 349.98 | ONE SIXTEEN & WEST | INVOICE 18285 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-03-31 00:00:00.000 |
| 349.76 | ONE SIXTEEN & WEST | INVOICE 18998 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-09-30 00:00:00.000 |
| 330.00 | BOISE STATE PUBLIC RADIO | BSU PUBLIC RADIO EE AD | Radio | 2022-10-31 00:00:00.000 |
| 299.78 | ONE SIXTEEN & WEST | INVOICE 019275 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-10-31 00:00:00.000 |
| 296.84 | 2022 REBATE ADVANTAG | | Bill insert | 2022-09-30 00:00:00.000 |
| 290.48 | DIY WEATHERIZATION W | | Bill insert | 2022-12-31 00:00:00.000 |
| 284.99 | HEATING AND COOLING | | Digital ads | 2022-09-30 00:00:00.000 |
| 271.53 | GET YOUR HOME READY | | Bill insert | 2022-09-30 00:00:00.000 |
| 251.70 | ONE SIXTEEN & WEST | INVOICE 18292 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-04-30 00:00:00.000 |
| 250.00 | BOISE HAWKS BASEBALL | INVOICE 21196A BOISE HAWK | Sports sponsorship | 2022-03-31 00:00:00.000 |
| 249.61 | ONE SIXTEEN & WEST | INVOICE 18399 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-04-30 00:00:00.000 |
| 248.52 | ONE SIXTEEN & WEST | INVOICE 18164 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-03-31 00:00:00.000 |
| 246.53 | JUNE 2022 SUMMER EE | | Customer newsletter | 2022-05-31 00:00:00.000 |
| 236.59 | EE SPRING TIPS BILL | | Bill insert | 2022-02-28 00:00:00.000 |
| 236.59 | HEATING AND COOLING | | Digital ads | 2022-03-31 00:00:00.000 |
| 236.59 | REBATE ADVANTAGE BIL | | Bill insert | 2022-03-31 00:00:00.000 |
| 234.18 | ONE SIXTEEN & WEST | INVOICE 19367 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 229.66 | ONE SIXTEEN & WEST | INVOICE 18697 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 199.75 | IDAHO BUSINESS REVIEW INC | INVOICE 1006947058 ADVERT | Print ad | 2022-11-30 00:00:00.000 |
| 192.27 | ONE SIXTEEN & WEST | INVOICE 18524 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-05-31 00:00:00.000 |
| 179.31 | ONE SIXTEEN & WEST | INVOICE 18818 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-07-31 00:00:00.000 |
| 175.00 | IDAHO BUSINESS REVIEW INC | INVOICE 1006946406 ADVERT | Print ad | 2022-10-31 00:00:00.000 |
| 167.76 | ONE SIXTEEN & WEST | INVOICE 18940 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-08-31 00:00:00.000 |
| 162.40 | EXPRESS PUBLISHING INC | INVOICE 10002188 EXPRESS | Print ad | 2022-07-31 00:00:00.000 |

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| 149.98 | ONE SIXTEEN & WEST | INVOICE 18285 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-03-31 00:00:00.000 |
| 146.25 | MCCLATCHY CO LLC, THE | INVOICE 126854 EE GUIDES | Print ad | 2022-07-31 00:00:00.000 |
| 136.10 | IDAHO PRESS-TRIBUNE | INVOICES 522222640 AND 06 | Print ad | 2022-07-31 00:00:00.000 |
| 128.46 | ONE SIXTEEN & WEST | INVOICE 019275 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-10-31 00:00:00.000 |
| 126.38 | KISU FM | INVOICE 22100018 COMMERC | Radio | 2022-11-30 00:00:00.000 |
| 125.07 | ONE SIXTEEN & WEST | INVOICE 18699 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 124.97 | ONE SIXTEEN & WEST | INVOICE 18820 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-07-31 00:00:00.000 |
| 124.74 | ONE SIXTEEN & WEST | INVOICE 19370 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 124.50 | KISU FM | INVOICE 22090018 KISU RAD | Radio | 2022-10-31 00:00:00.000 |
| 120.26 | MISC CORRECTIONS 1 | JUNE 2022 CONNECTION | Customer newsletter | 2022-06-30 00:00:00.000 |
| 120.11 | TIMES-NEWS | INVOICE 37419 RES EE NEWS | Print ad | 2022-08-31 00:00:00.000 |
| 115.66 | ONE SIXTEEN & WEST | INVOICE 18821 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-07-31 00:00:00.000 |
| 107.11 | ONE SIXTEEN & WEST | INVOICE 18700 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 106.64 | ONE SIXTEEN & WEST | INVOICE 19366 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 106.37 | IDAHO PRESS-TRIBUNE | INVOICES 522222640 AND 06 | Print ad | 2022-07-31 00:00:00.000 |
| 102.00 | IDAHO PRESS-TRIBUNE | INVOICES 522222640 AND 06 | Print ad | 2022-07-31 00:00:00.000 |
| 101.22 | A/C COOL CREDIT DIRE | | Postcard | 2022-05-31 00:00:00.000 |
| 100.25 | ONE SIXTEEN & WEST | INVOICE 18683 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 100.03 | ONE SIXTEEN & WEST | INVOICE 18283 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-03-31 00:00:00.000 |
| 100.02 | ONE SIXTEEN & WEST | SOW 1 MEDIA BUYING #18395 | EE Campaign (TV, radio, and digital) | 2022-05-31 00:00:00.000 |
| 100.02 | ONE SIXTEEN & WEST | SOW 1 MEDIA BUYING #18395 | EE Campaign (TV, radio, and digital) | 2022-05-31 00:00:00.000 |
| 100.01 | ONE SIXTEEN & WEST | INVOICE18997 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-09-30 00:00:00.000 |
| 100.00 | CREE-CX ACCRUALS Q4 2022 | 116 & WEST DEC MEDIA | EE Campaign (TV, radio, and digital) | 2022-12-31 00:00:00.000 |
| 100.00 | ONE SIXTEEN & WEST | INVOICE 18161 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-03-31 00:00:00.000 |
| 100.00 | ONE SIXTEEN & WEST | INVOICE 18807 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-07-31 00:00:00.000 |
| 100.00 | ONE SIXTEEN & WEST | INVOICE 18936 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-08-31 00:00:00.000 |
| 100.00 | ONE SIXTEEN & WEST | INVOICE 19352 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 100.00 | ONE SIXTEEN & WEST | INVOICE 19274 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 100.00 | ONE SIXTEEN & WEST | INVOICE 1948486 SOW 1 ME | EE Campaign (TV, radio, and digital) | 2022-12-31 00:00:00.000 |
| 98.06 | IRRIGATION EFFICIENC | | Postcards | 2022-01-31 00:00:00.000 |
| 95.10 | ONE SIXTEEN & WEST | SOW 1 MEDIA BUYING | EE Campaign (TV, radio, and digital) | 2022-02-28 00:00:00.000 |
| 90.81 | ONE SIXTEEN & WEST | INVOICE 18692 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 90.81 | ONE SIXTEEN & WEST | SOW 1 MEDIA BUYING | EE Campaign (TV, radio, and digital) | 2022-07-31 00:00:00.000 |
| 90.81 | ONE SIXTEEN & WEST | INVOICE 19363 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |

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| 90.81 | ONE SIXTEEN & WEST | INVOICE 19483 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-12-31 00:00:00.000 |
| 90.00 | KTVB | INV 2545246C1,2545246A1,2 | TV segment | 2022-12-31 00:00:00.000 |
| 89.07 | COMMERCIAL/INDUSTRIA | | Bill insert | 2022-06-30 00:00:00.000 |
| 87.50 | IDAHO BUSINESS REVIEW INC | INVOICE 1006933610 COMMER | Print ad | 2022-04-30 00:00:00.000 |
| 85.83 | MARCH 2022 COMMERCIA | | Bill insert | 2022-02-28 00:00:00.000 |
| 84.50 | DYKE,TONJA I | SPECTRA PRODUCTIONS | Booth registration | 2022-02-28 00:00:00.000 |
| 84.00 | HUMPHREYS,DENISE C | IBL EVENTS | Booth registration | 2022-06-30 00:00:00.000 |
| 80.00 | KTVB | KTVB- CORP COMM ADVERTISE | TV segment | 2022-07-31 00:00:00.000 |
| 77.79 | ALEXANDER CLARK PRINTING | COMMERCIAL/INDUSTRIAL EE | Printing charge | 2022-06-30 00:00:00.000 |
| 74.80 | IDAHO BUSINESS REVIEW INC | INVOICE 1006936263 ADVERT | Print ad | 2022-06-30 00:00:00.000 |
| 74.80 | IDAHO BUSINESS REVIEW INC | INVOICE 1006941467 ADVERT | Print ad | 2022-08-31 00:00:00.000 |
| 74.80 | IDAHO BUSINESS REVIEW INC | INV 1006942688 ADVERTISIN | Print ad | 2022-09-30 00:00:00.000 |
| 74.80 | IDAHO BUSINESS REVIEW INC | INVOICE 1006947769 ADVERT | Print ad | 2022-11-30 00:00:00.000 |
| 71.18 | ARGUS OBSERVER | EE AD INSERT | Print ad | 2022-07-31 00:00:00.000 |
| 70.06 | ONE SIXTEEN & WEST | INVOICE 19001 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-09-30 00:00:00.000 |
| 68.75 | HARRIS PUBLISHING CO | INVOICE 2022-65008 MEDIA | Print ad | 2022-02-28 00:00:00.000 |
| 68.75 | HARRIS PUBLISHING CO | INVOICE 68277 POTATO GROW | Print ad | 2022-07-31 00:00:00.000 |
| 68.75 | HARRIS PUBLISHING CO | INVOICE 70194 POTATO GROW | Print ad | 2022-10-31 00:00:00.000 |
| 68.75 | ONE SIXTEEN & WEST | INVOICE 2022-65008 SOW 1 | EE Campaign (TV, radio, and digital) | 2022-01-31 00:00:00.000 |
| 61.68 | AUTOSORT | INVOICE 116531 OFFSITE PR | Printing charge | 2022-06-30 00:00:00.000 |
| 61.68 | AUTOSORT | INVOICE 116531 OFFSITE PR | Printing charge | 2022-06-30 00:00:00.000 |
| 60.35 | IDAHO MAGAZINE | INVOICE 127775 MAGAZINE | Print ad | 2022-10-31 00:00:00.000 |
| 60.35 | ONE SIXTEEN & WEST | INVOICE 127775 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-10-31 00:00:00.000 |
| 60.35 | WEST,KRISTA J | IN IDAHO MAGAZINE | Print ad | 2022-10-31 00:00:00.000 |
| 60.33 | MEYER,ANNIE L | IN IDAHO MAGAZINE | Print ad | 2022-02-28 00:00:00.000 |
| 58.47 | CAPITAL PRESS | INVOICE 012218477 CAPITAL | Print ad | 2022-02-28 00:00:00.000 |
| 58.47 | CREE CORRECTIONS YTD 2022 | CAPITAL PRESS - IDAHO AG | Print ad | 2022-12-31 00:00:00.000 |
| 54.15 | ROSANDICK,JULIE A | E M CONSULTING INC | Print ad | 2022-08-31 00:00:00.000 |
| 53.53 | 2022 IRRIGATION PEAK | | Postcard | 2022-03-31 00:00:00.000 |
| 50.29 | ONE SIXTEEN & WEST | INVOICE 18813 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-07-31 00:00:00.000 |
| 50.29 | ONE SIXTEEN & WEST | INVOICE 18947 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-08-31 00:00:00.000 |
| 50.29 | ONE SIXTEEN & WEST | INVOICE 019277 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-10-31 00:00:00.000 |
| 50.23 | ONE SIXTEEN & WEST | INVOICE 19354 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 47.80 | HEATING AND COOLING | | Postcard | 2022-02-28 00:00:00.000 |

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| 47.75 | IDAHO BUSINESS REVIEW INC | INVOICE 1006933412 IBR RE | Print ad | 2022-04-30 00:00:00.000 |
| 46.20 | ONE SIXTEEN & WEST | INVOICE 18688 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 43.94 | ONE SIXTEEN & WEST | INVOICE 18948 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-08-31 00:00:00.000 |
| 43.45 | ONE SIXTEEN & WEST | INVOICE 18698 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-06-30 00:00:00.000 |
| 43.45 | ONE SIXTEEN & WEST | INVOICE 18819 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-07-31 00:00:00.000 |
| 43.45 | ONE SIXTEEN & WEST | INVOICE 18949 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-08-31 00:00:00.000 |
| 43.45 | ONE SIXTEEN & WEST | INVOICE 19000 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-09-30 00:00:00.000 |
| 43.45 | ONE SIXTEEN & WEST | INVOICE 019278 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-10-31 00:00:00.000 |
| 43.45 | ONE SIXTEEN & WEST | INVOICE 19364 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 42.25 | SHORT,RAY L | SPECTRA PRODUCTIONS | Booth registration | 2022-09-30 00:00:00.000 |
| 42.25 | SHORT,RAY L | SPECTRA PRODUCTIONS | Booth registration | 2022-09-30 00:00:00.000 |
| 41.25 | LAMAR COMPANIES | INVOICE 113261659 LAMARCO | Electronic billboards | 2022-02-28 00:00:00.000 |
| 41.25 | LAMAR COMPANIES | INVOICE 113341621 LAMARCO | Electronic billboards | 2022-03-31 00:00:00.000 |
| 41.25 | LAMAR COMPANIES | INVOICE 113427814 LAMARCO | Electronic billboards | 2022-03-31 00:00:00.000 |
| 41.25 | LAMAR COMPANIES | INVOICE 113533996 LAMARCO | Electronic billboards | 2022-04-30 00:00:00.000 |
| 41.25 | LAMAR COMPANIES | INVOICE 113622369 LAMARCO | Electronic billboards | 2022-05-31 00:00:00.000 |
| 41.25 | LAMAR COMPANIES | INVOICE 113711044 LAMARCO | Electronic billboards | 2022-06-30 00:00:00.000 |
| 41.25 | LAMAR COMPANIES | INVOICE 113800989 LAMARC | Electronic billboards | 2022-07-31 00:00:00.000 |
| 41.25 | LAMAR COMPANIES | INVOICE 113979550 LAMARCO | Electronic billboards | 2022-09-30 00:00:00.000 |
| 41.25 | LAMAR COMPANIES | INVOICE114061655 LAMARCOM | Electronic billboards | 2022-10-31 00:00:00.000 |
| 41.25 | LAMAR COMPANIES | INVOICE 114166471 LAMARCO | Electronic billboards | 2022-11-30 00:00:00.000 |
| 41.25 | LAMAR COMPANIES | INVOICE 114254741 LAMARCO | Electronic billboards | 2022-12-31 00:00:00.000 |
| 40.00 | THOM,MELISSA W | FACEBK 3KHGMEP3Z2 | Social media | 2022-07-31 00:00:00.000 |
| 38.62 | THOM,MELISSA W | FACEBK EURG7E33Z2 | Social media | 2022-07-31 00:00:00.000 |
| 38.50 | IDAHO STATE PUBLISHING | INVOICE 06223466 IDAHO ST | Print ad | 2022-07-31 00:00:00.000 |
| 37.12 | MORALES DIMMICK TRANSLATIO | INVOICE1017478 SPANISH TR | Translation services | 2022-08-31 00:00:00.000 |
| 36.32 | ONE SIXTEEN & WEST | INVOICE 18282 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-03-31 00:00:00.000 |
| 36.32 | ONE SIXTEEN & WEST | INVOICE 18397 SOW 1 MEDI | EE Campaign (TV, radio, and digital) | 2022-04-30 00:00:00.000 |
| 36.32 | ONE SIXTEEN & WEST | INVOICE 18526 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-05-31 00:00:00.000 |
| 36.32 | ONE SIXTEEN & WEST | INVOICE 19361 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 36.27 | ONE SIXTEEN & WEST | SOW 1 MEDIA BUYING | EE Campaign (TV, radio, and digital) | 2022-02-28 00:00:00.000 |
| 36.11 | ESP PRINTING & MAILING | INVOICE 64920 ESP PRINTIN | Printing/mailing charge | 2022-03-31 00:00:00.000 |
| 32.41 | MCCLATCHY CO LLC, THE | SALES TAX, NON-P.O. | Print ad | 2022-10-31 00:00:00.000 |
| 31.20 | IDAHO PRESS-TRIBUNE | INVOICE 217976 EE GUIDE | Print ad | 2022-08-31 00:00:00.000 |

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| 28.75 | MISC CORRECTIONS 3 | IDAHO STATE PUBLISHING | Print ad | 2022-09-30 00:00:00.000 |
| 28.44 | AUTOSORT | INVOICE 116126 OFFSITE PR | Printing charge | 2022-05-31 00:00:00.000 |
| 27.90 | ONE SIXTEEN & WEST | INVOICE 19440 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 26.00 | STAR NEWS | INVOICE 58485 CORP COMM A | Print ad | 2022-07-31 00:00:00.000 |
| 25.50 | ARGUS OBSERVER | INVOICE 0922437427 ARGUS | Print ad | 2022-10-31 00:00:00.000 |
| 25.50 | POWER COUNTY PRESS, THE | INVOICE 22087 IRRIGATION | Print ad | 2022-06-30 00:00:00.000 |
| 25.00 | CREE CORRECTIONS NOV 2022 | INVOICE 1006947010 ADVERT | Print ad | 2022-12-31 00:00:00.000 |
| 21.52 | ONE SIXTEEN & WEST | INVOICE 19354 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-11-30 00:00:00.000 |
| 21.49 | THOM,MELISSA W | FACEBK V2LFZEF3Z2 | Social media | 2022-08-31 00:00:00.000 |
| 19.60 | LAMAR COMPANIES | INVOICE113891451 LAMARCO | Electronic billboards | 2022-08-31 00:00:00.000 |
| 18.65 | ROSANDICK,JULIE A | EB 2022-2023 BOMA IDA | Sponsorship | 2022-10-31 00:00:00.000 |
| 17.81 | OWYHEE AVALANCHE | INVOICE 44179 PRINT AD | Print ad | 2022-03-31 00:00:00.000 |
| 17.81 | OWYHEE AVALANCHE | INVOICE 45816 IRRIGATION | Print ad | 2022-09-30 00:00:00.000 |
| 16.45 | LAMAR COMPANIES | INVOICE 113891451 LAMARCO | Electronic billboards | 2022-08-31 00:00:00.000 |
| 15.74 | TIMES-NEWS | INVOICE 36763 EE GUIDE IN | Print ad | 2022-07-31 00:00:00.000 |
| 15.00 | POWER COUNTY PRESS, THE | INVOICE 22088 EE INSERT | Print ad | 2022-06-30 00:00:00.000 |
| 13.50 | CREE CORRECTIONS YTD 2022 | INVOICE 22080016 RADIO AD | Radio | 2022-12-31 00:00:00.000 |
| 13.25 | WEST,KRISTA J | BOISE METRO CHAMBER OF CO | Print ad | 2022-03-31 00:00:00.000 |
| 11.76 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 11.51 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 11.50 | WEST,KRISTA J | IN IDAHO WORLD PUBLISHIN | Print ad | 2022-09-30 00:00:00.000 |
| 10.86 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 10.25 | RECORDER HERALD | INVOICE JUNE CORP COMM AD | Print ad | 2022-07-31 00:00:00.000 |
| 10.25 | RECORDER HERALD | INVOICE JUNE CORP COMM AD | Print ad | 2022-07-31 00:00:00.000 |
| 10.12 | AUTOSORT | INVOICE 115993 OFFSITE PR | Printing charge | 2022-04-30 00:00:00.000 |
| 10.02 | MEYER,ANNIE L | AMAZON.COM DG0OV7F73 AMZN | Contest prizes | 2022-09-30 00:00:00.000 |
| 10.02 | MEYER,ANNIE L | AMAZON.COM IK2G616Z3 | Contest prizes | 2022-09-30 00:00:00.000 |
| 10.02 | MEYER,ANNIE L | AMAZON.COM FN3PF9O83 | Contest prizes | 2022-09-30 00:00:00.000 |
| 10.02 | MEYER,ANNIE L | AMAZON.COM 4Z8FM8II3 | Contest prizes | 2022-09-30 00:00:00.000 |
| 10.02 | MEYER,ANNIE L | AMAZON.COM 4J3EK0O73 AMZN | Contest prizes | 2022-09-30 00:00:00.000 |
| 10.02 | MEYER,ANNIE L | AMAZON.COM DJ7SP3A53 AMZN | Contest prizes | 2022-09-30 00:00:00.000 |
| 10.02 | MEYER,ANNIE L | AMAZON.COM Z85B50O33 | Contest prizes | 2022-09-30 00:00:00.000 |
| 10.02 | MEYER,ANNIE L | AMAZON.COM MJ3WX64U3 AMZI | Contest prizes | 2022-09-30 00:00:00.000 |
| 9.98 | MEYER,ANNIE L | AMAZON.COM 1U1XB6FJ1 AMZN | Contest prizes | 2022-10-31 00:00:00.000 |

| | | | | |
|---|---|---|---|---|
| 9.93 | MEYER,ANNIE L | AMAZON.COM E72O007X3 | Contest prizes | 2022-10-31 00:00:00.000 |
| 9.75 | MISC CORRECTIONS 3 | IDAHO STATE PUBLISHING | Print ad | 2022-09-30 00:00:00.000 |
| 9.50 | AUTOSORT | INVOICE 116370 OFFSITE PR | Printing charge | 2022-05-31 00:00:00.000 |
| 8.95 | LEE FAMILY BROADCASTING INC | INVOICE 3087000170000 SOW | Radio | 2022-03-31 00:00:00.000 |
| 8.95 | LEE FAMILY BROADCASTING INC | INVOICE 3087-00017-0001 M | Radio | 2022-04-30 00:00:00.000 |
| 8.63 | MOUNTAIN HOME NEWS | INVOICE 1928331 MOUNTAIN | Print ad | 2022-07-31 00:00:00.000 |
| 7.26 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 7.00 | MALHEUR ENTERPRISE | INVOICE 11436 EE AD INSER | Print ad | 2022-07-31 00:00:00.000 |
| 7.00 | WEST,KRISTA J | IN COOL CREEK PUBLISHING | Print ad | 2022-07-31 00:00:00.000 |
| 6.90 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 6.85 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 6.76 | OWYHEE AVALANCHE | | Print ad | 2022-07-31 00:00:00.000 |
| 6.38 | OWYHEE AVALANCHE | INVOICE 45492 EE GUIDE | Print ad | 2022-07-31 00:00:00.000 |
| 6.36 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 6.36 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 6.00 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 5.67 | THOM,MELISSA W | LINKEDIN-693 4005156 | Social media | 2022-06-30 00:00:00.000 |
| 5.58 | AUTOSORT | INVOICE 116743 OFFSITE PR | Printing charge | 2022-06-30 00:00:00.000 |
| 5.25 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 5.08 | THOM,MELISSA W | LINKEDIN-697 5751756 | Social media | 2022-06-30 00:00:00.000 |
| 5.06 | THOM,MELISSA W | LINKEDIN-701 4336586 | Social media | 2022-07-31 00:00:00.000 |
| 5.02 | THOM,MELISSA W | LINKEDIN-695 4559736 | Social media | 2022-06-30 00:00:00.000 |
| 4.50 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 4.45 | THOM,MELISSA W | LINKEDIN-699 3817366 | Social media | 2022-07-31 00:00:00.000 |
| 4.25 | HELLS CANYON JOURNAL, THE | INVOICE 67045 EE INSERT | Print ad | 2022-07-31 00:00:00.000 |
| 4.25 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 3.47 | THOM,MELISSA W | LINKEDIN-704 2383316 | Social media | 2022-07-31 00:00:00.000 |
| 2.85 | THOM,MELISSA W | LINKEDIN-691 6728726 | Social media | 2022-06-30 00:00:00.000 |
| 1.43 | ONE SIXTEEN & WEST | INVOICE 18950 SOW 1 MEDIA | EE Campaign (TV, radio, and digital) | 2022-08-31 00:00:00.000 |
| 0.55 | FREEMAN,ALEXIS B | ONECARD ACCRUAL | Social media | 2022-12-31 00:00:00.000 |
| 0.36 | MEYER,ANNIE L | ONECARD ACCRUAL | Contest prizes | 2022-12-31 00:00:00.000 |
| 0.10 | FREEMAN,ALEXIS B | ONECARD ACCRUAL | Social media | 2022-12-31 00:00:00.000 |
| 0.10 | FREEMAN,ALEXIS B | ONECARD ACCRUAL | Social media | 2022-12-31 00:00:00.000 |
| 0.05 | ONE SIXTEEN & WEST | | EE Campaign (TV, radio, and digital) | 2022-03-31 00:00:00.000 |

| | | | | |
|---|---|---|---|---|
| 0.01 | FREEMAN,ALEXIS B | ONECARD ACCRUAL | Social media | 2022-12-31 00:00:00.000 |
| (6.37) | OWYHEE AVALANCHE | | | 2022-07-31 00:00:00.000 |
| (10.25) | RECORDER HERALD | INVOICE JUNE CORP COMM AD | | 2022-07-31 00:00:00.000 |
| (16.45) | LAMAR COMPANIES | INVOICE 113891451 LAMARCO | | 2022-08-31 00:00:00.000 |
| (28.44) | CREE CORRECTIONS AUG 2022 | INVOICE 116126 OFFSITE PR | | 2022-09-30 00:00:00.000 |
| (32.41) | MCCLATCHY CO LLC, THE | INVOICE 133533 IDAHO STA | | 2022-10-31 00:00:00.000 |
| (38.50) | MISC CORRECTIONS 3 | IDAHO STATE PUBLISHING | | 2022-09-30 00:00:00.000 |
| (47.75) | CREE CORRECTIONS YTD 2022 | INVOICE 1006933412 IBR RE | | 2022-12-31 00:00:00.000 |
| (58.47) | CAPITAL PRESS | INVOICE 012218477 CAPITAL | | 2022-03-31 00:00:00.000 |
| (60.35) | ONE SIXTEEN & WEST | INVOICE 127775 SOW 1 MEDI | | 2022-10-31 00:00:00.000 |
| (61.68) | CREE CORRECTIONS JUN 2022 | INVOICE 116531 OFFSITE PR | | 2022-07-31 00:00:00.000 |
| (68.75) | ONE SIXTEEN & WEST | INVOICE 2022-65008 SOW 1 | | 2022-02-28 00:00:00.000 |
| (77.79) | ALEXANDER CLARK PRINTING | COMMERCIAL/INDUSTRIAL EE | | 2022-06-30 00:00:00.000 |
| (100.02) | ONE SIXTEEN & WEST | SOW 1 MEDIA BUYING #18395 | | 2022-05-31 00:00:00.000 |
| (102.00) | CREE CORRECTIONS YTD 2022 | INVOICES 522222640 AND 06 | | 2022-12-31 00:00:00.000 |
| (220.25) | CREE CORRECTIONS DEC 2021 P2 | RES NEW CONS PO 00187590 | | 2022-01-31 00:00:00.000 |
| (236.59) | CREE CORRECTIONS FEB 2022 | EE SPRING TIPS BILL | | 2022-03-31 00:00:00.000 |
| (536.44) | MCCLATCHY CO LLC, THE | INVOICE 261550 EE GUIDES | | 2022-09-30 00:00:00.000 |
| (2,794.34) | ONE SIXTEEN & WEST | INVOICE 018812 SOW 1 MEDI | | 2022-08-31 00:00:00.000 |
| 13,713.15 | DECEMBER 2022 CONNEC | | Bill Insert - Project Share | 2022-12-31 00:00:00.000 |
| **70,672.67** | | | | |

CASE: UE 426
WITNESS: Luz Mondragon

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 900

## REDACTED
## OPENING TESTIMONY
### Expense for Customer Service and Customer Accounts, Transmission and Distribution O&M, Wildfire Mitigation Expense and Plant in Service, Gains/Sales of Property, Affiliated Interests
## Subject to General Protective Order No. 23-132

## March 25, 2024

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

A. My name is Luz Mondragon. I am a Senior Financial Analyst employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) 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/901.

**Q. What is the purpose of your testimony?**

A. My opening testimony discusses Staff's analysis and position on the following issues:

- Test Year expenses for Customer Account Expenses and Customer Service: Information and Sales Expense (Operations and Maintenance Non-Labor);
- Test Year expenses for Transmission and Distribution O&M Expenses (Non-Labor);
- Test Year expenses for Wildfire Mitigation Capital Placed in Service;
- Test Year expenses for Wildfire Mitigation O&M Expenses;
- Gains/sales on Property; and
- Affiliated interests

**Q. Did you prepare any exhibits for this docket?**

A. Yes. I prepared the following supporting exhibits:

Exhibit Staff/901. Witness Qualification
Exhibit Staff/902. Exhibits in Support of Opening Testimony
Exhibit Staff/903. Burke Inc, Idaho Power Q4, 2023 Scorecard (CONF)
Exhibit Staff/904. JD Power Electric Utility Residential Customer Satisfaction study (CONF)

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

Issue 1. Customer Accounts and Customer Service O&M (NL).................. 3

Issue 2. Transmission and Distribution O&M Non-labor ........................... 15
Issue 3. Wildfire Mitigation Costs ............................................................ 21
Issue 4. Gain/Loss on Sale of Propert ..................................................... 30
Issue 5. Affiliated Interest......................................................................... 33
Summary .................................................................................................. 36

**Q. Could there be changes or updates to Staff's position and recommendations?**

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

**ISSUE 1. CUSTOMER ACCOUNTS AND CUSTOMER SERVICE O&M (NON-LABOR)**

**Q. Please describe the activities and expenses associated with Customer Account Expenses and Customer Service: Sales and Information 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 Exhibit 600/Farrell.

Customer Service expense consists of FERC Accounts 906-910 (excluding 909 Informational and Instructional Advertising Expenses, which was analyzed separately). These expenses are for Supervision and expenses incurred in customer service and informational activities to encourage safe and efficient use of the utility's service, as well as to encourage conservation and to answer inquiries regarding proper use of the service.

**Q. How did Staff perform its analysis of the Company's Base Year costs recorded in FERC Accounts 901-910?**

A. Staff reviews expenses for 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.

Staff reviewed historical trends and Company's adjustments, as well as the Company's transactional data in its DR 57, and submitted multiple DRs inquiring about expense. Then, Staff reviewed the Company's adjustments to Base Year within the included FERC accounts. Adjustments were made for the following purposes:[1]

- COVID-19 adjustments to Uncollectibles: $198 thousand.
- Removal of Idaho Energy Efficiency Rider: ($31.7 million).
- Removal of the Oregon Energy Efficiency Rider: ($1.5 million).
- Miscellaneous reductions for memberships not included in the request: ($20,000).

**Q. Please describe the Company's customer account and customer service expenses in the Base Year.**

A. Idaho Power's Base Year is January through December 2022. For Customer Account expenses (FERC Accounts 901-903 and 905), the Company reported a Base Year Oregon allocated non-labor total of $212 thousand.

For Customer Service Sales and Information Expenses (FERC Accounts 906-910, excluding 909 Advertising) the Company reported a Base Year Oregon allocated non-labor total of $66 thousand.[2]

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1 Staff/Exhibit 902, Idaho Power's response to Staff DR 157.
2 Staff/Exhibit 902, Idaho Power's response to SDR 58.

*Figure 1: Base Year System Wide and Oregon Allocated*

**Idaho Power Company**

| | Actual Base Year Ending December 31, 2022 | | | | |
|---|---|---|---|---|---|
| | Allocations | | | | |
| | n) | p) | q) | r) | s) |
| Account | Total Regulated Utility Service | Oregon Alloc. Factor | Oregon Alloc./ Share | Oregon Situs | Total Included in Filed Rate Case q+r |
| Customer Account Expenses | | | | | |
| 901 | 48,414 | 0.0499 | 2,414 | | 2,414 |
| 902 | 393,056 | 0.1339 | 52,613 | | 52,613 |
| 903 | 4,775,985 | 0.0328 | 156,795 | | 156,795 |
| 905 | (3,031) | 0.0596 | (181) | | (181) |
| | | | | | **211,641** |
| Customer Service & Informational/Sales Expenses | | | | | |
| 907 | 66,663 | 0.0266 | 1,775 | | 1,775 |
| 908 | 2,028,588 | 0.0266 | 54,003 | | 54,003 |
| 910 | 392,661 | 0.0268 | 10,540 | | 10,540 |
| | | | | | **66,318** |

Customer Account Expenses (FERC Accounts 901-903, 905): Customer records and collection expenses (FERC 903) make up 74 percent of the Base Year Non-Labor expenses recorded in these accounts. This is largely for postage costs at 42 percent and Other Purchased Services at 30 percent.

Customer Service & Information/Sales Expenses (FERC Accounts 906-908, 910): Customer Assistance Expense (FERC 908) makes up 81 percent of the Base Year Non-Labor expenses. Customer assistance expense includes expense for the Oregon Solar Photovoltaic Pilot Program (OSPV) and Demand-side Management (DSM) services which, together, make up 97 percent of FERC 908.

- The OSPV program was implemented[3] to demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered by solar photovoltaic energy systems. The OSPV program has a tariff rider for the amounts associated with the incentive payments. The amount included in this rate case is for the labor related to the OSPV program.[4]
- DSM services include planning, implementing, and monitoring activities designed to encourage customers to modify and change patterns of electricity use. Idaho Power has the Energy Efficiency Rider to fund most costs associated with the service. The amounts included in the Test Year are those primarily associated with Weatherization Assistance.[5]

**Q. How did Staff perform its analysis of the Company's Test Year Customer Accounting and Customer Service Expense?**

A. The Test Year for Idaho Power is the twelve months ending December 31, 2024. The Company is asking to increase Customer Account and Customer Service Expenses by $19 thousand, or 6.9 percent.

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[3] ORS 757.365 and *In the Matter Public Utility Commission of Oregon Investigation into Pilot Programs to demonstrate the use and effectiveness of Volumetric Incentive Rates for Solar Photovoltaic Energy Systems*.UM 1452, Order No. 10-198 (May 28, 2010).

[4] Staff/Exhibit 902, Idaho Power response to DR 418.

[5] Staff/Exhibit 902, Idaho Power response to DR 418.

*Figure 2: Base Year to Test Year*

| | 2022 Base Year | 2024 Test Year | Change $$ | % |
|---|---|---|---|---|
| Total Customer Account Expenses | 211,641 | 226,245 | 14,603 | 6.90% |
| Total CS & Info/Sales Expenses | 66,296 | 70,870 | 4,574 | 6.90% |
| | **277,937** | **297,114** | **19,177** | **6.90%** |

The adjustments made to the Customer Accounts and Customer Service Expense Base Year to arrive at the Test Year are inflation based. Idaho Power used an inflation adjustment for O&M accounts that was developed using the Consumer Price Index (CPI) as outlined from Moody's Analytics forecast for the calendar years 2023 and 2024, 4.1 and 2.7 percent respectively.[6] The resulting comprehensive CPI used to escalate is 6.9 percent.

Staff also compared the Test Year to growth and the three-year average based on the information provided in SDR 58b. It is important to note that Idaho Power provided actuals for calendar years 2020-2022. Calendar year 2023 actuals have not been provided and therefore could not be included in the analysis.

6 Idaho Power/1002, Larkin/13.

*Figure 3: Customer Expenses Analysis*

| | | Test Year to Base Year | | Test Year to Escalated Average | | Growth To Test Year | |
|---|---|---|---|---|---|---|---|
| Account | | $$ | % | $$ | % | $$ | % |
| Customer Account Expenses | | | | | | | |
| 901 | Operation: Supervision | 167 | 6.9% | 1,084 | 72.5% | 2,090 | 426.5% |
| 902 | Meter reading Expenses | 3,630 | 6.9% | (9,928) | -15.0% | (7,357) | -11.6% |
| 903 | Customer records and collection expenses | 10,819 | 6.9% | (4,342) | -2.5% | (9,437) | -5.3% |
| 905 | Misc. Customer accounts expenses | (12) | 6.9% | (141) | 267.0% | (201) | -2596.9% |
| | | **14,603** | **6.9%** | **(13,326)** | **-5.6%** | **(14,904)** | **-6.2%** |
| Customer Service & Informational; Sales Expense | | | | | | - | 0.0% |
| 907 | Operation: Supervision | 122 | 6.9% | 342 | 22.0% | 1,508 | 388.1% |
| 908 | Customer Assitance Expense | 3,725 | 6.9% | 4,135 | 7.7% | 9,514 | 19.7% |
| 910 | Misc. Customer service and informational expenses | 727 | 6.9% | 820 | 7.8% | 3,113 | 38.2% |
| | | **4,574** | **6.9%** | **5,296** | **8.1%** | **14,135** | **24.9%** |
| Total Customer Expense | | 19,177 | 6.9% | (8,029) | -2.6% | (770) | -0.3% |

**Q. What other analysis did Staff conduct in regard to Customer Accounts and Customer Service Expenses?**

A. Staff issued several DRs inquiring about support to customers, customer satisfaction surveys, First Call Resolution, routing queues, project share, and Customer Service enhancements, which are discussed below.

**Q. What were Staff's findings regarding Idaho Power's Customer Satisfaction surveys?**

A. Idaho Power uses two companies to conduct customer satisfaction surveys. The first is Burke, Inc which provides Idaho Power's primary customer satisfaction research. They conduct quarterly customer relationship surveys and help determine the Company's Customer Relationship Index (CRI), which is a key metric used to evaluate the Company's overall customer satisfaction rate.[7] The annual cost of this service was $224 thousand in 2022 and 2023.

The second is J.D Power, which prepares an Electric Utility Residential Customer Satisfaction Study—a quarterly report used by the Company to benchmark to other electric utilities. The annual cost of this service was $106 thousand in 2022 and $60 thousand in 2023. The difference between 2022 and 2023 is due to a digital study JD Power and Associates conducted in 2022.

The Company states that results of the Burke, Inc survey have been used by Idaho Power, not only as a metric but to identify performance and experience gaps based on customer feedback. Customer input is integrated into the Company's processes and initiatives, which have resulted in the Company implementing a no-fee payment option on the website in 2012 and enhanced bill estimates for larger customers.[8] The visual of the results of the Burke, Inc survey is displayed below, and the full results are included as confidential Exhibit 903.

7 Idaho Power/600, Hanchey/6.
8 Staff/Exhibit 902, Idaho Power response to DR 337.

**[BEGIN CONFIDENTIAL**

[redacted]

**[END CONFIDENTIAL]**

The survey noted that in 2022, customer satisfaction decreased in comparison to the five years immediately prior. Idaho Power states that the decrease from 85.5 to 83.95 percent is a trend within the industry and partially attributable to factors outside the Company's control such as inflationary pressures.[9]

Results of the JD Power Electric Utility Residential Customer Satisfaction study include over 100 thousand customer responses nationwide, including Idaho Power's. Benchmarking against other utilities has helped the Company narrow in and focus on areas of improvement based on the positive impact to customers other utilities have experienced such as Idaho Power's mobile App

9 Idaho Power/600, Hanchey/7.

and improvements to My Account.[10] The JD Power study indicated that Idaho Power ranked third out of 17 within the West Midsize electric utility segment for overall residential customer satisfaction and sixth out of 92 in investor-owned utilities.[11] Visual results of the JD Power study are displayed below and the full results are included as confidential Exhibit 904.

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

**Q. Please summarize Idaho Power's First Call Resolution rate (FCR), Project share, and Customer Service enhancements.**

[10] Staff/Exhibit 902, Idaho Power response to DR 337.
[11] Idaho Power/600, Hanchey/7.

A. The First Call Resolution is Idaho Power's attempt to resolve customer concerns on the first call. The FCR rate is based on the total number of calls placed to the Company by the same phone number within a 24-hour period. In the last five years, the FCR rate for Idaho Power has been above 73 percent. The FCR ranges define a percentage of 71 to 79 percent as "Good."[12]

Project Share was established in 1982 and is administered by the Salvation Army. Funding is provided by customers, shareholders, other utilities, and private donation. 100 percent of donations go to Project Share recipients, which can be used to pay electric bills. In response to the cost pressures that customers are experiencing, contributions by shareholders have increased to $125 thousand in 2023 and will continue into 2024.[13] Fifty out of 1,429 customers that received Project Share funds in 2022/2023 are Oregon residential customers and make up about 3.5 percent of customers in the program.[14]

Idaho Power is pursuing enhancement of its digital offerings as part of Customer Service enhancements. Idaho Power states that investments to update the My Account platform allow customers to electronically elect flexible payment options, participate in Clean Energy Your Way, contribute to Project Share, and enroll in outage and account alerts among other enhancements.[15] Total costs to implement the update to My Account have totaled $6 million

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12 Staff/Exhibit 902, Idaho Power response to DR 151.
13 Idaho Power/10, Grow/20-21.
14 Staff/Exhibit 902, Idaho Power response to DR 225.
15 Idaho Power/600, Hanchey/9.

(system-wide) from 2019 through 2022. Ongoing associated costs for the 2024 Test Year are forecasted at $1.3 million (system-wide).[16]

In 2022, Idaho Power released a Mobile App. The Mobile App offers nearly all the same enhancements as My Account with additional push notification functionality. The costs to implement the Mobile App from 2021 through 2022 have totaled $1.6 million (system-wide), while ongoing costs for Test Year 2024 are forecasted at $303 thousand (system-wide).[17]

**Q. Please summarize the Company's "Idaho Power Cares Greeting Card" program.**

A. The Idaho Power Cares Greeting Card program was implemented in 2017. It enables customer-facing employees to send a Hallmark greeting card to a customer when they feel it is warranted.[18] In 2022 Idaho Power spent $31 thousand[19] in the program and sent out an average of fourteen cards each day.

Staff used Idaho Power's escalation method to calculate the Test Year amount for the project, which is $33,045.

**Q. Summarize Staff's analysis of the Customer Account and Customer Service Expenses.**

A. Staff issued and analyzed several DRs regarding multiple aspects of customer service/support, as well as financial information and trends. In Staff's financial

[16] Staff/902, Idaho Power response to DR 154.
[17] Staff/902, Idaho Power response to DR 154.
[18] Idaho Power/600, Hanchey/23.
[19] Staff/902, Idaho Power response to DR 149.

analysis, numbers line up with inflation and fall below a three-year average of historical costs. The customer satisfaction surveys provided by the Company reflect that overall customers are satisfied with the service and Idaho Power is taking steps to keep up with industry trends of customer service.

However, in Staff's analysis of year over year actuals, Staff found a $16 thousand damage claim payment in 2022.[20] Staff doesn't feel it prudent to include this amount in the Base Year and escalate it for the Test Year.

Staff also found that the "Idaho Power Cares Greeting Card" program is not necessary the provision of utility service and mostly benefits the Company by promoting its corporate image.

**Q. Does Staff recommend an adjustment?**

A. Staff proposes to Adjust the Test Year as follows:

- ($33,045) system-wide, ($887) Oregon-allocated, to expense recorded in FERC Account 910 for the "Idaho Power Cares Greeting Card" program, escalated.
- ($17,104) system-wide, ($853) Oregon-allocated, to expense recorded in FERC Account 901 for damage payment, escalated.

[20] Staff/902, Idaho Power response to DR 416.

## ISSUE 2. TRANSMISSION AND DISTRIBUTION O&M NON-LABOR

**Q. What is the company's proposal for Transmission and Distribution Operation and Maintenance non-labor expense?**

A. Idaho Power is proposing to increase the Oregon allocated Transmission and Distribution (T&D) expense by approximately $109 thousand to $1.7 million. This is an increase of 6.9 percent.[21] This excludes Oregon allocated Wildfire Mitigation expenses, which will be analyzed in Issue 3.

*Figure 6: Base Year to Test Year*

| | System Wide | | | | Oregon Allocated | | | |
|---|---|---|---|---|---|---|---|---|
| | 2022 Base Year Adj. | 2024 Test Year | Change $$ | % | 2022 Base Year Adj. | 2024 Test Year | Change $$ | % |
| Total transmission | 21,236,104 | 22,701,372 | 1,465,269 | 6.90% | 873,901 | 934,199 | 60,298 | 6.90% |
| Total distribution | 15,856,206 | 16,950,267 | 1,094,061 | 6.90% | 716,310 | 765,735 | 49,425 | 6.90% |
| | 37,092,310 | 39,651,640 | 2,559,330 | 6.90% | 1,590,211 | 1,699,934 | 109,723 | 6.90% |

**Q. How did Idaho Power Determine its Test Year estimate?**

A. Idaho Power took its 2022 actuals and adjusted for certain memberships, contributions, as well as portions of officer expenses allocated between Idaho Power and IDACORP, and other business expenses removed from regulatory recovery.[22] The Idaho Wildfire Mitigation (WM) deferred costs are then added back in to get an all-inclusive Base Year.[23]

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21 Staff/902, OR O&M Account Allocation-Jeppsen Workpaper 1.
22 Staff/902, Idaho Power response to DR 256.
23 Staff/902, OR O&M Account Allocation-Jeppsen Workpaper 1.

*Figure 7: Adjustments to T&D Actuals*

| FERC Account | Adjustment | Narrative explanation |
|---|---|---|
| 560000 | ($6) | Reduction of the IDACORP allocated portion of officer expense. |
| 562000 | ($1,446) | Reduction of 33.33% membership expense - Utilities Technology Council. |
| 562000 | ($7) | Reduction of the IDACORP allocated portion of officer expense. |
| 570000 | ($482) | Reduction of 33.33% membership expense - Utilities Technology Council. |
| 570000 | ($7) | Reduction of the IDACORP allocated portion of officer expense. |
| 580000 | ($10) | Reduction of the IDACORP allocated portion of officer expense. |
| 582000 | ($7) | Reduction due to nature of the business establishment. |
| 583000 | ($46) | Reduction due to nature of the business establishment. |
| 586000 | ($73) | Reduction due to nature of the business establishment. |
| 588000 | ($683) | Reduction of 33.33% membership expense - The Electrical Apparatus Service Association. |
| 588000 | ($327) | Reduction due to nature of the business establishment. |
| 592000 | ($344) | Reduction of 33.33% membership expense - Utilities Technology Council. |
| 592000 | ($7) | Reduction due to nature of the business establishment. |
| 593000 | ($7,000) | 100% reduction of Donation. |

The resulting Base Year is then adjusted to the Test Year using the Idaho Power-developed comprehensive CPI of 6.9 percent.

**Q. How did Staff arrive at Transmission and Distribution O&M (NL) amounts that did not include Wildfire Mitigation?**

A. Staff issued DRs to get Wildfire Mitigation amounts included in the T&D FERC accounts. Staff then took the Base Year provided by Idaho Power and subtracted $25.8 million (system-wide) for Wildfire Mitigation Non-Labor costs.[24]

**Q. Please describe Staff's review and analysis of Distribution O&M (NL) Expenses.**

A. Distribution O&M expenses are tracked in FERC Accounts 580 through 598. The total Oregon allocated Base Year amount for distribution O&M, excluding Wildfire Mitigation, is $716 thousand.

[24] Staff/Exhibit 902-Idaho Power response to DR 285.

Distribution O&M expenses make up 45 percent of the Oregon Base Year T&D O&M expenses. The biggest contributor in this category on an Oregon-allocated basis is Maintenance of Overhead Lines (FERC Account 593) at $179 thousand.[25] All amounts in Distribution O&M non-labor are allocated and not situs to the state in which the work occurred. This is a deviation from what is usually seen in other multi-state utilities. Idaho Power's response to Data Requests regarding situs assignment of Distribution expense is that *"because the Company does not record O&M costs on a situs basis, the Company's method for jurisdictional allocation is a reasonable measure of cost causation".*[26]

Staff also calculated the three-year average (2020-2022) of actual expense for Distribution O&M and compared it to the Test Year expense. The Test Year expense for Distribution O&M (NL) shows a decrease from the three-year average of 27 percent. This could be due to wildfire mitigation activities that are now being tracked as WM program expenses.

**Q. Please describe Staff's review and analysis of Transmission O&M Expenses.**

A. Transmission O&M expenses are tracked in FERC Accounts 560 through 576. The total Oregon allocated Base Year amount for transmission O&M, excluding Wildfire Mitigation, is $874 thousand.

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[25] Calculated based on Idaho Power response to SDR 58 and DR 284.
[26] Staff/Exhibit 902, Idaho Power response to DR 255.

Transmission O&M expenses make up 55 percent of the Oregon allocated Base Year T&D O&M expenses. The biggest contributor in this category is Transmission of Electricity by Others (FERC Account 565) at $481 thousand.[27] Idaho Power has several long-term firm transmission agreements, three of which are new, beginning service in the past three years. The Company enters into long-term service agreements for the time periods and for megawatts necessary to ensure it can reliably serve load. Over the years, expense for Transmission of Electricity by Others has grown by 181 percent. Idaho Power states these costs "*are subject to the Transmission Provider's applicable rates, which are subject to review by the Federal Energy Regulatory Commission*" and consequently, outside their control. Idaho Power offsets the cost of transmission by selling excess load to other parties.[28]

The Staff calculated a three-year average of actual costs and compared it to the amount of Transmission O&M in the Test Year. The Test Year expense is 36 percent higher than the three-year historical average.[29] The biggest contributor to this increase is growth in FERC Account 565 Transmission of Electricity by Others.

[27] Staff/902, Idaho Power response to SDR 58 and DR 284.
[28] Staff/Exhibit 902, Idaho Power response to DR 332.
[29] Calculated based on Idaho Power response to DR 122.

*Figure 8: T&D Analysis*

| O&M Category | Test Year to Base Year | | Test Year to Average | | Growth to Test Year | |
|---|---|---|---|---|---|---|
| | $$ | % | $$ | % | $$ | % |
| Transmission-Non WM | (873,901) | 6.9% | (687,135) | 36% | (533,795) | 75% |
| Distribution-Non WM | (716,311) | 6.9% | (1,044,060) | -27% | (1,133,200) | -32% |
| | | | | | | |
| **Total T&D O&M Non-labor** | **(1,590,212)** | **6.9%** | **(1,731,195)** | **-2%** | **(1,666,995)** | **2%** |

**Q. Please describe the adjustments proposed for O&M expenses**

A. The Company submitted information on variances in account actuals over the years. In FERC Account 580 Operation Supervision and Engineering, for the years of 2021 and 2022, there was a variance of 235 percent, in part due to two write offs. The first was for costs associated with development of an in-house joint use system that was ultimately resolved via third-party software, the system-wide write off amount totaled $400,949. The second was for communication equipment written off due to change in scope of the project. The system-wide write off amount was $403,271.[30] The Oregon allocated amount for both write offs is $37,584.

**Q. Does Staff recommend an adjustment?**

A. Yes. Staff proposes to exclude $40,177 from the Test Year the amount. This is the Oregon allocated escalated amount associated with the write-offs and is approximately two percent of the total T&D O&M expense.

**Q. Does Staff have other issues related T&D O&M expense?**

A. Staff does have concerns with the allocation of costs to Oregon. Staff found that in multiple situations the allocation factor used to allocate costs Oregon is

[30] Staff/902, Idaho Power response to DR 476.

disproportionate to the actual service or activities in Oregon. For example, $35,000 is allocated to Oregon for Distribution: Operation-Rents (FERC Account 589) but it appears that only .01 percent of distribution rental/leased property is in Oregon.[31] Additionally, another $125 thousand in Cost Element Account 549 Other Rents & Leases is allocated to Oregon, when in actuality only $300 of rental/leased property were identified as being in Oregon.[32] Oregon allocation factors will be addressed in detail in Exhibit 200.

[31] Staff/902, Idaho Power Response to DR 380.
[32] Staff/902,Idaho Power Response to DR 381.

## ISSUE 3. WILDFIRE MITIGATION COSTS

**Q. Please summarize the key elements in Idaho Power's Wildfire Mitigation Plan (WMP).**

A. Idaho Power uses a risk-based approach in identifying, analyzing, and selecting mitigation measures. The Company focuses on five key elements in their WMP to reduce wildfire risk.[33] These elements are:

- Risk analysis and mapping: Utilizing a risk-based approach for decision making and quantifying wildfire risk throughout the Company's service area.
- Situational awareness: Informing Company operations and practices by incorporating new methods of visual, geographical, and contextual awareness of the environments in which Idaho Power operates, specifically during wildfire season.
- Mitigation activities: Expanding and/or enhancing many of the same programs that the Company has carried out over the course of its operating history to mitigate wildfire risk to decrease the likelihood of ignition events and protect infrastructure from wildfire regardless of where it starts.
- Communication: Communicating with and educating customers and the public about wildfire and outage preparedness.

[33] Idaho Power/500, Colburn/16-17.

- Monitoring and tracking performance: Routine analysis of wildfire mitigation activities to gauge their effectiveness and build continuous improvement and risk reduction over time.

**Q. How does Idaho Power identify wildfire risk areas?**

A. Idaho Power uses a formula to calculate risk by considering the probability of a wildfire event multiplied by impact of the event (i.e. homes, businesses, and other structures).

***Wildfire Risk = Fire Probability x Consequence***

Using the formula above, risk can be assessed geographically and areas with both high probability of fire and consequence would be elevated risk areas. The areas are then sorted into wildfire risk zones (WRZ) tiers.[34]

- Tier 2 Yellow Risk Zones (YRZ) are deemed increased risk areas.
- Tier 3 Red Risk Zones (RRZ) are deemed higher risk areas.
- Areas of minimal wildfire risk are not within Red or Yellow Zones.

Areas in the RRZ are given priority because of the increased risk levels. In 2022, Oregon had no Idaho Power identified Red Risk Zones and limited Yellow Risk Zones.[35] In 2024, the Company added three new YRZs and one RRZ in Oregon.[36]

**Q. Please describe Idaho Power's proposal regarding wildfire mitigation (WM) Capital Placed in Service.**

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34 UM 2209 Idaho Power 2022 WMP Page 5.
35 UM 2209(1) Idaho Power 2023 WMP Page 25.
36 UM 2209(2) Idaho Power 2024 WMP Table 4 Page 34.

A. Idaho Power seeks to include $12 million in rate base for wildfire capital investment through December 31, 2022. $1,641 of the $12 million would be allocated to Oregon, and is for:

- Development of Fire Potential Index (FPI) ($1,362), and
- Communication Equipment ($279).

*Figure 9: Capital Placed in Service and Allocated to Oregon*

| Account | Amount | a. Oregon Allocated % | b. Oregon Allocated $ |
|---|---|---|---|
| 30310 | $32,058 | 4.25% | $1,362.47 |
| 36200 | $5,575 | 0.00% | $0.00 |
| 36400 | $6,107,273 | 0.00% | $0.00 |
| 36500 | $649,104 | 0.00% | $0.00 |
| 36600 | $399,595 | 0.00% | $0.00 |
| 36700 | $1,777,402 | 0.00% | $0.00 |
| 36800 | $2,917,641 | 0.00% | $0.00 |
| 36900 | $163,123 | 0.00% | $0.00 |
| 37000 | $1,115 | 0.00% | $0.00 |
| 39730 | $6,564 | 4.25% | $278.97 |
| Total | $12,059,450 | | $1,641 |

**Q. Please describe the capital projects placed in service.**

A. The FPI tool enhances the Company's meteorological forecasting capabilities in order to increase situational awareness. The FPI tool accounts for weather, prevalence of fuel (trees, shrubs etc.), and topography, then converts that data into easily understood forecasts of the short-term fire threat. Forecasts are used daily to assess wildfire risk level during the fire season and supports operational decision-making in order to reduce wildfire threats and risks.

Additionally, the tool also helps determine if and when a Public Safety Power Shutoff may be necessary.[37]

Idaho did not provide much information regarding the communication equipment placed in service. In their response to an inquiry to describe the General Plant, they responded with "*The general plant assets are communication assets for distribution equipment.*"[38]

**Q. Please describe Idaho Power's proposal regarding wildfire mitigation O&M expenses.**

A. Idaho Power is proposing to spend $37.8 million (system-wide)[39] and include $1.84 million in Oregon-allocated Wildfire Mitigation O&M expenses for Test Year 2024.[40] Of the Oregon-allocated amount, Vegetation Management makes up the bulk of the Wildfire Mitigation plan at 93 percent, or $1.7 million.

*Figure 10: Oregon Planned WMP costs*

| | Oregon |
|---|---|
| Idaho Power Wildfire O&M Expenditures ($000s) | 2024 Planned |
| A. Quantifying Wildland Fire Risk | $ 0.5 |
| B. Situational Awareness | $ 23 |
| C. Mitigation - Field Personnel Practices | $ 2 |
| D. Mitigation - Transmission & Distribution Programs | $ 94 |
| E. Vegetation Management | $ 1,707 |
| F. Communications | $ 8 |
| G. Information Technology | $ 8 |
| Total | $ 1,842 |

37 Idaho Power/500, Colburn/25.
38 Staff/Exhibit 902, Idaho Power response to DR 342.
39 UM 2209(2) Idaho Power Company's Wildfire Mitigation Plan. Table 7/Pages 57-58.
40 UM 2270 (1) Idaho Power Company's Application for Deferred Accounting of Costs Associated with Wildfire Mitigation Activities (December 29, 2022).

**Q. Has Idaho Power addressed Wildfire Mitigation in previous General Rate Cases?**

A. The current General Rate Case (GRC) is the first time Idaho Power has addressed and included Wildfire Mitigation costs in their GRC. However, in their previous GRC UE 233, Idaho Power did include $10.7 million (system-wide) for Vegetation Management.

**Q. Please explain Vegetation Management as part of Idaho Power's WMP.**

A. As mentioned previously, Vegetation Management (VM) makes up the bulk of Idaho Power's Wildfire Mitigation costs. The Company inspects and prunes more than 400,000 trees in its system. Idaho Power has transitioned from a four-year pruning cycle to a three-year vegetation cycle and conducts mid-cycle patrols in the second year to address "cycle buster" trees. Annual "hotspot" patrols are used to address any new hazard trees and unexpected vegetative growth.[41] Idaho Power's 2022 expense allocable to Oregon was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[42] and they plan to allocate $1.705 million to Oregon in 2024.[43] The Company does not record O&M expenses on a situs basis,[44] so it is unclear how much of the vegetation in Oregon was actually inspected, pruned, trimmed, or removed in 2022, nor can the costs-benefit to the Oregon customer be assessed.

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[41] Idaho Power/500, Colburn/29-30.

[42] Staff/902, Idaho Power response to DR 287 CONFIDENTIAL.

[43] UM 2209(2) Idaho Power Company's Wildfire Mitigation Plan. Table 7/Page 57-58 and UM 2270(2) Application for Reauthorization to Defer Costs Associated with Wildfire Mitigation Activities (December 29, 2023).

[44] Staff/902, Idaho Power response to DR 291.

**Q. What analysis did Staff complete?**

A. Staff compared the Test Year to Base Year, and the three-year historical average of actual costs Staff also escalated Base Year expense using Idaho Power's CPI escalation and compared those results to the Test Year. This analysis was completed for System wide spend and for Oregon allocated amounts.

*Figure 11: Analysis of WMP Test Year*

**[BEGIN CONFIDENTIAL]**

[redacted]

[redacted]

**[END CONFIDENTIAL]**

The analysis demonstrates growth of the WM program at a good rate, while the Oregon-allocated amounts are growing at a smaller rate. Staff found amounts and percentages to be reasonable given the increase in efforts to mitigate wildfires.

**Q. How does Idaho Power allocate WM costs to Oregon and does Staff agree with the methodology?**

A. Idaho Power used an average jurisdictional separation factor of 6.9 percent to allocate WM costs to Oregon.[45] As mentioned previously, the Company does not record O&M expenses on a situs basis, instead they allocate O&M over the corresponding plant accounts.[46]

Staff disagrees with this methodology and suggests the Company keep appropriate records in order track actual distribution costs to Oregon. Additionally, Staff disagrees with the percentage used to allocate WM distribution costs to Oregon. Based on information provided in Table 4 below,[47] Idaho Power has 1,447 distribution pole miles in WRZs in its system. Out of those, 29 distribution pole miles are in Oregon. Based on those numbers, Staff recommends a two percent allocation factor be used to allocate WM distribution costs to Oregon.

**Table 4**
Idaho Power's transmission and distribution lines by risk zone in Idaho and Oregon*

| Asset | Total | Total Pole Miles within Wildfire | | Wildfire Risk Zone by State | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Tier 2 - Idaho | | Tier 3 - Idaho | | Tier 2 - Oregon | | Tier 3 - Oregon | | Tier 2 - Nevada | | Tier 3 - Nevada | |
| | Pole Miles | Pole Miles | % | Pole Miles | % | Pole Miles | % | Pole Miles | % | Pole Miles | % | Pole Miles | % | Pole Miles | % |
| Transmission Lines | 4,778 | 517 | 11% | 376 | 8% | 110 | 2% | 20 | 0.42% | 0 | 0% | 11 | 0.23% | 0 | 0% |
| Distribution Lines | 19,297 | 1,447 | 7% | 837 | 4% | 581 | 3% | 29 | 0.15% | 0 | 0% | 0 | 0% | 0 | 0% |
| Total Pole Miles | 24,075 | 1,964 | 8% | 1,213 | 5% | 691 | 3% | 49 | 0.20% | 0 | 0% | 11 | 0.05% | [illegible] | [illegible] |

*Geospatial analysis was performed in 2022 to reconfirm the pole miles in wildfire risk zones.

[45] Idaho Power/500 Colburn/22.
[46] Staff/902, Idaho Power response to DR 291.
[47] Idaho Power/502, Colburn/35.

**Q. What applicable law governs or provides guidance for Wildfire Mitigation cost recovery in Oregon?**

A. In June 2021, Oregon legislature passed Senate Bill (SB) 762, which directs utilities that provide electricity to have a wildfire mitigation plan (WMP) to be filed with, and evaluated by, the Commission. Section 3 of SB 762 outlines the utility's responsibilities and requirements, requiring the utility to plan reasonable and prudent practices and in a manner that seeks to protect public safety, reduce risk to utility customers, and promote electrical system resilience to wildfire damage.[48]

In addition to SB 762, ORS 757.963(1) provides that "[a] public utility that provides electricity must have and operate in compliance with a risk-based wildfire protection plan that is filed with the Public Utility Commission and has been evaluated by the commission." ORS 757.963(8) provides that "[a]ll reasonable operating costs incurred by, and prudent investments made by, a public utility to develop, implement or operate a wildfire protection plan are recoverable in the rates of [a] public utility ...."

**Q. Does Staff support the Company's proposal to have WM costs included in the GRC?**

A. Yes. Staff supports the Company's proposal to include WM costs in base rates.

**Q. Does Staff recommend an adjustment?**

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[48] Oregon Senate Bill 762 (2021).

A. Yes. Staff recommends reducing the Oregon allocated WMP Test Year amount by $1.06 million to $781 thousand, based on a two percent allocation factor for distribution O&M.

## ISSUE 4. GAIN/LOSS ON SALE OF PROPERTY

**Q. How does Idaho Power treat Gains and losses on the sale of property?**

A. Idaho power records the sale of Plant Held for Future Use in accounts 411.6 for gains and 411.7 for losses. Gains in sales of Electric Plant in Service is recorded in FERC accounts 421.1 while losses are recorded in account 421.2. Gains and losses are not a component of Idaho Power's revenue requirement and therefor not allocated or passed down to customers. However, the sales of the property in Boardman to Portland General Electric is credited to Oregon customers thorough the Boardman Balancing Account mechanism. [49]

**Q. Did Idaho Power Corporation sell any assets since their last rate case? If so, what were the results?**

A. Since their last rate case, Idaho Power has sold 15 assets resulting in a Gain on Sale of $702 thousand.[50] Out of that amount only $11,500 has been allocated to Oregon.

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[49] Idaho Power response to DR 210.
[50] Idaho Power response to DR 211.

Net Gains/Losses on Sale of Property
2012-2023

| FERC Account | Company's Internal Account | Description | Counter Party | Location County, State | Total Gain/Loss since 2012 |
|---|---|---|---|---|---|
| 411.6 | 411600 | **GAIN ON DISP OF UTILITY PLANT** | | | |
| | | Dry Creek Substation Land | Private Party | Ada, ID | |
| | | Donnelly-McCall Land | Valley County | Valley, ID | |
| | | GAIN ON DISP OF UTILITY PLANT | | | (6,042.93) |
| 411.7 | 411700 | **LOSS ON DISP OF UTILITY PLANT** | | | |
| | | AJ Wiley Land | Private Party | Gooding, ID | |
| | | Castlerock Substation Land | Private Party | Twin Falls, ID | |
| | | LOSS ON DISP OF UTILITY PLANT | | | 6,766.06 |
| 421.1 | 421190 | **GAIN ON DISP OF PROPERTY** | | | |
| | | Boise Bench Substation Land | Ada County Highway District | Ada, ID | |
| | | Boardman Common Property | Portland General Electric | Morrow, OR | |
| | | Boise Operations Center Land | Ada County Highway District | Ada, ID | |
| | | Water Management Facility Land | Ada County Highway District | Ada, ID | |
| | | Hillsdale Subsubstation Land | Ada County Highway District | Ada, ID | |
| | | Hoku Substation Transformer | Private Party | Bannock, ID | |
| | | Ten Mile Substation Land | Ada County Highway District | Ada, ID | |
| | | Victory Substation Land | Ada County Highway District | Ada, ID | |
| | | GAIN ON DISP OF PROPERTY | | | (732,816.48) |
| 421.2 | 421200 | **LOSS ON DISP OF PROPERTY** | | | |
| | | Hemingway Substation Land | Owyhee County | Owyhee, ID | |
| | | Hillsdale Substation Land | Ada County Highway District | Ada, ID | |
| | | Peterson Substation Land | NW Energy | Beaverhead, MT | |
| | | LOSS ON DISP OF PROPERTY | | | 30,560.62 |
| | | Total Gain on Sale | | | (701,532.73) |

**Q. How do other multi-state utilities treat Gains/Losses on Sale of Property?**

A. PacifiCorp maintains a property sales balancing account that "flows through" any net gains or losses to customers.[51] Northwest Natural uses a schedule to pass down net gains to the customer through a one-time credit in the PGA.[52]

[51] UE 399 Staff/100, Fjeldheim/16.
[52] UG 435 Staff/302, Fox/68.

Avista does not maintain a balancing account to flow through the net gains/losses to customers as it reports few sales with small values.[53]

**Q. How does Idaho Power allocate Plant when it is purchased?**

A. Depending on the type of Plant, Idaho Power either direct assigns, uses the Coincident Peak (CP), or uses a factor of transmission service at the generation level to allocate to Oregon.

**Q. Is Staff proposing any adjustments related to gain / loss on the sale of property**

A. Staff does not propose an adjustment at this time but is issuing additional DRs to finalize the analysis.

[53] UG 433 Staff/1000, Zarate/2

## ISSUE 5. AFFILIATED INTEREST

**Q. Does Idaho Power have any affiliated interest subsidiaries.**

A. Yes, Idaho Power wholly owns Idaho Energy Resources (IERCo). IERCo's primary purpose is to mine the coal for the Bridger plant in Wyoming.[54] IERCo, has a one-third joint venture interest in the Bridger Coal Company (BBC) mine. PacifiCorp holds the other two-thirds interest. As one-third owner, IERCo's is entitled to 33 percent of net income and cash-flow.[55]

**Q. What is Idaho Power's treatment of IERCo in this rate case?**

A. Idaho Power adds IERCo's current year's earnings to Idaho Power's operating income. Capital investments are also added to rate base. In order for IERCo's rate base and earnings to reflect only the cash required to fund operations, adjustments are made to increase the rate base for notes payable to Idaho Power and the associated interest expense adjustment net of income tax.[56]

**Q. Explain IERCo's Base Year and Test Year.**

A. Idaho Power decreased the Base Year Cost of Service Components (FERC 418.1 and 419) by $6.5 million to arrive at a projected net income of $2.37 million for the Test Year. The adjustment estimates PacifiCorp's projected activity in the BBC mine and a $3 million earnings margin.[57]

IERCo Statement of Income[58]

[54] Idaho Power/900, Jeppsen/11.
[55] Idaho Power/1002, Larkin/23.
[56] Idaho Power/900, Jeppsen/11-12.
[57] A more detailed explanation of each line adjustment was provided in Idaho Power's response to DR 194.
[58] Idaho Power/901, Jeppsen/13.

| (1) Line No | (2) Description | (3) 2022 Actuals | (4) 2022 Adjustments | (5) 2022 Base | (6) Forecast Adjustment | Ref No | (7) 2024 Test Year |
|---|---|---|---|---|---|---|---|
| | Income: | | | | | | |
| 1 | Bridger Coal Company - joint venture | $ 10,211,212 | $ - | $ 10,211,212 | $ (7,211,212) | | $ 3,000,000 |
| 2 | Bridger Coal Company - overriding royalties | 247,311 | - | 247,311 | (14,817) | | 232,494 |
| 3 | Interest and dividend income | 3,248 | - | 3,248 | (3,248) | | - |
| 4 | Taxes Other than Income Taxes | - | - | - | - | | - |
| 5 | Total income | 10,461,771 | - | 10,461,771 | (7,229,277) | | 3,232,494 |
| | Expenses: | | | | | | |
| 6 | Operation expense | 247,311 | - | 247,311 | (14,817) | | 232,494 |
| 7 | Income taxes | 1,330,515 | - | 1,330,515 | (841,104) | | 489,411 |
| 8 | Provision for deferred income taxes | - | - | - | - | | - |
| 9 | Intercompany interest expense | 101,905 | - | 101,905 | 567,568 | | 669,473 |
| 10 | Interest expense | - | - | - | - | | - |
| 11 | Total expenses | 1,679,731 | - | 1,679,731 | (288,353) | | 1,391,378 |
| 12 | Net income from operations | 8,782,040 | - | 8,782,040 | (6,940,924) | | 1,841,116 |
| 13 | Add: Interest expense from notes payable to parent (Net of Tax) | 77,939 | - | 77,939 | 450,945 | | 528,884 |
| 14 | Net income (earnings to Idaho Power Company) | $ 8,859,979 | $ - | $ 8,859,979 | $ (6,489,979) | 1 | $ 2,370,000 |

Idaho Power then increases the rate base (FERC 123.1, 186 and 145) by $1.8 million above the 2022 thirteen-month average, to $31.3 million. The projected investment is calculated based on the actual 2022 activity and as one-third owner of the BBC mine.[59]

<u>IERCo Rate Base Components</u>[60]

[59] Idaho Power/1002, Larkin/31-32.
[60] Idaho Power/901, Jeppsen/21.

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | | (10) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2022 Actuals | | | | | | | | |
| Line No | Month | Investment | Advance Coal Royalties | Notes Rec from Subsidiary | Total | 2022 Adjustments | 2022 Base | Forecast Adjustment | Ref No | 2024 Test Year |
| 1 | December, 2021 | $27,909,477 | $961,328 | $6,169,545 | $35,040,350 | $ - | $ 35,040,350 | $ (5,132,056) | | $ 29,908,294 |
| 2 | January, 2022 | 28,761,648 | 940,660 | 5,869,705 | 35,572,013 | - | 35,572,013 | (7,576,742) | | 27,995,271 |
| 3 | February | 29,321,846 | 920,340 | 1,869,799 | 32,111,985 | - | 32,111,985 | (5,019,626) | | 27,092,359 |
| 4 | March | 29,868,676 | 895,180 | 769,870 | 31,533,726 | - | 31,533,726 | (3,778,487) | | 27,755,239 |
| 5 | April | 23,299,816 | 873,183 | 6,294,076 | 30,467,075 | - | 30,467,075 | 1,205,877 | | 31,672,952 |
| 6 | May | 23,705,051 | 852,741 | 1,996,857 | 26,554,649 | - | 26,554,649 | 6,099,737 | | 32,654,386 |
| 7 | June | 24,274,225 | 832,823 | 2,476,672 | 27,583,720 | - | 27,583,720 | 6,260,449 | | 33,844,169 |
| 8 | July | 25,078,116 | 813,730 | 2,280,171 | 28,172,017 | - | 28,172,017 | 4,576,051 | | 32,748,068 |
| 9 | August | 25,941,338 | 794,481 | 584,225 | 27,320,044 | - | 27,320,044 | 6,774,592 | | 34,094,636 |
| 10 | September | 27,468,901 | 772,589 | (1,674,522) | 26,566,968 | - | 26,566,968 | 6,530,785 | | 33,097,753 |
| 11 | October | 13,288,889 | 748,223 | 11,622,230 | 25,659,342 | - | 25,659,342 | 7,426,280 | | 33,085,622 |
| 12 | November | 14,024,236 | 733,392 | 13,562,845 | 28,320,473 | - | 28,320,473 | 3,964,417 | | 32,284,890 |
| 13 | December | 14,691,519 | 714,017 | 14,502,758 | 29,908,294 | - | 29,908,294 | 1,677,922 | | 31,586,216 |
| 14 | Average | $ 23,664,134 | $ 834,822 | $ 5,101,864 | $ 29,600,820 | $ - | $ 29,600,820 | $ 1,769,938 | P | $ 31,370,758 |

**Q. Explain Staff's analysis of EIRCo.**

A. Staff reviewed workpapers regarding the affiliated interest of EIRCo. Staff also issued and reviewed several data requests for financial statements for the calendar years of 2019 through 2022 as referenced in Jeppsen's testimony. Staff requested and reviewed coal production volumes as budgeted and actuals.

**Q. Is Staff proposing any adjustments for the affiliated interest in Idaho Energy Resources Co.?**

A. No.

## SUMMARY

**Q. Please summarize your recommendations, identifying any adjustments you propose.**

A. Staff proposes to the following adjustments:

- Customer Service
  - ($33,045) system-wide, ($887) Oregon-allocated in FERC Account 910 for the "Idaho Power Cares Greeting Card" program, escalated.
  - ($17,104) system-wide, ($853) Oregon-allocated in FERC Account 901 for damage payment escalated.
- Transmission and Distribution O&M NL expenses
  - ($40,177) from FERC Account 580. This is the Oregon-allocated amount associated with write-offs.
- Wildfire Mitigation
  - ($1.06) million based on a two percent allocation factor for distribution O&M.

My recommendations may change based on further review and as informed by the testimonies offered by other parties.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: LUZ MONDRAGON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 901

## Witness Qualifications Statement

**March 25, 2024**

**WITNESS QUALIFICATIONS STATEMENT**

| | |
|---|---|
| **NAME:** | Luz Mondragon |
| **EMPLOYER:** | Public Utility Commission of Oregon |
| **TITLE:** | Senior Financial Analyst<br>Rates, Safety and Utility Performance Program (RSUP) |
| **ADDRESS:** | 201 High Street SE. Suite 100<br>Salem, OR. 97301 |
| **EDUCATION:** | Western Governors University<br>Bachelors of Science in Accounting |
| **EXPERIENCE:** | I have been employed with the PUC since March of 2023 as a Senior Finance Analyst tasked primarily with research and analysis of utility company filings, including, affiliated interests and rate case dockets.<br>I have over 15 years of accounting/finance experience, most recently working for Northern Wasco County PUD as a Finance Analyst. My duties included financial reporting, internal and external, as well as budgeting. I also worked very closely with the Engineering team on work orders, inventory, capital budgets and Plant assets. |

CASE: UE 426
WITNESS: LUZ MONDRAGON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 902

## Exhibits in Support
## Of Opening Testimony

**March 25, 2024**

# “IPC Response to OPUC SDR 58 Attachment 2”

# Is filed in electronic format

UE 426
Idaho Power Company's Response to
Staff's Data Request Nos. 122-124

**Topic or Keyword: Transmission and Distribution O&M (Non-Labor)**

**STAFF'S DATA REQUEST NO. 122:**

For each of the Transmission and Distribution O&M Expense accounts (FERC 560-598) please provide the following for calendar years 2020, 2021, 2022 and 2023, and budgeted expenses for calendar year 2024. **Please use the excel spreadsheet provided**, adding rows and columns when necessary.

a. Budgeted expenses
   i. Company Total amount
      1. Labor
      2. Non-Labor
   ii. Oregon Allocated amount
      1. Labor
      2. Non-Labor

b. Actual Expenses
   i. Company Total amount
      1. Labor
      2. Non-Labor
   ii. Oregon Allocated amount
      1. Labor
      2. Non-Labor

**RESPONSE TO STAFF'S DATA REQUEST NO. 122:**

Please see Response to Staff Request No. 122 – Attachment for the requested information. Idaho Power does not budget operation and maintenance ("O&M") expenses by FERC account and therefore cannot provide budgeted O&M for the accounts identified in Request No. 122. However, the Company is providing 2024 Test Year amounts for these accounts. 2023 actual amounts are not yet available because Idaho Power is completing its 2023 year-end accounting close. This response will be supplemented with 2023 information when it is available.

UE 426
Idaho Power Company's Response to
Staff's Data Request Nos. 147-157

**Topic or Keyword: Customer Service**

**STAFF'S DATA REQUEST NO. 149:**

In Company Exhibit 600, Hanchey/6-9, the customer satisfaction survey programs of both Burke and J.D. Power are described. A) For the years 2019 through 2023 to date, please provide the annual costs for each program, Burke and J.D. Power. B) What FERC account were these costs booked in?

**RESPONSE TO STAFF'S DATA REQUEST NO. 149:**

A. Please see Response to Staff Request No. 149 – Attachment for the requested information.

B. The FERC account that these costs are booked in is 910000.

**Topic or Keyword: Customer Service**

**STAFF'S DATA REQUEST NO. 151:**

In Company Exhibit 600, Hanchey/20, the importance of First Call Resolution is discussed. Please explain:

a. How does the Company determine First Call Resolution for representative handled phone calls?

b. How does the Company determine First Call Resolution for IVR handled phone calls?

c. What are the First Call Resolution rates for each, representative and IVR for each period 2019 through 2023 to date?

d. Has the Company benchmarked its First Call Resolution rate versus other similar utilities? If so, what quartile of performance does your First Call Resolution rate rank among peer companies or provide performance assessment used against peer companies?

**RESPONSE TO STAFF'S DATA REQUEST NO. 151:**

a. The Company determines its First Call Resolution ("FCR") rate based on the total number of instances that a phone number calls into the Company's IVR within a 24-hour period (midnight to midnight MST). Phone numbers with only one call in occurrence during the 24-hour period are considered to have been resolved during the first call.

   The Company's FCR rate considers both representative and IVR handled calls since, currently, neither of these datapoints are individually tracked.

b. As noted above, the Company does not currently track the individual FCR rate of representative or IVR handled phone calls.

c. Please see Response to Staff Request No. 151 – Attachment for the requested information and note that the provided FCR rates represent all calls received regardless of jurisdiction since the Company does not currently track FCR call metrics by state.

d. The Company has benchmarked its FCR rates against contact center industry standards and, based on this data, 70 percent has been identified as the industry's standard average FCR rate.

   The Company's FCR rate for each of the last five years has been consistently above 73 percent and is defined as being within the "good" range. From research conducted, 70 percent was defined as "average", 71 to 79 percent was defined as "good," and 80 percent or greater is considered "excellent." While there were not defined quartiles within this dataset, the FCR ranges were defined as follows:

   - 69 percent and below – "Needs Improvement"
   - 70 percent – "Average"
   - 71 to 79 percent – "Good"
   - 80 percent or greater – "Excellent"

**Topic or Keyword: Customer Service**

**STAFF'S DATA REQUEST NO. 154:**

In Company Exhibit 600, Hanchey/9, the Customer Service Enhancements are described. For the years 2019 through 2023 to date, please provide the annual costs by enhancement. Please separate one-time implementation costs and ongoing costs. What FERC account were these costs booked in? What are the expected costs for the test year?

**RESPONSE TO STAFF'S DATA REQUEST NO. 154:**

Please see Response to Staff Request No. 154 – Attachment for the requested information.

Please note there were no additional costs incurred by the Company to implement the Enterprise Communication Coordinator or to execute the various Public Safety Power Shutoff ("PSPS") mock events mentioned.

UE 426
Idaho Power Company's Response to
Staff's Data Request Nos. 147-157

**Topic or Keyword: Customer Service**

**STAFF'S DATA REQUEST NO. 157:**

In Company Exhibit 1201, Noe/14, lines 553 and 563 for Column 4, the company shows an increase in the amount of $198,133 for "Total Customer Accounting Expenses" and a decrease for "Total Customer Serv & Information Expenses" of $33,217,109. Please explain how the Company determined these adjustments and why the adjustments are justified. How were these amounts determined by cost category and describe in detail the assumptions that went into determining these amounts?

**RESPONSE TO STAFF'S DATA REQUEST NO. 157:**

The adjustment from 2022 Actuals to 2022 Base of $198,133 for Customer Accounting Expenses is related to two adjustments for Oregon COVID-related expenses. The first adjustment removes $354,610 of amortization expense recorded to Account 904.002 in 2022 for the deferred incremental costs and savings through December 31, 2021, related to the COVID-19 Arrearage Management Program that is being collected in Oregon rates pursuant to Commission Order No. 22-192.

The second adjustment is related to a reserve recorded in 2021 for COVID-19 Arrearage Management Program costs. After the OPUC authorized collection of the deferred 2021 COVID-19 Arrearage Management Program costs on May 31, 2022, the reserve was reversed, resulting in a negative $552,743 being recorded to Account 904.003. Idaho Power made an adjustment to add this amount back, effectively zeroing out the recording of the reserve in 2021 and the reversal of the reserve in 2022.

The reduction of $(33,217,109) to Total Customer Service and Information expenses from 2022 Actuals to 2022 Base is comprised of three main components including the removal of the Idaho Energy Efficiency Rider in the amount of $(31,673,550), removal of the Oregon Energy Efficiency Rider in the amount of $(1,523,563) and miscellaneous reductions totaling $(19,996) for memberships not included in the request.

**Topic or Keyword: Idaho Energy Resource Company (IERCo)**

**STAFF'S DATA REQUEST NO. 194:**

Please provide a narrative description of how each line item was calculated for the Forecast Adjustment (column 6) as referenced on page 13 of Exhibit No. 901.

Please provide the underlined calculation for each line item in excel format with the formulae intact.

**RESPONSE TO STAFF'S DATA REQUEST NO. 194:**

**Line 1 Bridger Coal Company– joint venture**
Joint venture income from the prior 2011 settled rate case was set at $10.2 million (Column 5) for the Bridger Coal Company ("BCC"). The BCC's joint venture income is estimated at $3.0 million (Column 7) for **2024**. The $3.0 million estimate incorporates PacificCorp's earning margin calculated utilizing the most recent long-term forecast to estimate IERCo rate base and the Weighted Average Cost of Capital as approved in the 2011 Idaho General Rate Case. In 2023, IERCO's projected 13-month average rate base was $31.4 million. In 2023, IERCo's cost of capital was 9.594 percent which is the pretax weighted average cost of capital approved in 2011 Idaho General Rate Case. The $31.4 million (IERCo Rate Base) times 9.594 percent equals the $3.013 million. The $3.013 million was rounded down to $3.0 million. The forecast adjustment (Column 6) of ($7.2 million) is the difference between 2022 Base (Column 5) and 2024 Test Year (Column 7).

It should be noted that, while the BCC earnings margin does raise fuel Cost of Service as it is priced into the cost of coal, it reduces the equivalent in the Cost of Service as a credit to operating income. Both fuel expense and Bridger joint venture income have similar and offsetting tax impacts for Idaho Power Company.

**Line 2 Bridger Coal Company – overriding royalties**
The 2023 Test Year assumes that overriding royalty income is completely offset by royalty amortization expense included in operating expense. The $247,311 (Column 5) are the actual royalties for 2022. The $232,494 (Column 7) are the projected royalties for 2024. The $232,494 was calculated by using the last actual royalty amortization for December 2022 and annualizing this for 2024. The royalty amortization for December 2022 was $19,374.48. Taking the monthly amortization of $19,374.48 times 12 months arrives at the $232,494 for 2024 (Column 7). The forecast adjustment (Column 6) of ($14,817) is the difference between column 5 and column 7.

**Line 3 Interest and Dividend Income**
IERCo received $3,248 (Column 5) in interest income for 2022. This is not expected to occur in 2024 so the projection for 2024 is $0 (Column 7). The forecast adjustment (Column 6) is the difference between 2022 Base (Column 5) and 2024 Test Year (Column 7).

**Line 6 Operation Expense**
These operating expenses are the projected amortization expenses of overriding coal royalties. The $247,311 (Column 5) is equal to the royalties (Line 2, Column 5). The ($14,817) (Column 6) is equal to the royalties (Line 2, Column 6). The 232,494 is equal to the royalties (Line 2,

Column 7). Coal royalties have no impact on IERCo's net income as revenue is recognized when paid by BCC and expense is recognized when remitted to IPC.

**Line 7 Income Taxes**
Pretax income is assessed at a 21 percent federal income tax rate. There are no Wyoming state income taxes. The $1,330,515 (Column 5) is the income tax expense for 2022. The $489,411 for income taxes for 2024 (Column 7) is calculated using the federal tax rate of 21 percent. The income tax was calculated by taking the 2024 total income of $3,232,494 less 2024 operation expenses of $232,494 and 2024 intercompany interest expense of $669,473 to arrive at a 2024 taxable income of $2,330,527. The 2024 taxable income of $2,330,527 was multiplied times the federal tax rate of 21 percent to arrive at $489,411 for 2024 income taxes for the 2024 Test Year (Column 7). The ($841,104) (Column 6) is the difference between 2022 Base (Column 5) and 2024 Test Year (Column 7).

**Line 9 Intercompany Interest Expense**
Intercompany interest is forecasted and then removed from IERCo's income statement for purposes of calculating IERCo's cost of service (see Line 13) because financing costs are not included in Cost of Service. IERCo carries an intercompany note with Idaho Power. It is projected the note will bear an average interest rate of 0.45 percent per month in 2024. Actual intercompany interest rate for 2022 was approximately 0.12 percent per month. For 2022, the intercompany interest expense was $101,905 (Column 5). For 2024, the intercompany interest expense was estimated at $669,473 (Column 7). The $567,568 (Column 6) is the difference between 2024 Test Year (Column 7) and the 2022 Base (Column 5).

**Line 13 Add: Interest Expense from Notes Payable to Parent (Net of Tax)**
Related to Line 9 above, the increase in intercompany interest expense also increases this add-back to IERCo net income. For purposes of the Cost-of-Service Component of IERCo, the intercompany interest expense net of income tax adjustment is $528,884 [$669,473 (Line 9) times (1 - 21 percent (Federal Tax Rate))] is added back to remove interest expense from IERCo's net income for the 2024 Test Year (Column 7). For 2022, the interest expense from notes payable to parent (net of tax) was $77,939 (Column 5). The $450,945 (Column 6) is the difference between 2024 Test Year (Column 7) and the 2022 Base (Column 5). The intercompany note financing costs (net of tax) are not included in Cost of Service.

Please see Response to Staff Request No 194 – Attachment - IERCo Financial Statements

UE 426
Idaho Power Company's Response to
Staff's Data Request Nos. 204-211

**Topic or Keyword: Gain on the Sale of Property**

**STAFF'S DATA REQUEST NO. 210:**

Please provide a narrative description how any gains and losses on the sale of property is allocated to customers. In your response, please address gains or losses if the property sold is a direct assigned property or an allocated property and if the Company shares in any gains or losses.

**RESPONSE TO STAFF'S DATA REQUEST NO. 210:**

Gains or losses associated with the sale of property held in FERC Account 105 – Plant Held for Future Use are generally recorded in FERC Accounts 411.6 – Gains from Disposition of Utility Plant or 411.7 – Losses from Disposition of Utility Plant, while gains or losses associated with the sale of property held in FERC Account 101 – Electric Plant in Service are generally recorded in FERC Accounts 421.1 – Gain on Disposition of Property or 421.2 – Loss on Disposition of Property. While FERC Accounts 411.6, 411.7, 421.1, and 421.2 are not a component of the revenue requirement computation and therefore are not allocated to customers, the Oregon- jurisdictional share of the gain associated with the sale of the Boardman property to Portland General Electric reflected in the Response to Staff's Request No. 211 – Attachment was credited to customers through the Boardman Balancing Account mechanism.

UE 426
Idaho Power Company's Response to
Staff's Data Request Nos. 204-211

**Topic or Keyword: Gain on the Sale of Property**

**STAFF'S DATA REQUEST NO. 211:**

Has the Company sold any utility property since the rate effective date from the previous rate case in Docket No. UE 233? 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.
g. Amount of gain allocated to Oregon
h. Method by which gain was flowed through to customers and amount of gain credited to customers.

**RESPONSE TO STAFF'S DATA REQUEST NO. 211:**

a-f. Please see the Response to Staff's Data Request No. 211 – Attachment for a table of gain/loss activity from property sales reflected within FERC Accounts 411.6 – Gains from Disposition of Utility Plant, 411.7 – Losses from Disposition of Utility Plant, 421.1 – Gain on Disposition of Property, and 421.2 – Loss on Disposition of Property since the previous rate case.

g. The Oregon-jurisdictional share of the gain associated with the sale of the Boardman property was $11,500.

h. See Response to Staff's Request No. 210.

UE 426
Idaho Power Company's Response to
Staff's Data Request Nos. 225-226

**TOPIC OR KEYWORD: Customer Service**

**STAFF'S DATA REQUEST NO. 225:**

In Company Exhibit 600, Hanchey/20, of the 1300 customers assisted by Project Share, twenty-eight resided in Oregon or approximately 2 percent of customers served by the program.

a. How are the recipients and dollars available by state and by customer determined?
b. Please describe why the 28 in Oregon were chosen?
c. What is the percentage of customers residing in Oregon are low-income?
d. What is the similar percentage for Idaho?
e. Please explain why Oregon has a lower percentage level of recipients.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 225:**

a. Project Share's energy assistance funds are provided to eligible customers seeking energy assistance from a local outreach office, subject to the availability of funds. The amount of Project Share energy assistance provided is dependent upon the customer's need at the time of request, but not to exceed the program's annual benefit cap of $450. In regard to how Project Share's funds are made available by state, please see the Company's Response to Staff's Data Request No. 153a.

b. As noted within the Company's Response to Staff's Data Request No. 153b, there were actually 50 Oregon residential customers that received Project Share energy assistance pledges during program year 2022/2023 compared to the 28 originally reported. The selection of these 50 recipients was determined by the order in which they reached out to their local outreach office expressing a need for energy assistance, following a first-come, first-served approach, and because sufficient funds were available for distribution.

c. According to Idaho Power's Low Income Needs Assessment ("LINA")[1] conducted as part of its evaluation of potential HB 2475-related program offerings, approximately 19 percent of households within the Company's Oregon service area are estimated to have household incomes under 100 percent of the federal poverty limit, and 62 percent of residents are estimated to have household incomes under 60 percent of the State Median Income.

d. Idaho Power has not conducted a LINA in Idaho, however, utilizing five-year census data through 2021, approximately 10.8 percent of households within the Company's Idaho service area are estimated to be below the poverty limit.

e. The 50 Oregon customers that received Project Share pledges during the 2022/2023 program year comprised approximately 3.5 percent of the total number of customers that received pledges during such program year (1,429), while the number of Idaho Power Oregon residential customers comprises approximately 2.7 percent of all of Idaho Power's residential customers. Therefore, on a per capita basis and during program year 2022/2023, the percentage of Project Share recipients in Oregon was higher than the percentage of Project Share recipients in Idaho.

[1] The LINA is posted to the Oregon Public Utility Commission's HB 2475 implementation Docket No. UM 2211 eDockets page (https://edocs.puc.state.or.us/efdocs/HAH/um2211hah143035.pdf).

UE 426
Idaho Power Company's Response to
Staff's Data Request Nos. 252-257

**TOPIC OR KEYWORD: Transmission and Distribution O&M Expenses Non-Labor**

**STAFF'S DATA REQUEST NO. 255:**

Regarding Oregon allocation factors, for each Distribution O&M account (Non-Labor) (FERC 580-598) please explain:

a. The logic or reasoning behind allocating distribution costs to Oregon for work completed outside of Oregon.
b. The logic or reasoning behind why O&M distribution costs are not situs to the state where work was completed.
c. What factors are considered and included in the allocation base;
d. How is the allocation base spread or distributed;
e. How are Oregon allocation percentages calculated.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 255:**

a. Distribution operation and maintenance ("O&M") is allocated in accordance with the corresponding jurisdictional spread of distribution plant, which is almost entirely assigned on a situs basis. Because the Company does not record O&M costs on a situs basis, the Company's method for jurisdictional allocation is a reasonable measure of cost causation.

b. Please see the Company's response to part a.

c. The factors considered for Distribution O&M are the directly assigned plant in service, which serves as the allocation basis for Distribution O&M allocation.

d. Distribution O&M is allocated over the corresponding distribution plant accounts, except for the Supervision and Engineering costs which are allocated over total Distribution plant.

e. The Oregon allocation percentages are calculated by dividing the Oregon total by System total for each account. These calculations can be found in the Excel version of Idaho Power/1202 provided with the Company's initial filing. The allocation of distribution O&M begins on Row 522 of this model.

UE 426
Idaho Power Company's Response to
Staff's Data Request Nos. 252-257

**TOPIC OR KEYWORD: Transmission and Distribution O&M Expenses Non-Labor**

**STAFF'S DATA REQUEST NO. 256:**

Regarding P Jeppsen Workpaper 1-Exhibit 901, Adjustments to Base (column D). For Transmission and Distribution O&M non-labor expenses, please provide a narrative, by FERC account, explaining the adjustments.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 256:**

Regarding the Adjustments to Base in P Jeppsen Workpaper 1-Exhibit 901, as described in the testimony of P Jeppsen, Idaho Power/900/Pages 14 and 15, the Company reviews and screens accounting records to identify certain memberships and contributions, portions of officer expenses allocated between Idaho Power and IDACORP, and legitimate business expenses removed from regulatory recovery out of an abundance of caution, due to the nature of the business establishment. Additionally, these adjustments can be correlated from the Workpaper to Idaho Power/902/Pages 2 - 8.

| FERC Account | Adjustment | Narrative explanation |
|---|---|---|
| 560000 | ($6) | Reduction of the IDACORP allocated portion of officer expense. |
| 562000 | ($1,446) | Reduction of 33.33% membership expense - Utilities Technology Council. |
| 562000 | ($7) | Reduction of the IDACORP allocated portion of officer expense. |
| 570000 | ($482) | Reduction of 33.33% membership expense - Utilities Technology Council. |
| 570000 | ($7) | Reduction of the IDACORP allocated portion of officer expense. |
| 580000 | ($10) | Reduction of the IDACORP allocated portion of officer expense. |
| 582000 | ($7) | Reduction due to nature of the business establishment. |
| 583000 | ($46) | Reduction due to nature of the business establishment. |
| 586000 | ($73) | Reduction due to nature of the business establishment. |
| 588000 | ($683) | Reduction of 33.33% membership expense - The Electrical Apparatus Service Association. |
| 588000 | ($327) | Reduction due to nature of the business establishment. |
| 592000 | ($344) | Reduction of 33.33% membership expense - Utilities Technology Council. |
| 592000 | ($7) | Reduction due to nature of the business establishment. |
| 593000 | ($7,000) | 100% reduction of Donation. |

UE 426
Idaho Power Company's Response to
Staff's Data Request No. 283-298

**TOPIC OR KEYWORD: Wildfire Mitigation (WM) O&M**

**STAFF'S DATA REQUEST NO. 15:**

In the same format as SDR 58, please provide all information related to Wildfire Mitigation.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 284:**

Please see the file labeled 'Response to Staff Request No. 284 – Attachment 1' for the 2022 and 2021 wildfire mitigation data, which is in the same format as SDR 58. Idaho and Oregon direct-assigned costs are included in the account total column of the spreadsheet and excluded from the Total Regulated Utility Service column. This was done to properly display the system totals and Oregon-specific allocations. The direct-assigned Oregon items in 2021 were also added back to the Oregon allocation column. These points are documented in the attachment.

Please note that the Company does not develop its wildfire mitigation expenditure forecast based on FERC accounts. Therefore, the Company does not have the information for 2024 available in the format requested by Staff.

UE 426
Idaho Power Company's Response to
Staff's Data Request No. 283-298

**TOPIC OR KEYWORD: Wildfire Mitigation (WM) O&M**

**STAFF'S DATA REQUEST NO. 285:**

In the same format as P Jeppsen-Workpaper 1- Exhibit 901- O&M Account Allocation, please provide all information related to Wildfire Mitigation.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 285:**

Please see the file labeled 'Response to Staff Request No. 285 – Attachment 1' for 2021 and 2022 actual wildfire mitigation costs, which are in the same format as P Jeppsen-Workpaper 1 – Exhibit 901 – O&M Account Allocation. Wildfire mitigation costs were included in this format for 2021 and 2022. Please refer to the 'Total Allocated to FERC Accts'.

The Company does not have the wildfire mitigation costs by FERC account for 2024. Jeppsen's workpapers in Exhibit 901 for operations and maintenance ("O&M") include the wildfire mitigation costs in FERC accounts but those accounts also include other items, as they are accounts used for more than just wildfire costs.

UE 426
Idaho Power Company's Response to
Staff's Data Request No. 283-298

**TOPIC OR KEYWORD: Wildfire Mitigation (WM) O&M**

**STAFF'S DATA REQUEST NO. 287:**

In testimony 500 page 15, Colburn states that "Idaho Power began a proactive effort in 2019 to develop a guiding wildfire mitigation document-the WMP". How did actual spend in Wildfire Mitigation O&M compare to the forecast amounts for calendar years 2019-2023? Please provide the following System wide information

a. Calendar year
b. Mitigation Work Category
c. Budget
d. Actual
e. Where there is a 5 percent or greater variance in year-to-year, in actuals or budgets, please explain the reasons for the variance.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 287:**

Please see the file labeled 'Response to Staff Request No. 287 – Attachment 1' for the 2021-2023 total system actual spend on wildfire mitigation work compared to the Company's forecast of spend for those years, with notations to explain variances. Prior to 2021, Idaho Power was in the process of developing its Wildfire Mitigation Plan and was not tracking specific wildfire mitigation expenses.

UE 426
Idaho Power Company's Response to
Staff's Data Request No. 283-298

**TOPIC OR KEYWORD: Wildfire Mitigation (WM) O&M**

**STAFF'S DATA REQUEST NO. 291:**

Regarding the Average Jurisdictional separation factor of 6.9 percent used to allocate Wildfire Mitigation costs to Oregon please explain:

a. The logic or reasoning behind allocating O&M costs (non-transmission) to Oregon instead of direct charges to the state the work was completed in.
b. What factors are considered and included in the allocation base
c. How the allocation base is spread or distributed.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 291:**

As a point of clarification, wildfire mitigation costs are allocated based on the FERC account in which they are recorded, not at an average factor of 6.9 percent (the Company did not use this factor and assumes Staff derived it independently).

a. The Company does not record Operations and Maintenance ("O&M") expenses on a situs basis. Rather, the Company considers it a reasonable methodology to allocate distribution O&M over the corresponding plant accounts that are directly assigned.

b. For wildfire mitigation costs, the factors considered in the allocation of non-transmission O&M costs are the corresponding plant accounts.

c. The allocation base is the corresponding Distribution plant accounts.

UE 426
Idaho Power Company's Response to
Staff's Data Request No. 331-333

**TOPIC OR KEYWORD: Transmission and Distribution O&M Expenses Non-Labor**

**STAFF'S DATA REQUEST NO. 332:**

Regarding Idaho Power's response to DR 123, please

a. Provide a narrative explanation on why the LIDAR surveys are allocated to Oregon when, according to the 2023 WMP, "Idaho Power plans to conduct the assessments in its highest risk zones, which are located exclusively in Idaho".
b. Provide more information regarding the Energy Imbalance Market (EIM) administrative charges. Specifically,
   i. What does the administrative charge entail?
   ii. What benefits are associated with participation?
   iii. What alternatives are available?
   iv. What were the amounts in 2020, 2021, and 2023?
   v. Will this be an ongoing expense in the foreseeable future?
c. Provide more information regarding the Western Resource Adequacy administrative charges. Specifically
   i. What does the administrative charge entail?
   ii. What benefits are associated with participation?
   iii. What alternatives are available?
   iv. What were the costs in 2020, 2021, 2022 and 2023?
   v. What amount is forecasted for the Test Year?
   vi. Will this be an ongoing expense in the foreseeable future?
d. Provide more information regarding NERC Standard #27, specifically:
   i. What does the NERC Standard #27 entail?
   ii. What types of costs are associated with compliance?
   iii. Are there any other cost recovery mechanisms associated with such costs?
   iv. What were the costs in calendar years 2020, 2021, 2022 and 2023?
   v. What amount is forecasted for the Test Year?
e. Provide more information regarding the Satellite communication bandwidth services, specifically:
   i. What services are provided?
   ii. What alternatives are available?
   iii. What were the costs in calendar years 2020, 2021, 2022 and 2023?
   iv. What amount is forecasted for the Test Year?
   v. Will this be an ongoing expense for the foreseeable future?
f. Provide more information regarding the long-term transmission agreements, specifically:
   i. What were the actuals costs in 2023?
   ii. With cost growing exponentially year over year, what actions is the Company taking to control costs?
   iii. Explain the process of bidding the long-term agreements. What process is undertaken in making a decision to enter into a long term transmission agreement?
   iv. Provide a copy of the agreements currently in place and those that will be in effect during the Test Year.

UE 426
Idaho Power Company's Response to
Staff's Data Request No. 331-333

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 332:**

f. Provide more information regarding the long-term transmission agreements.

ii. Idaho Power cannot provide the long-term transmission costs within 565000 for 2023 as the results are not yet final.

ii. Idaho Power has had three new long-term firm transmission agreements begin service in the past three years. A 100 MW agreement for long-term firm transmission began in 2021, another 100 MW agreement began in 2022, and an 80 MW agreement began in 2023. These are in addition to preexisting agreements for smaller volumes of capacity. Idaho Power enters into long-term firm transmission service agreements such as these for the time periods and MW amounts necessary to ensure it can reliably serve load. See the answer to part (iii). Regarding the costs associated with these agreements, Idaho Power is a transmission customer of the Transmission Provider utility under the agreements. The service is subject to the Transmission Provider's applicable rates for the long-term firm transmission service, which are subject to review by the Federal Energy Regulatory Commission.

Idaho Power offers excess third-party transmission that it does not need for load service to other parties for resale. The transmission resale market is such that the resales generally occur at prices lower than the Transmission Provider's rate. Regardless, reselling the transmission is an option Idaho Power uses to offset the cost of the transmission when it is not needed for load service.

iii. Long-term transmission service is not procured via a bidding process. Under Federal Energy Regulatory Commission rules, Transmission Providers make transmission available to all customers on a first-come, first-served basis via software called the Open Access Same Time Information System ("OASIS"). Any transmission customer may request and purchase available transmission service via the OASIS system.

Idaho Power purchases and imports energy from outside its system to reliably and economically serve load throughout the year and especially during summer and winter peaks. Idaho Power purchases the majority of this energy for imports from the Mid-Columbia hub, with some also purchased at other locations. When Idaho Power purchases at these off-system locations, it then must use third-party transmission to import that energy to its system to serve load. On some occasions, and especially historically, Idaho Power was able to obtain short-term firm transmission with which to import that energy. Over the past several years, and particularly since 2020, firm transmission capacity on third-party systems to Idaho Power's border has been scarce. Other entities were seeking that same capacity on third party systems to move power from the Pacific Northwest to other locations or vice versa.

As a result of this lack of firm transmission capacity on neighboring transmission systems, Idaho Power's load serving operations department considers entering into agreements to purchase long-term firm transmission capacity on third party transmission systems if (1) Idaho Power determines there is a need for additional import capacity and (2) if such transmission capacity becomes available for sale on the transmission provider's Open Access Same Time Information System. In other words, if transmission capacity to Idaho Power's border becomes available, Idaho Power determines whether there is a need for additional import capability in order to reliably serve load; whether transmission is the most economic option for meeting that need, considering the economics and logistics of the transmission (for example, whether it provides a complete path to a market hub, or whether additional legs of transmission are needed); and the reliability benefits of the transmission (long-term firm transmission provides significant benefits in terms of certainty and reduced risk of curtailment). Idaho Power also considers the length of time the transmission is available (if transmission is available for five years or more, it qualifies for renewal rights, meaning the customer can extend the transmission reservation before it terminates for one or more years). Five-year agreements thus provide significant value and flexibility for future needs. With all these considerations in mind, Idaho Power seeks to purchase the least amount of long-term firm transmission capacity that will allow it to reliably serve load and preserve value and flexibility.

Additional transmission import capability provides valuable flexibility, diversity in supply, and access to markets to purchase when needed. Idaho Power's long-term firm transmission portfolio is a critical component of Idaho Power's resource stack, contributing to Idaho Power's ability to reliably serve load, particularly as Idaho Power's load has grown significantly and other resources have ceased operation (for example, N. Valmy Unit 1 and Boardman).

iv. See 'Response to Staff Request No. 332 – Attachments 1 - 8'.

UE 426
Idaho Power Company's Supplemental Response to
Staff's Data Request No. 331-332

**SUPPLEMENTAL RESPONSE TO STAFF'S DATA REQUEST NO. 332:**

b. Provide more information regarding the Energy Imbalance Market ("EIM") administrative charges.

   iv. Total system EIM administrative charges recorded in 2020, 2021, and 2023 were $566K, $795K, and $774K respectively.

c. Provide more information regarding the Western Resource Adequacy administrative charges.

   iv. Total system WRAP administrative charges recorded in 2020, 2021, 2022, and 2023 were $0, $0, $491K, and $72K respectively. Please note that the 2022 charge listed here differs from the Company's original response to Staff's DR No. 332. Originally stated, as $267K for 2022, the Company found charges that were previously missed while preparing this supplemental response.

d. Provide more information regarding NERC Standard #27, specifically:

   iv. $0 in 2020; $0 in 2021; $68,990 in 2022; and ($1,831) for 2023.

e. Provide more information regarding the Satellite communication bandwidth services, specifically:

   iii. $36,437 in 2020; $79,980 in 2021; $79,980 in 2022; and $108,371 for 2023.

f. Provide more information regarding the long-term transmission agreements.

   i. The long-term transmission costs within 565000 for 2023 are $11.051M.

UE 426
Idaho Power Company's Response to
Staff's Data Request No. 331-333

**TOPIC OR KEYWORD: Transmission and Distribution O&M Expenses Non-Labor**

**STAFF'S DATA REQUEST NO. 333:**

Regarding Idaho Power's response in DR 122 "Idaho Power does not budget O&M expenses by FERC account and therefore cannot provide budgeted O&M for the accounts identified…", please provide:

a. The requested budget information in DR 122 for the categories in which Transmission and Distribution O&M (non-labor) are recorded.
b. Where there is a 5 percent or greater change (in either direction) in year-to-year budgets or year to year actuals, please identify and explain the reasons for the variance in each instance.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 333:**

a. Because the FERC account is the basis for categorizing operations and maintenance ("O&M") by function (Generation, Transmission, Distribution, etc.) and Idaho Power does not budget by FERC account it cannot provide budgeted O&M for Transmission or Distribution.

b. Please refer to Idaho Power's response to Staff Request No. 123 – Attachment for an explanation of Transmission O&M variances and Staff Request No. 331 – Attachment for an explanation of Distribution O&M variances.

UE 426
Idaho Power Company's Response to
Staff's Data Request No. 336-338

**TOPIC OR KEYWORD: Customer Service**

**STAFF'S DATA REQUEST NO. 337:**

As a follow-up to Staff Data Request No 149, please explain how both the results of the Burke and JD Power studies are used by the Company.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 337:**

The Company partners with Burke, Inc., a marketing research and innovation firm, to assess customer satisfaction each quarter throughout the year. The survey results are compiled to determine the Company's customer relationship index ("CRI"), which is a key metric used to determine the Company's overall customer satisfaction rate. The results are also used to identify performance and experience gaps based on customer feedback, and as a means of integrating customer input into the Company's processes and initiatives. In addition to quantitative survey results, the Company also analyzes customer verbatim comments regarding their services to determine general customer sentiment by specific categories.

Some examples of customer-driven improvements resulting from Burke research activities are as follows:

- In 2012, the Company implemented a no-fee digital payment option on the website for customers in response to feedback and comments that customers wanted to pay their bill without being charged a fee.
- In 2019, efforts were made to improve customer satisfaction of Large Commercial and Industrial customers. Enhancements implemented for these customer segments include:
    - Faster response times to large customer inquiries.
    - Enhanced bill estimates provided to customers prior to receiving their bill.
    - Inclusion of Energy Advisor's contact information to the monthly bill.
    - Promoting electrification and energy efficiency.
    - Power quality improvements.
    - Increased communication regarding the Company's sustainability goals and clean energy initiative.
- Multiple years of enhancements made to energy advisor training, agricultural rep outreach, and proactive small business outreach campaigns.
- Implementation of several enhancements to community engagement since 2011, such as increased participation in volunteering, representation at community events, presence at home and garden shows, career fairs, among others.
- Enhanced company-wide Voice of the Customer campaign launched in 2012 and into 2013, encouraging employees to focus on customer satisfaction.

Idaho Power also subscribes to the JD Power Electric Utility Residential Customer Satisfaction study to assess customer satisfaction each quarter throughout the year. The study is made up of over 100,000 customer responses nationwide, including Idaho Power customers, and helps the Company understand how it's doing compared to other utilities in the country and the region. Benchmarking against other utilities helps the Company narrow in on focus areas for improvements, drawing on practices or enhancements made by other utilities that have had a positive impact on their customer satisfaction. Below are some examples of customer improvements implemented based on these research activities:

- **Mobile App**: JD Power research continues to show the value of native mobile apps in the utility industry, which grows year over year. This research, in combination with other utility research and benchmarking, drove the Company to start building a mobile app in 2019.
- **My Account Improvements**: In conjunction with the mobile app effort, the My Account website needed a full re-write to meet ever-evolving customer expectations and allow a seamless transition experience between the website and mobile app.
- **Other Digital Enhancements:** Many other digital enhancement initiatives were a result of JD Power research in combination with other benchmarking, such as proactive outage alerts, billing alerts, easy payment options, various other portals like the construction portal, large business portal, and more. This is a response to the rapid adoption of digital tools amongst consumers and the desire to self-serve when conducting business.
- **Various other Customer Experience ("CX") Improvements:** The JD Power study results have influenced many other CX initiatives, such as broad media communication enhancements, billing and payment enhancements, and community involvement.

UE 426
Idaho Power Company's Response to
Staff's Data Request No. 340-346

**TOPIC OR KEYWORD: Wildfire Mitigation Capital Placed in Service**

**STAFF'S DATA REQUEST NO. 342:**

In regards to Idaho Power's response to DR 179, please describe the General Plant that was placed into service.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 342:**

The general plant assets in DR 179 are communication assets for distribution equipment.

**TOPIC OR KEYWORD: Transmission and Distribution O&M Expenses Non-Labor**

**STAFF'S DATA REQUEST NO. 27**

Regarding 2022 Opr Dstr Rnt (FERC 589) transactions, please provide the following:

a. Lessor/Landlord.
b. What is being leased or rented?
c. Location of property.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 380:**

Please see "Response to Staff Request No. 380 – Attachment" for the 2022 FERC 589 transactions. While Idaho Power does not systematically record the details requested, the attachment provides transactions that can be sampled from and tied to invoices or other back-up. Note, some items included in the attachment have a DISTDESC of "PREPAID CONTRACT ACCTG," which reflects the amortization of prepaid lease amounts over the applicable accounting period.

UE 426
Idaho Power Company's Response to Staff's
Data Request Nos. 380-392

**TOPIC OR KEYWORD: Transmission and Distribution O&M Expenses Non-Labor**

**<u>STAFF'S DATA REQUEST NO. 28</u>:**

Regarding 2022 Other Rents & Leases (DCE 549) please provide transactional line-item accounting details that include:

a. FERC account
b. Lessor/Landlord.
c. What is being leased or rented?
d. Location of property.
e. Any other available descriptions of each expense

**<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 381</u>:**

Please see "Response to Staff Request No. 381 – Attachment" for the 2022 DCE 549 transactions. While Idaho Power does not systematically record the details requested, the attachment provides transactions that can be sampled from and tied to invoices or other back-up. Note, some items included in the attachment have a DISTDESC of "PREPAID CONTRACT ACCTG," which reflects the amortization of prepaid lease amounts over the applicable accounting period.

UE 426
Idaho Power Company's Response to Staff's
Data Request Nos. 414-423

**TOPIC OR KEYWORD: Customer Service (FERC 901-9017)**

**STAFF'S DATA REQUEST NO. 416:**

Regarding the response to DR 147, please provide a narrative explanation, by FERC account, of variances greater than 5 percent in year-to-year actuals.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 416:**

Please see "Response to Staff Request No. 416 – Attachment" for variance explanations for changes 5 percent or greater from 2020 to 2021 and 2021 to 2022. No explanations were provided for variances less than $1,000.

UE 426
Idaho Power Company's Response to Staff's
Data Request Nos. 414-423

**TOPIC OR KEYWORD: Customer Service (FERC 901-9017)**

**STAFF'S DATA REQUEST NO. 418:**

Please provide more information regarding the OSPV expenses in the Customer Service (FERC 901-9017), specifically:

a. What services are provided?
b. What alternatives are available?
c. What were the costs in calendar years 2020, 2021, 2022 and 2023?
d. What amount is forecasted for the Test Year?
e. Will this be an ongoing expense for the foreseeable future?

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 418:**

a. The OSPV program, or Oregon Solar Photovoltaic Pilot Program, was a program Idaho Power implemented pursuant to the directives in ORS 757.365 and Oregon Public Utility Commission Order No. 10-198 in Docket No. UM 1452 to demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered by solar photovoltaic energy systems. Under the program, Idaho Power entered into contracts with Oregon customers to purchase the output of their on-site solar photovoltaic systems that met certain eligibility requirements, including size requirements. Under these contracts, the customers received volumetric incentive payments for the solar production that offset the amounts they owed for the retail service they otherwise took from Idaho Power. The program offered enrollment periods from 2010-2014.

b. No alternatives to these contracts are available to the Company now nor were alternatives available at the time. The OSPV contracts were entered into pursuant to Commission requirements.

c.- d.

| | System Wide | Oregon |
|---|---|---|
| **2020** | $9,367 | $1,214 |
| **2021** | $21,211 | $2,768 |
| **2022** | $13,109 | $1,734 |
| **2023** | $18,800 | $2,318 |
| **Test Year** | $13,908 | $1,840 |

Note the amounts in the chart above are non-incremental labor charges to the OSPV program. The amounts associated with the volumetric incentive payments are collected from Oregon customers through the Solar Photovoltaic Pilot Program Rider, which is not a part of this case.

f. Idaho Power will incur expenses under this program into 2030. Idaho Power currently has 59 effective OSPV contracts. These contracts have terms of fifteen years each and contain no renewal rights. The earliest contract will terminate on 12/31/2025 and the latest-running contracts will terminate on 4/15/2030, with the majority terminating in 2027.

UE 426
Idaho Power Company's Response to Staff's
Data Request Nos. 476-484

**TOPIC OR KEYWORD: Transmission and Distribution O&M Expenses Non-Labor**

**STAFF'S DATA REQUEST NO. 476:**

Regarding Operation Distribution-Operation supervision and engineering (FERC account 580) in the response to DR 331,

a. Please provide the write off amounts in account 580 that are part of the variance between 2021 and 2022 actuals.
b. Please provide an explanation on why the write off amounts would be used and escalated to calculate the Test Year.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 476:**

a. The two write-offs referenced in the attachment to DR No. 331 were as follows:

   JOINT USE: $400,948.63 write-off of Joint Use system
   COMM SITES: $403,271.12 write-off for 2-way radio communication sites

   Joint Use System write-off. This project was originally investigated and moved forward with the best option at the time of the decision. However, after the project launched and progressed for many months, a better and more cost-effective solution became available (including the cost of the write-off). Once the project is live (expected this year), the ongoing cost of the system is expected to be between $160K and $180K depending on final terms, conditions, and length of the contract.

   2-way radio write-off. The projects were originally investigated and moved forward with the best option at the time of the decision. However, unforeseen external factors of having difficulty obtaining permits and purchasing land that were not anticipated at the outset of t, resulted in the Company writing-off project costs and changing course to another solution.

# "IPC UE 426 Workpapers"

# Is filed in electronic format

CASE: UE 426
WITNESS: LUZ MONDRAGON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 903
## IS CONFIDENTIAL
## SEE PROTECTIVE ORDER: 23-134

**March 25, 2024**

CASE: UE 426
WITNESS: LUZ MONDRAGON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 904
## IS CONFIDENTIAL
## SEE PROTECTIVE ORDER: 23-134

**March 25, 2024**

CASE: UE 426
WITNESS: Mitchell Moore

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 1000

## OPENING TESTIMONY
**Generation O&M, Board of Directors' Expenses, Materials and Supplies, Misc. Deferred Debits**

**March 25, 2024**

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

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) 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. What is the purpose of your testimony?**

A. The purpose of my testimony to address Idaho Power Company's (IPC) request for Test Year expenses for non-labor Generation O&M and Board of Directors' Fees. I also address the Company's Test Year forecast of non-fuel materials and supplies and miscellaneous deferred debits, in rate base.

**Q. Did you prepare any exhibits for this docket?**

A. Yes. I prepared the following supporting exhibits: Staff Exhibit 1002 – Company responses to Staff data request Nos 58, 232, 233, 438, and 475.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

Issue 1. Non-labor Generation O&M ........ 3
Issue 2. Board of Directors' Fees ........**Error! Bookmark not defined.**
Issue 3. Materials and Supplies........**Error! Bookmark not defined.**
Issue 4. Misc Deferred Debits ........**Error! Bookmark not defined.**

**Q. Could there be changes or updates to Staff's position and recommendations?**

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

# ISSUE 1. NON-LABOR GENERATION O&M

**Q. Please summarize this issue.**

A. IPC proposes recovery of $3.2 million in Oregon-allocated non-labor Generation O&M expense.[1] This represents a decrease from the adjusted 2022 Base Year expense of $4.2 million. The expense is recorded in FERC Account Nos. 500-557 and includes costs for operating and maintaining steam, hydraulic, and other generating plant.

**Q. Please describe your review and analysis of IPC's generation O&M expense.**

A. Staff reviewed the non-labor generation O&M expense for the historical years of 2020 through 2022. This review included looking at trends, transactional detail, and the test period expense adjustments in workpapers provided by IPC. Staff looked at the annual increase in non-labor generation O&M for the past three years to determine whether the proposed amount in the Test Year is consistent with historical increases. Staff also reviewed transaction details from the Base Year expense to ensure expenditures are justifiable for normal utility operations.

**Q. How does IPC arrive at its Test Year forecast?**

A. IPC explains in its opening testimony that it began with the 2022 Base Year actual expenses, made adjustments for certain known changes, and then added an escalation factor to reflect projected inflation. The Company adjusted 2022 Base Year expense for FERC Account 536 (cost of water for

[1] See Staff/1002, Moore/1, Company response to Staff DR No. 58.

hydraulic power generation) by ($307,335) to smooth out an anomalous expense year and reflect the 3-year average. IPC also adjusted the Base Year expense to remove expenses associated with the Bridger coal plant, reflecting the conversion of Units 1 and 2 to natural gas and change to O&M expense in the future.

**Q. What does Staff recommend regarding non-labor generation O&M expense?**

A. I find IPC's non-labor generation expense to be slightly below its 3-year average of $3.9 million, when adjusting for known expenses. I do not at this time recommend an adjustment for these expenses.

## ISSUE 2. BOARD OF DIRECTORS' FEES

**Q. Please summarize this issue.**

A. Idaho Power proposes to include an Oregon-allocated amount of $109,167 in the Test Year for non-employee Board of Director (BOD) compensation. This represents an allocation of 4.29 percent of the total company BOD expense of $2.54 million. The Company also includes $5,209 Oregon-allocated expense for travel, meals, and lodging for non-employee directors to attend in-person meetings in Boise.[2]

**Q. Please describe Staff's analysis of this issue.**

A. I reviewed the Company's filing and issued follow-up data requests to review Board of Director fees broken down by compensation categories, and to compare the expenses of the Base Year with the Test Year forecast.

BOD compensation categories have remained stable, but the total amount paid to directors is forecast to increase by 5.78 percent from the Base Year to the Test Year. The Company confirms that only non-employee directors receive compensation for Board participation.

Staff objects in principle to ratepayers paying the cost of Board of Directors, who oversee corporate governance mechanisms that are generally designed to encourage directors and officers to focus on generating financial returns for shareholders. The Company responded to a Staff data request about BOD compensation stating that "Idaho Power structures director

[2] See Staff/1002, Moore/2-3, Company response to Staff DR No. 232-233.

compensation to attract and retain qualified non-employee directors and to further align the interests of directors with the interests of shareholders."[3]

In a paper titled "The Corporate Governance of Public Utilities," researchers Aneil Kovvali and Joshua C. Macey conclude that there may be a misalignment of incentives such that "corporate governance mechanisms ensure that public utility companies are managed for the benefit of shareholders, it is the ratepayers who internalize the consequences of utilities' decisions."[4]

**Q. What is Staff's recommendation regarding BOD fees?**

A. Staff recommends the Commission disallow expense for non-employee Board of Director fees. The Company has not demonstrated how directors' roles advance the interests of ratepayers versus the interest of shareholders. Staff does not believe it is appropriate for utility ratepayers to shoulder the cost for corporate governance that is not explicitly geared toward returning the greatest value and benefit to the ratepayers. Accordingly, Staff recommends an adjustment of ($109,000) for BOD compensation, and an adjustment of ($5,200) for BOD travel and lodging expense.

3 See Staff/1002, Moore/4, Company Response to Staff DR No. 438.
4 See "*The Corporate Governance of Public Utilities*" – Yale Journal on Regulation, 2023.

## ISSUE 3. MATERIAL & SUPPLIES INVENTORY

**Q. Please summarize this issue.**

A. Idaho Power proposes an average Test Year balance for materials and supplies in rate base of $90,585,564 at a System level. The Oregon-allocated forecast Test Year rate base amount is $4,035,110.[5] This represents a 13 percent increase over the 2022 Base Year.

**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.

**Q. Please describe Staff's analysis of this issue.**

A. Staff reviewed historical balances for the years 2020-2022 and compared the average of monthly average balances for each year with the year-end forecast for 2024. Staff believes that using an average of monthly averages balance for rate-based items provides an accurate picture of yearly rate-based components that earn a rate of return.

Using an average of monthly average balances for 2020, 2021, and 2022, escalated for inflation of 6.9[6] percent results in a forecast 2024 year-end balance of $3,337,719.

**Q. What does Staff conclude from its review?**

---

5 See Idaho Power/1202, Noe/7.
6 This escalation factor is taken from Idaho Power's Oregon Forecast Methodology Manual – Idaho Power/1002, Larkin/12.

A. The amount Idaho Power's includes in rate base for materials and supplies is too high. In reviewing the 3-year average balance for the years 2020-2022, the average system-level balance is $70,755,040. Applying a 6.9 percent escalation factor and using Idaho Power's jurisdictional separation method to allocate for Oregon, Staff concludes that the Test Year Oregon-allocated forecast should be reduced to arrive at the recommended balance of $3,369,236.

**Q. Does staff recommend an adjustment to the Test Year forecast?**

A. Yes. I recommend an adjustment of ($666,400) to the materials and supplies balance.

## ISSUE 4. MISC DEFERRED DEBITS

**Q. Please summarize this issue**

A. Idaho Power's rate base includes three regulatory assets for deferred debits with amounts allocated to Oregon:[7]

- Deferred Pension cost - $219,697
- Siemens LTP Amortization – Oregon – $39,316
- Siemens LTP Amortization – Oregon deferred rate base -- $44,046

The deferred pension cost is the portion of pension expense with monthly amortization associated with the depreciation of electric plant in service. There is no interest accruing on this balance.

The Company intends to amortize the Siemens LTP Amortization balance on a straight-line basis over the length of the contract. This balance also accrues no interest. The Siemens LTP Amortization in deferred rate base is also to be amortized on a straight-line basis over the length of the contract. This asset is accruing interest, and in 2022 accrued $28,584 in interest.

**Q. Does staff have a recommendation with regard to this issue?**

A. Not at this time. However, Staff continues its discovery efforts in evaluating these regulatory assets and may have a recommendation at a later stage in this proceeding.

**Q. Does this conclude your testimony?**

A. Yes.

[7] See Staff/1002, Moore/5-6, Company response to Staff DR No. 475.

CASE: UE 426
WITNESS: MITCHELL MOORE

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 1001

## Witness Qualifications Statement

## March 25, 2024

**WITNESS QUALIFICATIONS STATEMENT**

| | |
|---|---|
| NAME: | Mitchell Moore |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Utility Analyst<br>Rates, Safety and Utility Performance Program |
| ADDRESS: | 201 High Street SE. Suite 100<br>Salem Oregon 97301-3612 |
| EDUCATION: | Bachelor of Arts, Journalism and Political Science<br>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, UE 374, UE 394, UE 399, UG 288, UG 305, UG 325, UG 344, UG 347, UG 366, UG 388, UG 390, and UG 461.<br><br>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.<br><br>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 426
WITNESS: MITCHELL MOORE

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1002

## Exhibits in Support
## Of Opening Testimony

**March 25, 2024**

From IPC Response to Staff DR No. 58:

| | Test Year Ending December 31, 2024 | | | | | | |
|---|---|---|---|---|---|---|---|
| Account | Account Total b+c | Non-Utility | Total Regulated Utility Service | Oregon Alloc. Factor | Oregon Alloc./ Share | Oregon Situs | Total Included in Filed Rate Case e+f |
| 500 | $187,108 | | $187,108 | 0.039549 | $7,400 | | $7,400 |
| 502 | $6,708,399 | | $6,708,399 | 0.041804 | $280,435 | | $280,435 |
| 505 | $1,206,329 | | $1,206,329 | 0.040975 | $49,430 | | $49,430 |
| 506 | $5,282,149 | | $5,282,149 | 0.039549 | $208,905 | | $208,905 |
| 507 | $122,647 | | $122,647 | 0.039549 | $4,851 | | $4,851 |
| 510 | ($262,051) | | ($262,051) | 0.039549 | ($10,364) | | ($10,364) |
| 511 | $2,715,268 | | $2,715,268 | 0.039549 | $107,387 | | $107,387 |
| 512 | $5,768,252 | | $5,768,252 | 0.040467 | $233,421 | | $233,421 |
| 513 | $1,301,549 | | $1,301,549 | 0.039046 | $50,820 | | $50,820 |
| 514 | $5,270,916 | | $5,270,916 | 0.039549 | $208,461 | | $208,461 |
| 535 | $1,090,904 | | $1,090,904 | 0.039763 | $43,377 | | $43,377 |
| 536 | $5,734,409 | | $5,734,409 | 0.039549 | $226,792 | | $226,792 |
| 537 | $12,099,645 | | $12,099,645 | 0.039549 | $478,532 | | $478,532 |
| 538 | $254,349 | | $254,349 | 0.040213 | $10,228 | | $10,228 |
| 539 | $1,374,894 | | $1,374,894 | 0.039549 | $54,376 | | $54,376 |
| 540 | $324,336 | | $324,336 | 0.039549 | $12,827 | | $12,827 |
| 541 | $12,338 | | $12,338 | 0.039549 | $488 | | $488 |
| 542 | $292,062 | | $292,062 | 0.039549 | $11,551 | | $11,551 |
| 543 | $176,268 | | $176,268 | 0.039549 | $6,971 | | $6,971 |
| 544 | $640,827 | | $640,827 | 0.040461 | $25,929 | | $25,929 |
| 545 | $1,513,079 | | $1,513,079 | 0.039549 | $59,841 | | $59,841 |
| 546 | $47,153 | | $47,153 | 0.039549 | $1,865 | | $1,865 |
| 547 | $17,029,870 | | $17,029,870 | 0.042514 | $724,011 | | $724,011 |
| 548 | $1,420,431 | | $1,420,431 | 0.04055 | $57,599 | | $57,599 |
| 549 | ($431,633) | | ($431,633) | 0.039549 | ($17,071) | | ($17,071) |
| 552 | $115,412 | | $115,412 | 0.039549 | $4,564 | | $4,564 |
| 553 | $921,005 | | $921,005 | 0.042332 | $38,988 | | $38,988 |
| 554 | $6,628,935 | | $6,628,935 | 0.039549 | $262,170 | | $262,170 |
| 557 | $1,372,019 | | $1,372,019 | 0.039549 | $54,262 | | $54,262 |
| 560 | 576221.8581 | | $576,222 | 0.039614 | $22,826 | | $22,826 |
| | | | | | | | **$3,220,872** |

**TOPIC OR KEYWORD: Board of Directors Fees**

**STAFF'S DATA REQUEST NO. 232:**

Please expand on the Company's response to Staff Data Request No. 62. Specifically, please provide:

a. A forecast of total Company and Oregon-allocated expenses, broken out by each of the categories identified in the response to SDR No. 62, and that are included in the Test Year forecast.
b. The number of non-employee Directors who receive compensation. What amount is included in the Test Year forecast.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 232:**

The table that follows lists the forms and amounts of compensation payable to Idaho Power's non-employee directors as included in the Test Year forecast.

| Annual Director Compensation Amounts Included in Test Year Forecast | | Number of Non-Employee Directors | Total Idaho Power Expenses in Test Year Forecast | Oregon-Allocated Expenses in Test Year Forecast |
|---|---|---|---|---|
| Base Retainer | $89,956 | 10.42* | $937,047 | $40,217 |
| *Base Committee Annual Retainers:* | | | | |
| Audit committee | $12,700 | 5 | $63,498 | $2,725 |
| Compensation and human resources committee | $8,762 | 3 | $26,987 | $1,158 |
| Corp. gov. and nom. committee | $7,731 | 4 | $31,749 | $1,363 |
| Executive committee | $3,092 | 5 | $15,875 | $681 |
| *Additional Chair Annual Retainers:* | | | | |
| Chair of the board | $103,077 | 1 | $105,831 | $4,542 |
| Chair of audit committee | $15,642 | 1 | $15,875 | $681 |
| Chair of compensation and human resources committee | $12,885 | 1 | $13,229 | $568 |
| Chair of corp. gov. and nom. committee | $10,308 | 1 | $10,853 | $454 |
| Annual Stock Awards (paid in IDACORP shares) | $126,997 | 10.42* | $1,322,890 | $56,777 |
| Total | | | $2,543,563 | $109,167 |

*There are currently 11 non-employee Directors who receive compensation, but the Test Year forecast was calculated based on 10.42 non-employee Directors as one non-employee Director retired in May of 2022, the base year, and so that assumption was included for the Test Year forecast.

**TOPIC OR KEYWORD:**

**STAFF’S DATA REQUEST NO. 233:**

Please identify the projected budget for travel and lodging expenses for Directors that are included in the Test Year forecast. Provide both the total Company and Oregon-allocated amounts. Include with your response a narrative description of the projected travel and lodging plans.

**IDAHO POWER COMPANY’S RESPONSE TO STAFF’S DATA REQUEST NO. 233:**

Directors are reimbursed for reasonable costs of travel, meals, and lodging for board meetings. The Test Year forecast includes $121,367 of total Company and $5,209 Oregon-allocated for travel, meals, and lodging for board meetings. The Test Year forecast expenses include the customary plans for the travel, meals, and lodging for directors to attend the four in-person board meetings normally held in Boise each year.

**TOPIC OR KEYWORD: Board of Directors' Fees**

**STAFF'S DATA REQUEST NO. 438:**

Regarding non-employee Board of Director compensation: Please explain and provide support demonstrating how this compensation is consistent with that awarded to peer companies.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 438:**

Idaho Power structures director compensation to attract and retain qualified non-employee directors and to further align the interests of directors with the interests of shareholders. The compensation and human resources committee of the board of directors reviews surveys of non-employee director compensation trends and a competitive analysis of peer company practices prepared by human resources and an independent compensation consultant (Pay Governance) every other year. Based on the bi-annual market analysis, the compensation and human resources committee then makes recommendations to the board of directors on compensation for non-employee directors, including their board and committee retainers and annual equity awards.

Please see "Confidential Response to Staff Request No. 438 – Attachment", which is the most recent director pay analysis as presented to the compensation and human resources committee in September 2023.

**TOPIC OR KEYWORD: Regulatory Assets**

**STAFF'S DATA REQUEST NO. 475:**

Regarding the Oregon allocated Regulatory Debits and Credits identified in Idaho Power/901, Jeppsen 11:

a. Please explain in narrative detail what each asset represents.
b. Please list the Commission Orders that created each asset.
c. Explain the status of each asset, including the reason the assets are not being amortized.
d. Explain how interest is applied to each asset, and the amount.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 475:**

Regarding Regulatory Debits and Credits identified in Idaho Power/901, Jeppsen 11, the applicable Oregon allocated assets are:

- Deferred Pension – Oregon
- Siemens LTP Amort – Oregon
- Siemens LTP Amort – Oregon Deferred RB

Please note: Intervenor Funding – Idaho, Siemens LTP Amort – Idaho, Siemens LTP Amort – Idaho Deferred RB, Cloud computing, and Wildfire Mitigation are all Idaho specific/allocated, hence excluded from this response. Additionally, all items listed in the table below are currently being amortized.

| | (a)<br>Please explain in narrative detail what each asset represents. | (b)<br>Please list the Commission Orders that created each asset. | (c)<br>Explain the status of each asset, including the reason assets are not being amortized. | (d)<br>Explain how interest is applied to each asset, and the amount. |
|---|---|---|---|---|
| Deferred Pension – Oregon | The capital portion of SFAS 87 pension expense recorded as regulatory asset to be amortized in a manner consistent with depreciation of electric plant in service. | OPUC Order 10-064 | The capital portion of SFAS 87 expense is incurred as a regulatory asset, with monthly amortization consistent with depreciation of electric plant in service until reviewed by the Commission for inclusion in rates in a subsequent rate proceeding. | No carrying charge applied to this regulatory asset. |
| Siemens LTP Amort – Oregon | Deferred costs associated with a Long-Term Contract with Siemens Energy, Inc. | OPUC 15-387 | Amortize the balance, straight line basis, over the length of the contract. | No carrying charge applied to this regulatory asset. |

| | | | | |
|---|---|---|---|---|
| | Spare parts transferred to Siemens that are currently included in rate base. | | | |
| Siemens LTP Amort – Oregon Deferred RB | Deferred costs associated with a Long-Term Contract with Siemens Energy, Inc. Spare parts transferred to Siemens that are currently not in rate base, plus initialization fees and associated tax expense. | OPUC 15-387 | Amortize the balance, straight line basis, over the length of the contract. | Accrue a carrying charge on amount using Company's most recent authorized rate of return. $28,584 of carrying charges accrued in 2022. |

CASE: UE 426
WITNESS: MING PENG

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 1100

## OPENING TESTIMONY

### Depreciation Expense, Amortization Expense, Depreciate Reserve, Amortization Reserve, and Allowance for Funds Used During Construction

## March 25, 2024

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

A. My name is Ming Peng. I am a Senior Economist employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) 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/1101.

**Q. What is the purpose of your testimony?**

A. I discuss my analysis of the depreciation expense and accumulated depreciation, or depreciation reserve, and portions of Idaho Power's (IPC or Company) revenue requirement for this rate case as documented by the Company witnesses in IPC/900, Paula Jeppsen, IPC/1000, Matthew T. Larkin, and IPC/1200, Kelley Noe. I also discuss my review of the Allowance for Funds Used During Construction (AFUDC) portion of revenue requirement for this rate case.

**Q. Did you prepare any exhibits for this docket?**

A. Yes. In addition to my witness qualifications statement, I prepared Exhibit Staff/1102, IPC Responses to Staff Data Requests.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

Summary of Findings and Recommendations……………………………3
Issue 1. Depreciation Expense ………………..……..……...…………...4
Issue 2. Amortization Expense...……………….……………………………13
Issue 3. Depreciation Reserve ………………..……………...……...…………14
Issue 4. Amortization Reserve...……………………….……………………15

Issue 5. Allowance for Funds Used During Construction (AFUDC)..…..16

## SUMMARY OF FINDINGS AND RECOMMENDATIONS

**Q. Please summarize your findings and recommendations.**

A. Please note that I may revise my recommendations based on testimony filed by other participants in this rate case.

1. Depreciation Expense: I made an adjustment to Bridger Units 1–4 depreciable life and depreciation expense. In the depreciation expense calculation, for Units 1 and 2, I shortened the service life from IPC-proposed 2037 to 2029, or extended service life to 2029 from the OPUC-authorized 2025; for Units 3 and 4, I moved the end-of-life date from the IPC-proposed 2029, back to the OPUC-authorized end-of-life date of 2025. As a result, the depreciation expense would increase by $1.128 million on an Oregon jurisdictional basis.
2. Amortization Expense: I made no adjustment to this issue.
3. Depreciation Reserve and Rate Base: My adjustment to depreciation reserve on an Oregon jurisdictional basis is an increase of $1.128 million; to correspond with my adjustment to depreciation expense; the rate base decreases by the same amount of $1.128 million.
4. Amortization Reserve: I made no adjustment to this issue.
5. AFUDC: I made no adjustment to this issue.

## ISSUE 1. DEPRECIATION EXPENSE

**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]

**Q. Why is depreciation important in a revenue requirement?**

A. NARUC states that:

> Depreciation has a profound effect on the revenue requirement of a utility, and for many utilities, depreciation expense represents a large percentage of total operating expenses. In

[1] NARUC, Public Utility Depreciation Practices, p.318 (1996).

> addition, deferred income taxes, rate base, and cost of capital are all affected by the depreciation practices of a utility.[2]

1. From a valuation perspective, depreciation is the loss in service value not restored by current maintenance.
2. 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.
3. 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:

> 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. Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission. The commission may make

[2] NARUC, Public Utility Depreciation Practices, p.195 (1996).

changes in such rates of depreciation from time to time as the commission may find to be necessary.

**Q. What is the Commission's historical treatment of a depreciation calculation in a revenue requirement?**

A. A utility should use the Commission-authorized depreciation parameters and rates to calculate the depreciation and amortization expense and reserve. A Company's depreciation expense is determined by (OPUC-Authorized Depreciation Rate) x (Oregon net plant in service) x (allocation factor).

**Q. Has IPC complied with the OPUC Order by using the Commission-authorized depreciation rates in the calculation of revenue requirement for the UE 426 general rate case?**

A. IPC used the depreciation rates that were authorized in Order No. 22-001, except that IPC used different depreciation rates for Jim Bridger (Bridger) coal-fired power plant.

**Q. Please provide background information about the Jim Bridger coal-fired power plant.**

A. The Jim Bridger Plant has four units and is a 2,441.9-megawatt (MW) coal-fired power station near Point of Rocks, Wyoming. Units 1 through 4 have output capacities of around 608 MW apiece, Unit 1 became operational in 1974 and has a retirement date in Oregon of 2025 after a 50-year service.

The plant is jointly owned by Idaho Power (34 percent) and PacifiCorp (66 percent). Jim Bridger has about 345,000 volts of transmission lines that connect the plant to the larger electrical grid, distributing the power produced there to customers in Utah, Idaho, Oregon, Washington, and portions of Northern California. The plant is operated by majority owner PacifiCorp.

**Q. Historically, how has the Oregon Commission treated the depreciable life for Jim Bridger Plant?**

A. When Jim Bridger coal plant was built and started generation service, the retirement year was 2025. On August 31, 2007, PacifiCorp filed an application for an order approving a change in depreciation rates in UM 1329. In the filing, PAC proposed to increase in the depreciable lives of the coal plants by seven to 17 years, which is greater than the existing depreciable life end of date for 11 coal plants. Out of these 11 coal power plants, Jim Bridger's depreciable life would be extended by 12 years, from 2025 to 2037. Oregon Commission in Order 08-327 stated:

> [W]e decline to adopt that portion of the Stipulation that increases the depreciable life estimates for Pacific Power's coal-fired generating plants. For these plants, Pacific Power should continue to use the currently-approved depreciable lives.

Therefore, Oregon's depreciable life for Jim Bridger was not extended and remained as 2025 for ratemaking purposes in Oregon, whereas the end-of-life date was extended for other jurisdictions. As a result, Oregon paid about $10 million more each year for depreciation expense than the other states between approximately 2008 and 2020, when other states shortened the end-of-life date for the Jim Bridger Plant to 2025 from 2037. Because of this, Oregon's net plant for Jim Bridger is smaller than the net plant in PacifiCorp's other jurisdictions. Until 2020, all states agreed with Oregon and took a 2025 end-of-life date for Jim Bridger Coal power plant.

**Q. What is IPC's depreciation rate proposal for Jim Bridger Plant?**

A. Idaho Power will convert Units 1 and 2 to natural gas by the summer of 2024, and expects to convert Units 3 and 4 by summer of 2030. Therefore, the Company's 2024 test year reflects the following:

1) Retirement of Unit 1 and 2 coal-related facilities as of year-end 2023;
2) Reclassification of existing facilities necessary to support gas operations at units.
3) Units 1 and 2 accounted for in the FERC 340 plant account series, to be depreciated using the currently-approved composite depreciation rate for natural gas generation plant for these accounts, with a 2037 end-of-life;
4) Addition of new gas-related investment at Units 1 and 2 in the FERC 340 plant account series with a 2037 end-of-life; and
5) Modification of the depreciable lives for estimated coal-related assets at Units 3 and 4 to a year-end 2029.

For Bridger Units 3 and 4 Idaho Power is proposing to utilize an end-of-life assumption of year-end 2029 for the remaining Unit 3 and 4 coal-related assets, continuing to use the coal depreciation rate for Bridger Unit 3 and 4 to calculate the depreciation expense and reserve. Idaho Power has calculated a depreciation rate to utilize for each steam production plant account based on the remaining net book value of the estimated coal-related assets, estimated coal-related plant additions and retirements, and remaining life of six years.

**Q. What is Staff's position for JB coal plant depreciation and why?**

A. The six-multistate, including Idaho, authorized end of life date for JB Units 1–4 is 2025. In UE 426 filing, for JB Units 1 and 2, IPC asked for

a) Extending the end-of-life for Bridger Units 1 and 2 from the currently OPUC and multistate approved 2025 to 2037.

b) Using Natural Gas depreciation rates instead of coal depreciation rates to calculate depreciation expense.

My recommendation a) to extend the service life for Units 1 and 2 from 2025 to 2029 is subject to the following requirement:

- The Company file an annual safety report on any accidents and potential risks for JB Units 1 and 2 with the Commission.

Staff recommends this condition because converting coal plants to burn gas not only requires use of the existing boiler, with new natural gas burners, but also requires use of the existing steam turbine, existing generator, and existing exhaust stack. The existing coal facilities for Units 1 and 2 would be worn out by the end-of-year 2025. Forcing the old coal plant to continue to operate after 50 years could create higher safety risk, therefore, we need to be sure Idaho Power is accounting for this higher risk.

My recommendation b) to use the natural gas depreciation rate temporarily instead of coal depreciation rate to calculate the depreciation expense, is subject the following condition:

- Temporarily use the gas depreciation rate in UE 426, until the 2025 depreciation study is filed by PacifiCorp and OPUC has approved the updated depreciation rates.

For Bridger Units 3 and 4, Staff does not agree with Idaho Power's proposal to extend the end-of-life from the currently approved 2025 to 2029.

Under Commission Order Nos. 03-457, 08-327, 08-427, 09-317, 17-186, 17-213, 20-374, and 22-001 in Oregon, the retirement year for the Jim Bridger coal plant has always been 2025 after its 50 years' service. Oregon customers have been paying for Bridger Units 1, 2, 3, and 4 at a rate that allows them to pay off the Oregon-allocated share of these units by 2025. It is inappropriate to require Oregon customers to continue to pay for depreciation of the existing Units 3 and 4 past 2025 in UE 426 filing.

Please note, the average operating coal-fired generating unit in the United States is 45 years old, according to U.S. Energy Information Administration, Preliminary Monthly Electric Generator Inventory, September 2021. According to Statista, a global data and business intelligence platform, the service life for coal power is 40 years.[3]

Jim Bridger power plant is reaching its 50-year service life. For a coal-to-gas conversion, the company not only requires adding gas turbines and heat recovery steam generators, but also needs to keep the existing 50-year-old steam turbine and generator.

[3] Statista: Lifetime of energy sources and power plants worldwide by type.

In addition to the Commission-ordered JB plant's 2025 retirement date, I used nationally recognized Survival Analysis to determine the end of asset physical life for JB plant. The analysis includes assessment and asset failure prediction based on the Characteristics of industrial assets, as well as my 25 years of energy industry experience, JB facility retirement observation, and an onsite visit to the JB coal plant.

**Q. What does the Commission Order say about IRP and the Ratemaking?**

A. OPUC Order No. 16-071 states:

> We reaffirm our long-standing view that decisions made in an IRP proceeding do not constitute ratemaking. Decisions whether to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate case proceeding. Just as acknowledgement does not guarantee favorable ratemaking, a decision to not acknowledge does not constitute a preliminary determination of imprudence.

In Oregon, an IRP is not a contested case proceeding. The Commission may acknowledge an IRP, but acknowledgement does not have presumption of prudency. In this UE 426 filing, the guidance in Order No. 16-071 definitely reduces utility regulatory risk and improves the transparency of the decision-making process for ratemaking.

**Q. What is the dollar impact from this adjustment?**

A. With the impact to the Depreciation Expense and Depreciation Reserve based on a 2029 end-of-life (EOL) for Bridger Units 1 and 2, and a 2025 end-of-life for Bridger Units 3 and 4, the depreciation expense would increase by $1.128 million on an Oregon jurisdictional basis, the reserve would increase by $1.128 million, and the rate base decrease by the same amount of $1.128 million (see IPC's data response 508). Please note that by the end of 2025, Oregon customers will pay off the JB Plant Units 3 and 4 for both IPC's (34 percent) and PAC's (66 percent) ownership share, and the JB coal-fired plant assets should be fully depreciated based on OPUC Orders.

## ISSUE 2. AMORTIZATION EXPENSE

**Q. What is amortization?**

A. Amortization is the practice of spreading an intangible asset's cost over that asset's useful life. Depreciation is the expensing a fixed asset as it is used to reflect its anticipated deterioration. Accounting rules stipulate that physical, tangible assets (with exceptions for non-depreciable assets) are to be depreciated, while intangible assets are amortized.[4]

**Q. What IPC proposed amortization expense in the filing?**

A. In Idaho Power/900, Jeppsen, IPC Proposed amortization expense in 2024 JSS Oregon. IPC requested an amortization expense of $6.044 million systemwide, and allocates to Oregon $241,317, or 3.993 percent.

**Q. Have you made an adjustment to Amortization?**

A. No. To review and verify the amortization expenses, I asked IPC to provide the calculation formular and links for the amortization rate used to check if they used authorized or newly-proposed rates and links to the RR model. I verified the calculation and data links provided by IPC. The calculations look fine.

[4] source: Investopedia, Amortization vs. Depreciation.

## ISSUE 3. DEPRECIATION RESERVE

**Q. What is depreciation reserve?**

A. Depreciation reserve is also called accumulated depreciation reserve. It is the sum of all recorded depreciation on an asset to a specific date.

**Q. What is the Commission's historical treatment of depreciation reserve?**

A. Accumulated depreciation reserve refers to the life-to-date depreciation that has been recognized that reduces the book value of an asset. The Commission treats this issue by following Generally Accepted Accounting Principles (GAAP) that is as reserve increases, the Rate Base decreases. Please note, rate base is the value of property on which the utility is allowed to earn a specified rate of return, in accordance with rules set by the Commission. In this issue, rate base is the value of property of a utility minus accumulated depreciation of those assets.

**Q. Have you adjusted depreciation reserve?**

A. Yes. The depreciation reserves are affected by depreciation expenses, asset retirements, sales, transfers, gross salvage, cost of removal, and other adjustments. If depreciation expense is changed, the accumulated depreciation should be changed accordingly. I made an adjustment to depreciation expense. Therefore, the accumulated depreciation would be changed accordingly. My adjustment to depreciation reserve on an Oregon jurisdictional basis is an increase of $1.128 million, and the rate base would be decreased by the same amount of $1.128 million.

## ISSUE 4. AMORTIZATION RESERVE

**Q. Describe Amortization Reserve.**

A. Amortization Reserve is accumulated amortization at a point in time, which includes the total amount of recorded amortization, retirements, gross salvage, cost of removal, transfer asset, and other adjustments.

**Q. What is the Commission's historical treatment of this issue?**

A. Amortization Reserve is also called accumulated amortization reserve. In a revenue requirement, as an amortization reserve increases, the Rate Base decreases. Rate Base is the value of property/assets of a utility minus accumulated amortization of those assets.

**Q. Have you made any adjustments to amortization reserve?**

A. Not at this time. The amortization reserves are affected by amortization expenses. If amortization expense is changed, the accumulated amortization should be changed accordingly. I did not make an adjustment to amortization expense. If any adjustments are made by other Staff witnesses, the Company's final amortization reserve would be changed accordingly.

## ISSUE 5. AFUDC

**Q. What is AFUDC?**

A. Electric (Gas) Plant Instruction No. 3(17) provides a formula for computing rates used to capitalize Allowances for Funds Used During Construction (AFUDC).[5] The formula includes a component for the weighted 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 balances in the trust or special funds. Fund earnings during construction should be credited to the cost of construction of the project facilities.

**Q. What is the purpose of the AFUDC review?**

A. The purpose of this review is to address whether the Company complied with guidance[6] related to AFUDC and the capitalization of assets based on the regulations of both the Federal Energy Regulatory Commission (FERC) and the Oregon Public Utility Commission (OPUC) in this filing.

**Q. Please provide more details regarding AFUDC.**

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5 https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/allowance-funds-used-during-construction.

6 FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101.

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).

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.
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 regulatory asset would be the difference between the State AFUDC rate and the FERC AFUDC rate.

The FERC formula and elements for the computation of the allowance for funds used during construction are:[8]

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7 FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101.

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.

$Ai=s*(S/W)+d*(D/D+P+C)*(1-S/W)$ = 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 <u>other</u> 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

**Q. Did you make any adjustments after the review?**

A. No. Staff proposed no adjustment to IPC's original filing for the following reasons:

- <u>Compliant monthly AFUDC rates</u>: The Company's calculation of its monthly AFUDC Rates complies with the FERC AFUDC rate formulas and accounting requirements. The monthly calculation method has been authorized by FERC. FERC requires utility companies to calculate AFUDC rates on a semiannual basis (biannually, i.e., twice a year), but FERC's letter on December 30, 1981, approved IPC to reflect in monthly determinations of AFUDC the fixed capital structure and component costs as of the end of the prior month for the current month's determination of AFUDC. The short-term debt balance and cost and construction work in progress balance will continue to be estimated for the current month.

- Meets FERC guidelines: Under FERC's AFUDC calculation guide, IPC calculates AFUDC rates in accordance with FERC guidance in 18 C.F.R. pt. 101 Electric Plant Instruction. When construction funding is not met by short-term debt, IPC calculates the maximum allowable AFUDC rates relevant to long-term debt by multiplying the total long-term debt cost rate by the ratio of total long-term debt to total capitalization. The maximum allowable AFUDC rates relevant to other funds (common equity & preferred stock) are calculated by multiplying the current authorized return on equity (ROE) by the ratio of total common equity to total capitalization. Lastly, cost rates for debt and equity sources of financing are each multiplied by one minus the ratio of weighted average short-term debt to CWIP to reflect that short-term debt financing is assumed to be the first source of financing in capital construction.
- Meets OPUC's rate of return: IPC's AFUDC rates are not higher than the authorized rate of return (Weighted Average Cost of Capital - WACC).
- AUTHORIZED RATE OF RETURN: IPC's current authorized Weighted Average Cost of Capital (WACC) is 7.75 percent, which was authorized in UE 248, based on a debt of 2.82 percent, an equity of 4.94 percent, and a 50.1/49.9 capital structure.
- AFUDC: The funds used for construction will not generate any returns. IPC did not include CWIP in the rate base in any situation.
- CAPITAL STRUCTURE: IPC's capital structure (Debts-bond/Equity-stocks ratios) was used for AFUDC with the Commission's authorization. In IPC's

UE 426 docket, IPC complied with the authorized capital structure of 50.1 percent debt (Bonds: borrowed money from bank and pay interest; tax deductible) and 49.9 percent equity (Stocks: sold to shareholders and pay dividends).

- OPUC POLICY: IPC did not include CWIP in the rate base, because OPUC does not allow a utility to put a plant not yet placed in service into a rate-base.

| IPC | AFUDC | AFUDC | AFUDC | Authorized | Authorized | Authorized | | |
|---|---|---|---|---|---|---|---|---|
| Year | Debt | Equity | Total AFUDC | weighted average LT Debt | weighted average Common Equity | WACC | OPUC | OPUC |
| | Rate | Rate | Rate | Rate | Rate | Rate | Order # | Docket # |
| 2017 | 2.28% | 5.36% | 7.64% | 2.82% | 4.94% | 7.75% | 12-358 | UE 248 |
| 2018 | 2.24% | 5.38% | 7.63% | 2.82% | 4.94% | 7.75% | 12-358 | UE 248 |
| 2019 | 2.16% | 5.47% | 7.63% | 2.82% | 4.94% | 7.75% | 12-358 | UE 248 |
| 2020 | 2.10% | 5.35% | 7.45% | 2.82% | 4.94% | 7.75% | 12-358 | UE 248 |
| 2021 | 2.06% | 5.41% | 7.47% | 2.82% | 4.94% | 7.75% | 12-358 | UE 248 |
| 2022 | 2.02% | 5.40% | 7.42% | 2.82% | 4.94% | 7.75% | 12-358 | UE 248 |
| 2023 | 2.34% | 5.08% | 7.41% | 2.82% | 4.94% | 7.75% | 12-358 | UE 248 |

IPC's current authorized Weighted Average Cost of Capital (WACC) is 7.75 percent, and the accrual AFUDC rate is 7.41 percent, which is lower than the authorized 7.75 percent. The Company's policy for AFUDC complies with the FERC requirement. In the month after it is placed in service, the facility being constructed is excluded from AFUDC base and thus, AFUDC accrual for the facility ceases.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: MING PENG

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 1101

## Witness Qualifications Statement

**March 25, 2024**

## WITNESS QUALIFICATIONS STATEMENT

NAME: Ms. Ming Peng

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Accounting and Finance Section of the Rates, Safety and Utility Performance Program

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 25 years. My roles have included:

**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 15 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 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 January 11, 1999. Historically, my reviews 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.

<u>Mentor in the ICER - International Confederation of Energy Regulators</u>: 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.; “Price-Cap Performance Based Regulation” in UK; Cost of Capital, Energy Demand and Price Forecasting Modeling; Least Cost Planning; Regulatory Policy; and Renewable Energy issues within regulated rate structures.

CASE: UE 426
WITNESS: MING PENG

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 1102

## Exhibits in Support
## Of Opening Testimony

**March 25, 2024**

**TOPIC OR KEYWORD: Jim Bridger Unit 1-4 Depreciation Expenses and Reserves**

**STAFF'S DATA REQUEST NO. 508:**

Please provide the total Depreciation Expense and Reserve based on the following JB end-of-life date:

1. For Units 1 & 2, the calculation results of the total depreciation expenses and reserves, systemwide and Oregon-allocated, based on a 2029 end-of-life date.
2. For Units 3 & 4, the calculation results of the total depreciation expenses and reserves, systemwide and Oregon-allocated, based on a 2025 end-of-life date.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 508:**

See Response to Staff Request No. 508 – Attachment for the depreciation expense and reserve values, on a system basis and an Oregon-jurisdictional basis, assuming a 2029 end-of-life date for Bridger Units 1 and 2 and a 2025 end-of-life date for Bridger Units 3 and 4. Note, the estimates assume the current approved depreciation rates are in effect through October 31, 2024, with the depreciation rates under the above scenario effective November 1, 2024. Idaho Power has also provided the forecasted 2025 depreciation expense that assumes the depreciation rates under the above scenario are in effect an entire year.

CASE: UE 426
WITNESS: Rose Pileggi

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1200

# OPENING TESTIMONY
## Hydro Facilities Investment, Capital Structure, 2023 and 2024 Resource Additions, Cost of Long-term Debt

## March 25, 2024

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

A. My name is Rose Pileggi. I am a Senior Energy Analyst employed in the Energy Costs Section of the Rates, Safety and Utility Performance Program (RSUP) 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/1201.

**Q. What is the purpose of your testimony?**

A. The purpose of this testimony is to address the Company's testimony on Hydro Facilities Investments, 2023 and 2024 Resource Additions, Capital Structure, and the Cost of Long-Term Debt.

**Q. Did you prepare any exhibits for this docket?**

A. Yes. I prepared the following supporting exhibits:

Exhibit Staff/1202. Non-Confidential Responses to Data Requests
Exhibit Staff/1203. Cost of Long-Term Debt Worksheet

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

Issue 1. Hydro Facilities Investments.......................................................... 3
Issue 2. 2023 and 2024 Resource Additions ........................................... 13
Issue 3. Capital Structure........................................................................ 19
Issue 4. Cost of Long-Term Debt............................................................ 21
Summary. ................................................................................................ 21

**Q. Could there be changes or updates to Staff's position and recommendations?**

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

## ISSUE 1. HYDRO FACILITIES INVESTMENTS

**Q. Please provide background on the hydro facilities investments.**

A. Since Idaho Power's (Idaho Power, IPC, or Company) last Oregon general rate case (GRC) filed in 2011, several hydro projects have been undertaken by the Company. In this GRC, the Company is seeking recovery of three major hydro facility investments. The investments at the three facilities—Brownlee, Shoshone Falls, and Lower Salmon Falls—are presented as a "prudent and proactive approach to managing the Company's hydro fleet" and ensuring that these facilities are able to provide safe, clean, and reliable service and energy to customers.[1] The total of these three investments is approximately $140.5 million.[2]

**Q. What is the total cost, separately, of each project?**

A. The cost of these projects is as follows:[3]

- Brownlee—$66.9 million:
  - $7.4 million in Labor
  - $5.0 million in Materials
  - $43.5 million in Purchased Services
  - $3.6 million in Overheads
  - $6.5 million in AFUDC
  - $0.9 million for Other Expenses
- Shoshone Falls—$27.1 million:

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[1] Idaho Power/300, Hackett/8 and 31.
[2] See Staff/1202, Pileggi/1-4, Idaho Power's response to Staff DR No. 355.
[3] Id.

- $2.4 million in Labor
- $2.7 million in Materials
- $18.1 million in Purchase Services
- $1.7 million in Overheads
- $1.9 million in AFUDC
- $0.3 million for Other Expenses

- Lower Salmon Falls—$46.6 million:
  - $7.3 million in Labor
  - $2.0 million in Materials
  - $30.4 million in Purchased Services
  - $2.4 million in Overheads
  - $4.1 million in AFUDC
  - $0.4 million for Other Expenses

**Q. What is the standard by which these projects are analyzed?**

A. Two standards of review are applied, that the plant is used and useful prior to the effective date of rates, and the investment is prudent. The prudence standard focuses on whether an action is reasonable given the facts that are known and knowable at the time that the decision is made. NARUC presents the following factors, among others, that should be considered when determining prudence:

- Utility executives are financial and technical experts;
- Prevailing practice is relevant but not determinative;

- The utility's legal obligation to provide safe, reasonable, and adequate service at lowest cost;
- The initial utility decision and its subsequent utility response to changing circumstances; and
- Prudence analysis is not based on hindsight."[4]

**Q. Will each of these projects be used and useful by the rate effective date of January 1, 2025?**

A. Yes. The last unit at Brownlee was placed into service in 2019, Shoshone Falls was placed into service in 2020, and the last unit at Lower Salmon Falls was placed into service in 2023.[5] Presently, all projects are used and useful.

**Q. Why does the Company present these investments as prudent?**

A. Each of these major projects was undertaken at an aging facility. At the time of project commencements, Brownlee turbines were 57 years old,[6] Shoshone Falls Units 1 and 2 were over 85 years old,[7] and Lower Salmon Falls turbines and generator cores were 70 old.[8] Each hydro facility required major work to ensure the continuation of operations. The work addressed issues such as cavitation damage, deterioration, and shutdowns caused by mechanical failure.

**Q. Have issues with the prudence of the projects been identified?**

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[4] " Management Audits / Prudency," NARUC, 2014. See: https://pubs.naruc.org/pub.cfm?id=537CC901-2354-D714-5154-339AD3909936

[5] Idaho Power/300, Hackett/6, lines 10 and 19; 8, line 16.

[6] Idaho Power/300, Hackett/5.

[7] Idaho Power/300, Hackett/6.

[8] Idaho Power/300, Hackett/7.

A. Yes. Staff has identified a few issues with the prudence of these projects. These issues are discussed later in Staff's testimony and summarized here:

- Lack of support for the economic prudency of each project.
- No Net Present Value (NPV) analyses were performed prior to commencement of each project.
- No alternate projects were evaluated for any of these projects.
- Lack of historical documentation regarding original project estimates.

**Q. Why does Staff state that there is a lack of support for the economic prudency of the projects?**

A. At no point in testimony, or in response to Staff Data Requests, did Idaho Power supply any support for the economic benefit of these projects. As stated above, NARUC opines that utility executives are financial and technical experts, and the utility has an obligation to provide safe, reasonable, and adequate service at the lowest cost. While the Company does provide justification for why the projects were needed, no evidence or workpapers were provided in testimony or responses to Staff Data Requests to show the investments are consistent with Idaho Power's obligation to provide service at lowest cost. This lack of support for economic prudency is further demonstrated by the other identified issues.

**Q. Why are Net Present Value analyses important in a decision-making process for capital expenditures?**

A. An NPV analysis helps show what the economic impact of an action is likely to be. In the selection of a project, performing an NPV analysis helps a company to evaluate the value provided by undertaking a project compared to that of competing projects.

**Q. Why is it important to evaluate more than one project?**

A. It is important to evaluate alternatives to any given project to ensure that the project selected provides a needed benefit at the lowest cost. For example, if a company needed more office space, they might evaluate the costs of remote working, leasing office space, building an addition to an existing structure, converting a structure, purchasing new office space, or constructing a new office. Without evaluating alternatives, it is difficult, if not impossible, to know if the undertaking is the most cost-effective solution.

**Q. Did Idaho Power evaluate alternatives to Brownlee, Shoshone Falls, or Lower Salmon Falls?**

A. No. While undertaking one, or all, of these projects might very well have been the least cost option at the time of decision-making, it is unknown whether each project was least cost, as Idaho Power states that no alternatives were evaluated.[9]

**Q. Why are the original project budgets important?**

A. The original project budgets provide a reference point so that major discrepancies between anticipated and actual costs can be identified, as well as ensure that all major changes in budget have been captured.

**Q. Was Idaho Power able to provide the original budget for each project?**

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9 See Staff/1202, Pileggi/1-4, Idaho Power response to Staff DR No. 355.

A. No. As Idaho Power has indicated in response to Staff Data Request No. 355, the process by which it manages budgets is real time approvals and frequent recasts each year to this original budget. It is Staff's understanding that this has caused some historical data to be overwritten. One result of this overwriting of data is that various records may have differing values for a given datapoint. Provided values for the original approved budget for Brownlee varied by as much as approximately $5 million. Specifically, the variance notes for Brownlee[10] first mention an original budget cost of approximately $47.3 million in the notes for the 2nd recast of 2015. In the confidential attachment 4 to Staff Data Request 355, Idaho Power provided an original approved budget of approximately $52.3 million. This $5 million increase to the original budget artificially changes the appearance of how well budgeted and managed the project was.

**Q. What is the impact of these variances to Idaho Power's estimates of costs?**

A. The impact of these variances to the costs is not fully known. The earliest budgetary information provided by Idaho Power may be based on data points that had already been recast several times.

**Q. How does the unclear budgetary information impact your analysis of the prudence of the upgrades?**

The economic prudence of undertaking a given project decision is based on what was known and knowable at the time of that decision. Absent reliable

[10] See Staff/1202, Pileggi/6, Idaho Power's response to Staff Data Request No. 355, Attachment 5

data for original budgets, it is impossible to know what the economics of a decision was at the time the project was commenced.

**Q. Please elaborate on what the combined impact of overwritten data points, lack of NPV analyses, and lack of alternate project analyses is to the ability of conducting a prudence review.**

A. The lack of reliable data and analyses creates a situation in which it is unknown what the predicted economic impact to the Company was, unknown whether a different project might have utilized ratepayer dollars more efficiently, and unknown how well managed and budgeted the project was. As such, the economic value of the projects can be roughly estimated but will be incomplete and likely inaccurate. Hydro is a major component of Idaho Power's generation mix, the projects all occurred at aged facilities, and these decisions might have been the best possible decisions at the time that Idaho Power chose to undertake each project. However, presumption of necessity is not a substitute for accurate recordkeeping and project management.

With an increase of almost 90 MW in nameplate capacity to the original 360.4 MW capacity of the four units, addressing a need for increased oxygen levels to meet FERC license requirements,[11] and a final price tag of about $66.9 million, it isn't hard to speculate that the Brownlee project very well might have been the best project to undertake. However, without reliable historical data or analyses of alternatives, it would be conjecture to say that this represented the least cost option.

[11] Idaho Power/300, Hackett/6.

At an overall price tag of approximately $27.1 million and increasing nameplate capacity of the units replaced by 2.2 MW, for a total of 3.2 MW of nameplate capacity for the project, Shoshone Falls was a far less efficient usage of ratepayer dollars. Without an analysis of alternate project or any the NPV analysis for the project, and no reliable data as to original budget estimates, many unanswered questions arise; such as, could the Company have found 3.2 MW of generation for less than the cost of shuttering the two older units at Shoshone Falls?

**Q. What was the rough value of the generation for the Shoshone Falls project at the time that the project was first identified?**

A. Prior to the refurbishment, Shoshone Falls had three units with a total nameplate capacity of 12.5 MW. The combined nameplate capacity of Units 1 and 2, units replaced at a cost of $27.5 million, was 1 MW, a very small portion of Idaho Power's hydro generation capacity. In Idaho Power's 2015 Annual Power Cost Update (APCU), the Commission issued Order No. 15-147 adopting a stipulation in which the estimated per-unit power costs 2015 APCU were $23.44 per MWh in the October 2015 update.[12] Assuming those units ran at nameplate capacity 24/7, the original two units could have been replaced at a cost of approximately $205,000 per year.[13] Post project completion, the 3.2

[12] *In the Matter of Idaho Power Company Annual Power Cost Update*, UE 293, Order No. 15-147, page 2, paragraph 1 (May 8, 2015).

[13] 8,760 hours per year, at 1 MW nameplate capacity, multiplied by $23.44 per MWh, equals roughly $205k. The 1 MW nameplate capacity was a miniscule amount of IPC's hydro generation, and overall generation. However, it should be acknowledged that recalculating the 2015 power cost estimates after removing those units might result in a slight change in per-MWh cost—as this is for purposes of example only at this time, no efforts to recalculate the estimated costs were made.

MW nameplate capacity of the new unit, at constant generation, would have generation that could have been roughly estimated at an approximate value of $657,100 per year using the 2015 APCU values. Running constantly at full nameplate capacity isn't realistic. To calculate a capacity factor for this estimate, we can average the annual hydro generation for the five APCUs prior to 2016 when Idaho Power identified this project, 8,608,479 MWh[14] and divide that by the nameplate capacity multiplied by the hours in the year. This calculation gives us an estimated capacity factor of 57.6 percent.[15] Utilizing this capacity factor, the annual replacement cost of generation for the units at Shoshone Falls could be estimated in 2015 at $118,200 prior to the project and $378,250 after the project.

**Q. Does Staff have an adjustment for these three projects?**

A. Yes. Staff proposes a managerial disallowance of 10 percent of the total project costs. Utility executives are financial and technical experts, and as such, should have full documentation of expected project benefits, as well as evaluating options to each project. A presumption of prudence is not a substitute for accurate recordkeeping or a full analysis of alternate options. With the original project budgets being overwritten regularly, the ongoing

[14] See Docket Nos. UE 293 (2015 APCU); UE 279, (2014 APCU); UE 257 (2013 APCU); UE 242, (2012 APCU); and UE 222 (2011 APCU).

[15] 8,608,479 MWh / (8,760 hrs/year x 1,707.1 MW nameplate capacity) = 57.6%. This calculation uses the listed nameplate capacity for IPC's 17 hydro facilities, available on IPC's website, and removes the recent increases to capacity.

management of the projects is cloudy as well. The 10 percent managerial disallowance is a permanent reduction to rate base, and is as follows:

- Brownlee—disallowance of $6.69 million
- Shoshone Falls—disallowance of $2.71 million.
- Lower Salmon Falls—disallowance of $4.66 million

This totals a disallowance of $14.06 million.

## ISSUE 2. 2023 AND 2024 RESOURCE ADDITIONS

**Q. Please provide background on the resource additions.**

A. In the spring of 2021, Idaho Power identified a resource capacity deficiency for 2023.[16] As a result, the Company issued RFPs in 2021 and 2022 to address this issue. The forecasted deficiency grew during the 2021 and 2022 Requests for Proposals (RFP) until the deficiency for 2024 was 186 MW, and 311 MW in 2025.[17] The 2021 RFP resulted in the procurement of 120 MW of dispatchable storage, and the 2022 RFP resulted in an additional 96 MW of dispatchable storage. The 2022 RFP sought to cover both the forecasted 2024 deficiency as well as part of 2025's forecasted deficiency.[18] Ultimately these two RFPs resulted in the Company acquiring four separate Battery Energy Storage Systems (BESS), which the Company is seeking to include in rate base. The total cost of the BESS resource additions is currently forecasted at $372.5 million.[19]

**Q. What is the total cost, separately, of each project?**

A. The cost of these projects is as follows:[20]

- Self-Build 80 MW BESS at Hemingway—$116.0 million:
  - $0.6 million in Labor
  - $106.0 million in Materials
  - $4.5 million in Purchased Services

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16 Idaho Power/300, Hackett/8.
17 Idaho Power/300, Hackett/9-10.
18 Id.
19 See Staff/1202, Pileggi/10 Idaho Power's response to Staff DR No. 358.
20 Id.

- $(53,333) in Accounting Entries
- $4,645 in Overheads
- $4.3 million in AFUDC
- $0.4 million for Other Expenses

- Black Mesa 40 MW BESS—$62.5:
  - $0.4 million in Labor
  - $42.0 million in Materials
  - $11.1 million in Purchase Services
  - $(26,667) in Accounting Entries
  - $3,953 in Overheads
  - $4.2 million in AFUDC
  - $4.8 million for Other Expenses
- Franklin/Duke 60 MW BESS—$125.2 million:
  - $0.1 million in Labor
  - $125.0 million in Materials
  - $0.2 million in Purchased Services
  - $7,639 in AFUDC
  - $(0.1) million for Other Expenses
- Self-Build 36 MW BESS at Hemingway—$68.8 million
  - $23,321 in Labor
  - $49.7 million in Materials
  - $17.2 million in Purchased Services
  - $1.9 million in AFUDC

- o $(67,520) in Other Expenses

**Q. What is the standard by which these projects are analyzed?**

A. As with the hydro plant investments above, two standards of review are applied, plant must be used and useful prior to the effective date of rates and prudent.

**Q. Will each of these projects be used and useful by the rate effective date of January 1, 2025?**

A. Yes. The 80 MW Hemingway BESS was placed into service in 2023, as was 54 percent of the 40 MW Black Mesa BESS. The remaining 46 percent of the Black Mesa BESS, the 36 MW Hemingway BESS, and 60 MW Franklin/Duke BESS are expected to be placed in service by summer of 2024.[21] All projects should be online by the rate effective date.

**Q. Have issues with the prudence of the projects been identified?**

A. Yes. Similar to the concerns in the hydro plant projects, Staff has identified a few issues with the prudence of these projects. These issues are discussed later in Staff's testimony and summarized here:

- No Net Present Value (NPV) analyses were performed prior to commencement of each project.
- Lack of historical documentation regarding original project estimates.

**Q. Why are Net Present Value analyses important in a decision-making process for capital expenditures?**

[21] See Staff/1202, Pileggi/11, Idaho Power's response to Staff Data Request No. 358.

A. An NPV analysis helps show what the economic impact of an action is likely to be. In the selection of a project, performing an NPV analysis helps a company to evaluate the value provided by undertaking a project compared to that of competing projects.

**Q. Did Idaho Power evaluate alternatives to the BESS projects selected under the 2021 and 2022 RFPs?**

A. Yes. Idaho Power had a handful of projects that were evaluated alongside the initial proposals submitted under either RFP. The evaluation consisted of taking the projects that passed an initial screening for timeliness and connectivity, and running Aurora to see which projects were most cost-effective.[22]

**Q. Why are the original project budgets important?**

A. The original project budgets provide a reference point so that major discrepancies can be identified, as well as ensure that all major changes in budget have been captured.

**Q. Was Idaho Power able to provide the original budget for each project?**

A. No. As Idaho Power has indicated in response to Staff Data Request No. 355, the process by which it manages budgets is real time approvals and frequent recasts each year to this original budget. It is Staff's understanding that this has caused some historical data to be overwritten.

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[22] See Staff/1202, Pileggi/9, Idaho Power response to Staff DR No. 358. For the 2021 RFP, only one project passed the initial screen.

Additionally, the Company provided an original approved budget for the 2024 Hemingway BESS that causes the projected total cost of the project to appear over budget "due to the timing of an actual charge."[23] The supporting attachment for original budgets shows an original approved budget of $28.6 million for this project,[24] which is about double what the Company represents the actual original budget to have been. The Company was not able to provide an original approved budget for this project that was not skewed by the timing of the "actual charge."

**Q. Does Staff have a monetary adjustment for these four BESS projects at this time?**

A. No. However, Staff is currently evaluating an adjustment for these projects as an overall allocations issue. Staff will be reviewing testimony from intervenors and might have a monetary adjustment for the BESS projects at a later time.

**Q. Why is Staff looking at this issue as an overall allocations issue?**

A. Staff is evaluating the allocation of costs of these resource additions due to the underlying growth factors. In the five years prior to Idaho Power identifying the resource deficiency, Oregon retail MWh sales averaged 671,606 MWh, with 2017's sales as high as 688,246 MWh.[25] Idaho Power uses a forecast of 679,610 MWh for the 2024 test year, only 8,004 MWh above the historic five-year average load prior to the year Idaho Power identified the resource

23 See Staff/1202, Pileggi/11, Idaho Power's response to Staff Data Request No. 358.
24 See Staff/1202, Pileggi/13, Idaho Power's response to Staff Date Request No. 358 Attachment 1.
25 See Staff/1202, Pileggi/14, Idaho Power's response to Staff Data Request No. 356 attachment 1 (years 2016-2020).

capacity shortage. Over this same period, Idaho retail sales averaged 12,962,174 MWh. During the test year, Idaho retail sales were forecasted at 13,706,379 MWh, 744,205 MWh above the average.

The percentage of load growth in Oregon is significantly lower than the percentage of growth in Idaho. Accordingly, Staff is considering whether it is just and reasonable to adjust how costs of new resources to meet load are allocated between Oregon and Idaho.

## ISSUE 3. CAPITAL STRUCTURE

**Q. When did the Commission last consider this issue?**

A. The Commission entered Order No. 12-055 in Docket No. UE 233.[26] This order adopted a partial stipulation in which the parties agreed to a capital structure of 49.9 percent equity and 50.1 percent long-term debt.[27] Idaho Power had requested a 51% equity in the UE 233 GRC, the same equity level proposed by the Company in its current GRC filing.

**Q. What rationale does the Company provide for proposing a capital structure increase to 51 percent equity?**

A. Idaho Power believes that a higher equity proportion than the "typical 50/50 split" is needed to help support the Company's credit ratings.[28]

**Q. Has the Company experienced benefits to its credit ratings from having a higher equity ratio?**

A. Yes. The Company states that it started increasing the equity ratio immediately following the last GRC, growing to 55 percent at the year-end 2022, which had a significant positive impact to the Company's credit ratings.[29]

**Q. Does the Company believe that an increase to the equity layer would improve its credit ratings?**

A. No. The Company does not believe that such a change would improve its credit ratings. Instead, the Company believes that this change would help to

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[26] *In the Matter of Idaho Power Company, Request for a General Rate Revision*, UE 233, Order No. 12-055 (February 23, 2012).

[27] Id., page 2.

[28] Idaho Power/800, Buckham/35, lines 6-8.

[29] Idaho Power/800, Buckham/35, lines 15-19.

mitigate the near-term risk of a downgrade or placement on a negative watch.[30] Idaho Power focused in on rating agencies considering the regulatory environment as a factor in evaluating IPC's credit ratings.[31]

**Q. How has the Commission treated capital structure for Idaho Power's peer in recent years?**

A. In UE 416, the Commission approved a stipulated notional capital structure for Portland General Electric of 50 percent equity, and 50 percent long-term debt. In UE 399, the Commission approved a stipulation where PacifiCorp had a capital structure of 50 percent equity.

**Q. What does Staff recommend for the capital structure of Idaho Power?**

A. Staff recommends a notional capital structure of 50 percent equity and 50 percent long-term debt. The notional capital structure acknowledges that the Company knows what timing of debt and equity issuances works best for the Company, centers around the "typical 50/50 split" that Idaho Power mentions, which provides some regulatory flexibility.

**Q. Could Staff's position change on this issue.**

A. Staff will closely monitor the Company's and intervenors' testimony and analysis, which will be considered in Staff analysis and rebuttal testimony.

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[30] See Staff/1202, Pileggi/15, Idaho Power's response to Staff Data Request No. 370.
[31] Id.

## ISSUE 4. COST OF LONG-TERM DEBT

**Q. What does Staff recommend for the Cost of Long-Term Debt for the Company?**

A. Staff recommends a Cost of Long-Term Debt (Cost of LT Debt) for the Company of 4.999 percent. This reflects the cost of servicing outstanding LT Debt as well as forecasted issuances in March 2024. No other issuances are forecasted through the end of the 2024 Test Year.

**Q. How is the Cost of LT Debt determined?**

A. The Cost of LT Debt is the cost to an organization to service outstanding debt. This may include costs to call or refinance the debt when advantageous to do so, coupon payments, and embedded costs of debt such as issuance fees, and whether the bonds were sold at par, discount, or a premium.[32] To provide a reasonable Cost of LT Debt, any outstanding issuances that will have a maturity of less than one year, from the rate effective date for this GRC, must be removed from the calculation.[33] Additionally, a reasonable Cost of LT Debt must be informed with values for forecasted debt issuances. Forecasted debt issuances are reviewed for impacts to maturity profile, and a reasonable expected coupon is calculated for each forecasted issuance date.

**Q. How is a reasonable expected coupon on future issuances calculated?**

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[32] The face value of a bond is the lump sum of money the investor receives at the maturity of the bond, generally $1,000. Par is a whole number percentage of price paid relative to the face value of the bond. A bond purchased at face value would have a par value of 100. A bond purchased above face is at a premium, and below face is at a discount.

[33] *In re PacifiCorp*, UE 116, Order No. 07-787 (September 7, 2001) ("[D]ebt that matures more than one year from the effective date of rates is long-term debt.").

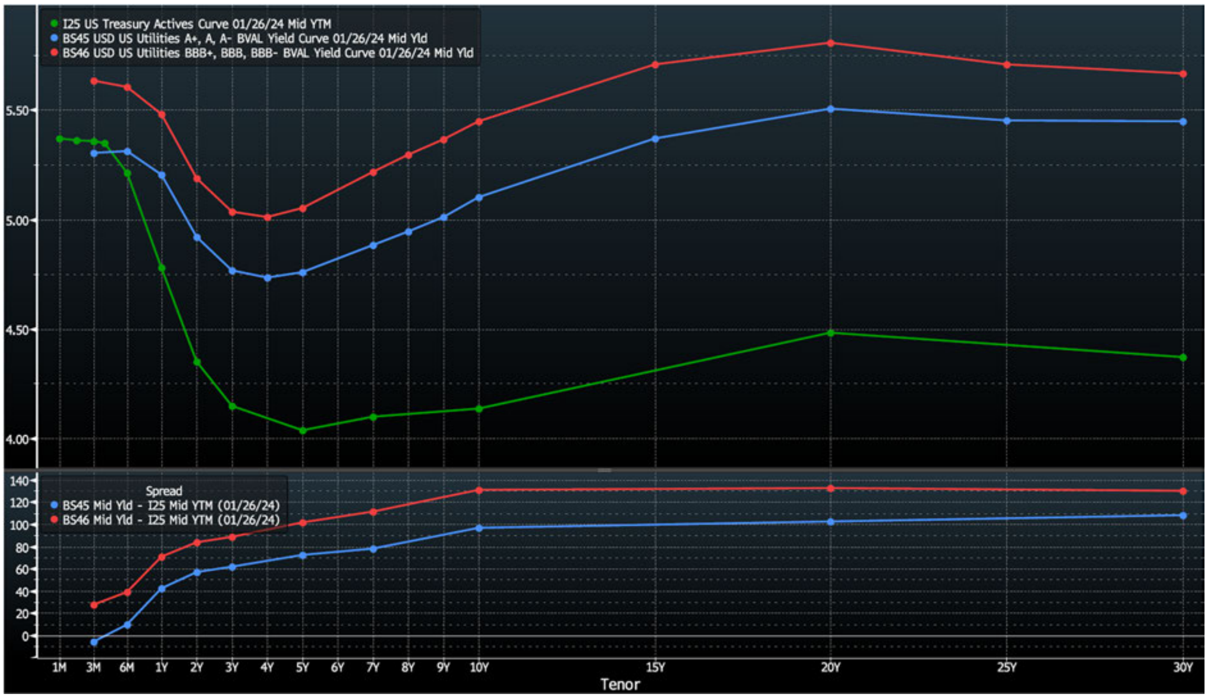
A. To forecast an expected coupon on a future debt issuance, Staff looks at the utility's credit rating, expected risk free rate, and calculates the current credit spread of similarly rated utility bonds over an appropriate risk-free rate.[34] This credit spread is applied to the forecasted risk-free rate to generate a reasonable coupon required by the market at the time of the debt issuance.

**Q. Please explain how Staff calculates an appropriate forecasted risk-free rate and credit spread.**

A. Staff utilizes a Bloomberg terminal to review forward curves of risk-free rates, at various tenors, and takes a 5-week average of these forecasted rates to provide a well-informed estimate of future rates that is reasonably assumed to be free from exogenous and endogenous shocks that might be captured if the forecasted rates were taken from a single data point. To calculate the current credit spread, Staff uses the Bloomberg terminal to review market indices of utility debt instruments with similar ratings and deducts the current active Treasuries yield. The indices and active Treasuries curves, as well as their spreads, are shown below in Figure 1:

[34] A credit spread is simply the premium required by investors to invest in a given debt instrument instead of in a risk-free alternative, such as a US Treasury instrument.

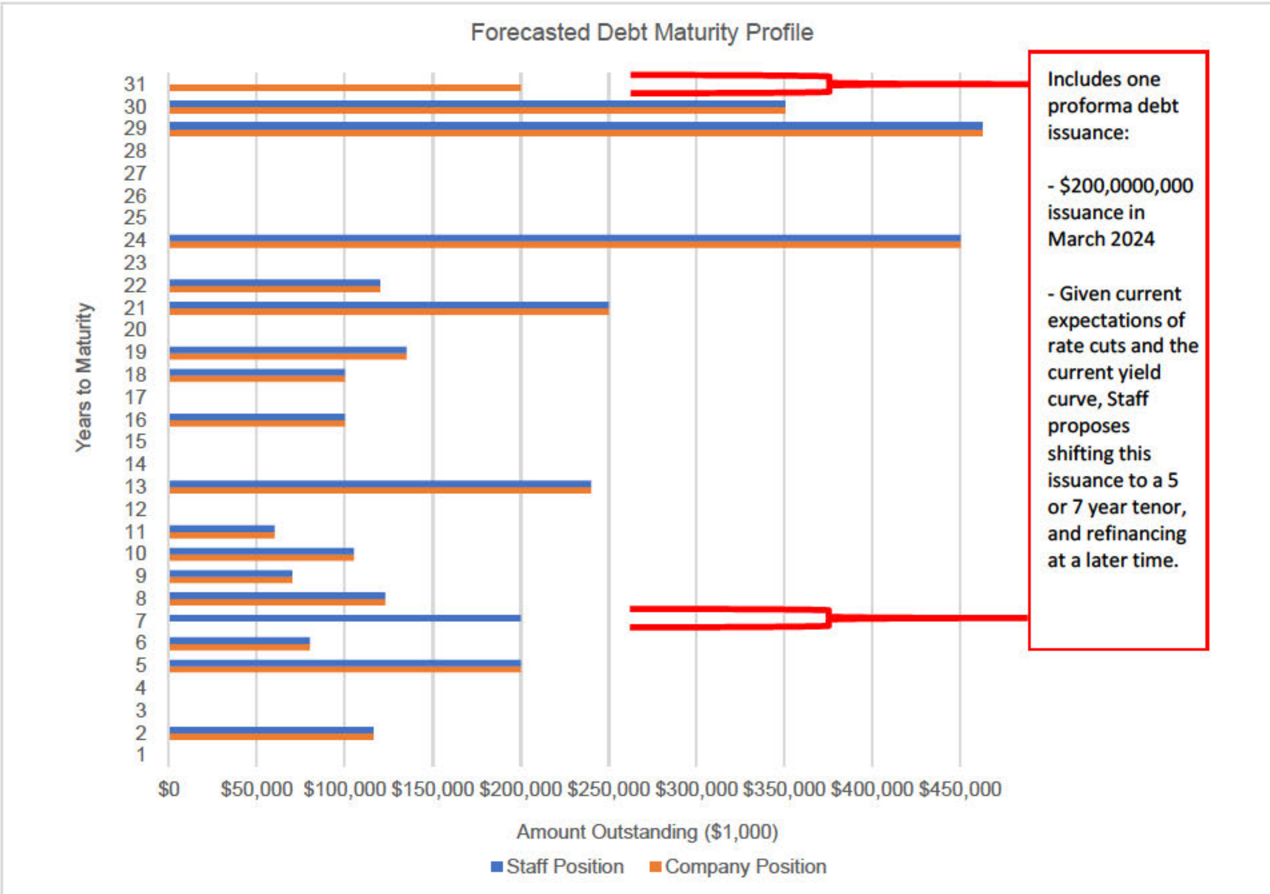
**FIGURE 1. UTILITY AND TREASURY CURVES**




**Q. Did Staff perform other analysis on the forecasted issuances?**

A. Yes. Staff also reviewed the outstanding debt profile of the Company and reviewed the forecasted issuances for their fit in the profile. Staff has reviewed the outstanding debt and forecasted issuances and recommends that a blend of the 5-year, 7-year, and 10-year tenors be used to calculate a reasonable coupon for the cost of long-term debt calculation. The Company may of course issue whatever securities that it considers reasonable, but for ratemaking purposes, Staff believes a reasonable company might select a cheaper shorter-term issuance given the market expectations of decreasing rates over the next several years. Utilizing a shorter-term issuance for the 2024 forecasted issuance does not negatively alter the debt maturity profile, as shown in Table 1.

**TABLE 1. IPC DEBT MATURITY PROFILE**




**Q. Please summarize Staff's recommendation on the Cost of Long-Term Debt.**

A. Staff recommends an overall Cost of LT Debt of 4.999 percent, comprised of a Cost of LT Debt of 5.011 percent for outstanding LT Debt, and 4.789 percent for forecasted issuances. This represents a decrease in the Cost of LT Debt of 0.105 percent, or 10.5 basis points, from the Company's proposed Cost of LT Debt of 5.104 percent.[35]

[35] See Staff/1203, Cost of Long-Term Debt Worksheet for detailed calculations.

**SUMMARY.**

**Q. Please summarize your recommendations, identifying any adjustments you propose.**

A. Staff recommends a managerial disallowance for the recordkeeping issues and lack of supporting documentation demonstrating that the hydro projects were the least cost options, totaling a permanent reduction to rate base of $14.06 million, an ongoing review of the Battery Energy Storage Systems as an overall allocations issue, a shift in capital structure from 49.9 percent equity and 50.1 percent debt to a nominal capital structure of 50/50, and a cost of long-term debt of 4.999 percent.

My recommendations may change based on further review and as informed by the testimonies offered by other parties.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: ROSE PILEGGI

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 1201

## Witness Qualifications Statement

## March 25, 2024

**WITNESS QUALIFICATIONS STATEMENT**

**NAME:** Rose T. Pileggi

**EMPLOYER:** Public Utility Commission of Oregon

**TITLE:** Senior Utility Analyst
Energy Costs Section

**ADDRESS:** 201 High Street SE. Suite 100
Salem, OR. 97301

**EDUCATION:** In 2013, I received a Bachelor of Science in Business Administration from Thomas Edison State University. In 2017, I received a Master of Science in Finance from the University of Portland.

**EXPERIENCE:** I have been employed by the Commission since July of 2022 analyzing finance, power cost, rate case and affiliated interest dockets.

From July 2021 through June 2022, I worked as an Analyst for the Oregon Judicial Department. Duties included data analysis, ensuring compliance with pertinent statutes and rules to ensure that data was being handled in accordance with requirements and recommending process improvements.

From 2017 to 2021, I worked as an Investment Analyst, Portfolio Manager, and Systems Manager for Northwest Capital Management. My work included analysis of the markets and investments, the management and rebalancing of portfolios, creating reports as required by the SEC, as well as managing software integrations for operational and reporting purposes.

CASE: UE 426
WITNESS: ROSE PILEGGI

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1202

## Exhibits in Support
## Of Opening Testimony

**March 25, 2024**

**TOPIC OR KEYWORD: Hydro Projects**

**<u>STAFF'S DATA REQUEST NO. 355</u>:**

For the projects at Brownlee, Shoshone Falls, and Lower Salmon Falls, please provide separate responses to each of the following:

a. What options did IPC evaluate prior to undertaking the project?
b. Please provide the NPV analysis, budget, and timeline of the project, and all other evaluated alternatives for that project, at the time that the project was greenlit, as well as any updates at the time the project was commenced.
c. Please provide a breakdown of the total cost of the project by broad category, as well as an accounting of the project.
d. Please describe the process that IPC conducted in the selection of manufacturers or contractors for the project.
e. For any overruns or savings on the project, please provide the causes.

**<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 355</u>:**

**Brownlee – Budget ID B00809249**

a. The Brownlee hydrogeneration facility consists of five turbines. The project was first identified in 2012 and constructed over eight years. At the time the refurbishment of the units commenced, four turbines had been in service for over 57 years. The turbines were nearing the end of their useful lives, cavitation damage had accumulated, and deterioration was observed on the turbines and wicket gates. As evidenced in the Response to Staff Data Request No. 355 – Attachment 1, the Company had been performing continued maintenance on the units until refurbishment was necessary. Replacing the turbines increased performance and addressed serious reliability concerns. Additionally, these new runners provide the added ability to aerate the water to meet dissolved oxygen improvements proposed in the new Hells Canyon Complex license. Further, the Unit 3 generator failure in 2015 accelerated the rewind schedule of this unit. To ensure the reliable operation of the plant and the continued availability of this source of low-cost, clean hydropower, refurbishment of the turbines was necessary.

b. As discussed in Brownlee – Budget ID B00809249 part (a) above, the Brownlee refurbishments were required to maintain reliability of the hydro facility, and there were no alternatives to the project. Please see the Response to Staff Data Request No. 355 – Attachment 2 and Response to Staff Data Request No. 355 – Attachment 3 for the Project Plan that detail the scope, objectives, and a list of deliverables for the project, including the timeline of milestone tasks.

   As explained in the Company's Response to Staff's Data Request No. 197, capital projects begin with the creation of a budget ID and several approval processes occur throughout the life cycle of the project. Once a project is initially approved, a budget is established, often prior to any project design or scoping. Throughout the year, projects are evaluated and reforecasted as necessary to increase or reduce forecasted spend during the remaining life of the project. However, these updated forecasts are not retroactively used to adjust the approved budget for that year, the original approved budget for that year stays as originally approved. Idaho Power monitors its capital budget monthly through variance analysis reporting and quarterly through budget update analysis and reporting, and approvals to changes happen in real-time. Variances in budget forecasts are also constantly evaluated and monitored within the overall portfolio of projects. See Response to Staff Data Request No. 355 – Attachment 4, BID B00809249, for the original approved budget for the project as well the approved Budget Update amounts.

c. Below is a summary of the Brownlee Refurbishment project costs by Budget ID and cost category as of January 31, 2024:

| Budget ID/Project | ACTUAL |
|---|---|
| B00809249 - BLPR U1234 Turbine Refurbishments | |
| Labor | $7,383,777 |
| Materials | 4,996,986 |
| Purchased Services | 43,509,683 |
| Overheads | 3,630,761 |
| AFUDC | 6,521,426 |
| Other Expenses | 850,579 |
| B00809249 - BLPR U1234 Turbine Refurbishments Total | $66,893,211 |

d. Project work was competitively bid through Idaho Power's Procurement Policy and Procurement Standard processes. Numerous competitive solicitations existed for this project for various material, design and consulting services, and construction.

e. See Response to Staff Data Request No. 355 – Attachment 5 which includes the Notes file for the history of the budget updates and associated variance notes for support of the budget revisions that were approved through the budget update cycles.

**Shoshone Falls – Budget ID CHQB150024**

a. The Shoshone Falls hydrogeneration facility consists of three units, of which Units 1 and 2 are over 100 years old and at the end of their life. Between 2018 and 2020, the Company replaced Units 1 and 2, replaced the exterior equipment conveyor, made improvements to the intake structure, and completed significant work to ensure the safe, reliable operation of the plant. Unit 2 had become inoperable due to cavitation damage from erosion and cracking of the turbine runner, while Unit 1 was shut down in 2017 due to a thrust bearing failure. Components of both turbines' mechanical packages were badly worn and in need of replacement and the exciters of both units were at their end of life. Further, under the existing configuration, both units could only be operated manually from the powerhouse, limiting the ability for dynamic dispatch. The project was first identified in 2015 and was completed in phases with the generator and turbine completing the upgrade. As can be seen in the project assessment document included in the Response to Staff Data Request No. 355 – Attachment 6, if not replaced the units would continue to be shutdown and it was not advisable to purchase a long-term solution other than replacement due to the lost generation. The project assessment document discusses the four options to progress the project that were evaluated and the potential financial impact of each.

b. As discussed in Shoshone Falls – Budget ID CHQB150024 part (a) above, the Shoshone Falls upgrades were required to maintain reliability of the hydro facility, and there were no alternatives to the project. Response to Staff Data Request No. 355 – Attachment 6 includes the initial scope, need, consequences for not performing the work, and an initial budget summary. See Brownlee – Budget ID B00809249 part (b) above for a discussion of the full budget process. See Response to Staff Data Request No. 355 – Attachment 4, BID CHQB150024, for the original approved budget for the project as well the approved Budget Update amounts.

c. Below is a summary of the Shoshone Falls replacement project costs by Budget ID and cost category as of January 31, 2024:

| Budget ID/Project | ACTUAL |
|---|---|
| CHQB150024 - Shoshone Falls Unit 1 & 2 Replacement | |
| Labor | $2,388,612 |
| Materials | 2,732,353 |
| Purchased Services | 18,132,708 |
| Overheads | 1,664,249 |
| AFUDC | 1,900,760 |
| Other Expenses | 275,605 |
| CHQB150024 - Shoshone Falls Unit 1 & 2 Replacement Total | $27,094,286 |

d. Project work was competitively bid through Idaho Power's Procurement Policy and Procurement Standard processes. Numerous competitive solicitations existed for this project for various material, design and consulting services, and construction. In addition to competitive bid events, Idaho Power purchases many minor and ancillary materials and services in accordance with the Idaho Power Procurement Policy and Procurement Standard. Many goods are stock items in Idaho Power warehouses and are not bid through an RFP on a project basis, but rather as wholesale purchases.

e. See Response to Staff Data Request No. 355 – Attachment 7 which includes the Notes file for the history of the budget updates and associated variance notes for support of the budget revisions that were approved through the budget update cycles.

**Lower Salmon Falls – Budget IDs LSPR140001, LSPR160002, and B00900276**

a. The Lower Salmon Falls hydrogeneration facility, consisting of four units, was constructed in 1910, acquired by Idaho Power in 1916 and rebuilt in 1946. Many components at Lower Salmon Falls were aging and in need of replacement. Annual condition-based testing of the generator coils, which were 32 years old, showed them to be deteriorated, and other various components were aging and in need of replacement including the generator core (70 years) and turbine and mechanical components (70 years). Failure of a coil would reduce the generator capacity by 17 MW on either unit. A coil failure while the unit is operating would likely cause additional damage to the generator resulting in an unscheduled outage of longer duration and higher cost than the planned outage associated with the refurbishment. The project was first identified in 2012, was constructed in phases over 11 years and completed in 2023. As a result the project is made up of a number of individual projects and work orders based on the work assigned to each generating unit.

As can be seen in the business cases included as Response to Staff Data Request No. 355 – Confidential Attachments 8 and 9 multiple solutions were analyzed but absent the work, a fault in the generator would likely occur.

b. As discussed in Lower Salmon Falls – Budget IDs LSPR140001, LSPR160002, and B00900276 part (a) above, the Lower Salmon Falls refurbishments were required to maintain reliability of the hydro facility, and there were no alternatives to the project. The project plans documents included as Response to Staff Data Request No. 355 – Confidential Attachment 10, Response to Staff Data Request No. 355 – Confidential Attachment 11, and Response to Staff Data Request No. 355 - Attachment 12 include the initial scope, schedule, and an initial budget summary. See Brownlee – Budget ID B00809249 part (b) above for a discussion of the full budget process. See Response to Staff Data Request No. 355 – Attachment 4, BIDs LSPR140001, LSPR160002, and B00900276, for the original approved budget for the project as well the approved Budget Update amounts.

c. Below is a summary of the Lower Salmon Falls refurbishment project costs by Budget ID and cost category as of January 31, 2024:

| Budget ID/Project | ACTUAL |
|---|---|
| B00900276 - Lower Salmon #4 Turbine Refurbishment | |
| Labor | $1,468,354 |
| Materials | 1,250,129 |
| Purchased Services | 5,740,980 |
| Overheads | 467,508 |
| AFUDC | 654,618 |
| Other Expenses | 85,544 |
| B00900276 - Lower Salmon #4 Turbine Refurbishment Total | $9,667,134 |
| | |
| LSPR140001 - LSPR U13 Turbine and Generator Refurbishment | |
| Labor | $3,489,836 |
| Materials | 476,287 |
| Purchased Services | 18,449,428 |
| Overheads | 1,282,929 |
| AFUDC | 2,724,765 |
| Other Expenses | 230,585 |
| LSPR140001 - LSPR U13 Turbine and Generator Refurbishment Total | $26,653,830 |
| | |
| LSPR160002 - LSPR U2 Turbine and Generator Refurbishment | |
| Labor | $2,343,508 |
| Materials | 273,262 |
| Purchased Services | 6,185,795 |
| Overheads | 644,914 |
| AFUDC | 672,394 |
| Other Expenses | 109,181 |
| LSPR160002 - LSPR U2 Turbine and Generator Refurbishment Total | $10,229,054 |

d. Project work was competitively bid through Idaho Power's Procurement Policy and Procurement Standard processes. Numerous competitive solicitations existed for this project for various material, design and consulting services, and construction. In addition to competitive bid events, Idaho Power purchases many minor and ancillary materials and services in accordance with the Idaho Power Procurement Policy and Procurement Standard. Many goods are stock items in Idaho Power warehouses and are not bid through an RFP on a project basis, but rather as wholesale purchases.

e. See Response to Staff Data Request No. 355 – Attachments 13, 14, and 15 which include the Notes file for the history of the budget updates and associated variance notes for support of the budget revisions that were approved through the budget update cycles.

**B00809249 - BLPR U1234 Turbine Refurbishments**
**Variance Notes**

**Microsoft Project Schedule Notes (PM managed schedules and routine variance notes)**

**2014-Recast 1:**
Increased 2014 projection is attributed to the fact that a progress payment of $1.5M was planned for in Jan 2015, but has been pulled back into 2014 because it is anticipated to be accrued into 2014.

**2014-Recast 3:**
Overall change was <2% for 2014
A $250K generator uprate study added to 2nd half of 2014
2014-Recast 2: $50K increase for estimated costs of unplanned generator study. Still awaiting quote on the work.

**2014-Recast 5:**
MS payment 6 ($2.1M) occurred in October and is forecast in October for this Recast, but may be accrued into September. If the payment is accrued for in September, then the actuals through September will increase by $2.1M, and the payment will also show again in October. MS Project budget file will be updated accordingly upon final review of the accrual.

**2015-Recast 1:**
Shipping issues from Voith's suppliers for the entrance edge castings and the first unit's crown and band castings delayed progress payments of $2.9M and $1.5M expected for 2014 to be delayed until April 2015 and January 2015, respectively. We are preparing to award another change order on the generator uprate; $143K. Planning to start work on vibration monitoring, flow measurement, and thrust bearing in 2015 instead of 2016 total value of $440K. Moved $40K Canyon Labor up into March through May to prepare for the outages.

**2015-Recast 2:**
Estimate at completion was $47,306,867 is now $47,325,946. 2015 was $12.1M is now forecasted to be $12.4M; front loaded materials on first unit for tooling. Increased estimate at completion $20K for CEATI purchases. CO 013 (Edge Casting Payment Split) moved $1.3M from Q2 into Q1.

**2015-Budget Update 3:**
Estimate at completion was $47,325,946 is now $48,096,882. Increased estimate at completion $770,900 - $459,000 for generator air cooler refurbishment based on condition assessment of unit 1 coolers; $215,800 for thrust bearing rebabbit and runner inspection; $60,000 for added owner's engineer support; $34,500 to update estimated rotor pole reinsulating to actual SOW value. Pushed $500K to 2016 based on contract negotiations with non-turbine contract suppliers; will pay upon delivery of completed work, no milestones or up-front charges.

**2015 Budget Update 4:**
Estimate at completion was $48,096,882 is now $48,160,885. Increased materials by $40,000. Increased Other by $17,000 for travel. Increased Labor by $7,000 to match current usage.

**2016 Budget Update 1**
Carryover: $1,368,500 --- Total Project Change: $4,032,856

Estimate at completion was $48,160,885 is now $52,193,741.
Carry Over ($1.3M) - Field machining was not completed until 2016 ($600K), pushed Discovery Work Contingency out to Unit 1 Guaranteed Delivery Date ($500K), moved unused disassembly labor to assembly ($200K).
Added ($5.25M) - Coil refurb and rewind materials ($450K), rewind labor ($1.25M), stator laminations ($1.4M), restacking labor ($132K), stator frame modification ($1.0M) and rewind labor contingency ($1.0M). Of the $5.25M, $4.85M will be in 2016 the remainder was added to 2017.
Removed - Discharge ring contingency ($1.0M) based on condition.

**2016 Budget Update 2**
Carryover: NONE --- Total Project Change: -$6,095
Estimate at completion was $52,193,741 is now $52,187,646
Removed - Remaining unit 1 contingency based on part delivery and negligible risk to change orders on existing contracts.

**2016 Budget Update 3**
Deferred: $1.1M (2016 to 2017)
Unit 3 Re-wind will span both years so moved material and labor across the re-wind schedule.
Estimate at completion was $52,187,646 is now $52,233,268
Voith slipped on Runner Bucket Fab ($600K from Q2 to Q3)

**2016 Budget Update 3**
Deferred: $1.1M (2016 to 2017)
Unit 3 Re-wind will span both years so moved material and labor across the re-wind schedule.

**2016 Budget Update 4**
Total Project Change $709K
-Added Tax Payment to Voith of $118K that was not budgeted for
-Added $519K for conduit and other wiring parts
Deferred $598K
-Unit 3 "Runner Balanced" moved from 2016 to 2017

**2017 Budget Update 1**
Carryover $2.55M from 2016. Lead abatement for the generator pushed payments for rewind materials and rewind labor into 2017.

**2017 Budget Update 2**
Deferred: $1.2M from 2017 to 2018 and 2019 to extend outage on U3 and match runner delivery for next units.

**2017 Budget Update 3**
Estimate at completion was $53,856,637 is now $53,475,399. Removed un-used unit alignment funds following successful survey of stator.

**2017 Budget Update 4**
($1,196,000) Deferred unit 4 disassembly milestones to 2018; Added $220,000 for labor and materials on unit 3.

**2018 Budget Update 1**
Added $390,000 for labor and materials on unit 3; Carryover of $680,000; Deferred $140,000 in taxes on unit 2. (Note: Added $500,000 in O&M to repair unit 4 stator.)

**2018 Budget Update 2**
Added $150,000 for material increases on unit 3.

**2018 Budget Update 3**
Total Project Change $1,590,711. Accelerated $281,000 for milestone adjustment. Added $30,000 for expected work vehicle expenses; Added $227,000 for Unit 2 2018 work to match expected costs based on prior units costs. (Note: Added $27,600 left in O&M to repair unit 4 stator.)

**2018 Budget Update 4**
Added $190,000 for labor, material and vehicle cost increases and expected closeout costs for Unit 4.

**2019 Budget Update 1**
Total Project Change: $860K. Project Change of $385K for Unexpected Stator Work Material and Services; Project Change of $81K for Wiring Crew Previously Unplanned Work; Carryover of $348K for Part Shipment and Field Machining Pushing Into 2019; Carryover of $219K Labor and Material for U2 2018 Late Start; Previously Accelerated ($173K) Contingency.

**2019 Budget Update 2**
Total Project Change: $950K. Project Change of $89K for Yearly Labor Rate Adjustment.

**2019 Budget Update 3**
Project Change of $20k for IsoPhase evaluation; Project Change of $42K for discovered generator shaft coupling stud replacement; Project Change $150K for U1 trailing edge modification. Project Change of $9K for material increases compared to budget.

**2019 Budget Update 4**
Project Change $431K for Rotor Pole Rework. Deferred ($1,113K) for Rotor Pole Rework Pushing Project Completion Labor and Services. Project Change ($147K) for Trailing Edge Modification Cancelation.

**2020 Budget Update 1**
Project Change ($127K) for Services No Longer Expected; Project Change $35K for Additional Material and Equipment for Commissioning; Carryover $156K for Labor, $39K for Material, $1,096K for Services, $33K for Equip and Travel Due To Rotor Pole Rework Pushing Project Completion.

**2020 Budget Update 2**
Project Change $102K for Spare Turbine Guide Bearing Refurbishment to Match New Design.

**2020 Budget Update 3**
Budget Update 3: Project Change $2K for Labor increase for Design Wrap-up. Project Change ($50K) for Reduction in Bearing Cost Due to LDs.

**2020 Budget Update 4**
Project Change $2K for Unit Modeling Cost Higher than Expected.

**TOPIC OR KEYWORD: Photovoltaic Solar PPAs and Battery Energy Storage Systems**

**STAFF'S DATA REQUEST NO. 358:**

For each BESS, please provide separate responses to each of the following:

a. Please provide the NPV analysis in spreadsheet form, budget, and timeline, and NPV analysis for all other evaluated alternatives to the project, at the time that the project was greenlit, as well as any updates at the time the project was commenced.
b. Please provide a breakdown of the total cost of the project by broad category, as well as an accounting of the project.
c. Please provide the completion status as well as an explanation for any cost overruns or savings on the project.
d. Please detail the lifespan of the BESS:
    i. Total years of operation.
    ii. Total battery capacity by year of useful life.
    iii. Energy loss on charging and discharging the battery by year of useful life.
    iv. Drain during storage by year of useful life.
    v. Major maintenance schedule and costs.
    vi. Salvage value at end of useful life.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 358:**

a. For 2023 resources, there was only one shortlist project resulting from the 2021 Request for Proposals ("RFP") that was able to meet the required commercial operation of June 2023, the 40 MW solar photovoltaic ("PV") plus 40 MW energy storage project, so no further evaluations of other project proposals were performed. Because the 40 MW solar PV plus 40 MW energy storage project was not sufficient to fully meet the 2023 capacity need, an 80 MW battery storage facility initially investigated and evaluated as a potential self-build option was identified as a feasible option.

   For evaluation of the project proposals for the 2024 resources submitted as part of the 2022 RFP, as explained in more detail in the Company's Response to Staff's Data Request No. 362, Idaho Power used AURORA's long-term capacity expansion ("LTCE") modeling capability to develop the least-cost, least-risk portfolio for meeting the identified capacity deficiencies. Under the LTCE modeling approach, the levelized cost of all final short list projects were input into AURORA as potential resource additions, along with their project specific operating characteristics. The LTCE model optimizes these potential resource selections based on the performance of each resource within Idaho Power's zone, optimizing for the cost function while meeting the Company's identified capacity deficiency. Through the indicative AURORA LTCE modeling, the resource addition(s) that result in a least-cost, least-risk portfolio for meeting the capacity deficiency are selected. See Response to Staff Data Request No. 358 – Attachment 1 for the original approved budget, by Budget ID, for each project as well as the approved Budget Update amounts.

b. Below is a summary of the battery project cost and remaining estimated forecasts by Budget ID and cost category as of January 31, 2024:

| Budget ID/Project | ACTUALS | REMAINING FORECAST | TOTAL |
|---|---|---|---|
| HMWY220002 - 2023 Resource - 80MW | | | |
| Labor | $619,790 | | $619,790 |
| Materials | 100,183,556 | $5,879,439 | 106,062,995 |
| Purchased Services | 4,540,653 | | 4,540,653 |
| Accounting Entries | -53,333 | | -53,333 |
| Overheads | 4,645 | | 4,645 |
| AFUDC | 4,349,891 | | 4,349,891 |
| Other Expenses | 441,425 | | 441,425 |
| HMWY220002 - 2023 Resource - 80MW Total | $110,086,626 | $5,879,439 | $115,966,065 |
| | | | |
| BMSU220002 - 2023 Resource - 40MW | | | |
| Labor | $449,338 | | $449,338 |
| Materials | 37,191,067 | $4,851,615 | 42,042,682 |
| Purchased Services | 11,124,310 | | 11,124,310 |
| Accounting Entries | -26,667 | | -26,667 |
| Overheads | 3,953 | | 3,953 |
| AFUDC | 3,991,823 | 163,077 | 4,154,900 |
| Other Expenses | 4,783,074 | | 4,783,074 |
| BMSU220002 - 2023 Resource - 40MW Total | $57,516,899 | $5,014,692 | $62,531,591 |
| | | | |
| FRBS230001 - Franklin/Duke 60MW BESS - 2024 Resource | | | |
| Labor | $86,664 | | $86,664 |
| Materials | 4,750 | $125,003,086 | 125,007,836 |
| Purchased Services | 164,793 | | 164,793 |
| Overheads | | | |
| AFUDC | 3,900 | 3,739 | 7,639 |
| Other Expenses | -112,404 | | -112,404 |
| FRBS230001 - Franklin/Duke 60MW BESS - 2024 Resource Total | $147,703 | $125,006,825 | $125,154,528 |
| | | | |
| HMWY230003 - Hemingway 36MW BESS - 2024 Resource | | | |
| Labor | $23,321 | | $23,321 |
| Materials | 17,233,165 | $32,502,053 | 49,735,218 |
| Purchased Services | 17,189,493 | | 17,189,493 |
| Overheads | | | |
| AFUDC | 745,860 | 1,172,222 | 1,918,082 |
| Other Expenses | -67,520 | | -67,520 |
| HMWY230003 - Hemingway 36MW BESS - 2024 Resource Total | $35,124,319 | $33,674,275 | $68,798,594 |

c. The 80 MW Hemingway BESS was placed in service in 2023 and approximately 54 percent of the 40 MW Black Mesa was placed in service in 2023. The remaining 46 percent of Black Mesa is anticipated to be placed in service in March 2024. The 36 MW Hemingway and 60 MW Franklin Project are anticipated to be placed in service in June 2024. When compared to budgeted costs presented in Response to Staff Request No. 358 – Attachment 1, all projects have come in or are anticipated to complete at or under budget. Currently, the 36 MW Hemingway BESS estimated costs appear to be overbudget due to the timing of an actual charge, however following completion of the project, total costs are estimated to equal the budget of $65 million.

d. The following details the lifespan of the BESS:
   i. All four BESS are expected to operate for 20 years.

   ii. The following is the total battery capacity by year of useful life of each BESS, based on the contracted energy and capacity values for each project:

      a. Hemingway: 80 MW, 320 megawatt-hours ("MWh")
      b. Hemingway: 36 MW, 144 MWh
      c. Black Mesa: 40 MW, 160 MWh
      d. Duke (Franklin): 60 MW, 240 MWh

      Note, there are two key drivers to the long-term degradation of the BESS: calendar degradation (time) and cycle degradation (throughput). Analysis of degradation should consider both factors together. See Response to Staff Request No 358 – Confidential Attachment 2 for a series of tables that visualize the two factors over the life of the BESS assets. The Y axis of the table is project life in years and the X axis is throughput calculated by the cumulative MWh of throughput divided by the contracted MWh for the project. Note, the Hemingway and Black Mesa BESS are computed based on a Powin performance guarantee and differ from the Duke/Franklin BESS, a different manufacturer.

   iii. See part (ii) above. In addition, the agreements for the Hemingway 80 MW BESS, the Hemingway 36 MW BESS, and the Black Mesa 40 MW BESS state that during a cycle of charge and discharge, the BESS will consume a certain amount of electricity due to thermal, collection and chemical conversion losses. Powin guarantees that, during the first year of Guarantee Period, the BESS's DC to DC round trip conversion efficiency will always equal or exceed the minimum required efficiency of 80 percent. For the Franklin 60 MW BESS, the Guaranteed Roundtrip Efficiency shall be 81.7 percent.

   iv. Not applicable. There is no rate of battery energy drain during extended periods of storage defined in the battery supply agreements.

v. BESS are maintained in a variety of ways including virtual monitoring of system health and alarms, periodic onsite inspections, performance testing, and corrective maintenance. Monitoring is done continuously, and in real-time, by both the manufacturer and Idaho Power, similar to other assets to provide continuous system status. On-site visual inspections are done by Company personnel monthly when inspecting adjacent substations. Preventative maintenance including visual inspections, air filter changes, and routine maintenance of components is done quarterly or as recommended by the manufacturer. Performance testing is conducted annually to ensure the BESS is operating to the guaranteed characteristics identified in the contract including capacity, roundtrip efficiency, and other parameters to ensure appropriate performance. Finally, if corrective maintenance is needed as a result of ongoing monitoring or inspection then action is taken as necessary. Due to Idaho Power's lack of experience and lack of trained personnel to operate energy storage systems, the Company has entered into a Long-Term Service Agreement with each manufacturer to provide ongoing maintenance of the BESS.

vi. The Company discussed battery recycle values and decommissioning costs with the developers and manufacturers as part of the RFP process. It is anticipated that there will be lithium and other valuable metals remaining in the batteries at their end of life and the Company anticipates that by the end of the BESS life there will be a mature market to recycle these metals. Some bidders indicated they would take the batteries back in 20 years and require only shipping to their facilities, with some locations in the United States and some in Asia. Because of the range of potential positive values offsetting costs related to decommissioning in 20 years, the Company has assumed a zero-salvage value at the end of the useful life.

| Budget ID Description | Year | Original Approved Budget | Budget Update 01 January | Budget Update 02 April | Budget Update 03 July | Budget Update 04 October |
|---|---|---|---|---|---|---|
| HMWY220002 - 2023 Peak Capacity Resource (2021 All Source RFP) - 80MW | 2022 | $67,500,000 | $0 | $67,460,593 | $69,700,684 | $37,637,081 |
| | 2023 | $73,883,879 | $72,111,612 | $75,166,021 | $69,244,937 | $69,549,467 |
| | 2024 | | $5,994,000 | | | |
| HMWY220002 - 2023 Peak Capacity Resource (2021 All Source RFP) - 80MW Total | | $141,383,879 | $78,105,612 | $142,626,614 | $138,945,621 | $107,186,548 |
| BMSU220002 - 2023 Peak Capacity Resource (2021 All Source RFP) - 40MW | 2022 | $27,000,000 | $0 | $21,622,792 | $20,881,487 | $17,469,167 |
| | 2023 | $41,920,868 | $48,255,594 | $44,903,072 | $44,177,551 | $44,672,226 |
| | 2024 | | $5,200,000 | $0 | $0 | $0 |
| BMSU220002 - 2023 Peak Capacity Resource (2021 All Source RFP) - 40MW Total | | $68,920,868 | $53,455,594 | $66,525,863 | $65,059,038 | $62,141,393 |
| FRBS230001 - FRBS (Franklin/Duke 60MW BESS) - 2024 Peak Capacity Resource | 2023 | | $0 | $33,386 | $74,301 | $75,977 |
| | 2024 | $125,000,000 | $125,006,496 | $125,000,000 | $125,000,000 | $125,000,000 |
| FRBS230001 - FRBS (Franklin/Duke 60MW BESS) - 2024 Peak Capacity Resource Total | | $125,000,000 | $125,006,496 | $125,033,386 | $125,074,301 | $125,075,977 |
| HMWY230003 - HMWY (Hemingway 36MW BESS) - 2024 Peak Capacity Resource | 2023 | | $8,500,000 | $8,500,000 | $19,464,404 | $36,874,268 |
| | 2024 | $28,606,516 | $35,300,000 | $28,606,516 | $28,606,516 | $28,606,516 |
| HMWY230003 - HMWY (Hemingway 36MW BESS) - 2024 Peak Capacity Resource Total | | $28,606,516 | $43,800,000 | $37,106,516 | $48,070,920 | $65,480,784 |

Response to Staff Request No. 356 - Attachment 1

| Year | Oregon Average Customers | | | Idaho Average Customers | | |
|---|---|---|---|---|---|---|
| | Residential | Comm/Ind | Irrigation | Residential | Comm/Ind | Irrigation |
| 2012 | 13,319 | 3,356 | 1,594 | 400,291 | 62,357 | 16,628 |
| 2013 | 13,350 | 3,376 | 1,650 | 405,542 | 63,095 | 16,980 |
| 2014 | 13,347 | 3,391 | 1,708 | 411,689 | 63,835 | 17,253 |
| 2015 | 13,369 | 3,418 | 1,806 | 418,906 | 64,699 | 17,552 |
| 2016 | 13,396 | 3,458 | 1,883 | 426,966 | 65,543 | 17,795 |
| 2017 | 13,423 | 3,466 | 1,928 | 435,376 | 66,501 | 17,924 |
| 2018 | 13,435 | 3,504 | 1,991 | 445,693 | 67,715 | 18,086 |
| 2019 | 13,543 | 3,547 | 2,028 | 457,755 | 68,910 | 18,181 |
| 2020 | 13,629 | 3,560 | 2,088 | 470,804 | 70,267 | 18,395 |
| 2021 | 13,742 | 3,584 | 2,137 | 485,474 | 71,823 | 18,593 |
| 2022 | 13,882 | 3,637 | 2,185 | 498,921 | 73,160 | 18,779 |
| 2023 | 14,012 | 3,656 | 2,246 | 511,098 | 74,425 | 18,979 |
| 2024* | 13,863 | 3,741 | 2,267 | 520,488 | 75,652 | 19,231 |

| Year | Oregon Retail MWh | | | Idaho Retail MWh | | |
|---|---|---|---|---|---|---|
| | Residential | Comm/Ind | Irrigation | Residential | Comm/Ind | Irrigation |
| 2012 | 185,711 | 387,328 | 49,626 | 4,866,591 | 5,753,770 | 1,998,809 |
| 2013 | 196,418 | 399,871 | 52,265 | 5,137,519 | 5,885,407 | 2,044,995 |
| 2014 | 184,150 | 387,642 | 52,168 | 4,850,381 | 5,937,952 | 1,914,129 |
| 2015 | 173,886 | 410,009 | 68,089 | 4,765,383 | 5,928,876 | 1,978,200 |
| 2016 | 173,310 | 414,049 | 71,529 | 4,734,419 | 5,914,618 | 1,876,550 |
| 2017 | 197,263 | 427,682 | 63,302 | 5,204,272 | 6,135,672 | 1,708,512 |
| 2018 | 178,340 | 428,197 | 71,996 | 4,977,767 | 6,130,571 | 1,904,591 |
| 2019 | 181,402 | 423,123 | 63,872 | 5,120,187 | 6,205,556 | 1,695,264 |
| 2020 | 180,003 | 415,700 | 68,261 | 5,234,948 | 6,048,786 | 1,919,157 |
| 2021 | 188,151 | 423,400 | 76,577 | 5,470,247 | 6,301,602 | 2,049,156 |
| 2022 | 199,956 | 422,880 | 70,379 | 5,822,251 | 6,437,177 | 1,879,386 |
| 2023 | 193,559 | 397,492 | 62,966 | 5,755,868 | 6,335,794 | 1,742,890 |
| 2024* | 193,228 | 419,712 | 66,669 | 5,764,406 | 6,115,796 | 1,826,177 |

* Projected values

**TOPIC OR KEYWORD: Capital Structure**

**STAFF'S DATA REQUEST NO. 370:**

Assuming an increase to the notional capital structure provided a real improvement to IPC's credit ratings, what would the change be to IPC's ROE calculations to reflect higher creditworthiness? Would there be a change to IPC's selected peer group?

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 370:**

Idaho Power does not anticipate that a capital structure of 51-percent equity and 49-percent debt would result in an improvement in the Company's credit rating. By contrast, Idaho Power's belief is that such a structure may help mitigate the potential of a near-term rating decrease or placement of the Company's credit on "negative watch" by one or both rating agencies. In Idaho Power's discussions with the rating agencies, the rating agencies have considered the constructiveness of the regulatory environment as a factor in evaluating Idaho Power's credit ratings, and regulatory outcomes that are premised on a capital structure outside of levels that are ordinary under the circumstances, such as approval of a low equity capital amount, could be a factor that one or both rating agencies evaluate in the context of the Company's prospects for future funds from operation available to support credit metrics. Were the approved capital structure to be relatively low, mathematically it could be addressed with a higher authorized rate of return on equity, as opposed to a lower rate of return on equity, and Idaho Power anticipates the credit rating agencies would consider both. In regard to peer groups, it is Idaho Power's belief that the credit rating agencies identify utility peers primarily based on geographic region and size, as opposed to assigning peer groups based on capital structure.

CASE: UE 426
WITNESS: ROSE PILEGGI

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1203

**CONFIDENTIAL**

**Exhibits in Support**
**Of Opening Testimony**

**March 25, 2024**

CASE: UE 426
WITNESS: Paul Rossow

# PUBLIC UTILITY COMMISSION OF OREGON

# STAFF EXHIBIT 1300

# OPENING TESTIMONY

## Expense for Memberships, Dues, Donations, and Promotional Activities and Concessions

**March 25, 2024**

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

A. My name is Paul Rossow. I am a utility analyst employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) 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/1301.

**Q. What is the purpose of your testimony?**

A. I discuss my review of several topics of Idaho Power Company's (IPC, Idaho Power, or Company) Test Year Operations and Maintenance (O&M) non-payroll expenses, including expenses for promotional activities and concessions, memberships, dues and donations, and meals and entertainment.

**Q. Did you prepare any exhibits for this docket?**

A. Yes. I prepared the following supporting exhibits:

Exhibit Staff/1301. Witness Qualification Statement
Exhibit Staff/1302. Responses to Data Requests (Non-Confidential)
Exhibit Staff/1303. Meals and Entertainment Work Paper

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

Issue 1. Promotional Activities and Concessions.......... 3
Issue 2. Memberships, Dues, and Donations .......... 5
Issue 3. Meals and Entertainment .......... 7
Summary. Findings and Recommendations .......... 10

**Q. Could there be changes or updates to Staff's position and recommendations?**

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

## ISSUE 1. PROMOTIONAL ACTIVITIES AND CONCESSIONS

**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]ctions 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 concessions 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.[1] Utilities are required to file a description of all promotional concessions with the Commission before making them.[2] 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.[3]

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1 OAR 860-026-0015(2).
2 OAR 860-026-0025(1).
3 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.[4]

**Q. Has the Company included any promotional activities and concessions in the base year?**

A. Staff's review did not discover promotional activities and concessions expenses recorded in the base year. On January 9, 2024, Staff met with Idaho Power and confirmed that the Company is not seeking cost recovery in the Test Year for promotional activities and concessions expenses.

**Q. What are Staff's findings regarding promotional activities and concessions?**

A. Staff finds that no adjustment is needed for the Test Year.

[4] OAR 860-026-0020.

## ISSUE 2. MEMBERSHIPS, DUES, AND DONATIONS

**Q. Please provide a summary of the Company's proposal for memberships and dues.**

A. Idaho Power classifies membership expenses by category and applies a specific percentage to determine the recoverable amounts. Idaho Power included $789,638 of expense in the Test Year, removing Base Year costs of ($410,686).

**Q. What is the Commission's historical treatment of memberships and dues?**

A. The Commission has determined that some expense associated with dues or membership fees to various organizations is not appropriately included in a utility's revenue requirement, primarily because some or all the organizational activities are:[5]

- Not necessary for utility service,
- Primarily to promote the company within the community,
- Do not benefit ratepayers, or
- Would not be recoverable in rates if done by the utility itself.

Staff follows Commission precedent by disallowing all memberships or dues 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

[5] See Order No. 87-406.

benefit ratepayers. Commission practice is to exclude membership expenses related to economic development and civic organizations.

**Q. Please explain your analysis for the memberships, dues, and donations adjustment.**

A. Staff analysis included the review of IPC's 2022 actual memberships and dues expenses recorded to FERC Accounts 537 through 935 provided by IPC in Exhibit No. 902 pages 2 and 3, its response to Standard Data Request (SDR) 90, and its response to Data Request 272. From Idaho Power's response to Data Request 272, Staff compiled a list of memberships to economic development organizations.

**Q. What was the result of Staff's analysis for memberships, dues, and donations?**

A. Staff's adjustment utilizes its list of memberships to economic development and civic organizations from Idaho Power's response to Data Request No. 272. Staff identified $38,180 expense for memberships related to economic development and civic organization results in IPC's Base Year, or an Oregon allocated amount of $1,630. Next, Staff applied Idaho Power's inflation factors of 4.1 percent and 2.7 percent in 2023 and 2024, respectively, resulting in an Oregon escalated Test Year adjustment to memberships of ($1,743).

**Q. What is Staff's total adjustment to memberships, dues, and donations?**

A. Staff's analysis results in an escalated Oregon allocated Test Year adjustment to memberships of ($1,743).

## ISSUE 3. MEALS AND ENTERTAINMENT

**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.[6] 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 to its Test Year to remove meals and entertainment and awards expenses?**

A. No.

**Q. Please describe your analysis for the meals and entertainment O&M non-payroll expenses.**

A. Staff reviewed Idaho Power's Direct Testimony, IPC's response to Standard Data Request No. 57,[7] Supplemental to Standard Data Request No. 57, and P-Card charges to Detailed Cost Element (DCE) 532 Business Meals and DCE

6 *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).

7 SDR No. 57 requested the Company to provide information for all non-payroll expenses recorded in all FERC accounts for the base year.

539 Other Employee Business Expenses, which would include entertainment and employee appreciation type expenses, to identify any O&M non-payroll discretionary expenses that appear to be excessive or not related to the provision of safe and reliable energy to customers. In the Company's responses to Supplemental to SDR 57 and its P-Card data, the Company provided O&M non-payroll transactional expenses in Excel format. The accounting data includes category fields, account number, DCE numbers, FERC accounts, transaction descriptions, source descriptions, and currency amount.

From this workbook, Staff searched through the worksheets 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 Business Meals, Other Employee Business Expense, and Other Miscellaneous Expenses.

Staff reviewed the selected expenditure types mentioned above to determine whether they benefit customers or are discretionary and should be shared between customers and shareholders according to Commission policy. Additionally, Commission policy does not require ratepayers to pay for causes that they do not necessarily support. [8]

Items Staff found to have no benefit to customers, Staff excludes at 100 percent. Those expenses Staff believed benefitted both customers and shareholders, Staff disallowed at 50 percent. Once Staff determined the

[8] See OPUC Order No. 87-406 at 40-41, Order No. 91-186 at 16, and Order No. 09-020 at 20-21.

disallowance based on 2024 dollars, Staff adopted the Moody's Analytics inflation factors as filed by Idaho Power. The inflation factors reflect assumed inflation of 4.1 percent and 2.7 percent in 2023 and 2024, respectively.

**Q. Would you please explain your adjustment?**

A. Yes. For example, within the selected expenditure types, Staff noted transactions related to expenses described as: coffee, recognition, gifts, awards, and meals that Staff recommended excluding 50 percent. Staff also noted transactions related to expenses described as: Christmas gift cards, holiday gifts, Santa, bowling, and Halloween that Staff recommended excluding 100 percent.

**Q. What was the result of Staff's review for these expense types?**

A. After reviewing O&M non-payroll DCE 532 and DCE 539, Staff identified 2024 total Company Test Year expense of $893,421 with an associated Oregon allocated Test Year amount of $39,072. Staff identified $36,773 of expense that should be disallowed at 50 percent, resulting in an adjustment to the Oregon allocated amount of ($18,386). Staff identified $2,299 of expense that should be 100 percent disallowed. Staff used the Oregon allocation expenses for the Test Year, resulting in an adjustment to the Oregon Test Year expense of ($20,685).

**Q. What is Staff's total meals and entertainment adjustment?**

A. Staff's total adjustment is an adjustment of ($20,683) to meals and entertainment expenses.

## SUMMARY FINDINGS AND RECOMMENDATIONS

**Q. Please summarize your findings and recommendations.**

A. Staff's recommendations are as follows: Issue 1 (Promotional Activity and Concessions) – no adjustment for FERC Account 913; Issue 2 (Memberships, Dues, and Donations) – a total adjustment of ($1,743) to the Oregon allocated total Test Year expense for FERC Accounts 908 – 930; and Issue 3 (Meals and Entertainment) – a total adjustment of ($20,685) to the Oregon allocated total expense for FERC Accounts 416 – 935.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: PAUL ROSSOW

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 1301

## Witness Qualifications Statement

**March 25, 2024**

**WITNESS QUALIFICATIONS STATEMENT**

NAME: Paul Rossow

EMPLOYER: Public Utility Commission of Oregon

TITLE: Utility Analyst
Rates, Safety and Utility Performance Program

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, UE 399, UG 152, UG 153, UG 181, UG 186, UG 201, UG 221, UG 246, UG 284, UG 344, UG 347, UG 388, UG 389, and UG 390.

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 426
WITNESS: PAUL ROSSOW

# PUBLIC UTILITY COMMISSION OF OREGON

## STAFF EXHIBIT 1302

## Exhibits in Support Of Opening Testimony

**March 25, 2024**

| Line No | Acct No | Organization | Memberships 2022 Actuals | 33.33% Excluded (66.66% Cost Sharing Applied) | 2022 Adjustments Total Cost Excluded (f+g) | Economic Development | Oregon Allocation Factor | Oregon 2024 Test Year Memberships Adj. |
|---|---|---|---|---|---|---|---|---|
| 16 | 908 | Kiwanis Club Capital City | 720 | 240 | 240 | 240 | 2.66% | 6 |
| 17 | 908 | Rotary Club Boise Metro | 750 | 250 | 250 | 250 | 2.66% | 7 |
| 22 | 921 | Chamber of Commerce Pocatello | 3,000 | 1,000 | 1,000 | 1,000 | 4.29% | 43 |
| 23 | 921 | Chamber of Commerce Boise Metro | 1,950 | 650 | 650 | 650 | 4.29% | 28 |
| 30 | 921 | Lions Club Twin Falls | 399 | 133 | 133 | 133 | 4.29% | 6 |
| 31 | 921 | Lions Twin Falls | 126 | 42 | 42 | 42 | 4.29% | 2 |
| 35 | 921 | Rotary Blue Lakes | 204 | 68 | 68 | 68 | 4.29% | 3 |
| 36 | 921 | Rotary Club Blue Lakes | 618 | 206 | 206 | 206 | 4.29% | 9 |
| 37 | 921 | Rotary Club Gooding | 552 | 184 | 184 | 184 | 4.29% | 8 |
| 38 | 921 | Rotary Club Jerome | 675 | 225 | 225 | 225 | 4.29% | 10 |
| 39 | 921 | Rotary Club Ketchum | 531 | 177 | 177 | 177 | 4.29% | 8 |
| 40 | 921 | Rotary Club Nampa | 1,101 | 367 | 367 | 367 | 4.29% | 16 |
| 41 | 921 | Rotary Club Twin Falls | 219 | 73 | 73 | 73 | 4.29% | 3 |
| 48 | 930 | Bannock Development | 8,001 | 2,667 | 2,667 | 2,667 | 4.29% | 114 |
| 49 | 930 | Boise Valley Economic Partnership | 17,499 | 5,833 | 5,833 | 5,833 | 4.29% | 250 |
| 51 | 930 | Cambridge Commercial Club | 39 | 13 | 13 | 13 | 4.29% | 1 |
| 53 | 930 | Chamber of Commerce Baker City | 1,077 | 359 | 359 | 359 | 4.29% | 15 |
| 54 | 930 | Chamber of Commerce Blackfoot | - | - | - | - | 4.29% | - |
| 55 | 930 | Chamber of Commerce Boise Metro | 28,563 | 9,521 | 9,521 | 9,521 | 4.29% | 408 |
| 56 | 930 | Chamber of Commerce Buhl | 624 | 208 | 208 | 208 | 4.29% | 9 |
| 57 | 930 | Chamber of Commerce Caldwell | 1,932 | 644 | 644 | 644 | 4.29% | 28 |
| 58 | 930 | Chamber of Commerce Donnelly | 51 | 17 | 17 | 17 | 4.29% | 1 |
| 59 | 930 | Chamber of Commerce Eagle | 474 | 158 | 158 | 158 | 4.29% | 7 |
| 60 | 930 | Chamber of Commerce Emmett | 501 | 167 | 167 | 167 | 4.29% | 7 |
| 61 | 930 | Chamber of Commerce Fruitland | 501 | 167 | 167 | 167 | 4.29% | 7 |
| 62 | 930 | Chamber of Commerce Garden City | 249 | 83 | 83 | 83 | 4.29% | 4 |
| 63 | 930 | Chamber of Commerce Garden Valley | 99 | 33 | 33 | 33 | 4.29% | 1 |
| 64 | 930 | Chamber of Commerce Gooding | 144 | 48 | 48 | 48 | 4.29% | 2 |
| 65 | 930 | Chamber of Commerce Hagerman | 195 | 65 | 65 | 65 | 4.29% | 3 |
| 66 | 930 | Chamber of Commerce Halfway | 81 | 27 | 27 | 27 | 4.29% | 1 |
| 67 | 930 | Chamber of Commerce Heyburn | 384 | 128 | 128 | 128 | 4.29% | 5 |
| 68 | 930 | Chamber of Commerce Horseshoe Bend | 201 | 67 | 67 | 67 | 4.29% | 3 |
| 69 | 930 | Chamber of Commerce Jerome | 600 | 200 | 200 | 200 | 4.29% | 9 |
| 70 | 930 | Chamber of Commerce Kuna | 999 | 333 | 333 | 333 | 4.29% | 14 |
| 71 | 930 | Chamber of Commerce Meridian | 999 | 333 | 333 | 333 | 4.29% | 14 |
| 72 | 930 | Chamber of Commerce Mountain Home | 549 | 183 | 183 | 183 | 4.29% | 8 |
| 73 | 930 | Chamber of Commerce Nampa | 4,449 | 1,483 | 1,483 | 1,483 | 4.29% | 64 |
| 74 | 930 | Chamber of Commerce Nyssa | 150 | 50 | 50 | 50 | 4.29% | 2 |
| 75 | 930 | Chamber of Commerce Ontario | 315 | 105 | 105 | 105 | 4.29% | 5 |
| 76 | 930 | Chamber of Commerce Payette | 276 | 92 | 92 | 92 | 4.29% | 4 |
| 77 | 930 | Chamber of Commerce Pocatello | 2,343 | 781 | 781 | 781 | 4.29% | 34 |
| 78 | 930 | Chamber of Commerce Riggins | 126 | 42 | 42 | 42 | 4.29% | 2 |
| 79 | 930 | Chamber of Commerce Star | 99 | 33 | 33 | 33 | 4.29% | 1 |
| 80 | 930 | Chamber of Commerce Twin Falls | 2,340 | 780 | 780 | 780 | 4.29% | 33 |
| 81 | 930 | Chamber of Commerce Weiser | 300 | 100 | 100 | 100 | 4.29% | 4 |
| 83 | 930 | City Club Boise | 549 | 183 | 183 | 183 | 4.29% | 8 |
| 85 | 930 | Eastern Oregon Vistor Association | 1,500 | 500 | 500 | 500 | 4.29% | 21 |
| 88 | 930 | Great Rift Business Development | 2,250 | 750 | 750 | 750 | 4.29% | 32 |
| 90 | 930 | Idaho Association of Counties | 3,000 | 1,000 | 1,000 | 1,000 | 4.29% | 43 |
| 91 | 930 | Idaho Manufacturing Alliance | 999 | 333 | 333 | 333 | 4.29% | 14 |
| 92 | 930 | Jerome 20/20 | 4,998 | 1,666 | 1,666 | 1,666 | 4.29% | 71 |
| 97 | 930 | Regional Economic Development Eastern Idaho | 2,001 | 667 | 667 | 667 | 4.29% | 29 |
| 98 | 930 | Rotary Club Twin Falls | 438 | 146 | 146 | 146 | 4.29% | 6 |
| 99 | 930 | Snake River Economic Development Alliance | 3,000 | 1,000 | 1,000 | 1,000 | 4.29% | 43 |
| 100 | 930 | Southern Idaho Economic Development | 5,001 | 1,667 | 1,667 | 1,667 | 4.29% | 72 |
| 101 | 930 | Southern Idaho Livestock Hall of Fame | 300 | 100 | 100 | 100 | 4.29% | 4 |
| 102 | 930 | Sun Valley Economic Development | 2,499 | 833 | 833 | 833 | 4.29% | 36 |
| 103 | 930 | Western Alliance for Economic Development | 3,000 | 1,000 | 1,000 | 1,000 | 4.29% | 43 |
| | | | 114,540 | 38,180 | 38,180 | 38,180 | | 1,630 |

| Oregon Allocated Memberships | 2023 Inflation Factor of 4.1% | 2023 Oregon Inflation | 2024 Inflation Factor of 2.7% | Oregon 2024 Test Year |
|---|---|---|---|---|
| 1,630 | 66.83 | 1,697 | 45.81 | 1,743 |

CASE: UE 426
WITNESS: PAUL ROSSOW

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 1303

## Meals and Entertainment Work Paper
## (Filed In Electronic Format)

**March 25, 2024**

CASE: UE 426
WITNESS: Scott Shearer

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1400

# OPENING TESTIMONY
## OAR Ch. 860, Div. 21 Customer Protections

## March 25, 2024

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

A. My name is Scott Shearer. I am a utility analyst employed in the Rates and Telecom Section of the Rates, Safety and Utility Performance Program (RSUP) 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/1401.

**Q. What is the purpose of your testimony?**

A. To discuss issues concerning the accessibility of Oregon Administrative Rules Chapter 860, Division 21, utility customer protections for Idaho Power Company's residential customers and make recommendations.

## PROTECTIONS FOR LOW-INCOME CUSTOMERS

**Q. Please describe the issue related to the accessibility of Oregon Administrative Rules (OAR) Chapter 860, Division 21 customer protections for Idaho Power Company customers.**

A. Staff is concerned that Idaho Power Company's current engagement and offerings with low-income communities is limiting the application of the Division 21 protections for eligible households. Specifically, Staff finds the present lack of an income-qualified bill discount program akin to those offered by the other five regulated energy utilities under the Energy Affordability Act and limited participation in existing energy assistance programs has hindered a more comprehensive inventory of income-eligible households in Idaho Power's service territory. As a result, there is greater potential for these households to face disconnections and additional charges and fees than should rightfully be assessed against them per the OARs.

Pursuant to ORS 757.230(1)[1,2] and as defined in OAR 860-021-0180, utilities must allow customers to qualify as low-income if the customer shows:

- The customer is a recipient of energy assistance within the past 12 months through LIHEAP or OEAP, or an energy assistance program offered by an energy utility; or
- The customer is enrolled in any of the utility's income-qualified energy assistance programs or qualifies to enroll in any program offered by a

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1 OAR 860-021-0180(b).
2 ORS 757.230.

utility to residential customers based on differential energy burdens based on factors that affect affordability.

Also, the energy utility may accept a customer as low income by:

- Allowing a customer to self-certify as an eligible low-income residential customer based on income that is at or below 60 percent of the Oregon state median income or participation in other low-income assistance programs offered in Oregon.

An energy utility may require a low-income residential customer to verify or recertify eligibility as per section (1) of this rule on an annual basis if the customer is to remain an eligible low-income residential customer.

According to the Company, Idaho Power (IPC) currently qualifies low-income customers for Division 21 protections if they have been a recipient of energy assistance through the Low-Income Home Energy Assistance Program (LIHEAP), the Oregon Energy Assistance Program (OEAP), or an income-qualified energy assistance program offered by an energy utility within the past 12 months.[3] However, as noted, the Company does not currently offer its own income-qualified assistance program as described under the authority of the Energy Affordability Act,[4] which other utilities have received Commission approval for and can use to flag customer accounts for Division 21 protections.

**Q. Does the Company plan to propose an income-qualified bill discount program under the Energy Affordability Act?**

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3 Per OAR 860-021-0108(a).
4 ORS 757.072.

A. Yes. The Company has engaged stakeholders working with Commission Staff on the Energy Affordability Act implementation docket and to date, has included a proposal for an income-qualified energy burden discount program in this proceeding.[5,6]

**Q. Does the Company plan to flag customers participating in the proposed bill discount program for Division 21 low-income protections?**

A. Yes. Per the response to Staff's Data Request No. 469:

> Because the Company does not currently offer an income-qualified energy assistance program requiring enrollment, or a program to residential customers based on differential energy burdens based on factors that affect affordability pursuant to ORS 757.230(1), the Company's residential customers are unable to qualify as low-income for the purposes of Division 21's rules through one of these means. However, should the Company's Bill Discount Program proposed as part of its general rate case be approved by the Commission, the Company's system will be configured to automatically waive all required charges pursuant to Division 21's rules for residential customers participating in such program.

**Q. Does Staff find this provides sufficient assurance that the Company will be able to mitigate accessibility concerns around Division 21 protections in a timely manner?**

A. Not necessarily. Staff notes that part of the Company's income-qualified bill discount proposal includes eligibility contingent upon both household income at or below 60 percent SMI *and* energy burden status via a 12-month calculation of monthly bills against heating type and reported income. However, the protection in the rule could be available to customers that meet only the first

5 See Direct testimony, Idaho Power/1300, Aschenbrenner/25.
6 See Staff/600, Farrell/10.

criteria. Idaho Power's low-income discount proposal may be focused on catching the most energy-burdened customers, but a consequence is that customers in Idaho Power's territory that could receive the Division 21 protections by self-certifying they are at or below 60 percent SMI will not receive these protections unless the Company also determines they meet the additional energy burden criteria.

**Q. How many of the Company's customers are estimated to be low-income and how many are classified as low-income?**

A. Per the Company's energy burden assessment,[7] the median household income for residents in Idaho Power's service area shows approximately 60 percent fall under 60 percent state median income, or approximately 7000 customers. Per the Company's testimony,[8] there are 1,319 customers identified as low-income, compared to 11,691 total residential customers. This is only 11 percent of their population and is significantly under the estimated 7000 customers who fall under 60 percent of the state median income.

**Q. Did Staff analyze whether low-income customers facing disconnection appear to be receiving the protections afforded in Division 21?**

A. Staff did endeavor to assess the extent to which low-income customers were accessing these protections. The Company's response to Staff's Data Request No. 470, showed the number of connection fees waived as required In OAR 860-021-0330.[9] From April 2023 to January 2024, the Company lists a

7 See Idaho Power's Energy Burden Assessment.
8 Idaho Power/1300, Aschenbrenner/12.
9 OAR 860-021-0330.

total of 36 connection fees waived out of the 149 customers with connections.[10] This is 24 percent of all connection charges. This is in line with the historical reporting from the Company, as filed in Commission Docket No. RO 12,[11] showing an average of 22 percent of all service connection tied to low-income customers for pre-pandemic statistics and prior to implementation of the additional protections mentioned above.

The Company has not evidenced a sufficient inventory of low-income households in their system to qualify for these protections, as such, Staff is unable to ascertain if the 36 waived connection fees represented all connections attributable to low-income households among the 149 customers with connections.

**Q. How does Staff recommend IPC address this discrepancy?**

A. To the extent that the Company does not sufficiently identify eligible households, Staff recommends the Company implement additional touch points from which to qualify and flag low-income households to access the Division 21 protections. Based on the Company's 2023 energy burden assessment, which used 2021-2022 data, there are approximately 12,800 occupied households (with a detectable energy use and not designated as shops, garages, or commercial properties). Of this group, the assessment estimated 62 percent were made up of households earning at or below 60 percent of the state median income.

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[10] Idaho Power response to Staff Data Request No. 471.
[11] See Commission Docket No. RO 12, IPC Reports Aug 2018-Feb 2020.

To this end, roughly 7,200 Idaho Power residential customers are eligible to receive Division 21 protections. However, as mentioned above, based on the Company's testimony, only 1,319 are flagged for these protections in the Company's system. This means 5,900 households may remain vulnerable to disconnection practices, fees, and charges that would not be assessed were the household appropriately flagged. Of particular concern to Staff is that among these additional costs are reconnection fees, which the Company has proposed to increase 50 percent, from $20 to $30 dollars in this filing.

While Staff is not opposing the proposed increase to reconnection fees at this time, Staff is cognizant that the magnitude of the increase is significant. Further, as was discussed in the proceeding that resulted in the Division 21 revisions, Docket No. AR 653, low-income households have historically faced disproportional rates of disconnection and are reconnection costs. Thus, Staff's position on the reconnection proposal is, in part, held with the assurance that the Division 21 protections exist. Given our understanding of the gaps in Idaho Power's capacity to extend these practices to eligible customers, Staff recommends that the Company expand its practices and ability to identify low-income households.

Staff believes the Commission should require IPC to enhance and expand their notification practices to inform customers of their protections and assistance options, particularly around credit related situations, such as past-due balance notices and disconnection/reconnection activities. Staff proposes that when a customer contacts the Company about needing a time-payment arrangement, IPC representatives should be discussing not only the time-payment arrangement but asking about income qualifications related to discounts that may also apply and; when a customer is disconnected for non-payment, during the call for reconnection, discussing with the customer options related to low-income discounts, including no cost reconnection fees.

**Q. Does Staff recommend changes to the company's tariff language?**

A. Yes. Staff recommends language be added to IPC Tariff, P.U.C. ORE No. E-28 Original Sheet No. F-1 - Rule F – Service Connection and Discontinuance that provides sufficient notification practices and considerations to address Staff's concerns regarding qualifying customers for the protections afforded under OAR Chapter 860, Division 21, as outlined in this testimony. Staff expects this to include, but not necessarily be limited to, alerting the customer to the availability of customer protections against disconnection and providing the opportunity to certify at and on all communications and media leading up to and at the time of a scheduled disconnection; similarly, alerting the customer to the availability of no-cost reconnection as afforded by the OAR at the time of disconnection and both during the scheduling and performance of reconnection; again, providing the opportunity to self-certify as income-qualified and receive additional information regarding available assistance options.

## SUMMARY.

**Q. Please summarize your recommendations.**

A. Staff recommends the following:

1. Require the Company to update their policy and procedures to ensure representatives actively notify customers about their options related to low-income benefits.
2. Require the Company to add language to their tariff that provides sufficient notification practices and considerations to address Staff's concerns regarding qualifying customers for the protections afforded under OAR Chapter 860, Division 21.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: SCOTT SHEARER

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## Staff Exhibit 1401

## Witness Qualification Statement

## March 25, 2024

**WITNESS QUALIFICATIONS STATEMENT**

| | |
|---|---|
| AME: | Scott Shearer |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Compliance Specialist<br>Consumer Services Section |
| ADDRESS: | 201 High Street SE. Suite 100<br>Salem, OR. 97301 |
| EDUCATION: | Corban University - Salem, Oregon<br>Bachelor of Science in Business, Organizational Leadership |
| EXPERIENCE: | 2014 - Current - Heritage Grove Credit Union<br>Board of Directors/Chairman of the Board<br>Provide strategic direction for a credit union with assets of over 100 million dollars.<br>Reviewing and approving monetary expenditures and budget.<br><br>2007 - Current - Oregon Public Utility Commission<br>Utility Analyst<br>Research and analysis of utility company filings; including rulemaking, affiliated interests, utility purchase and sale, jurisdiction, and rate case dockets.<br>Telecommunications Specialist/Consumer Specialist/Senior Compliance Specialist<br>Reviewing and applying Oregon Administrative Rules to tariffs in relation to consumer complaints.<br><br>2006 - 2007 - Oregon Department of Justice/Division of Child Support, Administrative Specialist<br>Researching responsible parties in Child Support orders<br><br>1999 - 2006 - EPIQ Systems/Poorman Douglas Corp.<br>Claims Analyst/Senior Claims Analyst<br>Reviewing and implementing orders and settlements for the largest Class Action Lawsuit administrator in the United States. Auditing and processing class action lawsuits with payouts from two-hundred thousand to over one billion dollars to claimants. |

CASE: UE 426
WITNESS: Bret Stevens

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1500

# OPENING TESTIMONY
# Load Forecast,
# Marginal Cost Study, Rate Spread,
# Rate Design, and Rate Base

**March 25, 2024**

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

A. My name is Bret Stevens. I am a Senior Economist employed in the Rates and Telecommunications Section of the Rates, Safety, and Utility Performance (RSUP) Program 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/1501.

**Q. What is the purpose of your testimony?**

A. I discuss and review several issues in Idaho Power's (IPC) general rate case. This includes IPC's Test Year load forecast, class cost-of-service (CCOS) study and rate spread, rate design, and the calculation of rate base for purposes of establishing the return component of IPC's revenue requirement.

**Q. Did you prepare any exhibits for this docket?**

A. No.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

Issue 1. Load Forecasting .......... 3
Issue 2. Class Cost-of-Service Study .......... 29
Issue 3. Rate Spread .......... 35
Issue 4. Rate Design .......... 40
Issue 5. Rate Base .......... 63
Summary .......... 65

**Q. Could there be changes or updates to Staff's position and recommendations?**

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

## ISSUE 1. LOAD FORECASTING

**Q. Please describe the results of IPC's load forecast.**

A. IPC forecasts an overall system load of 15.83 GWhs in the Test Year. This can be broken down to a forecast of 15.15 GWhs in its Idaho jurisdiction and 0.68 GWhs in its Oregon jurisdiction.

**Q. Please describe IPC's methodology for this forecast.**

A. IPC has four general parts of their load forecast. The customer forecast (i.e., customer count), the residential usage per customer (UPC) forecast, the non-residential UPC forecast, and the large customer forecast. Each of these forecasts has a different set of methodologies. These annual system forecasts are then jurisdictionalized and shaped at a monthly level.

**Q. Does Staff have any suggested changes to IPC's load forecast methodology?**

A. Yes. In general, Staff has two primary suggestions regarding IPC's load forecast. The first is that the total load forecast should be broken down and separately estimated for each of IPC's jurisdictions. The second is that for short-term load forecasts, such as those used in rate cases and its Annual Power Cost Update (APCU), IPC should use an Autoregressive Integrated Moving Average (ARIMA) model with weather and economic covariates.[1] Such an approach is used by other Oregon utilities. In Staff's view, Idaho Power's modelling would have more precision and transparency if it used a more

[1] Idaho Power uses a basic ARIMA model for its short-term forecasting with no economic variables and is not algorithmically parameterized.

simplified and reduced form ARIMA model. Staff would prefer that these ARIMA models are algorithmically parameterized (optimized) with any deviations requiring justification in testimony.

**Q. Has Staff performed these changes to the forecast?**

A. Largely, yes. However, Staff notes that the results and exact methods provided here are not meant to be taken as a final recommendations, but a good starting point that offers a more transparent and better fitting model than Idaho Power's approach. There are many variations on the models Staff presents that may be considered reasonable. Staff is open to suggestions from the Company that improve the models' fit and out-of-sample performance.

**Q. Please describe IPC's customer forecast.**

A. To forecast short-term systemwide customer growth, IPC uses a basic (2,2,2)(1,1,1)[12] ARIMA model. This type of model uses historical trends in customer data to forecast future customer counts. IPC also makes a small upward adjustment, known as an "add factor adjustment", to the raw regression forecast in order to improve the fit of the model.

**Q. Does Staff have any suggestions to improve IPC's customer forecast for residential customers?**

A. Yes. Staff has three adjustments to Idaho Power's forecast of the number of residential customers. First, the customer forecast should be jurisdictionally bifurcated so that customer counts in Oregon and Idaho are estimated separately. This is necessary for a complete Oregon specific load forecast to be conducted. Having separate forecasts for Oregon and Idaho is necessary to have confidence in the allocation factors used to establish revenue requirements for Idaho Power's Oregon jurisdiction. Staff prefers separately forecasting Oregon and Idaho loads in order to reduce reliance on assumptions based on historical data to determine the loads in each state.

Second, the ARIMA model used by IPC only takes into account historical trends related to customer growth. The Idaho Power model does not have weather or economic variables and is not algorithmically parameterized. For best forecasts, given sufficient time, Staff recognizes that customer counts can be impacted by local macroeconomic trends such as housing starts, jobs, and economic growth. Including covariates such as these can help improve the accuracy of customer forecasts, particularly when economic growth in the region is expected to fluctuate. Staff has not attempted to include economic covariates in the customer forecast model but encourages Idaho Power to explore this improvement and is interested in holding workshops with the Company to explore potential covariates.

Lastly, Staff recommends that the parameterization of the ARIMA model used by Idaho Power be more transparent and that no add factor adjustment be applied without strong justification. ARIMA parameters effectively tell the model what trends in the data to control for and how far back in time to look. As such, setting these parameters can significantly affect the model results. Staff recommends that, as a starting point, IPC use an ARIMA parameterization algorithm to parameterize this model. One such example is the Hyndman-Khandakar algorithm, which is easily applied using the "auto.arima()" command in the statistical programming language R.

In short, this algorithm iterates over possible variations of ARIMA parameterizations to find the combination of parameters that best forecast load growth by minimizing the measures of goodness of fit such as the Akaike Information Criterion (AIC) and Bayesian Information Criterion (BIC).[2] If IPC finds that this automatic parameterization creates a model that seems inappropriate or subpar, then changes to the model should be analyzed. These changes should be clearly outlined and justified in testimony and workpapers. This is meant to promote transparency in the load forecasting process and to remove the number of subjective decisions being made. Staff does note that this suggestion does not necessarily come from any action or lack of action from IPC. Instead, Staff sees this process as simply a more transparent practice that should be followed by all utilities.

**Q. Please describe IPC's residential UPC forecast.**

A. For IPC's residential UPC forecast, IPC uses Itron's Statistically Adjusted End-Use (SAE) model. This model uses historical and forecasted information about residential end-use appliances, heating, cooling, and weather to forecast residential customer usage via Ordinary Least Squares (OLS).

**Q. Is this methodology standard among Oregon utilities?**

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[2] Hyndman, R. & Yeasmin, K. (2008). Automatic Time Series Forecasting: The forecast Package for R. *Journal of Statistical Software*, 3(27); https://www.jstatsoft.org/article/view/v027i03

A. In Staff's opinion, no. Most investor-owned utilities (IOUs) in Oregon utilize ARIMA models for residential customer and demand forecasts. While IPC does use a basic ARIMA for residential customer counts, IPC does not use ARIMA models for its residential forecasting model. ARIMA models work well for forecasting electricity demand because of their ability to model data with trends. Most Oregon IOUs pair these ARIMA models with a covariate matrix that controls for outside factors such as weather and macroeconomic data that is relevant to the customer group being modeled.

**Q. Does Staff recommend that IPC use Itron's SAE model for short-term load forecasting?**

A. No. Staff recommends that IPC use an ARIMA model with weather and economic covariates as is done by its peer Oregon IOUs.

**Q. What advantages does Staff see for ARIMA models over Itron's SAE model?**

A. Staff sees three primary advantages to changing this methodology. First, ARIMA models provide a clearer interpretation of covariates. While covariate interpretation is not vital for forecasting, it can be a helpful diagnostic tool when models produce results that appear unrealistic. In IPC's current model, many variables dealing with appliance energy efficiency are transformed, both linearly and non-linearly, to create composite variables. These composite variables are meant to represent the total effect of all end-use heating, cooling, and non-temperature related behavior by residential customers. Since these variables are indexes based on many transformed data, it is difficult to understand how each piece of information is impacting the model. Staff advocates for using simpler more transparent modeling techniques like the ones presented later in this testimony. Staff notes that this simplification does not necessitate a decrease in model performance.

Second, to create the composite variables described above, IPC must use geographically broad-based regional data from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO). This data encompasses the entire Mountain West region, from Arizona and New Mexico north to Idaho and Montana. While the EIA and AEO are, in general, valid sources of information, this data can have a low signal to noise ratio in this setting. It may be preferable to simply use local weather and economic data paired with historical service territory level energy use trends, such as in an ARIMA model, to forecast customer usage.

Lastly, as they do in their customer count methodology, IPC uses an add-factor adjustment to better align the forecast with actuals. In general, Staff does not support the use of ex-post adjustments to load forecasts. Staff would prefer that the regression specification itself be tweaked to produce transparent results. It is Staff's understanding that SAE model is relatively rigid because of the complexity of the composite variables. An ARIMA model can more easily be added to or adjusted in a systematic and transparent way as opposed to the ex-post add-factor adjustment method is currently using. This is particularly true if the Company uses an algorithmic ARIMA parameterization as a starting point.

**Q. Does Staff see any value in the IPC SAE model?**

A. Yes. Staff understands that the methods used in the SAE model may have an advantage over longer time horizons where trends may deviate from historical norms. In this case, a more structural model using long-term regional technological forecasts may provide a distinct benefit over an ARIMA model. As such, Staff is making no comments in this case on the effectiveness of the SAE model in the IRP process.

**Q. Has Staff estimated residential models in the style it describes?**

A. Yes. Staff estimated the following monthly model to forecast IPC system-wide residential usage per customer:

$$Usage_t^* = \sum_q \gamma_q Usage_{t-q}^* + \sum_p \theta_p e_{t-p} + \sum_k \phi_k Month_m + \beta_1 HDD_t + \beta_2 CDD_t$$

$$+ \sum_j \boldsymbol{\kappa_j} \boldsymbol{X_t} + e_t$$

Where,

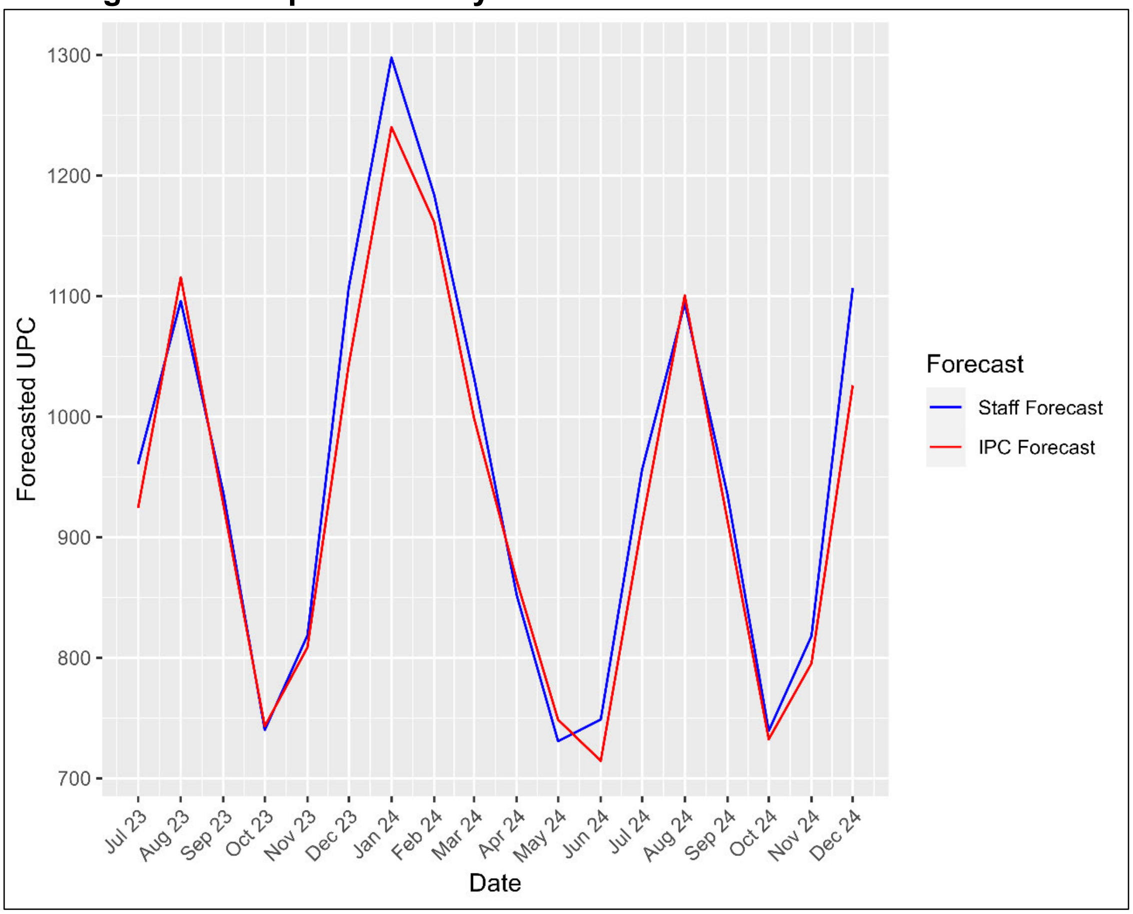
- $Usage_t^*$ is the monthly differenced residential usage,
- $e_t$ is the error term,
- $Month_m$ is the month of the year,
- $HDD_t$ is the heating degree days in each month,
- $CDD_t$ is the cooling degree days in each month,
- $\boldsymbol{X_t}$ is a vector of dummy variables controlling for extreme events.

This model estimates residential usage per customer based on historical usage, heating and cooling degree days, and has a vector of controls for extreme weather events and the 2020 COVID Pandemic.

**Q. How does Staff's forecast, using its proposed residential model, compare to IPC's forecast?**

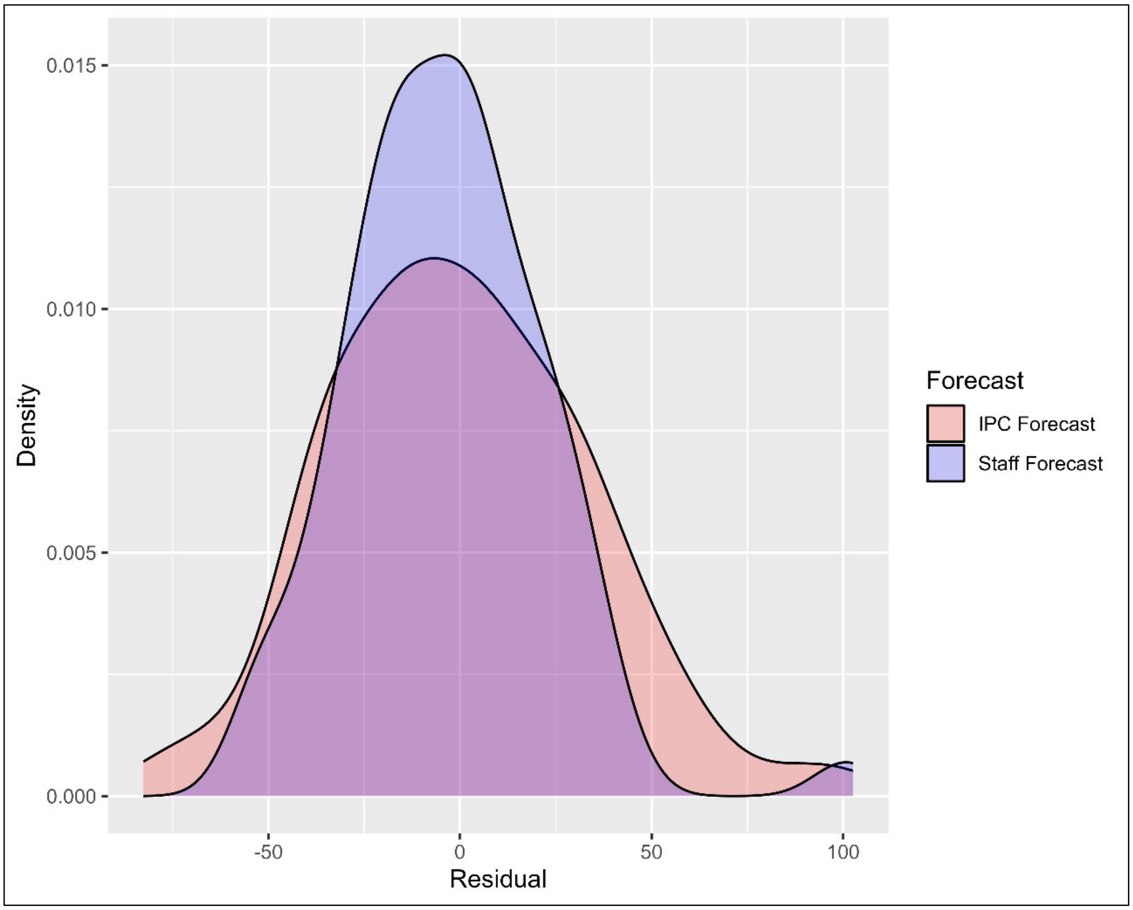
A. Figure 1 below depicts both Staff's and IPC's total Company residential use per customer forecasts in the test period. In general, Staff's model predicts higher winter usage than IPC, but predicts similar usage in the summer and shoulder periods.

**Figure 1. Comparison of System-Wide Residential Forecast**




Staff's recommended model also has a tighter distribution of residuals as seen below in Figure 2.

**Figure 2. Comparison of Residential Model Residuals**




In general, this means that Staff's model is better at modeling the historical actuals than IPC's model. A better way of testing a forecasting model's performance is to look at its out-of-sample predictive power. However, when Staff inquired about conducting such a test with IPC's model, the Company did not have the requisite data on available.

**Q. Does Staff have any other suggestions for IPC's residential model?**

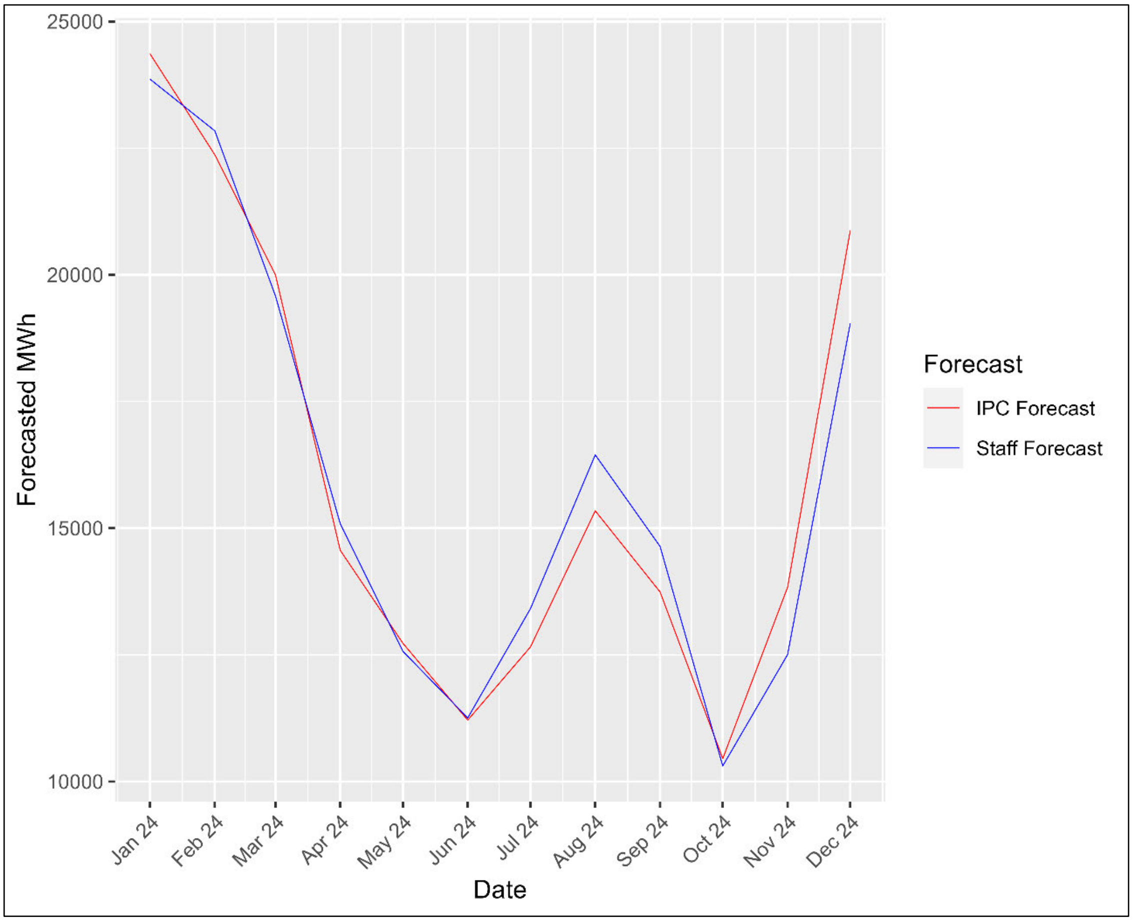
A. Yes. As mentioned above, Staff also strongly recommends that IPC estimate separate load forecasts for each of its jurisdictions. Currently, IPC assumes no growth in Oregon residential load from 2022. All residential growth found in the system load forecast is then attributed Idaho. While this method is preferable to assuming the same growth rate between jurisdictions, as Staff believes that Idaho is growing faster than Oregon due to Idaho's greater economic activity, Staff is concerned that this may obscure differences growth patterns between the jurisdictions.

**Q. Has Staff estimated a separate load forecast for each jurisdiction? If so, please describe the methods and results.**

A. Yes. For both the Idaho and Oregon forecasts, Staff used the Hyndman-Khandakar algorithm to parameterize its UPC ARIMA models. For the Oregon UPC model, this algorithm chose a (0,0,0) specification, effectively making the model a simple OLS regression. For the Idaho UPC model, the algorithm selected a more complex (1,1,2) specification. For the Oregon weather variables, Staff used weather data from the Ontario weather station. For Idaho, Staff used a customer-weighted average of Idaho weather stations. In both models, Staff used a binary indicator to control for the COVID-19 lockdown which turns on from March 2020 to December 2021. Staff also used binary indicators for extreme weather events in January of 2017 and August and September of 2022. Staff forecasted jurisdictional customer counts using annual jurisdictional data provided in DR 454. Staff used the same (2,2,0)(1,1,1)[12] ARIMA specification used by IPC for the customer count models and did not add any additional covariates.

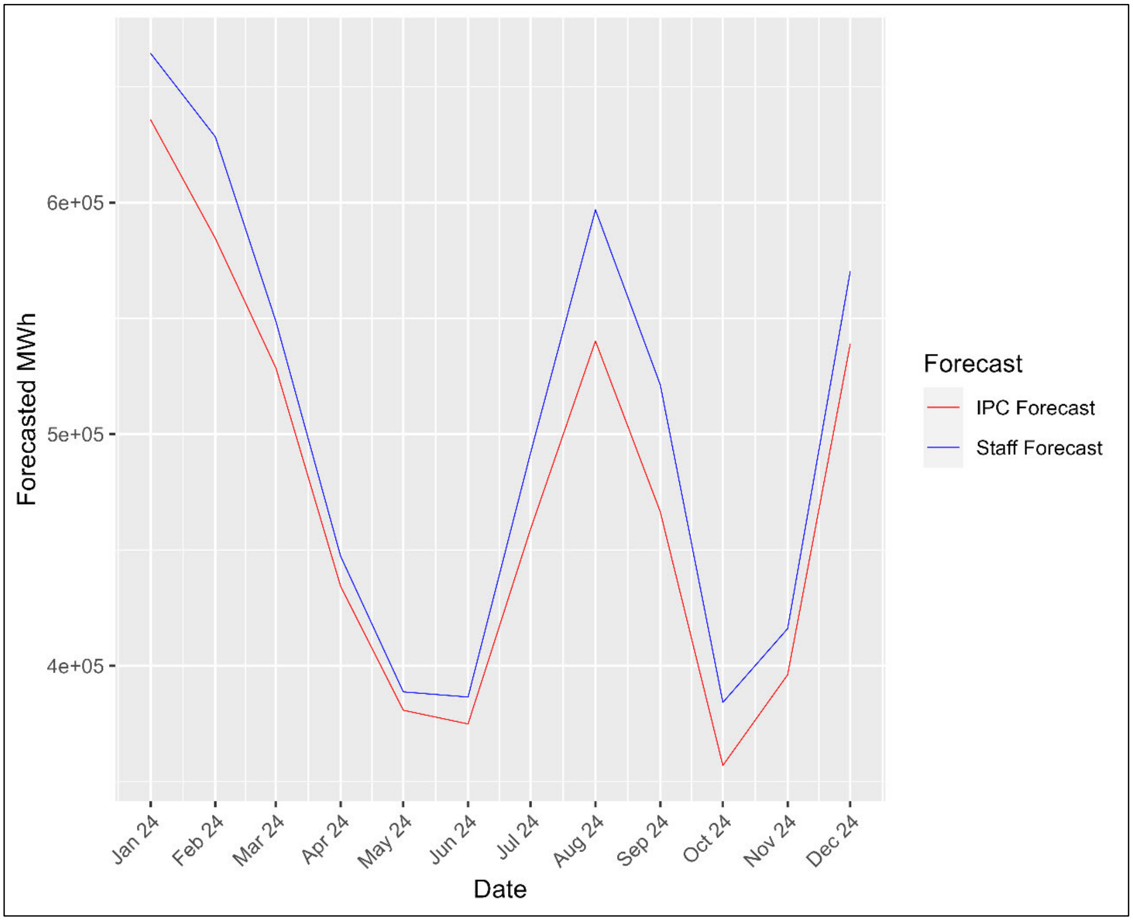
In general, Staff's and the Company's Oregon residential models are fairly similar. Saff's model predicts higher residential usage in the summer months, while IPC's model predicts slightly higher residential usage in the winter months. In total, Staff's model forecasts Oregon residential usage to be 191.55 MWhs, compared to Idaho Power's Test Year forecast of 192.14 MWhs. Staff recognizes that in this case, the difference in methodologies does not provide a significant movement in the residential forecast for Oregon customers. However, Staff maintains that using a jurisdictional ARIMA model is the preferred method going forward.

**Figure 3. Comparison of Oregon Test Year Forecasts**




Staff's residential forecast for Idaho residential customers does differ materially from the Company's. As seen in Figure 4 below, Staff's forecast is higher in each month for IPC's residential customers in Idaho. In total, Staff's model forecasts Idaho residential usage to be 6.04 GWhs, compared to Idaho Power's Test Year forecast of 5.70 GWhs. This represents a 6.11 percent increase in the Idaho residential load forecast. As a robustness check, Staff investigated whether excluding the seasonal fixed-effects from the Idaho residential model and instead imposing seasonal ARIMA parameters would enhance the model. While this did produce a more favorable AIC and BIC, the forecast from this model was nearly identical to the non-seasonal model.

**Figure 4. Comparison of Idaho Test Year Forecasts**




In total, Staff's systemwide residential forecast of 6.24 GWhs is roughly 6 percent higher than Idaho Power's system-wide residential forecast. This difference is largely driven by Staff's higher forecast for residential customers in IPC's Idaho jurisdiction.

**Q. Please describe IPC's non-residential UPC forecast.**

A. For IPC's non-residential forecasts, IPC uses an ARIMA model with weather and economic covariates.

**Q. Does Staff take issue with IPC's overall approach to non-residential UPC forecasts?**

A. Yes, to some degree. Staff recommends that IPC use an algorithmic ARIMA parameterization as a starting point and justify any deviations and conduct separate forecasts for each of its jurisdictions.

**Q. Has Staff estimated non-residential models with these changes?**

A. Yes. However, some deviations had to be made from Idaho Power's methodology to estimate these models. In Staff DR 454, Staff asked for jurisdictionalized versions of load data used by IPC. Idaho Power was able to provide these data, however Idaho Power was unable to make the same alterations to the data that were performed in its own models. Primarily, the Company separated commercial and industrial customers into "service" and "manufacturing" categories but was not able to produce these same categories at a jurisdictional level. As such, Staff only was able to forecast non-residential load at the jurisdictional customer class level. To compensate for this change, Staff combined all covariates used by IPC in each of the manufacturing and service models in each of the class-wide models.

Further, for customer classes that contain larger customers, Idaho Power would remove particular customers' load as to not give them too much weight in the model. While the data provided in DR 454 did not net out these customers, Staff was able to confirm that all of the customers that were removed from IPC's regressions were all located in Idaho. To adjust, Staff simply found the difference in the sum industrial load between the industrial load given in DR 454 and the data used in IPC's regressions and deducted that amount from the Idaho industrial load. Similarly, IPC was unable to add back energy efficiency and demand-side management figures into the historical data. As such, Staff estimated the incremental demand-side management (DSM) adjustment for the Test Year and included that amount in its Test Year estimate.

Lastly, Staff was provided jurisdictional data going back to 2005. Some of Idaho Power's regression models used longer time spans. However, Staff believes that a nearly 20-year panel is sufficient for this forecasting exercise.

**Q. Please describe the results of this analysis.**

A. Staff used the Hyndman-Khandakar algorithm to parameterize the non-residential models. In all cases, a (0,0,0), or simple OLS model was chosen except for Idaho's industrial load forecast, where a (1,0,0) model was chosen. Staff reviewed the residuals in all models and found that these simple models generally returned satisfactory results. Staff also excluded the lagged electricity price from the Oregon and Idaho Industrial forecasts as the coefficient on this variable was significant and positive, indicating that the model may have suffered from spurious correlation or endogeneity. The results for each non-residential class are given below in Table 1.

**Table 1. Comparison of Non-Residential Test Year Forecasts**

| Customer Class | State | IPC Forecast (MWh)[3] | Staff Forecast (MWh) |
|---|---|---|---|
| Commercial | Oregon | 150,926 | 152,711 |
| | Idaho | 4,125,933 | 4,123,366 |
| Industrial | Oregon | 268,724 | 242,737 |
| | Idaho | 1,989,615 | 2,304,345 |
| Irrigation | Oregon | 66,371 | 68,068 |
| | Idaho | 1,824,874 | 1,794,516 |

These results show some relatively large differences in the forecasts for the industrial class. Staff believes this stems from two main reasons. The first is that in Idaho Power's industrial load forecast for Oregon, IPC allocated Oregon's share of the system load forecast based on Oregon's share of 2022 industrial load. In 2023, an industrial customer left Oregon's service territory and Oregon's industrial load dropped significantly as a consequence. Staff's estimate takes this change into account, thus comparatively lowering Staff's Oregon industrial load forecast. Another difference likely lies in what adjustments were present in the data used by IPC and Staff for these forecasts. As mentioned, IPC removed certain large customers and DSM from their regression model and accounted for these factors via an outboard adjustment. In the jurisdictionalized data provided to Staff in DR 454, these adjustments were not made. Staff attempted to align these numbers by

[3] 1IPC forecasts taken from Confidential Prassinos Workpaper 14 - Confidential - 2024 Billed Sales by Rate.

modifying the outboard adjustments but may not have fully accounted for the difference. Staff is still in the process of investigating these differences and may have different results in later rounds of testimony as Staff's understanding of the data evolves.

**Q. Does Staff have any recommendation related to IPC's Special Contract and large customer load forecast?**

A. Not at this time. Staff agrees that Special Contract customer load should be situs assigned to the state in which the customer is located.

**Q. Please discuss the overall jurisdictional difference in Staff and Idaho Power's load forecasts.**

A. Staff and IPC's total load forecasts can be seen below in Table 2.

**Table 2. Comparison of Test Year Forecasts**

| | **Idaho (MWh)** | **Oregon (MWh)** | **Total (MWh)** |
|---|---|---|---|
| IPC | 15,154 | 678 | 15,832 |
| Staff | 15,784 | 655 | 16,438 |

Staff is forecasting a 3.8 percent higher system load than Idaho Power. The entirety of this increase is coming from Idaho. In total, Staff's load forecast for Oregon is 3.4 percent lower than IPC's, while Staff's Idaho load forecast is 4.2 percent higher than IPC's. Staff again notes that the handling of energy efficiency and DSM may be driving the increase in Idaho's forecasted load and is continuing to investigate this change to confirm that Staff's handling of these adjustments is correct.

**Q. How would Staff's energy forecast affect jurisdictional allocations?**

A. Staff's forecast lowers Oregon's jurisdictional customer energy allocator (E99) from 4.27 percent to 3.98 and its generation level energy allocator (E10) from roughly 4.25 percent to roughly 3.97 percent. If we assume that the demand factors change proportionally with the energy allocators, then Oregon's Production allocator (D10) would fall from 3.95 percent to 3.69 percent and its Distribution allocator (D60) would fall from 3.74 percent to 3.49 percent. Staff understands that the demand factors would not fall proportionally to the energy factor but list these changes to get a rough estimate of the affect of using Staff's proposed load forecast. Staff is currently working on flowing the load forecasting change through the demand allocation workpapers to get a more accurate representation of the change to the demand allocators.

**Q. Please describe how the Company calculates the 2024 Test Year coincident peak demand forecast.**

A. IPC used two measurements to determine coincident peak demand for the Test Year forecast. IPC first calculated the system demand factor, which is the 2022 observed system peak demand divided by the system average load. IPC then calculated the forecasted 2024 average demand, which is 2024 weather normal forecasted energy divided by total hours. The system coincident demand factor was then multiplied by the forecasted 2024 average demand to derive the 2024 system coincident peak demand. This calculation was then grossed up for line losses to provide the system coincident demand at the generation level for the Test Year forecast.[4]

**Q. How does the Company's Test Year peak demand forecast compare to historical actual peak demand?**

A. The Company's Test Year forecast includes a system peak demand estimate of 3,641 MW, which includes line losses and represents an increase of 70 MW or 2.0 percent compared to 2023. Oregon's allocation of this peak demand estimate is 128 MW, or 3.5 percent of the system total. Staff analyzed the Company's 10-year historical system peak demand, displayed in Table 3 below, and determined that the 10-year compound annual growth rate for IPC's system peak demand is 16 MW or 0.47 percent.

[4] Loss factors used in the calculations were determined in Idaho Power's 2022 loss study.

**Table 3. System Peak Demand**

| Year | Original Peak (MW) | MW Change | % Change |
|---|---|---|---|
| 2013 | 3,407 | - | - |
| 2014 | 3,184 | (223) | -6.5% |
| 2015 | 3,402 | 218 | 6.8% |
| 2016 | 3,299 | (103) | -3.0% |
| 2017 | 3,422 | 123 | 3.7% |
| 2018 | 3,392 | (30) | -0.9% |
| 2019 | 3,242 | (150) | -4.4% |
| 2020 | 3,392 | 150 | 4.6% |
| 2021 | 3,751 | 359 | 10.6% |
| 2022 | 3,568 | (183) | -4.9% |
| 2023 | 3,571 | 3 | 0.1% |
| **10-Year Average** | 3,421 | 16 | 0.47% |
| **Test Year Forecast** | 3,641 | 70 | 2.0% |

**Q. Is weather driving the Company's Test Year peak demand forecast?**

A. No. The Company's strongest HDD month normally occurs in January and the Company's strongest CDD month normally occurs in August.[5] IPC estimates summer peak demand to occur in June of the Test Year and the Company explains that the peak forecast is driven mainly by irrigation pumping.[6]

**Q. Does Staff recommend any changes to the Company's approach for estimating peak demand?**

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[5] Idaho Power/1100, Prassinos/ 9.
[6] IPC 2023 Integrated Resource Plan, p. 99.

A. Yes, somewhat. Staff does not propose any changes to the Company's general methodology to derive system peak demand. However, IPC's peak demand estimate is a function of volumetric energy sales estimated for the Test Year and Staff believes that the Company may be overestimating peak demand in response to the large increase recorded in 2021. Staff recommends IPC's Test Year peak increase should reflect a growth rate that more closely aligns to the 10-year average.

**Q. Please summarize how the Company incorporates weather into the Test Year sales forecast.**

A. The impact of weather is included as an explanatory variable in the Test Year sales forecast by using heating degree days (HDD) and cooling degree days (CDD). The HDD and CDD variables are based on a 65-degree Fahrenheit set point. If the average temperature for the day is above 65 degrees, the difference is the number of CDD for that day. If the average temperature for the day is below 65 degrees, the difference is the number of HDD for that day. Actual observed HDDs and CDDs are used as explanatory variables for the historical regression equation and the Company assumes normal weather to assess the most probable outcome for the Test Year forecast.

**Q. How does the Company establish a normal weather year for the Test Year forecast?**

A. IPC adopted a 30-year average measurement of HDDs and CDDs to establish a historical benchmark for normal weather used in the Test Year forecast. IPC created a weighted average composite weather variable consisting of five weather stations spread across the Company's service territory to capture weather disparities by region.

**Q. Is the use of a 30-year period to establish a normal weather Test Year considered to be an industry standard?**

A. There is ongoing debate regarding using a reduced weather base period to better capture the impacts of global warming. Recent warming trends may be leading to fewer HDDs and more CDDs than would typically be projected by using a 30-year base period. Many utilities have been migrating to a 20-year normal benchmark to assess the most probable outcome in recognition that temperatures have been increasing.[7]

**Q. Has Staff evaluated the potential for a trend bias in the 30-year weather data used by the Company to establish a normal weather Test Year?**

A. Yes. Staff performed an Augmented Dickey Fuller (ADF) stationarity test to determine if the 30-year weather data set contains a unit root or a trend. The presence of a unit root indicates non-stationarity and occurs when the statistical properties of the data set vary over time. Evidence of a trend, or non-stationarity, could lead to spurious regression results.

**Q. Please summarize the results of the ADF stationarity test Staff performed on the 30-year historical weather data set?**

A. The results do not conclude that weather has a trend. Table 1 below displays the results of Staff's test on the CDD data set. The ADF test statistic falls outside of the critical value at the 95 percent level of confidence allowing for

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[7] ITRON - Puget Sound Energy Temperature Trend Study (2020), p10.

the rejection of the null hypothesis that states the CDD data set contains a unit root. Table 4 below displays the results of Staff's test on the CDD data set. Once again, the CDD test statistic falls outside of the critical value at the 95 percent level of confidence, allowing for the rejection of the null hypothesis that states the CDD data set contains a unit root. Table 5 shows similarly for HDD.

**Table 4. Stationary Test on CDD**

Null Hypothesis: CDD has a unit root
Exogenous: Constant
Lag Length: 0 (Automatic - based on SIC, maxlag=7)

| | | t-Statistic | Prob.* |
|---|---|---|---|
| Augmented Dickey-Fuller test statistic | | -3.927650 | 0.0055 |
| Test critical values: | 1% level | -3.679322 | |
| | 5% level | -2.967767 | |
| | 10% level | -2.622989 | |

*MacKinnon (1996) one-sided p-values.

Augmented Dickey-Fuller Test Equation
Dependent Variable: D(CDD)
Method: Least Squares
Date: 02/16/24 Time: 13:40
Sample (adjusted): 1991 2019
Included observations: 29 after adjustments

| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| CDD(-1) | -0.726081 | 0.184864 | -3.927650 | 0.0005 |
| C | 758.9478 | 196.2812 | 3.866634 | 0.0006 |

| | | | |
|---|---|---|---|
| R-squared | 0.363604 | Mean dependent var | 1.068966 |
| Adjusted R-squared | 0.340034 | S.D. dependent var | 238.3452 |
| S.E. of regression | 193.6275 | Akaike info criterion | 13.43622 |
| Sum squared resid | 1012274. | Schwarz criterion | 13.53052 |
| Log likelihood | -192.8252 | Hannan-Quinn criter. | 13.46575 |
| F-statistic | 15.42644 | Durbin-Watson stat | 2.211936 |
| Prob(F-statistic) | 0.000536 | | |

**Table 5. Stationary Test on HDD**

Null Hypothesis: HDD has a unit root
Exogenous: Constant
Lag Length: 0 (Automatic - based on SIC, maxlag=7)

| | | t-Statistic | Prob.* |
|---|---|---|---|
| Augmented Dickey-Fuller test statistic | | -6.157349 | 0.0000 |
| Test critical values: | 1% level | -3.679322 | |
| | 5% level | -2.967767 | |
| | 10% level | -2.622989 | |

*MacKinnon (1996) one-sided p-values.

Augmented Dickey-Fuller Test Equation
Dependent Variable: D(HDD)
Method: Least Squares
Date: 02/16/24 Time: 13:58
Sample (adjusted): 1991 2019
Included observations: 29 after adjustments

| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| HDD(-1) | -1.145733 | 0.186076 | -6.157349 | 0.0000 |
| C | 6095.581 | 994.7008 | 6.128055 | 0.0000 |

| | | | |
|---|---|---|---|
| R-squared | 0.584058 | Mean dependent var | -14.68966 |
| Adjusted R-squared | 0.568653 | S.D. dependent var | 559.8980 |
| S.E. of regression | 367.7242 | Akaike info criterion | 14.71902 |
| Sum squared resid | 3650970. | Schwarz criterion | 14.81331 |
| Log likelihood | -211.4257 | Hannan-Quinn criter. | 14.74855 |
| F-statistic | 37.91294 | Durbin-Watson stat | 2.030573 |
| Prob(F-statistic) | 0.000001 | | |

**Q. Does Staff recommend any changes to the Company's approach for incorporating weather into the Test Year sales forecast?**

A. Not at this time given the statistical results. However, although a stationarity test of IPC's use of a 30-year average did not reveal the presence of a trend, Staff would recommend the Company consider a reduced timeline, perhaps 20 years, to establish a normal weather for future regulatory filings.

**Q. Is Staff currently recommending a revenue requirement change based on the analysis presented above?**

A. Yes. Staff is proposing changes to the jurisdictional allocation factors based on Staff's preferred load forecast. This change lowers Oregon's revenue requirement by $2,198,400.

**Q. Please summarize Staff's recommendation regarding IPC's load forecast.**

A. Staff recommends that in this case and all future rate cases, IPC algorithmically parameterize all ARIMA models as a starting point and justify deviations if any. Staff recommends that residential usage per customer be estimated using an ARIMA model with weather and economic covariates. Lastly, Staff recommends that IPC be directed by the Commission to provide separate forecasted loads for its Idaho and Oregon jurisdictions in future rate filings for allocations purposes.

**Q. Is Staff arguing that this proposed load forecast is its final recommendation on this subject?**

A. No. Staff plans to continue to work on its preferred load forecast and will likely offer refinements in future testimony. Staff notes that there are unresolved discrepancies between the data provided in IPC's response to Staff DR 454 and the data used by the Company. However, Staff does maintain that the overall goals of Staff analysis, as listed above, are sound. Staff welcomes the Company to implement these changes on its own and offer any suggestions to continue to improve the load forecast.

## ISSUE 2. CLASS COST-OF-SERVICE STUDY

**Q. Please describe IPC's proposed Class Cost-of-Service (CCOS) study.**

A. Since 1974, the Commission has used marginal costs as one of the principal factors for spreading revenue requirement among customer classes and for rate design as well. IPC explains that its marginal cost study results in, "the marginal cost associated with an added unit of electricity or serving an additional customer."[8] A marginal cost methodology is needed because book values do not have a comparable current economic basis and differ from replacement costs – thus book values would not clearly indicate which schedules are more costly to serve. In 1998, the Commission adopted a stipulation under which the marginal costs and revenue requirement should be separated into generation, transmission, and distribution components and then reconciled on a functional basis to calculate class revenue requirement responsibility.[9] Accordingly, IPC computes the incremental cost of replacing each major functional category of its system.

**Q. Have there been any changes made to IPC's CCOS study since UE 233?**

A. Yes. There have been two primary changes to the CCOS study since UE 233. The first is a change to how energy related costs are allocated. The second is a change to how meter costs are calculated.[10]

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8 IPC/1400, Maloney/6.

9 *In re Methods of Estimating Marginal Cost of Service for Electric Utilities*, Docket No. UM 827, Order No. 98-374 (September 1, 1998).

10 IPC/1400, Maloney/7.

**Q. Please describe the Company's proposed change to the allocation of energy-related costs.**

A. In the past, generation function and power supply expenses were classified as both energy and demand based on the jurisdictionalized load factor (EFAC). In UE 233, EFAC classified these costs to 46 percent demand and 54 percent energy. In this case, the EFAC would have provided a very similar classification of 47 percent demand and 53 percent energy. Instead, IPC is proposing to classify its generation function and power supply expenses either as 100 percent energy or 100 percent demand. An example of this change can be seen in Table 6.[11]

**Table 6. Primary Production and Power Supply Expense Classification Comparison**

| FERC Account | Description | Prior Classification | Recommended Classification |
|---|---|---|---|
| 501 | Steam Plant - Fuel | 100% Energy | 100% Energy |
| **536** | **Water lease & Other** | **Demand/Energy** | **100% Energy** |
| 547 | Other Generation - Diesel | 100% Energy | 100% Energy |
| 547 | Other Generation - Other Fuel | 100% Energy | 100% Energy |
| **555.0** | **Purchased Power** | **Demand/Energy** | **100% Energy** |
| **555.1** | **Purchased Power - PURPA** | **Demand/Energy** | **100% Energy** |
| **310-316** | **Steam Production** | **Demand/Energy** | **100% Demand** |
| **330-336** | **Hydraulic Production** | **Demand/Energy** | **100% Demand** |
| 340-346 | Other Production | 100% Demand | 100% Demand |

**Q. What is the Company's rationale for this change?**

A. IPC argues that this change is appropriate for three primary reasons. First, it better aligns with FERC accounting practices.[12] Second, it more efficiently

[11] Idaho Power/1400, Maloney/4, Table No 1.
[12] Idaho Power/1400, Maloney/3-4

allocates cost to cost causers.[13] Lastly, it better aligns GRC classifications to those used in the APCU.[14]

**Q. Does Staff agree with the IPC's rationale?**

A. No. Staff does not agree with this approach. Accounting does not control economics or cost causation. For example, fixed generation costs should be classified as 100 percent demand. Generation resources produce two products energy and capacity. For Jim Bridger, a major coal resource for IPC, PacifiCorp could have built less costly combustion turbines to supply electricity. But instead, PacifiCorp did not build high operating cost combustion turbines, and instead built coal plants to save on fuel costs. That is, much of the fixed costs were incurred to save on energy costs. Another example to illustrate the issues Staff has with the IPC approach, is to consider non-dispatchable resources. Under IPC's proposed classification system, a wind farm with no associated battery storage fixed costs would be classified as 100 percent demand, when the capacity value of such a resource may be between 25 and 45 percent. While IPC does not own any wind resources, IPC's classification can be seen to lack economic foundation.

**Q. What is Staff's preferred method for the allocation of energy related costs?**

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[13] Idaho Power/1400, Maloney/4-5.
[14] Idaho Power/1400, Maloney/4; Idaho Power/1300, Aschenbrenner/4.

A. Staff suggests that IPC classify these resources as 50 percent demand related and 50 percent energy related. Such a classification would reflect the fact that IPCs resources produce both energy and capacity, with most of the resources having large-fixed costs economically justified in part because they then had low, or very low (in the case of dams) operating costs.

**Q. Does Staff have an alternative recommendation?**

A. Yes. In the alternative to a 50/50 split, Staff could support a 75/25 demand/energy split. This method would be a mid-point between IPC's previous methodology and proposed methodology.

**Q. Please generally describe how Staff suggests IPC's costs be classified.**

A. Please see Table 7 below:

**Table 7. Staff's Proposed Cost Classifications**

| Cost Category | Classification |
|---|---|
| Net Power Supply | 100% Energy |
| Variable O&M | 100% Energy |
| Fuel | 100% Energy |
| Line Losses | 100% Energy |
| Transmission | 100% Demand (non-generation integration or built for renewable resources) |
| Distribution | 50% Demand/50% Customer |
| Fixed O&M | 100% Demand |
| Fixed Generation | 50% Demand/50% Energy |

**Q. Why do you propose Distribution costs be split between Customer and Demand costs?**

A. Distribution facilities would be needed in the event a customer uses a minimal amount of electricity. For example, poles, meters, and the line drop are customer-related distribution costs. Additional facilities, like more transformers, are needed to accommodate greater uses of electricity and so is related to demand.

**Q. Please describe the Company's proposed change to the derivation of meter marginal costs.**

A. In UE 233 IPC estimated the cost of new meters for the purposes of its CCOS study by using one year of historical data. In this case, IPC is proposing to use five years of historical data.[15]

**Q. What is the Company's rationale for this change?**

A. IPC states that this change is primarily due to the infrequent nature of industrial connections and their wide-ranging meter costs. They state that meter costs for industrial customers can range from roughly $500-$20,000. As such, using only one year of data my skew the results of the study.

**Q. Does Staff agree with this rationale?**

A. Yes. Staff agrees that using more historical data will help smooth out idiosyncrasies in the data and will likely provide more accurate results.

**Q. Has Staff calculated the effect on rate spread due to this change?**

A. Not at this time, although Staff plans to in later rounds of testimony. Staff anticipates this to lead to a relatively small change in the overall allocation of costs. In general, this adjustment will likely increase the marginal cost for large power customers and decreases the marginal cost for residential and irrigation customers.

[15] Idaho Power/1400, Maloney/8-9.

## ISSUE 3. RATE SPREAD

**Q. Please describe the Company's rate spread proposal.**

A. IPC generally advocates for using the results of the CCOS study to inform the spread of the revenue requirement. However, the Company recognizes that a purely cost-of-service (COS) allocation would lead to dramatic changes in prices for certain classes. As seen in Table 8, both Irrigation and Unmetered Service would experience very large increases using only the CCOS study results.[16]

[16] Idaho Power/1405.

**Table 8. Idaho Power's Proposed Rate Spread**

| Tariff Description | Rate Schedule | CCOS % Change | IPC Proposed % Change | IPC Increase Relative to Average |
|---|---|---|---|---|
| Residential Service | 1 | 26.87% | 26.76% | 139% |
| Small General Service | 7 | 19.05% | 18.94% | 98% |
| Large General Service | 9-S | 14.96% | 14.85% | 77% |
| Large General Service | 9-P | 16.42% | 16.31% | 85% |
| Large General Service | 9-T | 2.44% | 2.33% | 12% |
| Dusk/Dawn Lighting | 15 | 5.35% | 5.24% | 27% |
| Large Power Service | 19-P | 12.27% | 12.16% | 63% |
| Large Power Service | 19-T | -7.28% | 0.00% | 0% |
| Irrigation Service | 24 | 41.69% | 35.67% | 185% |
| Unmetered Service | 40 | 84.29% | 35.67% | 185% |
| Municipal Street Lighting | 41 | 14.79% | 14.67% | 76% |
| Traffic Control Lighting | 42 | 115.44% | 35.67% | 185% |
| Total Oregon Rates | | 19.28% | 19.28% | 100% |

To mitigate this change, IPC is proposing a "cap-and-floor" rate spread scheme. This methodology sets a limit on how much, or how little, the rate increase for each class can be relative to the overall rate increase. IPC proposed a floor of 0 percent and a cap of 185 percent of the system-wide revenue increase. The proposed system-wide revenue increase is 19.28 percent, making IPC's effective cap a 35.67 percent increase. The cap only applies to classes, Irrigation Service and Unmetered Service. The floor, of a 0 percent increase, only applies to Large Power Service, which would have seen a nearly 7.3 percent decrease under the CCOS rate spread.

Staff also notes that sticking exactly to IPC's cap and floor would lead to a small projected over collection of roughly $47,000. As such, IPC made some minor manual adjustments to other rate class spreads in order to make their proposal revenue neutral.

**Q. Does Staff agree with some aspects of IPC's general rate spread methodology?**

A. Yes. Staff agrees that the CCOS study should be used as the primary basis for spreading revenue requirement across schedules. Staff also agrees that other considerations such as rate stability be considered in this process.

**Q. Does Staff agree with IPC's proposed cap and floors?**

A. No. Staff agrees that the magnitude of increase for Irrigation Service and Unmetered Service is exceptionally high and would result in significant rate shock for these customers. However, Staff believes that given the magnitude of the total rate increase, the cap and floor should create a narrower spread. While the CCOS study is informative for spreading rates, and should be used in the future, a scenario where some customer classes see a rate increase of nearly 36 percent while others see no increase at all seems intractable.

**Q. Does Staff have an alternative cap and floor proposal?**

A. Yes. Staff would prefer to set a cap of 133 percent and a floor of 65.1 percent of the average increase. This creates an effective maximum rate increase of 25.7 percent and an effective minimum rate increase of 12.55 percent, if the Commission awarded IPC its full requested revenue requirement increase. The full impact of this proposal can be seen in Table 9 below and assumes the Company's revenue requirement.

**Table 9. Staff's Proposed Rate Spread**

| Tariff Description | Rate Schedule | IPC Proposed % Change | Staff Proposed % Change | IPC Increase Relative to Average |
|---|---|---|---|---|
| Residential Service | 1 | 26.76% | 25.7% | 133.3% |
| Small General Service | 7 | 18.94% | 19.05% | 98.8% |
| Large General Service | 9-S | 14.85% | 14.96% | 77.6% |
| Large General Service | 9-P | 16.31% | 16.42% | 85.1% |
| Large General Service | 9-T | 2.33% | 12.55% | 65.1% |
| Dusk/Dawn Lighting | 15 | 5.24% | 12.55% | 65.1% |
| Large Power Service | 19-P | 12.16% | 12.55% | 65.1% |
| Large Power Service | 19-T | 0.00% | 12.55% | 65.1% |
| Irrigation Service | 24 | 35.67% | 25.7% | 133.3% |
| Unmetered Service | 40 | 35.67% | 25.7% | 133.3% |
| Municipal Street Lighting | 41 | 14.67% | 14.79% | 76.7% |
| Traffic Control Lighting | 42 | 35.67% | 25.7% | 133.3% |
| Total Oregon Rates | | 19.28% | 19.28% | 100% |

**Q. Does this proposal change the Company's overall revenue requirement increase?**

A. No. Staff constructed the cap and floor such that it is revenue natural. Although, if the overall revenue requirement changes in this rate case, the cap or floor may have to be updated in response.

**Q. Does this proposal include Staff's proposed change to generation fixed cost classification?**

A. Not at this time, but Staff plans to continue to work on this calculation and present it in future testimony.

## ISSUE 4. RATE DESIGN

**Q. Please describe the changes IPC is proposing to make to its tariffs.**

A. IPC proposes the following changes:

Residential Service Charge Increase: IPC proposes to nearly double the residential Service Charge. Currently the Service Charge for residential customers is $8. IPC is proposing to increase the residential Service Charge to $15.

Residential Seasonal Rates: IPC proposes to institute a seasonal Energy Charge differential for residential customers. This would create a higher variable rate in the summer and a lower variable rate in the winter.

Non-Residential Shift in Cost Recovery: IPC proposes to move 15 percent closer to cost-of-service prices in all cost categories for large non-residential customers.

Agricultural Energy Charge: IPC proposes to eliminate the in-season load-factor pricing mechanism for the energy rate, instead charging a flat per kWh rate both in and out of growing season. To compensate, IPC proposes doubling demand charge for agricultural customers.

Adjust Seasonal Definitions: IPC proposes to adjust the Residential and Non-Residential “Summer” season to include September.

Adjust Time-of-Day Definitions: IPC proposes to adjust the Residential and Non-Residential peak periods to better reflect hours of system strain.

**Q. Please summarize IPC's proposal regarding the Residential Service Charge.**

A. IPC is proposing to increase the Residential Service Charge by $7.00. This represents an 87.5 percent increase in the Service Charge compared to current rates.[17] Staff notes that this proposal is revenue neutral as a compensatory decrease to the Energy Charge would accompany any increase to the Service Charge. The primary impact of this proposal is that it increases the minimum bill a customer pays and tightens the overall bill distribution.

**Q. Please summarize IPC's rationale for increasing the Residential Service Charge.**

A. IPC argues that the current Service Charge paid by Schedule 1 (Residential) and Schedule 5 (Residential Time-of-Day Pilot Plan) customers is far below the amount indicated in the CCOS study. IPC argues that the Service Charge should cover the marginal cost of metering, billing, and customer service. The Company argues that since these costs do not vary with electricity service, they should be recovered on a fixed basis. However, Idaho Power does not believe that the same argument can be extended to fixed distribution, generation, and transmission costs.[18]

**Q. Does Staff agree with the Company's rationale?**

A. Largely. Staff has long argued that the service charge, absent large rate impact considerations to low-use customers, should be set to recover the

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[17] Idaho Power/1300, Aschenbrenner/8.
[18] Idaho Power/1300, Aschenbrenner/8-9.

marginal cost of each customer addition to the system. The costs recovered by the service charge should be strictly increasing on a per customer basis. Costs related to billing, metering, and customer service have historically been included in this category. However, the clean interpretation of these costs as "customer-related" has been diluted in recent years. With the adoption of DSM programs that are managed through billing, smart meters, and customer relations systems, one could argue that a portion of these costs are now partially related to energy consumption as well.[19] As such, Staff would argue that IPC's interpretation of the customer marginal cost of $15 may be an upper bound.

Further, the Service Charge often has unequal impacts on low income and energy burdened residential customers. This impact can vary largely between utilities. As such, Staff argues that the full impact of raising the Service Charge should be evaluated on a utility-by-utility basis.

**Q. Does Staff agree with the Company's proposed increase of $7.00 to the Residential Service Charge?**

A. No. First, this movement would move Residential customers from paying roughly half of IPC's identified customer-related COS through their Service Charge to paying roughly $0.35 more than their customer related COS. As discussed above, Staff views IPC's customer-related COS to be an upper bound estimate of the residential customer-related COS. As such, an extreme

[19] For an expanded discussion of this topic, see UE 399, Staff/700, Dlouhy/12-13.

movement that places the Service Charge slightly above that upper bound is inappropriate.

Further, residential customers are typically more sensitive to movements in the Service Charge compared to non-residential classes. Often, there are concerns around lower income customers having less agency over lowering their bills by conserving usage. Alternatively by keeping the Service Charge lower, the volumetric price of energy is artificially inflated, making heating and cooling more costly. With recent extreme weather events leading to negative health outcomes, discouraging heating and cooling through artificially inflated rates is an issue in its own right.

**Q. Does Staff have an alternative proposal for the Service Charge?**

A. Yes. Staff is recommending a more moderate increase of the Service Charge to $10.

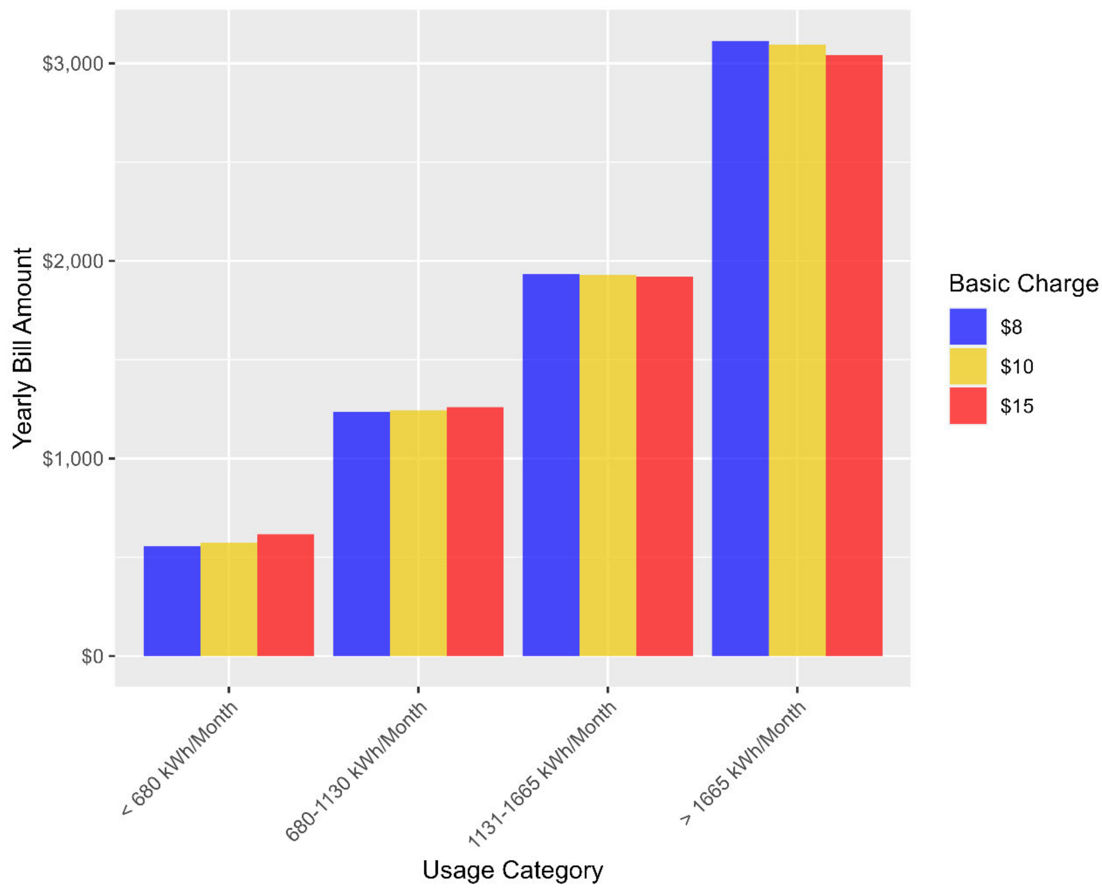
**Q. Please discuss Staff's rationale for proposing a $10 Service Charge.**

A. Staff is proposing this change for three primary reasons. First, Staff agrees that the Service Charge should be increased. The Service Charge has remained the same for over 15 years despite significant cost increases and inflation. Staff believes that the customer-related COS presented by the Company may be overstated, so levying a Service Charge that is above that amount is unreasonable. A $10 Service Charge represents a moderate increase that likely does not over state that customer-related COS.

Second, Staff argues that the Company proposed 87.5 percent increase to the Service Charge is an extreme movement, representing a movement towards COS of over 100 percent. As discussed later in this testimony, the Service Charge increase for non-residential customers only represents a 15 percent movement towards COS. The Company does not explain this discrepancy in treatment between rate classes. Staff assumes this disparate treatment stems from the fact that many non-residential schedules are paying Service Charges that are much closer, or above, their customer-related COS. While this may be true, this does not discredit the notion that the movement in the Residential Service Charge constitutes a major change to customer rates. If residential customers were to move 15 percent closer to their customer-related COS, similarly to how IPC is treating non-residential customers, it would produce a $9.00 Service Charge. Staff is recommending a $10.00 Service Charge to recognize the fact that more movement is needed from the residential customers to reach their customer-related COS, while also mitigating a rapid change to rate design.

Lastly, Staff's analysis of 2022 billings data finds that a $10.00 Service Charge would not significantly change yearly bills of customers in different usage categories. As discussed above, increasing the Service Charge affects customers at the tail of the usage distribution differently. Customers that consume less than the average amount of energy per month will likely see higher bills, while customers that consume more than the average will see lower bills. Staff created counterfactual bills using monthly residential billing data from Informal Data Intensive Request No. 1 assuming different service charges, no seasonal rates, and IPC's proposed residential revenue requirement and load forecast. Staff then found the quartiles of usage over the course of the year and found the median bill by usage quartile. The results of this analysis can be seen in Figure 5 below.

**Figure 5. Counterfactual Service charge Analysis**




Staff finds that only customers consuming below or above the 25th and 75th percentiles will be significantly affected by this change. The median customer consuming less than the 25th percentile would see an increase to their bill of roughly $60 per year, or $5 per month under IPC's proposal. Conversely, the median customer consuming above the 75th percentile would see a decrease to their bill of roughly $73 per year, or $6.13 per month, under

IPC's proposal. Under Staff's proposed Service Charge of $10, these impacts would be reduced to a $17.21 per year increase for low-use customers and a $20 decrease for high-use customers. Customers consuming around the median of usage will be minimally affected by this change under either proposal.

**Q. Does Staff have any concerns about increasing bills for low-usage customers while decreasing bills for high-usage customers?**

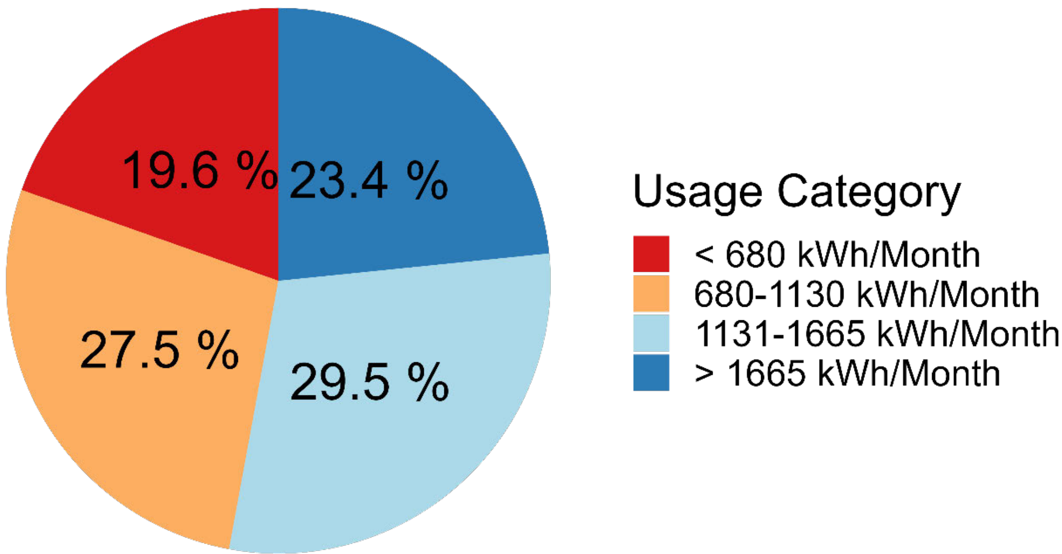
A. Yes. There have been many studies showing that electricity is a normal good, that is, usage increases in levels as income increases. As such, increasing low-usage customers' bills while decreasing high-usage bills may be seen as a transfer from low-income customers to high-income customers. To identify the magnitude of this problem, Staff explored the relationship between income usage using IPC's billing data from 2022.

Insight into customer income is limited. This is not to say that IPC has not tried to understand the income distribution of its customers, but instead is meant to reflect that short of accessing tax records, accurate income data is difficult to obtain. IPC has two primary indicators of household income for each customer. The first is LIHEAP participation. To participate in LIHEAP, customers must verify their income with the federal government. As a result, if a household is flagged as a LIHEAP participant, it is a fairly accurate indication that they are a low-income household. However, because of this lengthy application process, some qualifying families may not apply. As such, LIHEAP participation may be an accurate indication of low- income status but does not capture all low-income households.

The other measure of income available to IPC is income data derived from their Energy Burden Assessment (EBA).[20] These data were collected from a marketing firm that utilizes a variety of data sources, including credit data, to estimate household income. These data are less accurate, particularly for low-income customers who do not have access to credit. Further, in the data received by Staff in Informal Data Intensive Request No. 1, many households do not have an estimated income amount. Staff looked at both of these somewhat incomplete, measures of income to identify the effect of increasing the monthly Service Charge. Looking first at LIHEAP customers, Staff finds that LIHEAP customers are more likely than average to consume close to the median level of consumption. This relationship is displayed in Figure 6 below. Under Staff's proposed increase, roughly 80 percent of LIHEAP customers would see a negligible change or small decrease to their bill, while roughly 20 percent would see a small increase. Under IPC's proposal, both the increase and decrease would be more pronounced.

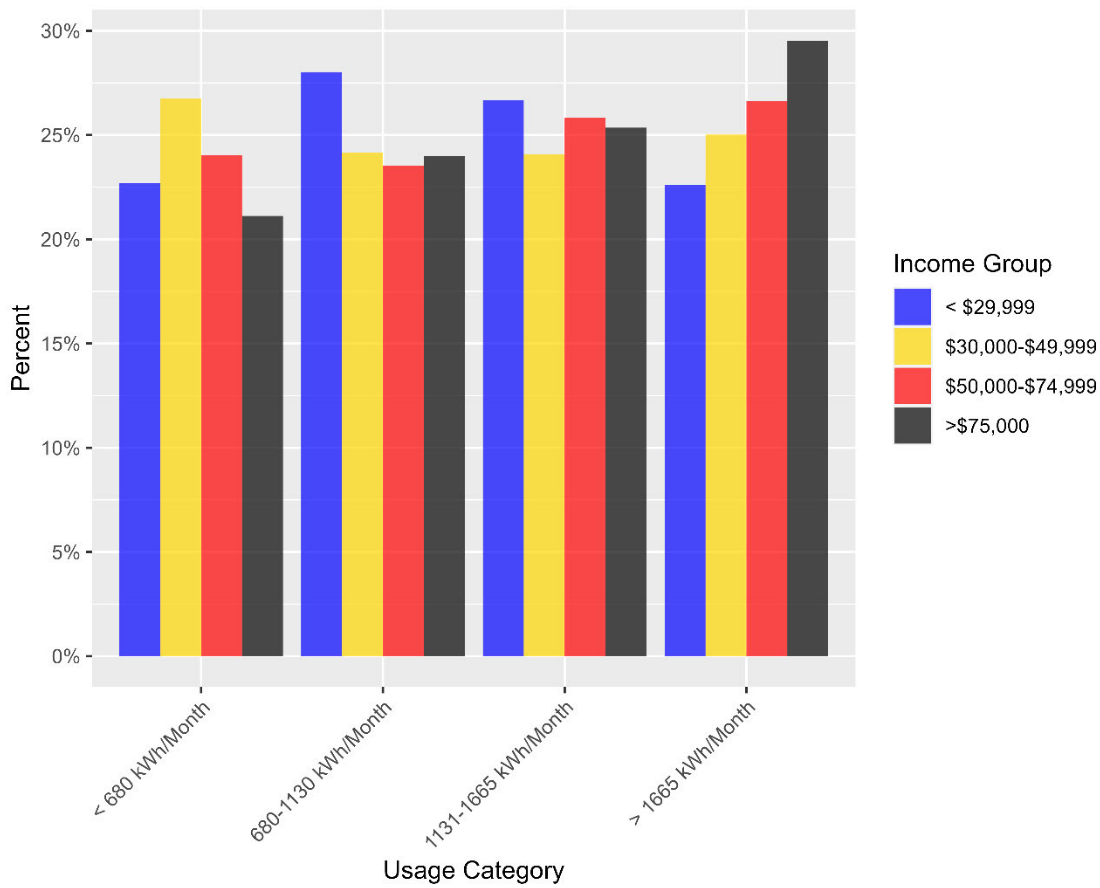
[20] Energy Burden Assessments are also referred to as Low-Income Needs Assessments (LINA) in some publications.

**Figure 6. LIHEAP Customer Usage**




Using IPC's income estimates from their EBA, Staff finds slightly different results. These data show customers estimated to be making between $30,000 and $49,999 per year would be disproportionately affected by the increased Service Charge as they consume in the first quartile of usage more often than other customers. Customers estimated to be in the lowest income quartile seem to disproportionately consume near the median. This is consistent with the LIHEAP discussion above. However, the customers in the highest income quartile seem to benefit the most from this change, having the highest likelihood of seeing a bill reduction.

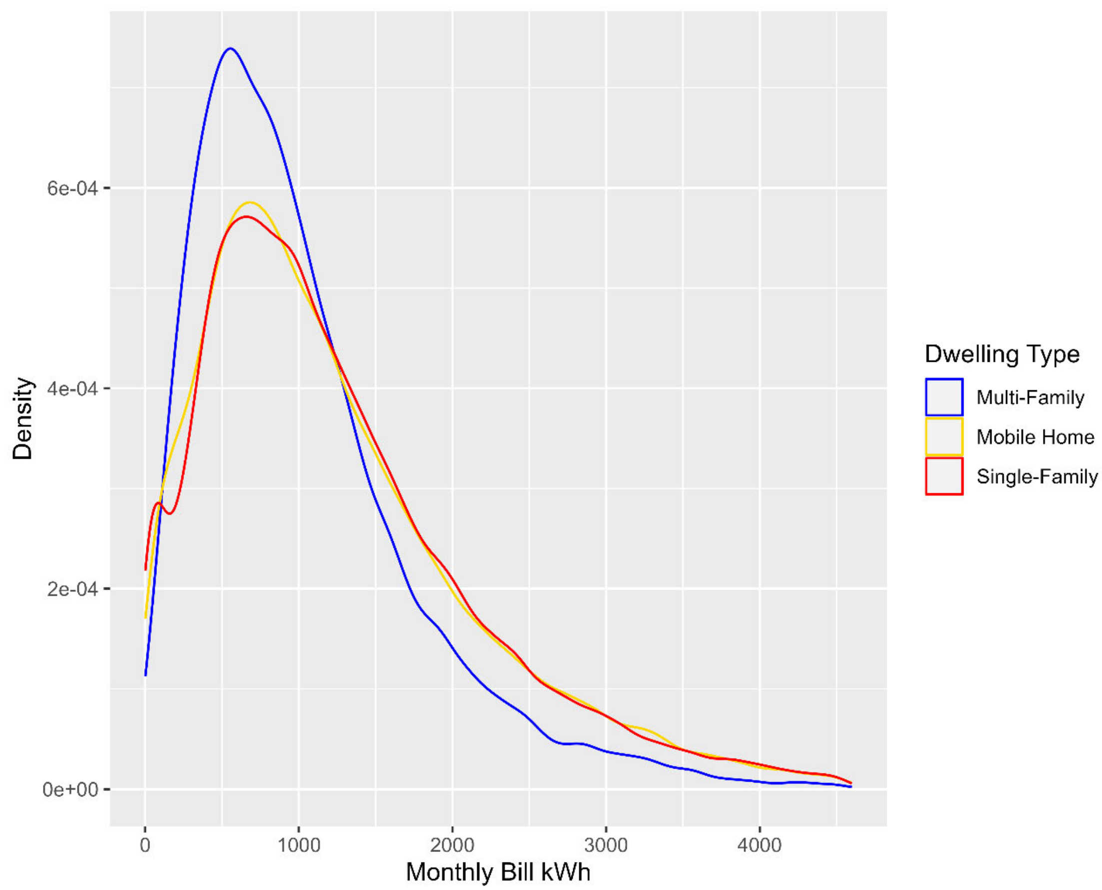
**Figure 7. Customer Usage by Estimated Income**




**Q. Did you find a subgroup that would be particularly affected by this change?**

A. Yes. Staff found that customers living in multi-family (MF) housing would be the most negatively affected by this change. Customers expected to be living in MF housing make up only 8 percent of IPC's residential customers. However, these customers are disproportionately estimated to be low-income. Roughly one-third of MF customers are LIHEAP participants and roughly half are estimated to make less than $30,000 a year. Further, MF customers use far less energy than any other group. This is illustrated in Figure 7 below. Given MF customers' low usage level, they will be disproportionately affected by any increase to the Service Charge. While this is true, MF customers only make up 20 percent of LIHEAP customers and 15 percent of customers estimated to make less than $30,000 per year.

**Figure 8. Monthly Usage by Dwelling Type**




**Q. How did the impact on low income and MF customers impact Staff's recommendation?**

A. Staff took into consideration both the fairness in moving towards COS and limiting the impact of this movement on low-income customers when forming its recommendation. Staff believes that a movement to $10 both makes significant improvement from a COS standpoint while not creating rate shock or significant harm to low-income customers.

**Q. Please summarize IPC's proposal regarding the Residential Seasonal Energy Charge.**

A. IPC is proposing adding a seasonal Energy Charge differential to its residential rates. This would create a seven (7) percent differential in the weighted average Energy Charge between the summer and non-summer periods. The higher Energy Charge would be levied in the summer, while the lower Energy Charge would be applied in the non-summer period.

**Q. Please summarize IPC's rationale for creating a Residential Seasonal Energy Charge.**

A. IPC argues that seasonal rates better reflect the time-varying COS for their system. IPC states that it is generally more expensive to meet customer energy requirements in the summer. IPC argues that seasonal rates can both send more efficient price signals to customers while also spreading costs more to cost causers. IPC also notes that nearly all its other service schedules have some form of seasonal rates.[21]

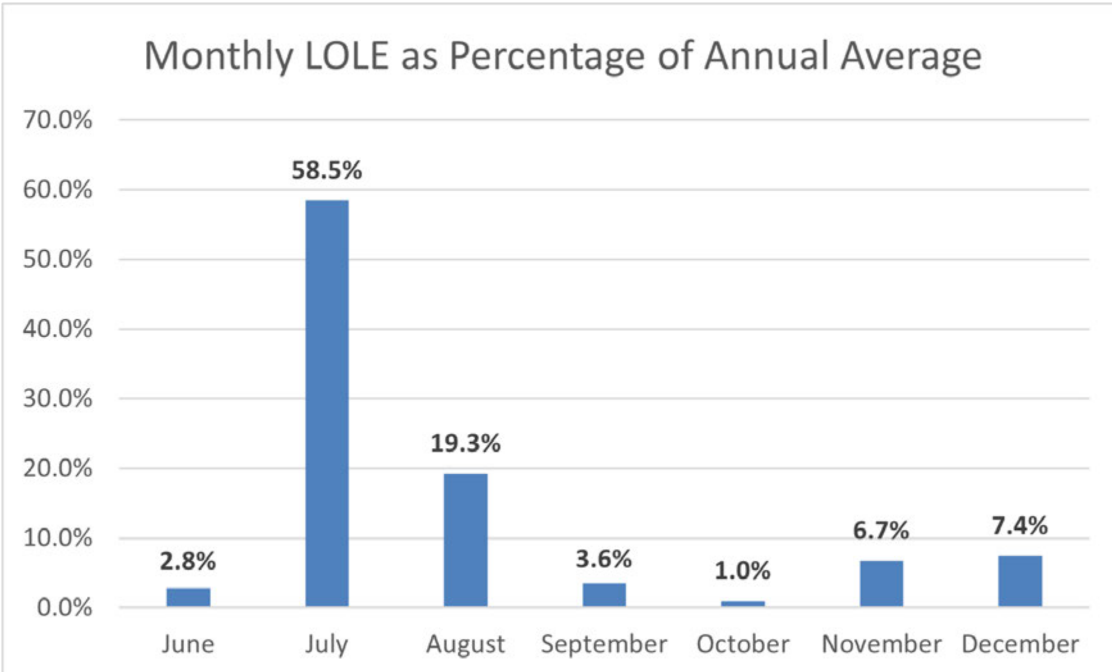
**Q. Does Staff agree with the Company's rationale?**

A. Partially. Staff agrees that IPC's system is most constrained in the summer. This, in turn, leads to higher COS in the summer months. This is fact is illustrated in Figure 8 below.[22] In total, the months of June through

[21] Idaho Power/1300, Aschenbrenner/6.
[22] Data provided in Idaho Power response to Staff DR 461.

September account for 84.2 percent of the annual average LOLE, with July and August alone accounting for 77.8 percent.

**Figure 9. Monthly LOLE as Percentage of Annual Average**




Staff also agrees that assigning costs to cost causers is a high priority in rate design. As a tertiary benefit of COS informed rates, more efficient price signals are often sent to customers as well. However, Staff does not agree that seasonal rates are the best way to achieve this goal. Further, Staff would need to see more analysis on the responsiveness of customers to seasonal rates. There may be unintended consequences for energy-burdened households if they are unable to respond to the seasonal price signals.[23]

[23] See Staff/300 for a more in-depth discussion on this issue.

**Q. Why does Staff not agree that mandatory seasonal rates are the most effective way allocate costs given IPC's system constraints?**

A. As stated above, seasonal rates do offer some advantages in comparison to IPC's current residential rate design. However, seasonal rates also pose some issues. First, in any non-real-time retail pricing scheme, some price signals will be lost to averaging. The question is then: What level of aggregation strikes the best balance of cost causation and parsimony? Figure 9 above highlights the strain on the system in the summer, but glosses over the points during the day this strain occurs. When looking at system tightness on an hourly level, its apparent that these costs are not occurring uniformly through the summer but are concentrated in the evening. Further evening, and to a lesser extent morning, hours in the winter also provide sizable system constraints. This can be seen in figures 10 and 11 below.[24]

[24] Idaho Power Response to Staff DR 459.

## Figure 10. Summer Risk Hours

### Summer Risk Hours (June 1–September 15)

| Hour End | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 2 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 3 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 4 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 5 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 6 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 7 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 8 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 9 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 10 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 11 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 12 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 13 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 14 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 15 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 16 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 17 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 18 | SLR | SMR | SMR | SMR | SMR | SMR | SMR | SLR |
| 19 | SLR | SMR | SMR | SMR | SMR | SMR | SMR | SLR |
| 20 | SLR | SHR | SHR | SHR | SHR | SHR | SHR | SLR |
| 21 | SLR | SHR | SHR | SHR | SHR | SHR | SHR | SLR |
| 22 | SLR | SHR | SHR | SHR | SHR | SHR | SHR | SLR |
| 23 | SLR | SMR | SMR | SMR | SMR | SMR | SMR | SLR |
| 24 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |

SLR—Summer Low-Risk
SMR—Summer Medium-Risk
SHR—Summer High-Risk

**Figure 11. Winter Risk Hours**

*Winter Risk Hours (November 1–February 28/29)*

| Hour End | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 2 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 3 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 4 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 5 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 6 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 7 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 8 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 9 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 10 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 11 | WLR | WMR | WMR | WMR | WMR | WMR | WMR | WLR |
| 12 | WLR | WMR | WMR | WMR | WMR | WMR | WMR | WLR |
| 13 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 14 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 15 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 16 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 17 | WLR | WMR | WMR | WMR | WMR | WMR | WMR | WLR |
| 18 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 19 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 20 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 21 | WLR | WMR | WMR | WMR | WMR | WMR | WMR | WLR |
| 22 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 23 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 24 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |

WLR—Winter Low-Risk
WMR—Winter Medium-Risk
WHR—Winter High-Risk

Judging by these data, it appears that applying a time-of-day differential for evening hours would better target the issue that IPC identifies in its proposal. While showing the system tightness in the summer, Figure 9 also shows that November and December represent the 4$^{th}$ and 3$^{rd}$ most contained months for IPC's system respectively. IPC's seasonal Energy Charge proposal would offer customers a lower rate in these months, running counter to cost causation principles. However, a year-round time-of-day rate would levy a higher rate in critical hours in all periods.

Staff agrees that a more accurate way of assigning these costs would be to pair a time-of-day rate with a seasonal rate – as IPC does in Schedule 5 (Residential Time-of-Day Pilot). However, Schedule 5 is relatively unpopular among IPC's Oregon customers, likely because of its relatively complicated rate design. It is Staff's general sentiment that a default or mandatory residential rate should only include one or two rate design elements beyond the standard fixed and variable charge design. If IPC were to explore one change to its default residential Energy Charge, Staff believes it would be better to explore default time-of-day rates.

**Q. Is Staff arguing for mandatory or opt-out time-of-day rates to be implemented in this rate case?**

A. No. Staff does encourage the Company to explore the potential impacts of this change and how it compares to default seasonal rates. In particular, Staff would need to see information about cost causation, customer responsiveness, equity, and a customer education proposal before being able to support such a proposal.

**Q. What treatment of the Energy Charge does Staff recommend in this rate case?**

A. Staff recommends that IPC keep the energy charge as it is; maintain the same tiered energy differential of 17 percent.

**Q. Please summarize IPC's proposal regarding non-residential cost recovery.**

A. With some exceptions, IPC is proposing to move each rate design component for non-residential customers 15 percent towards the cost to serve that component. This rule is uniformly true for Schedule 9P (Large General Service - Primary), Schedule 9T (Large General Service - Transmission), and Schedule 19 (Large Power) customers. For Schedule 7 (Small General Service), Schedule 9S (Large General Service - Secondary), and Schedule 24 (Agricultural Irrigation Service) the Service Charge is treated differently.

For Schedule 7, the single-phase Service Charge is calculated as a 40 percent movement towards their customer-related COS and the differential between the three-phase and single-phase service charges is largely kept the same. IPC proposes simply using the Schedule 7 Service Charge for Schedule 9S customers as well. Staff notes that this is peculiar as the customer-related COS is roughly $2.50 higher for Schedule 9S customers. Lastly, there is no indication to how the Service Charge for Schedule 24 customers was set.

**Q. Please describe the Company's rationale for this proposal.**

A. The Company did not elaborate in its Opening Testimony on why a 15 percent movement was chosen for most cost components. Staff understands the 15 percent proposal to represent a gradual shift towards COS pricing. The Company did not discuss its proposals for Schedule 7, Schedule 9S or Schedule 24 in Opening Testimony either. Although, in discussions with Idaho Power, they explained that Schedule 7 and Schedule 9S customers both have single- and three-phase service and customers can move between these schedules. As such, the Company preferred to align the Service Charge between these schedules. Further, the Company stated that the Service Charge structure for Schedule 24 was meant to mirror their Idaho rates as a non-trivial number of Schedule 24 customers are billed in both their Idaho and Oregon jurisdictions.

**Q. Does Staff agree with this proposal?**

A. Staff finds the 15 percent shift towards COS to be a reasonable movement. In general, Staff agrees that rates should reflect the cost of service and follow cost causation principles. Staff also finds the Company's rationale for the Schedule 7, Schedule 9S, and Schedule 24 Service Charges reasonable.

**Q. Please summarize IPC's proposal regarding the agricultural Energy Charge.**

A. Currently, the Schedule 24 In Season Energy Charge utilizes a load-factor pricing mechanism by separating charges into two blocks. The first block charges a rate per kWh rate for the first 164 kWh per kW of demand. The second block charges customers a lower per kWh for all other energy. Outside of the growing season, customers pay a flat per kWh Energy Charge. Irrigation Customers also pay an In Season Demand Charge.[25]

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[25] Idaho Power/1300, Aschenbrenner/21.

IPC is proposing to retire the load factor mechanism in the Energy Charge and replacing it with a flat per kWh Energy Charge that has an In Season and Out-of-Season cost differential. The Company is also proposing to double the Demand Charge to compensate for the removal of the load factor mechanism in the Energy Charge.[26]

**Q. Please describe the Company's rationale for this proposal.**

A. IPC states that the primary reason for this change is to help facilitate customer understanding of their bill components. The Company explains that the load factor mechanism was meant to help recover fixed costs, similar to the Demand Charge. However, the mechanism has been confusing to customers and a flat per kWh charge with a higher Demand Charge seems to be easier to understand, particularly because the rate structure does not change between seasons.

**Q. Does Staff agree with this rationale?**

A. Yes. Staff agrees that the load factor methodology could be confusing to customers and that the year-round flat per kWh charge and Demand Charge may be easier to understand.

**Q. Does Staff support this change?**

A. At this time, Staff does not oppose this change. Staff is still investigating the full ramifications of this change, particularly in terms of cost causation. Staff may comment on this proposal in a later round of testimony.

[26] Idaho Power/1300, Aschenbrenner/21-22.

**Q. Please summarize IPC's proposal regarding the definition of the summer season for customers with seasonal components to their rates.**

A. The Company is proposing to expand the definition of the summer season to include the month of September. Currently the summer season is defined as June-August.

**Q. Please describe the Company's rationale for this proposal.**

A. IPC states that their recent Integrated Resource Plans (IRP) have identified more frequent high-risk hours later in the summer, stretching into September. IPC recently expanded its summer definition in Idaho as a result.[27]

**Q. Does Staff agree with this rationale?**

A. Yes. The results of the Company's most recently published 2023 IRP are presented in Figure 9 above. This shows that 3.6 percent the total annual LOLE comes from the month of September. This places September as the 5th highest contributing month towards LOLE, following November. It also places it higher than June, which is already considered part of the summer season.

**Q. Does Staff agree with this change?**

A. Staff does not oppose this change at this time.

**Q. Please summarize IPC's proposal regarding the definition of time-of-day windows.**

[27] Idaho Power/1300, Aschenbrenner/7.

A. IPC is proposing to change the definition of its peak time-of-day windows. The proposed changes are shown below:

- Summer
  - From: 3pm-9pm; Mon-Fri
  - To: 7pm-11pm; Mon-Sat
- Winter
  - From: 7am-9am; 3pm-9pm; Mon-Fri
  - To: 6am-9am; 5pm-8pm; Mon-Sat

This proposal would shorten the summer peak period by two hours, shift it four hours later, and extend it by one day to include Saturdays. It would also expand the winter morning hours to include 6:00-7:00am, shorten the evening peak hours by 3 hours, and extend it by one day to include Saturdays.[28]

**Q. Please describe the Company's rationale for this proposal.**

A. Similar to its argument regarding the summer season expansion, IPC states that this change would better align rates with the hours of highest risk identified in its 2023 IRP. Further, these time-of-use windows were also proposed in the Company's most recent Idaho general rate case.[29]

**Q. Does Staff agree with this rationale?**

A. Yes. In general, Staff agrees that changes to time-of-day windows should only be made if significant evidence exists showing that a utility's hours of highest risk and cost have shifted. Barring any major concerns surrounding

[28] Idaho Power/1300, Aschenbrenner/19.
[29] Id.

this analysis in Idaho Power's 2023 IRP, Staff agrees that IPC's IRP points to this being the case.

**Q. Does Staff agree with this change?**

A. Staff does not oppose this change at this time.

## ISSUE 5. RATE BASE

**Q. From a high level, please describe how Idaho Power calculates rate base in this case.**

A. IPC first projects capital additions, depreciation expense, and accumulated depreciation through the Test Year. Then, IPC finds the 13-month average value over the course of the Test Year.

**Q. Does this methodology indicate a significant break from how rate base was calculated in the past?**

A. No. Staff reviewed testimony from UE 233 and the high-level rate base calculation has remained the same.

**Q. Does Staff agree with the Company's methodology?**

A. Yes. Given the Company's quasi-historical Test Year, Staff feels this methodology is appropriate. Given the fact that IPC is foregoing additional revenue requirement increases by way of cost escalation in using a quasi-historical Test Year, Staff does not oppose IPC's methodology.

**Q. Would Staff agree with this methodology if IPC used a forward-looking Test Year?**

A. No. In general, Staff advocates that the revenue requirement reflect the utility's average cost over the Test Year. Most of IPC's peer Oregon utilities use a forward-looking Test Year. Commonly, the Test Year is defined as being the 12-month period following the rate effective date. In this setting, Staff would argue that the rate base should be valued using the 13-month average approach, excluding capital additions in the Test Year included in accordance with ORS 757.355.

IPC is not using a strictly forward-looking Test Year. Instead, IPC is using a quasi-historical Test Year where most of the Test Year takes place prior to the rate effective date and part of the Test Year takes place after the rate effective date. Compared to a strictly forward-looking Test Year, IPC is foregoing additional escalation of expenses, while also avoiding additional accumulated depreciation. Given the Test Year proposed by IPC, Staff does not oppose their calculation as it captures the spirit of Staff’s position.

## SUMMARY

**Q. Please summarize your recommendations.**

A. Staff is proposing three primary changes to Idaho Power's load forecast. The first is that the short-term residential forecast be estimated using an ARIMA model with economic and weather covariates. Second, Staff suggests that all residential and non-residential ARIMA models be algorithmically parameterized as a starting point and any deviations from this parameterization be explicitly justified. Lastly, Staff proposes that all residential and non-residential load forecasts be estimated separately for each jurisdiction. These changes adjust both the jurisdictional energy and demand allocators leading to an Oregon jurisdictional revenue requirement decrease of 2,198,400 dollars.

For the Cost-of-Service Study, Staff argues that distribution and fixed generation costs be assigned on a 50 percent energy and 50 percent demand basis as opposed to the 100 percent demand basis proposed by the Company.

For rate spread, Staff is proposing an alternative cap-and-floor scheme that would cap the maximum increase to be 133 percent of the average increase and set a minimum increase of 65.1 percent.

For rate design, Staff argues that the Service Charge increase be limited to $2 as opposed to $7 as proposed by the Company. Staff opposes Idaho Power's proposal for a seasonal residential Energy Charge and recommends the Company instead wholistically explore opt-out time-of-day rates. These, and all other stances, may change based on further review and as informed by the testimonies offered by other parties.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: Bret Stevens

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 1501

## OPENING TESTIMONY
## Witness Qualifications Statement

**March 25, 2024**

**WITNESS QUALIFICATIONS STATEMENT**

| | |
|---|---|
| **NAME:** | Bret Stevens |
| **EMPLOYER:** | Public Utility Commission of Oregon |
| **TITLE:** | Senior Economist<br>Rates, Safety, and Utility Performance |
| **ADDRESS:** | 201 High Street SE. Suite 100<br>Salem, OR. 97301 |
| **EDUCATION:** | Ph.D., Agricultural & Resource Economics (2023)<br>University of California, Davis<br><br>M.S., Agricultural & Resource Economics (2017)<br>University of California, Davis<br><br>B.A., Economics/Environmental Studies (2016)<br>Western Washington University |
| **EXPERIENCE:** | I have been employed at the Public Utility Commission of Oregon since September of 2022. My primary responsibilities revolve around providing research and analysis on rate spread and rate design. I have been a staff witness in UE 407, UE 410, UE 412, UE 414, UE 416, UE 421, UE 425, and UG 461. Prior to working for the Commission, I was employed by the University of California, Davis as a graduate student researcher, associate instructor, and teaching assistant. I taught courses on econometrics, finance, and microeconomics. |

CASE: UE 426
Witnesses: Anna Kim and Charles Lockwood

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1600

# Joint Opening Testimony
## Demand Side Management,
## Low-Income Weatherization

## March 25, 2024

**Q. Please introduce yourselves.**

A. I am Anna Kim. I previously provided testimony in Staff/700 and provide my witness qualifications in Exhibit Staff/701.

I am Charles Lockwood. I previously provided testimony in Staff/800 and provide my witness qualifications in Exhibit Staff/801.

**Q. What is the purpose of your testimony?**

A. The purpose of this testimony is to discuss Demand-Side Management (DSM) and programs within DSM.

**Q. Did you prepare any exhibits for this docket?**

A. Yes. We prepared the following exhibits:

- Exhibit Staff/1601, Idaho Power's Low-Income Needs Assessment (Docket No. UM 2211).
- Exhibit Staff/1602, Staff workpaper demonstrating Staff's calculations used in this testimony.
- Exhibit Staff/1603, responses to data requests used in support of testimony.

**Q. How is your joint testimony organized?**

A. Our joint testimony is organized as follows:

DSM Overview (Kim and Lockwood) .......... 3
Issue 1. DSM Programs (Kim) .......... 6
Figure 1: Oregon Percentages of DSM Program Performance .......... 6
Figure 2: Oregon Percentages of DSM Program Costs .......... 7
Figure 3: Oregon Percentages of Shared Program Costs .......... 8
Issue 2. Low-Income Weatherization programs (Lockwood) .......... 12
Figure 4. Home Weatherized Per Year in IPC Service Territory .......... 13

Summary. Staff Recommendations (Kim and Lockwood)......................... 18

**DSM OVERVIEW (KIM AND LOCKWOOD)**

**Q. What is the purpose of your testimony on the topic of Demand-Side Management (DSM)?**

A. The purpose of our testimony is to discuss overall DSM including energy efficiency and demand response, including the Company's income-qualified weatherization program. This testimony does not address the federal Low-income Home Energy Program (LIHEAP), which can also provide weatherization support to customers. Additional context for equity considerations is covered in Ms. Scala in Staff/300.

**Q. What demand-side management costs are included in the revenue requirement for this General Rate Case (GRC)?**

A. The costs for income-qualified weatherization programs are recovered through base rates established in the GRC. Energy efficiency programs that are not low-income weatherization, which make up the majority of Idaho Power's energy efficiency programs, and demand response are not in the revenue requirement for the GRC. The costs for these programs are covered in the Energy Efficiency Rider.[1]

**Q. Why is DSM in general and energy efficiency in specific important to Oregon customers in the Company's service territory?**

A. DSM programs are cost-competitive non-emitting resources that reduce system costs in general by reducing system needs. Energy efficiency also provides long-lasting bill savings for individuals and can reduce energy burden

[1] Idaho Power/600, Hanchey/17.

over that period, especially in homes with high usage due to poor weatherization.

**Q. Please explain why supporting lower income customers with energy efficiency solutions such as weatherization is particularly important to Oregon customers in the Company's service territory.**

A. Energy efficiency directly addresses energy burden by reducing energy usage and thus impacting bills. As described in Scala/300, Idaho Power's Oregon customers face exceptionally high energy burden. Due to the quality of the average home in the Company's Oregon customers, poor weatherization practices are particularly burdensome.

Idaho Power's Oregon service territory currently consists of approximately 12,800 households, with approximately 3,500 households that are deemed to have a high energy burden, meaning that annual electricity bills exceeded six percent of their income for electrically heated homes and exceeded three percent of their income for non-electrically heated homes.[2] Therefore, approximately 27 percent of all customers in Idaho Power's Oregon service territory are facing high energy burden.

This high percentage of energy burdened households is due to several factors. First, the median household income for residents in Idaho Power's Oregon service area is approximately $48,000, well below the Oregon state average of $66,000.[3] Approximately 19 percent of households would fall under

[2] Staff/1601, Kim-Lockwood/17, Idaho Power's Low-Income Needs Assessment (Docket No. UM 2211).
[3] Id.

100 percent of the federal poverty limit, and 62 percent of residents would fall under 60 percent of the State Median Income (SMI).[4]

Second, of the homes with a known age, 24 percent were built prior to 1940 and 77 percent were built prior to 1980. These older homes typically have more opportunities for weatherization improvements and therefore are a good area for targeting weatherization efforts.

Finally, Idaho Power's Low Income Needs Assessment found that approximately 2,635 of the 3,500 customers with high energy burden also had high efficiency potential, meaning approximately 33.2 percent of all Idaho Power customers have high burden and high efficiency potential.[5]

**Q. Are energy efficiency programs for lower income customers duplicative of the bill discount program?**

A. No. The bill discount program addresses the symptom, not the causes. Poor weatherization and inefficient equipment can be a contributing factor to energy burden, and are not resolved through a bill discount.

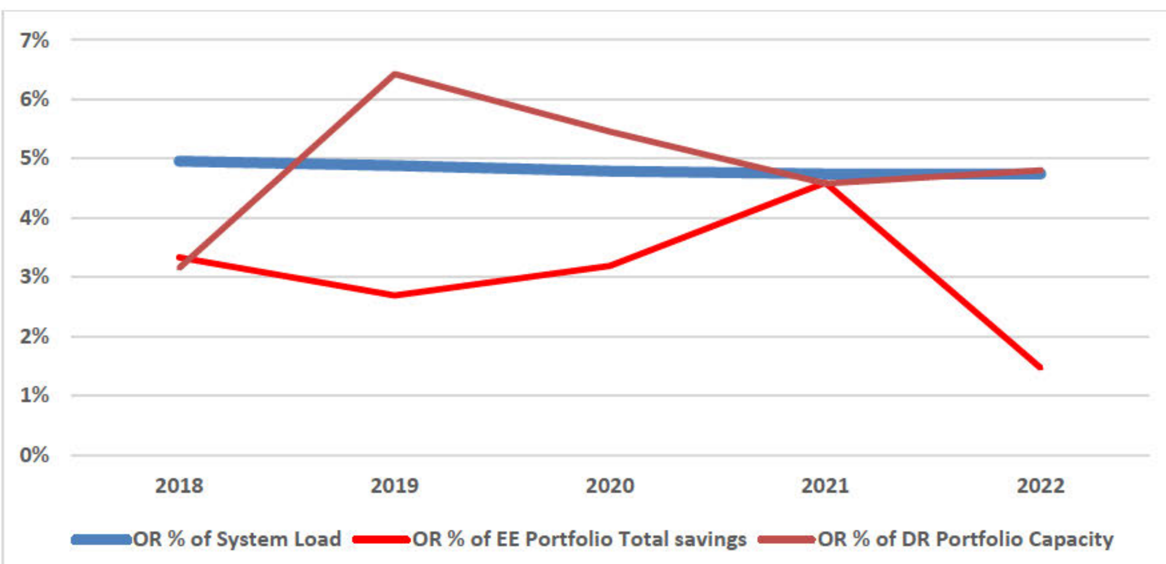
[4] Id.
[5] Id.

## ISSUE 1. DSM PROGRAMS (KIM)

**Q. How are the Company's DSM programs performing in Oregon relative to the rest of the Company's service territory?**

A. While demand response acquisition in Oregon is proportional to system load, energy efficiency program acquisitions in Oregon underperform when compared to the Company's acquisitions in Idaho. On average, from 2018 to 2022, while Oregon represents 4.8 percent of load, it represents 3.1 percent of energy efficiency savings and 4.9 percent of demand response capacity. Figure 1 demonstrates the difference between energy efficiency savings with respect to system load.[6]

**FIGURE 1: OREGON PERCENTAGES OF DSM PROGRAM PERFORMANCE7**




6 See Staff/1602, Staff workbook combining data from Idaho Power responses to DRs No. 217, 218, and 454.

7 Id.

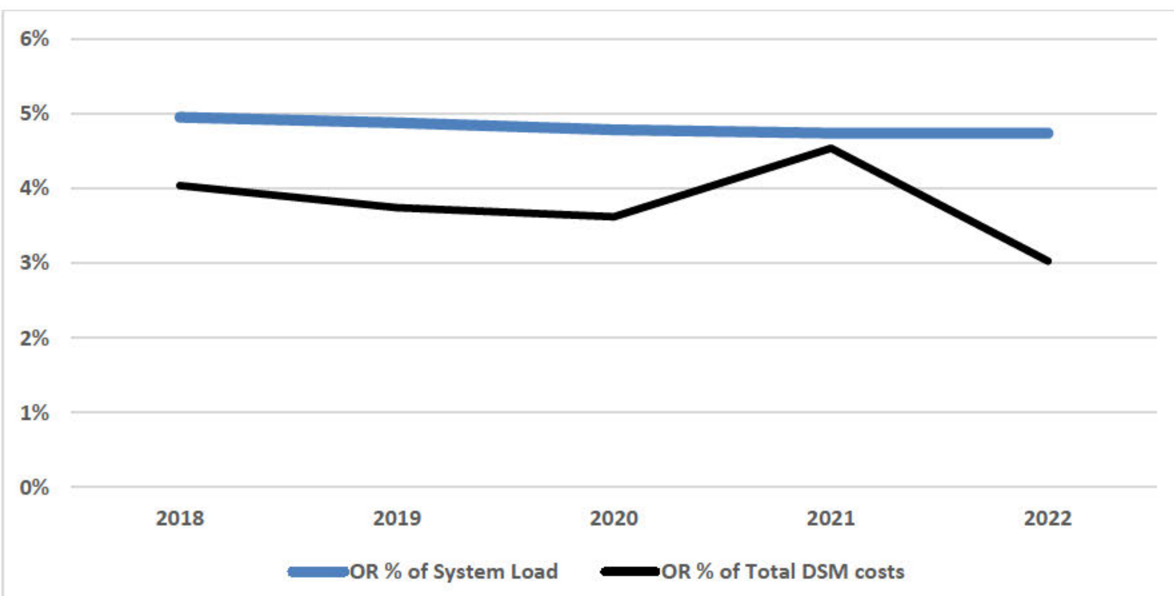
**Q. What percentage of the DSM program is spent on demand response?**

A. On average, in 2018-2022, program-specific demand response programs account for 20.9 percent of program-specific DSM spending (DSM spending excluding "indirect program expenses" and "other programs and activities").[8]

**Q. How does the Company's DSM program spending in Oregon compare to the rest of the Company's service territory?**

A. When compared to Oregon's share of system load, the Company underspends on DSM in Oregon. On average, Oregon has 4.8 percent of load, but accounts for 3.8 percent of DSM spending from 2018 to 2022. As seen in the following figure, expenditures on DSM are not proportional to state-specific load.

**<u>FIGURE 2: OREGON PERCENTAGES OF DSM PROGRAM COSTS9</u>**

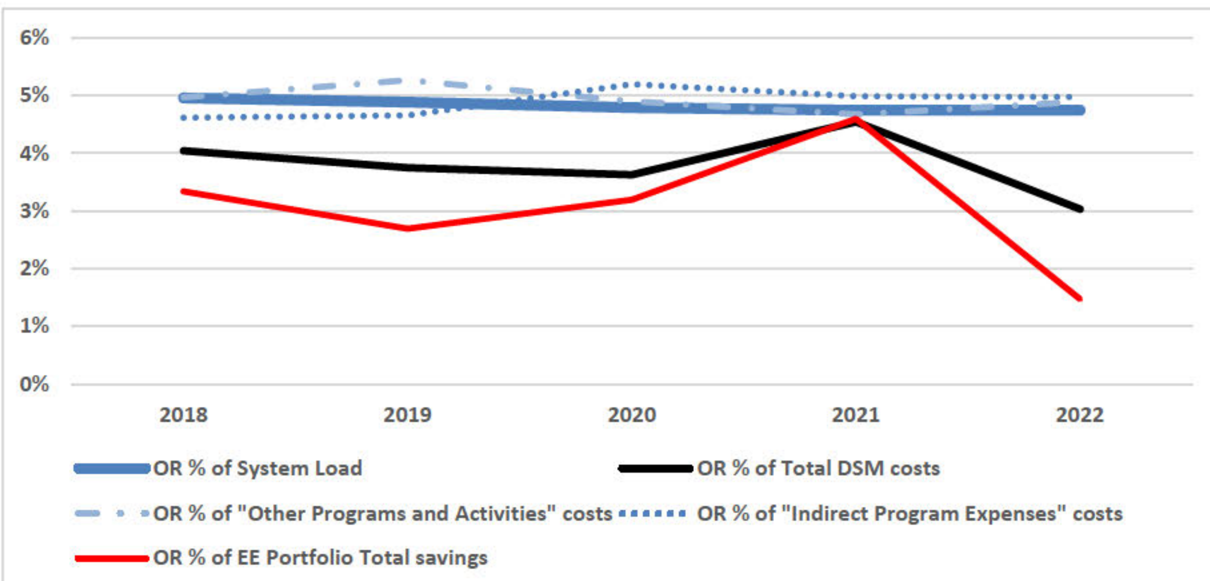



**Q. How much do Oregon customers contribute to DSM program costs?**

[8] Id.
[9] Id.

A. On average, Oregon DSM programs account for 3.1 percent in energy efficiency savings and 3.8 percent in energy efficiency spending from 2018-2022, but Oregon customers pay 4.8 percent of total DSM program costs and 4.9 percent of shared program costs. The figure below illustrates how overall spending outpaces program performance in energy efficiency, and further, that specific DSM costs (labeled Other Programs and Activities, and Indirect Program Expenses) are inconsistent with, and in fact greater than, overall program spending.

**FIGURE 3: OREGON PERCENTAGES OF SHARED PROGRAM COSTS10**




**Q. Why is the underperformance of energy efficiency concerning?**

A. Energy efficiency including weatherization is essential for addressing energy burden. As mentioned earlier, the Oregon customer base in the Company's service territory includes many energy-burdened customers, and many of those

[10] Id.

have a high potential for energy savings (see Staff/600). Energy efficiency in general and weatherization in specific are key to reducing energy burden one house at a time.

**Q. How does Staff propose to address the historic underperformance of the Company's energy efficiency programs for Oregon customers?**

A. Staff recommends that the Company better align its rate collection practices with the benefits that Oregon customers receive from the energy efficiency programs. Staff recommends a management disallowance of $75,445 to Idaho Power's Test Year expense for A&G. This disallowance is commensurate with historical underperformance of the Company's DSM programs for Oregon customers compared to the amount collected in 2018-2022. In other words, Idaho Power's DSM programs in Oregon have lagged behind DSM programs in Idaho although Oregon has paid its fair share of the programs. Staff does not think it is appropriate for Oregon ratepayers to pay rates reflecting equal allocation of effort with respect to DSM programs when the facts do not support such an allocation.

**Q. Is this adjustment permanent?**

A. Not necessarily. Although Staff recommends a disallowance of Test Year expense in this rate case, Staff seeks to encourage better performance on, not lower investment in, energy efficiency programs and would support an Idaho Power request to annually defer $75,445 for later amortization into rates as part of Idaho Power's Energy Efficiency Rider. However, Staff would only support amortization if the Company is able to show, for the period covered by the deferral, that it acquired energy efficiency savings in Oregon in proportion to system load, on par with energy efficiency acquisition rates in Idaho.

**Q. How was this number calculated?**

A. Staff adjusted the "Other Programs and Activities" and "Indirect Costs" to reflect the percentage share of energy efficiency acquisitions for each year from 2018 through 2022.[11]

**Q. Does Staff have other ideas for addressing the underinvestment in energy efficiency performance in Oregon?**

A. Yes. Staff recommends that avoided costs for energy efficiency in Oregon include costs that could be avoided through reducing the costs of the bill discount program discussed in Staff/600 by Mr. Farrell. The additional avoided cost would be added to the Company's current DSM avoided cost calculations as an additional cost avoided. Costs of the bill discount program are system costs paid for by Oregon customers to support customers with high energy burden. Investing in energy efficiency may diminish costs to provide support to energy burdened customers, the savings of which will be felt by all other customers.

**Q. How should the avoided cost of the bill discount program be calculated?**

A. Staff recommends this calculation be made by taking the budget of the bill discount program, less the Service Charge revenue from participants multiplied by the number of participants multiplied by the weighted average discount,

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[11] Id.

divided by the applicable kWhs. This method is expressed mathematically below.

$$Avoided\ Cost\ \left(\frac{\$}{kWh}\right) = \frac{Budget - (\overline{Discount} \times SC^*)}{kWh^*}$$

Where,

- $Budget$ is the bill discount program budget,
- $\overline{Discount}$ is the weighted average discount received by participating customers,
- $SC^*$ is the Residential Service Charge revenue from bill discount participants, and
- $kWh^*$ is the amount of kWhs consumed by bill discount participants.

**Q. Does Staff have any additional recommendations to improve the performance of the Company's energy efficiency programs?**

A. Yes. Staff recommends the Company work with stakeholders and Staff through Docket No. UM 2211[12] (see Staff/600) to identify and implement opportunities to reduce energy burden through its energy efficiency programs.

[12] *In the Matter of the Public Utility Commission of Oregon, Implementation of House Bill 2475*, UM 2211.

**ISSUE 2. LOW-INCOME WEATHERIZATION PROGRAMS (LOCKWOOD)**

**Q. How are low-income weatherization programs reflected and counted within rate base?**

A. Idaho Power funds its low-income weatherization program, called Weatherization Assistance for Qualified Customers ("WAQC"),[13] through base rates and makes at least $45,000 per year available to two Community Action Partnership agencies in Oregon; Community Connection of Northeast Oregon, Inc., and Community in Action.

**Q. Please describe the WAQC program.**

A. Idaho Power's WAQC program is a targeted energy efficiency program that assists income-qualified customers with measures such as water heater and window replacement at no cost. This assistance is available to income qualifying renters or homeowners in electrically heated residences.

**Q. How has the Commission historically treated low-income weatherization programs including the WAQC?**

A. ORS 469.633 requires investor-owned utilities to have energy efficiency programs, and ORS 757.262, states that the Public Utility Commission (Commission) may adopt policies designed to encourage the acquisition of cost-effective conservation resources and may authorize periodic rate adjustments associated with the implementation of such policies.

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[13] Idaho Power has several programs for low-income customers including WAQC and the Low-Income Home Energy Assistance Program (LIHEAP). WAQC funding comes from Idaho Power's rates and provides low-income customer with weatherization funding. LIHEAP is a federally funded program for qualified programs that provides direct bill assistance.

**Q. Please describe Staff's analysis of the implementation of the WAQC and other programs made available to low-income customers.**

A. Staff asked a series of DRs to better understand the impact of the Company's income qualified weatherization program and to better understand how the funds were being utilized. Idaho Power is currently partnered with five Community Action Partnership (CAP) agencies, with two of them interacting with Oregon customers, as mentioned previously. Projects funded through WAQC have declined since the COVID-19 pandemic in 2020, as shown in Figure 1.[14]

**FIGURE 4. HOMES WEATHERIZED PER YEAR IN IPC SERVICE TERRITORY**

| | Idaho Homes | Oregon Homes |
|---|---|---|
| **Program:** | **WAQC** | **WAQC** |
| 2014 | 239 | 11 |
| 2015 | 225 | 10 |
| 2016 | 231 | 12 |
| 2017 | 194 | 7 |
| 2018 | 188 | 3 |
| 2019 | 189 | 4 |
| 2020 | 115 | 0 |
| 2021 | 161 | 1 |
| 2022 | 147 | 0 |
| 2023 | 161 | 5 |
| **Average:** | **185** | **5.3** |

[14] Staff/1603, Kim-Lockwood/2, Idaho Power's Response to DR 265.

Staff notes that the Company does not work with Energy Trust of Oregon on energy efficiency activities, including the WAQC.

**Q. Why is Staff concerned with the effectiveness of the Company's WAQC program?**

A. Staff believes that energy efficiency should be Idaho Power's highest priority tool to mitigate energy burden. Staff is concerned that, given the nature of its Oregon customer base, the Company has not worked proactively overcome the barriers to WAQC program performance or identified other ways to target its portfolio of energy efficiency measures to the most energy burdened customers. This is particularly important due to the need for weatherization in the Company's Oregon service territory shown in the Low-Income Needs Assessment.

For fairness purposes and to best serve these customers, Idaho Power should be targeting these customers for weatherization programming. Because of the Company's failure to correct issues in the implementation of the program over a full decade, a management disallowance is warranted.

**Q. How has the WAQC program performed in Oregon compared to Idaho?**

A. First, in Oregon, the Company could weatherize a minimum of 6.8 homes per year, as the Company utilizes $45,000 per year with a maximum cost of $6,600 per home, given the maximum incentive of $6,000 plus $600 in administrative fees. On average over the last ten years, the Company has weatherized 5.3 homes per year, and an average of only two homes per year for the past five years.

Second, while Oregon customers contribute 3.5 percent of what the Company is collecting for the WAQC program, only 2.8 percent of homes served over the past ten years are Oregon households. If Oregon households made up the roughly 3.5 percent of all homes weatherized over the last ten years, the Company would have needed to weatherize 6.6 homes per years, yet they have only weatherized an average of 5.3 homes per year.

In Oregon, the Company averages 1.17 homes per $10,000 collected, whereas in Idaho the Company averages 1.53 homes per $10,000, which is approximately 31 percent higher. To match Idaho Power's 1.53 homes per $10,000 collected in Idaho, the Company would need to average approximately 6.9 homes weatherized per year. As stated previously, the Company is averaging 5.3 homes, therefore, the Company would need to weatherize an additional 1.6 homes per year to be on pace in Oregon with weatherization rates in Idaho.

Over the last ten years, the Company has given $450,000 to the CAP agencies for the WAQC program. If the fifty-three homes that were weatherized in Oregon received the maximum rebate of $6,600, that leaves $100,200 in leftover funds the Company and CAP agencies should be utilizing to weatherize more Oregon homes. Staff is proposing a management disallowance as an incentive to utilize those leftover funds and weatherize Oregon homes at the same rate as Idaho homes.

**Q. Therefore, what is Staff's recommendation?**

A. Staff recommends a management disallowance of $10,560 from the Company's Test Year expense for A&G in this docket.

**Q. How did Staff calculate and decide on a management disallowance of $10,560?**

A. To calculate a management disallowance of $10,560 from the Company's overall revenue requirement in this docket, Staff sought to reflect the proportionately lower performance of the WAQC in Orgon versus Idaho.

To match Idaho Power's 1.53 homes per $10,000 collected in Idaho, the Company would need to average approximately 6.9 homes weatherized per year. Currently, the Company is averaging 5.3 homes, therefore, the Company would need to weatherize an additional 1.6 homes per year to be on pace in Oregon with weatherization rates in Idaho.

With the maximum incentive plus administrative costs totaling $6,600 per home, Staff proposes a management disallowance of $10,560, which is approximately the cost of weatherizing 1.6 homes at the cost of $6,600.

Additionally, Staff recommends that the Commission allow Idaho Power to defer up to $10,560 of additional spend on the OR WAQC. Staff will recommend that Idaho Power be allowed to amortize deferred amounts upon demonstration that the Company has improved their performance of the WAQC to a level that exceeds 6.8 homes per year. Staff proposes this disallowance to signal the priority level of correcting its historic underperformance and not to spend less on the WAQC and energy efficiency programs generally.

**Q. Does Staff have any additional recommendations related to the performance of the Company's WAQC programs?**

A. Yes. Staff recommends the Company work with stakeholders and Staff through Docket No. UM 2211[15] (see Staff/600) to identify and implement solutions to increase the performance of the WAQC in Docket No. UM 2211. This venue will allow open and collaborative exploration of programmatic improvements that leverages input and expertise across utilities and programs.

[15] *In the Matter of the Public Utility Commission of Oregon, Implementation of House Bill 2475*, UM 2211.

**SUMMARY. STAFF RECOMMENDATIONS (KIM AND LOCKWOOD)**

**Q. Please summarize your adjustments.**

A. Staff recommends a downward adjustment to Idaho Power's Test Year expense of $75,445 to reflect the level of focus Idaho Power places on DSM in Oregon is not commensurate with amounts collected from Oregon ratepayers or with DSM offered in Idaho  Without incentive to change, Staff anticipates that Oregon DSM in future years would continue to be disproportionate to the amount collected for DSM in Oregon rates and to what is offered in Idaho.  If Idaho Power's efforts improve, lower savings and program expenditures that could be returned to the Company through an Idaho Power-initiated deferral and amortization under Idaho Power's Energy Efficiency Rider when energy efficiency acquisition rates match acquisition rates in Idaho.

Staff also recommends a management disallowance of $10,560 from the Company's Test year expense in this docket for low-income weatherization given Idaho Power's underperforming low-income weatherization programs in Oregon. Staff encourages Idaho Power to file a request to defer incremental spending on low-income weatherization (up to the $10,560 amount) that would be eligible for amortization if Idaho Power improves its performance on low-income weatherization.

**Q. Please summarize any additional recommendations.**

A. Staff also recommends the following:

1. Include avoided bill discount program costs in DSM avoided costs.

2. Discuss ways to overcome programmatic challenges and performance expectations in Docket No. UM 2211.
3. Allow Idaho Power opportunity to defer additional expenses spent on DSM and low-income weatherization and to request to amortize those costs.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: Anna Kim and Charles Lockwood

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1601

## Exhibits in Support
## Of Opening Testimony

**March 25, 2024**

An IDACORP Company

# OREGON LOW INCOME NEEDS ASSESSMENT

empower dataworks

# IDAHO POWER - OREGON LOW INCOME NEEDS ASSESSMENT

JULY 2023


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Empower Dataworks

# INTRODUCTION

This brief report presents the methodology and findings from Idaho Power's 2023 Oregon low income needs assessment. The results of the assessment are contained in the web dashboard at https://idahopower.empowerdataworks.com/.

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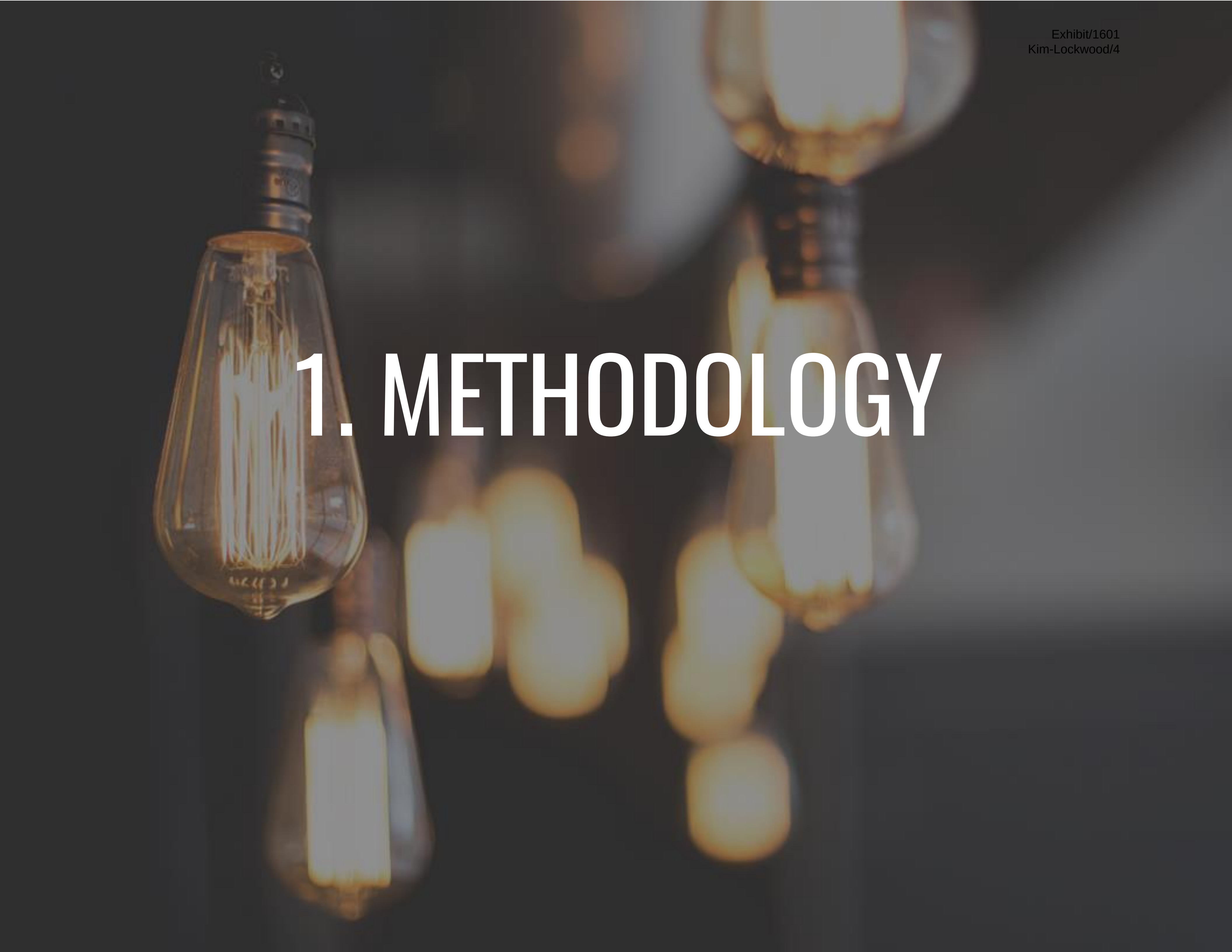

1. METHODOLOGY

# 1.1 GENERAL APPROACH

This low income needs assessment relies on collecting customer-level data, modeling missing attributes, then aggregating key metrics by geographic, demographic or building variables for analysis. The customer data (including estimated household income) comes from various sources as described in the rest of Section 1. Some demographic attributes were modeled or inferred using statistical techniques due to lack of primary data in the Customer Information System (CIS) or other sources. American Community Survey data was mainly used to sanity check aggregate statistics of customer-level data at the census tract level.

Three types of metrics were calculated:

- Metrics related to energy burden based on demographic and geographic characteristics
- Participation and funding in Energy Assistance Programs
- Customer energy use characteristics

The final dataset and results were packaged in a web dashboard for Idaho Power staff.

# 1.2 DATA SOURCES

The data sources leveraged for the analysis are described in this section.

## DATA PROVIDED BY IDAHO POWER

**Customer Information System (CIS):** This data included monthly electricity bills for 24 months in 2021-22, account numbers and service addresses. A separate data extract included the dates and customer accounts that received late payment and disconnection notices, allowing us to calculate the on-time payment rate for different customer segments.

**Direct Assistance Program Data:** We received a list of participating accounts in LIHEAP and Project Share program in 2021-22, along with discount amounts and dates. This allowed us to calculate the total assistance funding at the household level.

**Acxiom Demographics:** Idaho power provided data from a third-party data compiler that aggregates data from a variety of sources. This data was mapped to the CIS dataset using customer addresses and included estimated household income, and homeownership status for a little over 75% of residential households. Demographic attributes for some customers were modeled due to lack of primary data in CIS or other sources. The modeling approaches are described in the next section.

## DATA OBTAINED FROM OTHER SOURCES

**Geocoding:** All customer addresses were geocoded to a latitude/longitude pair to facilitate geographic analysis. In addition, we mapped the latitude/longitude pairs to census tracts, block groups and blocks in order to pull additional aggregate statistics.

**County Assessor Data:** We obtained publicly available assessor data from Baker, Harney and Malheur counties. The assessor data included appraised values for homes, square footage, building year built, building types (residential, mobile homes, commercial and industrial), number of buildings on a land parcel, and other minor data points that were useful for performing general QA.

The addresses in this dataset were standardized to US Postal Service format, then matched with addresses in the CIS data. Some addresses existed in the CIS data but not in the assessor data (typically happens when multiple buildings occupy the same land parcel).

**American Community Survey (ACS):** ACS data (2021 5 year estimates) was primarily used for QA to ensure that aggregate counts for various demographic attributes match the expected distributions from ACS.

# 1.3 FINAL ATTRIBUTES AND METRICS

The calculation methods for the metrics and attributes used in this report are described in this section. For all attributes, we also captured metadata related to the source of data and the confidence in the value (for example, data from primary sources has a high confidence, while modeled data has lower confidence). All of the data is robust for aggregate analysis, while high confidence data is better suited to customer-level marketing and program targeting.

**Household Income:** Income data could be matched to 75% of households in Idaho Power's Oregon service territory. To estimate the incomes for the remaining 25%, we used an interpolation procedure.

For households with missing income data, an estimated income was calculated as the average of the incomes of the three geographically closest households. Households that received LIHEAP were assigned an income under 150% of the Federal Poverty Limit, as their income had been verified as falling under this limit. The income of households that had estimated incomes under the median income for the region, but who lived in expensive homes were adjusted upwards. Realistically, a home with very high housing costs is unlikely to be low-income.

*Validation:* The median income in the region closely matches the median household income estimates from the American Community Survey.

**Poverty Status:** The number of people living in a household cannot be easily obtained from any public data sources. This makes it difficult to identify a household's poverty status compared to the Federal Poverty Limit or the Area Median Income, both of which are defined by household size. The median household size in the three Idaho Power counties varies from 2.3 to 2.8. In general, we used the income limits for three person households in this analysis as they produced the most accurate estimates of poverty compared to census data.

*Validation:* According to the US Census Bureau, between 16-20% of households in counties served by Idaho Power would fall under 100% of the Federal Poverty Limit. In this assessment, the poverty rate is 16-22%, depending on the household size used to determine the income thresholds (3-person vs 4-person), which is within the census range.

**Building type:** Meters were classified into one of five building types: single family, mobile homes and auxiliary dwelling units, multifamily apartments, commercial or master metered and unoccupied. Commercial meters were those tagged with a specific commercial use by the county assessor or that were on a commercial rate class. Additionally, we filtered out meters using in excess of 60,000 kWh per year as those are likely associated with commercial uses or are master metered. Meters that showed energy consumption less than 1200 kWh/year were flagged as potentially unoccupied.

Overall, the number of household meters excluding commercial, seasonal and unoccupied meters was approximately 12,800. Addresses with multiple units or tagged as multifamily properties by the county assessor were flagged as apartments. Mobile homes were either labelled as such by the county assessor or were sited in a mobile home park. Non-multifamily homes with addresses but without an identified land parcel are usually accessory dwelling units, trailers or mobile homes – these were all included in the “mobile home/secondary” category.

*Validation:* The aggregate housing type counts (62% single family/duplex, 7% multifamily and 31% mobile/ADU homes) are relatively similar to data from Idaho Power’s residential end use survey (65% single family and 26% mobile/manufactured homes). Some single family homes might be misclassified as ADUs in this assessment due to a failed address match.

**Homeownership Status:** Homeownership status (rent vs. own) was determined using two methods. The demographic dataset included homeownership for approximately 75% of customers. For the other 25%, households in multifamily apartments were tagged as “Likely Renters”, and households without any account changes during the two year analysis period were tagged as “Likely Homeowners”. Households with an account change and an accompanying sales record were also tagged as “Likely Homeowners”. This approach can potentially undercount long-term renters and tag them as homeowners. However, the accuracy of the approach seems sufficient for the purposes of large-scale aggregate analysis as in this study.

*Validation:* The owner-occupied housing rate from the American Community Survey is 59% in Malheur county (which represents 87% of Idaho power's service area). The homeownership rate from this analysis is 60%, and the two estimates fall within each other's margin of error.

**Load Disaggregation and Heating Type:** A simple load disaggregation was applied for all households using their monthly energy bills. This involved taking the tenth percentile of monthly energy use (normalized by the number of days in a billing period) as the assumed base load. Then, the energy use that exceeded the base load in the winter months (October through April) was designated as "heating-related energy use", while the energy use that exceeded the base load in the summer months (May through September) was designated as "cooling-related energy use".

Homes with a heating-related energy use that exceeded 15% were flagged as potentially utilizing electric heat (primary or secondary), while homes with under 15% heating-related energy use were flagged as non-electrically heated homes.

*Validation:* The approach has been previously tested by Empower Dataworks vs. a variable-base degree day regression and it yields similar results but at a much smaller computational cost.

**Energy Burden and Energy Efficiency Potential thresholds:** These thresholds were set as follows:

- Electrically heated:
  - High-burden threshold: Greater than 6%
  - High efficiency potential threshold: Greater than 14 kWh/sq.ft.
- Non-electrically heated:
  - High-burden threshold: Greater than 3%[1]
  - High efficiency potential threshold: Greater than 7 kWh/sq.ft.

**Energy Burden:** Energy burden for a household is calculated simply by dividing annual electricity expenses by gross household income.

$$Energy\ Burden\ [\%] = \frac{Annual\ Electricity\ Expenses\ [\$]}{Annual\ Household\ Income\ [\$]}$$

**Excess Burden:** Excess burden is the portion of a household's energy burden in excess of the 6%/3% threshold.

$$\begin{aligned} Excess\ Burden\ [\$] \\ &= \max(0, Energy\ Burden\ [\%] \\ &- High\ Burden\ Threshold [\%]) \\ &\times Annual\ Household\ Income [\$] \end{aligned}$$

**On-Time Payment Rate:** This is the proportion of all energy bills that did not require a late payment or disconnect notice to be sent out.

**Energy Assistance Funding:** The dollar amount of funding flowing through energy assistance programs (including discount, donation and weatherization programs) through discounts or rebates.

[1] The current accepted high energy burden threshold (6%) is a rule of thumb developed by Fisher, Sheehan and Colton based on total household energy expenses (gas + electricity + delivered fuels). There is currently no guidance on flagging high burden for non-electrically heated homes. The state of New Jersey uses a split high burden threshold by fuel: for customers with natural gas and electric service from different utilities, no more than 3% of income should be devoted to each. We use this as a guideline for non-electrically heated homes in this assessment, recognizing that there could be different interpretations or methods for designating customers as "high-burden".

**Customer Bill Reductions** (**Avoided Burden**)**:** The total bill impact (in dollars) from energy assistance programs. This is the same as the assistance funding for direct assistance programs and is based on measure savings for energy efficiency programs as described in Section 1.2.

**Avoided Need:** The total bill impact (in dollars) from energy assistance programs, specifically for program participants flagged as “high-burden”. Bill impact is equal to the amount of assistance grants or discounts for direct assistance programs and is equal to measure savings (kWh/year) multiplied by the residential kWh rate ($/kWh) for energy efficiency programs.

**Census Tract Statistics:** Since each customer has been mapped to a census tract and block group, we are also able to match customers to census tract average statistics (e.g. highly impacted communities, presence of children, non-English speakers, education level, environmental pollution etc.).

**Energy Assistance Need:** This is the sum of excess burden across all customers.

# 1.4 SOURCES OF UNCERTAINTY

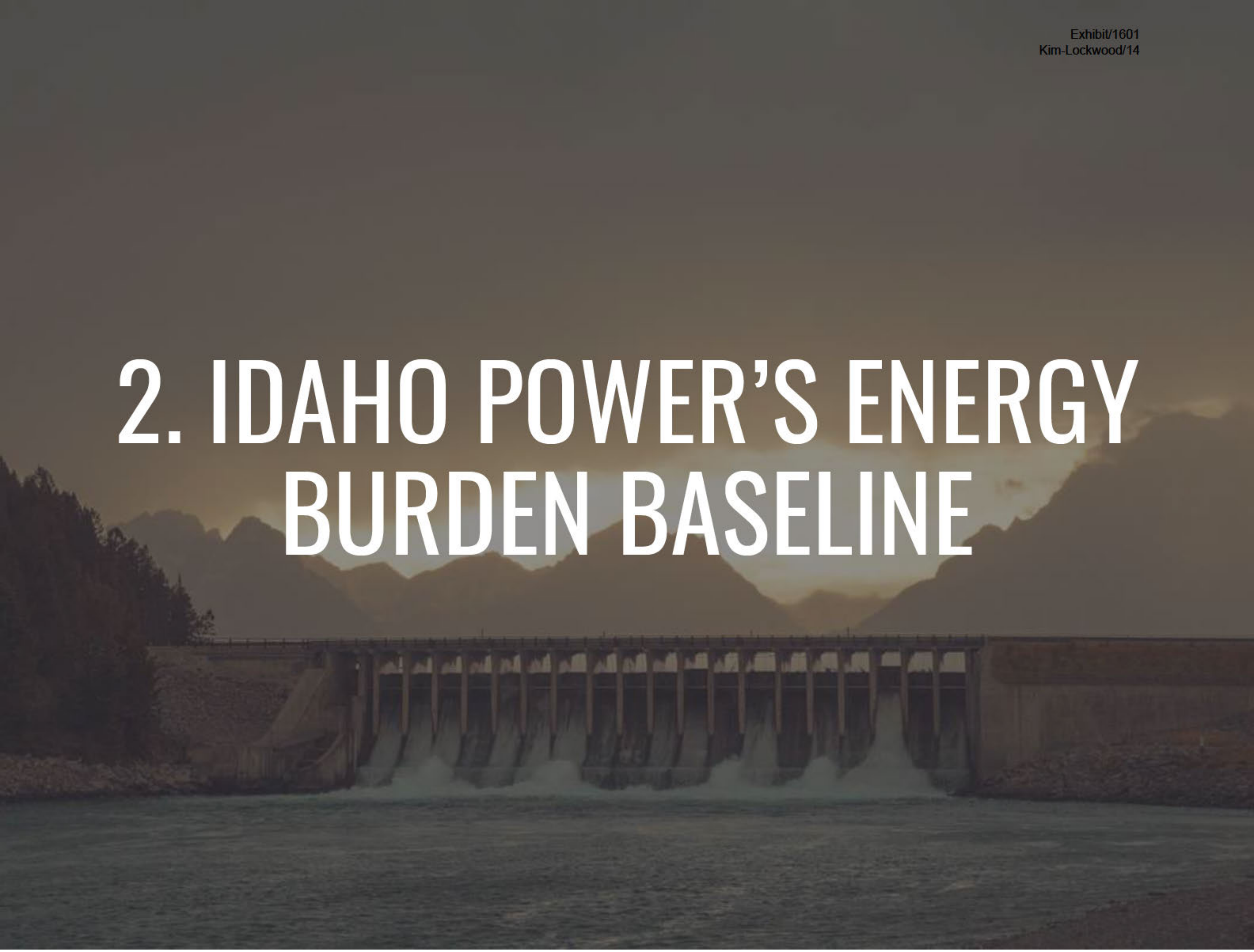
- **Household income** is a dynamic piece of data as residents move in and out of homes and income data can become outdated within a year or two.

- **Poverty status.** Since household size cannot be reliably captured through any available data source, household poverty status is subject to uncertainty. The Federal Poverty Limit and State Median Income both use household size as a scaling factor. In this analysis, we have used income thresholds for 3-person households for consistency and clarity, but they may under-estimate or over-estimate the actual income eligibility depending on the actual sizes of low-income households in this service area.

- **Individual vs. aggregate data usage.** The underlying dataset has customer-level flags for data quality – data from primary sources is considered high quality while modeled data is considered medium or low quality, depending on the availability of supporting sources of information (example, home values and location). Higher quality data can be used for individual program targeting, lower quality data can be used for program design and aggregate reporting.

- **Building types.** There is some uncertainty in the classification of building types as described in Section 1.3. This could results in misclassifying non-residential meters as occupied households or single family homes as auxiliary dwellings.

- **Achievable reductions in energy assistance need.** This analysis presents a *technical* energy assistance need based on energy burden. However, in our experience with energy assistance programs in general, many customers may not participate in programs, regardless of program design or available benefits due to a variety of barriers like access to information, application process difficulties, stigma and lack of trust. Understanding the *economically achievable* reduction in energy assistance need through utility programs would require a qualitative research of non-participants in a utility's service area.



# 2. IDAHO POWER'S ENERGY BURDEN BASELINE

# 2.1 IDAHO POWER OREGON RESIDENTIAL SECTOR PROFILE

Idaho Power's service territory in Oregon was composed of approximately **12,800 occupied households** (with a detectable energy use and not designated as shops, garages or commercial properties).

**Ethnicity:** According to the U.S. Census Bureau, approximately 63% of residents in Idaho Power's Oregon service area are non-Hispanic white. Hispanic residents comprise 32% of the population, mainly concentrated in Malheur county.

**Household Income:** The median household income for residents in Idaho Power's service area is approximately $48,000, well below the state average of $66,000. Approximately **19%** of households would fall under 100% of the federal poverty limit, and **62%** of residents would fall under 60% of the State Median Income. An additional 15% of households earn between 60-80% of the state median income. These "borderline" customers would be ineligible for almost all energy assistance programs, but still bear a relatively high level of energy burden. Designs for programs that are ratepayer-funded should take into account the degree of additional burden that would be imposed on these customers.

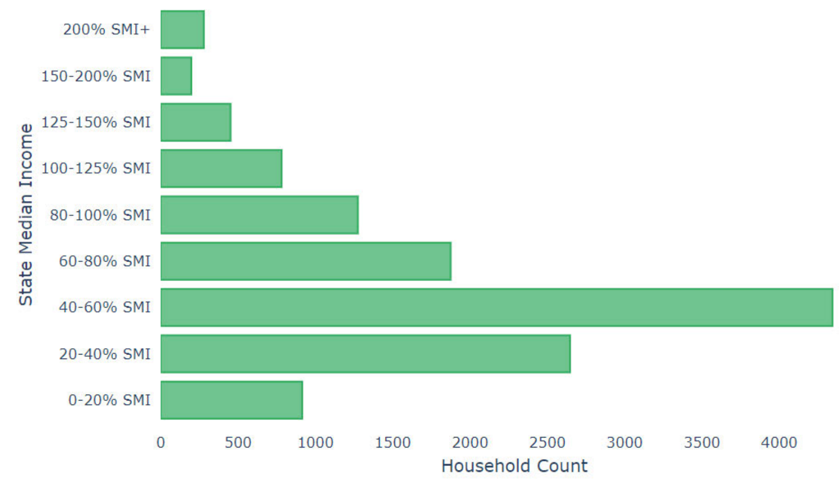



**Figure 1. Household income as a percent of state median income for Idaho Power's Oregon residential customers**

**Energy Bills:** Idaho Power residential electricity rates are about average for the region. Annual energy bills average **approximately $1,550/year with an average annual consumption of 15,400 kWh**, with approximately 66% of customers using electricity as a primary or secondary heating fuel. Figure 2 shows the distribution of annual electricity bills; with about half of households paying more than $1,380/year on their bills.

**Home Vintage:** Of the homes with a known age, approximately 23% were built after 1980, 53% were built between 1940 and 1980[2], with the remainder built prior to 1940. Older homes have more opportunities for weatherization, while newer homes could benefit more from lighting, controls and efficient appliances.

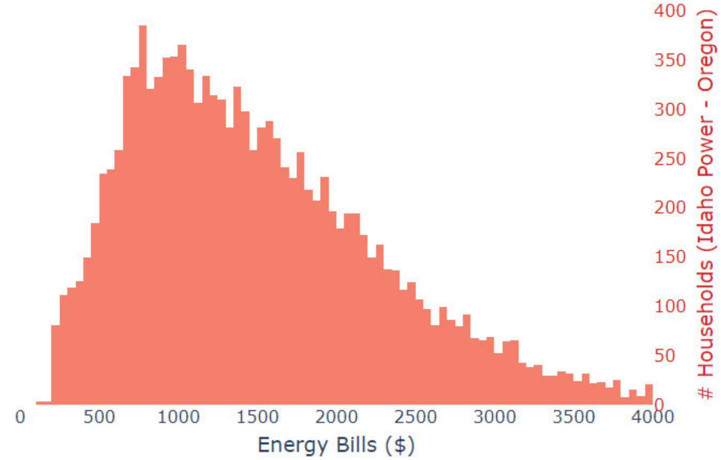



**Figure 2. Household electricity bill distribution for Idaho Power's Oregon residential customers**

[2] County Assessor Data for Malheur, Baker and Harney counties.

# 2.2 ENERGY BURDEN

Idaho Power customers have an **average and median electricity energy burden of 4.2% and 3%**, respectively. Figure 3 compares Idaho Power's median energy burden to values published in other jurisdictions. The median burden is comparable to rural regions in the Pacific Northwest.

The average household paid $1,550/year in electricity bills in 2021-22. Of 12,800 identified households, **3,500 were deemed to have a high energy burden**, meaning that annual electricity bills exceeded 6% of their income for electrically-heated homes and exceeded 3% of their income for non-electrically heated homes. These high-burden customers paid an average of $2,100 in annual electricity bills; the higher bill average reflects their higher likelihood to live in less efficient or older homes. The **total energy assistance need for Idaho Power customers in Oregon is approximately $2.7M**—the total reduction that would bring all customer electricity bills below the high burden threshold (6% of income for electric heat and 3% for non-electric heat).

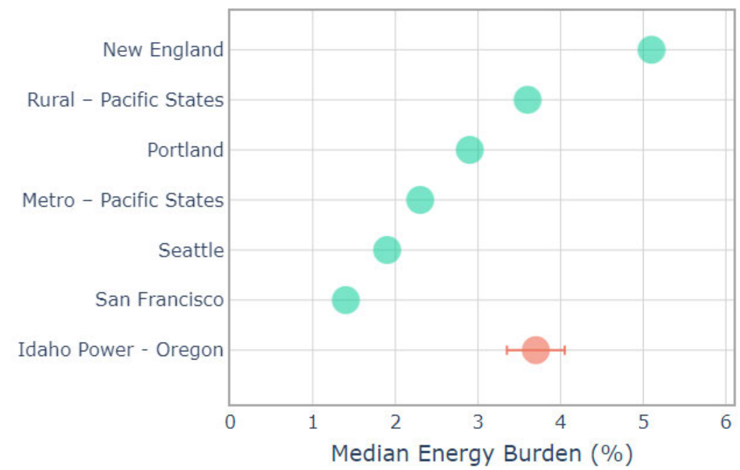



**Figure 3. Energy burden benchmarking vs. other regions**

Idaho Power's energy charge in its residential retail rate is between 8 and 10 cents/kWh, which is in line with other utilities in the region and below the national average of 16 cents/kWh. Therefore, low incomes and high energy use, rather than rates, appear to be the most significant drivers of high energy burden in the area.

Although averages and medians give a general indication of energy burden across a service territory, the reality is that **energy burden is a customer-level metric** and its distribution is a better indicator of the burden that customers experience. The distribution of energy burden among Idaho Power customers is shown in Figure 4.

The goal of an effective energy assistance portfolio should be to prioritize the customers who most need the assistance, i.e. the customers to the right of the 6%/3% thresholds.

Approximately 58% of the energy assistance need is borne by single family households, with 38% in mobile homes and the remainder in multifamily homes. The highest concentration of need is in mobile homes, requiring more than $820/burdened household in assistance on average, compared to $780/burdened household for single family and $470/burdened household multifamily households.

Approximately 37% of the energy assistance need for Idaho Power customers is among renters, indicating that conservation programs targeted at high-burden customers will need to grapple with the split incentive problem between landlords and tenants, but energy burden among homeowners is the more significant category in general. Other customer segments can be investigated in more detail in the data dashboard.

Number of Households

**~12,800**

Low Income Households

60% SMI*: **~8k**

150% FPL: **~4k**

Energy Burden
(Electricity)
Median: **~3%**
Average: **~4.2%**

High Burden Households

**~3,500**

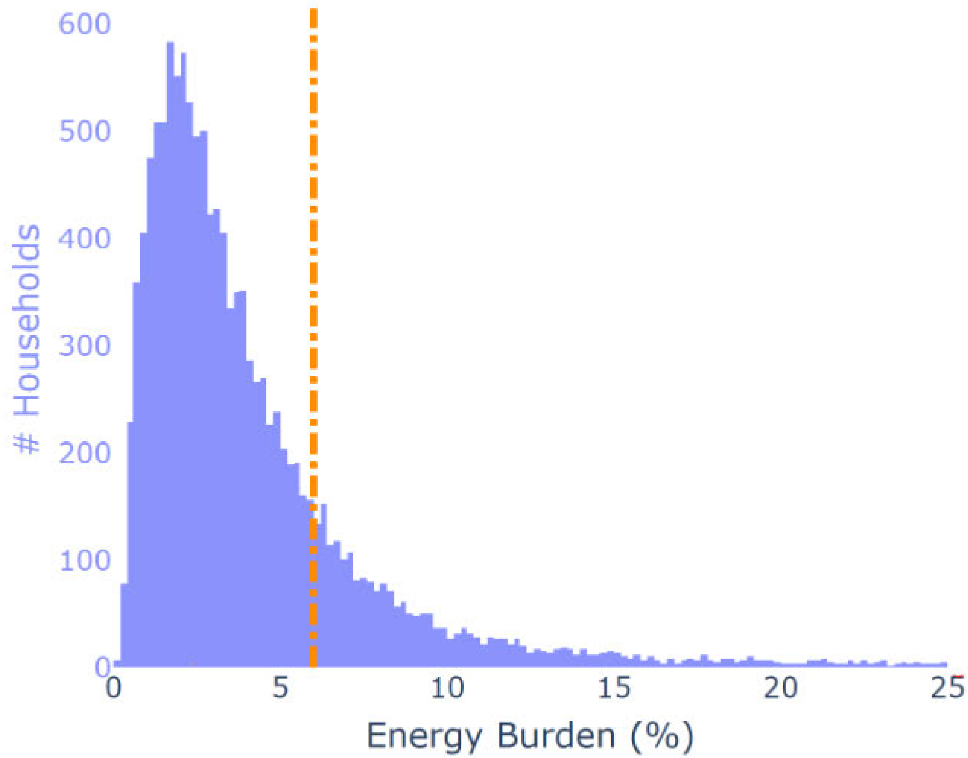



**Figure 4. Distribution of energy burden among Idaho Power - Oregon customers.**
**Figure shows all homes but dashed line indicating 6% high energy burden threshold applies to electric heat households.**

# 2.3 CONSERVATION VS DIRECT ASSISTANCE

Figure 4 shows the distribution of energy burden and energy efficiency potential (defined through Energy Use Intensity thresholds) across all low-income residential customers. In a perfect world, the energy assistance portfolio would match these customer segments. For example:

- Conservation and weatherization programs should primarily serve **high burden, high potential** households
- Direct assistance programs should primarily serve **high burden, low potential** households
- Crisis/emergency programs should primarily serve **low burden, low potential** households
- Traditional conservation programs with financing should serve **low burden, high potential** households

Aligning targeted customers with program strengths results are the most cost-effective pathway to energy burden reduction.

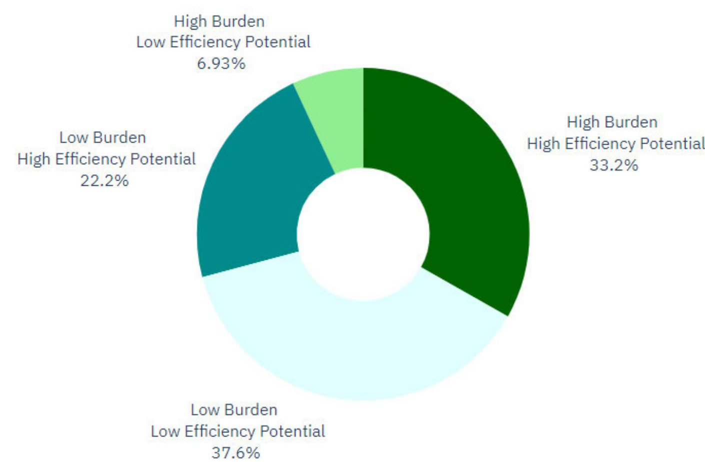



**Figure 5. Idaho Power Oregonlow-income customer segments by energy burden and energy efficiency potential.**

Approximately 38% of Idaho Power's low-income customers are low-burden and low-efficiency potential. These customers' energy bills may not be a huge expense relative to housing, medical and education expenses, and they should not be prioritized in the more intensive programs, such as weatherization.

33% of high burden customers also have a high efficiency potential indicating that the energy assistance program mix should equally prioritize sustained energy burden reductions through energy efficiency and weatherization. At the same time, we should recognize that scaling up low-income weatherization faces a host of barriers and these customers are in need of more immediate assistance options (through rates, grants or discounts).

# 3. KEY CUSTOMER SEGMENTS

# 3.1 OVERVIEW

This section presents statistics and profiles related to 3 key customer segments in Idaho Power's Oregon service area. These customer segments were selected for a combination of reasons:

1. Flagged in this assessment as having high overall burden or high prevalence of energy burden
2. Identified as having low access to existing programs
3. Identified as vulnerable through the Department of Energy's environmental justice screen

This analysis is primarily geographic, focusing on specific neighborhoods. The maps in the following sections display the level of energy assistance need in these areas as well as locations of social services for potential outreach.

These customer segments represent a big portion, but not the entirety of the high energy burden among Idaho Power's customers, so they should be targeted for any new programs or initiatives in the future using lists of customers who live in the block groups identified below.

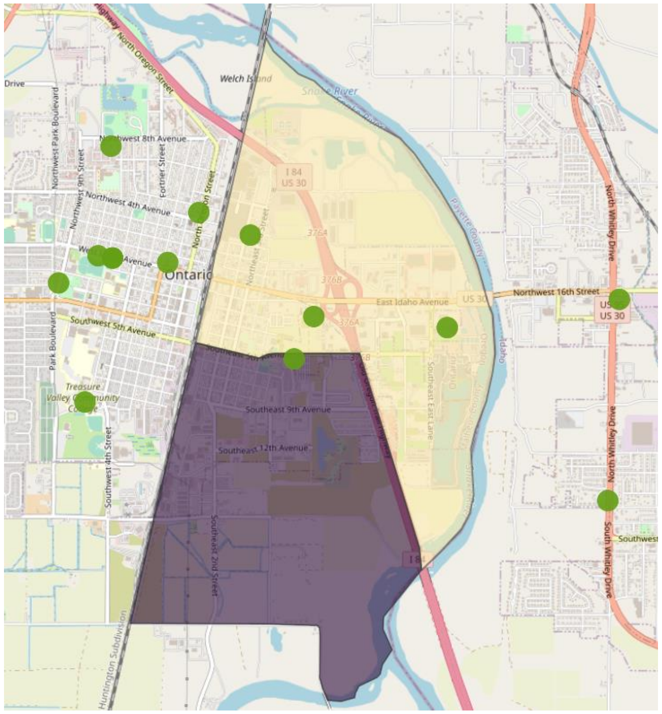
# 3.2 ONTARIO - EAST

Census block groups: **410459704003, 410459704005**

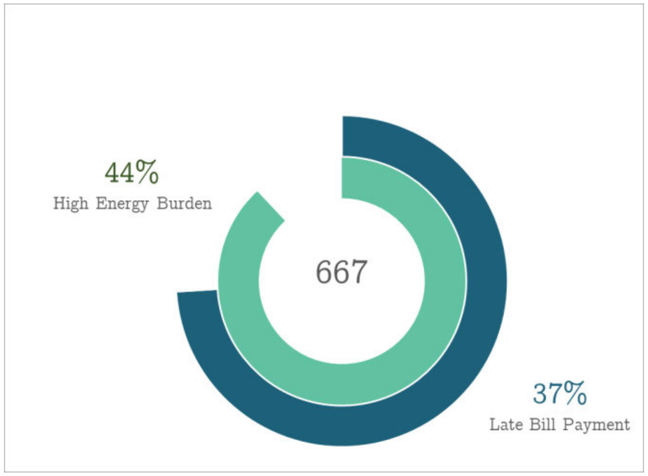
Total Assistance Need: **$235k** (**9% of total need**)

Total Assistance Funding: **$121k** (**13% of total funding**)

DOE Disadvantage Score: **5**




**PROFILE:** Customers in Eastern Ontario are a highly disadvantaged community with over 65% people of color (mostly Hispanic) and over 10% of the population living in linguistic isolation. Members of this community tend to be renters (58%) living in older homes (69 years old on average). 76% of these customers rely on electricity as a heating fuel with correspondingly higher bills, late payments and service disconnections. The area is partly commercial/industrial and has historically had a high crime rate. On the other hand, it appears to be well served by Community in Action, whose main office is located in the neighborhood.




**RECOMMENDATIONS:** This area is relatively densely populated and can be effectively reached through social media as well as by connecting to large property managers. On-site energy bill clinics or door-to-door canvassing could also provide a positive customer touchpoint for encouraging customers to apply to assistance programs.

# 3.3 MALHEUR – OUTLYING AREAS

Census block groups: **410459707001, 410459705006**

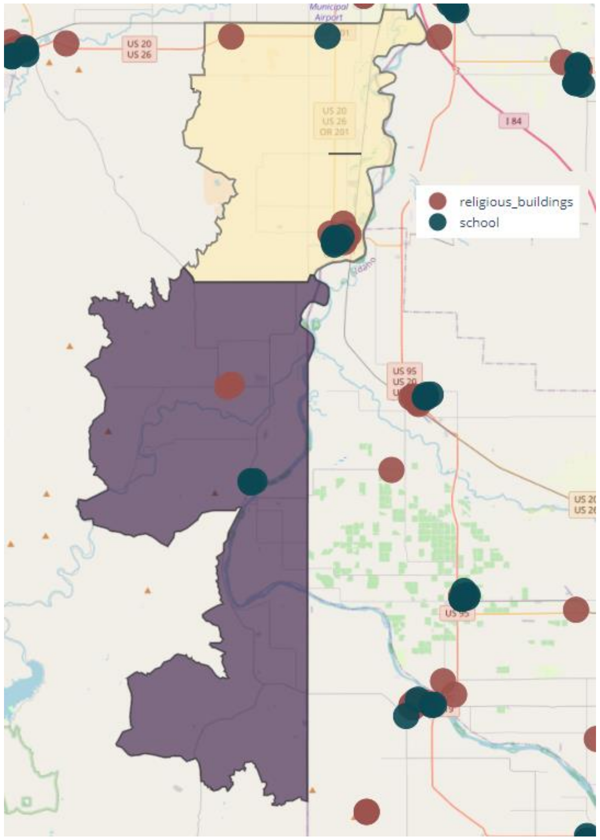
Total Assistance Need: **$253k (9% of total need)**

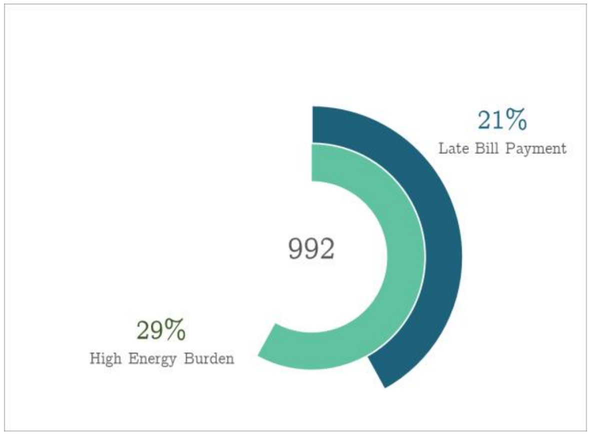
Total Assistance Funding: **$23k (2% of total funding)**

DOE Disadvantage Score: **0**

**PROFILE:** The area to the east and south of Nyssa has a moderate level of energy burden, with 29% customers experiencing high energy burden. The region was flagged for its low access to existing assistance program with a program participation rate among eligible customers of less than 6%. The closest energy assistance center is more than 20 miles away as the crow flies and customers in these areas are potentially not as aware of programs for which they may be eligible. Most of these residents are homeowners living in single family or mobile homes.

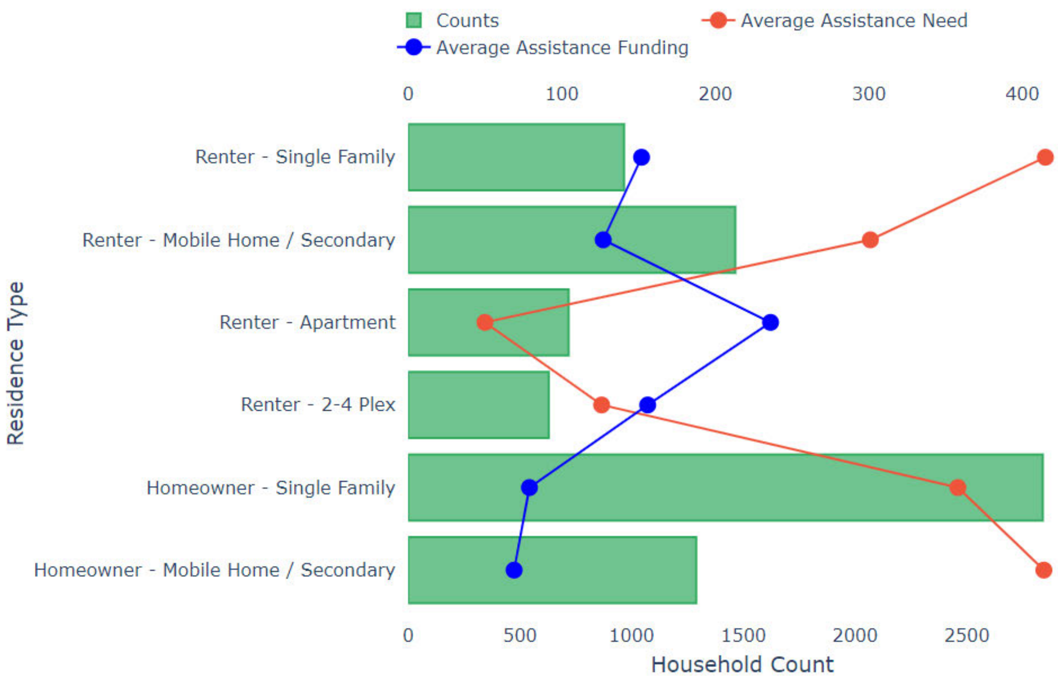
**RECOMMENDATIONS:** The area should be prioritized for weatherization or lighter touch energy efficiency (e.g. energy savings kits, thermostats and air sealing), as 64% of customers have a high energy savings potential. Outreach through traditional community based organizations may be challenging because of location, but connecting with the schools in Adrian and local churches might be more productive.



# 3.4 MOBILE HOME OWNERS

**PROFILE:** The figure to the right shows the energy assistance need and average energy assistance funding for all low-income customers in Idaho Power's Oregon service area, categorized by housing type and homeownership. In general, it appears that apartment dwellers are relatively well-served by existing programs as the gap between average need and average funding is very small (or negative in some cases). On the other hand, the least well-served segment appears to be homeowners living in mobile homes.




**RECOMMENDATIONS:** In addition to building partnerships with trailer park managers, local schools, churches and community organizations, it is recommended to develop targeted energy assistance marketing campaigns (direct mail and email) for these customers through the dataset developed in this assessment. These customers are more rural and local presence is an important factor - satellite offices of agencies or local community-based organizations can be very effective at reaching these customers. Consideration of an online application process or making program information easier-to-find online can also be helpful in facilitating customer applications.

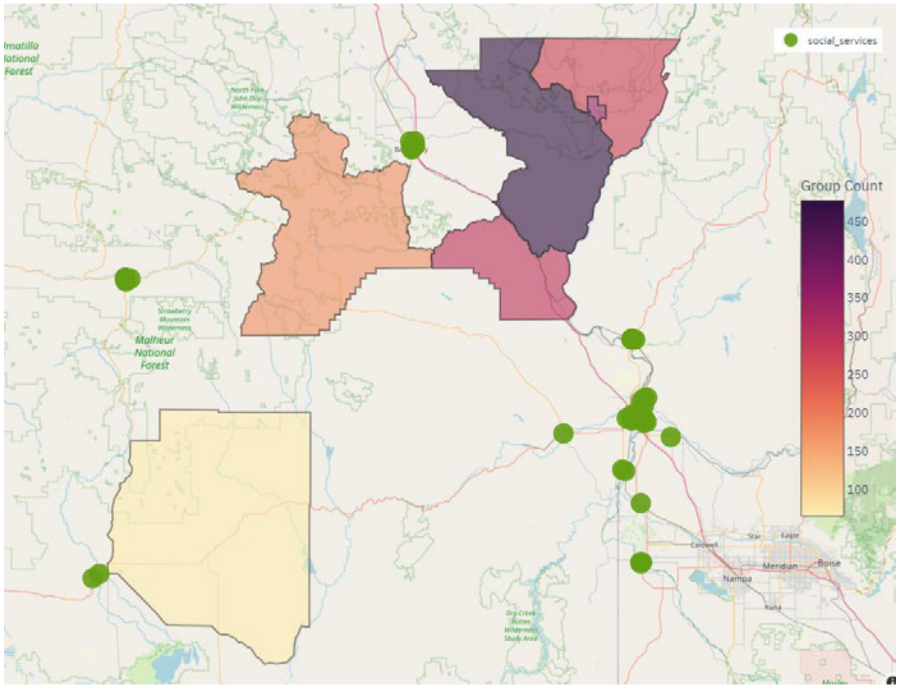
# 3.5 BAKER/HARNEY – OUTLYING AREAS

Census block groups: **41001950600, 41001950300, 41001950100**

Total Assistance Need: **$341k (13% of total need)**

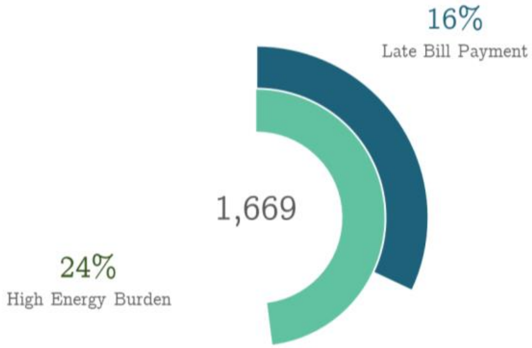
Total Assistance Funding: **$50k (5% of total funding)**

DOE Disadvantage Score: **0.2**




**PROFILE:** Some pockets in Baker and Harney counties also suffer from a high level of energy burden, especially in the Eastern part of Baker County. Moreover, these areas are rural and physically distant from services. A large percentage of these customers live in mobile homes, secondary units or ADUs.

**RECOMMENDATIONS:** Outreach through traditional community based organizations may be challenging because of location, but connecting with the schools in Keating and Huntington or distributing flyers in local business in Richland and Crane would help reach customers in these more remote areas.



CASE: UE 426
WITNESS: Anna Kim and Charles Lockwood

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 1602

## Exhibits in Support
## Of Opening Testimony

**March 25, 2024**

**Staff Workpaper titled UE 426 OT 1602
Workpaper is available in electronic
spreadsheet format only**

CASE: UE 426
WITNESS: Anna Kim and Charles Lockwood

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1603

## Exhibits in Support
## Of Opening Testimony

**March 25, 2024**

**TOPIC OR KEYWORD: Low-Income Weatherization**

**<u>STAFF'S DATA REQUEST NO. 265</u>:**

Please provide an overall narrative description and any associated workpapers related to the administration and performance of Idaho Power's low-income weatherization. Please also provide the following information.

a. How many homes have been weatherized in each state, by year and program in the Company's service territory over the last ten years
b. Oregon territory home energy scores by zip-code.
c. Does the Company perform energy assessments? If so, please provide and describe the methodology used for the assessments, the Company's actions relative to assessment results, the administrating body and compensation—if third party, and any tracked data relative to the results of energy assessments, by year, zip-code, and income brackets, if available.

**<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 265</u>:**

The Weatherization Assistance for Qualified Customers ("WAQC") program provides financial assistance to regional Community Action Partnership ("CAP") agencies in Idaho Power's service area. This assistance helps fund weatherization costs of electrically heated homes occupied by qualified customers who have limited incomes. Weatherization improvements enable residents to maintain a more comfortable, safe, and energy-efficient home while reducing their monthly electricity consumption and are available at no cost to qualified customers who own or rent their homes. These customers also receive educational materials and ideas on using energy wisely in their homes. Regional CAP agencies determine participant eligibility according to federal and state guidelines. The WAQC program also provides limited funds to weatherize buildings occupied by non-profit organizations that primarily serve special needs populations, regardless of heating source, with priority given to electrically heated buildings.

In 1989, Idaho Power began offering weatherization assistance in conjunction with the State of Idaho Weatherization Assistance Program ("WAP"). In Oregon, Idaho Power offers weatherization assistance in conjunction with the State of Oregon WAP. This allows CAP agencies to combine Idaho Power funds with federal weatherization funds to serve more customers with special needs in electrically heated homes.

Idaho Power has an agreement with each CAP agency in its service area for the WAQC program that specifies the funding allotment, billing requirements, and program guidelines. Currently, Idaho Power oversees the program in Idaho through five regional CAP agencies: Eastern Idaho Community Action Partnership ("EICAP"), El Ada Community Action Partnership ("EL ADA"), Metro Community Services ("Metro Community"), South Central Community Action Partnership ("SCCAP"), and Southeastern Idaho Community Action Agency ("SEICAA"). In Oregon, Community Connection of Northeast Oregon, Inc. ("CCNO"), and Community in Action ("CINA") provide weatherization services for qualified customers.

Please see attachments 1-8 for this response for the associated workpapers.

- Agencies begin the process with a customer application for weatherization assistance - Attachment 1 provided for this response.

- Once qualified, a weatherization manager visits the customer's residence to perform a weatherization audit - Attachments 2 and 3 provided for this response (for mobile and stick built homes).
- Agencies weatherize the home according to their state Weatherization Operations Manual, published by the Oregon Housing and Community Services Department - Attachment 4 provided for this response.
- Agencies provide Idaho Power an invoice with a corresponding Job Cost Calculator for each job requesting payment - Attachments 5 and 6 provided for this response.
- CAP Agency staff provides a Customer Survey for the customer to complete after the job is finished - Attachments 7 and 8 provided for this response (English and Spanish).

a. The table below shows the number of homes weatherized in each state, by year and program over the last 10 years below.

| | IDAHO HOMES | | OREGON HOMES |
|---|---|---|---|
| **Program:** | **WAQC** | **WEATHERIZATION SOLUTIONS** | **WAQC** |
| 2014 | 239 | 118 | 11 |
| 2015 | 225 | 171 | 10 |
| 2016 | 231 | 232 | 12 |
| 2017 | 194 | 164 | 7 |
| 2018 | 188 | 141 | 3 |
| 2019 | 189 | 129 | 4 |
| 2020 | 115 | 27 | 0 |
| 2021 | 161 | 7 | 1 |
| 2022 | 147 | 27 | 0 |
| 2023 | 161 | 12 | 5 |

b. Idaho Power does not calculate, track, or utilize home energy scores.

c. The Company does not perform energy assessments. Energy assessments are performed by CAP Agency weatherization personnel as part of the low-income weatherization programs.

CASE: UE 426
WITNESS: STEPH YAMADA

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1700

# OPENING TESTIMONY

## March 25, 2024

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

A. My name is Steph Yamada. I am a Senior Utility Analyst employed in the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program (RSUP) 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/1701.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to provide background, analysis, and recommendations regarding the Company's Test Year inclusions for wages, salary, incentives, and full-time equivalents (FTE).

**Q. Did you prepare any exhibits for this docket?**

A. Yes. In addition to my witness qualifications statement provided in Exhibit Staff/1701, I prepared the following supporting exhibits: Exhibit Staff/1702 (Idaho Power's Non-Confidential DR Responses), Exhibit Staff/1703 (Idaho Power's Confidential DR Responses), and Exhibit Staff/1704 (Staff Workpapers).

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

Issue 1. Salaries & Wages .......... 3
CONF Figure 1: Test Year Salaries, Wages, Overtime.......... 4
CONF Figure 2: W&S Model Adjustments, Base Salaries & Wages.......... 7
CONF Figure 3: W&S Model Adjustments to Overtime.......... 8
Issue 2. Incentives.......... 10

Figure 4: Staff's Initial Incentives Adjustment – System Level .................. 12
Issue 3. FTE ........................................................................................ 13
CONF Figure 5: Company Proposed FTE – System Level ....................... 13
CONF Figure 6: Staff's Officer FTE Adjustment....................................... 14
Issue 4. Other Related Adjustments ............................................................. 15
Figure 7: Summary of Staff's Adjustments – Oregon ................................ 16

**Q. Could there be changes or updates to Staff's position and recommendations?**

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

## ISSUE 1. SALARIES & WAGES

**Q. Please summarize the Company's proposal for salaries and wages in this case.**

A. The Company proposes to include operations and maintenance (O&M) labor totaling $183,317,379 at the system level in the Test Year.[1] However, that amount includes only the expensed portion of the associated labor cost and ignores any amounts attributable to capitalized labor. The $183,317,379 amount also includes O&M labor loadings of $60,578,358.[2]

**Q. Has Idaho Power identified the amount of capitalized labor it proposes to include in the Test Year?**

A. No. The Company explains that its $183,317,379 O&M labor proposal was developed by adjusting August 2023 year-to-date actuals through to the end of 2023 and then applying a three percent general wage adjustment.[3] Capital labor was not forecasted separately for the Test Year and is embedded in the forecast of Test Year plant closings.[4] According to the Company, the amount of capitalized labor embedded in the Test Year rate base is not separately identifiable due to the methodologies used to develop Test Year costs.[5]

**Q. What assumptions did Staff make regarding the total amount of labor reflected in the Company's Test Year, including capitalized labor?**

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1 Idaho Power/1002, Larkin/12.
2 Staff/1702, Idaho Power's response to Staff's DR 347.
3 Idaho Power/1002, Larkin/11-12.
4 Staff/1702, Idaho Power's response to Staff's SDR 93.
5 February 7, 2024, Staff/Idaho Power Labor Discussion.

A. Staff assumed the Projected Test Year compensation Idaho Power reported in response to discovery requests reflects the total amount included in the Test Year, including both capitalized and expensed labor. These amounts are summarized in Figure 1.[6] Staff made this assumption because Staff cannot complete its salary & wage analysis without consideration of capitalized labor and the amount of capitalized labor included in the Test Year is not yet known or may be unknown, as described in response to the previous question.

**CONF FIGURE 1: TEST YEAR SALARIES, WAGES, OVERTIME**

**[BEGIN CONFIDENTIAL]**

| Category | Base Salaries & Wages | Overtime |
|---|---|---|
| Officers | [redacted] | |
| Exempt | | |
| Nonexempt | | |
| Union | | |
| **Total** | | |

**[END CONFIDENTIAL]**

These figures include **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[7]

**Q. How does the Company determine employee compensation?**

A. When a job is created, the Company establishes base compensation using peer wage data obtained from salary surveys and union contracts, along with similar internal positions already matched to market data.[8] The Company

6 Staff/1703, Idaho Power's Supplemental Response to Staff's SDR 92, CONFIDENTIAL Attachment.

7 Staff/1703, Idaho Power's Supplemental Response to Staff's SDR 92, CONFIDENTIAL Attachment.

8 Idaho Power/700, Griffin/11, Lines 7-10.

explains that it uses a grade and step pay system wherein Step 13 represents the highest step in any grade, and that it sets Step 13 to be approximately equal to the median market pay.[9] The Company also undergoes a longer term job review process to ensure base wages are competitive and appropriate relative to market.[10]

**Q. Please provide a summary of the Commission's historical method for determining the amount to include in a utility's revenue requirement for salaries and wages, including overtime.**

A. The Commission generally determines the appropriate level of wages and salaries for employees in the Test Year using Staff's three-year wage and salary (W&S) model to estimate union and non-union payroll levels for energy utilities.[11,12] The model calculates 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 labor) or negotiated increases (for union labor). The model then applies a sharing mechanism between the wages and salaries determined by the W&S model and the wages and salaries proposed by the utility. In the

9 Idaho Power/700, Griffin/11, Lines 18-22.
10 Idaho Power/700, Griffin/12-13.
11 *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).
12 *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).

case of Idaho Power, the issue of union labor is not relevant as the Company does not utilize any such labor.

**Q. Why has the Commission used the W&S model to determine Test Year expense for non-union wages and salaries?**

A. The Commission has explained its rationale in previous orders. For example, in an order issued in 1999, the Commission explained:

> The [Three Year] model incorporates actual market-based data by using, as a starting point, actual historic wages. We also agree with Staff's use of the All-Urban CPI index to adjust historic wages and salaries. Adjusting payroll levels by changes in inflation provides the employees the same real level of compensation as in the base year and provides an incentive to companies to minimize labor costs. Contrary to the assertions by NW Natural, 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. Moreover, Staff's method of sharing the difference between payroll projections equally between ratepayers and shareholders also allows NW Natural some ability to increase wages above the rate of inflation in response to changes in market conditions without allowing unchecked escalation.[13]

**Q. Please explain how Staff used the Three-Year W&S model to arrive at its recommendation for base wage and salary levels for the Test Year.**

A. Consistent with the W&S model, Staff began with actual wage information from three years prior to the Test Year.[14] With a Test Year of 2024 in this case, Staff began with 2021 wage information and escalated it to 2024 using All-Urban CPI rates, which are 8.0 percent for 2022, 4.1 percent for 2023, and

[13] *In the Matter of Northwest Natural*, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999).

[14] Staff/1703, Idaho Power's Supplemental Response to Staff's SDR 92, CONFIDENTIAL Attachment.

2.7 percent for 2024.[15] Staff then applied the sharing principle to Staff's and the Company's projected 2024 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, results in a ($1,581,252) adjustment to Staff's projection in the nonexempt employee category at the system level. The results of Staff's analysis are summarized in Figure 2 as follows.

**CONF FIGURE 2: W&S MODEL ADJUSTMENTS, BASE SALARIES & WAGES**

**[BEGIN CONFIDENTIAL]**

| Description | Officers | Exempt | Nonexempt | Total |
|---|---|---|---|---|
| Actual Base Payroll (2021) calendar year | [redacted] | [redacted] | [redacted] | [redacted] |
| Ave. # of Employees (FTE) (2021) | [redacted] | [redacted] | [redacted] | [redacted] |
| Average Salary | [redacted] | [redacted] | [redacted] | |
| Allowable % Increase | [redacted] | [redacted] | [redacted] | |
| Ave. # of Employees (FTE) (Test Year) | [redacted] | [redacted] | [redacted] | [redacted] |
| Projected Payroll | [redacted] | [redacted] | [redacted] | [redacted] |
| Test Period Payroll | [redacted] | [redacted] | [redacted] | [redacted] |
| Total Difference for Sharing | [redacted] | [redacted] | [redacted] | |
| 10% Band - Allowable | [redacted] | [redacted] | [redacted] | |
| 50% Sharing of Lesser of Diff or Band | [redacted] | [redacted] | [redacted] | |
| Staff Proposed Level | [redacted] | [redacted] | [redacted] | [redacted] |
| **Net Payroll Adjustment** | **$0** | **$0** | **($1,581,252)** | **($1,581,252)** |

**[END CONFIDENTIAL]**

Finally, this adjustment is allocated 4.29 percent to Oregon,[16] and is further allocated 62.8 percent to O&M and 37.2 percent to capital.

[15] Oregon Economic & Revenue Forecast - March 2024 - Volume XLIV, No. 1, Table A.4, page 43.

[16] Idaho Power/1202, Noe/15, line 66.

The capital/O&M allocation is based on a three-year average of actual capitalized labor from 2020 through 2022.[17]

**Q. What is Staff's recommended adjustment for base salaries and wages?**

A. Staff recommends a total adjustment of ($67,836) attributable to the Company's base salaries and wages for Oregon. This amount is allocated ($42,569) to O&M and ($25,267) to capital.

**Q. Please explain how Staff used the Three-Year W&S model to arrive at Staff's overtime recommendation for the Test Year.**

A. Staff's overtime analysis follows the same methodology as that used for base salaries and wages, which was discussed previously. The results of this analysis are summarized in Figure 3, as follows.

**<u>CONF FIGURE 3: W&S MODEL ADJUSTMENTS TO OVERTIME</u>**

**[BEGIN CONFIDENTIAL]**

| **Description** | **Officers** | **Exempt** | **Nonexempt** | **Total** |
|---|---|---|---|---|
| Actual Overtime (2021) | [redacted] | [redacted] | [redacted] | [redacted] |
| Average No. of FTE (2021) | [redacted] | [redacted] | [redacted] | [redacted] |
| Average Overtime per FTE | [redacted] | [redacted] | [redacted] | |
| Allowable % Increase | [redacted] | [redacted] | [redacted] | |
| Staff Proposed Level FTE for Test Period | [redacted] | [redacted] | [redacted] | [redacted] |
| Projected Overtime | [redacted] | [redacted] | [redacted] | [redacted] |
| Test Period Overtime | [redacted] | [redacted] | [redacted] | [redacted] |
| Total Difference | [redacted] | [redacted] | [redacted] | |
| 10% Band - Allowable | [redacted] | [redacted] | [redacted] | |
| 50% Sharing of Lesser of Diff or Band | [redacted] | [redacted] | [redacted] | |
| Staff Proposed Level | [redacted] | [redacted] | [redacted] | [redacted] |
| **Net Payroll Adjustment** | **$0** | **$0** | **($496,744)** | **($496,744)** |

**[END CONFIDENTIAL]**

[17] Staff/1702, Idaho Power's response to Staff's SDR 102, Attachment.

**Q. Why is there overtime associated with exempt employees?**

A. The amounts shown under the Exempt column of Figure 3 reflect overtime associated with employees transitioning from nonexempt to exempt positions during the year.[18] The amounts represent overtime earned when the employees were classified as nonexempt and eligible for overtime.[19] The movement of existing employees from nonexempt to exempt positions is a common occurrence for Idaho Power.[20]

**Q. What is Staff's recommended adjustment for overtime?**

A. Staff recommends an adjustment of ($21,310) attributable to the Company's overtime for Oregon. This amount is allocated ($13,373) to O&M and ($7,938) to capital.

[18] Staff/1702, Idaho Power's response to Staff's DR 243.
[19] Staff/1702, Idaho Power's response to Staff's DR 243.
[20] Staff/1702, Idaho Power's response to Staff's DR 440.

## ISSUE 2. INCENTIVES

**Q. Please summarize the Company's proposal for incentives in this case.**

A. Idaho Power states that it proposes to include Test Year incentives totaling $10,273,516 at the system level.[21] This amount consists of $9,315,722 for short-term employee incentives and $957,795 attributable to the associated payroll tax.[22] These amounts are allocated 4.29 percent to Oregon.[23]

**Q. What types of incentives are reflected in the Company's Test Year proposal?**

A. Idaho Power's incentive plan consists of three components: 1) an electrical network reliability goal that considers the frequency and duration of customer outages, 2) a customer satisfaction goal that is based on customer survey responses, and 3) a profit-sharing goal based on net income.[24] The Company's rate request includes only the network reliability and customer satisfaction components, which are each included at the medium target level of two percent of payroll.[25] The Company has excluded all incentives relating to the profit-sharing goal as well as 100 percent of officer incentives.[26] Noncash incentives are excluded.[27] The Company states that its proposed incentive

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[21] Idaho Power/1002, Larkin/14.
[22] P Jeppsen – Workpaper 8 – Exhibit 901 – 2024 Incentive & Salary Structure Adjustments, Payroll-Source Page A tab.
[23] Idaho Power/901, Jeppsen/6, lines 15-16; Idaho Power/1201, Noe/15, line 566; Idaho Power/1202, Noe/15, line 66.
[24] Idaho Power/700, Griffin/17.
[25] Idaho Power/700, Griffin/18.
[26] Idaho Power/700, Griffin/18.
[27] Staff/1702, Idaho Power's response to Staff's DR 348.

expense (including payroll tax) represents a $16,325,155 reduction from 2022 actuals of $26,598,671.[28]

**Q. Please provide a summary of the Commission's historical method for determining the amount to include in a utility's revenue requirement for incentives.**

A. 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.[29] It is also Commission policy to 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.[30] In this case, the issue of union bonuses is not relevant because the Company does not utilize union labor.

**Q. Please describe Staff's analysis with regard to incentives.**

A. As discussed previously, the Company proposes to include $9,315,722 attributable to its network reliability and customer satisfaction short-term incentives, excluding payroll tax. Since these incentives are calculated as a

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[28] Idaho Power/1002, Larkin/14.
[29] 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).
[30] See Order No. 20-473 at 97; Order No. 99-697 at 44-45; Order No. 99-033 at 62.

percentage of payroll and Staff made downward payroll adjustments as described previously, Staff first made a corresponding adjustment to the Company's proposal for incentives. This adjustment is summarized in Figure 4 as follows.

**FIGURE 4: STAFF'S INITIAL INCENTIVES ADJUSTMENT – SYSTEM LEVEL**

| **Initial Adjustment – Incentives (System Level)** | |
|---|---|
| Company proposed incentives total excluding payroll tax | $9,315,722 |
| Staff adjustment to salaries, wages, overtime | -0.81% |
| Staff corresponding incentive adjustment | -$75,416 |
| **Staff adjusted starting incentive excluding payroll tax** | **$9,240,306** |

Staff then allocated this figure to exempt and nonexempt employees using the same proportions reflected in base salaries & wages. As described previously, the Company has already excluded 100 percent of officer incentives, in line with standard Commission practice. Staff further removed 50 percent of nonofficer incentives from its adjusted figure shown above, in accordance with standard Commission practice. Staff's adjustment was allocated to Oregon and to O&M/capital in the same manner as described previously for salaries and wages.

**Q. What is Staff's recommended adjustment for incentives?**

A. Staff recommends a total Oregon-allocated adjustment of ($201,440) attributable to the Company's employee incentives. This amount is allocated ($126,409) to O&M and ($75,031) to capital.

## ISSUE 3. FTE

**Q. Please summarize the Company's proposal for FTE in this case.**

A. Idaho Power proposes to include **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** FTEs in the Test Year,[31] as summarized in Figure 5, following.

**CONF FIGURE 5: COMPANY PROPOSED FTE – SYSTEM LEVEL**

**[BEGIN CONFIDENTIAL]**

| **Category** | **FTE** |
|---|---|
| Officers | 15.0 |
| Exempt | [redacted] |
| Nonexempt | [redacted] |
| Union | 0 |
| **Total** | [redacted] |

**[END CONFIDENTIAL]**

**Q. How has the Commission previously determined the appropriate FTE level for inclusion in rates?**

A. Specific methodologies may vary somewhat on a case-by-case basis. However, the Commission has previously adopted Staff's principle that A&G non-union workforce should be limited to levels forecasted as a function of customers per FTE.[32]

**Q. Please describe Staff's analysis with regard to FTEs.**

A. For exempt and nonexempt employees, Staff analyzed FTEs as a function of customers served per FTE. Staff's analysis indicated that the number of

[31] Staff/1703, Idaho Power's Supplemental Response to Staff's SDR 92, CONFIDENTIAL Attachment.

[32] See Order No. 99-033 at 63.

customers served per FTE (excluding officers) has increased by 27 percent since 2012,[33] indicating that the Company is utilizing its human resources effectively. Consequently, Staff made no adjustment to the Company's proposed FTEs for exempt and nonexempt employees.

For officers, the Company indicated that the increase from 13 officers in the 2022 Base Year to 15 in the Test Year is temporary.[34] Consequently, Staff reduced the Company's officer FTE count to 13.

**Q. What is Staff's recommended adjustment for FTEs?**

A. Staff's adjustment for officer FTEs at the system level is summarized in Figure 6 as follows.

**CONF FIGURE 6: STAFF'S OFFICER FTE ADJUSTMENT**

**[BEGIN CONFIDENTIAL]**

| Description | Amount |
|---|---|
| [redacted] | |
| **Net Payroll Adjustment** | **($717,329)** |

**[END CONFIDENTIAL]**

This adjustment is allocated between capital/O&M and to Oregon in the same manner as salaries & wages, as discussed previously. Staff's resulting recommended adjustment totals ($30,773) for Oregon, which is allocated ($19,311) to O&M and ($11,462) to capital.

33 See CONFIDENTIAL Exhibit Staff/1704, PUC FTE tab.
34 Staff/1702, Idaho Power's Response to Staff's DR 441.

## ISSUE 4. OTHER RELATED ADJUSTMENTS

**Q. Do Staff's recommended adjustments to base salaries and wages, overtime, incentives, and FTEs, as discussed previously in this testimony, result in other related adjustments to the Test Year?**

A. Yes. Staff's adjustments in these areas also result in associated reductions to depreciation expense and payroll tax.

**Q. Please explain Staff's adjustment to depreciation expense.**

A. Staff's recommended adjustments to base salaries and wages, overtime, incentives, and FTEs result in a total capital reduction of $119,698 in Oregon. The removal of this amount from rate base requires a corresponding reduction to depreciation expense. The Company's filing reflects depreciation expense representing 2.48 percent of gross plant; Staff applied that percentage to its proposed capital reduction, resulting in a ($2,974) adjustment to O&M.

**Q. Please explain Staff's adjustment to payroll tax.**

A. Staff's payroll adjustments reflect a 2.76 percent reduction compared to the Company's proposed amounts.[35] Staff made a corresponding adjustment to the Company's proposed inclusion for payroll taxes.[36] The resulting adjustment attributable to Oregon is ($21,976).

**Q. Please summarize the adjustments described in your testimony.**

A. The Oregon-allocated adjustments reflected in my testimony are summarized in Figure 7, as follows.

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[35] See CONFIDENTIAL Exhibit Staff/1704, PUC Payroll Taxes tab.
[36] Idaho Power/901, Jeppsen/12, line 23.

**FIGURE 7: SUMMARY OF STAFF'S ADJUSTMENTS – OREGON**

| Description | O&M | Capital |
|---|---|---|
| Wages & Salaries | $(42,569) | $(25,267) |
| FTE Adjustment | $(19,311) | $(11,462) |
| Incentives | $(126,409) | $(75,031) |
| Overtime | $(13,373) | $(7,938) |
| Payroll Taxes | $(21,976) | $0 |
| Depreciation Expense | $(2,974) | $0 |
| **Total** | **$(226,612)** | **$(119,698)** |

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UE 426
WITNESS: STEPH YAMADA

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1701

## Witness Qualifications Statement
## Staff: Yamada

**March 25, 2024**

# WITNESS QUALIFICATIONS STATEMENT

| | |
|---|---|
| NAME: | Steph Yamada |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Utility Analyst<br>Rates and Telecommunications Section<br>Rates, Safety and Utility Performance Program |
| ADDRESS: | 201 High St SE, Suite 100, Salem, OR, 97301 |
| EDUCATION: | Master of Business Administration<br>Western Governors University<br><br>Bachelor of Science in Accounting<br>University of Oregon |
| EXPERIENCE: | I have been employed with the Public Utility Commission of Oregon since 2013. I am currently a Senior Utility Analyst in the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program. My responsibilities include leading research and providing technical support on a wide range of technical and policy issues for water and telecommunications companies. I have analyzed and addressed numerous telecommunications issues including special contracts, promotional concessions, tariff changes, price listings, numbering issues, service abandonment, property sales, and price plans, and provided testimony in UM 1895. With regard to water, I have analyzed and addressed numerous issues including tariff changes, property sales, affiliated interest transactions, financing requests, revenue requirement calculations, cost of service, rate spread, and rate design. I have also served as case manager and provided testimony in UW 163, UW 166, UW 173, UP 384, UW 176, UW 181, UW 189, UW 191, UW 192, UW 195, UW 196, and UW 197. |

CASE: UE 426
WITNESS: STEPH YAMADA

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1702

# Idaho Power's Non-Confidential DR Responses
# Staff: Yamada

**March 25, 2024**

**TOPIC OR KEYWORD: Wage and Salary, FTEs, Incentives**

**STAFF'S DATA REQUEST NO. 347:**

In response to Staff's DR 244, the Company stated, "data provided in response to SDR 92 is not equal to the labor included in the 2024 Test Year."

a. Please provide the FTEs, base salary & wages, overtime, and incentive & bonus costs included in the Company's 2024 Test Year. Please provide this information in the same format as reflected in SDR 92 and include both capitalized and expensed labor in the response.
b. Please provide a reconciliation between the information requested in a) above and the Company's confidential supplemental response to SDR 92.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 347:**

Please refer to Response to Staff Request No. 347 – Attachment which restates SDR 92 to reflect 2024 Test Year operations and maintenance ("O&M") labor per discussion with OPUC Staff on Wednesday, January 7, 2024.

As discussed in Note 2 of the attachment to this response, total O&M labor included in the 2024 Test Year is $183,317,379, which includes Base Wages plus Overtime in the amount of $122,739,021 (the sum of cells C11 and D11) and O&M labor loadings of $60,578,358. It should be noted that the testimony of Company Witness Ms. Sarah Griffin (Idaho Power/700) discusses rounded O&M base wage costs of $123.2 million (Idaho Power/700, Griffin/16) and rounded O&M benefits-related costs of $60.1 million (Idaho Power/700, Griffin/22). While the figures provided in Idaho Power/700 sum to the $183.3 million discussed in Note 2 of the attachment to this response, the breakout between base wages and benefits loading is slightly different as the initial breakout of benefits from base wages was estimated at the time Idaho Power/700 was prepared. While the Company was preparing its response to this request it refined this breakout percentage resulting in the slight variation in the rounded numbers provided in Idaho Power/700 and the figures provided in the attachment.

**Topic or Keyword:** Wage and Salary Data

**STAFF'S STANDARD DATA REQUEST NO. 93:**

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 STAFF'S STANDARD DATA REQUEST NO. 93:**

Please refer to "Response to Request No. 102 – Attachment" for Test Year Operation & Maintenance (O&M) labor by Federal Energy Regulatory Commission (FERC) account. Capital labor was not forecasted separately for the test year. Rather, capital labor is embedded in the forecast of plant closings forecast for the test year. Please refer to the Forecast Methodology Manual, pages 18 through 20, Larkin 1002 (Plant Additions to Electric Plant in Service) for a description of the methodology used by the Company to forecast plant additions.

In the Company's filed test year, O&M expenses at the FERC account level were allocated to the jurisdictions based on total expenses, not by expense cost element (labor/non-labor). Therefore, the requested Oregon labor allocation percentages are not available.

**Topic or Keyword:** Wage and Salary Data

**STAFF'S STANDARD DATA REQUEST NO. 102:**

Please provide a schedule separately showing payroll charged to expense accounts and charged to capital accounts by FERC account for the Base Year, the four most recent calendar years, and an estimate for the Test Year. Please do not include contract labor, bonuses, incentives, or below-the-line activities in this schedule.

**RESPONSE TO STAFF'S STANDARD DATA REQUEST NO. 102:**

Please see "Response to Staff Request No. 102 – Attachment." This data is not available for the Test Year capital labor because Idaho Power did not project capital accounts at that level of detail. Please refer to the Forecast Methodology Manual, page 18, Larkin Exhibit 1002, (Plant Additions to Electric Plant in Service) for a description of the methodology used by the Company to forecast plant additions and page 5 for a description of the methodology used by the Company to forecast O&M labor.

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**Idaho Power's Attachment provided in response to Staff's DR 102 is available in electronic spreadsheet format only.**

**TOPIC OR KEYWORD: Wages & Salaries, Incentives, Workforce Levels**

**STAFF'S DATA REQUEST NO. 243:**

Idaho Power Company's (IPC or Company) response to Staff's Standard Data Request (SDR) No. 92 indicates that the Company proposes to include $107,511.37 attributable to exempt employee overtime in the test year.

a. Are exempt employees eligible for overtime?
b. If not, why is there overtime associated with exempt employees?

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 243:**

As noted in the Company's Response to Standard Data Request ("SDR") 92, information provided for 2024 was an estimate of actual paid cash compensation derived from the projected year end 2023 cash compensation and increased by 3 percent. Upon further review of the Company's Response to SDR 92, Idaho Power is in the process of supplementing its response to contain what is reflected in the 2024 Test Year rather than an estimate of actual paid cash compensation for the 2024 time period as initially provided. Idaho Power will contact Staff directly to discuss 2024 Test Year labor costs and the availability of data at the requested level of granularity.

a. Exempt employees are not eligible for overtime.

b. The data provided in the Company's Response to SDR 92 is based on an employee's status as of the end of each year. In some cases, an employee may have a job change during the year that resulted in them going from a position that is non-exempt and overtime eligible to a position that is exempt. The overtime associated with exempt employees in SDR 92 is overtime paid during the year when the employee was in a non-exempt (overtime eligible) position.

**TOPIC OR KEYWORD: Salaries & Wages, FTEs**

**STAFF'S DATA REQUEST NO. 440:**

In response to Staff's DR 243, the Company stated, "In some cases, an employee may have a job change during the year that resulted in them going from a position that is non-exempt and overtime eligible to a position that is exempt. The overtime associated with exempt employees in SDR 92 is overtime paid during the year when the employee was in a non-exempt (overtime eligible) position." Regarding this statement:

a. Please explain why it is appropriate to include overtime costs associated with employees who are now exempt in the test year given that those employees are no longer eligible for overtime compensation.
b. Is it common for Idaho Power's employees to change from a nonexempt to exempt position? Please explain.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 440:**

a. Please refer to the Company's Response to Staff Request No. 347 – Attachment for details regarding the 2024 Test Year operations and maintenance ("O&M") Labor Forecast. As can be seen in cell D8 there is $76,115 of overtime on a system basis associated with exempt employees included in the Test Year. This forecast was based on overtime earned by employees when they were in a non-exempt position. It is appropriate to include these overtime costs in the Test Year because it is reasonable to expect that these employees will be replaced by non-exempt employees that will also earn overtime pay. For example, a service specialist (non-exempt position) moves into a distribution designer (exempt) position. It is reasonable to assume the non-exempt service specialist position will be filled and that employee will work a similar amount of overtime.

b. Yes, it is common for employees to change from a nonexempt to exempt position. These types of changes generally happen through a competitive hiring process. Idaho Power has a significant number of job postings each year, many of which are filled by internal employees. In 2023, the Company had 174 employees who were successful candidates for posted positions. Of those 174 employees, 21 were non-exempt and moved into exempt positions.

**TOPIC OR KEYWORD: Wage and Salary, FTEs, Incentives**

**STAFF'S DATA REQUEST NO. 348:**

The Company provided information about non-cash incentives in its confidential response to Staff's DR 164. Please confirm that such incentive costs are excluded from the Company's proposed revenue requirement or, alternatively, state the amount of such incentives included in the Company's rate request, separated by employee category (officer, exempt, nonexempt).

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 348:**

Confirmed. The non-cash incentives shown in the Company's Response to Staff Request No. 164 are excluded from the revenue requirement.

**TOPIC OR KEYWORD: Salaries & Wages, FTEs**

**STAFF'S DATA REQUEST NO. 441:**

Idaho Power's response to Staff's DR 167 shows that the Company has 15 officers as of January 1, 2024. The Company's initial (non-confidential) response to Staff's SDR 92 indicates that the Company had 13 officers in the 2022 base year.

a. Please explain why this increase in officers was necessary, and
b. Identify the titles, responsibilities, and compensation associated with the new positions.

**IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 441:**

a. The increase in officer headcount is temporary and both are successors for current officers who will retire in 2024.

b. There are no new positions associated with this temporary increase in officer count.

CASE: UE 426
WITNESS: STEPH YAMADA

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1703

## Idaho Power's CONFIDENTIAL DR Responses
## Staff: Yamada

## March 25, 2024

**Topic or Keyword:** Wage and Salary Data

**STAFF'S STANDARD DATA REQUEST NO. 92:**

For the Test Year and the preceding 4 calendar years, please provide (on a Total Company basis), a summary table (using the categories and format shown below) that includes the number of FTE's (exclude FTE's created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year. Please note which months and figures are associated with both the actual and forecast data.

| Year: 2XXX | | Actual (Unadjusted) Paid Cash Compensation | | | |
|---|---|---|---|---|---|
| Category | Total Company FTE | Base Wages or Salaries | Overtime | Incentive or Bonus | Total |
| Officers | | | | | |
| Exempt | | | | | |
| Nonexempt | | | | | |
| Union | | | | | |
| **Total** | | | | | |
| Please Exclude Full-Time Equivalent (FTE) Created by Overtime | | | | | |

**SUPPLEMENTAL RESPONSE TO STAFF'S STANDARD DATA REQUEST NO. 92:**

The updated information is provided in Confidential Supplemental Response to Staff Request No. 92 – Attachment.

For this supplemental response, the following updates were made to the data:

- 2023 is updated to reflect actuals paid as of 12/31/2023.
- Officer incentives or bonuses were added to years 2020-2024, these amounts were previously excluded as Idaho Power does not include Officer incentives in rate recovery.
- Adjustments were made to the allocation of wages by category in all years. While reviewing cash and non-cash incentives, as requested in Staff Request No. 162, it was found that the original data was allocating all terminated employees wages to the non-exempt category regardless of actual status at the time of termination.

**Idaho Power's CONFIDENTIAL Attachment provided in its supplemental response to Staff's DR 92 is available in electronic spreadsheet format only.**

CASE: UE 426
WITNESS: STEPH YAMADA

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1704

## CONFIDENTIAL Staff Workpapers
## Staff: Yamada

## March 25, 2024

**Staff's CONFIDENTIAL workpapers are available in electronic spreadsheet format only.**

# UE 426 – SERVICE LIST

| | |
|---|---|
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CERTIFICATE OF SERVICE

UE 426

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 25th day of March, 2024 at Salem, Oregon

*Kay Barnes*

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (971) 375-5079