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April 22, 2022

Via Electronic Filing

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

RE: Docket No. UG 435– In the Matter of NW NATURAL Request for a General Rate Revision.

Attached for filing are the following:
Highly-confidential materials are printed either on green or orange paper and placed in today's mail to parties who have signed MPO Order no: 21-465.

NWN UG 435 Staff OT Exh 100-1700 Redacted and Confidential consisting of :

Exh 100-109 Muldoon (Exh 100 Hi-Conf pages)
Exh 200-203 Fjeldheim (Exh 203 Conf)
Exh 300-303 Fox (Exh 300 Conf pages)
Exh 400-403 Bain
Exh 500-503 Bolton
Exh 600-604 Cohen
Exh 700-704 Dlouhy (Exh 704 Conf)
Exh 800-804 Enright (Exh 800 Conf pages)
Exh 900-903 Farrell
Exh 1000-1003 Jent (Exh 1000 Conf pages)
Exh 1100-1102 Peng
Exh 1200-1203 Rossow
Exh 1300-1303 Scala
Exh 1400-1403 Storm (Exh 1403 Conf)
Exh 1500-1501 Dlouhy_Fox_Storm
Exh 1600-1602 Gibbens
Exh 1700 Muldoon (Highly Conf)

Certificate of Service and Service List are included with this filing.

/s/ Kay Barnes
C: (971) 375-5079
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CASE: UG 435
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony:
Overview, Public Comments,
Overall Rate of Return, Return on Equity, and
Renewable Natural Gas and Hydrogen

April 22, 2022

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

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

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. I introduce Staff-sponsored adjustments and issues regarding the Northwest Natural Gas Company (NW Natural, NWN, or Company) request for a general rate revision, docketed as Docket No. UG 435. Please refer to Exhibit No. Staff/200, the testimony of Brian Fjeldheim for additional detail about component revenue, expense, and rate base components of Staff proposed adjustments.

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

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

Finally, I point to my additional testimony, Staff/1700, containing Staff's discussion of Renewable Natural Gas (RNG), cost recovery for the Lexington RNG project, and Hydrogen issues. Because this discussion addressed the

Company's testimony that is provided in Highly Confidential testimony, Staff's testimony on these topics must also be Highly Confidential.

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

A. Yes. Each Staff assigned to Docket No. UG 435 is submitting separate testimony. In my testimony, I first introduce the Staff witnesses and their respective assignments and estimate the revenue requirement impact of Staff recommended adjustments to the Company's initial filing. These are the issues identified to date. Staff's recommendations and issues may change after reviewing testimony and analysis by other parties.

Q. How is your testimony organized?

A. My testimony is organized as follows:

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

Exh.	Staff Witness	Issue No.	Proposed Staff Adjustments	Revenue Requirement Effect $(000)
NWN UG 435 Topics				**$ 78,020**
100	Muldoon	1	Revenue Requirement by Staff Topic	
		2	Intro to Staff Opening Testimony	
		3	Cap on Revenues, Notice to Customers	
		4	Summary of Findings, Overall ROR	
		5	Return on Common Equity (ROE)	(6,274)
		6	Renewable Natural Gas and Hydrogen	
200	Fjeldheim	1	Revenue Requirement, and Interest Synchronization	**47**
		2	Horizon - Phase 1, and Information Technology (IT) Projects	(1,992)
		3	Horizon - Phase 1 Depreciable Life	**2,327**
		4	Cyber Security and Safety	[redacted]
		5	Transportation Security Administration (TSA) Compliance	[redacted]
		6	Prepaid Expenses	
		7	Uncollectible Accounts	
		8	Cash Working Capital	
300	Fox	1	Escalation	**69**
		2	Oregon Corporate Activity Tax – OCAT	[redacted]
		3	Federal Income Tax – ARAM EDIT	(141)
		4	Property Tax	(61)
		5	OPUC Fee	**420**
		6	Test Year Plant – Additions	[redacted]
		7	NWN Errata Filing – Error Correction	**759**
		8	Test Year Plant - Budget Over-projection	[redacted]
		9	Test Year Plant Central Resource Center	
		10	Lincoln City Property Sale	
400	Bain	1	Load and Revenue Forecast	
		2	Miscellaneous Revenues	
500	Bolton	1	Materials and Supplies	(202)
		2	Rate Case Expense	
		3	Atmospheric Testing Expense	

Continued on Next Page

600	Cohen	1	Wages, Salaries and FTE	(5,946)
		2	Customer Account, Customer Service, and Sales Expenses	(601)
		3	Miscellaneous O&M Expense	
700	Dlouhy	1	Pension and Post-Retirement Medical Expenses	(6,549)
800	Enright	1	Capital Structure	
		2	Cost of LT Debt.	(176)
		3	Williams Pipeline Outage	
		4	Gas Inventory	
		5	Gas Storage Operating Expense	
		6	Affiliate Interest Charges	
900	Farrell	1	Operations and Maintenance Expense	(430)
		2	Administrative and General Expense	(770)
		3	Maintenance of General Plant	
1000	Jent	1	Advertising Expenses	(1,029)
		2	Promotional Activity and Concessions	
		3	Current Medical and health insurance	
		4	Insurance (Non-Medical) and Risk (Non-Medical)	
		5	D&O Insurance	[redacted]
1100	Peng	1	Depreciation Expense	
		2	Depreciation Reserve	
		3	AFUDC	
1200	Rossow	1	Memberships and Dues	(456)
		2	Meals and Entertainment and Miscellaneous Operations and Maintenance Expenses	(541)
1300	Scala	1	Equity, Affordability, and Customer Assistance	
		2	Decoupling and Weather Adjusted Rate Mechanism	
		3	Rate Spread and Rate Design	
1400	Storm	1	IRP and the General Rate Case	
		2	Current Deferrals	
1500	Dlouhy, Fox, and Storm	1	Staff's Review of Amounts Deferred	
		2	Earnings Review and Amortization	
		3	Rate Spread	
1600	Gibbens	1	Long-Run Incremental Cost Study	
1700	Muldoon	1	Lexington Renewable Natural Gas (RNG)	
			Total Staff-Proposed Adjustments (Base Rates):	[redacted]
			Staff-Calculated Revenue Requirements Change (Base Rates):	[redacted]

2. INTRODUCTION TO OTHER STAFF OPENING TESTIMONY

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

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

In Exhibit 200, Brian Fjeldheim, Senior Financial Analyst, addresses revenue requirement in this rate case in greater detail than in Table 1 herein, showing revenue, expense, and rate base elements of Staff's proposed adjustments, as well as overall revenue requirement impacts. Mr. Fjeldheim's modeling considers the appropriate revenue requirements of the Company and captures Staff adjustments to the revenue requirement proposed by NW Natural.

In addition, Mr. Fjeldheim analyzes: Horizon - Phase 1 and IT Projects, Cyber Security and Safety, Transportation Security Administration (TSA) Compliance, Prepaid Expenses, Uncollectible Accounts, and Cash Working Capital.

In Exhibit 300, John Fox, Senior Financial Analyst, discusses cost management and efficiencies including: escalation of costs; income taxes including: Oregon Corporate Activity Tax (OCAT) deduction for State income tax, and excess deferred income tax; taxes other than income, including property taxes and OPUC fee; and utility plant, including plant test year capital expenditures, land and building adjustments subsequent to the Company's errata filing, excess budget for district regulators, attestations and other project adjustments, and property sales. Mr. Fox's comprehensive analysis led to material errata filings by the Company.

In Exhibit 400, Dr. Ryan Bain, Ph.D., Senior Economist, analyzes the Company's load and revenue forecasting and miscellaneous revenues.

In Exhibit 500, Madison Bolton, Utility and Energy Analyst, considers the reasonableness of the Company's materials and supplies in rate base and rate case and atmospheric testing expenses.

In Exhibit 600, Heather Cohen, Senior Utility Analyst, reviews wages, salaries, and FTEs (including Officer's incentives); as well as customer accounts, customer service, promotions and concessions, and miscellaneous O&M expense. This testimony may be of interest to public commenters who expressed concern about executive compensation. A large number of commenters noted the imbalance between the growth rate of executive pay compared to pay for ordinary Oregonians. That concern is substantiated in the Wall Street Journal's article by Theo Francis of April 4, 2022, "CEO Pay Increases Heads for a New Record".[1]

In Exhibit 700, Dr. Curtis Dlouhy, Ph.D., Senior Economist, analyzes NW Natural's pension and post-retirement medical expenses.

In Exhibit 800, Moya Enright, Utility Economist, examines NW Natural's Capital Structure, Cost of Long-Term (LT) Debt, Williams Pipeline Outage, Gas Inventory, Gas Storage Operating Expense, and Affiliated Interest Charges. NW Natural completed a common equity stock flotation

1 This article is provided for your convenience in Exhibit Staff/108 Muldoon/4.

on March 29, 2022, after Staff opening testimony was prepared. Ms. Enright will address this issuance in her Rebuttal Testimony.[2] Staff also continues to monitor U.S. Federal Reserve (Fed) plans to lift interest rates, noting however, that current utility secured first mortgage bond (FMB) long-term borrowing rates continue to be very low compared to past borrowing rates.[3]

In Exhibit 900, Bret Farrell, Senior Economist, reviews operations and maintenance (O&M) expense, administrative and general (A&G) expense and maintenance of general plant.

In Exhibit 1000, Julie Jent, Utility Analyst, examines advertising expenses, current medical and health insurance, non-medical insurance and risk, and D&O insurance. She scrutinizes the appropriateness of NW Natural's advertising and promotional expenses, which is another concern of many public comments regarding this case.

In Exhibit 1100, Ming Peng, Senior Economist, analyzes the Company's depreciation expense, depreciation reserve, and allowance for funds used during construction AFUDC.

In Exhibit 1200, Paul Rossow, Utility Economist, reviews NW Natural's memberships and dues, meals, entertainment, and miscellaneous operations and maintenance (O&M) expenses.

[2] See Supporting Exhibit Staff/108 Muldoon/17 and /19 for news and details regarding NW Natural's common stock issuance.

[3] See Supporting Exhibit Staff/108 Muldoon/6 regarding Fed plans to lift rates.

In Exhibit 1300, Michelle Scala, Senior Utility Analyst, reviews equity, affordability, and customer assistance; decoupling and NW Natural's weather adjusted rate mechanism (WARM); and rate spread and rate design. Commenters concerned about affordability, energy burden and social equity in the context of HB 2475 will want to read those portions of Ms. Scala's testimony.

In Exhibit 1400, Steve Storm, Senior Economist, analyzes the nexus between Integrated Resource Planning (IRP) and this general rate case, as well as current deferrals.

In Exhibit 1500, Dr. Dlouhy, John Fox, and Steve Storm have prepared joint testimony addressing Deferrals related to Covid-19, including: Staff's review of amounts deferred, the appropriate earnings review and amortization, and rate spread. At the end of this section, I address how timely amortization of deferrals helps prevents generational inequity.

In Exhibit 1600, Scott Gibbens, analyzes NW Natural's Long-Run Incremental Cost Study.

In Highly Confidential Exhibit 1700, I review the Company's Lexington RNG Project and NW Natural's proposed RNG cost recovery mechanism.

3. OVERALL CAP ON REVENUES, COMPANY PROPOSALS, AND NOTICE TO CUSTOMERS

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

A. Yes. NW Natural filed a new depreciation study in December 2021 to comply with the requirement in OAR 860-027-0350(2) to file a depreciation study no less frequently than every five years. NW Natural's depreciation filing has been docketed as UM 2114; and, in that docket, NW Natural asks that the Commission delay the effective date of its updated depreciation dates until November 1, 2023. Therefore, NW Natural has not incorporated updated depreciation rates into this general rate case. Instead, NW Natural asked the Commission to base NW Natural's depreciation expense, etc., in this case on the depreciation rates approved in 2018 and based on 2015 data.

Staff witness Peng addresses NW Natural's proposed depreciation rates in her testimony. Staff does not oppose NW Natural's decision to not propose an increase to its retail rates in this general rate case to reflect changes in depreciation rates found from the depreciation study. Staff does oppose NW Natural's proposal to delay the effective date of its updated depreciation rates. However, Staff opposes NW Natural's proposal for a single-issue ratemaking proceeding to incorporate the updated depreciation rates, with the rate change effective November 2023.

When the Commission adopts new depreciation rates, it does so based on finding those new rates are appropriate for recording costs such as depreciation and associated net plant. Accordingly, it is important to timely implement the new rates as they reflect the most appropriate allocation of the costs of the Company's investments across the lives of the investments. To do otherwise results in inter-generational inequity.

NW Natural explains that it asks to delay the effective date of its depreciation rate update to save customers the approximately $8 million increase to revenue requirement associated with the update to depreciation rates.[4] Staff has no objection to NWN's wish to avoid the revenue requirement increase associated with updated depreciation rates. However, as noted, Staff does not think it is appropriate to accomplish this by delaying for a year the effective date of the depreciation rates. Further, Staff does not support NW Natural's proposal for a single-issue ratemaking proceeding in 2023.

Q. Please provide an example of this.

A. Under the deferral alternative, the Company earns its authorized Rate of Return (ROR) on the deferred amount. This is like the Company made a smart investment expecting a return of about seven percent, at the expense of customers paying these carrying costs, until these expenses are amortized.

A deferral would only serve to pass the rate increase, plus the carrying cost, along to a different set of future customers for whom it would then increase their energy burden. As the ROR is the weighted average of the Company's authorized Return on Equity (ROE) and Cost of Long-Term (LT) Debt, it is higher than the interest the Company pays when borrowing from a bank. Better ratemaking results from the timely matching of benefits and costs to the customers experiencing them.

[4] The delay in implementing the depreciation rate increase does not "save" customers money, instead it delays when the increase occurs—namely this year or next. If the depreciation change occurred this year, and it was an increase in rates, depreciation expense would increase and average rate base for the test year would decrease, with the effect of the depreciation increase outweighing the rate base effect.

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

A. NW Natural's requested revenue requirement now exceeds the revenue requirement increase specified in NWN's notice to the public. This is because the Company's notice did not include costs associated with certain rate base accounts (discussed in Staff Exhibit 300 by John Fox), resulting in errata filings by NW Natural. In its errata filing NW Natural notes:

> With this correction, NW Natural's total requested increase to revenue requirement in this case would be $78.0 million. NW Natural will provide to the parties updated work papers reflecting these changes. NW Natural notes that while its revenue requirement in this case has been corrected, the Company understands that the base rates finally adopted by the Commission in this proceeding will not exceed the revenue requirement amount reflected in its initial filing.[5]

Although it may not be an issue, Staff notes that the same limitation noted in NW Natural's errata filing may apply if NW Natural proposes to include updated depreciation expense in this rate case and that increases NW Natural's revenue requirement.

Q. Does this conclude your Introduction?

A. Yes.

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[5] NWN Errata Sheets, p. 1 (February 28, 2022).

4. SUMMARY OF PUBLIC COMMENTS RECEIVED

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

A. This case has produced a very large number of public comments. Staff reviewed 951 public comments (hereinafter referred to as "Comments") received up to April 10, 2022 in its Opening Testimony.

For Increase	Against Increase	Form Comments	Request Additional PM's	Total Comments as of 4/10/2022
0%	100%	774	181	951

Docket No. UG 435's public comments reflect vehement opposition to a rate increase from NW Natural. This request as noticed includes an 11 percent rate increase for residential customers. 100 percent of the comments are in opposition to the rate increase, and range in various intensities of negative emotion.

A significant number of comments are from residential customers and the comments all reflect similar feelings. In fact, there are multiple sets of form emails. The first set includes 181 identical emails that express concerns over the increase being used for political activities, executive salaries, and other expenses that are "counter to the public interest". These comments also indicate that the commenters do not want funds to further fund fossil fuels and that Oregon should be focused on renewable energy options. Additionally, many comments request additional public meetings (PM) or informational hearings to be held in this case.

The second set includes 454 identical emails. This set of comments explains that the commenters do not want to pay for increased profits for the company executives. The major concern in this set of comments is that the increase is too high and that Oregon families are struggling to get by and therefore should not have a large increase in their gas bills.

The third set includes 134 identical emails that indicate that ratepayers should not be forced to pay for NW Natural's advertising, especially when the advertising is greenwashing the impacts of natural gas.

The fourth set includes five identical emails. These comments state that a rate increase will lead to more deaths in Oregon from heat waves because people will have to choose between cooling their homes and buying food. These comments also point out that a rate increase would disproportionately affect vulnerable populations such as the retired and people of color.

This is a total of 774 form comments. In addition to these comments, there are many individual comments for a total of 951 public comments.

All comments that have been received reflect anger, frustration, or general negative feelings about the proposed rate increase. The major themes of the comments are:

1. Climate change is a huge issue for Oregon and the world and investing in natural gas and fossil fuel infrastructure is a bad investment. The money should be used instead to switch to renewable energy sources.
2. Ratepayers should not have to pay for pay increases and executive bonuses. NW Natural has excellent profits, and the executives make huge salaries. Ratepayers are struggling financially due to the state of

the world and the COVID-19 virus and should not have to pay for these increases.

3. Rate increases will disproportionately impact vulnerable communities including senior citizens on fixed incomes, people of color, and low-income households. Exhibit Staff/1300 addresses energy burden and HB 2475 issues.
4. NW Natural had a rate increase in November of 2020 and having another double-digit rate increase this year is more than ratepayers are able to handle.
5. Advertising is an inappropriate use of customer funds because NW Natural is a monopoly, the advertisements utilize greenwashing to encourage the public to believe that natural gas is a clean energy source, and there should not be advertisements for an energy source that should be phased out as soon as possible. Advertising is addressed in Exhibit Staff/1000.

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

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

The Commission will post a link or instructions on how the public can see all public comments received, and the public comments from the edited transcript for the Public Informational Hearing, of Thursday, March 10, 2022, at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23085.

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 UG 435 testimony.

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

Q. Does Staff Opening Testimony address comments received?

A. Yes.

5. OVERALL RATE OF RETURN (ROR)

Q. Did you prepare tables showing NW Natural's current, NW Natural's-earlier proposed and the Staff calculated ROR?

A. Yes, the following three tables provide that information.

TABLE 2

NWN Current OPUC Authorized (UG 388 Order Nos. 20-364, 20-369)			NWN
Component	**Percent of Total**	**Stipulated or Implied Cost**	**Weighted Average**
Long Term Debt	50.00%	4.529%	2.265%
Preferred Stock	0.00%		0.000%
Common Stock	50.00%	9.40%	4.700%
	100.00%		**6.965%**

TABLE 3

NWN Requested – UG 435		NWN Direct Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**50.00%**	**4.271%**	2.136%	**-0.079%**
Preferred Stock	0.00%		0.000%	
Common Stock	**50.00%**	**9.50%**	4.750%	
	100.00%		**6.886%**	

TABLE 4

Staff Proposed – UG 435		Staff Opening Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**50.0%**	**4.258%**	2.129%	**-0.336%**
Preferred Stock	0.00%		0.000%	
Common Stock	**50.0%**	**9.00%**	4.500%	
	100.00%		**6.629%**	

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

A. Staff recommends a **point ROE** of **9.0 percent** within a range of reasonable ROE's of 8.6 percent to 9.2 percent derived from Staff's two separate Three-Stage Discounted-Cash-Flow (DCF) models.

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 8.3 percent using Staff's peer gas utilities and 8.4 percent with the Company's peer gas utilities.

The CAPM generated a mean ROE of 7.5 percent using Staff's peer gas utilities and 7.5 percent as well with the Company's peer gas utilities.

Based on these checks, Staff finds that the point estimate for ROE in Staff's range of reasonable ROE's generated by its two separate Three-Stage DCF models should not be the top end of that range, but rather a lower point reflective of the above checks on reasonableness.

<u>ROE</u>

Q. Does your recommended ROE meet appropriate standards?

A. Yes. The 9.0 percent ROE Staff recommends is appropriate for overall rates that are reflective of forward looking conditions in conjunction with Staff's adjustments and meets the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statute (ORS) 756.040.[6] 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."[7]

Q. What is the primary contributing modeling that supports Staff's recommended 9.0 percent point ROE?

A. Staff's two different Three-Stage DCF models are the primary foundation for Staff's recommended point ROE. The Commission has traditionally relied upon the Three-Stage DCF model results for primary focus.

Q. Did you perform indicator modeling as a general check on this recommendation?

A. Yes. Staff performed a Gordon Growth model and a CAPM as checks on its two larger models.

PEER SCREEN

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

A. Staff used companies that met the following criteria as peer utilities to the regulated gas utility activities of NW Natural:

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

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

1. Covered by Value Line (VL) as a gas utility;
2. Forecasted by VL to have positive dividend growth;
3. LT Issuer Credit Rating equal to or better than BBB- from S&P, or Baa3 from Moody's;
4. No decline in annual dividend in last four years based on VL;
5. Has heavily regulated natural gas LDC revenue;
6. Has LT Debt under 56 percent in VL Capital Structure; and,
7. Has no recent merger and acquisition activity.

Q. NW Natural also looked at water investor owned utilities (IOU) followed by Value Line in addition to natural gas utilities. Did Staff also look at water utilities?[8]

A. Not in this testimony, as there were a sufficient number of natural gas peer companies. Staff looks at water IOUs as a sensitivity for tracking, but not for decision making at this time. Staff's only sensitivities in its modeling for its Opening Testimony on Cost of Capital is the use of Staff's models with NW Natural's peer gas utilities. Staff's peer group size is statistically sound and most representative of NW Natural, which is primarily a Natural Gas distribution company.

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

[8] See NW Natural/303, Villadsen and Figueroa/23, Schedule No. BVJF 6.6.

TABLE 5[9]

1	2	3	4	6	7
		Screen:	1	80% Mid Cap	
Natural Gas		Sensitivities:	2		
NWN UG 435					VL Cap
		Gas Group			Small
	Abbreviated	UG 435	UG 435	NYSE	Mid
#	Utility	Company	Staff	Ticker	Large
1	Atmos	Yes	Yes	ATO	L
2	Chesapeake	Yes	Yes	CPK	M
3	New Jersey	Yes	No	NJR	M
4	NiSource	Yes	No	NI	L
5	NW Natural	Yes	Yes	NWN	M
6	ONE Gas	Yes	No	OGS	M
7	South Jersey	Yes	No	SJI	M
8	Southwest Gas	Yes	Yes	SWX	M
9	Spire	Yes	Yes	SR	M
10	UGI	No	No	UGI	L

A comparison of the peer groups used by Staff and NW Natural are set forth in Table 5. Staff excluded four of the companies used by NW Natural based on its screening criteria described above. Otherwise, NW Natural and Staff included five of the same companies and both declined to use UGI Corporation with its heavy reliance on propane distribution and WGL Holdings, Inc.

Q. Does Staff exclude some potential peer utilities because of material pending mergers or acquisitions?

A. Yes. Staff excludes South Jersey Industries because the utility is involved in a proposed $8.1 billion buyout of South Jersey Industries by Infrastructure Investments Fund. Staff includes, but continues to monitor, SW Gas, for which

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

Carl Icahn proposes a hostile takeover. Staff discounts Mr. Icahn's success in taking over because of utility management and regulatory opposition.[10]

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

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

TABLE 6 – RESULTS OF STAFF'S 3-STAGE DCF MODELING[11]

Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :					**12.5**	bps
Range of Modeled Results		8.55%	**to**	9.13%	**ROE**	
Best Fit Range of Reasonable ROEs		8.6%	**to**	9.2%	**ROE**	
(Best fit is Staff's Hamada adjusted screened gas utilities that have most similar characteristics to NWN regulated gas operations in Oregon)						
	Staff Point ROE Recommendation:	**9.0%**	**ROE**			
CAPM and Gordon-Growth Single-Stage-DCF are both downward pointing indicators.						

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

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

A. NW Natural is averaging in results from unreliable and unproven models like Empirical CAPM or ECAPM. In addition, the Company is also running sensitivities relying on hyper-optimistic inputs (without labeling these as extreme and unlikely to occur) and then giving results using extreme inputs equal weighting to outcomes using rational inputs. These practices heavily skew aggregated modeling results upward.

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[10] See Exhibit Staff/108, Muldoon/3 and /28 for M&S news regarding Southwest Gas and South Jersey respectively.

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

Q. Please provide an example of an extreme input that NW Natural has not labeled as such.

A. NW Natural, shown in NW Natural/300 Villadsen-Figueroa/67, relies variously on a Long-Term Market Risk Premium of 7.25 percent and 8.61 percent. This is important in models like CAPM and Gordon Growth Models (single stage DCF) because doubling one input assumption skews results tremendously. By adding a numerical brick to the scale, one can push results higher. Naturally one would not want to use NWN inputs on their own investing or managing money they were responsible for, as shown in Example 1 below.

Example 1 – NOT a Staff Recommendation:

1.86%	**Risk Free Rate as St. Louis FRED (FRED) Mar. 7, 2022 effective 10 Yr US Treasury (UST) Yield**
2.24%	**Risk Free Rate as FRED Mar. 7, 2022 effective 30 Yr UST Yield**
4.50%	**Ibbotson Market Risk Premium (MRP) (Since 1980 — My Adult Lifetime)**
6.00%	**Morningstar in Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook (Very Long Run since 1926)**
	$R_{AVA} = R_f$+Beta*MRP
8.61%	NW Natural's Market Risk Premium

Note that NW Natural does not identify its “extreme” market risk premiums as such.

Extreme NW Natural MRP Skews Results Upward 30-Yr Forward UST CAPM w VL Beta	Abbreviated Utility	#
9.13%	Atmos	1
9.13%	Chesapeake	2
10.85%	New Jersey	3
9.56%	NiSource	4
9.13%	NW Natural	5
9.13%	ONE Gas	6
10.85%	South Jersey	7
10.42%	Southwest Gas	8
9.56%	Spire	9

This generates a mean of 9.75 percent.

Normally, Staff does not call out odd methods like that used by NW Natural in the Company's testimony. Staff does so in this case however, because inputs are not labeled as outlier values and because results using extreme inputs are given equal weighting with more reasoned inputs. Staff provides the above example of how NW Natural's approaches more heavily weight unlikely modeling results to values far above prevailing natural gas utility authorized ROEs in the greater Northwest.

Q. Once models not used for calculating ROE but for sensitivity analysis and extreme inputs are eliminated, are there still differences in Staff model outcomes vs. the Company's?

A. Yes. First, supporting Exhibit Staff/102 captures Value Line's historical and projected dividends as well as Earnings per Share (EPS). NW Natural has a much smaller rate of dividend growth projected than that of either Staff's or the Company's peer utilities. That makes sense in that NW Natural may see that it can put free cash flow to the firm to better use by growing the HoldCo such as through acquiring more water utilities and investing in RNG and H opportunities. This may reflect sound management decision making, and one should note that NW Natural's dividend growth rate is positive and is one of only three companies listed on the New York Stock Exchange (NYSE) that can claim 66 consecutive years of growing dividends. Staff is not second-guessing the Company.[12]

However, the effect on both single-stage and three-stage DCF modeling results is less pronounced the bigger the peer utility group. Though a smaller and tighter group most similar to the utility studied is preferable, one can see in Exhibit NW Natural/303 Villadsen and Figueroa/23 that the Company is using

[12] See NW Natural's March 2022 Investor Presentation on its website under "investors" for an overview of the Company's business opportunities, and in particular page 47 for its statement regarding its 66 years of dividend growth.

17 utilities as its peer group in that instance. That substantially masks the slower than typical NW Natural dividend growth rate.

Q. What is the second primary factor for Staff vs. Company modeling differences?

A. Second, NW Natural supporting Exhibit Staff/102 captures Value Line's historical and projected dividends as well as Earnings per Share (EPS). NW Natural has a relatively low rate of EPS growth compared to certain utilities like South Jersey. When Staff excludes South Jersey due to its merger and acquisition (M&S) activity, this removes a utility with a high EPS growth.[13]

Q. What is a third factor causing modeling results differences?

A. A third driver is that NW Natural selected peer utilities that have much different capital structure trends than NW Natural. That causes Staff's peer group to perform better when Hamada adjusted to benefit from capital structure differences than the Company's peers, particularly in conjunction with EPS impacts. It is important to note that results for disparate capital structures when un-levered move up <u>or down</u> to re-lever at the target NW Natural capital structure.

Q. NW Natural/300 Villadsen-Figueroa/6 at line 7, relying on Figure 1, indicates the Company finds a reasonable range of ROEs from 9.5 to 10.5 percent, with a point recommendation of 9.5 ROE at the low end of this range. Why is that not a reasonable recommendation?

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[13] See Exhibit Staff/102, Muldoon/3 for EPS growth rates.

A. If one eliminates ECAPM as unreliable, selects only peer gas utilities most like NW Natural using Staff's standard screening methods, and eliminates the Company's Risk Premium Modeling, one arrives at Staff's recommendations.[14] Finally it is important to remember that this exercise is trying to find a best point ROE in a range of reasonable ROEs for the Commission jurisdictional LDC, Northwest Natural Gas Company, not for NW Natural Holding Company.

GROWTH RATES USED IN THIRD STAGE OF DCF MODELS[15][16]

Q. What long-term growth rates did you use in Staff's two three-stage DCF models?[17,18]

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

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

Staff's second Composite Growth Rate applies a 50 percent weight to the average annual growth rate resulting from estimates of long-term GDP by the U.S. Energy Information Administration (EIA), the U.S. Social Security Administration, PricewaterhouseCoopers estimate for long-run (10- to 30-years from now), and the CBO, with each receiving one-quarter of that

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14 Exhibits Staff/102, 103, 104, and 105 show how Staff's recommendations are generated.

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

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

17 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

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

50 percent weight.[19] The remaining 50 percent is the average annual historical real GDP growth rate, established using regression analysis, for the period 1980 through 2021 to which we apply a TIPS implied inflation forecast.

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

TABLE 7
GROWTH RATES STAFF RELIED UPON

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates					
Component	Real Rate	TIPS Inflation Forecast	20-Yr Nominal Rate	Weight	Weighted Rate
Energy Information Administration	2.10%	2.23%	4.38%	12.50%	0.55%
PricewaterhouseCooper	2.40%	2.23%	4.68%	12.50%	0.59%
Social Security Administration	2.00%	2.23%	4.27%	12.50%	0.53%
Congressional Budget Office	1.60%	2.23%	3.87%	12.50%	0.48%
BEA Nominal Historical,1980 Q1 – 2021 Q4	2.66%	2.23%	4.95%	50.0%	2.47%
Composite				100%	4.62%
Congressional Budget Office Long-Term 20-Year Budget Outlook			4.00%	100.0%	4.00%
BEA Nominal Historical,1980 Q1 – 2021 Q4	2.66%	2.23%	4.95%	100.0%	4.95%

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-

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

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 and productivity in the long-run (20-year) modeling period.

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

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

Q. How do your 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 general rate cases, with the exception that we have at times spent more time in prior cases working with water utilities as a sensitivity in addition to the primary analysis. 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.[20]

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 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

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

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 gas 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?

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

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

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

A. Yes. Staff's recommended 9.0 percent point ROE is consistent with findings modeling the perspectives of both types of investors through Staff's two different three-stage DCF models.

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

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

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

A. Yes. In many of the Company's prior rate cases, Staff has shared plots of U.S. gas 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 gas sales and dividend growth rates.

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

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

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

A. Yes. Over-extrapolating a snapshot of short-term data undermines confidence in modeling results. For example, Value Line, Blue Chip, and a variety of other financial resources focus primarily on the next five years. The next five years may be affected by recent events. Over the long run, people and productivity are the key drivers of economic growth. This is of concern with declines in the rate of growth of America's population.[22]

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 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 NW Natural's target capital structure increases required ROE. Why is this adjustment reasonable?

[22] See Exhibit Staff/108, Muldoon/1 and /20 for long-run concerns about U.S. and Oregon birth rate declines respectively.

A. Staff employs the Hamada Equation as a check on the reasonableness of its modeling results. This allows Staff 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[23] to calculate an adjustment for differences in capital structure between each peer utility and the Staff-proposed capital structure for the Company. When few peer utilities are available, the Hamada equation ensures Staff's analysis addresses differences in peer utility capital structures.

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

[23] Dr. Robert Hamada's Equation as used in Staff/1304 separates the financial risk of a levered firm, represented by its mix of common stock, preferred stock, and debt, from its fundamental business risk. Staff corrects its ROE modeling for divergent amounts of debt, also referred to as leverage, between the Company and its peers.

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

Q. Did you use robust and proven analytical methodologies?

A. Yes. Staff's methods are robust, proven, and parallel Staff's work over the last decade. The Commission for example expressly relies on the multi-stage DCF to determine the range of ROEs, and relies on CAPM and risk premium models to check result. This can be seen in Order No. 20-473 in 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 top supportable finding of 9.0 percent point ROE?

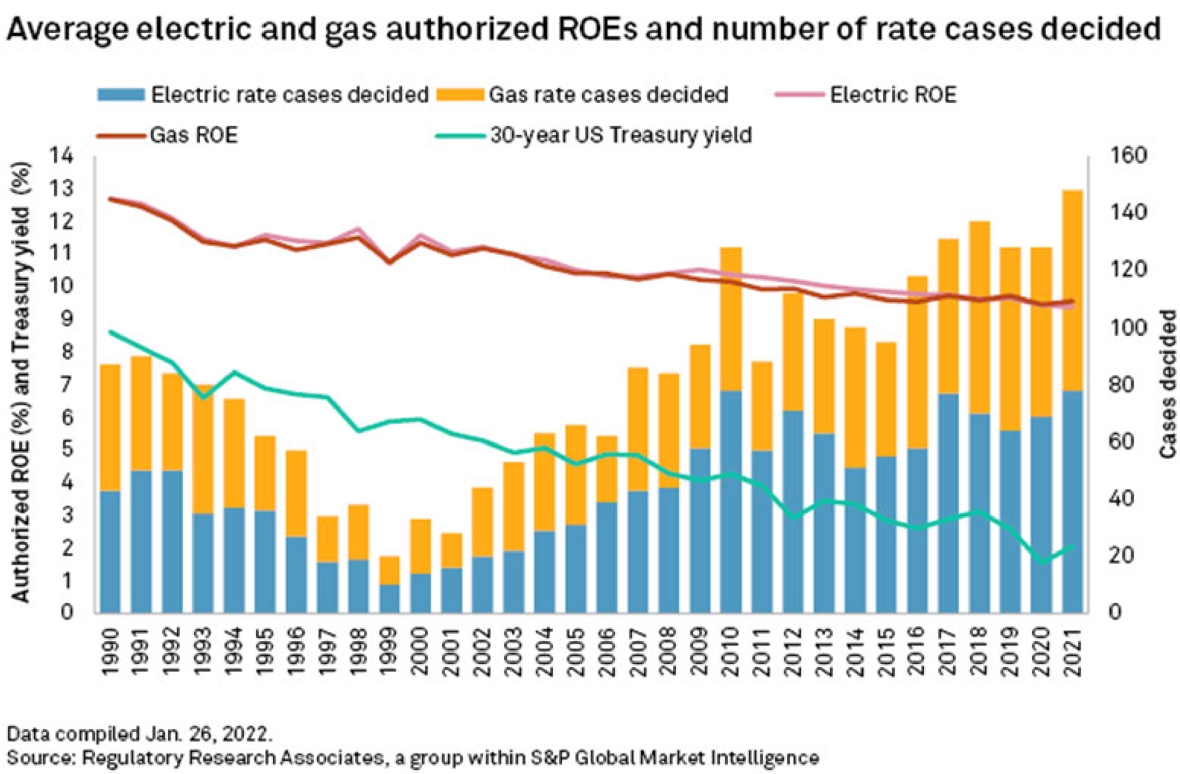
A. Yes.

BALANCED APPROACH TO ROE

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

A. Yes. The downward glide path for ROE in Figure 1 below, is not linear and may fluctuate through these uncertainties, but long-run GDP growth rates are mostly determined by the long future U.S. working age population and its productivity.[24]

FIGURE 1 – Downward Glide Path of Utility ROES[25]



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

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

Q. What trend is Staff seeing?

A. Since 1990, according to Regulatory Research Associates (RRA), Gas and Electric Utility authorized ROEs have declined as the 30-year US Treasury (UST) has also declined. While the Fed now proposes to raise interest rates, to date it has only increased short term rates by 25 basis points, leaving Treasury yields still close to all-time lows.

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

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

<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 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.[26]

[26] 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.

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 valuation without needing complex inputs or analysis, beyond selecting a trusted source for the next quarter's expected dividend. 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 to entice new investors. This is important to bear in mind when considering the results of any Single-Stage model, as reliance on overly optimistic inputs or use of outboard after-the-fact adjustments can have a large impact on the model output.

The Single-Stage model is based on simple principles and serves as a rough estimation of investor required ROE. It cannot incorporate known, measurable, and material information about the future usually built into Three-Stage DCF analysis. For this reason, Staff consistent with

Commission precedent, has traditionally only relied on it as a sensitivity check when rate making.

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

A. Much like Staff's Multi-Stage DCF, Staff sources its expected dividends from Value Line. We calculate the average dividend growth rate by comparing the expected dividend in 2026 by Value Line and actual dividend for each in 2020 for each company in the peer screen.

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

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

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

A. Using Staff's peer utility screen, the average required ROE under Staff's Gordon Growth model is 8.3 percent, with a minimum estimated peer ROE of 4.3 percent and a maximum estimated peer ROE of 9.6 percent. The average required ROE varies minimally if the Company's larger peer screen is used instead. This implies that Staff's recommended ROE of 9.0 percent is more reasonable than the Company's recommendation of 9.5 percent. Table 8 summarizes the results of Staff's modelling.

TABLE 8[27]

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: **Best Point ROE may not be Top of 3-Stage DCF Modeling Value**

	1	2	3	4	5	6	7	8	9	11 = 8 + 9	13	
Screen #	Abbreviated Utility	UE 435 NWN	UE 435 Staff	Ticker	Recent Stock $ Price	Current Dividend Yield	Next VL Annual Dividend	Anticipated Dividend Yield	VL Dividend Growth	Investor Required ROE	Screen #	
1	Atmos	Yes	Yes	ATO	107.07	2.5%	$ 2.92	2.7%	6.9%	9.6%	1	1
2	Chesapeake	Yes	Yes	CPK	136.27	1.5%	$ 2.16	1.6%	7.7%	9.3%	2	2
3	New Jersey	Yes	No	NJR	41.17	3.5%	$ 1.49	3.6%	4.9%	8.6%	3	3
4	NiSource	Yes	No	NI	28.33	3.3%	$ 0.98	3.5%	4.3%	7.7%	4	4
5	NW Natural	Yes	Yes	NWN	49.53	3.9%	$ 1.94	3.9%	0.4%	4.3%	5	5
6	ONE Gas	Yes	No	OGS	79.06	3.1%	$ 2.64	3.3%	6.3%	9.7%	6	6
7	South Jersey	Yes	No	SJI	28.53	4.4%	$ 1.28	4.5%	4.0%	8.5%	7	7
8	Southwest Gas	Yes	Yes	SWX	68.85	3.6%	$ 2.60	3.8%	5.4%	9.2%	8	8
9	Spire	Yes	Yes	SR	66.73	4.1%	$ 2.86	4.3%	4.8%	9.1%	9	9
	No. of Peers:	9	5							Mean		
									Company Screen	8.4%	ROE	
									Staff Screen	8.3%	ROE	
									Staff Lowest	4.3%		
									Staff Highest	9.6%		

Suggests Staff's Point ROE of 9.0 is reasonable in 3-Stage DCF Modeling

CAPM – As Check on ROE Findings

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

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

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

Where $\boldsymbol{r_f}$ is the risk-free rate and $\boldsymbol{r_m}$ is the market return. Generally, the risk-free rate is assumed to be the rate of return on bonds. Taking cues from long-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. Are there any reasons the Commission should be wary of CAPM?

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

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

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

Q. Where does one 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 does one 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. One must be careful 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. The average VL Beta for Staff's peer screen was .85 while the average VL beta for the Company's peer screen was .88.

It is common to see market return estimates vary by as much as 400 basis points. This means that by only substituting in a different estimate for market returns, a required return estimate can vary by over 300 basis points for a typical regulated utility.

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

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

As has been done in past rate cases, Staff uses the market risk premium calculated by Ibbotson and the implied market risk premium from Morningstar's Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook, which measures average returns since 1926. These two sources imply that the risk premium would be 4.5 percent and 6.0 percent, respectively. At the time of measurement on March 7, 2022, the 10-year and 30-year yields on US Treasury bonds were 1.86 percent and 2.24 percent, respectively. This creates four distinct methods to estimate ROE using a CAPM and a representative set of peers.

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 the sets of assumptions listed above vary from a high of 7.94 percent to a low of 5.46 percent. Using the Company's peer screen, the maximum estimated ROE observed is 8.24 percent.

Of the four methods to estimate CAPM outlined above, the mean ROE of the five companies contained in Staff's peer screen ranges from 5.76 percent and 7.52 percent.

All of this points to Staff's recommended ROE of 9.0 percent being more reasonable than the Company's recommended ROE of 9.5 percent. These findings are summarized in the Table 9 below:

TABLE 9[28]

Staff's Representative CAPM Modeling Results

1.86%	**Risk Free Rate as St. Louis FRED (FRED) Mar. 7, 2022 effective 10 Yr US Treasury (UST) Yield**
2.24%	**Risk Free Rate as FRED Mar. 7, 2022 effective 30 Yr UST Yield**
4.50%	**Ibbotson Market Risk Premium (Since 1980 — My Adult Lifetime)**
6.00%	**Morningstar in Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook (Very Long Run since 1926)**

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

#	Abbreviated Utility	UG 435 Company	UG 435 Staff	Ticker	VL 2/25/2022 Beta	Morningstar Very Long Historical Perspective: 10-Yr Forward UST CAPM w VL Beta	Morningstar Very Long Historical Perspective: 30-Yr Forward UST CAPM w VL Beta	
1	Atmos	Yes	Yes	ATO	0.80	6.66%	7.04%	
2	Chesapeake	Yes	Yes	CPK	0.80	6.66%	7.04%	
3	New Jersey	Yes	No	NJR	1.00	7.86%	8.24%	
4	NiSource	Yes	No	NI	0.85	6.96%	7.34%	
5	NW Natural	Yes	Yes	NWN	0.80	6.66%	7.04%	
6	ONE Gas	Yes	No	OGS	0.80	6.66%	7.04%	
7	South Jersey	Yes	No	SJI	1.00	7.86%	8.24%	
8	Southwest Gas	Yes	Yes	SWX	0.95	7.56%	7.94%	
9	Spire	Yes	Yes	SR	0.85	6.96%	7.34%	
	TOTAL PEERS	9	5		**Mean**	7.14%	7.52%	**Staff Gas Screen**
			80% Mid Cap			7.09%	7.47%	**Company Peer Screen**
						7.06%	7.44%	**Company Peer Screen - w/o M&A**

CONCLUSION REGARDING ROE

Q. What is Staff's recommendation regarding ROE?

A. Staff recommends that the Commission adopt a point ROE of 9.00 percent consistent with the findings herein.

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

A. Staff's calculations generate a 6.629 percent Overall Rate of Return. Though 65 bps lower than the Company last authorized ROR, this is a fair and reasonable recommendation to the Commission.

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

6. RENEWABLE NATURAL GAS (RNG) AND HYDROGEN

Q. Does your testimony address the Lexington RNG project and RNG and hydrogen cost recovery mechanisms?

A. Yes. However, this testimony is restricted to Highly Confidential (**HCONF**) Exhibit Staff/1700 because NW Natural's testimony and responses to data requests on this topic and more specifically the Lexington RNG project cost recovery mechanism are almost entirely designated **HCONF** by the Company.

Q. Does that conclude your testimony?

A. Yes.

CASE: UG 435
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

April 22, 2022

WITNESS QUALIFICATION STATEMENT

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

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

CASE: UG 435
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

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

April 22, 2022

CASE: UG 435
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

ROE – Three-Stage DCF:
Models X and Y
(Electronic)

April 22, 2022

CASE: UG 435
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

ROE – Three-Stage DCF:
Summary and Recommendation
(Electronic)

April 22, 2022

CASE: UG 435
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

ROE: CAPM, and
Gordon Growth – Single Stage DCF
(Electronic)

April 22, 2022

CASE: UG 435
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 106

ROE: BEA Historical
GDP Growth
(Electronic)

April 22, 2022

CASE: UG 435
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 107

ROE: TIPS Implied Inflation
(Electronic)

April 22, 2022

CASE: UG 435
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 108

ROE: Financial News that Investors in Natural Gas Utilities Are Seeing

April 22, 2022

News Articles Cited

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

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

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

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

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

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

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

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

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

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

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

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

Census finds Black population grows in suburbs and shrinks in cities

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

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

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

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

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

More on the census:

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

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Carl Icahn Calls Southwest Gas Business Split a 'Desperate Measure'

by Tom DiChristopher – S&P Global Market Intelligence – Mar. 7, 2022

Activist investor **Carl Icahn accused Southwest Gas** Holdings Inc. of **seeking** to **spoil his bid t**o **take control** of the gas utility operator by announcing a business split.

Southwest Gas on **March 1 announced** it would **separate** its **Centuri Group** Inc. **energy infrastructure services segment from** its **core business in gas distribution**, **transmission** and **storage**. The **company** has **not** yet **decided** how it will structure the separation and **expected** to **update investors** in 45 to **60 days**.

Icahn blasted Southwest Gas leadership in a March 7 letter to stockholders. Southwest Gas President and CEO John Hester "doesn't quite explain what he is doing" and appears to claim that the split will "cure all past ills caused by his leadership," Icahn said.

"But be not fooled: the vague promise to separate Centuri is not necessarily a step in the right direction nor is it something he ever wanted to do," Icahn wrote. "It is simply a desperate measure to somehow block our tender offer."

Maneuvering and messaging

Icahn warned Southwest Gas stockholders n an October 2021 letter that Hester would continue to dangle the prospect of splitting off Centuri for months, quarters or even years.

In that same letter, Icahn advocated for a business split. He called on Southwest Gas to use the proceeds from any spinoff, sale or IPO of Centuri to improve its balance sheet and fund future business growth.

Southwest Gas executives on March 2 said the Centuri split would "meaningfully reduce future equity financing needs," including funding its nearly **$2 billion purchase** of **Dominion Energy Questar Pipeline** LLC.

In a March 7 response to Icahn's latest letter, Southwest Gas reiterated the business case for the separation. The company said it expects Centuri to fetch a premium valuation and expects the separation to be complete in nine to 12 months. Southwest Gas also said it is confident that it can "obtain permanent financing on attractive terms" and lower its future borrowing costs as a purely regulated gas infrastructure operator.

Equity financing at issue

Icahn opposed the Questar acquisition, but he has offered to finance the purchase, allowing Southwest Gas to avoid raising $900 million to $1 billion in strategically timed equity issuances. In his March 7 letter, Icahn questioned whether the equity raise was off the table and criticized Southwest Gas for taking several months to respond to his unconditional financing offer.

Southwest Gas said in a Feb. 28 filing that Icahn declined to share terms of his proposed financing when reached by the company's financial adviser on Feb. 21. **According to Southwest Gas, Icahn said** his priority is to **purchase** the **company** for **$75 per share**. Icahn stated he would provide the financing only if his tender offer closed first or if Southwest Gas agreed to move forward with the tender offer but it did not close, the company said.

Icahn wrote an open letter to Southwest Gas shareholders on March 1, calling the company's account of the conversation "a highly inaccurate and intentionally misleading summary." Icahn reiterated that he would beat any superior financing offer. He said his offer to finance the Questar purchase "has absolutely nothing to do with" his proxy contest and tender offer, nor is it contingent upon his associates securing any governance provisions or board seats.

"**Five months ago**, we **offered publicly** to **purchase $1 billion of common equity from** [**Southwest Gas**] at **$75 per share** in **cash** to finance the Questar acquisition," Icahn said. "That **offer** still remains **outstanding today**."

–

CEO Pay Increases, Heads for a New Record

by Theo Francis – WSJ – Apr. 4, 2022

Pay increases for U.S. chief executives have gained steam, putting compensation on pace to set a record amid a tight labor market that is also driving pay higher for many of their workers.

Median pay rose to $14.2 million last year for the **leaders** of **S&P 500 companies**, up from a record $13.4 million for the same companies a year earlier, according to a Wall Street Journal analysis of pay data for more than half the index from MyLogIQ LLC.

Most CEOs received a pay increase of 11% or more, and pay rose by at least 25% for nearly one-third of them. Pay fell for about a quarter of the CEOs, including Paycom Soft-ware Inc.'s Chad Richison, last year's highest-paid S&P 500 leader, whose pay fell to about $3 million from $211 million.

In **2020**, while **CEO** pay rose overall, nearly **one-third** of these **executives had** their **total compensation decline** from a year earlier, and **many forfeited some pay during** the **pandemic**.

Pay last year for rank-and-file employees rose, too, but more slowly, as measured by the compensation figures the companies report for their median employee. Half the companies said pay for their median worker increased by 3.1% or less in 2021, and at one-third of companies, median employee pay declined year over year – broadly similar to pre-pandemic rates of change.

CEOs at about **half** the **companies** were **paid at least 186 times** what **their median worker** made **in 2021**, according to the Journal analysis. That is **up from 166 times** in the **year before the pandemic and 156 times in 2018**.

The Securities and Exchange Commission requires companies to disclose how much their typical worker makes and how it compares with their CEO's compensation. The disclosure was mandated by the 2010 Dodd-Frank Act in the wake of the financial crisis.

At some large companies, board compensation committees have expanded their scope beyond executive pay to that of the workforce generally, said Caitlin McSherry, director of investment stewardship at Neuberger Berman, which manages more than $460 billion. At the same time, investors have few tools to understand how companies pay workers.

"It all comes back to thinking about the workforce in totality," Ms. McSherry said. "There aren't too many disclosures out there that provide insight into workforce pay."

Companies said the pay ratio offers little meaningful insight in part because businesses have a range of operational structures. **Outsourcing low-wage work**, for instance, **can lift employee median pay** and **make** a **company's ratio lower**. In addition, the SEC disclosure rule gives companies wide leeway in identifying median workers, making comparisons among companies more difficult. **Executive pay** also can be **highly variable**, **with some** companies making **multiyear grants**, **leading** to **periodic surges** in the **pay ratio**.

The **widening gap between CEO pay and median worker pay** comes amid a tight U.S. labor market, thrown askew as millions of people dropped out of the workforce during the pandemic. Executives at airlines, manufacturers, retailers and restaurants alike have talked about the struggles of finding and hiring enough workers in the U.S.

U.S. average hourly wages rose by about **4.9% for all workers in 2021**, according to the Labor Department.

The **CEO compensation figures** are reported by companies and **include** the **value of stock awards at** the **time of grant**, along with **salary**, **cash bonuses**, perks and **some retirement-benefit increases**. Equity awards, the value of which can rise or fall significantly after grant, accounted for the bulk of pay for the highest-paid CEOs in the Journal's analysis. These awards typically vest, or become fully the executive's, over several years and can be tied to performance targets.

Discovery Inc.'s David Zaslav, at nearly $247 million, had the highest 2021 pay disclosed so far among the S&P 500 CEOs who served the full year. Mr. Zaslav's pay was nearly 3,000 times the $82,964 that the company reported paying its median worker last year, up from a multiple of 1,511 in 2018.

Discovery said that much of Mr. Zaslav's 2021 pay consists of stock-option awards tied to a contract signed last year, and his pay excluding one-time awards would be 527 times the median worker's. The media company's share price would have to rise significantly for the options to be in the money.

The second-highest paid CEO so far in the S&P 500 was Amazon.com Inc.'s Andy Jassy, who was awarded compensation valued at nearly $213 million, all in restricted stock. That was nearly 6,500 times the median Amazon worker.

Mr. Jassy took over in July 2021 and won't feature in the full rankings because he was CEO less than a full year.

Most of Mr. Jassy's equity won't vest for at least five years, and the award is structured to give him about the same number of shares each year, valued at $33 million to $35 million at recent share prices, after 2023, Amazon said. An Amazon spokesman called the award competitive with that of CEOs at other large companies.

As in recent years, some of the highest-paid CEOs of public companies weren't running businesses in the S& P 500.

Private-equity giant KKR & Co. reported paying co-CEOs Joseph Bae and Scott Nuttall compensation valued at $559.6 million and $523.1 million, respectively. The men took over last fall from company cofounders Henry Kravis and George Roberts.

"The **vast majority** of the **compensation** is **performance-based stock** that will have to more than double in value for the stock awards to fully vest," a KKR spokeswoman said.

–

Fed Lifts Rates, and Signals Six More Increases

by Nick Timiraos – WSJ – Mar. 17, 2022

Central bank pencils in additional boosts this year as it seeks to combat high inflation.

Federal Reserve officials **voted** Wednesday to **lift interest rates** and **penciled in six more increases by year's end**, the most aggressive pace in more than 15 years, in an escalating effort to slow **inflation** that is **running** at its **highest levels in four decades.**

Left: Fed Chairman Jerome Powell speaking Wednesday at his post-meeting press conference

The **Fed will raise** its **benchmark federal**-**funds rate** by a **quarter percentage point to** a range between **0.25% and 0.5%**, the **first increase since 2018**.

Officials signaled they **expect** to **lift** the **rate** to **nearly 2% by** the **end** of **this year** – slightly higher than the level that prevailed before the pandemic hit the U.S. economy two years ago, when they slashed rates to near zero. Their **median projections show** the **rate** rising to **around 2.75%** by the **end** of **2023**, which would be the **highest since 2008**.

The Fed's move to combat inflation cheered stock investors, as major indexes rocketed sharply higher. The blue-chip Dow Jones Industrial Average rose 518.76 points, or 1.5%, to 34063.10.

The Fed's post-meeting statement hinted at rising concern about inflation that initially appeared last year to be driven by pandemic-related bottlenecks but has since broadened.

"As I looked around the table at today's meeting, I saw a committee that's acutely aware of the need to return the economy to price stability and determined to use our tools to do exactly that," Chairman Jerome Powell said at a news conference that followed the Fed's first fully in-person meeting in two years.

Mr. Powell signaled greater concern that higher inflation might persist due to a hot job market with record job openings and wages up at their fastest pace in years. "That's a **very**, **very tight labor market** – tight to an unhealthy level, I would say," he said.

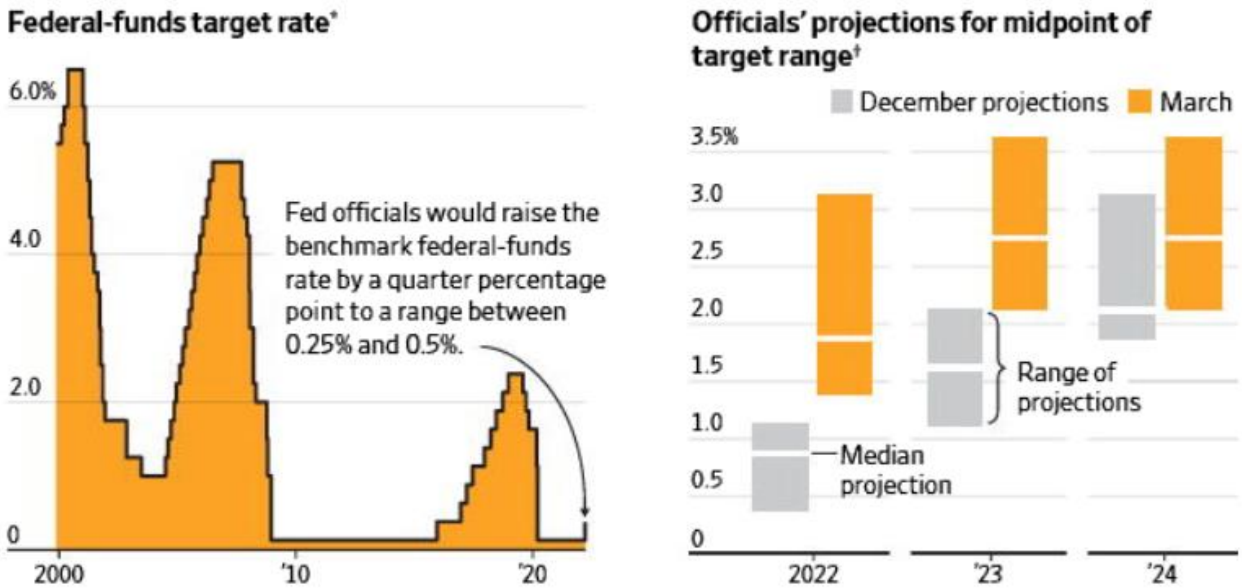
Stock indexes rallied after Mr. Powell began speaking. **Yields** on the benchmark **10-year Treasury note rose to 2.185%**, compared with 2.16% on Tuesday and the highest level since May 2019.

The rate-setting **Federal Open Market Committee approved** the **rate increase** on an **8-to-1 vote**, with **St. Louis Fed President James Bullard dissenting in favor** of a **larger half-point increase**.

Mr. Powell said that the **Fed could finalize** a **plan** to **shrink** its **$9 trillion asset portfolio** at its **next meeting**, **May 3-4**, and to implement it shortly after. The central bank ended a long-running asset-purchase stimulus program last week.

New projections show officials expect to raise rates at a much faster pace than they projected in December, when most penciled in three quarter-percentage point rate increases for this year, and considerably quicker compared with a series of nine interest rate increases between 2015 and 2018. It would be closer to the 2004-06 period, when the Fed raised rates 17 times in succession.

Most officials expect the fed-funds rate to rise to at least 1.875% by the end of this year and 2.75% by the end of 2023, holding there in 2024.



*Shows midpoint of range since 2008. †Based on responses of 18 officials in December and 16 officials in March.
Source: Federal Reserve

At the same time, most Fed officials indicated they didn't anticipate a need to raise interest rates above 3% over the next few years. "The rhetoric is 'do-whatever- it-takes,' but the forecast is 'hope-for-the-best,' " said Vincent Reinhart, chief economist at Dreyfus and Mellon.

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

How much other interest rates rise will depend on how investors, businesses and households respond.

The **Fed's** decision Wednesday marked a **sharp reversal from just two years ago**, **when** it **lowered rates to near zero** and launched a suite of programs to steady markets and support the economy as **Covid-19** shut down large swaths of the country. The **pandemic triggered** a **severe two-month recession** in **2020** and **record job losses**.

Since then, economic output has recovered amid **massive federal stimulus** and vaccinations, and **inflation surged** one year ago. The recent episode has been a far cry from the seven years of near-zero interest rates the Fed maintained after the 2008 financial crisis.

Inflation rose 6.1% in January from a **year earlier**, according to the Fed's preferred gauge. Core inflation, which includes food and energy, rose 5.2%. Most officials now see core inflation ending the year at 4.1%. They see interest-rate increases bringing inflation down further, to 2.6% at the end of 2023 and to 2.3% the year after.

Even **before Russia's invasion** of **Ukraine**, Fed officials had turned uneasy at the prospect inflation might not diminish as rapidly as they had been expecting. **U.S. labor markets have tightened rapidly**, with the **unemployment rate falling to 3.8% in February**.

Now, officials are facing the **prospect** of **even higher inflation due to escalating sanctions** by the **West against Moscow**, which risk higher energy and commodity prices, together with new pandemic lockdowns in China that further roil battered global supply chains.

Mr. Powell continued to lay the groundwork for the possibility of raising rates by a half point later this year. Seven officials projected the Fed would need to raise rates above 2% this year, a level that would require at least one of their moves this year to be a half-point increase, which the Fed hasn't done since 2000.

In the weeks leading up to Wednesday's meeting, Mr. Bullard, who favored the bigger rate increase, had said the Fed needed to raise rates faster or "risk squandering policy credibility." Due to the Fed's policies that limit communications before and after policy meetings, Mr. Bullard isn't likely to comment publicly on his dissent before Friday.

"They played it safe," said Johan Grahn, who oversees exchange- traded funds at Allianz Investment Management in Minneapolis, who had advocated a half-point hike. "To get their credibility back, they will need to do something bolder."

Economists said there is a growing risk that Mr. Powell could feel pressure to lift rates to levels that tip the economy into recession. That would especially be the case if policy makers conclude that consumers' and businesses' expectations of future inflation are rising or if officials see growing evidence of a wage-price spiral in which workers coping with climbing prices demand more pay increases, leading businesses to continue raising prices.

Fed officials face three important questions as they consider their next moves. First, how quickly do they need to raise rates to an estimated "neutral" level that neither speeds nor slows growth? Second, has that neutral level increased as rising inflation sends down real, or inflation-adjusted, borrowing costs? And third, will the Fed need to raise rates above neutral to deliberately slow growth, and if so, by how much?

Wednesday's projections show Fed officials thought they might need to raise the fed-funds rate slightly above a neutral level this year or next. Most officials estimate that is between 2% and 3% when underlying inflation – stripped of idiosyncratic influences such as from supply shocks – is at the Fed's 2% target.

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Inflation is Outpacing Oregon Wages

by Mike Rogoway – Oregonian – April 3, 2022

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

Here's how major industries measure up.

Oregon wages losing ground

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

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

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

Source: Oregon Employment Department • Get the data

OREGONLIVE
The Oregonian

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

–

Inflation Reached 7.9% in February; Consumer Prices Are the Highest in 40 Years

by Gabriel T. Rubin – WSJ – Mar. 10, 2022

Surging energy costs related to Russian invasion of Ukraine are pushing prices higher.

The outbreak of war is threatening higher inflation for longer.

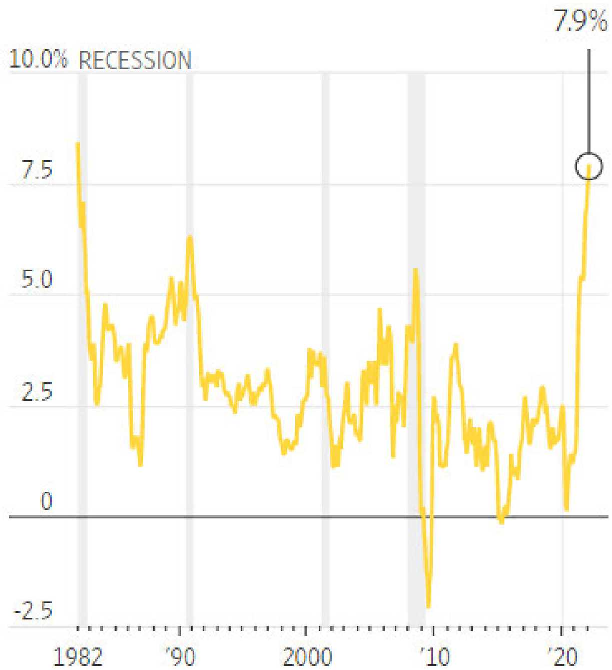
U.S. inflation climbed to a **7.9% annual rate in February**, another **four-decade high**, as **skyrocketing energy** and **commodity prices related** to the **Russian invasion** of **Ukraine pushed already-elevated costs higher**.

The **Labor Department's consumer-price index**, which measures the cost of goods and services across the economy, was at its **highest rate since January 1982**, **when annual inflation** was **8.4%**

Rising energy prices, including higher gasoline prices, helped push up the inflation reading, along with increases for groceries, restaurant food, transportation services and apparel. Economists expect additional price increases related to the Ukraine crisis after crude oil prices in March hit their highest levels since 2008, and U.S. gasoline prices reached record highs.

Excluding volatile energy and food prices, the Labor Department reported Thursday that consumer inflation rose at a 6.4% annual rate in February, up from 6% the prior month.

Consumer-price index, 12-month change



Source: Labor Department

The 12-month rates aren't adjusted for seasonality. The CPI measures what consumers pay for goods and services, including groceries, clothes, restaurant meals, recreation and vehicles. Month to month, CPI rose a seasonally adjusted 0.8% in February.

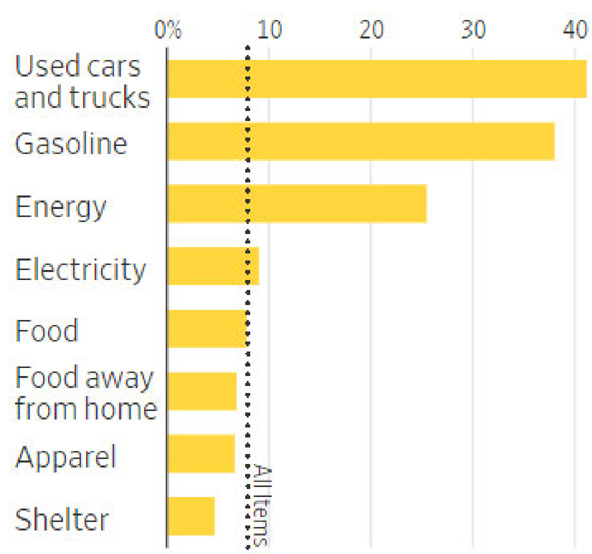
Gasoline prices were **up** a **seasonally-adjusted 6.6% from** the **prior month**, for an **unadjusted annual increase of 38%**. Groceries were up 1.4% over the prior month for an annual rate of 8.6%. Housing-rental costs rose at a slower rate, up 4.7% over the year. Used car prices declined slightly last month, pausing double digit price increases over the past year.

High demand for goods from consumers and supply-chain constraints have elevated inflation over the past year, with persistent shipping bottlenecks and shortages of supplies like semiconductors rippling across the economy. A **historically-tight labor market** has pushed wages higher and led to more open jobs than there are workers looking for work, leading businesses struggling to keep up with demand.

Before the Ukraine crisis, economists and policy makers had been hoping for a peak in year-over-year inflation this spring as supply chains heal from pandemic-related disruptions and the Federal Reserve begins an expected series of interest rate increases next week. But the **outbreak of war** has **supercharged prices** for **oil**, **wheat**, and **precious metals**, threatening higher inflation for longer.

"We thought that inflation would come down, especially due to the untangling of the global supply chain, but we don't know

Consumer-price index, 12-month change ending in February



Note: Not seasonally adjusted
Source: Labor Department

how what's happening in Ukraine will re-tangle that," said Joel Naroff, chief economist at Naroff Economics LLC.

Fed officials were braced for a run of higher inflation to start the year, but recent trends have been higher than expected. Housing and food costs have risen sharply, and hints at moderating prices in the used-car market have been overshadowed by further disruptions in new automotive manufacturing.

Economic disruptions from Russia's invasion of Ukraine and the global response could further stoke inflation, in part because **Russia** is a top global **supplier** of **oil** and **natural gas**. One rule of thumb, which Fed Chairman Jerome Powell referenced last week, holds that a **$10-per-barrel increase in oil prices boosts overall U.S. inflation by 0.2 percentage point**. Brent crude, the global oil benchmark, has increased by around $40 a barrel since the start of the year. **Russia also** is a **major player** in global markets for **metals** used in the production of cars and airplanes and for components in fertilizer, a big expense in food production.

Because of Russia's role in global energy and other commodity markets, "we're going to see upward pressure on inflation at least for a while," Mr. Powell told the Senate Banking Committee last week.

Mr. **Powell** has **said** he **expects** the **central bank** to **raise rates** by a **quarter percentage point** at its **March 15-16 meeting** with additional increases to follow later in the year. The **plan** was **formulated ahead of** the **Ukraine invasion**.

"I do think it's going to be appropriate for us to proceed along the lines we had in mind before the Ukraine invasion happened," Mr. Powell said. "In this very sensitive time at the moment, it's important for us to be careful in the way we conduct policy simply because things are so uncertain and we don't want to add to that uncertainty."

On Sunday, the **nation's average gasoline price surpassed $4 a gallon** for the **first time since 2008**, according to AAA, which tracks retail prices daily. By Wednesday, prices had hit their highest level ever, unadjusted for inflation.

The surge in energy and commodity prices is the latest challenge for businesses that have had to test whether their customers are willing to pay higher prices for products and services.

John Merritt, vice president of Elaine Bell Catering in Napa, Calif., has been pleased to see the recovery of his business after a tough two years in which in-person events dried up and planning for the future seemed impossible. But the rising cost of labor and the lack of price stability for food and gas has hurt business.

"We're able to pass some costs on to customers, but a lot of people were contracted at lower prices," and rising costs have eaten up his profit margin, Mr. Merritt said.

To hedge against future price increases, Elaine Bell Catering has started to include an inflation rider in new contracts. "We're giving them the best price we can if they were having their event today," Mr. Merritt added. "But where we are booking things 18 months out commonly, we have to price this more like a long-term labor contract that has a CPI adjustment."

The nation's average gasoline price unadjusted for inflation hit a new high this week.

Some economists believe that inflation is still likely to peak soon, perhaps as early as this month. But the war in Ukraine increases the chance that the peak will be higher, and the descent to lower levels will take longer, they say.

"Momentum on the supply-chain front is disrupted by the war," said Kathy Bostjancic, chief economist at Oxford Economics. She has now raised her expectations for annual inflation at the end of 2022 to closer to 4% rather than 3%.

A primary worry for policy makers going forward is that higher wages will keep pressure on inflation by causing companies to raise prices to account for labor costs. Still, **private-sector average hourly earnings rose** a **seasonally adjusted 5.1%** in **February from** the **previous year**, **lower than** the **rate of inflation**.

Nitin Kumar, a Herndon, Va., resident who works at a financial technology company, was grateful to get a "substantial raise" at the beginning of 2022, but after seeing the rate of inflation, has questioned how far his money really goes. He is considering whether he should shop at a discount grocery store or take other cost-saving measures.

"I need to start considering things I can do myself – like walk more instead of driving," Mr. Kumar said. "It's not a sustainable practice to spend more."

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NW Natural Holdings Announces Common Stock Offering

Co. Press Release – Mar. 29, 2022

Northwest Natural Holding Company, (NYSE: **NWN**) (NW Natural Holdings), **announced** today the commencement of an **underwritten public offering** of **2,500,000 shares** of its **common stock**. In conjunction with this offering, NW Natural Holdings intends to grant the **underwriters** a **30-day option** to **purchase up to** an **additional 375,000 shares** of its common stock.

The **net proceeds** from the offering will be used for general corporate purposes, including **repayment** of its **short-term indebtedness** and/or making **equity contributions to** NW Natural Holdings' subsidiaries, **Northwest Natural Gas Company** (NW Natural), **NW Natural Water Company** (NW Natural Water), and NW **Natural Renewables Holdings** (NW Natural Renewables). Contributions to NW Natural, NW Natural Water, and NW Natural Renewables will be used for general corporate purposes. **A portion** of any contribution **received** by **NW Natural** may be **used** to **repay** its **short-term indebtedness**.

Wells Fargo Securities, **J.P. Morgan** and **RBC** Capital Markets are acting as **book-running managers** of the offering. **Siebert Williams Shank** is acting as **co-manager of** the **offering**.

This offering is being made under an effective **shelf registration** statement filed with the U.S. **S**ecurities and **E**xchange **C**ommission, and only by means of a prospectus supplement for this offering and a related base prospectus. Copies of the **prospectus** supplement and related base prospectus may be obtained by contacting:

Wells Fargo Securities, LLC
Attention: Equity Syndicate Department
500 West 33rd Street
New York, NY 10001
Telephone: (833) 690-2713
Email: cmclientsupport@wellsfargo.com

J.P. Morgan Securities LLC
c/o Broadridge Financial Solutions
1155 Long Island Avenue
Edgewood, NY 11717
Telephone: (866) 803-9204

RBC Capital Markets, LLC
Attention: Equity Syndicate
200 Vesey Street, 8th Floor
New York, NY 10281
Telephone: (877) 822-4098
Email: equityprospectus@rbccm.com

Email: prospectus-eq_fi@jpmorganchase.com

This press release does not constitute an offer to sell or the solicitation of an offer to buy the securities described herein, nor shall there be any sale of these securities in any jurisdiction in which such an offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction.

ABOUT NW NATURAL HOLDINGS

Northwest Natural Holding Company, (NYSE: NWN) is a public utility holding company headquartered in Portland, Oregon, which, through its largest subsidiary, Northwest Natural Gas Company, provides natural gas distribution service to approximately two million people in more than 140 communities through more than 785,000 meters in Oregon and Southwestern Washington. NW Natural Water provides water distribution and wastewater services to communities through the Pacific Northwest and Texas. NW Natural Renewables is investing in renewable energy and the transition to a decarbonized future with a focus on the production and supply of net low-carbon fuels supporting a variety of sectors.

Forward-Looking Statements

This press release contains forward-looking statements regarding our planned offer and sale of common stock and the use of the net proceeds from any such sale. NW Natural Holdings cannot be sure that we will complete the offering or, if we do, on what terms we will complete it. Forward-looking statements are based on current beliefs and expectations and are subject to inherent risks and uncertainties, including those discussed under the captions “Risk Factors” and “Forward-Looking Statements” in the prospectus and prospectus supplement. In addition, NW Natural Holdings’ management retains broad discretion with respect to the allocation of the net proceeds of this offering. The forward-looking statements speak only as of the date of this release, and NW Natural Holdings is under no obligation to, and expressly disclaims any such obligation to, update or alter its forward-looking statements, whether as a result of new information, future events, or otherwise, except as may otherwise be required by law.

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NW Natural Holdings Prices Public Offering of Common Stock

Co. Press Release – Mar. 29, 2022

Northwest Natural Holding Company (NYSE: **NWN**) (NW Natural Holdings) announced today the **pricing** of an **underwritten public offering of 2,500,000 shares** of its **common stock**, at a price to the public of **$50.00 per share**. In connection with the offering, NW Natural Holdings granted the **underwriters** involved in the offering with a **30-day option** to **purchase** up to an **additional 375,000 shares** of its **common stock**. The offering is **expected** to **close** on **April 1, 2022**, subject to customary closing conditions.

The net proceeds from the offering will be used for general corporate purposes, including repayment of its short-term indebtedness and/or making equity contributions to NW Natural Holdings' subsidiaries, Northwest Natural Gas Company (NW Natural), NW Natural Water Company (NW Natural Water), and NW Natural Renewables Holdings (NW Natural Renewables). Contributions to NW Natural and NW Natural Water will be used for general corporate purposes. A portion of any contribution received by NW Natural may be used to repay its short-term indebtedness.

Wells Fargo Securities, J.P. Morgan and RBC Capital Markets are acting as book-running managers of the offering. Siebert Williams Shank is acting as co-manager of the offering.

This offering is being made under an effective shelf registration statement filed with the U.S. Securities and Exchange Commission, and only by means of a prospectus supplement for this offering and a related base prospectus. Copies of the prospectus supplement and related base prospectus may be obtained by contacting:

Wells Fargo Securities, LLC
Attention: Equity Syndicate Department
500 West 33rd Street
New York, NY 10001
Telephone: (833) 690-2713
Email: cmclientsupport@wellsfargo.com

J.P. Morgan Securities LLC
c/o Broadridge Financial Solutions
1155 Long Island Avenue
Edgewood, NY 11717
Telephone: (866) 803-9204
Email: prospectus-eq_fi@jpmorganchase.com

RBC Capital Markets, LLC
Attention: Equity Syndicate
200 Vesey Street, 8th Floor
New York, NY 10281
Telephone: (877) 822-4098
Email: equityprospectus@rbccm.com

This press release does not constitute an offer to sell or the solicitation of an offer to buy the securities described herein, nor shall there be any sale of these securities in any jurisdiction in which such an offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction.

About NW Natural is not duplicated herein.

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

by Kristine de Leon – Oregonian – Mar. 27, 2022
https://www.oregonlive.com/business/2022/03/portland-metro-slammed-the-brakes-on-population-growth-in-2021-census-estimates-show.html

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

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

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

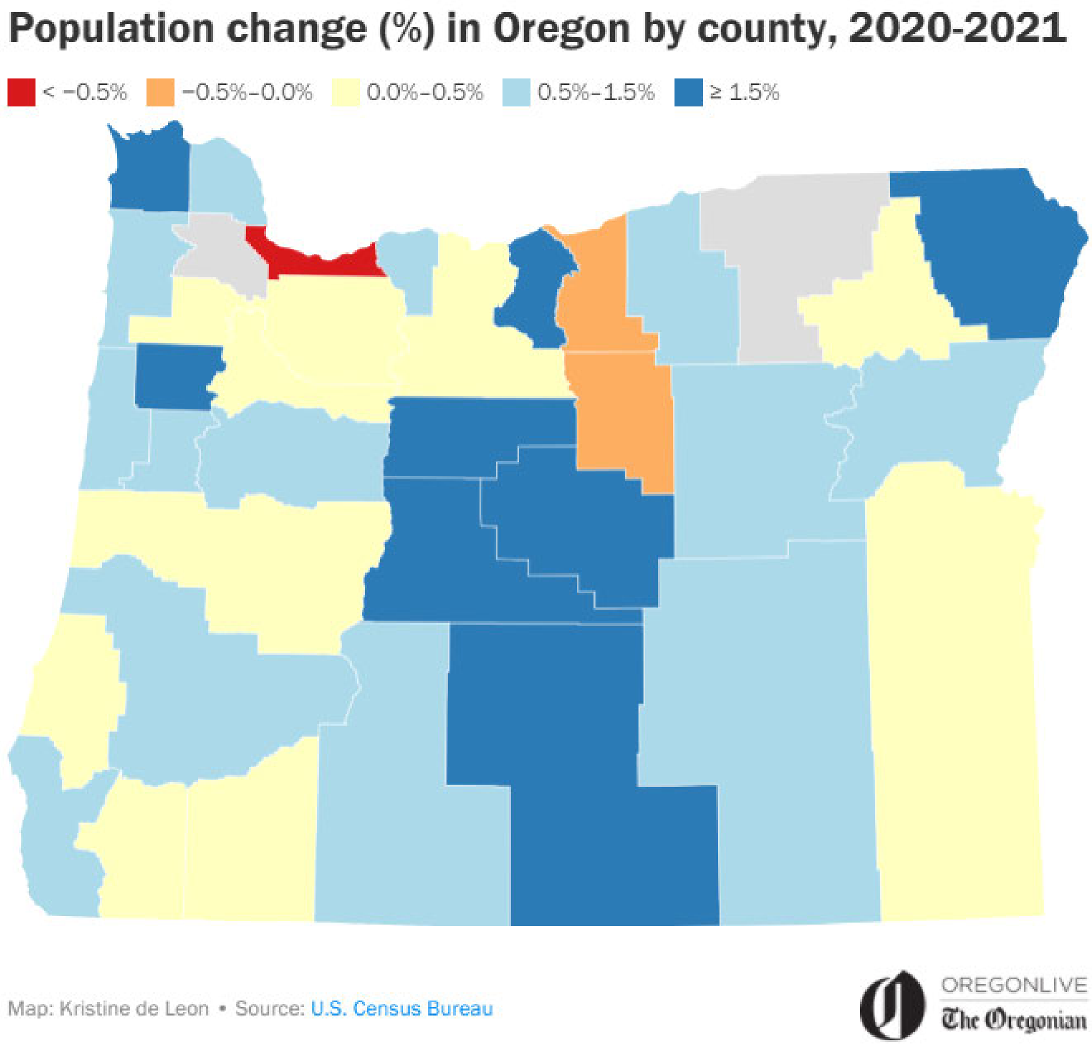
The relatively small decline conflicts with other estimates. Charles Rynerson, a faculty member of the Population Research Center at Portland State University, said the center's own estimates for 2021 showed a slight increase in population.

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

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

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

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



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

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

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

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

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

Oregon metro area population change, 2020-2021

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

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

OREGONLIVE The Oregonian

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

The **Census Bureau updates population estimates every year using** the **most recent decennial census** — **in this case**, the **2020 figures** — **as** a **baseline**. Annual population estimates are **projected using vital records** such as **birth and death certificates**, **tax returns from** the **IRS**, **housing counts**, **building permits** and **school enrollment**.

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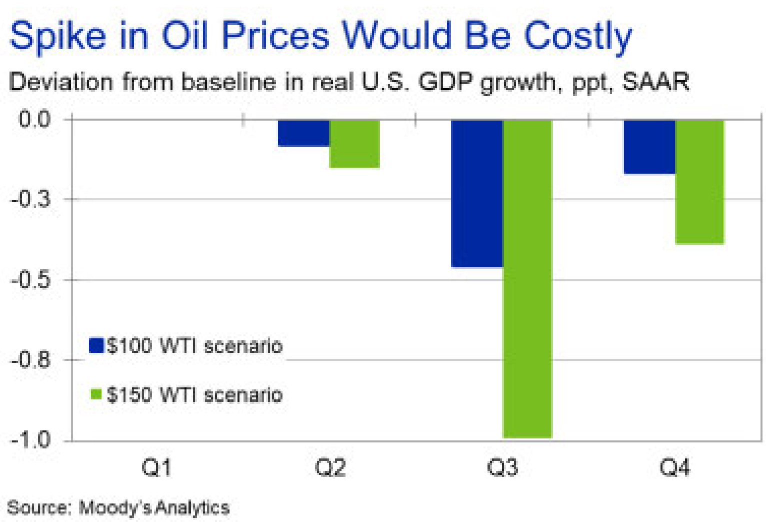
Russia's Invasion of Ukraine Rattles Global Markets

Moody's Analytics – Feb. 24, 2022

The significant escalation of the **Ukraine-Russia conflict rattled equity markets** and led to an **increase** in **global oil prices**, which likely had some risk premium already embedded. West Texas Intermediate and Brent crude oil prices both increased and are trading near, or above, $100 per barrel. The conflict will have a significant impact on economic growth in Eastern Europe, as it is the most reliant on Russian imports. The effect on the U.S. economy is tied to equity markets and oil prices.

Earlier this month, we ran two scenarios through our Global Macroeconomic Model. In the first scenario, West Texas Intermediate crude oil prices jump to $100 per barrel, and the second has oil prices hitting $150. In each scenario, increases in oil prices occur in the second quarter and remain there in the third quarter before returning to the baseline. This movement in oil prices would be consistent with a sudden but temporary supply shock.

The more economic costs increase, the higher oil prices rise. In the $100-per-barrel oil price scenario, GDP growth in the second quarter is reduced by 0.1 of a percentage point, but it reduces GDP growth in the third quarter by 0.5 of a percentage point and 0.2 of a percentage point in the final three months of the year. If oil prices are $150 per barrel in the second and third quarters, the hit to GDP growth this year is more noticeable. GDP growth in the second quarter is reduced by 0.2 of a percentage point, 1 percentage point in the third quarter, and 0.4 percentage point in the final three months of the year. Year-over-year growth in the CPI is 0.5 of a percentage point higher than in the baseline in the second quarter and 0.6 of a percentage point in the third quarter



Higher oil prices will boost inflation and increase the cost at the pump. Wholesale gasoline futures, which lead U.S. retail gasoline prices by two weeks, point toward prices at the pump reaching $3.75 per gallon, compared with $3.58 in the week ended February 18. If oil prices continue to climb, then $4-per-gallon gasoline will become a reality. Our rule of thumb is that **for every $10 increase** in **oil prices**, **retail gasoline prices rise by 30 cents per gallon**.

U.S. corporate bond market not immune

U.S. high-yield corporate bond issuance has come to a grinding halt as geopolitical tensions, wider spreads, heightened volatility in equity markets and fund outflows have taken a toll. The Barclays/Bloomberg high-yield corporate bond spread has widened by 76 basis points since the beginning of the year to 359 basis points, the widest since early 2021. Though high-yield corporate bond spreads are well below their historical average of 496 basis points, the abruptness of the widening in spreads is hurting issuance, contributing to the more-than-4% decline in junk bond total returns this year.

Investors have been pulling money out of high-yield funds for more than a month. Issuance doesn't look like it's going to improve soon as the pipeline is very lean and geopolitical tensions have intensified. So far, the issues in the high-yield corporate bond market are attributed to interest rates rather than defaults, with the latter near historic lows. High-yield corporate bond issuance normally doesn't thrive when there is a lot of volatility in equity markets. The VIX has jumped recently and is at 30, which foreshadows further widening in high-yield corporate bond spreads.

The Russian-Ukraine conflict will continue to impact the U.S. high-yield corporate bond market, but the **implications** for the **broader domestic banking system** are **minimal**. U.S. banks have a small exposure to Russian banks, according to the Bank for International Settlements. Therefore, **U.S. sanctions** are **unlikely** to **ripple through the domestic banking system**, keeping the risk of contagion low. The Russian-Ukraine conflict is weighing on U.S. equity markets, but there has also been a significant increase in Russia's five-year credit default-swap spreads

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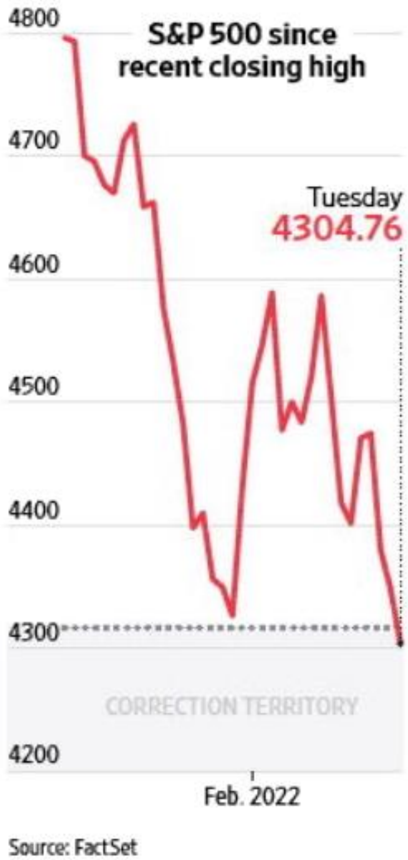
S&P 500 Slips into Correction, Off 10% from Its January High

by Will Horner and Michael Wursthorn – WSJ – Feb. 23, 2022

Investors say the situation remains too fluid to say the selling is done.



Stocks dropped in a volatile trading session Tuesday that pushed the S& P 500 into correction territory as **tensions** in **Eastern Europe escalated**.

The broad stock-market index closed down 1%, hitting its lowest level in more than four months, as investors digested the ramifications of **Russia's deployment** of **soldiers into Ukraine's eastern Donbas region**.

The threat of war has become the latest wild card for investors who were already concerned with supply-chain disruptions, rapidly rising inflation and central banks' plans to tighten monetary policy.

The **S&P 500** declined 44.11 points to 4304.76, leaving the index **down more than 10% from** its **Jan. 3 high** and marking its **first correction since** the onset of the Covid-19 pandemic in **February 2020**.

The index pared even bigger losses of nearly 2% after President Biden unveiled sanctions against Russia that were less aggressive than feared, analysts and investors said.

Stocks, which were near their session lows during Mr. Biden's speech outlining the sanctions, recouped a chunk of their declines.

"We don't think heightened sanctions by themselves would meaningfully impact the long-term earnings potential of U.S. companies," said Dave Sekera, Morningstar's chief U.S. market strategist.

The sanctions followed similar actions by the European Union. The U.K. froze the assets of some oligarchs and cut five midsize Russian lenders off from its financial system. **Germany** said it **halted** moves to **open** a **natural-gas pipeline** to Europe that would bypass Ukraine, helping to send energy prices higher.

The greatest risk, Mr. Sekera said, is the U.S. potentially being drawn directly into the conflict, which would inevitably weigh on stocks.

The Dow Jones Industrial Average ended the session down 482.57 points, or 1.4%, to 33596.61, while the Nasdaq Composite, which suffered a correction in January, declined 166.55 points, or 1.2%, to 13381.52. The Dow is off 8.7% from its January record, and the Nasdaq is 17% below November's high.

Investors said the situation remains too fluid to say the selling is done and warned that more sessions could play out like Tuesday.

"Investors are de-risking as the situation escalates and uncertainty builds regarding the path forward," said Lindsey Bell, chief markets and money strategist for Ally Invest. "Markets are likely to be on edge for the next several weeks."

Ms. Bell added geopolitical tensions tend to have a dramatic, immediate effect on markets, but the shock usually wears off over time. Besides higher oil prices, Russia's invasion of Ukraine isn't likely to have a significant impact on the U.S. economy, she said.

Brent oil rose $1.45 a barrel, or 1.5%, to $96.84.

All 11 sectors of the **S&P 500** closed **lower Tuesday**. **Sectors** of the **market** that **investors** tend to **flock to during** periods of **uncertainty** – **including** shares of **utilities** and real-estate firms—**suffered** relatively **minor losses**, while **riskier** corners of the market, such as **growth stocks**, **suffered bigger losses**.

Consumer-discretionary stocks were **hit** the **hardest**, with the group shedding 3%. Geopolitical tensions played a part, analysts said, as did concerns about economic growth this year.

Home Depot shares led the group lower, falling $30.70, or 8.9%, to $316.17 after the company posted slightly slower sales growth than it did earlier in the pandemic, making it the biggest drag on the price-weighted Dow.

Other retail stocks followed, including Best Buy, Lowe's and Dollar General, all falling more than 3.6% each. Makers of household durables, including Whirlpool and D.R. Horton, also fell alongside shares of hotels, restaurants and leisure companies.

Technology stocks in the S& P 500, which were briefly higher earlier in the day, fell 0.9%. Communication companies shed 1%. Energy stocks, which got a momentary boost higher from oil prices, were also in the red, with Exxon Mobil and Halliburton falling at least 1.2% each.

The showdown along Ukraine's border spoiled some relatively upbeat earnings news. Shares of Macy's, which had been trading higher most of the morning, declined $1.28, or 5%, to $24.42 despite posting better-than-expected earnings.

In the bond market, the yield on the benchmark U.S. Treasury note edged higher to 1.947%. Gold prices rose 0.1%.

Russia's benchmark MOEX stock index climbed 1.6%, turning higher after the sanctions unveiled in the EU and U.K. didn't target Russia's biggest banks. The U.S. sanctions focus on two Russian financial institutions, the nation's sovereign debt and the country's elite individuals. The index had dropped 10.5% Monday, which was its biggest daily percentage decline in almost eight years. The ruble edged higher against the dollar after falling to its lowest level since February 2020.

European stock indexes reversed earlier sharp losses, with the pan-continental Stoxx Europe 600 up 0.1%.

"Investors have switched from thinking it is posturing, saber-rattling to thinking there has become a real threat of a conflict," said Altaf Kassam, head of investment strategy and research for Europe, the Middle East and Africa at State Street Global Advisors. "Things have gotten to a point where it feels like it is hard to step back from."

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South Jersey Industries Deal Reinforces Lofty Gas Utility Valuations

by Tod DiChristopher – S&P Global Market Intelligence – Feb 24, 2022

Financial sector buyers such as infrastructure funds appear willing to pay premiums for gas utility assets and could drive M&A activity in the sector, analysts say

The **$8.1 billion buyout** of **South Jersey Industries** Inc. presents further **evidence** that **local gas distribution companies** will continue to **command strong valuations** in the **m**ergers **and a**cquisitions market, analysts said.

The strength of local gas distribution company valuations has been top-of-mind for industry watchers since **April 2021** when **CenterPoint** Energy Inc.'s **Arkansas and**

Oklahoma gas utilities fetched premium value. The market has also seen the valuations as a bellwether for sector sentiment at a time when **pipeline project headwinds** and **building gas bans** have unsettled investors.

"The acquisition represents a significant premium to current market prices and validates that LDCs will continue to play a significant role in U.S. energy and evolve with the energy transition," Stifel analyst Selman Akyol said in a Feb. 24 research note.

LDC valuations remain strong

The **deal values South Jersey** Industries, or SJI, at **21 times** Stifel's **2022 EPS estimates** for the company and 20 times its 2023 EPS estimates, Akyol said. Guggenheim Securities LLC said the deal carried a multiple of **17.9 times consensus estimates** for **SJI's 2024 EPS**. **SJI's stock had been trading** at **12.1 times** the **company's 2024 EPS**, Guggenheim said in a Feb. 24 research note.

Expressed as a multiple of utility rate base, the deal value did not quite match **CenterPoint's 2021 sale**, though the SJI announcement reinforced recent strong valuations. The CenterPoint deal **valued** the **assets at 2.5 times** their **combined 2020 rate base**, **while** the **SJI buyout** penciled out to **2 times** its **2021 utility rate base**, according to Guggenheim.

Dominion Energy Inc.'s recent **sale** of **Hope Gas** Inc. **valued** the **West Virginia gas distributor** at **2 times** its **2021 rate base** and **26 times 2021 EPS**, Guggenheim said.

In interviews with S&P Global Market Intelligence shortly after the CenterPoint deal, gas utility executives were optimistic that the valuation would telegraph to investors that gas distribution systems remained valuable assets. But they also saw those lofty valuations as hurdles to strategic M&A among utilities seeking to bolt on complementary territory.

Financial buyers may drive M&A

The multiples may not put a stop to deal-making, according to Guggenheim analyst Shahriar Pourreza. The SJI deal cemented Guggenheim's view that financial sector buyers will bid on LDC deals of all sizes.

"Over the past two years we have seen financials begin to pay-up for gas LDC assets," Guggenheim said. "While transactions of late have been generally on the smaller side, we believe this latest data point opens up the environment for larger deals and increases the funding optionality for gas/electric hybrids in the space."

SJI's acquirer, Infrastructure Investments Fund, **was** the **buyer behind CenterPoint's blockbuster LDC sale**, through one of the fund's portfolio companies, Summit Utilities Inc. The **buyer** in the **Hope Gas acquisition was** also **an infrastructure fund**, **operated by Ullico** Inc.

In Guggenheim's view, future LDC sellers could be multi-utilities that need to finance electric power investments and execute decarbonization policies, similar to CenterPoint's strategy. During a Feb. 23 conference call, NiSource Inc. President and CEO Lloyd Yates said the company would consider selling LDC assets and rebalancing its portfolio toward electric operations.

Potential for additional LDC sales

SJI's sale could also hint at M&A among other small gas utility operators, **such as** New Jersey Resources Corp., **Northwest Natural** Holding Co., Spire Inc. and One Gas Inc., Guggenheim said. However, those companies either have larger nonregulated business lines or multi-state footprints that differentiate them from SJI, the analyst report noted.

Guggenheim speculated that SJI's management and board of directors may have tired of gas utilities' persistent valuation discount to electric peers and other parts of the market. Guggenheim said it did not see an opportunity for SJI to reset its valuation based on fundamentals, which drove Guggenheim to downgrade SJI's stock recently.

Asked about the SJI deal and the difference between private and public market valuations of LDCs, One Gas President and CEO Sid McAnnally acknowledged the dislocation during a Feb. 24 quarterly conference call. However, the executive suggested the company's five-year, $3.5 billion capital plan across its three-state footprint would drive shareholder value.

"Given the opportunities that we have going forward on both the growth and the system integrity-slash-maintenance side, we feel like we're really well positioned to execute this plan," McAnnally said.

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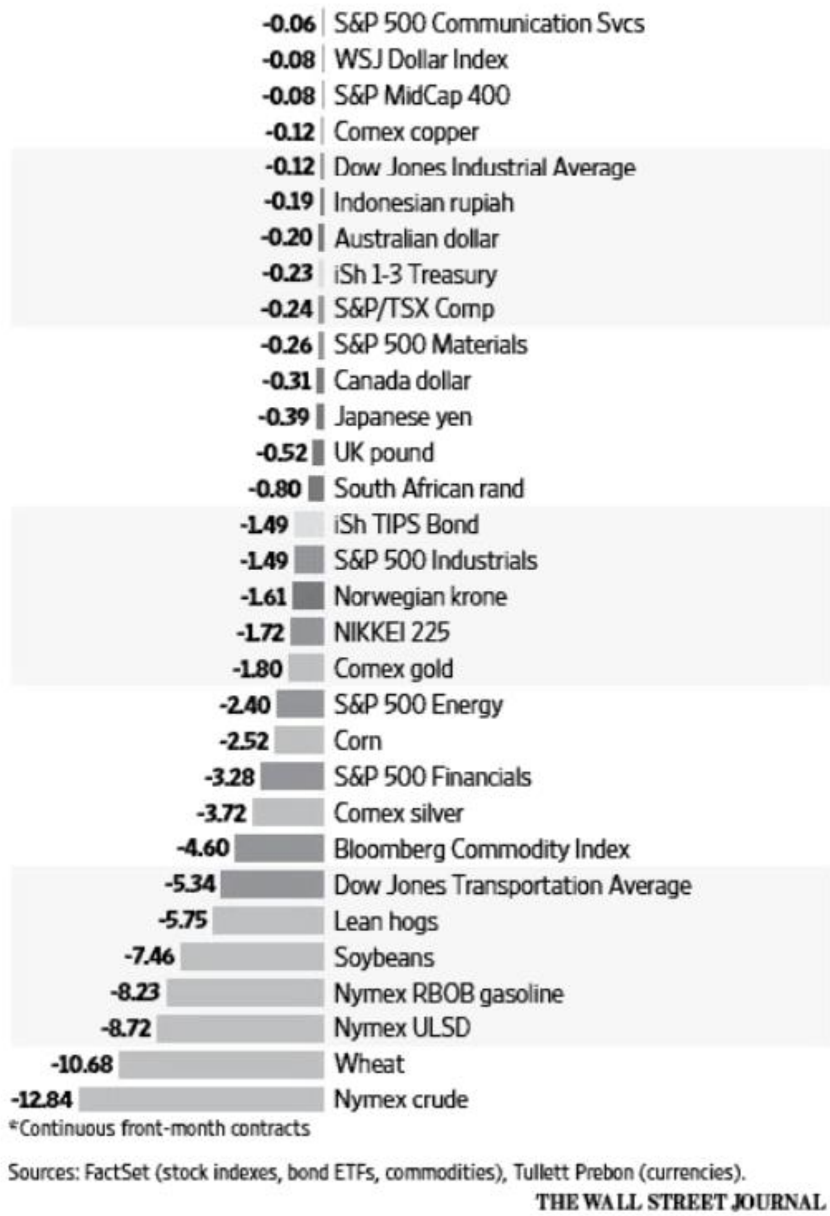
Track the Market Winners and Losers

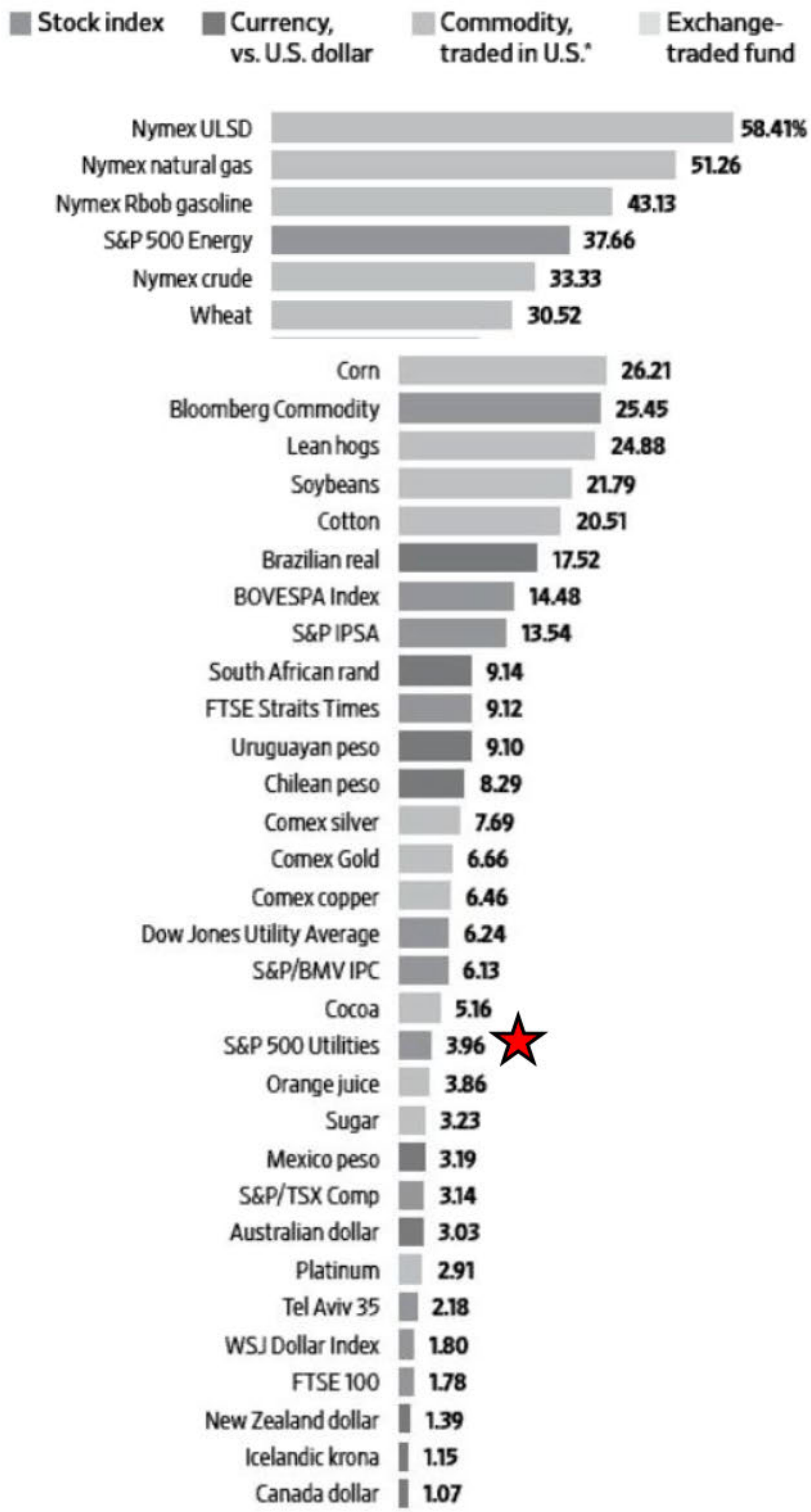
WSJ – April 2, 2022

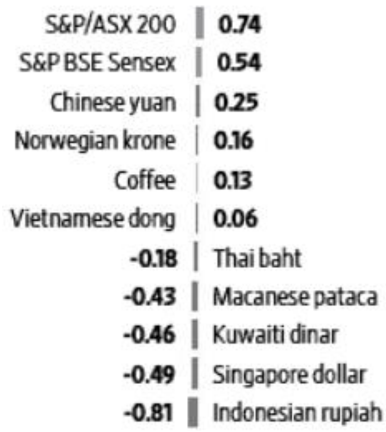
A look at how selected global stock indexes, bond ETFs, currencies and commodities performed around the world for the **week**.

Continued on next page



A look at how selected global stock indexes, bond ETFs, currencies and commodities performed around the world for the **quarter**.


Stock index
Currency, vs. U.S. dollar
Commodity, traded in U.S.*
Exchange-traded fund
Nymex ULSD 58.41%
Nymex natural gas 51.26
Nymex Rbob gasoline 43.13
S&P 500 Energy 37.66
Nymex crude 33.33
Wheat 30.52
Corn 26.21
Bloomberg Commodity 25.45
Lean hogs 24.88
Soybeans 21.79
Cotton 20.51
Brazilian real 17.52
BOVESPA Index 14.48
S&P IPSA 13.54
South African rand 9.14
FTSE Straits Times 9.12
Uruguayan peso 9.10
Chilean peso 8.29
Comex silver 7.69
Comex Gold 6.66
Comex copper 6.46
Dow Jones Utility Average 6.24
S&P/BMV IPC 6.13
Cocoa 5.16
S&P 500 Utilities 3.96
Orange juice 3.86
Sugar 3.23
Mexico peso 3.19
S&P/TSX Comp 3.14
Australian dollar 3.03
Platinum 2.91
Tel Aviv 35 2.18
WSJ Dollar Index 1.80
FTSE 100 1.78
New Zealand dollar 1.39
Icelandic krona 1.15
Canada dollar 1.07



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-0.83 Czech koruna
-0.92 Malaysian ringgit
-1.11 Swiss franc
-1.18 Dow Jones Transportation Average
-1.54 Philippine peso
-1.63 S&P 500 Consumer Staples
-1.85 Indian rupee
-1.91 S&P 500 Financials
-2.14 South Korean won
-2.20 Hungarian forint
-2.56 Romanian new leu
-2.56 iSh 1-3 Treasury
-2.60 Israeli shekel
-2.67 Bulgarian lev
-2.69 Danish krone
-2.69 Euro area euro
-2.74 S&P 500 Industrials
-2.84 S&P 500 Materials
-2.85 UK pound
-2.88 Taiwan Weighted
-2.99 S&P 500 Health Care
-3.08 IBEX 35
-3.24 New Taiwan dollar
-3.37 NIKKEI 225
-3.42 Croatian kuna
-3.51 Bel-20
-3.58 iSh TIPS Bond
-3.67 Swedish krona
-4.06 Polish zloty
-4.34 Pakistani rupee
-4.43 DJ Select REIT

-4.57	Dow Jones Industrial Average
-4.93	VangdTotIntlBd
-4.95	S&P 500
-5.22	S&P MidCap 400
-5.42	Japanese yen
-5.42	iShiBoxx$HYCp
-5.55	Swiss Market Index
-5.71	iShNatlMuniBd
-5.93	S&P SmallCap 600
-5.99	Hang Seng
-6.15	VangdTotalBd

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*Continuous front-month contracts
Sources: FactSet (stock indexes, bond ETFs, commodities), Tullett Prebon (currencies).

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U.S. Inflation Accelerated to 8.5% in March, Hitting Four-Decade High

by Gwynn Guilford – WSJ – Apr. 12, 2022

Consumer-price index increase from year earlier driven by skyrocketing energy and food costs.

Gasoline prices have come down slightly in recent weeks,
but they remain near record highs.

U.S. inflation surged to a **new four-decade high** of **8.5% in March** from the same month a year ago, driven by **skyrocketing energy and food costs**, **supply constraints and strong consumer demand**.

The Labor Department on Tuesday said the **C**onsumer-**P**rice **I**ndex – which measures what consumers pay for goods and services – **last month rose** at its **fastest annual pace since December 1981**, up from the 7.9% annual rate in February. Rising prices have been unrelenting, with **six straight months** of **inflation above 6%** that is well above the Federal Reserve's average 2% target.

U.S. stocks gave up their early gains and government-bond yields declined following the inflation report.

High inflation is the downside of booming growth as the economy bounces back from Covid-19, powered in part by low interest rates and government stimulus to counter the pandemic's impact. The Fed's top goal is to reduce inflation, Fed governor Lael Brainard said Tuesday at The Wall Street Journal Jobs Summit. The central bank faces a tough balancing act of tightening monetary policy without damping growth.

Russia's invasion of Ukraine drove a **March surge** in **oil and gasoline prices**, which hit records in mid-March, and overall energy prices shot up 11% from the prior month, the department said. **Prices** for **groceries accelerated** in March, rising 1.5% from a month earlier, while the cost increases for dining out moderated.

The so-called core price index, which excludes the often-volatile categories of food and energy, increased 6.5% in March from a year earlier – up from February's 6.4% rise, and the sharpest 12-month rise since August 1982.

Economists and investors are looking for evidence the inflation surge that started in early 2021 is close to a peak. One possible early sign came from the monthly change in the core index. It rose 0.3% in March from the prior month, the slowest pace in six months, driven by a 3.8% decline in used vehicle prices.

Another encouraging sign was that airline fares, hotel prices and other more volatile categories drove much of the price gains for services, while pressure from categories such as housing, which tend to be more persistent, eased, said Blerina Uruci, U.S. economist at T. Rowe Price Group Inc.

However, Ms. Uruci added that supply-chain constraints continue to push prices up, except for an easing of the costs for used cars.

"The other red flag is Russia's invasion of Ukraine and the **rise of Covid in China**," she said. "Those pose risks that the so-called normalization of supply chains takes longer to materialize."

Consumers are growing savvy to **shrink-flation**, the practice of **downsizing** the **contents** of a product rather than raising prices. So companies are getting creative. WSJ's Annie Gasparro explains how to spot it in all its forms. Illustration: Adele Morgan

China has in recent weeks **locked down** parts of the country, including **Shanghai**, as **Covid-19 cases hit** a **pandemic record there**, leading to the possibility of additional supply disruptions.

U.S. airline fares leapt 10.7% in March from February, accelerating as travel demand recovered from the last Covid-19 wave. Air-travel prices were 23.6% higher than they were a year earlier.

Auto prices, which have powered much of the inflationary surge, eased in March. New vehicle prices decelerated on a one-month basis, rising 0.2% in March from the prior month. However, the 12.5% 12-month increase was the sharpest since 1975. Despite the monthly decline in used-vehicle prices, those were still up 35.3% from a year earlier.

Persistently higher prices come as the overall economy is strong and the labor market is tight. **Employers added 431,000 jobs** in **March**, the **11th consecutive**

month with **gains above 400,000** – the **longest** such **stretch since records began** in **1939**.

High and rising inflation readings have cranked up pressure on the Fed to keep lifting interest rates this year to lower price pressures. The central bank raised its benchmark rate in March for the first time since 2018.

With job growth strong and inflation well above the Fed's target, many **Fed officials** have indicated they **could support raising rates by** a **half percentage point**—**instead of** the **traditional quarter point** – at their next meeting **in** early **May**.

Left: Steady price increases for meat, eggs and citrus fruits are pushing up consumers' grocery bills.

Food inflation is also raising consumers' grocery bills. Meat prices were up 14.8% in March from a year ago, with hot dogs and lunch meats rising at the fastest clip since 1979. Breakfast cereal prices climbed 9.2% in the past year, the sharpest increase since 1989. The **Ukraine** crisis is likely to add more pressure in coming months because of disruptions to global wheat and fertilizer production.

The burden of price rises could be triggering a consumer pullback, said Richard F. Moody, chief economist at Regions Financial Corp. **Consumer spending decelerated** in **February**, rising 0.2% from January, **though** it remains strong – **up 13.7% from** the **same month** in **2021**.

"There's an element of sticker shock when people go to fill up their tank or go to the grocery store. Lower-and middle-income households are already having to make choices about what to buy because they're having to pay so much more for food and energy," Mr. Moody said.

Alex Salwisz, 40 years old, is facing the rising costs of raising his five children. "The thing about having a big family is that each incremental increase is multiplied," he said.

He said he has tried to substitute generic food products for name-brand foods as prices shot up—not always successfully. His children – ages 3 to 12 – pushed back recently when he sneaked a bag of off-brand marshmallow cereal into a Lucky Charms box. "It didn't pass," said Mr. Salwisz, a program manager in information technology who lives in the Denver suburbs. "They had a little revolt, and more than one of them told me I shouldn't do that again."

Inflation has eroded their living standard in other ways, Mr. Salwisz said. The children have grumbled when the family crams uncomfortably into the smaller of two vans to save on gas. They have substituted a fast-food meal for the once-a-month sit-down dining experience. He and his wife, Amber Salwisz, are considering scrapping plans for summer camp because of a sharp increase in prices. One partial-day camp increased its price to $800 a week this summer from $500 the prior.

Left: A job fair earlier this month. Solid demand for labor has shifted bargaining power toward workers.

The bounce-back in demand for travel, dining and other services as Covid-19 cases decreased is also driving price gains, and could gain momentum as summer holidays spur more recreational spending. A steady **upswing** in **housing** costs, **which account** for nearly **one-third** of the **CPI**, is also **adding** to **inflationary pressure**.

Solid demand for labor has shifted bargaining power toward workers, putting upward pressure on wages, which could feed into broader price gains. **Annual wage growth** was **6% in March**, the **fastest pace since records began** in **1997**, according to the Federal Reserve Bank of Atlanta's wage tracker.

Still, wages for most are growing too slowly to offset inflation. This could push workers to demand higher wages, creating a feedback loop that puts upward pressure on inflation.

"Inflationary pressures are building across the basket but also across both prices and wages. We need to see that process start to settle down," said Robert Rosener, senior U.S. economist at Morgan Stanley.

One indicator of building inflationary pressure moderated in March. Consumers' median inflation expectation for three years from now fell to 3.7% last month, down from 3.8% in February, according to a survey by the New York Fed released on Monday. However, the **median expectation** for inflation a **year from now shot up to 6.6%** from 6% **in February**.

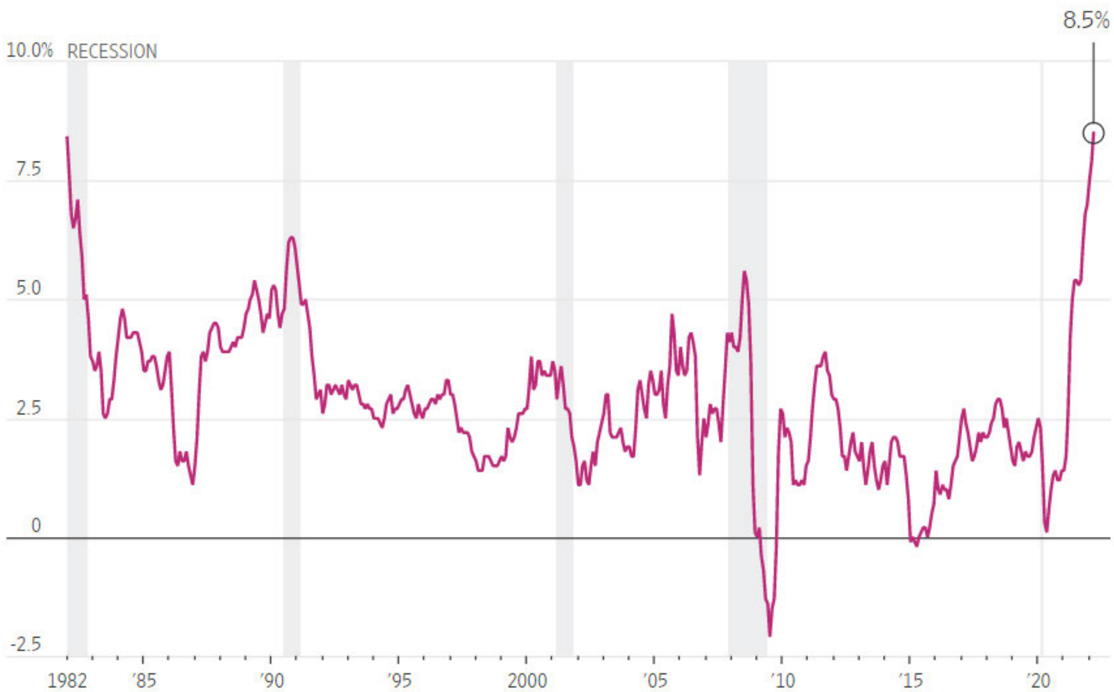
Ron Mayland, an aerial photographer in Cedar Rapids, Iowa, has experienced the triple-whammy of high costs from energy, supply-chain disruptions and labor.

"If you think filling up a car is expensive, try an airplane," he said, adding that he puts hundreds of dollars' worth of fuel in the tank every day. When he needed to buy small parts to repair one of his plane's oil-pressure systems, it took him two or three days to find the materials and they cost twice as much as he expected.

"I'm still getting sticker shock when pulling up to the pump, and then for the parts and the repairs – that's where it's really hitting me," he said. "It seems like the numbers are just getting bigger."

Iowa-based aerial photographer Ron Mayland has felt the impact from higher prices for fuel and airplane parts.

Consumer-price index, change from a year earlier



Source: Labor Department

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US DOJ Unseals Indictments Alleging Russia Cyberattacks on Energy Infrastructure

by Molly Christian – S&P Global Market Intelligence – Mar. 25, 2022

Four Russian nationals and their **co-conspirators carried out two separate cyberattack campaigns between 2012 and 2018** that **targeted energy infrastructure in** the **U.S. and** more than 135 **other countries**, the **U.S. D**epartment **of J**ustice **said in indictments unsealed March 24**.

The **hacking campaigns targeted thousands** of **computers** at **hundreds** of **companies and organizations**, **including** a foreign petroleum refinery and the **operator** of a **nuclear plant** in **Kansas**, according to the DOJ.

The Justice Department unsealed the charges as **U.S. energy companies** are **bracing for** potential **cyberattacks** in **retaliation for sanctions** that the **U.S. and other countries** have **imposed on Russia after** its **invasion** of **Ukraine**.

"The potential of cyberattacks to disrupt, if not paralyze, the delivery of critical energy services to hospitals, homes, businesses and other locations essential to sustaining our communities is a reality in today's world," U.S. Attorney Duston Slinkard for the District of Kansas said in a news release about the indictments.

"We must acknowledge there are individuals actively seeking to wreak havoc on our nation's vital infrastructure system, and we must remain vigilant in our effort to thwart such attacks."

Campaign focused on refineries

The **first indictment**, from June 2021, **alleged** that **Evgeny Viktorovich Gladkikh**, an employee of a **Russian Ministry of Defense research institute**, **and** his c**o-conspirators tried to damage** a **refinery** outside the U.S., causing two emergency shutdowns. Between May and September 2017, the defendant and co-conspirators allegedly **hacked** the refinery's systems and **installed malware** known as "**Triton**" or "**Trisis**" **on** a safety system produced by **multinational** corporation **Schneider Electric** SE.

The **malware** was **designed** to **prevent** the **refinery's safety system from functioning**. However, the malware caused a fault when deployed that prompted Schneider Electric's safety systems to initiate the automatic emergency shutdowns of the refinery's operations.

The DOJ said the conspirators in 2018 unsuccessfully attempted to hack the computer systems of a U.S. company that owned similar refineries in the U.S.

Another targeted global energy sector

The **second indictment** was more wide-ranging. In August 2021, a federal grand jury in Kansas City, Kan., **charged three Russian nationals** with violating U.S. laws related to computer fraud and abuse and causing damage to the property of an energy facility, among other offenses. The defendants – **Pavel Aleksandrovich Akulov, Mikhail Mikhailovich Gavrilov and Marat Valeryevich Tyukov** – were all **officers** of **Russia's Federal Security Service**, known as **FSB** due to its Russian name, **Federalnaya Sluzhba Bezopasnosti**.

Between 2012 and 2017, the three FSB officers and their co-conspirators "engaged in computer intrusions, including **supply chain attacks**, in furtherance of the Russian government's efforts to maintain surreptitious, unauthorized and persistent access to the computer networks of companies and organizations in the international energy sector," the DOJ's release said. The alleged hacking campaign targeted victims in the U.S. and more than 135 other countries.

In the first phase of the attacks, defendants are said to have **compromised** the **computer networks** of **companies' industrial control systems**, or **ICS**, and **supervisory control and data acquisition**, or **SCADA**, **systems**. They **installed malware on** more than **17,000 unique devices in** the **U.S. and other countries**, **including ICS**/**SCADA controllers used by power and energy companies**, **according to** the **DOJ**.

During the second phase of their campaign, the Justice Department alleged, the FSB officers and their co-conspirators conducted **spear-phishing attacks** on over

3,300 users at more than **500 U.S. and international** companies and **entities**, **as well as government agencies such as** the **U.S. Nuclear Regulatory Commission**.

The **defendants succeeded in some instances**, according to the DOJ, **managing** to **compromise** the **business network of** the **Wolf Creek Nuclear Operating Corp**. The company **operates** the **Wolf Creek plant** in **Kansas** owned by Evergy Inc. utilities Evergy Kansas South Inc. and Evergy Metro Inc., as well as Kansas Electric Power Cooperative Inc.

FBI 'laser-focused' on cybersecurity

Gladkikh, Akulov, Gavrilov and Tyukov were residents of Russia, the indictments said. The U.S. State Department has announced rewards of up to $10 million for information leading to arrests.

A federal district court judge will determine any sentences if the defendants are convicted, the DOJ said.

"The FBI, along with our federal and international partners, is laser-focused on countering the significant cyber threat Russia poses to our critical infrastructure," FBI Deputy Director Paul Abbate said. "We will continue to identify and quickly direct response assets to victims of Russian cyber activity."

Russia has long been a source of concern on the cybersecurity front for U.S. energy companies, with **cyber** experts attributing a December 2015 **attack** on **Ukraine's electric grid** to Russian actors. **Russia's invasion of Ukraine** has **ratcheted up** that alarm, with U.S. President Joe Biden repeating **warnings** recently that the **Russia**n government **could launch cyberattacks** on **U.S. critical infrastructure as retribution** for **economic sanctions imposed** in **response** to the **war on Ukraine**.

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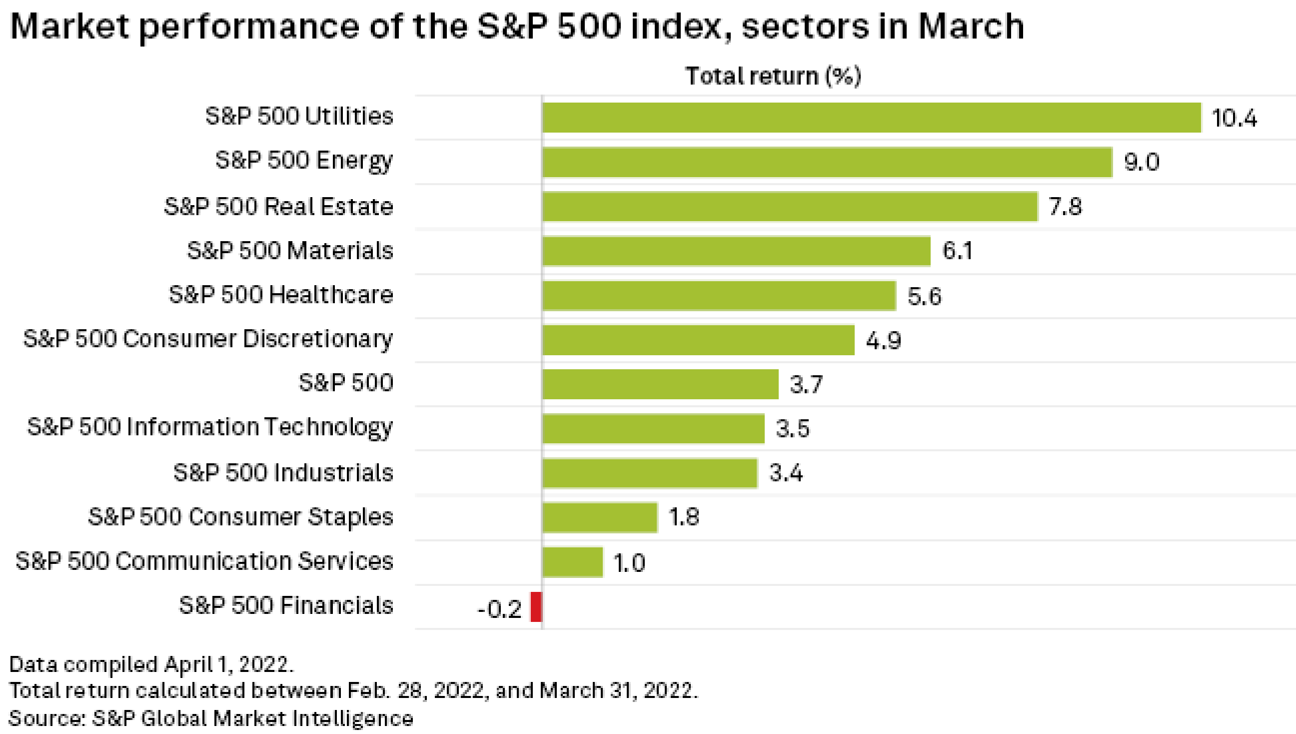
Utilities, Energy Outperform Other S&P 500 Sectors in March

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

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

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



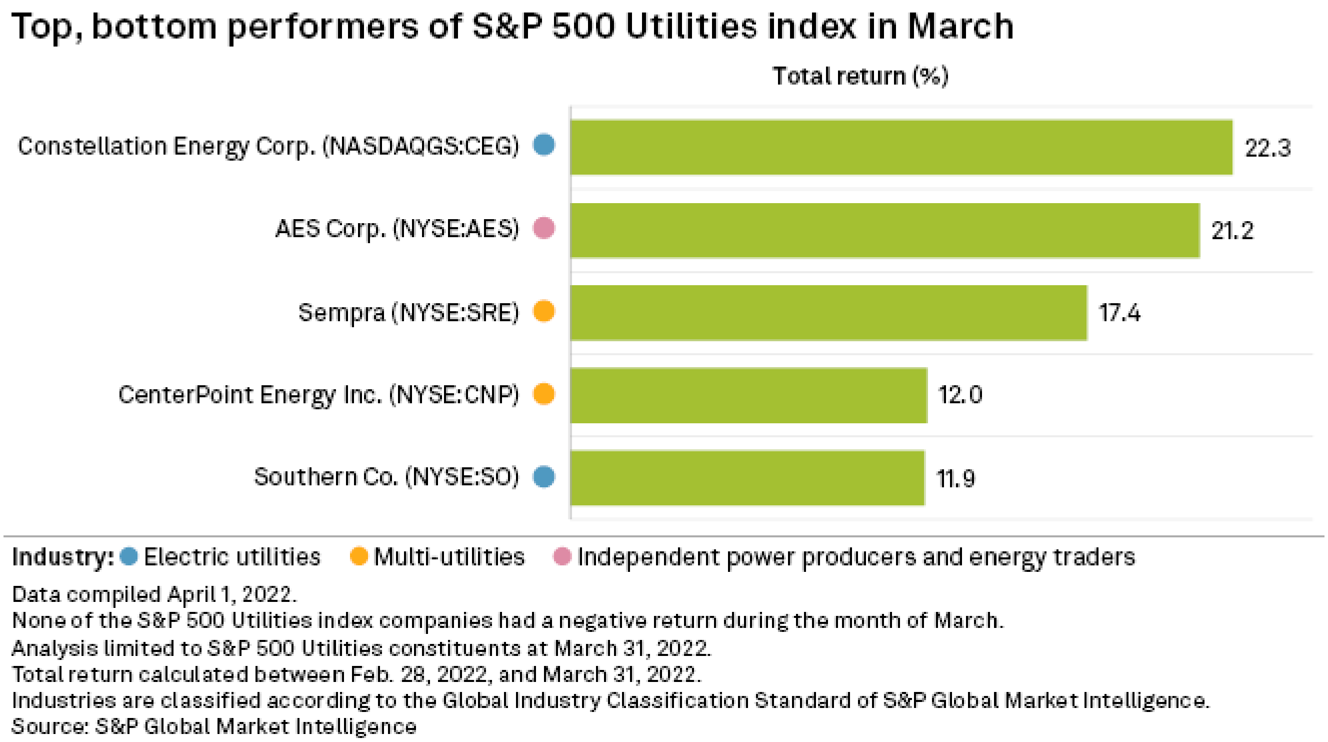
Fresh from its spinoff from Exelon Corp., Constellation Energy Corp. saw its share price climb 22.3% in March, leading the components of the S&P 500 Utilities sector.

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

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

Southern Co. recorded a share price increase of 11.9% in March. Southern shareholders reached a settlement connected to the utility's abandoned 745-MW Plant Ratcliffe (Kemper County IGCC) project that will require certain corporate governance reforms.

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

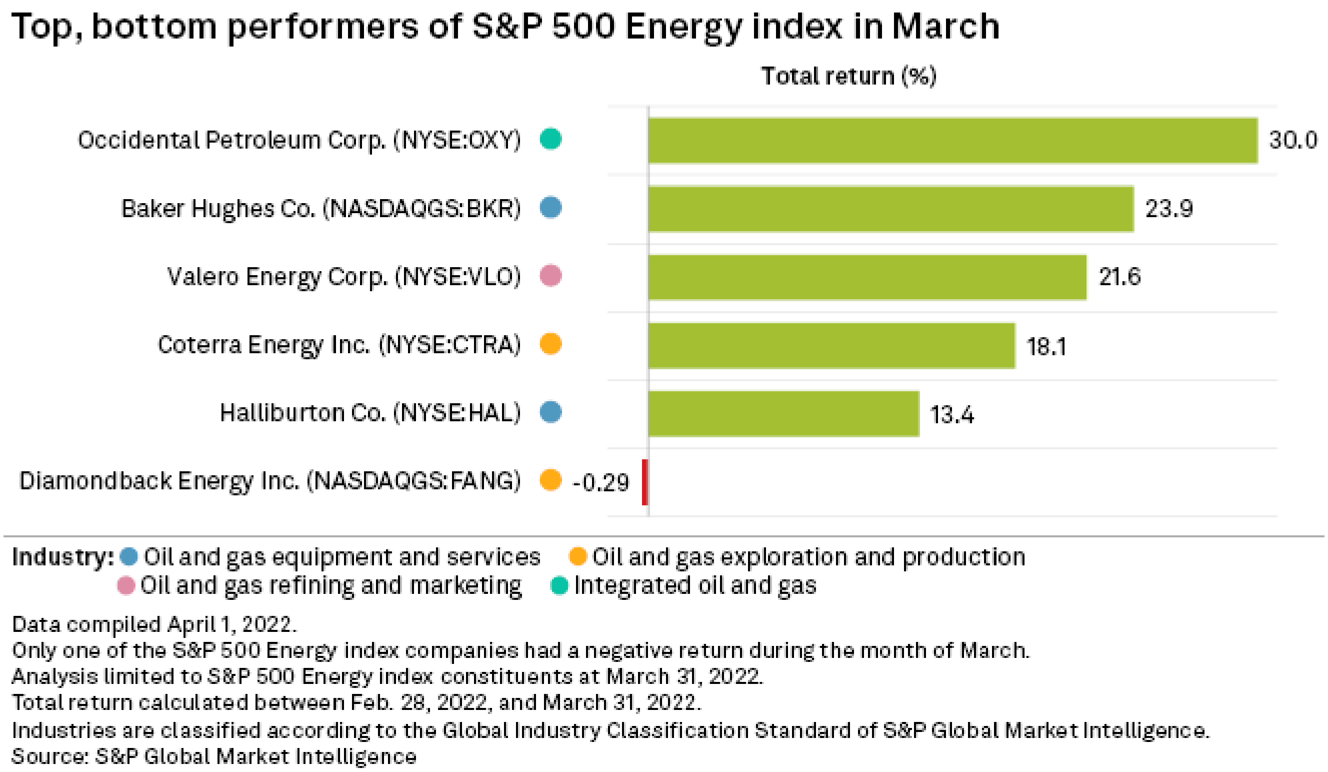


Occidental Petroleum Corp. outperformed other energy companies, recording a total return of 30.0% in March.

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

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

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



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Utility Stocks Ascend as Inflation, Recession Concerns Spur 'Flight to Safety'

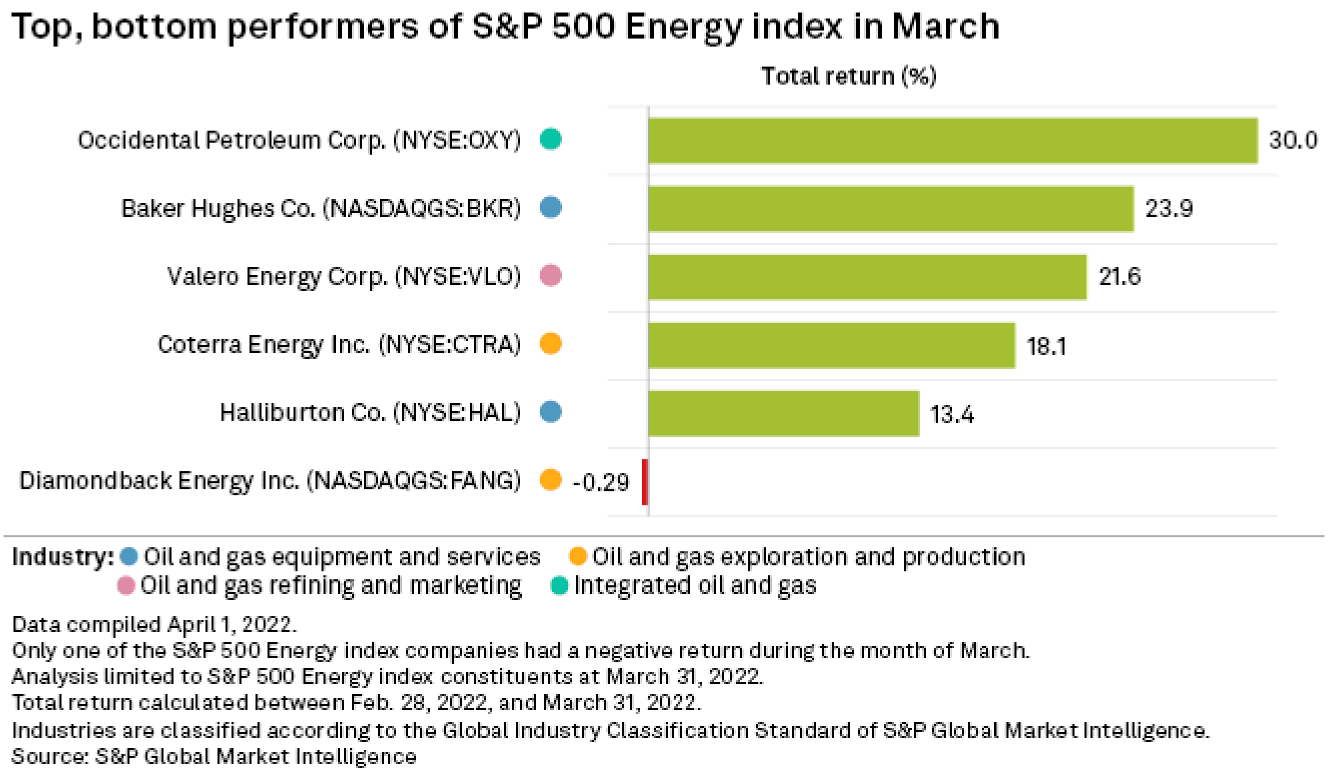
by Allison Good – S&P Global Market Intelligence – Apr. 8, 2022

Investor interest in **U.S. utilities** has **soared** in recent weeks as **geopolitical turmoil** and **macroeconomic concerns about inflation** and a **potential recession drive** the **sector's** stock market **outperformance**.

The **S&P 500 Utilities** index **logged** a **total return** of **10.4%** in **March**, **besting other sectors and** the **broader S&P 500 index**, which **surprised Guggenheim Securities** LLC **given** that **elevated U.S. Treasury yields usually have** a "strong **inverse correlation**" to **utility equity valuations**, analysts told clients April 4.

But **average electric utility share price volatility also declined** to 19.5% from 29.2% in March, **indicating** "a **flight to safety** by investors as they buy utilities and hold them for longer, especially such as in times of heightened geopolitical stress," Jason Lehmann of Regulatory Research Associates wrote on April 6.

For now, Lehmann added, "**utilities** appear to be **markedly less exposed to short interest activity**" driven by expectations of another broader market downturn.



Morgan Stanley said it has also noticed more generalist interest in utility stocks, while analysts at Scotiabank agreed that, combined with higher oil and gas prices due to Russia's invasion of Ukraine, fears of an economic recession are driving generalist investors to prioritize "safety and defense."

"Consistent with recent weeks, last week we received multiple inbounds from generalists and investors who cover multiple sectors and don't 'spend a lot of time on utilities' but believe that they 'have a time and a place,'" the analysts wrote April 5.

While many of those conversations about risk focused on NextEra Energy Inc., CMS Energy Corp., Entergy Corp., DTE Energy Co and WEC Energy Group Inc., the analysts initially told clients March 29, Scotiabank is not counting on "many of these investors to stay in the sector long if the war is resolved soon and on reasonable terms."

In March, according to data collected by S&P Global Market Intelligence, Constellation Energy Corp. saw its share price climb 22.3%, leading the components of the S&P 500 Utilities sector following its spinoff from Exelon Corp. Clean energy giant AES Corp. and Sempra, whose **liquefied natural gas** business has experienced a surge in buyer interest during the **Ukraine conflict**, also logged **double-digit share price increases**.

Morgan Stanley, meanwhile, named American Electric Power Co. Inc. as a top pick because the company "is following the playbook of premium Midwest utilities: Build cheap renewables and shut down expensive coal plants." Morgan Stanley also emphasized that Exelon "is a big hit with ESG investors" following its restructuring.

AES has also accelerated its exit from coal-fired generation to the end of 2025 to attract new investors and boost credit ratings.

The utility sector stock price swing could dampen prospects for more gas utility M&A, according to Guggenheim.

"Despite the valuation optics, apart from several anomalistic situations like [NiSource Inc.] and [CenterPoint Energy Inc.], we believe our coverage will be more likely to retain their [local distribution companies], rather than rely on M&A, with a focus on organic spending opportunities," the client note said.

Still, investment bankers remain confident that catalysts are in place to drive more natural gas utility deal-making in 2022 amid improving sentiment on the longevity of the business and a renewed emphasis on natural gas's role in the energy transition.

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After lackluster 2021, Utility Valuations Converge with S&P 500 in January

by Jason Lehmann – Regulatory Research Associates (RRA)
an Affiliate of S&P Global Market Intelligence – Feb. 8, 2022

Forward valuations on a next-12-months basis between the **S&P 500 Utilities Index** and the **S&P 500 converged in January** as energy utility stocks outperformed the highly volatile S&P 500 and tech-heavy Nasdaq Composite indexes amid interest rate concerns, rising inflation and ongoing COVID-19 fears. The **S&P 500 Utilities index declined 3.3%** in **January versus** the **S&P 500** and Nasdaq Composite's **5.3%** and 9.0% respective **declines**.

Multi-utilities outperformed other energy utility subsectors in January, rising 0.3% on average, led by NiSource Inc.'s 5.7% rise amid a leadership change that will see President and CEO Joseph Hamrock step down in mid-February, to be replaced by board director Lloyd Yates. For additional detail, see the Jan. 27 S&P Global Market Intelligence news article, "Hamrock to retire as NiSource CEO; former Duke executive to take helm."

After closing out 2021 at a forward price-to-earnings, or P/E, discount to the broader S&P 500 index, utility forward valuations converged with broad markets, having outperformed in January. Multi-utility P/E’s increased 1.1% on average, led by NiSource Inc., while electric and gas utility P/E’s declined 2.3% on average last month.

Looking ahead, issues that may affect utility financial performance, and thus equity performance, in the new-year include energy transition-related stranded costs and cost recovery associated with severe storms and the ongoing COVID-19 pandemic. Fourth-quarter 2021 EPS results may also weigh on equity performance, with S&P Global

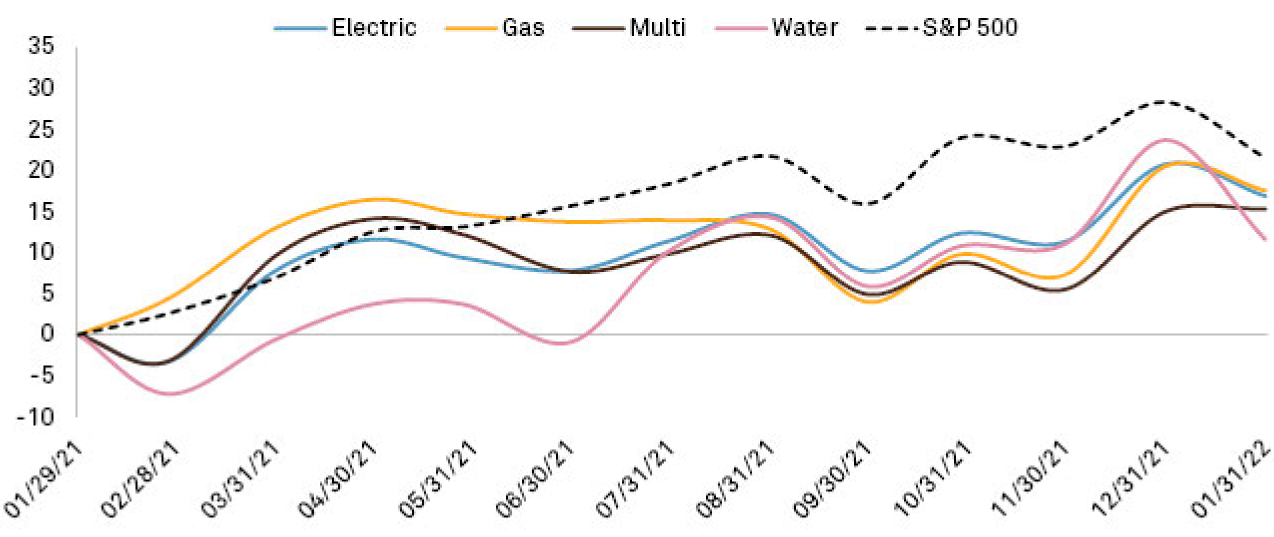
Market Intelligence estimates anticipating just 0.2% year-over-year EPS growth within the S&P 500 Utilities sector, the lowest among other S&P 500 sectors.

Avangrid Inc. continued to **underperform** multi-utility equities – declining 6.3% in January – as it **seeks** to **push its acquisition** of **PNM** Resources Inc. over the finish line. **PNM** has **appealed** the **New Mexico Public Regulation Commission's** Dec. 8, 2021, **order rejecting** the companies' proposed business **combination**, **and** the companies' **merger agreement** has been **extended to April 20, 2023**. The PNM shares declined 1.8% in January.

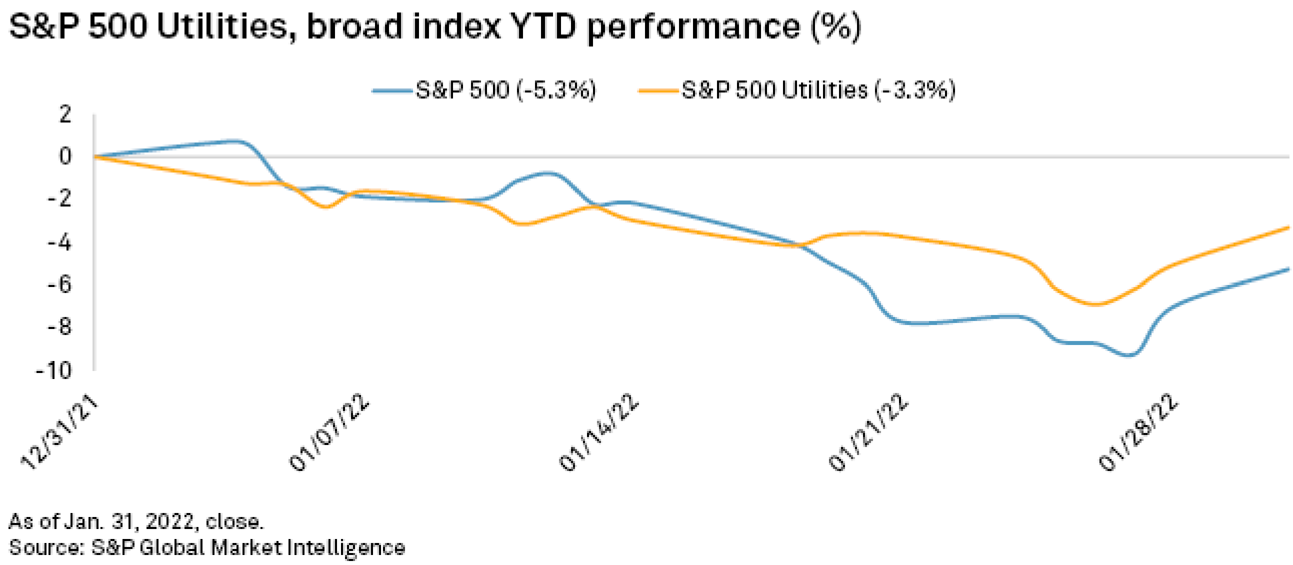
Electric utilities declined 3.0% on average in **January**, driven by NextEra Energy Inc.'s approximately 16.3% decline on news that President and CEO Jim Robo plans to relinquish his leadership role, effective in March. The news accompanies NextEra's fourth-quarter 2021 earnings report that saw EPS increase more than 10% to $2.55. Management also lifted its 2022 EPS outlook to a range of $2.75 to $2.85 from $2.55 to $2.75.

After closing out 2021 with an average 11% rise in December, water utility stocks retreated in January – possibly on profit-taking – with sector names declining 9.4% on average. Middlesex Water Co. and American Water Works Co. Inc. fared worst, declining 15.8% and 14.9%, respectively. Looking ahead, authorized return on equity trends will continue to be a focus for investors. ROEs will likely remain constrained in 2022 as regulators focus on ratepayer impacts, which could impact water utility equity performance and valuation throughout the year. For additional detail, see the Jan. 21 RRA Regulatory Focus report, "Noteworthy water utility regulatory items to watch in 2022."

Utility monthly average share price change (%)



Prices are through Jan. 31, 2022.
Source: S&P Global Market Intelligence



Price-to-earnings trends

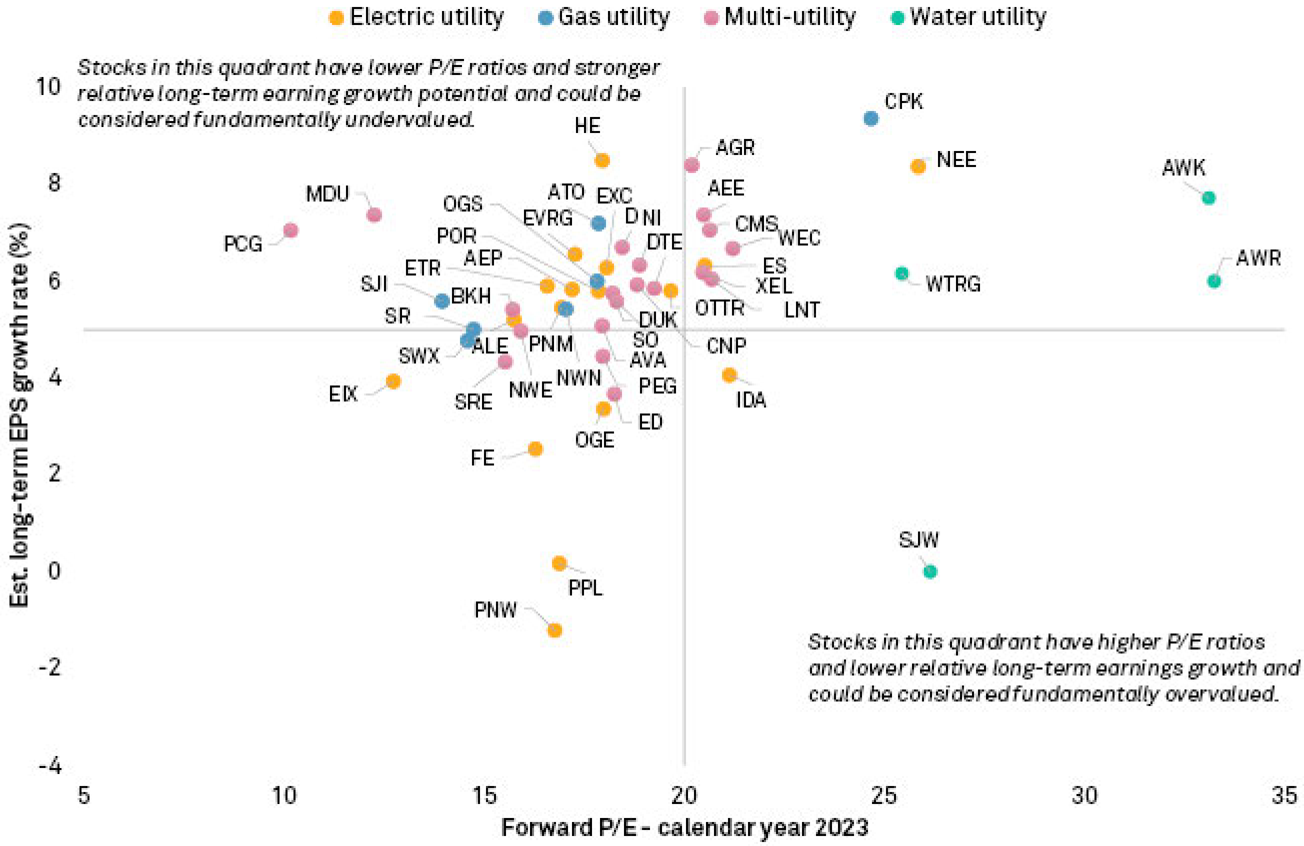
With the energy utility sector's stock price outperformance in January, the forward share price-to-EPS multiple between the S&P 500 Utilities and the S&P 500 converged to just above 20x at month's end; utilities had traded at an approximately 4% discount to the S&P 500 in November 2021, and an approximately 9% discount for several months prior as investors favored other S&P 500 sector stocks amid improving U.S. economic conditions.

Within the electric and gas utility sectors, calendar 2023 P/E multiples declined 2.3% on average, weighed by respective sector outliers NextEra Energy and Chesapeake Utilities Corp. The Chesapeake Utilities shares have underperformed energy utility stocks two of the prior three months. The Dover, Del.-based gas utility is scheduled to report fourth-quarter 2021 financial results on Feb. 23, with S&P Capital IQ consensus EPS estimates projecting a 6.5% increase to fourth-quarter EPS to $1.32. More generally, sell-side analysts anticipate mixed EPS results within the gas utility sector: as of late January, analysts expected just over half of nine gas utility operators to report year-over-year EPS increases this earnings season, according to S&P Capital IQ consensus estimates.

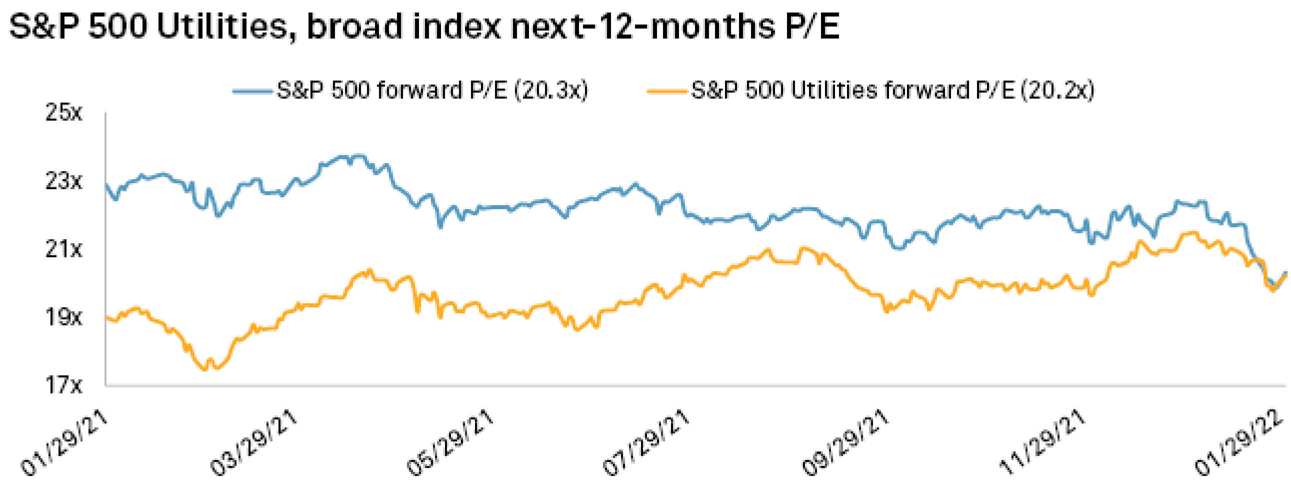
Atmos Energy Corp. was the lone gas utility to see 2023 P/E multiple appreciation in January, with the stock trading at nearly 18x 2023 estimated EPS, a 1.5% improvement from December 2021. The company is scheduled to report fiscal first-quarter EPS on Feb. 9, with S&P Capital IQ consensus EPS estimates projecting an 8.2% increase to $1.85.

The quadrant chart below shows how the RRA utility universe appears when comparing the P/E ratio and the estimated long-term earnings growth rate. A sizeable portion of utility 2023 P/E multiples remained largely in the upper-left quadrant throughout 2021 and into 2022, suggesting the names could be relatively undervalued considering their lower P/E values and long-term earnings growth potential.

Valuation quadrant: EPS growth forecast vs. forward P/E



As of Jan. 31, 2022, close.
For the 12 months ended Dec. 31, 2023. P/E = stock price-to-earnings ratio
Source: S&P Global Market Intelligence



As of Jan. 31, 2022, close.
P/E = stock price-to-estimated EPS ratio
Source: S&P Global Market Intelligence

Share price volatility:

Smaller-cap companies generally have lower trading liquidity and therefore, all other things being equal, tend to have more significant share-price swings than larger-cap equities. An analysis of the standard deviation of log-normalized daily price returns for utility stocks over the last year supports this thesis, with the generally smaller-cap gas and water utility sectors displaying the highest average price volatility.

Share price volatility within the electric utility sector remained stable at approximately 16.7%, with several exceptions, including NextEra Energy's increase to 48.2% from 15.8%, and FirstEnergy Corp.'s decline to 8.3% from 10.7%. Gas utility share price volatility decreased to 18.5% from 19.8%, while multi-utility share price volatility decreased to 15.6% from 16.6%.

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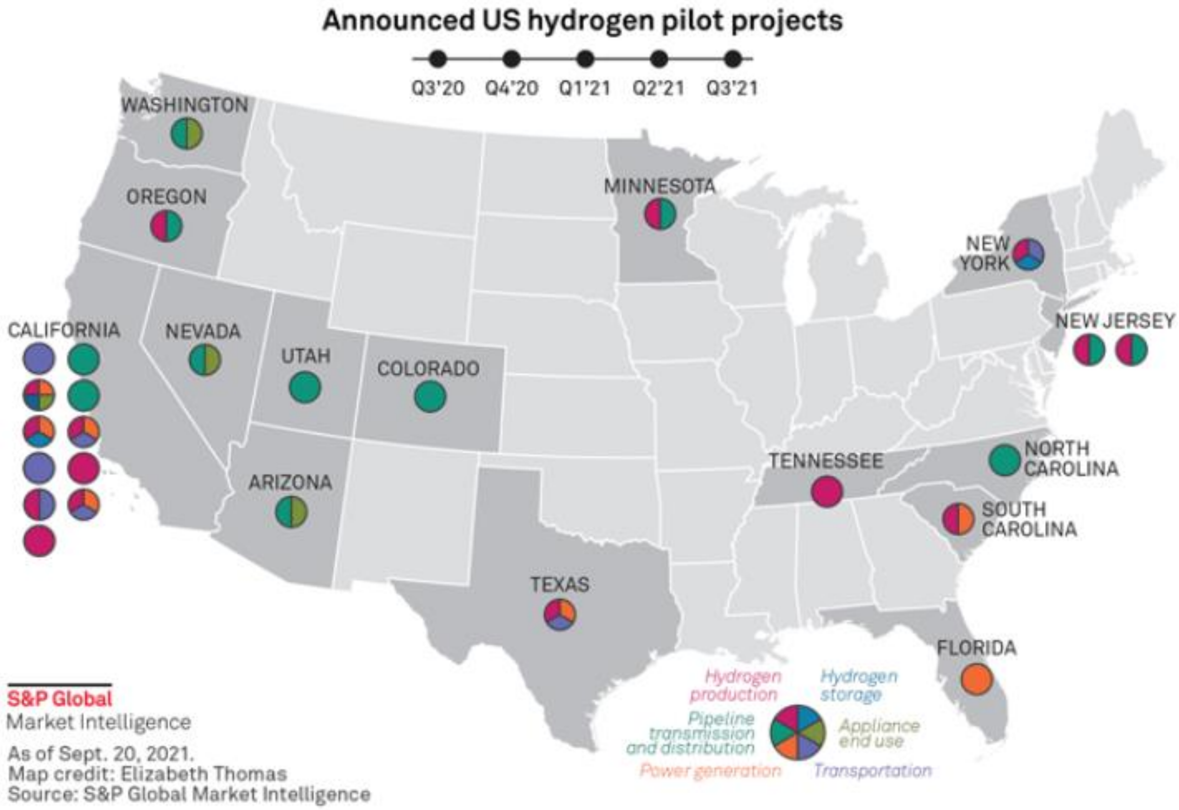
Gas Utilities Get to Work Piloting Hydrogen Use in Distribution Systems

by Tom DiChristopher – S&P Global Market Intelligence – Mar. 10, 2022

Hydrogen pilot project updates from gas utilities show that the industry is starting to execute on its plans to demonstrate the fuel's ability to decarbonize distribution systems.

Some of the more than two dozen projects announced since 2020 are preparing to get underway, while others are already producing data and yielding lessons for operators, according to S&P Global Commodity Insights' review of quarterly earnings conference calls. The opening months of 2022 also saw one of the sector's hydrogen leaders, Southern California Gas Co., ramp up its commitment to the low-carbon fuel beyond pilot projects.



On Feb. 17, SoCalGas announced that it aims to build a dedicated hydrogen pipeline system in the Los Angeles area. The Angeles Link, billed as the largest green hydrogen infrastructure network in the nation, would be part of SoCalGas' effort to develop a green hydrogen hub in the Los Angeles Basin.

The support for the project among various California stakeholders illustrates that "clean molecules have a big role to play in this energy transition," Kevin Sagara, utilities group president at parent company Sempra, said during a Feb. 25 call.

Hydrogen advocates have long said dedicated pipelines will be necessary to link supply and demand once the market achieves scale. **Most gas utilities**, including SoCalGas, have focused on **blending hydrogen into existing gas infrastructure**. That strategy is **cost-effective**, **but today's gas grid can only handle limited hydrogen volumes withoutcompromising pipeline integrityor end-use appliances**.

Hydrogen blending projects advance

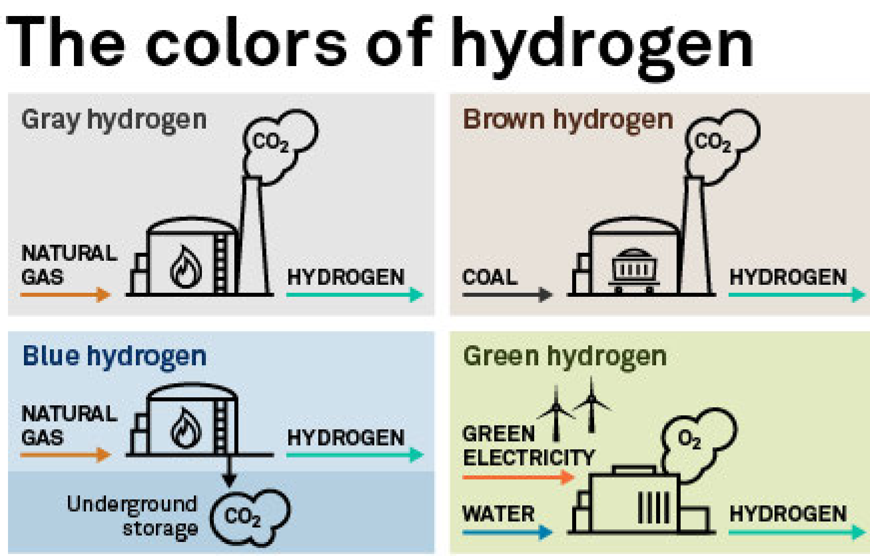
Dominion Energy Inc. is continuing to **pilot hydrogen blending** in **Utah**. Based on early assessments, the company's distribution system can handle at least a **5%**

blend of **hydrogen**, and **potentially up to 10%**, without adverse impacts on appliance performance, leak surveys, system safety or secondary emissions, Dominion Chairman, President and CEO Bob Blue said during a Feb. 11 call.

Hydrogen blending is one pathway through which Dominion aims to achieve its newly announced goal of reaching net-zero Scope 3 greenhouse gas emissions, which are tied to ratepayers' gas consumption, Blue said.

CenterPoint Energy Inc. is preparing to start up its green hydrogen blending pilot in the Minneapolis area, CFO Jason Wells said during a Feb. 22 conference call. The company plans to produce green hydrogen for injection into its distribution system at low volumes, allowing it to safely assess the risk of leakage and the impact on pipes and appliances.

The company took delivery of an **electrolyzer**, which splits water into oxygen and hydrogen, in January and expects the pilot to get underway in the coming weeks, CenterPoint spokesperson Ross Corson said in an email.



As of Nov. 20, 2020.
Credit: Cat Weeks
Sources: S&P Global Market Intelligence; Gasunie Bbl B.V.

As **Northwest Natural** Holding Co.'s western **Oregon pilot** project advances, the company has explored **blending** either **green hydrogen or synthetic** gas into its system. Northwest Natural has **proposed making synthetic gas** by **pairing green hydrogen with waste carbon**, known as **methanated hydrogen**. Unlike hydrogen, synthetic gas releases carbon when burned, but it is also **interchangeable with natural gas in distribution systems**, **according** to **Kim Heiting**, senior vice president of operations and chief marketing officer at Northwest Natural.

Analysis by Northwest Natural found that synthetic gas could be cost-competitive with renewable natural gas if produced at scale at zero-carbon electric power plants, Heiting said during a Feb. 25 call. Asked whether subsidies would be necessary, Heiting acknowledged that synthetic gas projects would likely require federal incentives to drive down hydrogen costs.

Power generation pilot yields gas distribution lessons

During the reporting period, Chesapeake Utilities Corp. announced that it successfully completed its hydrogen blending pilot project at a Florida combined heat and power plant. On the power generation side, Chesapeake is validating the project's emissions reductions and assessing the blend's impact on the plant's gas turbine and other equipment. The company plans to replace the turbine in 2022 with one capable of handling a 20% hydrogen blend, Chesapeake President and CEO Jeff Householder said during a Feb. 24 call.

But the company also designed the program to refine the practices necessary to safely inject hydrogen into a gas distribution system. It injected hydrogen into a modified interconnection point and delivered the gas blend into the plant through existing steel service mains.

"This was an important first step in demonstrating that hydrogen can play a significant role in providing lower-carbon energy options to industrial customers," Householder said. "We believe there are numerous opportunities to provide hydrogen to assist customers in their emissions reduction efforts."

WEC Energy Group Inc. announced that it will pilot hydrogen blending at one of its gas-fueled reciprocating internal combustion engine units in Michigan's Upper Peninsula. The plan is to pilot a maximum 25% hydrogen blend in the power plant, WEC Executive Chairman Gale Klappa said during a Feb. 3 call.

The company is optimistic that the project will demonstrate that hydrogen, when paired with reciprocating internal combustion engine technology, "could be a major player going forward in decarbonizing the economy," Klappa said.

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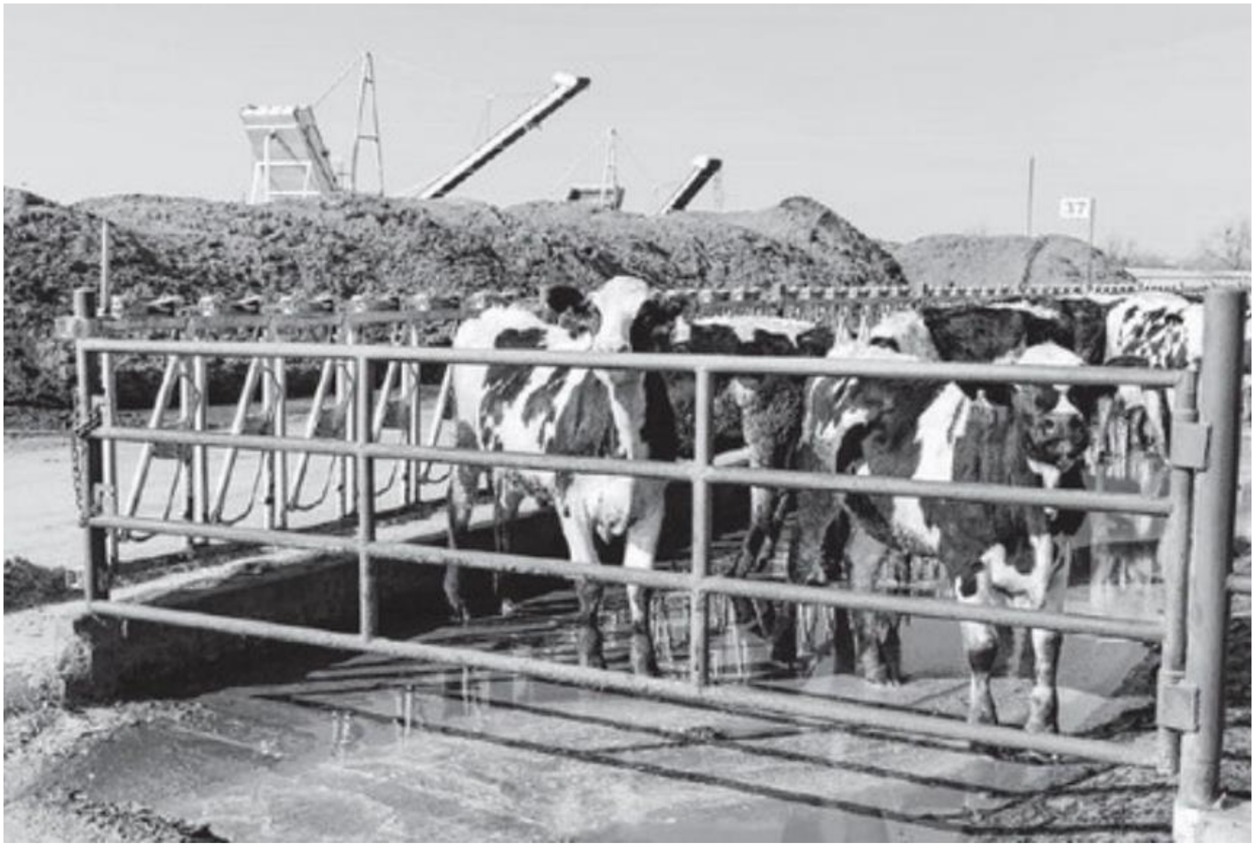
California Green Subsidies Boost New Biofuel

by Phred Dvorak – WSJ – Feb 22, 2022



Clean Energy Fuels Corp., a major **distributor** of **natural gas made from waste**, **found** a **way** to **boost** its **earnings by millions of dollars**, nearly **overnight**.

All it had to do was **switch** the **main biofuel it supplies to power cars and trucks in California** – a type of natural gas produced with methane emissions **from garbage** – **to** a **chemically identical gas produced from cow manure**.

California's clean-fuels grading system gives cow-poop gas a **much better score**—and **much higher subsidies**—**than landfill gas**. So that substitution **could net Clean Energy** an **additional $70 million** in **e**arnings **before i**nterest, **t**axes, **d**epreciation and **a**mortization by 2026, the company estimates. "It is like magic," said Andrew Littlefair, Clean Energy's president and chief executive, of the projected earnings boost.

Together with BP PLC and **TotalEnergies** SE, **Clean Energy** is **pouring hundreds of millions of dollars** into **gas production on dairy farms**. A host of developers, financiers and carbon-conscious corporations, from **Chevron** Corp. **to Amazon**. com Inc., are **looking to buy or produce the fuel as well**.

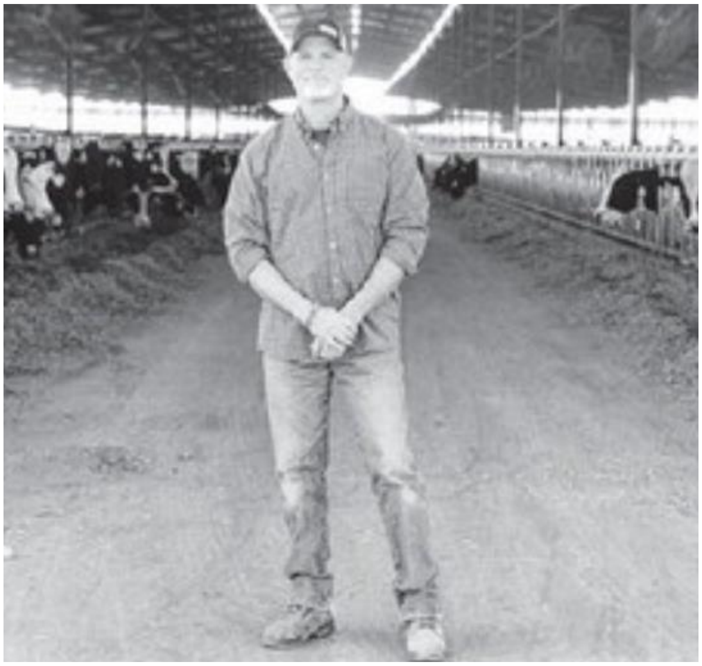
The **surging interest** in **dairy renewable natural gas shows how incentives can spur action** to address the emissions linked to climate change – and **sometimes unintended consequences**. **Until** a **few years ago**, the **gas**, which is **interchangeable with conventional natural gas** and can replace dirtier fuels like diesel, was a niche product that was **too expensive to make commercially**.

California's subsidies prompted what some observers are dubbing a **manure gold rush**. One developer said he showed up at a dairy only to discover that the farmer had gotten more than 10 pitches for business tie-ups. Others said competition for business has gotten so heated that some developers are promising to pay farmers a fixed amount per cow – a risk if the price of the California credits plummets.

Driving the **boom** is **California's Low-Carbon Fuel Standard**. The standard requires companies that sell transportation fuels in the state to lower their products' carbon intensity – the carbon dioxide emitted during manufacture, distribution and consumption. Companies that exceed the carbon-intensity maximums have to buy offset credits. Those with low-scoring fuels generate credits, whose price goes up and down depending on demand.

California Bioenergy LLC, which **develops** projects to **make energy out of manure**, in 2016 received the first provisional carbon-intensity score – around negative 270 – for a dairy-gas facility. Diesel by comparison has an average carbon-intensity score of more than 100. **CalBio**, as it is known, has **41 dairy-gas projects in operation** and another **60**-odd projects **in development**.

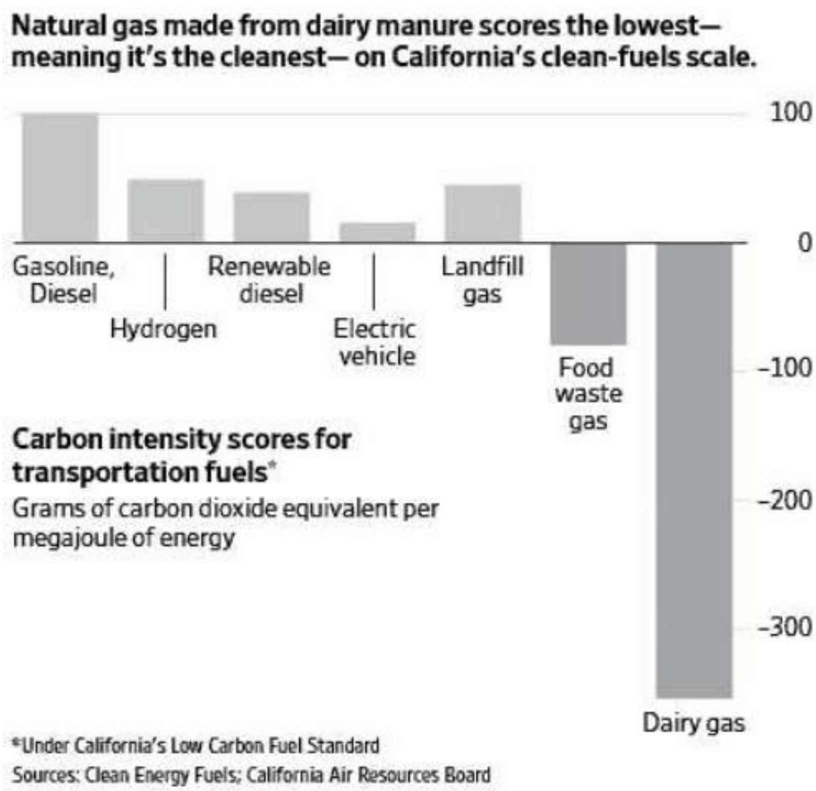
Its **latest project** to go online is the 1**,500-cow Rib-Arrow Dairy** in **central California**, where **manure** is **flushed from** the **stalls into** a **covered lagoon**, called a **digester**, so the **methane** can be **collected for processing rather than released** into the air. That **raw biogas**, which is around **60% methane** and the **remainder mostly carbon dioxide**, is **piped** to a **central facility** that **collects gas from** a **cluster** of **dairies** in the area **and purifies it for injection into** the **local utility's pipeline**.



David Ribiero, left, co-owner of Rib-Arrow Dairy, in central California, said methane sales have become economically feasible.

David Ribeiro, a third-generation co-owner of Rib-Arrow, said he was approached by digester salesmen, but adding the gas sales to the environmental benefits finally made everything economically feasible.

There are **116** such **facilities** operating **in** the **U.S.** – more than **half** of which **went online last year**—and **another 121 planned or in construction**, according to the Coalition for Renewable Natural Gas, a nonprofit that promotes gas made from waste.



The market is likely to remain small compared with the U.S.'s overall appetite for natural gas. Even in an optimistic scenario, biogas from manure would supply around 3% of today's demand by 2040, according to a 2019 study commissioned by the American Gas Foundation.

Still, **Clean Energy said** it is **working on** more than a **billion dollars worth of deals** through its dairy-gas joint ventures with BP and Total, and that it hopes to channel more than $2 billion in investment by 2026.

Chevron committed around **$500 million** to **develop renewable natural-gas supply**, starting with dairies.

Amazon set a **deal with Clean Energy** to **buy biogas for** its **trucking fleet**; it declined to comment.

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Higher Meat Prices Boost Tyson

by Patrick Thomas – WSJ – Feb. 8, 2022

Processing company says demand outpaces its ability to supply products

Escalating meat prices haven't slowed restaurant **and retailer demand for meat**, **Tyson Foods** Inc. executives said, as **rising prices helped** to more than **double** the company's **quarterly profit**.

Tyson, the **biggest U.S. meat processor by sales**, said that orders for beef, chicken and pork continue to outpace its ability to supply products, with its plants still short on workers. Raising wages and expanding benefits to recruit and retain staff is helping drive meat prices higher, Tyson said, along with transportation and other costs.

Over the three months ended Jan. 1, Tyson said its average beef prices rose by nearly one-third compared with the same period a year earlier, while pork prices increased by 13% and chicken by about 20%.

"We're seeing inflation across our supply chain," Chief Executive Officer Donnie King said on a call with reporters.

Tyson and other U.S. meatpackers are under pressure to keep up with surging demand from supermarkets and reopening restaurants.

A **nationwide labor shortage** has **left many processing plants understaffed** and unable to keep up, leading to higher prices and shortages of some products, industry officials have said.

The Arkansas-based company said it **raised prices** across its business units in its fiscal first quarter **as** its **cost of goods sold increased 18% from** a **year ago**. **Freight costs rose 32%,** the company said, and **rising wages** and additional **employee benefit programs** to improve staffing, such as subsidizing child care, **pushed labor costs up 20%**.

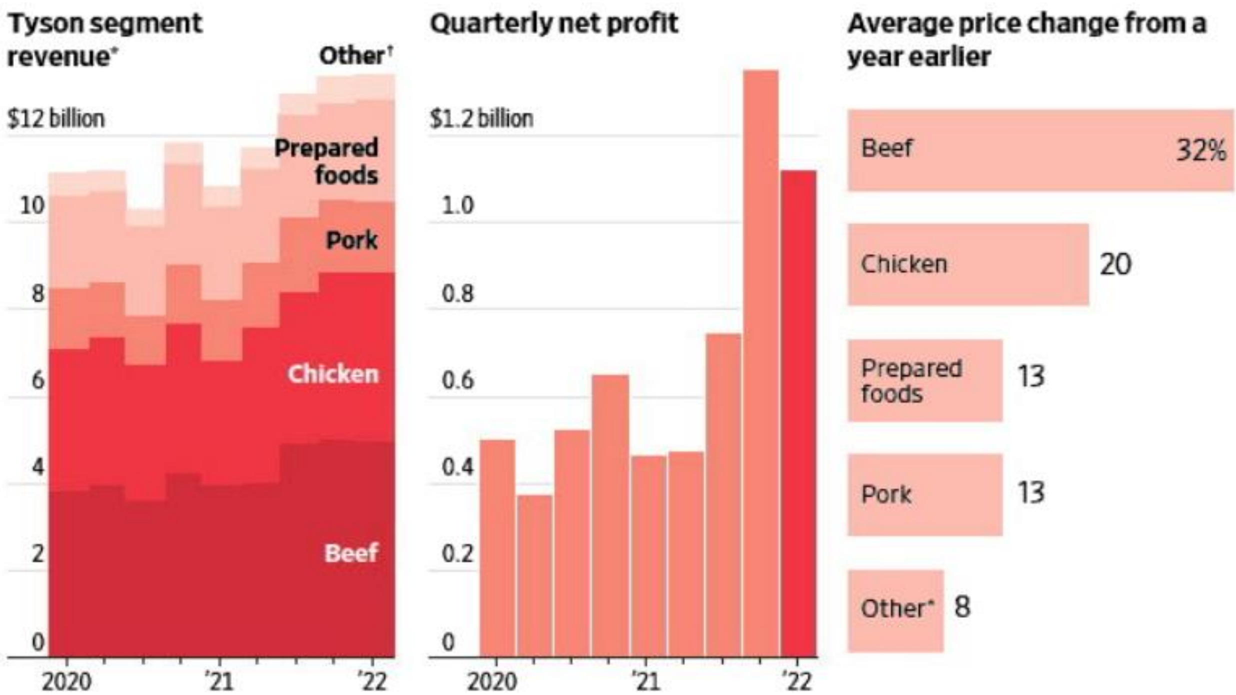
Inflation throughout the supply chain is leading to higher prices for many products and services in a variety of industries, especially food. U.S. inflation hit its fastest pace in nearly four decades last year.

Rising food prices are leading some consumers to seek out cheaper groceries and discounts, supermarket operators have said, with some shoppers buying more store-brand meat and trading down from beef to less-expensive alternatives such as chicken or pork.

Despite higher prices, **consumer demand** for its products has **stayed strong**, Tyson executives said.

"We're not asking customers or the consumer ultimately to pay for our inefficiencies, we're asking them to pay for inflation," said **Mr. King**, a **three-decade veteran** of the **company** who **took over as Tyson's CEO** in the summer of **last year**. "The rest of what we do is we try to find ways to be more productive."

The meat processor said its net income for the quarter rose to $1.12 billion from $467 million a year ago, propelled by higher profit margins in its beef, pork and chicken divisions. Tyson's quarterly sales grew 24% from a year ago to $12.93 billion. The results surpassed Wall Street expectations, and Tyson forecast continued strength in its operations. Tyson shares jumped 12% Monday.



*Excludes intersegment eliminations †Includes international sales Sources: S&P Capital IQ (revenue, profit); the company (price change)

Despite continuing labor shortages in its meat plants, Tyson said it has largely moved past the recent surge of Covid-19 infections from the Omicron variant that stretched workforces from processing plants to grocery stores.

"We're back to normal levels," said Mr. King. "We think our vaccine mandates served us well."

Tyson said it plans to spend about $2 billion mainly focused on increasing production capacity and automation capabilities in its plants in its 2022 fiscal year. Covid-19 infections among meat-plant workers have deepened the U.S. meat industry's long-run- difficulties keeping plants fully staffed, leading meatpackers like Tyson to increase investments in **automation**.

Operating income margins in Tyson's beef business grew to 19% in the most recent quarter, compared with 13% in the same period a year ago. Sales volumes in beef declined about 6% as the company struggled to staff its plants to keep up with higher demand, company officials said.

Tyson's chicken business margins over the quarter improved to about 4% from being negative a year earlier, and sales increased 37% to $3.9 billion for the quarter. The top U.S. chicken company said it expects higher chicken volumes in 2022 as it focuses on running its plants more efficiently, and hatching rates improve among chicks to be shipped to farms.

The meat industry's rising profit margins have drawn the ire of the White House. In January, the Biden administration outlined tighter regulations for U.S. meatpackers, accusing the industry of using its scale to inflate Americans' food bills. The steps outlined range from funds for regional meat processors to help them better compete with big companies, to stricter rules for livestock purchasing and meat labeling, which are aimed at supporting U.S. farmers and ranchers.

Meat companies have said their results reflect market forces that have arisen from persistent supply chain problems and labor shortages, which have constrained meat production as the economy recovers from the pandemic.

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Tyson Replaces CEO Dean Banks after Eight Months on the Job

by Jacob Bunge – WSJ – Jun 2, 2021

Company veteran Donnie King to take top post after Banks leaves for personal reasons.

Tyson Foods has been contending with production constraints from Covid-19.

Tyson Foods Inc. **replaced** its **chief executive officer after** about eight months on the job as the top U.S. meat company contends with **production constraints** and fallout **from Covid-19**.

Dean Banks stepped down from the CEO role and from Tyson's board of directors, the company said on Wednesday. He was **succeeded** immediately **by Donnie King**, a three-decade veteran of the Arkansas company who earlier this year was named chief operating officer.

Mr. Banks decided to leave Tyson for personal reasons, the company said. He didn't immediately respond to a request for comment. Mr. King wasn't available for an interview, a Tyson spokesman said.

Left: New CEO Donnie King is a three-decade Tyson veteran named chief operating officer earlier this year.

The **abrupt change** at the top of the largest U.S. meat processor by sales **makes Mr. King Tyson's fifth chief executive in as many years**. A Tyson spokesman said that while the CEO plays an important part, the company's leadership team is also responsible for driving Tyson forward.

"The board and I know that Donnie has a deep understanding of our business, values and culture and the solid leadership skills needed to continue to implement our strategy and deliver strong results," said John Tyson, chairman of Tyson Foods' board and a controlling shareholder.

Tyson's workers and **plants** were **among** the **hardest hit** in the **spring** of **2020** as **Covid-19 infected thousands** of **meat-packing employees across** the **U.S.**, leading the company to spend hundreds of millions of dollars on protective measures and bonus pay. As the U.S. economy rebounds from the pandemic, **Tyson** has **struggled** to **meet demand** for staples like chicken, with **understaffed plants** and **trouble** with **breeding flocks leading** the **company** to **purchase meat from competitors to fill orders**.

Mr. King joined Tyson in 1982, managing chicken plant operations and supply chains before running Tyson's North American operations and its international business, which Tyson has been expanding recently through acquisitions.

Left: Dean Banks stepped down from the CEO role and from Tyson's board of directors.

Mr. **Banks** was an **unconventional choice** to take over leadership at Tyson last year in the midst of the pandemic. A former Silicon Valley tech executive who **worked** at **Alphabet** Inc.'s high-tech incubator X, Mr. Banks joined Tyson's board in 2017 and became president of the company in December 2019.

He took over as CEO in October 2020, with Mr. Tyson praising his background in technology and healthcare as the company **ramped up investments** in **automation** and **worker safeguards**. A Tyson spokesman on Wednesday declined to provide further details on Mr. Banks' departure, citing respect for Mr. Banks' privacy.

Tyson reported in May that net income grew about 7% in the six months ended April 3, with sales rising slightly. Tyson's share price rose about 35% since Mr. Banks took leadership of the company in early October, compared with a 25.5% rise in the S&P 500 stock index.

CASE: UG 435
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 109

Value Line (VL)
Natural Gas Utilities

April 22, 2022

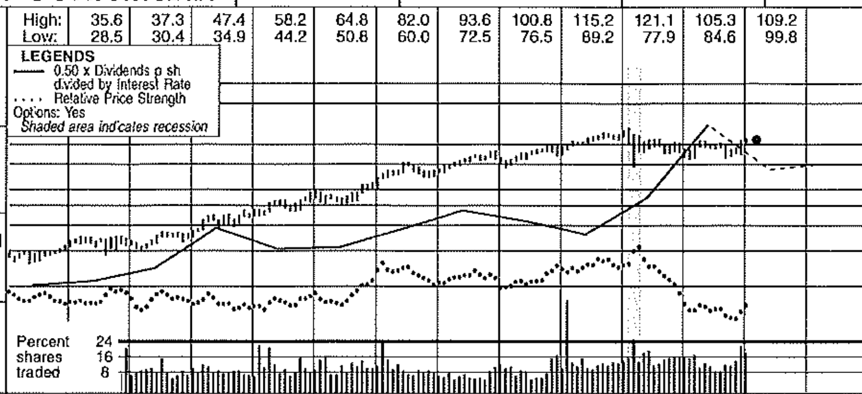
ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 105.98 | P/E RATIO 19.3 (Trailing: 20.0 / Median: 20.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 3 Raised 2/18/22
SAFETY 1 Raised 6/6/14
TECHNICAL 2 Raised 2/25/22
BETA .80 (1.00 = Market)

High:	35.6	37.3	47.4	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.3	109.2
Low:	28.5	30.4	34.9	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6	99.8

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



Target Price Range
2025 | 2026 | 2027
200 / 160 / 100 / 80 / 60 / 50 / 40 / 30 / 20

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$81-$123 $102 (-5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+50%)	13%
Low	130	(+25%)	8%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	256	247	262
to Sell	258	223	217
Hld's(000)	107920	109549	114371

Percent shares traded 24 / 16 / 8

% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.7	15.7
3 yr.	17.2	56.8
5 yr.	57.0	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
75.27	66.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	*26.45*	*27.90*	Revenues per sh A	*35.50*
4.26	4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	*9.30*	*9.95*	"Cash Flow" per sh	*11.95*
2.00	1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	*5.50*	*5.90*	Earnings per sh AB	*7.30*
1.26	1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	*2.72*	*2.92*	Div'ds Decl'd per sh C■	*3.50*
5.20	4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	*17.75*	*17.60*	Cap'l Spending per sh	*18.00*
20.16	22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.16	53.95	59.71	*64.35*	*68.45*	Book Value per sh	*82.85*
81.74	89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	*138.00*	*142.00*	Common Shs Outst'g D	*155.00*
13.5	15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
.73	.84	.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.00	*Value Line*		Relative P/E Ratio	*1.10*
4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	*estimates*		Avg Ann'l Div'd Yield	*2.4%*

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3438.5	3886.3	4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	*3650*	*3965*	Revenues ($mill) A	*6000*
192.2	230.7	289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	*760*	*840*	Net Profit ($mill)	*1130*
33.8%	38.2%	39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	*8.0%*	*17.5%*	Income Tax Rate	*25.0%*
5.6%	5.9%	5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	*20.8%*	*21.2%*	Net Profit Margin	*18.8%*
45.3%	48.8%	44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
54.7%	51.2%	55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	*60.0%*	*60.0%*	Common Equity Ratio	*60.0%*
4315.5	5036.1	5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	*14800*	*16200*	Total Capital ($mill)	*21400*
5475.6	6030.7	6725.9	7430.6	8280.5	9259.2	10371	11788	13355	15064	*16500*	*18000*	Net Plant ($mill)	*23000*
6.1%	5.9%	6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	*6.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	*8.5%*	*8.5%*	Return on Com Equity	*9.0%*
2.8%	4.0%	4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
65%	56%	50%	51%	50%	50%	48%	48%	49%	49%	*49%*	*49%*	All Div'ds to Net Prof	*48%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $7956.6 mill. Due in 5 Yrs $2410.0 mill.
LT Debt $5555.2 mill. LT Interest $330.0 mill.
(LT interest earned: 10.8x; total interest coverage: 10.8x)
Leases, Uncapitalized Annual rentals $41.8 mill.

Pfd Stock None

Pension Assets-9/21 $596.8 mill.
Oblig. $596.0 mill.
Common Stock 135,432,277 shs.
as of 2/4/22

MARKET CAP: $14.4 billion (Large Cap)

CURRENT POSITION ($MILL.)	2020	2021	12/31/21
Cash Assets	20.8	116.7	264.0
Other	450.5	2722.0	3010.2
Current Assets	471.3	2838.7	3274.2
Accts Payable	235.8	423.2	398.4
Debt Due	.2	2400.5	2401.4
Other	546.4	686.7	626.7
Current Liab.	782.4	3510.4	3426.5
Fix. Chg. Cov.	1306%	1457%	1440%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-7.5%	-10.0%	6.5%
"Cash Flow"	6.0%	7.0%	7.0%
Earnings	8.5%	8.5%	7.5%
Dividends	5.5%	8.0%	7.0%
Book Value	8.5%	11.0%	7.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	877.8	1094.6	485.7	443.7	2901.8
2020	875.6	977.6	493.0	474.9	2821.1
2021	914.5	1319.1	605.6	568.3	3407.5
2022	1012.8	*1400*	*640*	*597.2*	*3650*
2023	*1060*	*1485*	*730*	*690*	*3965*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	1.38	1.82	.68	.49	4.35
2020	1.47	1.95	.79	.53	4.72
2021	1.71	2.30	.78	.37	5.12
2022	1.86	*2.34*	*.82*	*.48*	*5.50*
2023	*2.00*	*2.42*	*.91*	*.57*	*5.90*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.485	.485	.485	.525	1.98
2019	.525	.525	.525	.575	2.15
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	2.56
2022	.68				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2021: 67.9%, residential; 26.8%, commercial; 3.6%, industrial; and 1.7% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .9% of common stock (12/21 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy started fiscal 2022 on a good note. (Years conclude September 30th.) First-quarter share net of $1.86 was 9% above the fiscal 2021 total of $1.71. One supporting factor was the distribution division, aided by favorable rate case outcomes and an expanded customer base. What's more, results of the pipeline and storage unit received a boost from a GRIP filing approved in May, 2021. A significantly reduced effective income tax rate also helped the company. Even though pandemic-related uncertainties linger, we look for full-year earnings to advance around 7%, to $5.50 a share, compared to fiscal 2021's $5.12 tally. Concerning the following year, share net may grow at a similar percentage rate, to $5.90, as operating margins expand further.

There's enough liquidity to satisfy various commitments for a while. When the first quarter ended, cash stood at $264 million. Also, long-term debt was reasonable (40% of total capital) and short-term borrowings did not seem to be a big hurdle. Moreover, $3.2 billion in common stock and/or debt securities remained available for issuance (out of $5 billion) under a shelf registration statement expiring in June, 2024. Lastly, Atmos can access four revolving credit facilities aggregating $2.5 billion plus a $1.5 billion commercial paper program.

Capital expenditures for this year are anticipated to lie between $2.4 billion and $2.5 billion. (That's 24% higher than the fiscal 2021 figure if the midpoint of this range is used.) Almost 90% of the funds are being utilized to enhance the safety and reliability of the company's natural gas distribution and transmission systems. Leadership adds that it projects total capital spending from fiscal 2022 through fiscal 2026 to be between $13 billion and $14 billion. A major portion of the investments will continue to be allocated to where they are presently. Assuming that finances stay healthy, Atmos ought to have little trouble achieving those goals.

The stock possesses unspectacular long-term total return potential. Given recent price strength, upside possibilities don't impress. Too, the dividend yield is below the average of *Value Line's* Natural Gas Utility group.

Frederick L. Harris, III *February 25, 2022*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next egs. rpt. due early May.
(C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail.
(D) In millions.
(E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	100

CHESAPEAKE UTIL. NYSE-CPK

RECENT PRICE 129.01 | P/E RATIO 26.3 (Trailing: 27.5 Median: 20.0) | RELATIVE P/E RATIO 1.49 | DIV'D YLD 1.6% | VALUE LINE

TIMELINESS 3 Lowered 12/31/21
SAFETY 2 New 6/5/15
TECHNICAL 2 Raised 2/4/22
BETA .60 (1.00 = Market)

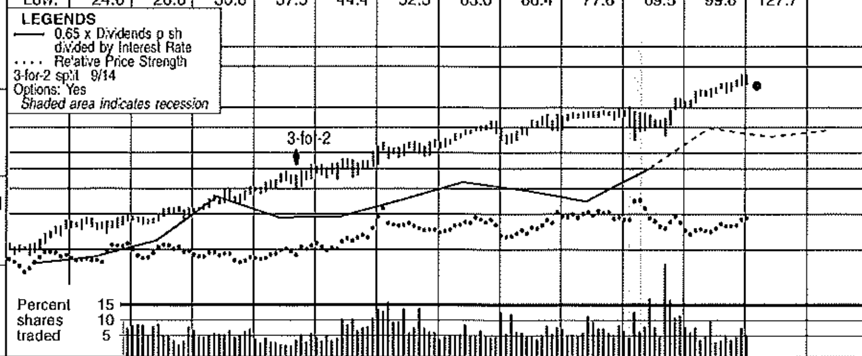
High:	29.7	32.6	40.8	52.7	61.1	70.0	86.4	93.4	98.6	111.4	146.1	146.3	
Low:	24.0	26.6	30.6	37.5	44.4	52.3	63.0	66.4	77.6	69.5	99.6	127.7	

Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$112-$190 $151 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	170	(+30%)	9%
Low	125	(-5%)	1%



Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	95	91	84
to Sell	96	93	93
Hld's(000)	13167	13128	13078

Percent shares traded 15 10 5

% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	36.3	15.7
3 yr.	58.4	56.8
5 yr.	127.1	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
23.05	25.41	28.46	19.07	29.93	29.13	27.26	30.73	34.19	30.07	30.60	37.79	43.81	29.24	27.96	*30.85*	*35.15*	*39.20*	Revenues per sh	*61.70*
2.18	2.52	2.50	2.15	3.50	3.69	3.95	4.35	4.73	5.05	5.16	5.42	6.47	6.50	7.37	*8.65*	*9.50*	*10.35*	"Cash Flow" per sh	*12.55*
1.15	1.29	1.39	1.43	1.82	1.91	1.99	2.26	2.47	2.68	2.86	2.68	3.45	3.72	4.21	*4.70*	*4.95*	*5.20*	Earnings per sh A	*6.50*
.77	.78	.81	.83	.87	.91	.96	1.01	1.07	1.12	1.19	1.26	1.39	1.55	1.69	1.84	*2.00*	*2.16*	Div'ds Decl'd per sh B■	*2.65*
4.87	3.08	3.00	1.89	3.18	3.28	5.00	6.72	6.66	9.47	10.42	10.73	16.47	11.26	9.48	*10.70*	*11.35*	*11.60*	Cap'l Spending per sh	*13.50*
11.08	11.76	12.02	14.89	15.84	16.78	17.82	19.28	20.59	23.45	27.36	29.75	31.65	34.23	39.92	*44.35*	*48.65*	*52.75*	Book Value per sh	*56.15*
10.03	10.17	10.24	14.09	14.29	14.35	14.40	14.46	14.59	15.27	16.30	16.34	16.38	16.40	17.46	*18.00*	*18.50*	*19.00*	Common Shs Outst'g C	*23.50*
17.9	16.7	14.2	14.2	12.2	14.2	14.8	15.6	17.7	19.1	21.8	27.8	22.9	24.7	21.6	*25.8*	*Bold figures are*		Avg Ann'l P/E Ratio	*22.5*
.97	.89	.85	.95	.78	.89	.94	.88	.93	.96	1.14	1.40	1.24	1.32	1.11	*1.38*	*Value Line*		Relative P/E Ratio	*1.25*
3.8%	3.6%	4.1%	4.1%	3.9%	3.4%	3.3%	2.9%	2.4%	2.2%	1.9%	1.7%	1.8%	1.7%	1.9%	1.5%	*estimates*		Avg Ann'l Div'd Yield	*1.8%*
						392.5	444.3	498.8	459.2	498.9	617.6	717.5	479.6	488.2	*555*	*650*	*745*	Revenues ($mill)	*1450*
						28.9	32.8	36.1	40.2	44.7	43.8	56.6	61.1	70.6	*85.0*	*92.0*	*100*	Net Profit ($mill)	*155*
						40.1%	40.2%	39.9%	39.5%	38.8%	39.5%	27.1%	25.6%	25.0%	*25.5%*	*26.0%*	*26.0%*	Income Tax Rate	*29.0%*
						7.4%	7.4%	7.2%	8.8%	9.0%	7.1%	7.9%	12.7%	14.5%	*15.3%*	*14.2%*	*13.4%*	Net Profit Margin	*10.7%*
						28.4%	29.7%	34.5%	29.4%	23.5%	28.9%	37.9%	43.9%	42.2%	*40.0%*	*40.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
						71.6%	70.3%	65.5%	70.6%	76.5%	71.1%	62.1%	56.1%	57.8%	*60.0%*	*60.0%*	*60.0%*	Common Equity Ratio	*60.0%*
						358.5	396.4	458.8	507.5	583.0	683.7	834.5	1001.7	1205.6	*1330*	*1500*	*1670*	Total Capital ($mill)	*2200*
						541.8	631.2	689.8	855.0	986.7	1126.0	1384.0	1463.8	1601.2	*1750*	*1900*	*2100*	Net Plant ($mill)	*2700*
						8.8%	8.8%	8.5%	8.9%	8.6%	7.3%	7.8%	7.2%	6.8%	*7.5%*	*7.5%*	*7.0%*	Return on Total Cap'l	*8.0%*
						11.2%	11.8%	12.0%	11.2%	10.0%	9.0%	10.9%	10.9%	10.1%	*10.5%*	*10.0%*	*10.0%*	Return on Shr. Equity	*11.5%*
						11.2%	11.8%	12.0%	11.2%	10.0%	9.0%	10.9%	10.9%	10.1%	*10.5%*	*10.0%*	*10.0%*	Return on Com Equity	*11.5%*
						6.4%	7.1%	7.4%	6.8%	6.1%	4.9%	6.7%	6.5%	6.2%	*6.5%*	*6.0%*	*6.0%*	Retained to Com Eq	*7.0%*
						43%	40%	38%	40%	39%	45%	39%	40%	38%	*39%*	*40%*	*41%*	All Div'ds to Net Prof	*40%*

CAPITAL STRUCTURE as of 9/30/21
Total Debt $713.7 mill. Due in 5 Yrs $270.0 mill.
LT Debt $505.5 mill. LT Interest $25.0 mill.
(LT interest earned: 5.3x; total interest coverage: 5.3x) (40% of Cap'l)
Leases, Uncapitalized Annual rentals $2.0 mill.
Pfd Stock None
Pension Assets-12/20 $60.6 mill. Oblig. $76.5 mill.
Common Stock 17,604,196 shs. as of 11/1/21

MARKET CAP: $2.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2019	2020	9/30/21
Cash Assets	7.0	3.5	5.9
Other	127.8	132.9	127.1
Current Assets	134.8	136.4	133.0
Accts Payable	54.1	60.3	53.0
Debt Due	293.0	189.2	208.2
Other	76.2	79.5	93.3
Current Liab.	423.3	329.0	354.5
Fix. Chg. Cov.	568%	618%	630%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	2.5%	1.0%	9.0%
"Cash Flow"	9.5%	7.5%	9.0%
Earnings	9.5%	9.0%	8.0%
Dividends	6.5%	7.5%	8.0%
Book Value	9.5%	11.0%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	160.5	94.5	92.6	132.0	479.6
2020	152.7	97.1	101.4	137.0	488.2
2021	191.2	111.1	107.3	*145.4*	*555*
2022	*210*	*140*	*135*	*165*	*650*
2023	*237*	*163*	*157*	*188*	*745*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.75	.54	.38	1.04	3.72
2020	1.77	.64	.56	1.24	4.21
2021	1.96	.78	.71	*1.25*	*4.70*
2022	*2.05*	*.86*	*.74*	*1.30*	*4.95*
2023	*2.12*	*.94*	*.79*	*1.35*	*5.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.325	.325	.37	.37	1.39
2019	.37	.37	.405	.405	1.55
2020	.405	.405	.44	.44	1.69
2021	.44	.44	.48	.48	1.84
2022	.48				

BUSINESS: Chesapeake Utilities Corporation consists of two main units. The Regulated Energy segment distributes natural gas in Delaware, Maryland, and Florida; distributes electricity in Florida; and transmits natural gas on the Delmarva Peninsula and in Florida. The Unregulated Energy operation wholesales and distributes propane; markets natural gas; and provides other unregulated energy services, including midstream services in Ohio. Revenue breakdown for 2020: Regulated Energy, 72.3%; Unregulated Energy, 31.2%; Other, d3.5%. Officers and directors own 2.6% of common stock; BlackRock, 15.2% (4/21 Proxy). CEO: Jeffry M. Householder. Inc.: DE. Address: 909 Silver Lake Boulevard, Dover, DE 19904. Tel.: (302) 734-6799. Internet: www.chpk.com.

Chesapeake Utilities Corporation stands to deliver better profits in 2022. (Note that fourth-quarter, 2021 numbers were not available when this report went to press.) One contributor ought to be the Regulated Energy division, supported by pipeline expansions by the Eastern Shore and Peninsula Pipeline operations, plus incremental benefits from the purchases of Elkton Gas and Escambia Meter Station. Also, we expect the performance of the Unregulated Energy unit to get a lift from higher retail propane margins per gallon, acquisitions, and a rise in demand for Marlin Gas Services' CNG transportation services. Though COVID-19 has not vanished, full-year share net may advance around 5%, to $4.95, compared to our 2021 target of $4.70. Concerning 2023, the bottom line ought to rise at a similar percentage rate, to $5.20 a share, as operating margins widen further.

There has been movement on the acquisition front. Chesapeake just bought the propane business of Diversified Energy Company (with 19,000 residential and commercial customers), expanding its footprint into the promising North Carolina and South Carolina markets. Financial terms were not disclosed, but we estimate that the deal will add several cents to 2022 share net and be increasingly accretive to earnings thereafter.

Capital spending for last year was expected to be between $185 million and $200 million. (That's around 16% higher than the 2020 figure of $165.5 million if the midpoint of this range is used.) Around 75% of the investments were deployed to the Regulated Energy unit, with a focus on the natural gas distribution and transmission operations. Leadership adds that it looks for total expenditures to be $750 million—$1 billion for the five-year period between 2021 and 2025. We believe the company can accomplish those goals if, of course, the balance sheet remains in sonnd condition.

The equity holds unspectacular total return potential over the 2025-2027 period. Capital appreciation possibilities are subpar. The dividend yield does not stand out, either. Meanwhile, these shares are neutrally ranked for Timeliness.

Frederick L. Harris, III February 25, 2022

(A) Diluted shrs. Excludes nonrecurring items: '08, d7¢; '15, 6¢; '17, 87¢. Excludes discontinued operations: '19, 24¢; '20, 5¢. Quarters for 2019 don't equal total because of rounding.
Next earnings report due early May.
(B) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan. Direct stock purchase plan available.
(C) In millions, adjusted for split.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	85
Earnings Predictability	95

NEW JERSEY RES. NYSE-NJR

RECENT PRICE 40.30 | P/E RATIO 17.5 (Trailing: 16.9 / Median: 17.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Raised 2/18/22
SAFETY 2 Lowered 4/17/20
TECHNICAL 3 Raised 1/21/22
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$27-$49	$38 (-5%)

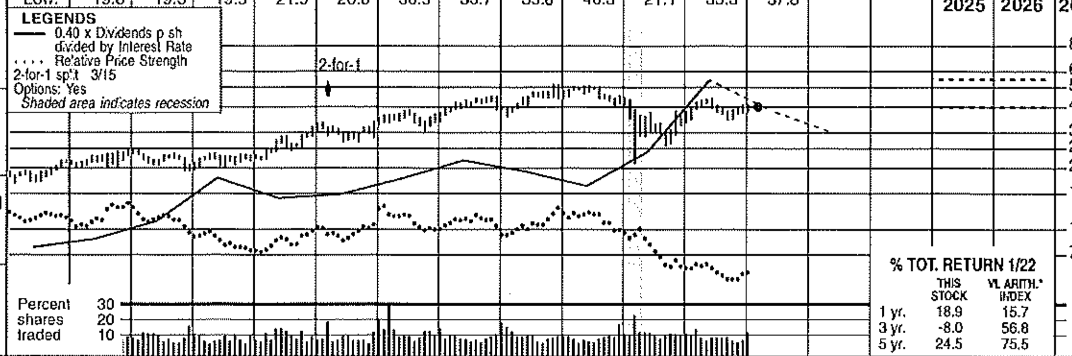
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+35%)	11%
Low	40	(Nil)	4%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	105	102	109
to Sell	139	130	121
Hld's(000)	68468	68609	66131

High:	25.2	25.1	23.8	32.1	34.1	38.9	45.4	51.8	51.2	44.7	44.4	41.3
Low:	19.8	19.3	19.5	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3	37.8



Target Price Range
2025 | 2026 | 2027

% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.9	15.7
3 yr.	-8.0	56.8
5 yr.	24.5	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
39.81	36.31	45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	24.65	25.10	Revenues per sh A	27.20
1.37	1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.65	3.70	"Cash Flow" per sh	4.20
.93	.78	1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.30	2.35	Earnings per sh B	2.70
.48	.51	.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.49	Div'ds Decl'd per sh C ■	1.70
.64	.73	.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	5.35	5.30	Cap'l Spending per sh	5.50
7.50	7.75	8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	18.70	19.80	Book Value per sh D	22.80
82.88	83.22	84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	98.00	99.00	Common Shs Outst'g E	100.00
16.1	21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	Bold figures are		Avg Ann'l P/E Ratio	17.0
.87	1.15	.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.94	Value Line		Relative P/E Ratio	.95
3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	estimates		Avg Ann'l Div'd Yield	4.0%

CAPITAL STRUCTURE as of 12/31/21
Total Debt $2836.6 mill. **Due In 5 Yrs** $442.8 mill.
LT Debt $2274.2 mill. **LT Interest** $78.6 mill.
Incl. $6.0 mill. capitalized leases.
(LT interest earned: 5.0x; total interest coverage: 5.0x)
Pension Assets-9/21 $469.5 mill. **Oblig.** $640.2 mill.
Pfd Stock None

Common Stock 96,061,402 shs.
as of 1/31/22
MARKET CAP: $3.9 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
2248.9	3198.1	3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2415	2485	Revenues ($mill) A	2715
112.4	113.7	176.9	153.7	138.1	149.4	240.5	175.0	196.2	207.7	225	235	Net Profit ($mill)	270
7.1%	25.4%	30.2%	26.3%	15.5%	17.2%	--	--	NMF	10.3%	5.0%	5.0%	Income Tax Rate	5.0%
5.0%	3.6%	4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	9.4%	10.0%	Net Profit Margin	10.0%
39.2%	36.6%	38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.5%	57.0%	Long-Term Debt Ratio	57.5%
60.8%	63.4%	61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.5%	43.0%	Common Equity Ratio	42.5%
1339.0	1400.3	1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4335	4560	Total Capital ($mill)	5230
1484.9	1643.1	1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4145	4225	Net Plant ($mill)	4485
9.2%	9.0%	12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	6.5%	6.0%	Return on Total Cap'l	6.5%
13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	12.5%	12.0%	Return on Shr. Equity	12.0%
13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	12.5%	12.0%	Return on Com Equity	12.0%
6.2%	5.2%	11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	4.5%	4.5%	Retained to Com Eq	4.5%
55%	59%	40%	50%	60%	59%	40%	59%	60%	56%	63%	63%	All Div'ds to Net Prof	63%

CURRENT POSITION ($MILL.)	2020	2021	12/31/21
Cash Assets	117.0	4.7	1.3
Other	505.3	629.6	759.0
Current Assets	622.3	634.3	760.3
Accts Payable	270.1	429.6	353.7
Debt Due	152.6	450.1	562.4
Other	111.0	171.7	181.7
Current Liab.	533.7	1051.4	1097.8
Fix. Chg. Cov.	545%	545%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.0%	-6.0%	2.0%
"Cash Flow"	7.0%	4.5%	4.5%
Earnings	5.0%	2.5%	4.5%
Dividends	6.5%	6.5%	5.0%
Book Value	7.5%	7.0%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	811.8	866.2	434.9	479.1	2592.0
2020	615.0	639.6	299.0	400.1	1953.7
2021	454.3	802.2	367.6	532.5	2156.6
2022	675.8	855	430	454.2	2415
2023	690	875	445	475	2485

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	.61	1.27	d.20	.29	1.96
2020	.44	1.12	d.06	.57	2.07
2021	.46	1.77	d.15	.07	2.16
2022	.69	1.70	d.14	.05	2.30
2023	.70	1.72	d.13	.06	2.35

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.273	.273	.273	.2925	1.11
2019	.2925	.2925	.2925	.3125	1.19
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625				

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 564,000 cust. at 9/30/21. Fiscal 2021 volume: 112 bill. cu. ft. (20% interruptible, 61% residential, commercial & firm transportation, 19% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2021 dep. rate: 2.4%. Has 1,251 empls. Off./dir. own less than 1% of common; BlackRock, 15.3%; Vanguard, 10.6% (12/21 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources is off to a good start in fiscal 2022 (ends September 30th). The company's top line advanced 48.8%, to $675.8 million, handily besting our call of $510 million. This sharp rise reflected hefty volume increases at the Natural Gas Distribution and Energy Services units. In fact, operating revenues in those divisions climbed 40% and 60%, respectively. Moreover, the NJNG utility business added 1,730 new customers during the quarter. The Clean Energy Ventures arm was also nicely complementary to the overall business mix. Alternatively, the Transportation & Storage segment registered a year-over-year decline in volumes. On the profitability front, total expenses increased 30 basis points as a percentage of the top line. On balance, these factors drove the bottom line 50% higher, to $0.69 a share. This was well above our outlook of $0.48.

The better-than-expected first-quarter results have prompted us to raise our revenue outlook for this year. We have added $165 million to our top-line estimate, bringing that figure to $2.415 billion. Our revised figure would represent an annual increase of about 12%. This ought to stem from solid improvements in both the Utility and Nonutility operations. The modest rise in volumes should help to improve overall cost absorption. And we continue to look for NJR to post a roughly 6.5% earnings gain this year, to $2.30 a share, which is near the top end of management's reiterated guidance range of $2.20-$2.30. Meanwhile, we have initiated our fiscal 2023 top- and bottom-line estimates at $2.485 billion and $2.35 a share, respectively.

At this juncture, shares of New Jersey Resources do not stand out for the short or long term. Our Timeliness Ranking System has the stock pegged to mirror the broader market averages in the coming year. What's more, the equity is trading near the low end of our 3- to 5-year Target Price Range, suggesting that it offers limited upside potential over that time frame. Alternatively, income-seeking accounts may want to keep an eye on NJR. A near-term correction in the stock's price could present an attractive entry point into these already high-yielding shares.

Bryan J. Fong *February 25, 2022*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early May.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2021: $522.1 million, $5.49/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	50
Earnings Predictability	55

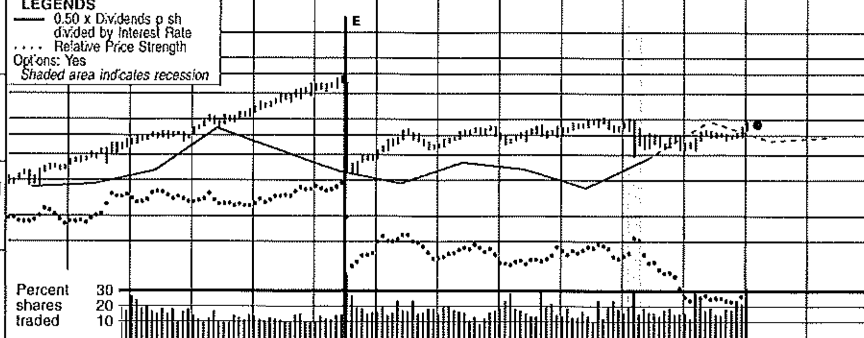
NISOURCE INC. NYSE-NI

RECENT PRICE 28.41 | P/E RATIO 19.5 (Trailing: 21.0; Median: 21.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 5 Lowered 12/17/21
SAFETY 3 Lowered 3/19/21
TECHNICAL 3 Raised 2/4/22
BETA .85 (1.00 = Market)

High:	24.0	26.2	33.5	44.9	49.2	26.9	27.8	28.1	30.7	30.5	27.8	30.2
Low:	17.7	22.3	24.8	32.1	16.0	19.0	21.7	22.4	24.7	19.6	21.1	26.4

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



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$20-$31 $26 (-10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+95%)	21%
Low	35	(+25%)	9%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	252	256	230
to Sell	188	197	208
Hld's(000)	361696	367884	376481

Percent shares traded 30 20 10

Target Price Range 2025 2026 2027: 80, 60, 50, 40, 30, 25, 20, 15, 10, 7.5

% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	36.6	15.7
3 yr.	17.1	56.8
5 yr.	51.6	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
27.37	28.96	32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.65	13.50	14.30	Revenues per sh	17.05
3.18	3.20	3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.10	3.30	3.55	"Cash Flow" per sh	4.45
1.14	1.14	1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.35	1.50	1.65	Earnings per sh A	2.40
.92	.92	.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	.98	Div'd Decl'd per sh B ■	1.08
2.33	2.88	3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.55	4.50	4.45	Cap'l Spending per sh	4.35
18.32	18.52	17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.66	13.15	13.80	14.50	Book Value per sh C	17.70
273.65	274.18	274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	395.00	400.00	405.00	Common Shs Outst'g D	415.00
19.2	18.8	12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	64.4	19.3	21.3	18.7	18.2	Bold figures are	Value Line	Avg Ann'l P/E Ratio	19.0
1.04	1.00	.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	3.24	1.04	1.13	.96	.95	estimates		Relative P/E Ratio	1.05
4.2%	4.3%	5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%			Avg Ann'l Div'd Yield	2.5%

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
5061.2	5657.3	6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	5000	5400	5780	Revenues ($mill)	7080
410.6	490.9	530.7	198.6	328.1	128.6	478.3	549.8	562.6	525	595	660	Net Profit ($mill)	990
34.4%	34.8%	36.9%	41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	19.0%	19.0%	19.0%	Income Tax Rate	19.0%
--	--	--	--	--	--	--	--	2.9%	2.0%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
55.1%	56.3%	56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	61.2%	60.5%	59.5%	58.0%	Long-Term Debt Ratio	53.5%
44.9%	43.7%	43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	32.9%	34.0%	35.0%	36.0%	Common Equity Ratio	41.5%
12373	13480	14331	9792.0	10129	11832	12856	13843	15058	15315	15680	16085	Total Capital ($mill)	17680
12916	14365	16017	12112	13066	14360	15543	16912	16620	16750	17000	18000	Net Plant ($mill)	20000
5.0%	5.2%	5.3%	4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	3.5%	4.0%	4.0%	Return on Total Cap'l	5.5%
7.4%	8.3%	8.6%	5.2%	8.1%	3.0%	8.3%	9.2%	9.6%	8.5%	9.5%	10.0%	Return on Shr. Equity	12.0%
7.4%	8.3%	8.6%	5.2%	8.1%	3.0%	9.6%	9.7%	10.2%	8.5%	9.5%	10.0%	Return on Com Equity	12.0%
2.5%	3.1%	3.4%	NMF	3.0%	NMF	4.0%	3.8%	3.7%	2.5%	3.0%	3.5%	Retained to Com Eq	6.5%
67%	62%	61%	NMF	63%	NMF	60%	64%	67%	71%	68%	65%	All Div'ds to Net Prof	48%

CAPITAL STRUCTURE as of 9/30/21
Total Debt $9623.9 mill. Due in 5 Yrs $2651 mill.
LT Debt $9188.2 mill. LT Interest $379 mill.
(Interest cov. earned: 2.2x) (58% of Cap'l)

Leases, Uncapitalized Annual rentals $32.7 mill.
Pension Assets-12/20 $2.1 bill. Oblig. $2.1 bill.

Pfd Stock $880 mill. Pfd Div'd $28.5 mill.

Common Stock 392,704,679 shs.
as of 10/25/21
MARKET CAP: $11.2 billion (Large Cap)

CURRENT POSITION ($MILL.)	2019	2020	9/30/21
Cash Assets	139.3	116.5	38.5
Other	1714.6	1542.9	1432.9
Current Assets	1853.9	1659.4	1471.4
Accts Payable	666.0	589.0	487.2
Debt Due	1783.6	526.3	435.7
Other	1296.2	1164.1	1323.7
Current Liab.	3745.8	2279.4	2246.6
Fix. Chg. Cov.	250%	250%	255%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	-7.0%	-6.0%	5.0%
"Cash Flow"	-0.5%	--	6.0%
Earnings	2.0%	0.5%	10.5%
Dividends	-1.5%	-3.0%	4.5%
Book Value	-3.0%	-5.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1869.8	1010.4	931.5	1397.2	5208.9
2020	1605.5	962.7	902.5	1211.0	4681.7
2021	1545.6	986.0	959.4	1509	5000
2022	1645	1085	1060	1610	5400
2023	1740	1180	1155	1705	5780

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.82	.05	--	.45	1.31
2020	.76	.13	.09	.34	1.32
2021	.77	.13	.11	.34	1.35
2022	.80	.17	.15	.38	1.50
2023	.84	.21	.19	.41	1.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.195	.195	.195	.195	.78
2019	.200	.200	.200	.200	.80
2020	.21	.21	.21	.21	.84
2021	.22	.22	.22	.22	.88
2022	.235				

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 479,185 electric in Indiana, 3,200,000 million gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2020: electrical, 31%; gas, 69%; other, less than 1%. Generating sources, coal, 69.4%; purchased & other, 30.6%. 2020 reported depreciation rates: 2.9% electric, 2.2% gas. Has 7,304 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

Since our November review, NiSource stock has climbed higher. In fact, over that time frame, the equity's price has advanced more than 11%.

Meanwhile, the company likely registered modest gains last year. (Note: The utility provider was expected to issue its annual financials shortly after this report went to press.) Revenues probably advanced nearly 7%, to $5.0 billion, reflecting continually increasing contributions from the Electricity and Gas Distribution divisions. The Northern Indiana Public Service Company (NIPSCO) electric utility has been performing well over the past 12 months, and logging steady volume gains. However, we think there was some margin compression last year, as the company continued to operate in a challenging business environment. On balance, these factors ought to have translated to a modest bottom-line advance of about 2.5%, to $1.35 per share.

Some changes have been made in the C-suite. Joe Hamrock has decided to retire after an accomplished 10-year career with NiSource. The succession plan, which had been in place for some time, named Lloyd Yates as the company's new President and CEO. This shift went into effect on February 14th.

We look for revenue and earnings growth momentum to improve this year. The NIPSCO utility recently filed for a $115 million increase in its annual base rate. Once finalized, that hike will go toward infrastructure modernization and system reliability upgrades. Meanwhile, there are pending rate cases filed in Ohio, Pennsylvania, Kentucky, and Maryland, which should help the company to recoup prior capital growth initiatives, as well as forge the way for future expansion. NiSource has roughly $10 billion in planned CAPEX spending through 2024. Too, we are introducing our 2023 top- and bottom-line estimates at $5.8 billion and $1.65 a share, respectively.

Our Timeliness Ranking System suggests NiSource shares will lag the broader market averages in the year ahead. However, a near-term correction may afford an attractive entry point into these high-yielding shares that currently offer about average upside potential.

Bryan J. Fong *February 25, 2022*

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, (4¢); gains (losses) on disc. ops.: '05, 10¢; '06, (11¢); '07, 3¢; '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due late April. Qtl'y egs. may not sum to total due to rounding. (B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail. (C) Incl. intang in '20: $1485.9 million, $3.79/sh. (D) In mill. (E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	20
Earnings Predictability	45

N.W. NATURAL NYSE-NWN

RECENT PRICE 46.63 | P/E RATIO 17.6 (Trailing: 17.0 Median: 24.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 5 Lowered 11/19/21
SAFETY 3 Lowered 3/19/21
TECHNICAL 3 Raised 2/18/22
BETA .80 (1.00 = Market)

High:	49.0	50.8	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.6	50.1
Low:	39.6	41.0	40.0	40.1	42.0	40.9	56.5	51.5	57.2	42.3	41.7	45.9

18-Month Target Price Range

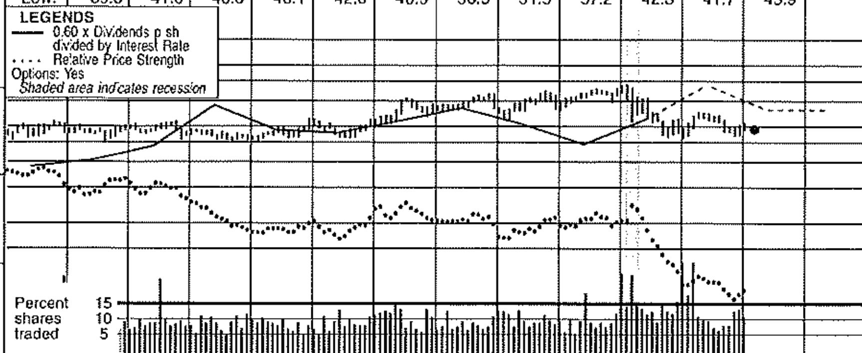
Low-High	Midpoint (% to Mid)
$41-$65	$53 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+105%)	22%
Low	65	(+40%)	12%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	103	114	95
to Sell	89	81	95
Hld's(000)	21451	21444	21597



Target Price Range 2025 | 2026 | 2027
128
96
80
64
48
40
32
24
16
12

% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.3	15.7
3 yr.	-16.7	56.8
5 yr.	-6.0	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
37.20	39.13	39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	*26.75*	*27.75*	*29.05*	Revenues per sh	*32.65*
4.76	5.41	5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	*5.75*	*6.10*	*6.40*	"Cash Flow" per sh	*7.25*
2.35	2.76	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	*2.50*	*2.70*	*2.85*	Earnings per sh A	*3.35*
1.39	1.44	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	*1.93*	*1.94*	Div'ds Decl'd per sh B■	*1.96*
3.56	4.48	3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	*8.40*	*8.70*	*9.05*	Cap'l Spending per sh	*9.40*
22.01	22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	*33.95*	*36.05*	*37.95*	Book Value per sh D	*42.75*
27.24	26.41	26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	*31.00*	*31.00*	*31.00*	Common Shs Outst'g C	*32.00*
15.9	16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	--	26.6	30.9	25.0	*20.0*	*Bold figures are*		Avg Ann'l P/E Ratio	*24.0*
.86	.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	--	1.44	1.65	1.28	*1.04*	*Value Line*		Relative P/E Ratio	*1.35*
3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	*3.8%*	*estimates*		Avg Ann'l Div'd Yield	*2.6%*

CAPITAL STRUCTURE as of 9/30/21
Total Debt $1315.8 mill. **Due in 5 Yrs** $360.2 mill.
LT Debt $916.0 mill. **LT Interest** $43.1 mill.

(Total interest coverage: 3.1x)

Pension Assets-12/20 $373.9 mill.
Oblig. $595.2 mill.

Pfd Stock None

Common Stock 30,730,274 shares as of 10/27/21

MARKET CAP $1.4 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
730.6	758.5	754.0	723.8	676.0	762.2	706.1	746.4	773.7	*830*	*860*	*900*	Revenues ($mill)	*1045*
59.9	60.5	58.7	53.7	58.9	d55.6	67.3	65.3	70.3	*75.0*	*85.0*	*90.0*	Net Profit ($mill)	*105*
42.4%	40.8%	41.5%	40.0%	40.9%	--	26.4%	16.2%	23.1%	*21.0%*	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
8.2%	8.0%	7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	*9.0%*	*9.9%*	*10.0%*	Net Profit Margin	*10.0%*
48.5%	47.6%	44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	*49.0%*	*46.5%*	*44.5%*	Long-Term Debt Ratio	*44.5%*
51.5%	52.4%	55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	*51.0%*	*53.5%*	*55.5%*	Common Equity Ratio	*55.5%*
1424.7	1433.6	1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	*2065*	*2090*	*2120*	Total Capital ($mill)	*2465*
1973.6	2062.9	2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	*2640*	*2750*	*2865*	Net Plant ($mill)	*3235*
5.7%	5.8%	5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	*4.0%*	*4.0%*	*4.0%*	Return on Total Cap'l	*4.5%*
8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	*7.5%*	*7.5%*	*8.0%*	Return on Shr. Equity	*8.0%*
8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	*7.5%*	*7.5%*	*8.0%*	Return on Com Equity	*8.0%*
1.6%	1.5%	1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	*1.5%*	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
80%	81%	85%	92%	87%	NMF	76%	82%	79%	*77%*	*72%*	*68%*	All Div'ds to Net Prof	*59%*

CURRENT POSITION ($MILL.)	2019	2020	9/30/21
Cash Assets	9.6	30.2	19.5
Other	284.1	293.0	338.7
Current Assets	293.7	323.2	358.2
Accts Payable	113.4	97.9	97.9
Debt Due	224.2	399.9	399.8
Other	144.6	129.3	237.2
Current Liab.	482.2	627.1	734.9
Fix. Chg. Cov.	336%	335%	312%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	-3.5%	-2.0%	*4.0%*
"Cash Flow"	0.5%	1.5%	*4.5%*
Earnings	-1.5%	1.5%	*6.0%*
Dividends	1.5%	0.5%	*.5%*
Book Value	1.0%	--	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	285.4	123.4	90.3	247.3	746.4
2020	285.2	135.0	93.3	260.2	773.7
2021	315.9	148.9	101.4	*263.8*	*830*
2022	*320*	*150*	*110*	*280*	*860*
2023	*330*	*160*	*120*	*290*	*900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.50	.07	d.61	1.26	2.19
2020	1.58	d.17	d.61	1.50	2.30
2021	1.94	d.02	d.67	*1.25*	*2.50*
2022	*1.96*	*.01*	*d.57*	*1.30*	*2.70*
2023	*2.00*	*.05*	*d.55*	*1.35*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.4725	.4725	.4725	.475	1.89
2019	.475	.475	.475	.4775	1.90
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	1.92
2022	.483				

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 775,000 customers, in Oregon (89% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 37%; commercial, 22%; industrial, gas transportation, 41%. Employs 1,167. BlackRock Inc. owns 16.4% of shares; State Street, 15.4%; Off./Dir., 1.03% (4/21 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Since our November review, shares of Northwest Natural Holding Co. have held firm. In fact, over this time frame, the stock's price remained relatively unchanged. By comparison, the S&P 500 Index has declined roughly 4.5% in price over this same period.

Meanwhile, we look for the distributor of natural gas to post solid financial results for 2021. (Note: The company was expected to issue its fourth-quarter and annual earnings release shortly after this report went to press.) To that point, NWN appeared well positioned to register a top-line increase of approximately 7.5%, to $830 million. This uptick in volumes ought to have stemmed from the more-than-12,000 new customer accounts added over the past year. The company's final tally should show even more natural gas meters added in the fourth quarter. At the same time, pending rate cases in Oregon and Washington have set graduated increases that augur well for prospects. The rate hikes should pave the way for reliability and growth projects. All told, NWN's earnings probably advanced about 8.5% last year, to $2.50 a share. Meanwhile, we look for similar bottom-line growth to persist in 2022. Finally, we have introduced our 2023 revenue and share-net estimates at $900 million and $2.85, respectively.

The balance sheet is in good shape. At the end of the September-quarter, the last period for which financial data were available, cash reserves sat at $19.5 million. And the long-term debt load sat at 51% of total capital, which is on the lower side for the industry.

Short-term investors will probably want to steer clear of Northwest Natural Holdings. Indeed, our Timeliness Ranking System has the stock pegged to lag the broader market averages in the coming year, Timeliness: 5 (Lowest).

However, these shares have appeal as an income vehicle. The recent increase in the quarterly dividend may have been modest, but Northwest Natural's yield is still well above the *Value Line* median. What's more, patient accounts with an eye on income generation may appreciate the substantial recovery potential out to 2025-2027.

Bryan J. Fong *February 25, 2022*

(A) Diluted earnings per share. Excludes nonrecurring items: '06, ($0.06); '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early May.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2020: $69.2 million, $2.26/share.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	10

ONE GAS, INC. NYSE-OGS

RECENT PRICE **74.98** | P/E RATIO **18.6** (Trailing: 19.6; Median: NMF) | RELATIVE P/E RATIO **1.05** | DIV'D YLD **3.4%** | VALUE LINE

TIMELINESS 4 Lowered 6/11/21
SAFETY 2 New 6/2/17
TECHNICAL 3 Raised 2/25/22
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$66-$107	$87 (15%)

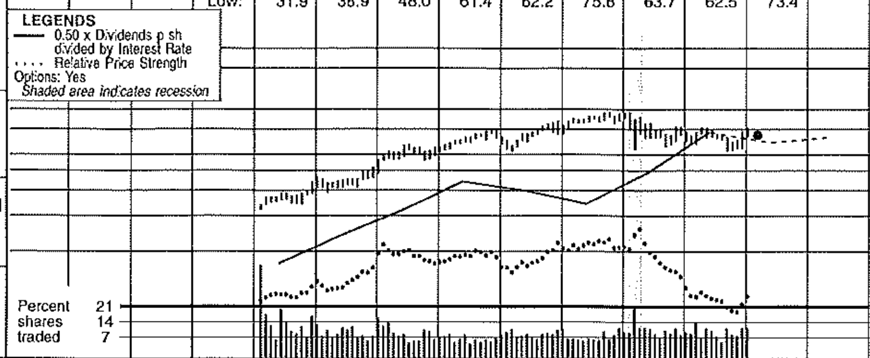
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	145	(+95%)	20%
Low	105	(+40%)	12%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	127	111	135
to Sell	144	140	122
Hld's(000)	42395	43179	42681

	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	81.6
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	73.4



Target Price Range 2025 | 2026 | 2027

% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.0	15.7
3 yr.	2.3	56.8
5 yr.	36.6	75.5

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
--	--	34.92	29.62	27.30	29.43	31.08	31.32	28.78	32.05	34.20	36.10	Revenues per sh	45.60
--	--	4.52	4.82	5.43	5.96	6.32	6.96	7.36	7.75	8.20	8.70	"Cash Flow" per sh	10.55
--	--	2.07	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.05	4.25	Earnings per sh A	5.30
--	--	.84	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	2.64	Div'ds Decl'd per sh B■	3.12
--	--	5.70	5.63	5.91	6.81	7.50	7.91	8.87	9.00	9.20	9.40	Cap'l Spending per sh	9.80
--	--	34.45	35.24	36.12	37.47	38.86	40.35	42.01	46.05	49.50	53.20	Book Value per sh	71.60
--	--	52.08	52.26	52.28	52.31	52.57	52.77	53.17	53.50	53.50	54.00	Common Shs Outst'g C	57.00
--	--	17.8	19.8	22.7	23.5	23.1	25.3	21.7	18.9	Bold figures are		Avg Ann'l P/E Ratio	23.5
--	--	.94	1.00	1.19	1.18	1.25	1.35	1.11	1.01	Value Line		Relative P/E Ratio	1.30
--	--	2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	estimates		Avg Ann'l Div'd Yield	2.5%
--	--	1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1715	1830	1950	Revenues ($mill)	2600
--	--	109.8	119.0	140.1	159.9	172.2	186.7	196.4	205	215	230	Net Profit ($mill)	300
--	--	38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	17.0%	17.5%	17.5%	Income Tax Rate	22.0%
--	--	6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	12.0%	11.7%	11.8%	Net Profit Margin	11.5%
--	--	40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.5%	60.0%	58.0%	Long-Term Debt Ratio	52.0%
--	--	59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	38.5%	40.0%	42.0%	Common Equity Ratio	48.0%
--	--	2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6400	6620	6840	Total Capital ($mill)	8500
--	--	3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5150	5380	5615	Net Plant ($mill)	6300
--	--	4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	5.0%	5.0%	5.0%	Return on Total Cap'l	5.0%
--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.5%	8.0%	8.0%	Return on Shr. Equity	7.5%
--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.5%	8.0%	8.0%	Return on Com Equity	7.5%
--	--	3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.0%	3.0%	Retained to Com Eq	3.0%
--	--	40%	53%	52%	55%	56%	56%	58%	61%	62%	62%	All Div'ds to Net Prof	59%

CAPITAL STRUCTURE as of 9/30/21
Total Debt $4019.1 mill. **Due in 5 Yrs** $1020.0 mill.
LT Debt $3683.1 mill. **LT Interest** $150.0 mill.
(LT interest earned: 4.8x; total interest coverage: 4.8x)
Leases, Uncapitalized Annual rentals $7.9 mill.
Pfd Stock None
Pension Assets-12/20 $987.6 mill. **Oblig.** $1077.6 mill.
Common Stock 53,587,508 shs. as of 10/25/21
MARKET CAP: $4.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2019	2020	9/30/21
Cash Assets	17.9	8.0	6.5
Other	488.3	531.9	746.4
Current Assets	506.2	539.9	752.9
Accts Payable	120.5	152.3	127.5
Debt Due	516.5	418.2	336.0
Other	235.7	226.6	256.6
Current Liab.	872.7	797.1	720.1
Fix. Chg. Cov.	567%	587%	600%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	--	-1.0%	6.0%
"Cash Flow"	--	8.0%	6.5%
Earnings	--	10.0%	6.0%
Dividends	--	14.5%	6.5%
Book Value	--	3.0%	8.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	661.0	290.6	248.6	452.5	1652.7
2020	528.2	273.3	244.6	484.2	1530.3
2021	625.3	315.6	273.9	500.2	1715
2022	650	355	310	515	1830
2023	680	385	340	545	1950

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.76	.46	.33	.96	3.51
2020	1.72	.48	.39	1.09	3.68
2021	1.79	.56	.38	1.12	3.85
2022	1.85	.62	.45	1.13	4.05
2023	1.90	.67	.50	1.18	4.25

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.46	.46	.46	.46	1.84
2019	.50	.50	.50	.50	2.00
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	2.32
2022	.62				

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 153 Bcf of natural gas supply in 2020, compared to 174 Bcf in 2019. Total volumes delivered by customer (fiscal 2020): transportation, 58.3%; residential, 31.7%; commercial & industrial, 9.4%; other, .6%. ONE Gas has around 3,600 employees. BlackRock owns 11.9% of common stock; The Vanguard Group, 9.7%; American Century Investment, 7.6%; officers and directors, 1.9% (4/21 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas stands to generate increased profits, once again, in 2022. (Last year's fourth-quarter figures were expected to be available shortly after this report went to press.) That improvement should be made possible partly by benefits from new rates. Another plus is a growing customer base, especially in Texas and Oklahoma. Operating expenses ought to continue to rise, but that's to be expected as the company expands. If there are no significant pandemic-related disruptions, full-year share net may advance around 5%, to $4.05, relative to our 2021 target of $3.85. Concerning next year, the bottom line ought to increase at a similar percentage rate, to $4.25 a share, as operating margins widen further.

This year's capital spending budget, including asset removal costs, is anticipated to be around $650 million. (That would be about 20% higher than the 2021 estimate of $540 million.) More than 65% of the funds are being deployed to system integrity and pipeline replacement projects. It's worth mentioning that the energy firm projects total expenditures to be some $3.5 billion ($650 million—$750 million annually) between 2022 and 2026, with roughly the same percentage of capital allocated to where it is currently. These goals appear achievable assuming, of course, that corporate finances remain adequate.

The quarterly dividend was just increased several pennies, to $0.62 a share. That was brought about, of course, by ONE Gas' solid capital position. What's more, our 3- to 5-year projections indicate that additional steady hikes in the distribution will take place. The payout ratio during that period ought to be in the neighborhood of 60%, which is manageable. Even so, the yield does not stand out from the average yield in our Natural Gas Utility group.

These good-quality shares have rallied around 10% in price since our last full-page review in November. We think that movement stems, to a certain degree, from the company's favorable business prospects this year. Too, capital gains potential over the 2025-2027 span looks solid, versus the *Value Line* median. But the stock is untimely.

Frederick L. Harris, III *February 25, 2022*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early May. Quarterly EPS for 2018 don't add up due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 24.51 | P/E RATIO 14.3 (Trailing: 14.2 / Median: 19.0) | RELATIVE P/E RATIO 0.81 | DIV'D YLD 5.1% | VALUE LINE

TIMELINESS 4 Lowered 12/17/21

SAFETY 3 Lowered 8/28/20

TECHNICAL 3 Raised 2/11/22

BETA 1.00 (1.00 = Market)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	29.0	29.0	31.1	30.6	30.4	34.8	38.4	36.7	34.5	33.4	29.2	26.7	
Low:	21.4	22.9	25.3	25.9	21.2	22.1	30.8	26.0	26.6	18.2	20.8	23.8	

18-Month Target Price Range

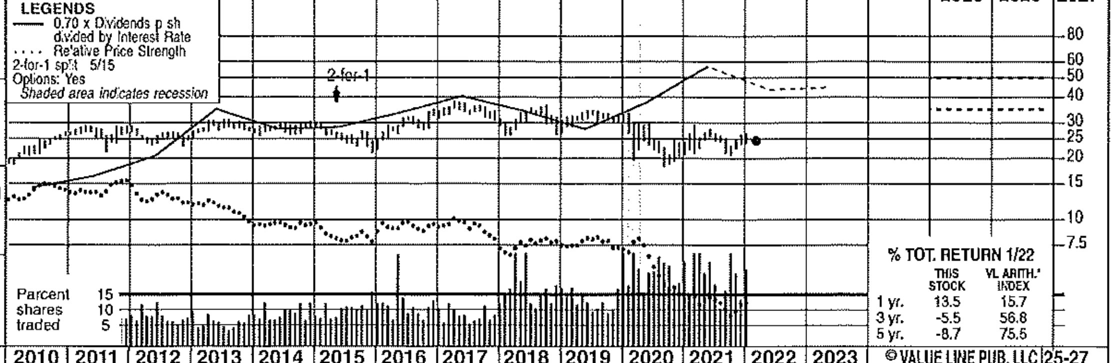
Low-High	Midpoint (% to Mid)
$14-$30	$22 (-10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+105%)	22%
Low	35	(+45%)	13%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	141	132	125
to Sell	89	106	90
Hld's(000)	102245	105367	102702



% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.5	15.7
3 yr.	-5.5	56.8
5 yr.	-8.7	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.52	13.04	15.63	19.20	17.63	15.32	*16.65*	*17.40*	*18.00*	Revenues per sh	*21.60*
1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	2.42	2.67	2.79	2.91	2.56	3.32	*2.70*	*2.90*	*3.25*	"Cash Flow" per sh	*4.25*
1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	1.44	1.34	1.23	1.38	1.12	1.68	*1.65*	*1.75*	*1.95*	Earnings per sh A	*2.70*
.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	1.06	1.10	1.13	1.16	1.19	1.22	*1.25*	*1.28*	Div'ds Decl'd per sh B ■	*1.50*
1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	4.87	3.50	3.43	3.99	5.46	4.84	*4.90*	*5.65*	*6.35*	Cap'l Spending per sh	*8.00*
7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	14.62	16.22	14.99	14.82	15.41	16.51	*16.20*	*16.95*	*17.80*	Book Value per sh C	*21.60*
58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	70.97	79.48	79.55	85.51	92.39	100.59	*112.50*	*115.00*	*118.00*	Common Shs Outst'g D	*125.00*
11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	17.9	21.7	27.9	22.6	28.3	14.9	*14.9*	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	.90	1.14	1.40	1.22	1.51	.77	*.80*	*Value Line*		Relative P/E Ratio	*.90*
3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	3.9%	3.6%	3.2%	3.6%	3.7%	4.8%	5.0%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/21

Total Debt $3404.5 mill. Due In 5 Yrs $380.1 mill.
LT Debt $3195.9 mill. LT Interest $112.0 mill.

Leases, Uncapitalized Annual rentals $1.2 mill.
Pension Assets-12/20 $331 mill. Oblig. $481.8 mill.

Pfd Stock None

Common Stock 112,448,495 shs. as of 11/1/21

MARKET CAP: $2.8 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
706.3	731.4	887.0	959.6	1036.5	1243.1	1641.3	1628.6	1541.4	*1875*	*2000*	*2125*	Revenues ($mill)	*2700*
93.3	97.1	104.0	99.0	102.8	98.1	116.2	103.0	163.0	*180*	*195*	*225*	Net Profit ($mill)	*330*
10.8%	--	--	5.9%	42.0%	--	--	--	9.9%	*22.0%*	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
13.2%	13.3%	11.7%	10.3%	9.9%	7.9%	7.1%	6.3%	10.6%	*9.6%*	*9.8%*	*10.6%*	Net Profit Margin	*12.2%*
45.0%	45.1%	48.0%	49.2%	38.5%	48.5%	62.4%	59.2%	62.6%	*64.0%*	*64.0%*	*63.0%*	Long-Term Debt Ratio	*60.5%*
55.0%	54.9%	52.0%	50.8%	61.5%	51.5%	37.6%	40.8%	37.4%	*36.0%*	*36.0%*	*37.0%*	Common Equity Ratio	*39.5%*
1337.6	1507.4	1791.9	2043.9	2097.2	2315.4	3373.9	3493.9	4437.3	*5075*	*5400*	*5700*	Total Capital ($mill)	*6850*
1578.0	1859.1	2134.1	2448.1	2623.8	2700.2	3653.5	4073.5	4464.2	*4850*	*5200*	*5600*	Net Plant ($mill)	*6500*
7.4%	6.8%	6.4%	5.4%	5.4%	5.1%	4.4%	4.0%	4.8%	*4.5%*	*4.5%*	*5.0%*	Return on Total Cap'l	*6.0%*
12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.8%	*10.0%*	*10.0%*	*10.5%*	Return on Shr. Equity	*12.0%*
12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.8%	*10.0%*	*10.0%*	*10.5%*	Return on Com Equity	*12.0%*
5.8%	4.8%	4.3%	2.8%	1.6%	.9%	1.7%	NMF	2.9%	*2.5%*	*2.5%*	*3.5%*	Retained to Com Eq	*5.5%*
55%	59%	61%	71%	80%	89%	82%	104%	70%	*76%*	*74%*	*67%*	All Div'ds to Net Prof	*57%*

CURRENT POSITION ($MILL.)

	2019	2020	9/30/21
Cash Assets	6.4	34.0	25.4
Other	646.1	472.8	546.3
Current Assets	652.5	506.8	571.7
Accts Payable	232.2	256.6	301.0
Debt Due	1316.6	739.2	208.6
Other	183.1	167.8	309.2
Current Liab.	1731.9	1163.6	818.8
Fix. Chg. Cov.	176%	238%	246%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	1.5%	6.5%	*2.5%*
"Cash Flow"	4.5%	3.0%	*5.0%*
Earnings	1.5%	-1.5%	*10.0%*
Dividends	6.5%	4.0%	*3.5%*
Book Value	5.5%	2.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	637.3	266.9	261.2	463.2	1628.6
2020	534.1	260.0	261.5	485.8	1541.4
2021	674.3	311.8	365.6	*523.3*	*1875*
2022	*700*	*335*	*380*	*585*	*2000*
2023	*725*	*360*	*415*	*625*	*2125*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.09	d.13	d.30	.46	1.12
2020	1.15	d.01	d.06	.62	1.68
2021	1.26	.02	d.17	*.54*	*1.65*
2022	*1.27*	*.02*	*d.12*	*.58*	*1.75*
2023	*1.35*	*.04*	*d.06*	*.62*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	--	.280	.280	.567	1.13
2019	--	.287	.287	.582	1.16
2020	--	.295	.295	.598	1.19
2021	--	.303	.303	.613	1.22
2022					

BUSINESS: South Jersey Industries, Inc. is a holding company. The company distributes natural gas in New Jersey and Maryland. South Jersey Gas rev. mix '20: residential, 48%; commercial, 23%; cogen. and electric gen., 9%; industrial, 20%. Acq. Elizabethtown Gas and Elkton Gas, 7/18. Nonutil. oper. incl. South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 1,130 empl. Off./dir. own less than 1% of common; BlackRock, 14.4%; State Street Corporation, 13.9%; The Vanguard Group, 10.8% (3/21 proxy). Pres. & CEO: Michael J. Renna. Chairman: Joseph M. Rigby. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Web: www.sjindustries.com.

South Jersey Industries reported mixed results for the third quarter, and this pattern probably continued in the December period. We expect a healthy revenue advance for the recent quarter, supported by strength in the company's nonutility operations. However, greater costs likely constrained the bottom line, and we envision an unfavorable share-earnings comparison for the December period. For full-year 2021, we expect top-line growth exceeded 20% but with a slight decline in share net.

Long-term prospects appear to be relatively sound here. We expect solid bottom-line growth in the years ahead. Significant share-earnings increases appear likely for 2023 and 2025, thanks to the timing associated with utility rate cases and clean energy investments. Utility South Jersey Gas ought to further benefit from healthy growth in its customer base. This business should continue to capitalize on the popularity of natural gas within its service territories. Elizabethtown Gas should also continue to perform well. The company's utilities will likely further benefit from the conversion of customers to natural gas from oil and propane, and new construction. A long runway for infrastructure modernization, as well as clean energy and decarbonization investments, should also drive performance here. Clean Energy investments include the Bronx fuel cell project (currently under development) and a renewable natural gas production project at more than 10 dairy farms that is expected to commence operations in the current year. The company is looking to become a national leader in waste-to-energy projects by 2025. Also, pre-construction engineering and permitting of a liquefied natural gas redundancy project have begun.

This stock is ranked to underperform the broader market averages for the coming six to 12 months. Looking further out, we anticipate solid growth in revenues and earnings per share for the company over to mid-decade. From the recent quotation, this stock offers wide long-term total return potential. This is supported by a generous dividend yield. All told, patient, income-seeking accounts may want to take a closer look.

Michael Napoli, CFA *February 25, 2022*

(A) Based on economic egs. from 2007. GAAP EPS: '11, $1.49; '12, $1.49; '13, $1.28; '14, $1.46; '15, $1.52; '16, $1.56; '17, ($0.04); '18, $0.21; '19, $0.84; '20, $1.62. Excl. nonrecur. gain (loss): '11, $0.04; '12, ($0.03); '13, ($0.24); '14, ($0.11); '15, $0.08; '16, $0.22; '17, ($1.27); '18, ($1.17); '19, ($0.28); '20, ($0.06). Totals may not sum due to rounding. Next egs. rpt. due early May. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2020: $674.0 mill., $6.70 per shr. (D) In mill., adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	65
Price Growth Persistence	15
Earnings Predictability	65

Docket No. UG 435

Muldoon/8

Staff/109

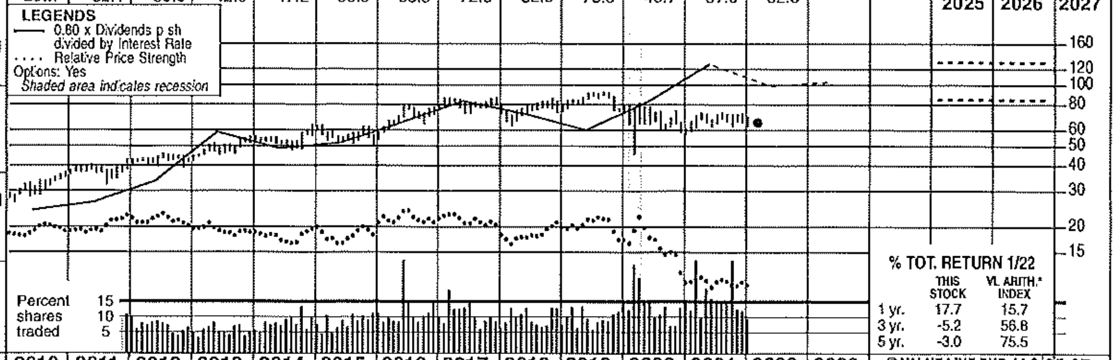
SOUTHWEST GAS NYSE-SWX

RECENT PRICE 65.52 | P/E RATIO 15.3 (Trailing: 16.0 / Median: 19.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS — Suspended 10/29/21
SAFETY 3 Lowered 1/4/91
TECHNICAL — Suspended 10/29/21
BETA .95 (1.00 = Market)

High:	43.2	46.1	56.0	64.2	63.7	79.6	86.9	86.0	92.9	81.6	73.5	70.3
Low:	32.1	39.0	42.0	47.2	50.5	53.5	72.3	62.5	73.3	45.7	57.0	62.6

Target Price Range
2025 | 2026 | 2027



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$47-$82	$65 (0%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+100%)	21%
Low	85	(+30%)	10%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	144	125	121
to Sell	132	137	122
Hld's(000)	48499	48501	52325

% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.7	15.7
3 yr.	-5.2	56.8
5 yr.	-3.0	75.5

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
	48.47	50.28	48.53	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	56.72	57.68	*58.70*	*67.45*	*72.30*	Revenues per sh	*88.55*
	5.97	6.21	5.76	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	9.87	*9.50*	*10.80*	*11.90*	"Cash Flow" per sh	*15.85*
	1.98	1.95	1.39	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	4.14	*3.80*	*4.50*	*5.10*	Earnings per sh A	*6.75*
	.82	.86	.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	2.28	2.38	*2.48*	*2.60*	Div'ds Decl'd per sh B■†	*3.10*
	8.27	7.96	6.79	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	14.43	*11.05*	*13.50*	*15.40*	Cap'l Spending per sh	*22.15*
	21.58	22.98	23.49	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	46.77	*49.60*	*52.00*	*54.60*	Book Value per sh	*67.85*
	41.77	42.81	44.19	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	57.19	*61.00*	*63.00*	*65.00*	Common Shs Outst'g C	*70.00*
	15.9	17.3	20.3	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	16.8	*17.8*	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
	.86	.92	1.22	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.13	.86	*.95*	*Value Line*		Relative P/E Ratio	*.90*
	2.6%	2.6%	3.2%	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%	3.3%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*2.9%*
							1927.8	1950.8	2121.7	2463.6	2460.5	2548.8	2880.0	3119.9	3298.9	*3580*	*4250*	*4700*	Revenues ($mill)	*6200*
							133.3	145.3	141.1	138.3	152.0	173.8	182.3	213.9	232.3	*228.0*	*280.0*	*325.0*	Net Profit ($mill)	*460*
							36.2%	35.0%	35.7%	36.4%	33.9%	32.8%	25.3%	20.5%	21.6%	*21.0%*	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
							6.9%	7.4%	6.7%	5.6%	6.2%	6.8%	6.3%	6.9%	7.0%	*6.4%*	*6.6%*	*6.9%*	Net Profit Margin	*7.4%*
							49.2%	49.4%	52.4%	49.3%	48.2%	49.8%	48.3%	47.9%	50.5%	*54.5%*	*53.5%*	*52.5%*	Long-Term Debt Ratio	*48.5%*
							50.8%	50.6%	47.6%	50.7%	51.8%	50.2%	51.7%	52.1%	49.5%	*45.5%*	*46.5%*	*47.5%*	Common Equity Ratio	*51.5%*
							2576.9	2793.7	3123.9	3143.5	3213.5	3613.3	4359.3	4806.4	5407.2	*6625*	*7025*	*7450*	Total Capital ($mill)	*9250*
							3343.8	3486.1	3658.4	3891.1	4132.0	4523.7	5093.2	5685.2	6176.1	*6500*	*6900*	*7400*	Net Plant ($mill)	*9000*
							6.4%	6.3%	5.7%	5.5%	5.8%	5.8%	5.2%	5.4%	5.3%	*4.0%*	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
							10.2%	10.3%	9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	*7.5%*	*8.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
							10.2%	10.3%	9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	*7.5%*	*8.5%*	*9.0%*	Return on Com Equity	*9.5%*
							6.1%	6.1%	5.0%	4.0%	4.1%	4.5%	3.6%	3.9%	4.0%	*2.5%*	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
							40%	41%	47%	54%	55%	53%	55%	54%	54%	*64%*	*56%*	*52%*	All Div'ds to Net Prof	*47%*

CAPITAL STRUCTURE as of 9/30/21
Total Debt $4143.1 mill. **Due in 5 Yrs** $750.9 mill.
LT Debt $3573.8 mill. **LT Interest** $100.0 mill.
(Total interest coverage: 3.7x) (54% of Cap'l)
Leases, Uncapitalized Annual rentals $13.9 mill.
Pension Assets-12/20 $1238.7 mill.
Oblig. $1581.4 mill.
Pfd Stock None

Common Stock 60,385,084 shs.
as of 10/29/21

MARKET CAP: $4.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2019	2020	9/30/21
Cash Assets	49.5	83.4	186.7
Other	810.4	787.6	1205.9
Current Assets	859.9	871.0	1392.6
Accts Payable	238.9	231.3	223.0
Debt Due	374.5	147.4	569.3
Other	466.5	533.3	562.9
Current Liab.	1079.9	912.0	1355.2
Fix. Chg. Cov.	340%	379%	373%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '25-'27
Revenues	2.5%	4.0%	*6.5%*
"Cash Flow"	4.0%	1.5%	*8.0%*
Earnings	7.5%	5.5%	*8.0%*
Dividends	8.5%	8.0%	*5.0%*
Book Value	6.0%	7.0%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	833.6	713.0	725.2	848.1	3119.9
2020	836.3	757.2	791.2	914.2	3298.9
2021	885.9	821.4	888.7	*984.0*	*3580*
2022	*1100*	*975*	*1025*	*1150*	*4250*
2023	*1250*	*1100*	*1100*	*1250*	*4700*

Cal-endar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.77	.41	.10	1.67	3.94
2020	1.31	.68	.32	1.82	4.14
2021	2.03	.43	d.19	*1.53*	*3.80*
2022	*2.05*	*.50*	*.20*	*1.75*	*4.50*
2023	*2.25*	*.60*	*.25*	*2.00*	*5.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.495	.520	.520	.520	2.06
2019	.520	.545	.545	.545	2.16
2020	.545	.570	.570	.570	2.26
2021	.570	.595	.595	.595	2.36
2022					

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas and Centuri Group. Southwest Gas is a regulated gas distributor serving 2.1 million customers in Arizona, Nevada, and California. Centuri provides construction services. 2020 margin mix: residential and small commercial, 85%; large commercial and industrial, 3%; transportation, 12%. Total throughput: 2.2 billion therms. Has 11,149 employees. Off. & dir. own .8% of common; BlackRock, Inc., 12.3%; The Vanguard Group, Inc., 9.8%; Lazard Asset Management LLC, 9.4% (3/21 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: John P. Hester. Inc.: DE. Addr.: 8360 S. Durango Drive, P.O. Box 98510 Las Vegas, Nevada 89193. Tel.: 702-876-7237. Web: www.swgas.com.

An affiliate of activist investor Carl Icahn has extended its tender offer to acquire outstanding common shares of Southwest Gas for $75.00 each in cash. The billionaire investor was also seeking to replace the company's board of directors. For its part, the company has rejected the offer as inadequate, highly conditional, and subject to significant regulatory hurdles. The board of directors recommends that stockholders not tender any shares into the offer.

The company has completed the acquisition of Questar Pipeline from Dominion Energy. It has created a new subsidiary named MountainWest Pipelines Holding Company that owns the new operation. Questar Pipeline will be rebranded under the MountainWest name in the coming months. This segment provides over 2,100 miles of regulated interstate natural gas pipelines in the Rocky Mountain region. The deal is expected to be accretive to earnings per share in the current year. This addition will accelerate growth opportunities for the company and position it as a leader in an evolving energy landscape where natural gas pipelines will play an important role.

Southwest Gas has expanded its service territory in Graham County. Following the approval of the Arizona Corporation Commission, the transition of the natural gas service provider for customers in Graham County to Southwest Gas formally began in January. This adds another 5,300 users to the company's growing customer base.

This stock offers attractive total return potential out to mid-decade. Long-term prospects look fairly solid for the company's utility and nonutility businesses. We project solid growth in earnings during this time. Moreover, the dividend yield is fairly healthy for a utility, and the payout should continue to rise. Southwest Gas earns good marks for Financial Strength, Price Stability, and Earnings Predictability. Long-term investors may want to take a closer look. The shares remain unranked for year-ahead relative price performance. The outcome of the proxy battle could have a significant, though unpredictable, effect on the stock price in the coming months.

Michael Napoli, CFA *February 25, 2022*

(A) Diluted earnings. Excl. nonrec. gains (losses): '06, 7¢. Next egs. report due early May. (B) Dividends historically paid early March, June, September, and December. ■†
Div'd reinvestment and stock purchase plan avail. (C) In millions.
(D) Totals may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	45
Earnings Predictability	95

SPIRE INC. NYSE-SR

RECENT PRICE 64.54 | P/E RATIO 19.0 (Trailing: 14.9 Median: 19.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 4 Lowered 6/20/21

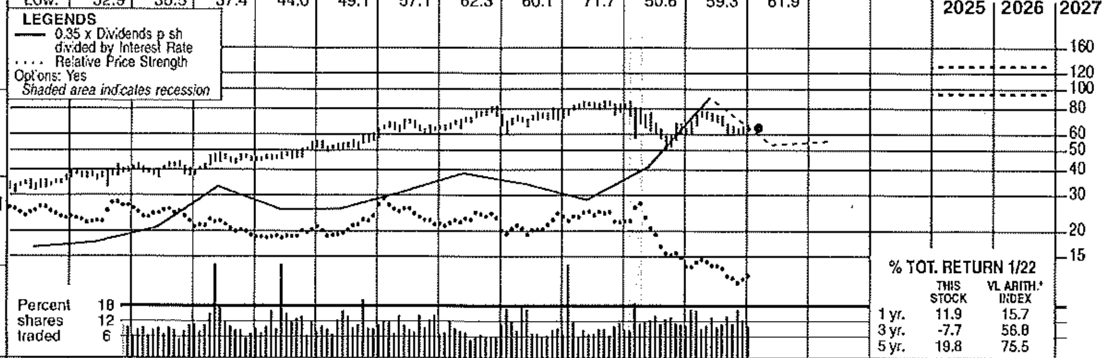
SAFETY 2 Raised 6/20/03

TECHNICAL 4 Raised 2/25/22

BETA .85 (1.00 = Market)

High:	42.8	44.0	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9	67.1
Low:	32.9	36.5	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3	61.9

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



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$47-$75	$61 (-5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+100%)	22%
Low	95	(+45%)	13%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	124	112	125
to Sell	139	126	113
Hld's(000)	42475	42992	42729

% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.9	15.7
3 yr.	-7.7	56.8
5 yr.	19.8	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
93.51	93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	38.95	40.75	Revenues per sh A	63.65
3.81	3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	7.75	8.55	"Cash Flow" per sh	10.90
2.37	2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	3.40	3.90	Earnings per sh A B	5.50
1.40	1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	2.74	2.86	Div'ds Decl'd per sh C■	3.30
2.97	2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	10.95	11.15	Cap'l Spending per sh	11.50
18.85	19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	51.25	56.10	Book Value per sh D	67.10
21.36	21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	52.00	52.50	Common Shs Outst'g E	55.00
13.6	14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	NMF	13.6	Bold figures are		Avg Ann'l P/E Ratio	20.5
.73	.75	.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	NMF	.73	Value Line		Relative P/E Ratio	1.15
4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	estimates		Avg Ann'l Div'd Yield	3.0%

CAPITAL STRUCTURE as of 12/31/21
Total Debt $4084.0 mill. Due in 5 Yrs $1520.0 mill.
LT Debt $3206.8 mill. LT Interest $145.0 mill.
(Total interest coverage: 4.2x)

Leases, Uncapitalized Annual rentals $8.8 mill.
Pension Assets-9/21 $945.7 mill. Oblig. $1318.0 mill.
Pfd Stock $242.0 mill. Pfd Div'd $14.8 mill.
Common Stock 51,750,217 shs. as of 1/28/22

MARKET CAP: $3.3 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1125.5	1017.0	1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	2025	2140	Revenues ($mill) A	3500
62.6	52.8	84.6	136.9	144.2	161.6	214.2	184.6	88.6	271.7	175	205	Net Profit ($mill)	300
29.6%	25.0%	27.6%	31.2%	32.5%	32.4%	NMF	15.7%	12.3%	20.1%	25.0%	25.0%	Income Tax Rate	25.0%
5.6%	5.2%	5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	8.6%	9.6%	Net Profit Margin	8.6%
36.1%	46.6%	55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	53.0%	52.0%	Long-Term Debt Ratio	51.0%
63.9%	53.4%	44.9%	47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	43.0%	44.0%	Common Equity Ratio	45.0%
941.0	1959.0	3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	6200	6700	Total Capital ($mill)	8200
1019.3	1776.6	2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	5360	5670	Net Plant ($mill)	7100
7.9%	3.3%	3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	4.5%	4.5%	Return on Total Cap'l	5.0%
10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	6.5%	7.0%	Return on Shr. Equity	8.0%
10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	6.5%	7.0%	Return on Com Equity	8.0%
4.3%	1.0%	1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	.5%	1.5%	Retained to Com Eq	3.0%
59%	81%	73%	58%	59%	60%	51%	66%	NMF	54%	90%	80%	All Div'ds to Net Prof	65%

CURRENT POSITION ($MILL.)	2020	2021	12/31/21
Cash Assets	4.1	4.3	8.2
Other	586.5	1312.2	1427.1
Current Assets	590.6	1316.5	1435.3
Accts Payable	243.3	409.9	427.5
Debt Due	708.4	727.8	877.2
Other	497.5	470.6	416.0
Current Liab.	1449.2	1608.3	1720.7
Fix. Chg. Cov.	373%	448%	430%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-6.5%	--	8.5%
"Cash Flow"	5.0%	6.0%	7.5%
Earnings	2.0%	2.5%	9.0%
Dividends	4.5%	6.0%	5.0%
Book Value	6.5%	4.5%	7.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	602.0	803.5	321.3	225.6	1952.4
2020	566.9	715.5	321.1	251.9	1855.4
2021	512.6	1104.9	327.8	290.2	2235.5
2022	555.4	892	325	252.6	2025
2023	570	942	340	288	2140

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	1.32	3.04	d.09	d.74	3.52
2020	1.24	2.54	d1.87	d.45	1.44
2021	1.65	3.55	.03	d.26	4.96
2022	1.01	2.78	.05	d.44	3.40
2023	1.49	2.85	.04	d.48	3.90

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.5625	.5625	.5625	.5625	2.25
2019	.5925	.5925	.5925	.5925	2.37
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	2.60
2022	.685				

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2021: 3.3 bill. Revenue mix for regulated operations: residential, 58%; commercial and industrial, 28%; transportation, 6%; other, 8%. Has about 3,710 employees. Officers and directors own 3.0% of common shares; BlackRock, 11.5% (1/22 proxy). Chairman: Edward Glotzbach; CEO: Suzanne Sitherwood. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

Spire Inc. began fiscal 2022 (which concludes September 30th) on a sour note. Indeed, first-quarter share net of $1.01 plunged nearly 40%, relative to the previous-year total of $1.65. That was attributable primarily to the Gas Utility segment, squeezed by unseasonably warm temperatures across the service territories plus heightened depreciation & amortization expenses. To make matters worse, the performance of the Gas Marketing division was hurt by less favorable market conditions and diminished storage margins.

It appears that profits will fall substantially for the year as a whole. There ought to be a challenging second-quarter share-net matchup. Moreover, the company was disappointed with a Missouri rate proceeding, particularly regarding recovery of overhead costs. So, the annual pre-tax impact on results is estimated to range between $20 million and $30 million. At the time of this report, there were plans to file a new rate case in that state that will, hopefully, remedy the situation. Lastly, the company is authorized by the Federal Energy Regulatory Commission to operate the important Spire STL Pipeline, temporarily, while it reviews whether permanent approval should be granted. (Management expects the process to continue into calendar 2023.) All told, full-year earnings may plummet over 30%, to $3.40 a share, relative to fiscal 2021's $4.96 tally. Please be aware that our fiscal 2023 target of $3.90 a share is tentative, given the aforesaid uncertainties.

This year's capital spending budget is anticipated to be roughly $570 million. (That is about 9% lower than the fiscal 2021 figure of $624.8 million.) Investments are being deployed to such segments as infrastructure upgrades at the utilities and new business development initiatives. Leadership adds that it expects total expenditures from fiscal 2022 through fiscal 2026 to be in the neighborhood of $3 billion. If finances stay in good shape, Spire should have little trouble achieving those objectives.

These shares, though unfavorably ranked for Timeliness, ought to draw the attention of total return-oriented investors with a long-term bent.

Frederick L. Harris, III February 25, 2022

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late April. (C) Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '21: $1,171.6 mill., $22.66/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	45

UGI CORP. NYSE-UGI

RECENT PRICE 37.49 | P/E RATIO 12.9 (Trailing: 12.6; Median: 17.0) | RELATIVE P/E RATIO 0.73 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 5 Lowered 1/28/22
SAFETY 2 Raised 9/17/04
TECHNICAL 2 Raised 2/25/22
BETA 1.05 (1.00 = Market)

18-Month Target Price Range
Low-High: $31-$52 | Midpoint (% to Mid): $42 (10%)

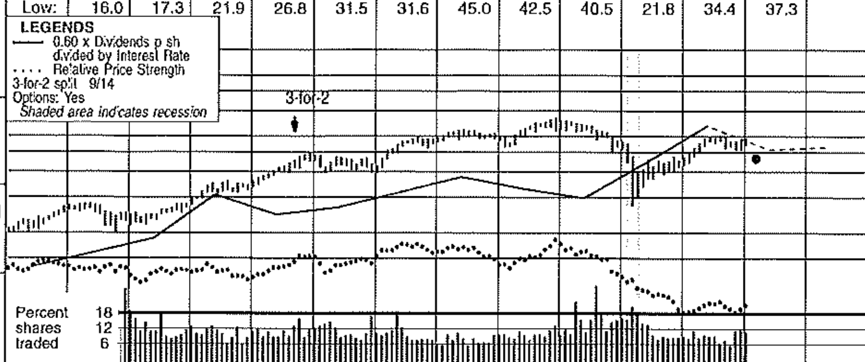
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+85%)	20%
Low	55	(+45%)	13%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	223	233	209
to Sell	201	193	211
Hld's(000)	163933	170052	167355

High:	22.4	22.4	28.8	39.7	38.6	48.1	52.0	59.3	57.3	45.3	48.6	47.0		
Low:	16.0	17.3	21.9	26.8	31.5	31.6	45.0	42.5	40.5	21.8	34.4	37.3		



Target Price Range 2025 | 2026 | 2027
128
96
80
64
48
40
32
24
16
12

% TOT. RETURN 1/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	30.0	15.7
3 yr.	-12.5	56.8
5 yr.	12.0	75.5

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
33.01	34.24	41.27	35.25	34.01	36.31	38.56	42.10	47.92	38.65	32.84	35.18	43.94	35.03	31.31	35.49	*40.00*	*42.85*	Revenues per sh A	*48.20*
2.05	2.26	2.48	2.82	2.87	2.75	3.05	3.75	4.05	4.20	4.39	4.73	5.40	4.12	4.99	4.34	*5.20*	*5.75*	"Cash Flow" per sh	*6.55*
1.10	1.18	1.33	1.57	1.59	1.37	1.17	1.59	1.92	2.01	2.05	2.29	2.74	2.28	2.67	2.96	*2.90*	*3.40*	Earnings per sh AB	*3.90*
.46	.48	.50	.52	.60	.68	.71	.74	.79	.89	.93	.96	1.02	1.15	1.31	1.35	*1.38*	*1.42*	Div'ds Decl'd per sh C ■	*1.54*
1.21	1.39	1.44	1.85	2.11	2.15	2.01	2.84	2.64	2.83	3.26	3.67	3.30	3.37	3.13	3.29	*3.35*	*3.35*	Cap'l Spending per sh	*3.35*
6.95	8.26	8.80	9.78	11.10	11.79	13.21	14.59	15.39	15.55	16.46	18.18	21.14	18.27	19.70	25.27	*27.75*	*29.65*	Book Value per sh D	*35.90*
158.18	159.97	161.09	162.78	164.38	167.75	169.06	170.88	172.73	173.12	173.15	173.99	174.14	209.01	209.51	209.84	*210.00*	*210.00*	Common Shs Outst'g E	*210.00*
14.0	15.1	13.3	10.3	10.9	15.0	16.4	15.4	15.8	17.7	19.3	20.8	17.8	23.4	13.8	13.9	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.76	.80	.80	.69	.69	.94	1.04	.87	.83	.89	1.01	1.05	.96	1.25	.71	.74	*Value Line*		Relative P/E Ratio	*.90*
3.0%	2.7%	2.9%	3.2%	3.5%	3.3%	3.7%	3.0%	2.6%	2.5%	2.3%	2.0%	2.1%	2.2%	3.6%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*2.4%*

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
6519.2	7194.7	8277.3	6691.1	5685.7	6120.7	7651.2	7320.4	6559.0	7447.0	*8400*	*9000*	Revenues ($mill) A	*10125*
199.4	278.1	337.2	353.8	360.0	406.5	485.6	412.9	561.0	629.0	*615*	*720*	Net Profit ($mill)	*824*
34.8%	27.6%	30.6%	30.0%	31.4%	26.5%	--	16.6%	19.4%	45.4%	*17.0%*	*17.0%*	Income Tax Rate	*17.0%*
3.1%	3.9%	4.1%	5.3%	6.3%	6.6%	6.3%	5.6%	8.6%	8.4%	*7.3%*	*8.0%*	Net Profit Margin	*8.1%*
60.0%	58.7%	56.4%	56.1%	56.9%	55.8%	53.0%	60.2%	59.2%	53.4%	*50.0%*	*48.5%*	Long-Term Debt Ratio	*44.0%*
40.0%	41.3%	43.6%	43.9%	43.1%	44.2%	47.0%	39.8%	40.8%	44.7%	*46.5%*	*48.0%*	Common Equity Ratio	*52.5%*
5580.7	6034.7	6092.7	6133.8	6616.9	7157.9	7827.9	9597.4	10109	11861	*12040*	*12535*	Total Capital ($mill)	*13955*
4233.1	4480.2	4543.7	4994.1	5238.0	5537.0	5808.2	6687.8	6960.0	7558.0	*8205*	*8910*	Net Plant ($mill)	*11410*
5.6%	6.6%	7.5%	7.7%	7.2%	7.2%	7.7%	5.6%	7.1%	6.6%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
8.9%	11.2%	12.7%	13.1%	12.6%	12.9%	13.2%	10.8%	13.6%	11.4%	*10.5%*	*11.5%*	Return on Shr. Equity	*11.0%*
8.9%	11.2%	12.7%	13.1%	12.6%	12.9%	13.2%	10.8%	13.6%	7.7%	*10.5%*	*11.5%*	Return on Com Equity	*11.0%*
3.6%	6.1%	7.6%	7.4%	7.0%	7.5%	8.4%	5.6%	7.0%	2.4%	*5.0%*	*6.5%*	Retained to Com Eq	*6.5%*
60%	45%	40%	43%	45%	42%	36%	48%	49%	45%	*47%*	*41%*	All Div'ds to Net Prof	*39%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $7118.0 mill. **Due in 5 Yrs** $4848 mill.
LT Debt $6416.0 mill. **LT Interest** $310.0 mill.
(Total interest coverage: 4.0x) (55% of Cap'l)

Leases, Uncapitalized Annual rentals $102.0 mill.
Pension Assets-9/21 $736 mill. **Oblig.** $870 mill.

Pfd. Stock $213.0 mill. **Pfd. Div'd.** $26.5 (2% of Capital)

Common Stock 209,804,302 shares as of 1/31/22

MARKET CAP: $7.9 bill. (Large Cap)

CURRENT POSITION ($MILL.)	2020	2021	12/31/21
Cash Assets	336	855	334
Other	1207	2415	3097
Current Assets	1543	3270	3431
Accts Payable	475	837	973
Debt Due	400	577	702
Other	880	883	906
Current Liab.	1755	2297	2581
Fix. Chg. Cov.	445%	450%	450%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-0.5%	-3.0%	*3.5%*
"Cash Flow"	5.0%	1.0%	*5.5%*
Earnings	5.5%	6.0%	*7.0%*
Dividends	8.0%	8.0%	*3.5%*
Book Value	7.0%	6.0%	*9.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	2200	2606	1364	1150	7320
2020	2007	2228	1199	1124	6559
2021	1932	2581	1496	1438	7447
2022	2673	*2645*	*1560*	*1522*	*8400*
2023	*2825*	*2795*	*1710*	*1670*	*9000*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	.81	1.43	.13	d.09	2.28
2020	1.17	1.56	.08	d.14	2.67
2021	1.18	1.99	.13	d.33	2.96
2022	.93	*2.04*	*.19*	*d.26*	*2.90*
2023	*1.28*	*2.09*	*.24*	*d.21*	*3.40*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.25	.25	.26	.26	1.02
2019	.26	.26	.30	.325	1.15
2020	.325	.325	.33	.33	1.31
2021	.33	.33	.345	.345	1.35
2022	.345				

BUSINESS: UGI Corp. operates six business segments: AmeriGas Propane (accounted for 35.1% of net income in 2021), UGI International (35.6%), Gas Utility (13.6%), Midstream & Marketing (15.9%), and Corp. & Other (-.2%). UGI Utilities distributes natural gas and electricity to over 672,000 customers mainly in Pennsylvania; wholly-owned AmeriGas Ptrs. is the largest U.S. propane marketer, serving about 1.5 million users in 50 states. Acquired remaining 80% interest in Antargaz (3/04); Energy Transfer Partners (1/12). Vanguard Group owns 11.0% of stock; BlackRock, 11.8%; Officers/directors, 2.0% (12/21 proxy). Has 11,300 empls. President & CEO: John L. Walsh. Inc.: PA. Address: 460 N. Gulph Rd., King of Prussia, PA 19406. Tel.: 610-337-1000. Internet: www.ugicorp.com.

Since our November review, shares of UGI Corp. have lost some ground. In fact, over that time frame, the stock's price declined more than 10%.

Meanwhile, the company recently posted mixed December-quarter financial results. On the upside, revenues advanced 38.4%, to $2.673 billion, reflecting better-than-expected contributions from the UGI International and Midstream & Marketing segments. Those two units benefit from colder weather patterns, and higher average wholesale propane prices, which drove volumes higher by 50% and 57%, respectively. Meanwhile, the AmeriGas Propane business also registered attractive top-line growth, just at a more modest clip of about 17%. The hefty uptick in the top line bested our call of $1.985 billion. Alternatively, cost of goods sold shot up sharply, which pressured margins. On balance, these factors drove the bottom line 22% lower, to $0.93 a share, well below our outlook of $1.23.

Consequently, we have sliced $0.30 off our fiscal 2022 share-net estimate, to $2.90. Our revised figure would represent a year-over-year earnings decline of about 2%. We look for this downturn to come from margin compression, as UGI appears poised to register a more-than-12% uptick in revenues this year, to $8.4 billion. Finally, we have introduced our fiscal 2023 top- and bottom-line estimates at $9.0 billion and $3.40 a share, respectively.

A pending rate case with the PA Public Utility Commission augurs well for prospects. UGI Utilities recently filed for an overall distribution rate hike of $83.0 million along with a request for a weather normalization adjustment mechanism. It may take some time for that to get approved, but once finalized it should be nicely additive to overall operations.

The $190 million acquisition of Stonehenge Appalachia by UGI Energy Services was recently completed. That deal adds more than 47 miles of pipeline and associated compression assets with gathering capacity of 130 million cubic feet per day.

These shares are ranked to lag the broader market averages in the coming year. And long-term appreciation potential is underwhelming.

Bryan J. Fong — *February 25, 2022*

(A) Fiscal year ends Sept. 30. Quarterly sales and earnings may not sum to total due to rounding and/or change in share count. (B) Diluted earnings. Excludes nonrecur. gains/(losses): '06, 5¢; '07, 12¢; '15, (41¢); '16, 3¢; '17, 17¢; '18, $1.32; '21, $3.96. Next egs. report due late April. (C) Dividends historically paid in early Jan., April, July, and Oct. ■ Div. reinvest. plan available. (D) Incl. intang. At 9/21: $4,353 mill., $20.74/sh. (E) In mill., adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	50
Earnings Predictability	90

WGL HOLDINGS NYSE-WGL

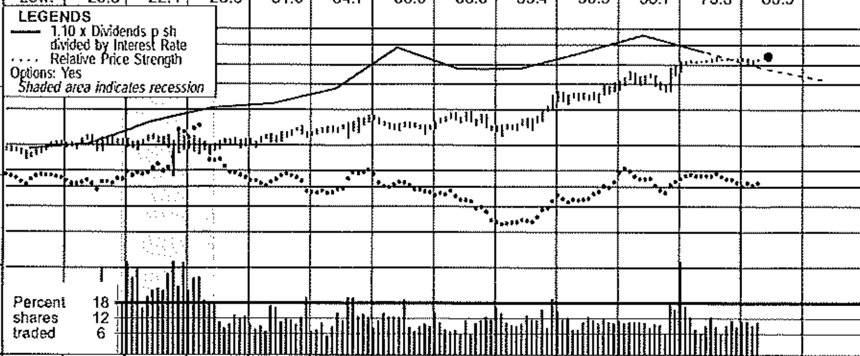
RECENT PRICE 88.19 | P/E RATIO 20.9 (Trailing: 21.8, Median: 16.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 2.3% | VALUE LINE

TIMELINESS – Suspended 2/3/17
SAFETY 1 Raised 4/2/93
TECHNICAL – Suspended 2/3/17
BETA .75 (1.00 = Market)

High:	35.9	37.1	35.5	40.0	45.0	45.0	47.0	56.8	65.6	80.0	86.9	88.3
Low:	29.8	22.4	28.6	31.0	34.7	36.0	38.0	35.4	50.9	58.7	73.5	80.9

Target Price Range 2021 | 2022 | 2023

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



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+15%)	6%
Low	85	(-5%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	14	0	0	8	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	132	113	103
to Sell	105	113	90
Hld's(000)	40665	41917	37069

Percent shares traded 18 12 6

% TOT. RETURN 4/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.7	9.5
3 yr.	68.0	25.8
5 yr.	114.1	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
32.63	42.45	42.93	44.94	53.96	53.51	52.65	53.98	53.60	53.75	47.07	47.70	53.73	53.43	45.74	45.99	47.65	47.70	Revenues per sh A	51.15
2.63	4.00	3.87	3.97	3.84	3.89	4.34	4.44	4.11	4.01	4.53	4.29	4.80	5.60	5.77	6.11	7.05	7.20	"Cash Flow" per sh	7.70
1.14	2.30	1.98	2.13	1.94	2.09	2.44	2.53	2.27	2.25	2.68	2.31	2.68	3.16	3.27	3.11	4.15	4.25	Earnings per sh B	4.60
1.27	1.28	1.30	1.32	1.35	1.37	1.41	1.47	1.50	1.55	1.59	1.66	1.72	1.83	1.93	2.02	2.06	2.12	Div'ds Decl'd per sh C■	2.24
3.34	2.65	2.33	2.32	3.27	3.33	2.70	2.77	2.57	3.94	4.87	6.04	7.63	9.33	10.33	10.09	10.85	11.10	Cap'l Spending per sh	11.80
15.78	16.25	16.95	17.80	18.66	19.83	20.99	21.89	22.82	23.49	24.64	24.65	24.08	24.97	26.78	29.35	33.10	35.90	Book Value per sh D	43.10
48.56	48.63	48.67	48.65	48.89	49.45	49.92	50.14	50.54	51.20	51.52	51.70	51.76	49.78	51.37	51.21	53.00	54.00	Common Shs Outst'g E	55.00
23.1	11.1	14.2	14.7	15.5	15.6	13.7	12.6	15.1	17.0	15.3	18.2	15.2	17.0	20.0	25.4	Bold figures are		Avg Ann'l P/E Ratio	20.0
1.26	.63	.75	.78	.84	.83	.82	.84	.96	1.07	.97	1.02	.80	.86	1.05	1.32	Value Line		Relative P/E Ratio	1.10
4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	4.6%	4.4%	4.1%	3.9%	3.9%	4.2%	3.4%	2.9%	2.6%	estimates		Avg Ann'l Div'd Yield	2.4%

CAPITAL STRUCTURE as of 3/31/18
Total Debt $2404.1 mill. Due in 5 Yrs $801.4 mill.
LT Debt $1879.3 mill. LT Interest $74.0 mill.
(LT interest earned: 6.2x; total interest coverage: 5.7x) (51% of Total Capital)
Pension Assets-9/17 $1,356.5 mill. Oblig. $1,413.0 mill.
Preferred Stock $28.2 mill. Pfd. Div'd $1.3 mill.

Common Stock 51,359,182 shs. as of 4/30/18

MARKET CAP: $4.5 billion (Mid Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
2628.2	2706.9	2708.9	2751.5	2425.3	2466.1	2780.9	2659.8	2349.6	2354.7	2525	2575	Revenues ($mill) A	2815
122.9	128.7	115.0	115.5	138.4	119.7	139.0	158.2	165.1	160.2	220	230	Net Profit ($mill)	255
37.1%	39.1%	38.7%	42.4%	40.1%	30.2%	29.0%	39.9%	37.9%	39.2%	22.0%	22.0%	Income Tax Rate	22.0%
4.7%	4.8%	4.2%	4.2%	5.7%	4.9%	5.0%	5.9%	7.0%	6.8%	8.5%	9.0%	Net Profit Margin	9.0%
35.9%	33.3%	33.4%	32.3%	31.2%	28.7%	34.8%	42.6%	50.7%	48.3%	50.0%	49.0%	Long-Term Debt Ratio	42.0%
62.4%	65.0%	65.0%	66.2%	67.3%	69.8%	63.8%	56.1%	48.3%	50.7%	49.0%	50.0%	Common Equity Ratio	57.5%
1679.5	1687.7	1774.4	1818.1	1886.9	1826.8	1954.0	2215.6	2848.0	2961.7	3580	3875	Total Capital ($mill)	4405
2208.3	2269.1	2346.2	2489.9	2667.4	2907.5	3314.4	3672.7	4127.2	4630.1	5195	5825	Net Plant ($mill)	8225
8.5%	8.8%	7.6%	7.5%	8.3%	7.5%	8.1%	8.3%	6.7%	6.7%	8.0%	8.0%	Return on Total Cap'l	7.5%
11.4%	11.4%	9.7%	9.4%	10.7%	9.2%	10.9%	12.4%	11.8%	10.5%	12.5%	12.0%	Return on Shr. Equity	11.0%
11.6%	11.6%	9.9%	9.5%	10.8%	9.3%	11.0%	12.6%	11.9%	10.7%	12.5%	12.0%	Return on Com Equity	11.0%
5.0%	5.0%	3.3%	3.4%	4.8%	2.6%	4.3%	5.4%	5.3%	3.7%	6.0%	6.0%	Retained to Com Eq	3.0%
57%	57%	67%	64%	56%	72%	62%	58%	56%	65%	49%	50%	All Div'ds to Net Prof	70%

CURRENT POSITION ($MILL.)

	2016	2017	3/31/18
Cash Assets	5.6	8.5	46.3
Other	837.9	977.4	974.7
Current Assets	843.5	985.9	1021.0
Accts Payable	405.4	423.8	358.0
Debt Due	331.4	809.8	524.8
Other	290.1	255.4	271.0
Current Liab.	1026.9	1489.0	1153.8
Fix. Chg. Cov.	546%	550%	550%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-.5%	-1.0%	1.0%
"Cash Flow"	4.0%	6.5%	4.5%
Earnings	4.5%	6.0%	6.5%
Dividends	3.5%	4.5%	2.5%
Book Value	3.5%	2.5%	8.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2015	749.2	1001.7	441.2	467.7	2659.8
2016	613.4	835.7	440.6	459.9	2349.6
2017	609.5	841.7	474.4	429.1	2354.7
2018	652.4	886.4	510	476.2	2525
2019	675	880	530	490	2575

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2015	1.16	2.02	.22	d.23	3.16
2016	1.18	1.78	.33	d.01	3.27
2017	1.15	1.87	.26	d.17	3.11
2018	1.84	2.12	.41	d.22	4.15
2019	1.90	2.02	.48	d.15	4.25

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.42	.44	.44	.44	1.74
2015	.44	.463	.463	.463	1.83
2016	.463	.488	.488	.488	1.93
2017	.488	.51	.51	.51	2.02
2018	.51	.515			

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,163,655 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers nat. gas and provides energy-related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. BlackRock owns 10.8% of common stock; Vanguard, 9.2%; Off./dir. less than 1% (1/18 proxy). Chrmn. & CEO: Terry D. McCallister. Inc.: D.C. and VA. Addr.: 101 Const. Ave., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

The acquisition of WGL Holdings by AltaGas Ltd. is progressing nicely and appears on pace to close in mid-2018. To that end, the share price continues to hover right around the tender offer price of $88.25 in cash. As a recap, this price point represents an almost 28% premium from the level WGL was trading at on November 28, 2016, the day prior to the announcement of the takeover. The stock had been trading at a discount from the purchase price for some time, which likely reflected the possibility that the deal could be derailed, given the lengthy time to completion. At this point, the equity is no longer trading on earnings, and as a result, we have suspended the Timeliness rank of these shares until the purchase is finalized. If for some reason the transaction is not completed, we would expect WGL shares to fall back toward preannouncement levels. In May, 96.22% of the voting shares approved the acquisition. More recently, the Maryland Public Service Commission passed the $4.5 billion merger. Finally, AltaGas and WGL Holdings announced a settlement agreement with key stakeholders in Washington, DC. Assuming all parties are on board and any final regulatory hurdles are cleared, the deal may well close in the middle of this year. Investors should note, however, that the merger was anticipated to be completed in the March quarter.

Meantime, the company posted better-than-expected second-quarter financial results. To that end, the top line advanced 5.3% on a year-over-year basis, to $886.4 million. This reflected an impressive 12.3% rise in utility volumes partially offset by a 3.3% downturn in nonutility operations. On the margin front, cost of goods sold increased 620 basis points as a percentage of the top line. Alternatively, operating expenses fell 470 basis points. On balance, WGL's March-quarter earnings increased 13.4%, to $2.12 a share. This was markedly above our call of $1.95. As a result, we have raised our outlook for fiscal 2018 by $0.15, to $4.15 a share.

Risk-averse accounts may wish to lock in gains now and redeploy capital elsewhere, rather than to wait for the deal to close.

Bryan J. Fong *June 1, 2018*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '02, (34¢); '07, (4¢); '08, (14¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late July.
(C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '17: $868.1 million, $16.95/sh.
(E) In millions.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	55
Earnings Predictability	75

CASE: UG 435
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200
Highly Confidential – TSA SSI
Subject to Modified Protective Order 21-465

Opening Testimony

April 22, 2022

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

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

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. I present background information regarding all Staff analysis of Northwest Natural Gas Company's (NW Natural or Company) request for a general rate increase and provide Staff analysis and recommendations for NW Natural's Test Year expense and rate base, when appropriate, for information technology (IT) projects including Horizon – Phase I; cyber security and safety; Transportation Security Administration (TSA) compliance; prepaid expenses; uncollectible accounts; and cash working capital.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Exhibit Staff/202 – Responses to Staff Data Requests.

Exhibit Staff/203 – Confidential Responses to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. SUMMARY CHART OF PROPOSED STAFF ADJUSTMENTS

Opening Testimony Exhibit No.	Staff Witness	Issue No.	Proposed Staff Adjustments	Revenue	Expense	Rate Base	Revenue Requirement Effect
	NW Natural Errata Filing UG 435 - Staff Rate Case Topics for 12 months ended October 31, 2023 ($000's)						$ 78,020
100	Muldoon	1	CoC - Staff Opening Testimony				$ (6,274)
200	Fjeldheim	1	Interest Synchronization	$ -	$ -	$ -	$ 47
		2	Horizon - Phase 1 and IT Projects	$ -	$ (502)	$ (17,300)	$ (1,992)
		3	Horizon - Phase 1 depreciable life		$ 2,467	$ (2,467)	$ 2,327
		4	Cyber Security and Safety	[redacted]			
		5	TSA Compliance				
		6	Prepaid Expenses		$ -	$ -	$ -
		7	Uncollectible Accounts		$ -	$ -	$ -
		8	Cash Working Capital		$ -	$ -	$ -
300	Fox	1	Escalation	$ -	$ 67	$ -	$ 69
		2	State Excise Tax - OCAT	[redacted]			
		3	Federal Income Tax - ARAM EDIT		$ -	$ -	$ (141)
		4	Property Tax		$ -	$ -	$ (61)
		5	OPUC Fee		$ 408	$ -	$ 420
		6	Test Year Plant - Additions	[redacted]			
		7	NWN Errata Filing - Error Correction		$ -	$ 2,843	$ 759
		8	Test Year Plant - Budget Over projection	[redacted]			
		9	Test Year Plant - Central Resource Center		$ -	$ -	$ -
		10	Lincoln City Property Sale	$ -	$ -	$ -	$ -
400	Bain	1	Load and Revenue Forecast	$ -	$ -	$ -	$ -
		2	Miscellaneous Revenues	$ -	$ -	$ -	$ -
500	Bolton	1	Materials and Supplies	$ -	$ -	$ (2,366)	$ (202)
		2	Rate Case Expense	$ -	$ -	$ -	$ -
		3	Atmospheric Testing Expense	$ -	$ -	$ -	$ -
600	Cohen	1	Wages, Salaries and FTE	$ -	$ (5,560)	$ (2,650)	$ (5,946)
		2	Customer Account, Customer Service, and Sales Expenses	$ -	$ (584)	$ -	$ (601)
		3	Miscellaneous O&M Expense	$ -	$ -	$ -	$ -
700	Dlouhy	1	Pension and Post-Retirement Medical Expenses	$ -	$ (6,367)	$ -	$ (6,549)
800	Enright	1	Capital Structure	$ -	$ -	$ -	$ -
		2	Cost of LT Debt.	$ -	$ -	$ -	$ (176)
		3	Williams Pipeline Outage	$ -	$ -	$ -	$ -
		4	Gas Inventory	$ -	$ -	$ -	$ -
		5	Gas Storage Operating Expense	$ -	$ -	$ -	$ -
		6	Affiliate Interest Charges	$ -	$ -	$ -	$ -
900	Farrell	1	Operations and Maintenance Expense	$ -	$ (418)	$ -	$ (430)
		2	Administrative and General Expense	$ -	$ (749)	$ -	$ (770)
		3	Maintenance of General Plant	$ -	$ -	$ -	$ -
1000	Jent	1	Advertising Expenses	$ -	$ (1,000)	$ -	$ (1,029)
		2	Promotional Activity and Concessions	$ -	$ -	$ -	$ -
		3	Current Medical and health insurance	$ -	$ -	$ -	$ -
		4	Insurance (Non-Medical) and Risk (Non-Medical)	$ -	$ -	$ -	$ -
		5	D&O Insurance	[redacted]			
1100	Peng	1	Depreciation Expense	$ -	$ -	$ -	$ -
		2	Depreciation Reserve	$ -	$ -	$ -	$ -
		3	AFUDC	$ -	$ -	$ -	$ -
1200	Rossow	1	Memberships and Dues	$ -	$ (443)	$ -	$ (456)
		2	Meals and Entertainment and Miscellaneous Operations and Maintenance Expenses	$ -	$ (526)	$ -	$ (541)
1300	Scala	1	Equity, Affordability and Customer Assistance	$ -	$ -	$ -	$ -
		2	Decoupling and Weather Adjusted Rate Mechanism	$ -	$ -	$ -	$ -
		3	Rate Spread and Rate Design	$ -	$ -	$ -	$ -
1400	Storm	1	IRP and the General Rate Case	$ -	$ -	$ -	$ -
		2	Current Deferrals	$ -	$ -	$ -	$ -
1500	Dlouhy, Fox, and Storm	1	Staff's Review of Amounts Deferred	$ -	$ -	$ -	$ -
		2	Earnings Review and Amortization	$ -	$ -	$ -	$ -
		3	Rate Spread	$ -	$ -	$ -	$ -
1600	Gibbens	1	Long-Run Incremental Cost Study	$ -	$ -	$ -	$ -
1700	Muldoon	1	Renewable Natural Gas	$ -	$ -	$ -	$ -
			Total Staff-Proposed Adjustments (Base Rates):	[redacted]			
			Staff-Calculated Revenue Requirements Change (Base Rates):				[redacted]

ISSUE 2. HORIZON - PHASE 1 AND IT PROJECTS

Q. Please summarize NW Natural's Horizon – Phase 1 and IT Projects.

A. In NW Natural's Exhibit/600, Company witness Downing provides an overview of seven separate IT projects, with significant emphasis placed on Horizon – Phase 1:

1. The Horizon Program is a two phase, multi-year upgrade to the Company's primary enterprise resource planning (ERP) and core technology platforms used for the Company's essential business functions. Phase 1 of the upgrade primarily focuses on back-office functions such as finance, human capital and talent management, asset management, and supply chain management. The estimated Oregon allocated project cost for Phase - 1 is $63.7 million, consisting of $36.7 million for project implementation, including labor, $11.2 million for hardware and software purchases, $8.0 million for pre-implementation and project planning, and $7.8 million in contingency costs.[1] Additionally, NW Natural included projected ongoing incremental operations and maintenance (O&M) costs of $4.5 million[2] and amortization of $8.6 million in deferred, one time start-up O&M costs.[3] In total, the Company is requesting recovery of $76.8 million for Phase 1 costs and ongoing O&M expense.

[1] NW Natural/600, Downing/30, Table 1.
[2] NW Natural/600, Downing/29 at lines 22-23.
[3] NW Natural/600, Downing/29-30 and page 32, at lines 7-8.

2. Microsoft 365 E5 (M365) Implementation Program encompasses the renewal of Microsoft's Enterprise Agreement (EA) and Server Cloud Enrollment (SCE) contracts, affecting licenses for Microsoft applications such as Office 365, Teams, SharePoint, and OneDrive. This project also includes Enterprise Mobility + Security, and Windows 10. M365 is the cloud based version of various Microsoft productivity applications using Microsoft's Azure cloud computing service, replacing all legacy versions of Microsoft productivity applications. The estimated Oregon allocated capital cost is $6.6 million.

3. Success Factors Employee Central, Onboarding, and Learning Modules for SAP[4] are add-on components to the SAP ERP software platform the Company is procuring and implementing as part of the Horizon Project. Employee Central is a human capital and talent system for employee records, Onboarding is a system that helps automate new employee onboarding, and Learning is a centralized tool for managing and assigning employee training.[5] The estimated Oregon allocated project cost is $4.3 million.[6] Additionally, NW Natural included projected ongoing incremental O&M costs of $346 thousand/year.[7]

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4 Systems, Applications, and Products in Data Processing (or Systemanalyse und Programmentwicklung) is a worldwide enterprise application software vendor headquartered in Walldorf, Germany.

5 NW Natural/600, Downing/4, lines 1-9.

6 NW Natural/600, Downing/51, line 8.

7 *Id.,* line 9.

4. Planview Implementation includes the Planview Portfolio and Resource management module for project portfolio management (PPM) and the Strategy and Programs module for strategic planning. Together, these Planview modules bring all Company capital and enterprise projects into a single platform, allowing NW Natural to track capital costs and O&M expenses, dependencies and risks, and provides enhanced reporting capabilities.[8] The estimated Oregon allocated project capital cost is $2.5 million[9] and there is a projected ongoing incremental O&M cost of $180 thousand for annual licensing fees.[10]
5. Field and Web Mapping Program is a new geospatial data mapping tool used to visualize the Company's infrastructure assets and to collect data on the Company's physical system for use in an employee field and web mapping solution. The Oregon allocated project capital cost is $2.4 million[11] and there is an ongoing incremental O&M cost of $390 thousand for annual licensing fees.[12]
6. Data Analytics and Reporting Implementation is a Company-wide tool that catalogs and stores all Company data and will govern stored data to ensure data quality and enable data extraction into data management and analytics reporting tools. This project modernizes Company data foundations and adds additional analytics capabilities while maximizing

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8 NW Natural/600, Downing/4, lines 10-19.
9 NW Natural/600, Downing/56, lines 17-18.
10 *Id.,* lines 18-19.
11 NW Natural/600, Downing/60, lines 3-4.
12 *Id.,* lines 4-5.

data use in Company decision making. The Oregon allocated project capital cost is $2.9 million[13] and there is an ongoing incremental O&M cost of $502 thousand/year for annual licensing fees.[14]

7. The Voice Radio Project is complete replacement and upgrade of the Company's outdated and unsupported analog radio system to a modern digital radio communications system. The Oregon allocated project capital cost is $2.9 million.[15]

Q. Please summarize Staff's review and analysis of the proposed Horizon - Phase 1 and IT Projects.

A. Staff reviewed Mr. Downing's, Mr. Anderson's, and Mr. Walker's testimony, noting the Company's statements regarding the age, reliability issues, lack of vendor support, and cybersecurity vulnerabilities of the legacy information systems Horizon – Phase 1 and the IT Projects are replacing. Throughout Mr. Downing's testimony, there is a recurring theme that the Horizon – Phase 1 and IT Projects will enhance the Company's digital resiliency and reliability, provide enhanced data analytical resources, significantly enhance the Company's ability to integrate and leverage data to drive business decisions, and improve its cyber security posture to counter evolving and increasing cyber security threats. The significant age and lack of vendor support for many of the Company's critical IT systems is a primary driver in the Company's need to

[13] NW Natural/600, Downing/ 65, lines 3-4.
[14] *Id.,* lines 4-5.
[15] NW Natural/600, Downing/67, lines 14-15.

make these IT investments now.[16] Staff issued numerous data requests to gain a better understanding of the underlying functionality of the proposed projects, why they are needed now, and what steps the Company took to achieve least cost/least risk solutions.[17]

Q. Please summarize Staff's analysis of Horizon – Phase 1 and the IT Projects.

A. Staff will address each component for Horizon – Phase 1 and the IT Project individually. To avoid duplicative Staff adjustment, any adjustments contemplated in Staff testimony here will be coordinated with members of other Staff that are responsible for analyzing plant additions/adjustments in this proceeding.

Horizon – Phase 1: This project is a major overhaul and modernization to the Company's current SAP based ERP platform.[18] The Company is upgrading from their legacy SAP ERP Central Component (ECC) platform to SAP's S/4HANA, a newer, cloud-based ERP product that is faster, uses a simplified data model, lean architecture, and allows for complex data analysis and problem solving in real time.[19] Staff reviewed the Company's responses to Staff DRs 169, 205, 293-294, and 296-297, and the Company's response to

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16 NW Natural/600, Downing/ 2-6, 10-16, 37-39, 45-47, 51-53, 56-58, and 60-62.
17 Staff issued DRs 288-297 and 478-483. The Company responses to Staff DRs 478-483 are pending.
18 NW Natural/600, Downing/65, lines 3-4.
19 O'Donnell, Jim. *What is SAP S/4HANA?* TechTarget Network, March 2022, https://www.techtarget.com/searchsap/definition/SAP-S-4HANA?vgnextfmt=print. Accessed March 30, 2022.

AWEC DR 089.[20] The Company's responses for Staff DRs 478-483 are pending.

Per the Company's response to Staff DR 297, because the costs of the various underlying components for this project exceed $150 thousand, the Company's IT acquisition policy requires a competitive bidding process.[21] The Company states a driving force behind this project is SAP's plan to discontinue vendor support for the ERP ECC product in 2027. Mr. Downing noted at several points that he is concerned other ERP ECC users will move to exit the older software closer to the end-of-life date, and that waiting to upgrade to S/4HANA could result in a constrained supply of knowledgeable external IT talent necessary to facilitate the transition, thereby increasing costs and project risk to NW Natural.[22]

Additionally, the Company asserts that upgrading to SAP 4/HANA now allows the Company to modernize several other systems that are also nearing/at end of service life and that updating these systems concurrently maximizes the integration and functionality of the new software and will minimize customer costs by avoiding a piecemeal approach to software/systems modernization.[23]

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20 See Staff/202, Fjeldheim, NW Natural's non-confidential responses to Staff and AWEC DRs. See Staff/203, Fjeldheim, NW Natural's Confidential responses to Staff DRs., Fjeldheim for NW Note: NW Natural's Highly Confidential responses are only accessible in a read-only format on Huddle and therefore will not be included with Staff testimony as exhibits.
21 See Staff/202, Fjeldheim, NW Natural response to Staff DR 297.
22 NW Natural/600, Downing/14-15 and page 22, at lines 7-15.
23 NW Natural/600, Downing/14, lines 3-22.

To date, the Company has not indicated that Horizon – Phase 1 is running over budget.[24] Staff submitted DR 482 requesting additional information and clarification of the $63.7 million Oregon-allocated capital cost. In DR 482, Staff asked if any project contingency funds of $8.8 million ($7.8 million Oregon allocated)[25] have been used, and to provide a detailed description and break-out of expenses to justify project cost overruns requiring use of contingent funds. Barring a reasonable justification that contingent funds were/are needed, Staff recommends removing $7.8 million of capital contingency funds from the current rate filing.

Staff noted that from 2015 - 2019, the Company engaged three separate outside vendors to study the Company's IT environment and develop applications plans and business cases to upgrade, enhance, migrate, or replace the Company's ERP and customer information system (CIS) systems. Two of the studies, conducted by TMG Consulting, and Infosys, focused on the CIS portion of the Company's systems.[26] As the Company's CIS is not contemplated in Horizon – Phase 1, Staff recommends any study costs related to the CIS, if present in the current filing, be removed.

The Company states the upgrade to SAP S/4HANA will produce "aspirational" incremental O&M cost savings of approximately $1.85 million.[27] Staff requested the Company supply addition supporting documentation

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[24] The Company has conducted several briefings and workshops with Staff and Parties to discuss the progress and status of Horizon Phase - 1. See NW Natural/600, Downing/36-37.
[25] NW Natural/600, Downing/30, Table 1 at line 6.
[26] NW Natural/600, Downing/11-13.
[27] NW Natural/600, Downing/20 at lines 8-20.

supporting the projected O&M savings, clarification of how the Company proposes to identify and confirm O&M savings, and additional explanation of how the Company proposes to return any additional O&M savings that may occur to customers.[28]

Q. Does Staff have any concerns regarding the requested accounting treatment for the Horizon – Phase 1 upgrade?

A. Yes. The Company proposes to depreciate/amortize approximately $24.7 million of Horizon – Phase 1 cloud computing assets over a period of 10 years, using a straight-line depreciation rate of 10 percent.[29] The Company asserts that by using a 10 percent depreciation rate, the Company's annual revenue requirement is approximately $2.1 million lower than it would be if a five-year depreciation rate is used.[30]

However, the Company's undepreciated plant/asset balance earns interest at the Company's approved rate of return (ROR), which means that by depreciating/amortizing the Horizon – Phase 1 upgrade over 10 years versus five years, customers will pay approximately $5.0 million in additional interest costs than if the cost of the project is depreciated/amortized over a five-year period.[31] Given these different considerations, Staff supports having the depreciation life for Horizon – Phase 1 set consistent with standard

[28] NW Natural's response to Staff DR 480 is pending and due back April 7, 2022.
[29] NW Natural/1300, Walker/33, at lines 1-13.
[30] NW Natural/1300, Walker/33, at lines 16-17.
[31] Five-year depreciation/amortization interest payments ≈ $4,561,293; whereas 10-year depreciation/amortization interest payments ≈ $9,531,383.

depreciation practices, which means a depreciation/amortization period of five years.

A decade is a long time, especially when considering how fast modern business software and computing technology evolves. If the Commission adopts a 10-year useful life for Horizon – Phase 1, customers will pay a significantly higher price over the Company's projected useful life of this project, and that assumes the underlying technology/software is supported for a full 10 years. In Staff's opinion, if 10-year amortization/depreciation is adopted, customers will experience a "rent to own" premium, paying less money per year but making those payments over a much longer time period.

Additionally, Generally Accepted Accounting Practices (GAAP) traditionally recognizes a shorter useful life for internal use computer software. While the Company may be eligible to renew their licensing agreement(s) for up to 10 years, Staff believes there is a technology/software obsolescence risk to customers that is not fully captured in the requested 10-year depreciation/amortization period.

The Company has filed a petition for an accounting order asking the Commission to adopt a 10-year amortization period for Horizon – Phase I. The petition has been docketed as Docket No. UM 2215. The Commission has not issued an order regarding the Company's requested accounting treatment.

Staff recommends an adjustment of $2.468 million to annual depreciation expense to reflect a five-year depreciation schedule.

Microsoft 365 E5 (M365) Implementation Program: Staff reviewed the Company's responses to SDRs 057 and 058, as well as Staff DRs 169, 205, 293-294, and 296-297, and found no discrepancies in the requested dollar amounts or reported expenditures for this project. This project is replacing the Company's previous suite of Microsoft productivity software, which is nearing end of life. Microsoft continues to commit significant resources to developing and supporting Office 365, and there is speculation that Microsoft may be looking to transition away from the existing long standing business model of iterative product releases via perpetual licenses for their productivity software. While Microsoft did release Office 2021 and is discussing an updated version for 2022,[32] Microsoft productivity software users may eventually have to transition to M365 if they wish to continuing using Microsoft supported productivity software.[33]

Staff notes this project appears to provide several cyber and system security features, is optimized for mobile computing devices, will enhance the interconnectivity of their workforce, will free up internal IT staff from having to perform ongoing product updates and security patching, and will further protect the Company's core computing systems from external intrusions.[34] Microsoft is well known for providing direct pricing for their products and a competitive bid

[32] DeNisco Rayome, Alison, and Brown, Shelby. *New Microsoft Office rollout: When you'll get it, pricing and major changes*. CNET, October 18, 2021, https://www.cnet.com/tech/services-and-software/new-microsoft-office-roll-out-when-youll-get-it-pricing-and-major-changes/. Accessed March 30, 2022.

[33] NW Natural/600, Downing/35-37.

[34] NW Natural/600, Downing/37-43.

process for this project appears unnecessary.[35] Staff noted the Company's projected completion date for this program is October of 2022. Because of the close proximity to the November 1 rate effective date, Staff recommends the Company be required to submit a progress report with officer attestations to all parties 60 and 30 days prior to the rate effective date on the status of the M365 Implementation project.

If this project is not "used and useful" at the time rates go into effect, Staff recommends removing the effects of the associated dollar amounts from the Test Year rate base by having the Company agree to file a rate credit to offset the revenue requirement of this project to customers. Absent such a rate credit filing, the Company would need to identify the new revenue requirement for such plant that is not projected to be in service 30 days prior to the rate effective date, provide this information in the Company's 30 days' prior status report, and remove this dollar amounts from the Test Year rate base. The Oregon allocated capital expense is $6.6 million. Staff has not identified specific costs that should be disallowed and proposes no adjustment to this component.

Planview Implementation Project: Staff reviewed the Company's responses to SDRs 057 and 058, as well as Staff DRs 169, 205, 293-294, and 296-297, and found no discrepancies in the requested dollar amounts or reported expenditures for this project. Per Mr. Downing:

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[35] Microsoft enterprise subscription pricing available https://www.microsoft.com/en-us/microsoft-365/compare-microsoft-365-enterprise-plans. Accessed March 30, 2022.

> Planview provides portfolio and work management software that offers enterprise solutions through different modules that function together as a single tool to help companies more effectively manage projects and leverage technologies at an enterprise level. This cloud-based program allows NW Natural to move away from utilizing nine different tools and applications to track and manage its project and technology portfolios, the use of which led to inefficient and suboptimal portfolio management.[36]

> The Planview tool is necessary because without it, the Company has no enterprise-wide visibility into its projects or software applications and enterprise architecture. Instead, as noted above, project and technology portfolios are managed through disparate, siloed, department-specific processes. The status quo leads to an inefficient use of time and resources; a lack of visibility into projects, portfolios, and applications; inconsistencies in the project management process; and difficult-to-access and inconsistent data, all of which impedes strategic analysis and decision-making. This lack of a single comprehensive project and portfolio management tool has led to an information gap, making it difficult to prioritize time and resource investments and to ensure strategic alignment between projects and Company goals, thereby exacerbating the risk of project overruns, impaired assets, unexpected interdependencies, and overall project failures.[37]

The Company engaged a third-party consultant, Deloitte, to review and vet four competing bids submitted for the Company's procurement consideration.[38] Additionally, the Company used quantitative industry scoring and vendor performance analysis provided by Gartner to compare and evaluate the competing vendor applicants for this project.[39] Staff has not identified costs that should be disallowed and proposes no adjustment to this component.

36 NW Natural/600, Downing/51, lines 12-18.
37 NW Natural/600, Downing/52-53.
38 NW Natural/600, Downing/53-54.
39 NW Natural/600, Downing/54-56.

Field and Web Mapping Program: Staff reviewed the Company's responses to SDRs 057 and 058, as well as Staff DRs 169, 205, 293-294, and 296-297, and found no discrepancies in the requested dollar amounts or reported expenditures for this project. Per Mr. Downing:

> NW Natural relies on its field and web mapping tools for viewing its infrastructure and other assets in a geospatial format and for collecting various types of data related to these assets. The field and web mapping tools provide field and office employees with visual online and offline representations of NW Natural facilities and assets, which they use for various business purposes, including for inspection compliance programs. The Company previously utilized two applications for its field and web mapping activities—MapFrame and Visual Fusion—that are end-of life and therefore no longer vendor-supported.[40]

The Company first began using IQGeo in 2019 for the Company's leak and inspection program and was granted rate recovery in the previous rate case, Commission Docket No. UG 388.[41] The Company has since expanded its use of IQGeo to bolster its point-inspection compliance program. Staff has not identified costs that should be disallowed and proposes no adjustment to this component.

Data Analytics and Reporting Implementation Project: Staff reviewed the Company's responses to SDRs 057 and 058, as well as Staff DRs 169, 205, 293-294, and 296-297, and found no discrepancies in the requested dollar amounts or reported expenditures for this project. Per Mr. Downing:

> In March 2020, the Company engaged IBM to assess NW Natural's enterprise reporting and analytics capabilities. IBM's analysis highlighted several key challenges and obstacles

[40] NW Natural/600, Downing/ 57-58.
[41] NW Natural/600, Downing/page 59 at lines 10-13.

> preventing the Company from realizing its goal of becoming more data driven. These obstacles included a general difficulty in locating and accessing data, inconsistent data quality, insufficient data structure, reports that were not tied to key performance indicators, and no single source of accurate data. Furthermore, the Company is currently dependent on employees with specialized data source-specific expertise to extract data and move it to a platform from which it can be reported.[42]

The Company issued a competitive bid RFP for this project and received four vendor responses, two of which were selected for final consideration.[43] Staff noted the Company's projected completion date for this program is October of 2022. Staff recommends the Company also include this project in a progress report with officer attestations to all Parties 60 and 30 days prior to the rate effective date on the status of the Data Analytics and Reporting Implementation project.

If this project is not "used and useful" at the time rates go into effect, Staff recommends removing the effects of the associated dollar amounts from the Test Year rate base by having the Company agree to file a rate credit to offset the revenue requirement of this project to customers. Absent such a rate credit filing, the Company would need to identify the new revenue requirement for such plant that is not projected to be in service 30 days prior to the rate effective date, provide this information in the Company's 30 days' prior status report, and remove this dollar amounts from the Test Year rate base. The Oregon allocated capital expense is $2.9 million and ongoing annual O&M

[42] NW Natural/600, Downing/page 61 at lines 8-11.
[43] NW Natural/600, Downing/page 63 at lines 3-22.

expense is $502 thousand. Staff has not identified specific costs that should be disallowed and proposes no adjustment to this component.

<u>Voice Radio Project</u>: Staff reviewed the Company's responses to SDRs 057 and 058, as well as Staff DRs 169, 205, 293-294, and 296-297, and found no discrepancies in the requested dollar amounts or reported expenditures for this project. Per Mr. Downing:

> NW Natural will replace its existing analog radios that are no longer produced or supported with new digital radios and related equipment. To accomplish this, the Company will license new frequency spectrums and the Tait radio interface to NW Natural's dispatch console system. The Company will also purchase design and implementation services from RACOM and new digital radios and related infrastructure and base stations from Tait. In short, the Company is transitioning its field communication system from analog to digital.[44]

An example of an analog radio device can be found in older automobiles. If you have ever manually tuned in a radio station using a twist dial and watched the needle move along the radio face plate, this was an analog radio system. Modern radios use digital tuning for channel switching and can hop instantaneously from channel to channel. Additionally, digital radios allow for additional signal compression, effectively doubling system bandwidth when compared to analog radio systems. Digital radios are also able to transmit electronic data and communicate with computing devices, whereas analog radio systems cannot.[45]

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[44] NW Natural/600, Downing/65 at lines 9-13.

[45] *Analog vs Digital Radio - 7 Key Differences*. RadioDepot blog August 1, 2020, https://www.radiodepot.com/blogs/resources/analog-vs-digital-radio. Accessed March 28, 2022.

Staff has not identified specific costs that should be disallowed and proposes no adjustment to this component.

Q. Please summarize Staff's proposed adjustments for Horizon – Phase 1 and all other IT Projects"?

A. Regarding Horizon – Phase 1, barring a reasonable justification that contingent funds were/are needed, Staff recommends removing $7.8 million of capital contingency funds from the current rate filing. Additionally, any study costs associated with the Company's CIS system should be removed from the present case as the CIS system upgrade is not included in the Horizon – Phase 1 scope of work. Pending the outcome of Commission Docket No. UM 2215 concerning the Company's request to depreciate the Horizon - Phase 1 project over 10 years, Staff reserves the right to make an adjustment in Staff Surrebuttal testimony.

Regarding the Microsoft 365 E5 (M365) Implementation Program and the Data Analytics and Reporting Implementation Project, due to the projected in service timeframe of October 2022, Staff recommends the Company be required to submit a progress report with officer attestations to all Parties 60 and 30 days prior to the rate effective date on the status of both projects. If this project is not "used and useful" at the time rates go into effect, Staff recommends removing the effects of the associated dollar amounts from the Test Year rate base by having the Company agree to file a rate credit to offset the revenue requirement of this project to customers. Absent such a rate credit filin, the Company would need to identify the new revenue requirement for such plant that is not projected to be in service within 30 days of the rate effective date and provide this information in the Company’s 30 days’ prior status report.

ISSUE 3. CYBER SECURITY AND SAFETY

Q. Please summarize NW Natural's security expenditures in this rate filing.

A. Much of the information pertaining to cyber security will be addressed in Staff Issue 3 – TSA Directive 2 Compliance. Throughout Mr. Downing's testimony in NW Natural/600 and NW Natural/700-703, the Company illustrates that cybersecurity is a driving force in all levels of Company IT procurement and operational activities. Additionally, NW Natural's Highly Confidential responses to Staff DRs 288-292 shed additional light on specific steps the Company is taking to maintain and continuously improve its cybersecurity posture. Throughout Mr. Downing's testimony,[46] the Company's cybersecurity and data protection needs are discussed in detail. While many of the Horizon – Phase1 and IT projects discussed in Issue 1 contain elements of cyber and data security, the Company is requesting specific rate recovery of **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** for cybersecurity enhancements necessary to comply with TSA's Security Directive Pipeline-2021-2: Pipeline Cybersecurity Mitigation Actions, Contingency Planning, and Testing (TSA Security Directive 2) requirements.

Q. How did Staff review cyber security in this filing?

[46] NW Natural's Highly Confidential response to Staff DR 291(d) provides specific cites in the current filing for cybersecurity investments and expenditure details.

A. Staff issued DRs 288-292 requesting supplemental information on the Company's cyber security spending and provide narrative details concerning whether the Company experienced any data breaches or cyber intrusions in the past five years. NW Natural responded **[BEGIN HIGHLY CONFIDENTIAL]**

[redacted]

> [redacted]

[redacted] **[END HIGHLY CONFIDENTIAL]**. On March 29, 2022, Staff traveled to the Company's main offices in Portland, Oregon to review TSA Sensitive Security Information (SSI) documents concerning the Company's compliance with TSA Security Directive 2 and obtained additional verbal explanation of the Company's compliance costs included in the current rate case filing. Staff's review of the Company's compliance with TSA Security Directive 2 are described separately in the Section 3 of Staff's testimony.

Q. Please summarize NW Natural's cybersecurity expenditures during the past five years.

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[47] See NW Natural's Highly Confidential response to Staff DR 292.
[48] *Id.* Staff DR 292(c.)

A. From 2016 - 2019, the Company's average annual spending on cyber security was approximately **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL].**

Q. Please summarize NW Natural's safety expenditures in this rate filing.

A. In NW Natural's Exhibit/400, pages 28-34, Company witness Kizer provides an overview of four separate safety projects related to transmission, distribution, and gas storage facilities. In total, the Company is seeking recovery of approximately $12.0 million in capital investments for the following projects:

1. The Inline Inspection (ILI) Conversion Projects is part of the Company's seven-year pipeline inspection program required by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). The Company is converting three separate pipeline segments to use ILI instrumentation. Per Mr. Kizer's testimony:

    > Inline inspection tools have the advantage over direct assessment and pressure testing because they assess the entire pipeline, maintaining constant contact with the inner wall providing data allowing for the identification of interacting anomalies such as pipe deformation and metal loss. [49]

    The affected pipeline segments are:

    i.) The E08 Springfield transmission line, consisting of three miles of eight-inch pipe that serves downtown Springfield and large industrial customers, at a cost of $1.5 million:[50]

    ii.) The P31 McMinnville/Lafayette transmission line, consisting of 13 miles of six-inch pipe along Oregon Highway 99 serving the City of McMinnville at an estimated cost of $3.8 million;[51] and

    iii.) The E04 North Eugene Industrial transmission line, consisting of five miles of six-inch and eight-inch pipe along Randy Pape Beltline

49 See NW Natural/400, Kizer/29-30.
50 See NW Natural/400, Kizer/29 at lines 18-22.
51 See NW Natural/400, Kizer/30 at lines 1-4.

Highway serving North Eugene at an estimated cost of $3.0 million.[52]

2. The Underground Storage Facilities – Well Integrity Program is needed to comply with PHMSA's 2020 Underground Storage Facilities final rule. Per Mr. Kizer:

> The Underground Storage Facilities rule addresses critical safety issues related to downhole facilities, including wells, wellbore tubing, and casing, at underground natural gas storage facilities through integrity management techniques, such as risk models, inspections, and remediation activities. This regulation responds to Section of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, which was enacted following the serious natural gas leak at the Aliso Canyon facility in California on October 23, 2015.[53]

As part of the Company's 2022 storage well integrity program for the Mist storage facility, the Company will be inspecting and assessing six storage wells to include downhole wireline logging of production casing strings using multi-arm caliper and magnetic flux tools to identify deformations and metal loss features at an Oregon allocated cost of $2.7 million. This will be a recurring annual expense for the remaining life of the Mist storage facility.[54]

3. The Seismic and Other Natural Force Mitigation Projects are using a recent 2021 seismic study to prioritize projects and develop programs that will address seismic activity threats system-wide, including but not limited

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[52] See NW Natural/400, Kizer/30 at lines 5-8.
[53] See NW Natural/400, Kizer/30 at lines 15-22.
[54] See NW Natural/400, Kizer/31 at lines 6-14.

to installation of automatic shut-off valves or remote control valves, elimination of bridge crossings, natural forces mitigation work, system reinforcement, and installation of Excess Flow Valves (EFV).[55] The Company did not indicate a request for rate recovery in the current filing for this program and Staff did not identify expenditures in the Company's response to Staff SDR 057 indicating any expenses were recorded for this program in the Base Year.

4. As part of the Proactive EFV Installation Program, the Company installs EFVs, an automatic shutoff device that attaches to a service line that automatically stops gas flow in the event of a line being damaged or severed. EFVs are installed on all new service lines to single family homes, as well as multi-family homes and small commercial customers with consumption rates of no more than 50 therms/hour.[56]

Additionally, the Company will install an EFV if a customer requests this feature at the customer's expense. Separate from the new service and customer requested EFV installations, the Company installs EFVs in areas it deems to be high risk for potential damage. The Company is investing $0.6 million as part of its Distribution Integrity Management Program (DIMP) annual budget for EFV retrofit installations in areas deemed high consequence.

Q. How did Staff analyze the safety projects included in this filing?

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[55] See NW Natural/400, Kizer/31-32.
[56] See NW Natural/400, Kizer/33-34.

A. Staff reviewed Mr. Kizer's filed testimony as well as the Company's responses to Staff SDRs 057-058, and DRs 169, 205, and 475-477.

Q. Does Staff recommend an adjustment(s) for cyber security or safety project spending?

A. No. Staff does not recommend an adjustment for either cyber security or safety projects.

ISSUE 4. TRANSPORTATION SECURITY ADMINISTRATION (TSA) COMPLIANCE

Q. What prompted the TSA's Security Directive Pipeline-2021-2: Pipeline Cybersecurity Mitigation Actions, Contingency Planning, and Testing (TSA Security Directive 2)?

A. In the Summer of 2021, the Colonial Pipeline, one of the United States largest oil pipelines that supplies nearly half of the fuel used on the East Coast, was hacked by a foreign entity demanding a ransom payment of approximately $4.4 million in bitcoin. As a result of this intrusion, Colonial was forced to take the pipeline offline in an attempt to mitigate the scope of the hack on the company's IT and physical operating infrastructure.

While the hackers did not directly attack the pipeline's physical control systems, numerous IT systems were encrypted and rendered unusable. Colonial decided to pay the ransom the same day the attack occurred and received the encryption key necessary to unlock their IT systems. However, it took approximately six days for Colonial, in conjunction with U.S. law enforcement agencies and external cybersecurity professionals, to re-store the pipeline to normal working order.[57]

Q. Why is NW Natural affected by TSA Security Directive 2?

[57] Kerner, Sean M. *Colonial Pipeline hack explained: Everything you need to know*. TechTarget, July 7, 2021, https://whatis.techtarget.com/feature/Colonial-Pipeline-hack-explained-Everything-you-need-to-know. Accessed March 31, 2022;
Kelly, Stephanie and Resnick-ault, Jessica. *One password allowed hackers to disrupt Colonial Pipeline, CEO tells senators*. Reuters, June 8, 2021, https://www.reuters.com/business/colonial-pipeline-ceo-tells-senate-cyber-defenses-were-compromised-ahead-hack-2021-06-08/. Accessed March 31, 2022.

A. The TSA deemed **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**.

Q. What is the Company required to do in order to comply with TSA Security Directive 2?

A. The TSA provided the Company with a comprehensive list of activities and cybersecurity requirements that must be completed within the timeframe specified by TSA. The TSA requirements are focused on enhancing the cybersecurity posture of notified pipeline and facility owners/operators by requiring that all physical IT and operational technology (OT) hardware systems meet certain minimum requirements, that specified security practices are adopted and used, and that specific security software and hardware requirements are met to the satisfaction of the TSA's Cybersecurity and Infrastructure Security Agency (CISA).[59]

Additionally, the affected parties must engage in ongoing audits and evaluations of their cybersecurity systems and capabilities by qualified third parties, with the results of the audit/evaluation to be shared with the TSA and CISA to determine continued compliance with TSA Security Directive 2. It is Staff's understanding that TSA Security Directive 2 requirements are Federal

[58] See NW Natural/701, Downing/1, paragraph 1.

[59] *Id.,* Pages 19-24. Note: TSA has since updated the language of Attachment 1 to TSA SD Pipeline 2021-02 to Version B. Because several components of the document are deemed Sensitive Security Information (SSI), Staff is unable to procure a copy of the current version, but physically viewed the updated document at NW Natural's offices.

cybersecurity mandates and are generally non-negotiable by the Company, with limited exception.

Furthermore, Staff has seen no evidence that the TSA, CISA, or any other agency of the Federal government will provide funding or direct assistance to the Company to help meet these requirements in the required timeframe. It appears that the Company must incur any and all costs necessary to meet TSA's compliance requirements and that the Company's sole recourse to recover these costs is to pass them on to customers.

Q. Did the Company include TSA Security Directive 2 compliance costs in this filing?

A. Yes. On an Oregon allocated basis, the Company has requested **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**.

Q. Does Staff propose any adjustment to the Company's requested recovery amount?

A. Yes. Staff proposes the following adjustments **[BEGIN HIGHLY CONFIDENTIAL/SSI** [redacted]

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60 See NW Natural/700, Downing/33 at lines 14-17.
61 See NW Natural/700, Downing/29 at lines 11-14.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[END HIGHLY CONFIDENTIAL/SSI]

[redacted]

ISSUE 5. PREPAID EXPENSES

Q. What are prepaid expenses and how are they recorded?

A. Prepaid expenses are payments made in advance for items such as undelivered gas, insurance, rent, and taxes. As the periods covered by prepayments expire, the value of these prepayments is reduced and the associated expense is charged to the proper operating account. Prepaid expenses are recorded in FERC account 165.

Q. Did the Company include prepaid expenses in the rate case?

A. The Company stated in response to SDR 086 that "No prepayments are included in the Base Year's or Test Year's rate base (FERC account 165)".

Q. Does Staff have any adjustments associated with this issue?

A. No.

ISSUE 6. UNCOLLECTIBLE ACCOUNTS

Q. Please provide a summary of the Commission's historical treatment of uncollectible expense, the Company's filed proposal, and Staff's analysis of the issue.

A. The amount included in a utility's Revenue Requirement for uncollectible expense is considered revenue sensitive because it is dependent on the amount of forecasted revenue. The amount of uncollectible expense included in the Revenue Requirement is a function of the Test Year revenue and the uncollectible rate factor. The uncollectible rate is based on an average of the net-write offs, i.e., the uncollectible amounts that were written off the books, for the base year and preceding two years divided by the average of the revenues for those same years. The uncollectible rate derived from this three-year average methodology is then multiplied by the forecasted Test Year revenue to determine the projected uncollectible expense for a utility's Revenue Requirement. In addition, Commission Staff reviews other materials to determine the reasonableness of the rate and level of expense produced by the three-year model.

Q. Please provide a summary of the Company's filed proposal for uncollectible expenses and Staff's analysis of the issue.

A. The Company's proposal adheres to the three-year average methodology. Per Company witness Walker:

> The adjustment for Uncollectible Accrual for Gas Sales reflects the difference between the Base Year expense and the Test Year expense derived by taking the three year

> historical average for the twelve months ending September 2017, 2018 and 2019 of write-offs as a percent of total revenues, times Test Year sales revenue. The three historical years chosen are the same years used in the Company's last general rate case (UG 388), which also provides the baseline in the COVID-19 deferral.[63]

Mr. Walker further supports the calculation of the uncollectible account factor of 0.097 percent in NW Natural/1306, Walker/1 at line 28. The Company continued to utilize 2017, 2018, and 2019 based on an October 1 through September 30 time period, trending the three-year rolling average of write-offs and revenues for that period. Staff continues to find the Company's uncollectible rate of 0.097 percent to be reasonable.

Q. What is Staff's recommendation?

A. Staff recommends the continued use of 0.097 percent for the uncollectible rate factor. Because this factor is revenue sensitive, the overall adjustment will depend on all proposed Staff and Parties adjustments to Test Year revenues.

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[63] See NW Natural/1300, Walker/13 at lines 13-20.

ISSUE 7. CASH WORKING CAPITAL

Q. Please describe cash working capital (CWC).

A. Generally, a utility provides service to customers prior to receiving payment (revenue lag). When a utility purchases goods and services, there is normally a billing delay for the payment to the vendor/seller (expense lead). Calculating an appropriate level of CWC relies on two components: 1) the number of days of revenue lag versus the number of days of expense lead the utility experiences in a time period; and 2) the dollar amounts for each. If it takes longer for a company to receive billed revenues than it does to make payments to the utility's vendors, an operational cash shortfall can develop that needs to be filled from an alternative source. A utility could borrow funds on a short-term basis to meet their cash needs, attempt to extend their repayment period to vendors to reduce monthly cash outlays, or it can recover additional funds from customers necessary to bridge the operational cash need gap.

Q. Did the Company request CWC in the rate filing or provide a recent lead/lag study?

A. No. Staff did not identify any segment of the Company's initial filing testimony where CWC was included in the Company's proposed revenue requirement, nor did Staff locate a current lead/lag study amongst the supporting work papers.

Q. Is CWC included in the Company's filing?

A. No. However, the Company has requested a separate rate base component for materials and supplies (M&S), which is discussed in Staff/500, Bolton.

Q. Does this conclude your testimony?

A. Yes.

WITNESS QUALIFICATION STATEMENT

NAME:	Brian Fjeldheim
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Science, Business Accountancy Regis University, Denver, CO Bachelor of Science, Aviation Technology Metropolitan State College of Denver, Denver, CO
EXPERIENCE:	I have been employed as a Senior Financial Analyst by the Oregon Public Utility Commission since May of 2018 in the Rates, Finance, and Audit Division. I currently perform a range of financial analysis duties related to natural gas and electric utilities, with a focus on rate case, operational audit, and annual Purchased Gas Adjustment (PGA) filings. I have participated in utility general rate cases and power cost filings in the following dockets: Cascade Natural Gas – UG 347, Avista Utilities – UG 366, NW Natural – UG 388, PacifiCorp – UE 374, Avista Utilities – UG 389, Cascade Natural Gas – UG 390, PacifiCorp – UE 390, PGE – UE 391, PGE – UE 394, and Avista Utilities – UG 433. I have nine years of professional level financial analysis and accounting experience. I was previously employed as a Budget and Fiscal Analyst with the Oregon Department of Justice (DOJ), where I was responsible for the budget build and ongoing budget execution of four legal divisions with 165 staff members and a biennial budget of $75 million. Prior to DOJ, I was employed as a Senior Budget Analyst with the Oregon Department of Administrative Services (DAS) and was responsible for the budget build, ongoing budget execution and cash flow analysis for the state data center with a biennial budget of $165 million. Prior to DAS, I worked as a Financial Analyst for the Insurance Division of the Department of Consumer and Business Services (DCBS), where I performed financial analysis and solvency surveillance of nine Oregon insurers with annual revenues of $1.4 billion and assets of $1.1 billion.

CASE: UG 435
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202
Responses to Staff Data Requests

Exhibits in Support
Of Opening Testimony

April 22, 2022

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 293

293. Please provide IT cost information in the following MS Excel table format:

Costs	2016	2017	2018	2019	2020	2021	UG 435 Request	Percent Change 2016 to UG 435
Personnel								
Software								
Hardware								
Contracting / Professional Services								
Other								
Total								

Response:

Please see UG 435 OPUC DR 293 Attachment 1.

Costs	2016	2017	2018	2019	2020	2021	UG 435	Percent Change 2016 to UG 435
Personnel	$9,331,808	$10,079,695	$9,360,242	$10,047,054	$10,134,258	$10,962,502	$11,239,634	20%
Software	$2,344,211	$2,826,203	$3,273,700	$3,678,002	$4,316,357	$5,477,045	$20,274,444	765%
Hardware	$616,183	$503,311	$533,487	$690,501	$765,392	$1,131,407	$1,136,344	84%
Contracting / Professional Services	$800,338	$762,668	$1,488,645	$1,034,917	$1,576,157	$2,446,808	$2,718,784	240%
Other	$1,683,444	$1,725,343	$2,491,523	$2,196,512	$2,449,553	$2,496,269	$2,879,706	71%
Total	**$14,775,984**	**$15,897,219**	**$17,147,597**	**$17,646,985**	**$19,241,718**	**$22,514,031**	**$38,248,913**	159%

Expenses reflect OR allocated expenses prior to any administrative transfer
Increase in UG 435 expense in O&M discussed in NW Natural/1200 Davilla/Page 14 and in detail in direct testimonies of Jim Downing (NW Natural/600 & 700)

NW Natural

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 294

294. Please provide NW Natural's FTE count for IT staff in the following MS Excel table format:

	2016	2017	2018	2019	2020	2021	UG 435 Request	Percent Change 2016 to UG 435
FTE								

Response:

Please see UG 435 OPUC DR 294 Attachment 1.

	2016	2017	2018	2019	2020	2021	UG 435 Request**	Percent Change 2016 to UG 435
FTE*	72.5	74.5	77.0	84.0	92.0	90.0	92.0	26.9%

*numbers reflect year end FTE counts

**FTE does not reflect additional expense to support the requirement of the Department of Homeland Security's TSA Directive Pipeline-2021-02. This additional expense does include labor to support and is discussed in further detail in Jim Downing's Direct Testimony (NW Natural/700, Downing). This expense was included as non-payroll in this case due to the current uncertainty around whether the labor will come as Company employees, managed services, or a combination thereof.

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 295

295. For each of the component FTE included in NW Natural's response to the previous DR:

a. Please list the current job-title (i.e. Database Administrator 2, etc.).
b. Please provide the time in-service at the Company.

Response:

Please see UG 435 OPUC DR 295 Attachment 1.

Docket No: UG 435

Job Title	Job In Date
Change Mgmt & IT Compliance Manager	2/20/2017
Solutions Architect	9/30/2019
BI Developer/Analyst 2	2/1/2015
Network Engineering 3	12/30/2019
Cybersecurity & Compliance Director	8/31/2015
Applications Engineering 3	1/1/2005
Applications Engineering 3	4/1/2021
Applications Engineering 3	12/30/2019
Solutions Architect	11/15/2021
Applications Engineering 2	3/1/2017
Applications Engineering 3	4/13/2020
Engineering 3	12/17/2018
Applications Engineering 3	10/1/2019
Solutions Architect	12/10/2018
Telecom Analyst 3	1/1/2005
Solutions Architect	3/16/2014
Network Engineering Manager	3/31/2017
Applications Engineering 3	8/1/2009
IT Business Analyst 2	2/12/2018
Operational Technology Sr Manager	1/24/2017
Applications Engineering 2	7/23/2018
Business/Budget/Finance Analyst 2	8/1/2007
IT Compliance Analyst 3	12/27/2017
Syst Admin IT Spec 3	12/16/2019
Engineering 3	8/28/2018
Applications Engineering 4	11/1/2013
IT Security Specialist 2	3/9/2020
Service Desk Spec 3	8/6/2018
Applications Engineering 3	5/1/2016
Proc/Asset Mgt IT Spec 3	8/1/2010
Engineering 3	4/1/2021
Applications Engineering 3	7/2/2018
Applications Engineering 4	1/1/2005
Applications Engineering 2	8/19/2019
Staff Assistant 2	9/15/2020
Applications Engineering 4	7/13/2020
IT Compliance Analyst 2	3/2/2020
Syst Admin IT Spec 2	12/30/2019
DB Developer/Administrator 3	7/13/2020

Job Title	Job In Date
Applications Engineering 3	2/1/2014
Applications Engineering 3	9/16/2019
Dsktp Admin IT Spec 2	5/20/2013
IT Security Specialist 3	2/1/2014
Applications Engineering 2	7/30/2018
Applications Engineering 3	9/21/2015
IT Compliance Analyst 2	8/16/2019
Dsktp Admin IT Spec 3	7/16/2012
DB Developer/Administrator 3	6/1/2017
Network Engineering 3	7/23/2018
Service Desk Spec 3	5/21/2018
Syst Admin IT Spec 2	4/16/2014
Enterprise Architecture Director	7/23/2018
Syst Admin IT Spec 3	11/11/2019
Network/Infrastructure/Svc Delivery Dir	8/27/2018
Applications Engineering 3	5/16/2020
Service Desk Spec 3	1/14/2019
Applications Engineering 2	6/5/2017
Applications Engineering 4	6/16/2014
Applications Engineering 4	4/15/2011
IT Security Specialist 3	4/1/2017
Syst Admin IT Spec 3	9/18/2017
Dsktp Admin IT Spec 3	3/2/2020
Syst Admin IT Spec 3	4/13/2017
Communications & Controls Supervisor	2/19/2018
Syst Admin IT Spec 2	12/16/2019
Dsktp Admin IT Spec 3	1/2/2019
IT Planning Senior Manager	9/1/2018
Enterprise Applications Manager	11/30/2017
Infrastructure Manager	11/12/2018
IT Security Specialist 2	5/11/2020
Enterprise Applications Manager	8/3/2015
Systems Analyst/QA 3	7/1/2016
Applications Engineering 3	8/19/2019
Syst Admin IT Spec 2	6/4/2018
Solutions Architect	12/10/2018
Enterprise Applications Manager	6/1/2015
IT&S Security Operations Manager	1/20/2020
IT Business Analyst 3	3/1/2021
Systems Analyst/QA 2	8/10/2020

Job Title	Job In Date
Applications Engineering 3	12/1/2012
Enterprise Applications Director	9/1/2014
Applications Engineering 3	1/1/2005
Syst Admin IT Spec 2	2/17/2020
Dsktp Admin IT Spec 3	6/16/2019
Service Desk Spec 3	12/29/2017
DB Developer/Administrator 3	4/1/2016
Syst Admin IT Spec 3	12/15/2013
Applications Engineering 3	10/1/2019
Applications Engineering 3	3/1/2010
Applications Engineering 4	7/6/2020

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 296

296. Does the Test Year include new IT projects, IT system upgrades, and/or incremental IT rate base additions? If yes, please provide:

a. A breakout of expenditures by project, to include the total Company dollar amount, the Oregon allocated dollar amount, and the FERC account.

b. The approved budgeted amount for each individual project.

c. A comparison of budget to actuals for each project, with a projected total spend. For projects with a projected cost of ± 10 percent of the budgeted amount, please provide a supplemental narrative explaining the cause(s) of the deviation and what steps the Company took to manage project costs for the benefit of ratepayers.

d. A brief narrative describing why each project is needed and how ratepayers will benefit.

e. The projected in-service date for each project.

Response:

a. Please see UG 435 OPUC DR 296 Attachment 1, tab “A and E” for a list of IT rate base additions in the Test Year. Included is the total project expense, OR allocation, and the FERC account.

b. Please see UG 435 OPUC DR 296 Attachment 1, tab “B – D” for approved budgets of active capital projects and forecasted project budgets for those not yet started.

c. Please see UG 435 OPUC DR 296 Attachment 1, tab “B – D.”

d. Please see UG 435 OPUC DR 296 Attachment 1, tab “B – D.”

e. Please see response (a) for in-service dates.

FERC Account	Applicant	Project	State	In-Service Date	System Amount	OR Allocation 88.25%	Testimony Reference
391.2 COMPUTERS	38.1 Computer Hardware	200067-1 Tech Refresh - Large Servers/Storage (Hardware)	System	1-2023	$19,816.75	$17,488.28	
391.2 COMPUTERS	38.1 Computer Hardware	200067-1 Tech Refresh - Large Servers/Storage (Hardware)	System	2-2023	$19,928.41	$17,586.83	
391.2 COMPUTERS	38.1 Computer Hardware	200067-1 Tech Refresh - Large Servers/Storage (Hardware)	System	10-2023	$20,010.60	$17,659.35	
391.2 COMPUTERS	38.1 Computer Hardware	200067-1 Tech Refresh - Large Servers/Storage (Hardware)	System	9-2023	$20,318.50	$17,931.08	
391.2 COMPUTERS	38.1 Computer Hardware	200067-1 Tech Refresh - Large Servers/Storage (Hardware)	System	7-2023	$20,458.63	$18,054.74	
391.2 COMPUTERS	38.1 Computer Hardware	200067-1 Tech Refresh - Large Servers/Storage (Hardware)	System	6-2023	$20,471.99	$18,066.53	
391.2 COMPUTERS	38.1 Computer Hardware	200067-1 Tech Refresh - Large Servers/Storage (Hardware)	System	8-2023	$20,584.90	$18,166.17	
391.2 COMPUTERS	38.1 Computer Hardware	200067-1 Tech Refresh - Large Servers/Storage (Hardware)	System	5-2023	$20,619.18	$18,196.43	
391.2 COMPUTERS	38.1 Computer Hardware	200067-1 Tech Refresh - Large Servers/Storage (Hardware)	System	4-2023	$20,627.71	$18,203.96	
391.2 COMPUTERS	38.1 Computer Hardware	200067-1 Tech Refresh - Large Servers/Storage (Hardware)	System	3-2023	$21,951.62	$19,372.30	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	200067-2 Tech Refresh - Large Servers/Storage (Software)	System	1-2023	$46,239.08	$40,805.99	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	200067-2 Tech Refresh - Large Servers/Storage (Software)	System	2-2023	$46,499.63	$41,035.93	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	200067-2 Tech Refresh - Large Servers/Storage (Software)	System	10-2023	$46,691.39	$41,205.16	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	200067-2 Tech Refresh - Large Servers/Storage (Software)	System	9-2023	$47,409.83	$41,839.18	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	200067-2 Tech Refresh - Large Servers/Storage (Software)	System	7-2023	$47,736.81	$42,127.74	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	200067-2 Tech Refresh - Large Servers/Storage (Software)	System	6-2023	$47,767.98	$42,155.24	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	200067-2 Tech Refresh - Large Servers/Storage (Software)	System	8-2023	$48,031.42	$42,387.73	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	200067-2 Tech Refresh - Large Servers/Storage (Software)	System	5-2023	$48,111.43	$42,458.33	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	200067-2 Tech Refresh - Large Servers/Storage (Software)	System	4-2023	$48,131.33	$42,475.90	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	200067-2 Tech Refresh - Large Servers/Storage (Software)	System	3-2023	$51,220.45	$45,202.04	
391.2 COMPUTERS	38.1 Computer Hardware	200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hard	System	11-2022	$40,501.27	$35,742.37	
391.2 COMPUTERS	38.1 Computer Hardware	200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hard	System	12-2022	$42,120.03	$37,170.93	
391.2 COMPUTERS	38.1 Computer Hardware	200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hard	System	1-2023	$87,381.67	$77,114.33	
391.2 COMPUTERS	38.1 Computer Hardware	200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hard	System	2-2023	$87,874.06	$77,548.86	
391.2 COMPUTERS	38.1 Computer Hardware	200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hard	System	10-2023	$88,236.45	$77,868.66	
391.2 COMPUTERS	38.1 Computer Hardware	200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hard	System	9-2023	$89,594.13	$79,066.82	
391.2 COMPUTERS	38.1 Computer Hardware	200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hard	System	7-2023	$90,212.05	$79,612.14	
391.2 COMPUTERS	38.1 Computer Hardware	200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hard	System	6-2023	$90,270.95	$79,664.11	
391.2 COMPUTERS	38.1 Computer Hardware	200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hard	System	8-2023	$90,768.81	$80,103.47	
391.2 COMPUTERS	38.1 Computer Hardware	200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hard	System	5-2023	$90,919.99	$80,236.89	
391.2 COMPUTERS	38.1 Computer Hardware	200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hard	System	4-2023	$90,957.61	$80,270.09	
391.2 COMPUTERS	38.1 Computer Hardware	200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hard	System	3-2023	$96,795.35	$85,421.90	
391.2 COMPUTERS	38.1 Computer Hardware	201693-1 Tech Refresh Network Hardware	System	1-2023	$8,492.89	$7,494.98	
391.2 COMPUTERS	38.1 Computer Hardware	201693-1 Tech Refresh Network Hardware	System	2-2023	$8,540.75	$7,537.21	
391.2 COMPUTERS	38.1 Computer Hardware	201693-1 Tech Refresh Network Hardware	System	11-2022	$8,556.61	$7,551.20	
391.2 COMPUTERS	38.1 Computer Hardware	201693-1 Tech Refresh Network Hardware	System	10-2023	$8,575.97	$7,568.29	
391.2 COMPUTERS	38.1 Computer Hardware	201693-1 Tech Refresh Network Hardware	System	9-2023	$8,707.93	$7,684.75	
391.2 COMPUTERS	38.1 Computer Hardware	201693-1 Tech Refresh Network Hardware	System	7-2023	$8,767.99	$7,737.75	
391.2 COMPUTERS	38.1 Computer Hardware	201693-1 Tech Refresh Network Hardware	System	6-2023	$8,773.71	$7,742.80	
391.2 COMPUTERS	38.1 Computer Hardware	201693-1 Tech Refresh Network Hardware	System	8-2023	$8,822.10	$7,785.50	
391.2 COMPUTERS	38.1 Computer Hardware	201693-1 Tech Refresh Network Hardware	System	5-2023	$8,836.79	$7,798.47	
391.2 COMPUTERS	38.1 Computer Hardware	201693-1 Tech Refresh Network Hardware	System	4-2023	$8,840.45	$7,801.70	
391.2 COMPUTERS	38.1 Computer Hardware	201693-1 Tech Refresh Network Hardware	System	12-2022	$8,898.60	$7,853.01	
391.2 COMPUTERS	38.1 Computer Hardware	201693-1 Tech Refresh Network Hardware	System	3-2023	$9,407.84	$8,302.42	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	201694 Tech Refresh Microwave	System	11-2022	$76,058.72	$67,121.82	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	201694 Tech Refresh Microwave	System	12-2022	$79,098.65	$69,804.56	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	201694 Tech Refresh Microwave	System	1-2023	$113,238.57	$99,933.04	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	201694 Tech Refresh Microwave	System	2-2023	$113,876.66	$100,496.15	

FERC Account	Applicant	Project	State	In-Service Date	System Amount	OR Allocation	Testimony Reference
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201694 Tech Refresh Microwave	System	10-2023	$114,346.27	$100,910.59	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201694 Tech Refresh Microwave	System	9-2023	$116,105.71	$102,463.29	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201694 Tech Refresh Microwave	System	7-2023	$116,906.48	$103,169.97	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201694 Tech Refresh Microwave	System	6-2023	$116,982.80	$103,237.32	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201694 Tech Refresh Microwave	System	8-2023	$117,627.98	$103,806.69	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201694 Tech Refresh Microwave	System	5-2023	$117,823.90	$103,979.59	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201694 Tech Refresh Microwave	System	4-2023	$117,872.65	$104,022.61	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201694 Tech Refresh Microwave	System	3-2023	$125,437.83	$110,698.88	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201695 Tech Refresh - Telemetry	System	11-2022	$28,522.02	$25,170.68	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201695 Tech Refresh - Telemetry	System	12-2022	$29,661.99	$26,176.71	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201695 Tech Refresh - Telemetry	System	1-2023	$122,675.11	$108,260.79	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201695 Tech Refresh - Telemetry	System	2-2023	$123,366.38	$108,870.83	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201695 Tech Refresh - Telemetry	System	6-2023	$126,731.37	$111,840.43	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201695 Tech Refresh - Telemetry	System	4-2023	$127,695.37	$112,691.17	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201695 Tech Refresh - Telemetry	System	3-2023	$135,890.98	$119,923.79	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201695 Tech Refresh - Telemetry	System	7-2023	$150,029.98	$132,401.46	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201695 Tech Refresh - Telemetry	System	10-2023	$158,179.01	$139,592.98	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201695 Tech Refresh - Telemetry	System	9-2023	$183,834.04	$162,233.54	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201695 Tech Refresh - Telemetry	System	8-2023	$186,244.30	$164,360.59	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201695 Tech Refresh - Telemetry	System	5-2023	$186,554.51	$164,634.36	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201696 Tech Refresh - Telephony	System	1-2023	$33,027.92	$29,147.14	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201696 Tech Refresh - Telephony	System	2-2023	$33,214.02	$29,311.38	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201696 Tech Refresh - Telephony	System	10-2023	$33,351.00	$29,432.25	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201696 Tech Refresh - Telephony	System	9-2023	$33,864.16	$29,885.13	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201696 Tech Refresh - Telephony	System	7-2023	$34,097.72	$30,091.24	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201696 Tech Refresh - Telephony	System	6-2023	$34,119.98	$30,110.89	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201696 Tech Refresh - Telephony	System	8-2023	$34,308.16	$30,276.95	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201696 Tech Refresh - Telephony	System	5-2023	$34,365.30	$30,327.38	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201696 Tech Refresh - Telephony	System	4-2023	$34,379.52	$30,339.93	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEME	201696 Tech Refresh - Telephony	System	3-2023	$36,586.03	$32,287.17	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201936 Patch and SW Delivery Automation	System	1-2023	$8,492.89	$7,494.98	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201936 Patch and SW Delivery Automation	System	2-2023	$8,540.75	$7,537.21	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201936 Patch and SW Delivery Automation	System	11-2022	$8,556.61	$7,551.20	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201936 Patch and SW Delivery Automation	System	10-2023	$8,575.97	$7,568.29	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201936 Patch and SW Delivery Automation	System	9-2023	$8,707.93	$7,684.75	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201936 Patch and SW Delivery Automation	System	7-2023	$8,767.99	$7,737.75	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201936 Patch and SW Delivery Automation	System	6-2023	$8,773.71	$7,742.80	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201936 Patch and SW Delivery Automation	System	8-2023	$8,822.10	$7,785.50	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201936 Patch and SW Delivery Automation	System	5-2023	$8,836.79	$7,798.47	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201936 Patch and SW Delivery Automation	System	4-2023	$8,840.45	$7,801.70	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201936 Patch and SW Delivery Automation	System	12-2022	$8,898.60	$7,853.01	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201936 Patch and SW Delivery Automation	System	3-2023	$9,407.84	$8,302.42	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201963-2 Tech Refresh Network Software	System	1-2023	$5,661.93	$4,996.65	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201963-2 Tech Refresh Network Software	System	2-2023	$5,693.83	$5,024.81	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201963-2 Tech Refresh Network Software	System	11-2022	$5,704.40	$5,034.14	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201963-2 Tech Refresh Network Software	System	10-2023	$5,717.31	$5,045.53	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201963-2 Tech Refresh Network Software	System	9-2023	$5,805.29	$5,123.16	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201963-2 Tech Refresh Network Software	System	7-2023	$5,845.32	$5,158.50	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201963-2 Tech Refresh Network Software	System	6-2023	$5,849.14	$5,161.87	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201963-2 Tech Refresh Network Software	System	8-2023	$5,881.40	$5,190.33	

FERC Account	Applicant	Project	State	In-Service Date	System Amount	OR Allocation	Testimony Reference
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201963-2 Tech Refresh Network Software	System	5-2023	$5,891.20	$5,198.98	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201963-2 Tech Refresh Network Software	System	4-2023	$5,893.63	$5,201.13	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201963-2 Tech Refresh Network Software	System	12-2022	$5,932.40	$5,235.34	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201963-2 Tech Refresh Network Software	System	3-2023	$6,271.89	$5,534.94	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201987 GMACS Enhancements	System	1-2023	$28,309.64	$24,983.26	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201987 GMACS Enhancements	System	2-2023	$28,469.16	$25,124.04	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201987 GMACS Enhancements	System	11-2022	$28,522.02	$25,170.68	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201987 GMACS Enhancements	System	10-2023	$28,586.57	$25,227.65	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201987 GMACS Enhancements	System	9-2023	$29,026.43	$25,615.82	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201987 GMACS Enhancements	System	7-2023	$29,226.62	$25,792.49	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201987 GMACS Enhancements	System	6-2023	$29,245.70	$25,809.33	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201987 GMACS Enhancements	System	8-2023	$29,406.99	$25,951.67	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201987 GMACS Enhancements	System	5-2023	$29,455.98	$25,994.90	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201987 GMACS Enhancements	System	4-2023	$29,468.16	$26,005.65	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201987 GMACS Enhancements	System	12-2022	$29,661.99	$26,176.71	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	201987 GMACS Enhancements	System	3-2023	$31,359.46	$27,674.72	
391.2 COMPUTERS	38.1 Computer Hardware	202054-1 I-Series CIS Hardware Refresh (HW)	System	12-2022	$428,094.42	$377,793.33	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	202145 Tech Refresh Network Radio Infill	System	1-2023	$28,309.64	$24,983.26	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	202145 Tech Refresh Network Radio Infill	System	2-2023	$28,469.16	$25,124.04	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	202145 Tech Refresh Network Radio Infill	System	11-2022	$28,522.02	$25,170.68	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	202145 Tech Refresh Network Radio Infill	System	10-2023	$28,586.57	$25,227.65	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	202145 Tech Refresh Network Radio Infill	System	9-2023	$29,026.43	$25,615.82	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	202145 Tech Refresh Network Radio Infill	System	7-2023	$29,226.62	$25,792.49	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	202145 Tech Refresh Network Radio Infill	System	6-2023	$29,245.70	$25,809.33	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	202145 Tech Refresh Network Radio Infill	System	8-2023	$29,406.99	$25,951.67	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	202145 Tech Refresh Network Radio Infill	System	5-2023	$29,455.98	$25,994.90	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	202145 Tech Refresh Network Radio Infill	System	4-2023	$29,468.16	$26,005.65	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	202145 Tech Refresh Network Radio Infill	System	12-2022	$29,661.99	$26,176.71	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	202145 Tech Refresh Network Radio Infill	System	3-2023	$31,359.46	$27,674.72	
391.2 COMPUTERS	38.1 Computer Hardware	202149-1 Telematics and Dash Cameras (EOD) (Hardware)	System	11-2022	$6,278.49	$5,540.77	
391.2 COMPUTERS	38.1 Computer Hardware	202149-1 Telematics and Dash Cameras (EOD) (Hardware)	System	12-2022	$6,529.44	$5,762.23	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	202149-2 Telematics and Dash Cameras (EOD) (On Prem)	System	11-2022	$25,113.98	$22,163.09	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	202149-2 Telematics and Dash Cameras (EOD) (On Prem)	System	12-2022	$26,117.74	$23,048.91	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	202282-2 M365 Implementation Program (On Prem)	System	11-2022	$12,224.20	$10,787.86	NW Natural/600/Downing pg 3, 37-45
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	202282-3 M365 Implementation Program (Cloud Based)	System	11-2022	$17,705.66	$15,625.25	NW Natural/600/Downing pg 3, 37-45
303.1 COMPUTER SOFTWARE	38.2 Computer Software	202399 Application Lifecycle Mgmt - Digital Portal 2022	System	11-2022	$47,536.70	$41,951.14	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	202399 Application Lifecycle Mgmt - Digital Portal 2022	System	12-2022	$49,436.66	$43,627.85	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990577 Disaster Recovery Implementation	System	12-2022	$1,015,192.17	$895,907.09	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990586 Application Lifecycle Mgmt - Digital Portal 2023	System	10-2023	$190,577.12	$168,184.31	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990586 Application Lifecycle Mgmt - Digital Portal 2023	System	9-2023	$193,509.51	$170,772.15	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990586 Application Lifecycle Mgmt - Digital Portal 2023	System	7-2023	$194,844.13	$171,949.95	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990586 Application Lifecycle Mgmt - Digital Portal 2023	System	8-2023	$196,046.63	$173,011.15	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990586 Application Lifecycle Mgmt - Digital Portal 2023	System	6-2023	$1,182,911.73	$1,043,919.60	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990587 Application Lifecycle Mgmt - ECM/Open Text 2022/2023	System	1-2023	$94,365.47	$83,277.53	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990587 Application Lifecycle Mgmt - ECM/Open Text 2022/2023	System	2-2023	$94,897.21	$83,746.79	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990587 Application Lifecycle Mgmt - ECM/Open Text 2022/2023	System	10-2023	$95,288.56	$84,092.15	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990587 Application Lifecycle Mgmt - ECM/Open Text 2022/2023	System	9-2023	$96,754.76	$85,386.07	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990587 Application Lifecycle Mgmt - ECM/Open Text 2022/2023	System	7-2023	$97,422.07	$85,974.97	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990587 Application Lifecycle Mgmt - ECM/Open Text 2022/2023	System	6-2023	$97,485.67	$86,031.10	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990587 Application Lifecycle Mgmt - ECM/Open Text 2022/2023	System	8-2023	$98,023.31	$86,505.58	

FERC Account	Applicant	Project	State	In-Service Date	System Amount	OR Allocation	Testimony Reference
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990587 Application Lifecycle Mgmt - ECM/Open Text 2022/2023	System	5-2023	$98,186.58	$86,649.66	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990587 Application Lifecycle Mgmt - ECM/Open Text 2022/2023	System	4-2023	$98,227.21	$86,685.51	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990587 Application Lifecycle Mgmt - ECM/Open Text 2022/2023	System	3-2023	$104,531.52	$92,249.07	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990593 Dev Ops Standardization Implementation	System	2-2023	$845,377.05	$746,045.25	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990652 Application Lifecycle Mgmt - TALON (Com/Ind. Metering) 2023	System	6-2023	$58,777.34	$51,871.00	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990661-2 Contact Center IVR Lifecycle/Enhancements 2022	System	12-2022	$276,850.95	$244,320.97	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990665 Enterprise System Integration Platform: Legacy Migration	System	9-2023	$943,494.64	$832,634.02	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990666 Enterprise System Integration Platform: New Capabilities	System	7-2023	$1,069,306.16	$943,662.69	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990670 Meter Technology: Asset Management Planning and Impl.	System	7-2023	$872,599.62	$770,069.17	
391.2 COMPUTERS	38.1 Computer Hardware	990680-1 Pipeline Awareness: Mobile Control Room Mgmt (Hardware)	System	4-2023	$169,967.46	$149,996.28	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990680-2 Pipeline Awareness: Mobile Control Room Mgmt (On Prem)	System	4-2023	$169,967.46	$149,996.28	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990684 Technology Business Development: Design	System	11-2022	$95,073.39	$83,902.27	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990727-1 Application Lifecycle Mgmt - Allegro Upgrade 2022	System	12-2022	$274,144.25	$241,932.30	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990732 NWN Plants IT Sys & Ops Streamlining & Standardization: Planning 8	System	12-2022	$1,562,358.92	$1,378,781.75	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990738 Cloud Strategy Foundation Implentation 2022	System	12-2022	$340,514.09	$300,503.68	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990818 Cloud Foundation: Optimization of the Cloud	System	4-2023	$58,936.33	$52,011.31	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990818 Cloud Foundation: Optimization of the Cloud	System	2-2023	$85,407.49	$75,372.11	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990818 Cloud Foundation: Optimization of the Cloud	System	3-2023	$94,078.37	$83,024.16	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990818 Cloud Foundation: Optimization of the Cloud	System	1-2023	$616,771.98	$544,301.27	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990819 Data Foundation: Onboard & Optimization	System	7-2023	$93,525.18	$82,535.98	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990819 Data Foundation: Onboard & Optimization	System	6-2023	$93,586.24	$82,589.86	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990819 Data Foundation: Onboard & Optimization	System	5-2023	$94,259.12	$83,183.67	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990819 Data Foundation: Onboard & Optimization	System	4-2023	$94,298.12	$83,218.09	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990819 Data Foundation: Onboard & Optimization	System	3-2023	$100,350.26	$88,559.10	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990819 Data Foundation: Onboard & Optimization	System	8-2023	$117,627.98	$103,806.69	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990819 Data Foundation: Onboard & Optimization	System	1-2023	$933,934.42	$824,197.13	
303.7 CLOUD-BASED SOFTWARE	CLOUD-BASED SOFTWARE - 50	990821 DevSecOps - Replatforming	System	6-2023	$479,995.32	$423,595.87	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990827 Network Security: Preimeter Controls	System	12-2022	$885,923.05	$781,827.09	
391.2 COMPUTERS	38.1 Computer Hardware	990831 Tech Refresh - Newport ICS - Hardware	System	12-2022	$393,682.06	$347,424.41	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	990832 Tech Refresh - Newport ICS - Software	System	12-2022	$393,682.06	$347,424.41	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	Blanket Project Applicant 17	System	10-2023	$1.36	$1.20	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	Blanket Project Applicant 17	System	9-2023	$2.03	$1.79	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	Blanket Project Applicant 17	System	8-2023	$3.02	$2.67	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	Blanket Project Applicant 17	System	7-2023	$4.50	$3.97	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	Blanket Project Applicant 17	System	6-2023	$6.70	$5.91	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	Blanket Project Applicant 17	System	5-2023	$9.97	$8.80	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	Blanket Project Applicant 17	System	4-2023	$14.85	$13.10	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	Blanket Project Applicant 17	System	3-2023	$22.10	$19.51	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	Blanket Project Applicant 17	System	2-2023	$32.91	$29.04	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	Blanket Project Applicant 17	System	1-2023	$48.99	$43.23	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	Blanket Project Applicant 17	System	12-2022	$72.93	$64.36	
397.2 OTHER THAN MOBILE & TELEM	RADIO & ELECTRONIC IMPROVEMEI	Blanket Project Applicant 17	System	11-2022	$108.64	$95.88	
303.1 COMPUTER SOFTWARE	COMPUTER SOFTWARE/HARDWARI	Blanket Project Applicant 38	System	10-2023	$358.52	$316.39	
303.1 COMPUTER SOFTWARE	COMPUTER SOFTWARE/HARDWARI	Blanket Project Applicant 38	System	9-2023	$533.73	$471.02	
303.1 COMPUTER SOFTWARE	COMPUTER SOFTWARE/HARDWARI	Blanket Project Applicant 38	System	8-2023	$794.58	$701.21	
303.1 COMPUTER SOFTWARE	COMPUTER SOFTWARE/HARDWARI	Blanket Project Applicant 38	System	7-2023	$1,182.90	$1,043.90	
303.1 COMPUTER SOFTWARE	COMPUTER SOFTWARE/HARDWARI	Blanket Project Applicant 38	System	6-2023	$1,760.99	$1,554.08	
303.1 COMPUTER SOFTWARE	COMPUTER SOFTWARE/HARDWARI	Blanket Project Applicant 38	System	5-2023	$2,621.61	$2,313.57	
303.1 COMPUTER SOFTWARE	COMPUTER SOFTWARE/HARDWARI	Blanket Project Applicant 38	System	4-2023	$3,902.83	$3,444.25	

FERC Account	Applicant	Project	State	In-Service Date	System Amount	OR Allocation	Testimony Reference
303.1 COMPUTER SOFTWARE	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	3-2023	$5,810.19	$5,127.49	
303.1 COMPUTER SOFTWARE	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	2-2023	$8,649.71	$7,633.37	
303.1 COMPUTER SOFTWARE	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	1-2023	$12,876.93	$11,363.89	
303.1 COMPUTER SOFTWARE	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	12-2022	$19,170.06	$16,917.58	
303.1 COMPUTER SOFTWARE	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	11-2022	$28,557.64	$25,202.11	
391.2 COMPUTERS	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	10-2023	$119.51	$105.46	
391.2 COMPUTERS	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	9-2023	$177.91	$157.01	
391.2 COMPUTERS	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	8-2023	$264.86	$233.74	
391.2 COMPUTERS	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	7-2023	$394.30	$347.97	
391.2 COMPUTERS	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	6-2023	$587.00	$518.03	
391.2 COMPUTERS	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	5-2023	$873.87	$771.19	
391.2 COMPUTERS	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	4-2023	$1,300.94	$1,148.08	
391.2 COMPUTERS	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	3-2023	$1,936.73	$1,709.16	
391.2 COMPUTERS	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	2-2023	$2,883.24	$2,544.46	
391.2 COMPUTERS	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	1-2023	$4,292.31	$3,787.96	
391.2 COMPUTERS	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	12-2022	$6,390.02	$5,639.19	
391.2 COMPUTERS	COMPUTER SOFTWARE/HARDWARE	Blanket Project Applicant 38	System	11-2022	$9,519.21	$8,400.70	
391.2 COMPUTERS	38.1 Computer Hardware	Blanket Project Applicant 38.1	System	11-2022	$4,726.89	$4,171.48	
391.2 COMPUTERS	38.1 Computer Hardware	Blanket Project Applicant 38.1	System	12-2022	$5,212.31	$4,599.87	
391.2 COMPUTERS	38.1 Computer Hardware	Blanket Project Applicant 38.1	System	1-2023	$5,758.91	$5,082.24	
391.2 COMPUTERS	38.1 Computer Hardware	Blanket Project Applicant 38.1	System	2-2023	$6,138.80	$5,417.49	
391.2 COMPUTERS	38.1 Computer Hardware	Blanket Project Applicant 38.1	System	3-2023	$6,624.48	$5,846.10	
391.2 COMPUTERS	38.1 Computer Hardware	Blanket Project Applicant 38.1	System	4-2023	$6,799.89	$6,000.90	
391.2 COMPUTERS	38.1 Computer Hardware	Blanket Project Applicant 38.1	System	5-2023	$6,916.74	$6,104.02	
391.2 COMPUTERS	38.1 Computer Hardware	Blanket Project Applicant 38.1	System	6-2023	$6,978.47	$6,158.50	
391.2 COMPUTERS	38.1 Computer Hardware	Blanket Project Applicant 38.1	System	7-2023	$7,018.40	$6,193.74	
391.2 COMPUTERS	38.1 Computer Hardware	Blanket Project Applicant 38.1	System	10-2023	$7,020.08	$6,195.22	
391.2 COMPUTERS	38.1 Computer Hardware	Blanket Project Applicant 38.1	System	9-2023	$7,056.95	$6,227.76	
391.2 COMPUTERS	38.1 Computer Hardware	Blanket Project Applicant 38.1	System	8-2023	$7,059.62	$6,230.11	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	Blanket Project Applicant 38.2	System	11-2022	$74,324.75	$65,591.59	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	Blanket Project Applicant 38.2	System	5-2023	$77,895.02	$68,742.36	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	Blanket Project Applicant 38.2	System	2-2023	$78,103.54	$68,926.38	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	Blanket Project Applicant 38.2	System	4-2023	$78,459.36	$69,240.38	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	Blanket Project Applicant 38.2	System	3-2023	$79,283.97	$69,968.10	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	Blanket Project Applicant 38.2	System	1-2023	$80,026.21	$70,623.13	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	Blanket Project Applicant 38.2	System	12-2022	$83,091.62	$73,328.36	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	Blanket Project Applicant 38.2	System	10-2023	$93,319.47	$82,354.43	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	Blanket Project Applicant 38.2	System	9-2023	$102,528.88	$90,481.74	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	Blanket Project Applicant 38.2	System	8-2023	$115,679.01	$102,086.73	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	Blanket Project Applicant 38.2	System	7-2023	$134,771.24	$118,935.62	
303.1 COMPUTER SOFTWARE	38.2 Computer Software	Blanket Project Applicant 38.2	System	6-2023	$163,423.76	$144,221.47	
					$23,011,699.80	$20,307,825.07	

Row Labels	In Service in Test Year Sum of System Amount	Sum of OR Allocation	Active Capital Project Total Budget	Forecasted Projects (not started)	Actuals plus forecast	Variance	Narrative
200067-1 Tech Refresh - Large Servers/Storage (Hardware)	204,788	180,726		204,788	n/a	n/a	Ongoing refresh of depreciated HW/SW
200067-2 Tech Refresh - Large Servers/Storage (Software)	477,839	421,693		477,839	n/a	n/a	Ongoing refresh of depreciated HW/SW
200068-1 Tech Refresh - Desktop/Laptop/Periph -Field Laptop Refresh (Hardware)	985,632	869,821		985,632	n/a	n/a	Ongoing refresh of depreciated HW/SW
201693-1 Tech Refresh Network Hardware	105,222	92,858		105,222	n/a	n/a	Ongoing refresh of depreciated HW/SW
201694 Tech Refresh Microwave	1,325,376	1,169,645		1,325,376	n/a	n/a	Ongoing refresh of depreciated HW
201695 Tech Refresh - Telemetry	1,559,385	1,376,157		1,559,385	n/a	n/a	Ongoing refresh of depreciated telemetry
201696 Tech Refresh - Telephony	341,314	301,209		341,314	n/a	n/a	Ongoing refresh of depreciated telephony
201936 Patch and SW Delivery Automation	105,222	92,858		105,222	n/a	n/a	This project is the continued effort to modernize our patching and software automation to bring more efficiency to NW Natural. This includes packing software in Software Center as well as modernizing software patch deployment via the SCCM tool.
201963-2 Tech Refresh Network Software	70,148	61,905		70,148	n/a	n/a	Ongoing refresh of depreciated HW/SW
201987 GMACS Enhancements	350,739	309,527		350,739	n/a	n/a	Several small projects, each under $100k covering reporting enhancements and integration of data into SCADA.
202054-1 I-Series CIS Hardware Refresh (HW)	428,094	377,793		428,094	n/a	n/a	Ongoing refresh of depreciated HW
202145 Tech Refresh Network Radio Infill	350,739	309,527		350,739	n/a	n/a	Expanding radio footprint throughout the estate to enable more RF telemetry sites and move away from legacy copper connections
202149-1 Telematics and Dash Cameras (EOD) (Hardware)	12,808	11,303	422,957		422,957	0	Final Installations of Dash Cameras in all NWN fleet vehicles
202149-2 Telematics and Dash Cameras (EOD) (On Prem)	51,232	45,212	358,288		308,288	(50,000)	Final Installations of Dash Cameras in all NWN fleet vehicles
202282-2 M365 Implementation Program (On Prem)	12,224	10,788		12,224	n/a	n/a	M365 enhancements following go-live
202282-3 M365 Implementation Program (Cloud Based)	17,706	15,625		17,706	n/a	n/a	M365 enhancements following go-live
202399 Application Lifecycle Mgmt - Digital Portal 2022	96,973	85,579		96,973	n/a	n/a	Lifecycle upgrades and minor enhancements of NWN systems that support Digital Portal - NWN website.
990577 Disaster Recovery Implementation	1,015,192	895,907		1,015,192	n/a	n/a	Maturing the disaster recovery program at NW Natural
990586 Application Lifecycle Mgmt - Digital Portal 2023	1,957,889	1,727,837		1,957,889	n/a	n/a	Application upgrades as part of software lifecycle management
990587 Application Lifecycle Mgmt - ECM/Open Text 2022/2023	975,182	860,598		975,182	n/a	n/a	Application upgrades as part of software lifecycle management
990593 Dev Ops Standardization Implementation	845,377	746,045		845,377	n/a	n/a	This initiative is to standardize and establish the "DevOps" processes for key eco systems in our environment (SAP, CIS and other development systems). The process specifications will be followed by tool recommendations to bring consistency and eliminate redundancy.

Row Labels	Sum of System Amount	Sum of OR Allocation	Active Capital Project Total Budget	Forecasted Projects (not started)	Actuals plus forecast	Variance	Narrative
990652 Application Lifecycle Mgmt - TALON (Com/Ind. Metering) 2023	58,777	51,871		58,777	n/a	n/a	Application lifecycle management of Commercial/Industrial meter reading
990661-2 Contact Center IVR Lifecycle/Enhancements 2022	276,851	244,321	276,851		258,572	(18,279)	Application enhancements to CCC/IVR
990665 Enterprise System Integration Platform: Legacy Migration	943,495	832,634		943,495	n/a	n/a	The project is the planning phase of the migration of existing interfaces to new integration platform to obtain improvements in security, supportability and efficiency
990666 Enterprise System Integration Platform: New Capabilities	1,069,306	943,663		1,069,306	n/a	n/a	This initiaitive will be to continue the API management exploration and solution architecture, an important capability to improve the systems integration. The goal is to change the way we integrate our systems to improve our agility to deliver integrated solutions for customer services. We will start the architecture process in 2022 and complete in 2023.
990670 Meter Technology: Asset Management Planning and Impl.	872,600	770,069		872,600	n/a	n/a	Implement recommendations from Meter Technology Strategy
990680-1 Pipeline Awareness: Mobile Control Room Mgmt (Hardware)	169,967	149,996		169,967	n/a	n/a	This initiative is to establish a pilot implementation of data and analytis use case to improve the functionality of the Gas control operations. The goal is to target the analytics to improve the visibility and insights on safety and reliability of gas distribution services.
990680-2 Pipeline Awareness: Mobile Control Room Mgmt (On Prem)	169,967	149,996		169,967	n/a	n/a	This initiative is to establish a pilot implementation of data and analytis use case to improve the functionality of the Gas control operations. The goal is to target the analytics to improve the visibility and insights on safety and reliability of gas distribution services.
990684 Technology Business Development: Design	95,073	83,902		95,073	n/a	n/a	This initiative will be to establish business capability portfolio and technology portfolio management to provide enhanced visibility into continually improving the functionality, reliability, functionality and security of the capabilities.
990727-1 Application Lifecycle Mgmt - Allegro Upgrade 2022	274,144	241,932		274,144	n/a	n/a	Lifecycle upgrade of NWN gas management system.
990732 NWN Plants IT Sys & Ops Streamlining & Standardization: Planning & Impl	1,562,359	1,378,782		1,562,359	n/a	n/a	To define and architect NWN storage and LNG plants to meet business and application requirements at an enterprise level. The intent is to define standards architecture to allow for the implementation of a scalable and flexible platform providng reliability through a standard management framework.

Row Labels	Sum of System Amount	Sum of OR Allocation	Active Capital Project Total Budget	Forecasted Projects (not started)	Actuals plus forecast	Variance	Narrative
990738 Cloud Strategy Foundation Implentation 2022	340,514	300,504		340,514	n/a	n/a	This initiative is refine the cloud adoption roadmap based on our learning over the past year that is more logical and realistic. We will follow with implementions of the cloud adoption in 2023 and beyond.
990818 Cloud Foundation: Optimization of the Cloud	855,194	754,709		855,194	n/a	n/a	This initiative is to optimize the cloud architecture and cloud security foundations we established in 2021, based on relevant use cases and additional planning activities.
990819 Data Foundation: Onboard & Optimization	1,527,581	1,348,091		1,527,581	n/a	n/a	This project is continuation of the establishment of Enterprise Data and Analytics Platform (aka EDP). The focus will be to optimize, enhance and add new functionality to the platform capabilities. The goal is to improve our understanding of the data and the quality of the data to get better insights on customer services and experience.
990821 DevSecOps - Replatforming	479,995	423,596		479,995	n/a	n/a	Realigining DevSecOps to new standard
990827 Network Security: Preimeter Controls	885,923	781,827		885,923	n/a	n/a	Recinding request. Some of this work is included in TSA SD2. The remainder will be restructured.
990831 Tech Refresh - Newport ICS - Hardware	393,682	347,424		393,682	n/a	n/a	Lifecycle replacements and/or improvements of network equipment in SCADA networks
990832 Tech Refresh - Newport ICS - Software	393,682	347,424		393,682	n/a	n/a	Lifecycle replacements and/or improvements of network equipment in SCADA networks
Blanket Project Applicant 17	328	289		328	n/a	n/a	Radio & Electronics improvements
Blanket Project Applicant 38	114,960	101,452		114,960	n/a	n/a	Hardware/software lifecycle management
Blanket Project Applicant 38.1	77,312	68,227		77,312	n/a	n/a	Hardware lifecycle management
Blanket Project Applicant 38.2	1,160,907	1,024,500		1,160,907	n/a	n/a	Software lifecycle management
Grand Total	**23,011,700**	**20,307,825**					

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 297

297. Does the Company have a formal acquisition policy or procurement procedure for IT projects? If yes:
a. Please provide a copy of the current policy/procedure(s).
b. Please provide a narrative description of NW Natural's process(es) for acquiring IT resources.

Response:

a. Yes. Please refer to UG 435 OPUC DR 297 Attachment 1.

b. UG 435 OPUC DR 297 Attachment 1 contains procedures related to the various phases of a project where procurement may occur. Beginning on page 8, IT-specific tasks are described. Pages 28 – 30 detail all purchasing practices. UG 435 OPUC DR 297 Attachment 2 contains NW Natural's Corporate Purchasing and Expenditure Procedure. This document is currently being reviewed and updated and we will supplement this data request when the updated version is finalized.

PROJECT MANAGEMENT HANDBOOK

NW Natural

Last updated February 22, 2022

Contents

About this Document

The PM Handbook is a tool for project managers across NWN who are following the PMO process. It is not meant to be all inclusive, but it is intended to be a foundation for managing a project within the PMO's standards. If you are a PMO contractor, there is also a section on need to knows in the appendix.

This is also a living document – if you see something that you think should be added to the handbook, let us know. Additional questions can be directed to ppm@nwnatural.com.

NW Natural's PMO

As a PM, your role is to **own** your project and you are responsible for **proactively driving the project forward**. At any time, you should be able to report out on what's happening and what risks and issues might prevent success. We expect you to build a strong relationship with your sponsor and project team and escalate any issues thoughtfully and proactively.

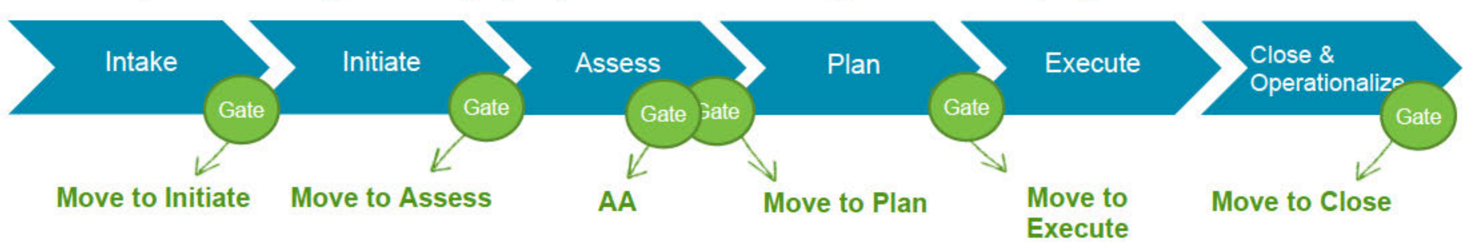
NWN has a centralized PMO that manages Tier 4, and supports Tier 1-3 projects. The PMO provides project managers, business analysts and change managers for projects typically serving one of three disciplines: IT&S, Facilities and Engineering. Projects are broken out by Tier based on their cost:

Tier based on Funding w/o COH, including capital and O&M		PPM Requirement	Stage Gate Requirement	PMC Approval Requirement	Project Management Requirement	Sponsorship Requirement	Governance Toolkit Requirement
Less than $50K	**Tier 0 (Other Planned Work)**	Recommended, but not required	None	None	None	None	None
$50K - $250K	**Tier 1**	Recommended, but not required	Goes through Stage Gate, to sponsors	None (through Port Mgr approval)	None	Exec Sponsor must be a Sr. Director or above	None
$250K - $500K	**Tier 2**	Required	Goes through Stage Gate, to sponsors	Recommended, but not required (otherwise Port Mgr approval)	Acting PM required; may be sourced through PMO	Exec Sponsor must be an officer or above	None
$500K - $1MM	**Tier 3**	Required	Goes through Stage Gate, to sponsors	Required (exception for Eng w/o other effort needed)	Acting PM required; may be sourced through PMO	Exec Sponsor must be an executive	Recommended, but not required
> $1MM	**Tier 4**	Required	Goes through stage gate, up to EC	Required	PMO-approved or PMO PM required	Exec Sponsor must be an executive	Required

The PMO is particularly important in a public utility, as there is an additional layer of governance and regulatory compliance, especially when it comes to large projects. This includes the Oregon Public Utility Commission and the Washington Utilities and Transportation Committee (OPUC/WUTC), Securities and Exchange Commission (SEC), Federal Energy Regulatory Commission (FERC), Pipeline and Hazardous Material Safety Administration (PHMSA), US Department of Transportation (DOT), Energy Facility Siting Council (EFSC), etc. This means we are especially focused on:

- Ensuring *prudent* decision making in the selection and execution of projects
- Giving consistent visibility into the budget, scope and schedule of a project to ensure sound oversight
- Following a process to ensure we select the best solution upfront

We accomplish this through a clear project process with distinct gates to review progress.



Projects are managed through a set of three tools:

1. The project process (intake of a new idea, gates, schedule, financial forecast, risks, etc.) are all managed in Planview, NW Natural's PPM tool
2. Project actuals and the record of approved spend are tracked in SAP (and imported into Planview)
3. Large projects have a SharePoint site where all documents are stored

* indicates that the document must be complete and accepted in order to move to the next phase
blue indicates that the document is formally attached or described to the stage gate request

Project Lifecycle at a Glance

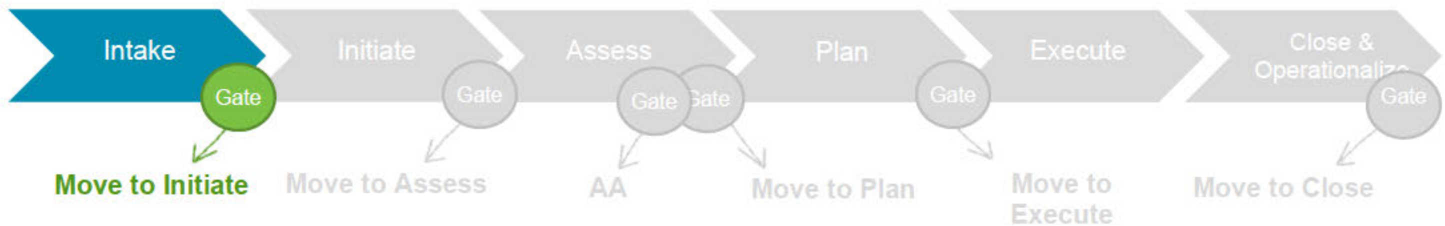
	INTAKE	INITIATE	ASSESS	PLAN	EXECUTE	CLOSE
Goal	Understand the root problem and opportunity to inform the selection of the right projects at the right time	Align and approve on business case, and the resources needed to assess the project	Develop requirements, assess options, determine alternatives and preferred solution	Fully flesh out the selected solution and define the execution path to achieve the project goals	Track, monitor and control the project as work is completed	Operationalize, adopt and hand over the project deliverables
Project Management **(Budget, Schedule, Scope, Resourcing + Project Governance)**	***Sponsor**: Intake form ***PMC**: Project review and selection	*PM: Assess Phase Budget *PM: Initial Project Charter ***PM**: Decision Log, Risk Log, Issues Log ***PM**: Assess Phase Resource Plan ***PM**: Monthly Status Reports ***PM**: Org Chart ***PM**: RACI and RAPID **PM**: SharePoint Project Site **PM**: Stakeholder Register **PM**: Steering Committee + CCB **Sponsor**: Project oversight + governance ***PM**: Submit "Move to Assess" Gate	**PM**: Assess the cost of possible solutions *PM: Design/Plan Phase Budget ***PM**: Design/Plan Phase Resource Plan ***PM**: Design/Plan Phase Schedule *PM :Final Project Charter ***PM**: Decision Log, Risk Log, Issues Log ***PM**: Monthly Status Reports **Sponsor**: Project oversight + governance ***PM/Sponsor**: Alternatives Analysis (if over $1MM w/ COH) ***PM**: Submit "Move to Plan" Stage Gate	**PM**: Confirm the costs of the selected solution, forecast costs to plan the project *PM: Execution Budget and forecast *PM: Project Execution Approach / Plan ***PM**: Execution Phase Resource Plan ***PM**: Execution Phase Schedule ***PM**: Monthly Status Reports **PM/BA/Tech Lead/Sponsor**: Determine final project scope ***PM**: Decision Log, Risk Log, Issues Log **Sponsor**: Project oversight + governance **PM/Sponsor**: Transition to Operations Plan (IT only) ***PM**: Submit "Move to Execute" Stage Gate	**PM**: Weekly Status Reports **PM**: Monitor and control costs, compare to actuals **PM**: Monitor and control scope delivery, resource capacity, schedule and all other project aspects to ensure project is on track ***PM**: Decision Log, Risk Log, Issues Log **Sponsor**: Project oversight + governance **PM**: Go/No Go Criteria ***Sponsor**: Go/No Go Approval PM: Move project to "Prepare for Closure"	**Sponsor**: Project oversight + governance ***PM**: Lessons Learned ***PM**: TECO ***PM**: Project close activities **PM/Sponsor**: Final Transition to Operations Plan (IT only) *PM: Final budget true-up **PM**: Submit "Move to Close" Stage Gate
Business Requirements / Design	**BA**: Triage **BA**: Context Diagram (as applicable)	**BA**: Initiation Context Document (BOSCARD) **BA**: Context Diagram **BA**: Business Analysis Work Plan	**BA**: Elicitation + Results ***BA**: Business Case ***BA**: Current State Documentation **BA**: Gap Analysis **BA**: Requirements Documentation	**BA**: To-be process map and documents ***BA**: Requirements Documentation **BA**: Gap Analysis ***BA**: Functional Specs	**BA/QA**: User Acceptance Plan **BA/QA**: Functional Test Plan **BA/QA**: UAT Results and Approval ***BA**: Updated Requirements Documentation ***BA**: Knowledge Base Articles ***BA/QA**: Requirements Traceability Matrix	**BA**: Completed Requirements Traceability Reports **BA/CM**: User Surveys + Interviews
Change Management (if a CM is assigned to the project)	**CM**: Rough Change Assessment	***CM**: 1 Pg Case for Change ***CM**: Change Artifact List **CM**: Change Portfolio Assessment Form	***CM**: Change Impact Assessment ***CM**: Stakeholder Analysis ***CM**: Change + Engagement Strategy **CM**: Change KPI Development	***CM**: Training Needs Assessment, Plan + Materials ***CM**: Comms Plan + Materials **CM**: Engagement Plan + Materials **CM**: Change Portfolio Assessment Form	***CM**: Training Materials (including FAQs, QRGs) **CM**: Training, Communications + Engagement Delivery + Support ***CM/Application Owner**: Change Artifacts / Operations Handover **CM**: Change Readiness Assessment	**CM**: Training, Communications + Engagement Delivery + Support **CM**: Adoption Tracking **CM**: Change Close Survey **CM**: Knowledge and Tools Transfer, Lessons Learned
Technical Development	**EArch**: Confirmation that IT&S Alignment Committee Review is complete	**Tech Lead**: Technical resource plan	**EArch**: Solution Context Diagram **EArch**: Solution Options + Design **EArch**: ARB and TRB are initiated ***EArch**: RFP scoring criteria against architecture and requirements and/or assessment of alternatives and recommendation of selected option **EApps**: Software Development Estimate **IT Security**: Assess security needs	***EArch**: ARB and TRB Approval **EArch**: IT&S Ticket Request ***EArch**: Solution Architecture Summary **EArch**: Data Model and Migration Plan **Application Owner**: Technical Specs **Tech Lead**: Source Target Mapping **Tech Lead**: Business Impact Assessment ***Tech Lead**: Final Design and Tech Specs **Tech Lead**: SOX Compliance Plan **Tech Lead**: ETL/Integration Plan **IT SecOps**: Vendor Risk Assessment ***IT SecOps**: Security Design and Review **IT SecOps**: Incident Response Plan **IT SecOps**: PCI Assessment Questionnaire of Attestation of Compliance **IT SecOps**: Security Plan of Action and Milestones **Solution Architect**: Infrastructure Implementation Plan **Solution Architect**: Infrastructure Specifications	**EApps**: Software and Configuration Source Code **EApps**: Software Build **EApps**: Deployment **EApps**: Rollback Scripts **EApps**: Software Runtime Artifacts **EApps**: Release Notes ***EApps**: Run Book **Tech Lead**: Solution Cutover Plan **Tech Lead**: Data Conversation / Migration Plan **Tech Lead**: Solution Test Plan, Scripts, Results, Defect List **Tech Lead**: Production Release Verification Plan and Results **Tech Lead**: Information Transfer Agreement **Tech Lead**: Vendor Security Assessment **IT SecOps**: Security Testing / Vulnerability Scans, Remediation Plan **Disaster Recovery, Tech Lead**: Disaster Recovery Testing and Plan **Business Continuity**: Business Continuity Plan **Tech Lead**: Change Control Review Board Release Approval **IT**: Technical Support Plan	**IT Security**: Security Plan of Action and Milestones
Engineering Requirements and Design	**Eng**: Triage	**Eng/PM**: Survey and Assessment Plan	**PM**: Survey, Assessments **Risk + Land**: Easements ***Eng**: Initial (10-30%) Designs ***Eng**: Permitting Assessment and Plan ***Environmental**: Enviro Assessment **PM**: Geotech **PM/Sponsors**: Resourcing Plan	**Eng**: Specifications (if externally resourced) ***Eng**: Traffic Control Plan **Eng**: Potholing ***Eng**: 90% Design **PM**: Geotech **Permitting Specialist**: Permits **Purchasing/Stores**: Stock and Non Stock Material Requirements, Material Reservations, Bids including Q&A, Quotes, RFQs **RMC**: Field Resource Schedules **Construction**: Resourcing	***PM**: Operations + Maintenance Plan, Engineering Procedures **PM/Eng**: Construction Management **Tech Training**: Field Training	**PM**: O&M Manuals ***Eng**: As-Builts, Management of Change, CDM, Testing and Verification Documentation
Vendor Selection + Procurement		**Procurement**: Procurement and purchasing strategy / sourcing strategy **IT Compliance**: TISA for new vendors **Procurement**: Purchasing Process if a vendor is needed for assessment: **Procurement**: RFP and vendor selection for any assess-vendors **Corp Security**: Background checks	**Procurement**: RFx development, process and responses **Project Manager**: Competitive Assessment Memo (CAM) if no RFx **Procurement**: Scorecard **Procurement / Sponsor**: Vendor selection **IT Compliance**: TISA to shortlisted RFx finalists	***Procurement**: SOW **Procurement**: PO Management (for change orders, etc.) **Legal/Procurement**: Contracting and Negotiation **PM**: Onboarding **PM**: ITP checklist (for IT projects)	**Procurement**: PO Management (for change orders, etc.)	

Project Phase Checklists

The NWN project process currently has 6 stages, with 6 routine stage gates at major milestones. The below checklists walk through the standard expectations at each phase, with the required gates highlighted in green. **Additional information on the Stage Gating process can be found in the Stage Gate Section**.

Intake Checklist

An idea is generated, funneled through a prioritization and selected to begin.



☐ The owner/sponsor generates an idea, socializes it with an executive sponsor

☐ The owner aligns with any department-specific approval processes. For instance, if the project has IT component, the project is reviewed by the IT&S Enterprise Architecture team, IT&S Alignment Committee and Architecture Review Board (ARB) before it becomes a project

☐ If the project is >$50K, the owner of the project submits a proposal for New Work in Planview (guide here!), which outlines the underlying problem; they also have the *option* of estimating what teams might be involved and the rough order of magnitude. If this information is not easily accessible, a BA will complete the estimate

Engineering Addition: Engineering PM submits the intake request and completes triage:

☐ If it's a tier 3-4 project, they complete **the Triage section of the New Work form;** if the project is <$500K or there are no other teams impacted, the system will bypass the additional triage steps

☐ Once submitted, a "triage" step will be assigned to the engineer in Planview that will include:

- Final review of the triage section of the intake form
- Reach out to potentially-impacted teams to understand their involvement then:
    - Add any organizational impacts (e.g. teams impacted by the project when launched), or leave blank if none exist
    - If applicable, add any shared services resources (e.g. SCADA) into the Work and Assignments screen
- Add where the $50K of initiation funding will be spent into the financial view (e.g. for internal labor)
- Once submitted, project will route to the PMC for review

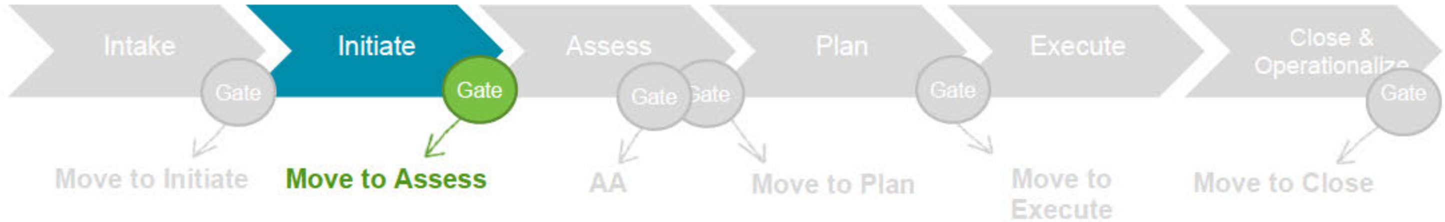
☐ Proposed ideas are "Triaged" by a BA to assess the problem, approximate order of magnitude. The Intake and Triage information are then channeled to the Portfolio Management Committee (PMC) for review and prioritization

☐ A representative from the PMC nominates the project for selection. The PMC will validate that the necessary resources are ready and able to take on the project and then will vote to move the idea forward. The portfolio manager **Moves the project to initiation** and the project is funded with $50,000 and assigned a PM (that's you!) to "initiate" the project.

Item	Score
Safety or High Risk	5 pts = safety or high risk 0 pts = none
Officer Goal Alignment	5 pts = listed goal 0 pts = not listed goal
Value Creation	5 pts = strong potential 0 pts = low potential
Dept Roadmap	4 pts = on roadmap 0 pts = not on roadmap
Operational Necessity	3 pts = maintains ops 1 pt = improves ops 1 pt = adds new capability
Time Sensitivity	2 pts = tangible deadline 1 pt = desired deadline 0 pts = no deadline

Initiate Checklist

Once the project has been selected by the PMC, it becomes an official project and a PM is assigned. This phase focuses on approving the business case and gathering the resources needed to assess the project.



☐ Identify your **core project team**: project sponsor, executive sponsor and team leads; work with each individual 1:1 to level set about their responsibilities and role on the project.

☐ Identify and align on **initiate-phase deliverables**, assigning owners and approvers; you'll use this to ensure accountability and clarity of roles throughout the phase. If a tier 4 project, develop your **governance tools** including RACI, RAPID, org chart and stakeholder list

☐ Review the accounting practices and with insight from your department managers and your sponsor, sit down with the PMO Accountant and determine capital vs. operational costs for assess and plan phases.

☐ Hold a **Project Kickoff Meeting** (with your core team) and a **kickoff SteerCo meeting** (if applicable). Leverage the Kickoff Deck to reinforce roles, and set ground rules and a communication cadence.

☐ Identify **NWN partner resources** that are needed for the project as early as possible. If the resource need is meaningful (>5% for more than a few weeks), each resource needs to be requested via a Requirement in Planview. Leverage the Stakeholder Register when considering resources to engage. Of Note:

- If there are **environmental**, **safety** or **permitting** requirements, meet with relevant teams early to develop a plan; hint: leverage the Environmental Checklist to assess enviro team needs
- If there are elements of rental, lease, easements, rights-of-way, insurance, etc., reach out to **Risk and Land**, ensuring plenty of lead time (easements can take 10-18 months to procure)
- If your project has IT components, engage **Enterprise Architecture**
- If your project leverages endpoint technology (mobile phone, laptop, desktop, tablet, etc.) even if it isn't an IT project, loop in **Service Delivery (Desktop Support)** at the start of the work so you can determine the proper level of involvement (estimating FTEs to maintain the product, support needs, etc.)
- If the project meets at least one of the below criteria, engage with **IT Information Security**:
  - Use of Personally Identifiable Information (PII) or Confidential Information
  - External facing applications or systems or interaction with existing applications
  - Control systems for pipelines or gas storage facilities
  - Information Security review is required by a regulatory or oversight body

☐ Identify and work with Procurement to plan for **contractors and vendors** who might be needed to assess, plan and design the project

- If trying to select a vendor, work with Purchasing to engage existing vendors first or so that Purchasing can lead an RFx (Request for Information/Quote/Proposal); refer to the Purchasing Overview in the appendix for more information
- Confirm if a current Master Service Agreement (MSA) or other contract is on file for the vendor(s). If contracting with new vendors or contractors that will have access to project SharePoint sites, be sure to implement permission levels on the site to exclude 3rd parties from access to the contracts folder
- If engaging new contractors or vendors, inform Legal and Purchasing with plenty of lead time. If customer data, or company confidential/sensitive information may be shared/transferred

/created, notify Legal to determine the proper NDA before proceeding. When in doubt of contracting or potential sensitive information, reach out to Legal for discussion and feedback

- If required for contractors, engage Corporate Security to initiate background checks; ensure the vendor is completing a drug test aligned to Purchasing requirements

- [ ] Request a **SharePoint project site** by filing a Request for Support through the Self-Service Portal (IT&SM Portal); this site is where you'll house all of your project documents not inherent to Planview. An overview of how to manage and what to store on your SharePoint site can be found in the appendix.
- [ ] Finalize the **budget for the assess phase**, building into your Financial Detail Screen in Planview. Be sure to include contingency. If you need support, work with the PMO accountant. Note: budgets in Planview should be developed *without Construction Overhead (COH)*, but COH does need to be considered when determining the need for an Alternatives Analysis during the Assess phase; please check with accounting on the latest COH rate for your project during this process.
- [ ] Develop a **schedule for the assess phase** (and beyond if you can!), building major milestones, dates, dependencies, etc. into your Work and Assignments Screen in Planview. If you are leveraging any internal contractors or FTEs (e.g. IT&S resources, SMEs, etc.), you also need to **request those resource roles** by filing Requirements at the top of your schedule for the Assess Phase.
- [ ] Establish your **change control board** (who reviews changes in scope, budget, schedule or quality and approves the use of contingency when a change order is filed). This should likely include your sponsors and a few key stakeholders / steerco members who are knowledgeable about the project.
- [ ] Build your **initial project charter** (form can be found in your Work Detail in Planview). This process should include interviewing stakeholders to the project's overall requirements and their definition of project success. In parallel, confirm your project is tied to the correct officer goal and strategy pillar in Planview.
- [ ] **Get sign off from all relevant parties on initiate-phase deliverables**. Leverage your RACI and RAPID forms to identify required deliverables and key approvers, then ensure they have reviewed and approved the documents they are accountable for. This step needs to be completed before a gate is requested.
- [ ] Submit Stage Gate Request in Planview to **Move to Assess,** which will include a request for Assess budget and a link to your initial project charter, budget, schedule, risks, etc. It is best practice to also send an email to your sponsors before submitting the gate for awareness.

Engineering Additions

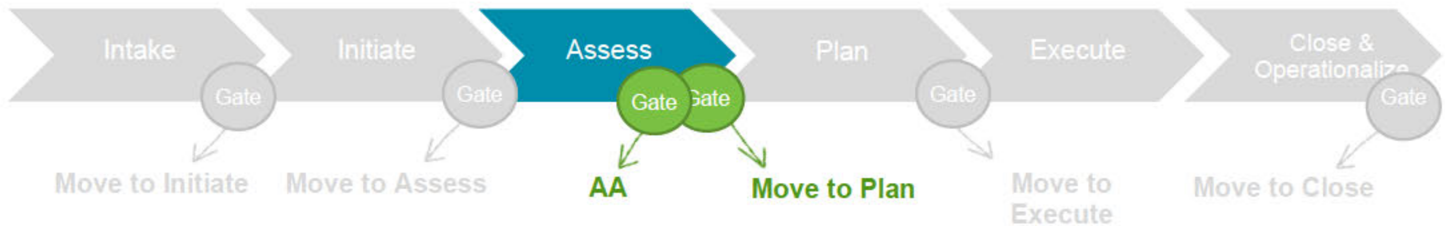
- [ ] Initiation funding can also be used to hire external resources for initial assessments needed to design the project; work with Purchasing to identify and onboard the right resource to support this work
- [ ] For record keeping, add all documents to Engineering project site (critical for rules around maintaining records)
- [ ] Before entering your stage gate request, schedule a planning meeting with your core group to review the plan, and a follow up meeting for approval including the RMC

IT&S Additions

- [ ] For large projects, identify an IT&S project sponsor and executive sponsor to share the responsibilities and escalations from the IT point of view
- [ ] Identify Tech Lead and Solution/Enterprise Architect and onboard them as part of the project team; ensure they are aware of and follow the Software Development Life Cycle Policy and are working each step into the project schedule
- [ ] Include your BA from the start – their role is to define the underlying needs of the project, impacted stakeholders, current state, etc.
- [ ] If there's a new vendor, Hardware or SaaS involved: complete a Software Request before the vendor is contracted to start the process for a TISA, Vendor Risk Assessment and Security Operations review (more info here)

Assess Checklist

The Assess phase is used to fully develop requirements, assess options, and determine alternatives and a preferred solution. If a significant study is needed to explore a potential solution, the Assess phase is used to take the time for this evaluation. If the project is >$1MM with COH, the Assess phase culminates in submitting an Alternatives Analysis, where a solution to the problem is proposed. Everything before the AA is exploration of a problem, and does not commit to any decisions on how to tackle the solution.



☐ Manage the **overall project progress**, including:

- Manage project team resources to keep momentum, keeping your requirements up to date for any resources on your project
- Engage purchasing resources as needed
- Complete status reports (monthly during Assess) in Planview
- Carefully manage your budget, including:
    - Before the end of every month, update accruals
    - Track / receive / audit invoices on an ongoing basis and manage costs accordingly
    - Keep your Planview Financial Detail up to date with the latest forecast; on a monthly basis, the system will snapshot a baseline
- Hold regular meetings with the project team and steering committee (see meeting standards); remember to find the right balance of providing the most important information while being sensitive to busy schedules; leverage the project walking deck as a starting place
- Build a detailed Risk and Issue Log in Planview, using our risk standards to assess severity
- Perform contractor performance management as needed

☐ Submit a **purchase request** (more info here) to kick off the purchasing process for any studies or assessments. Remember that your purchase request cannot exceed your current approved spend. If you need to request an execution purchase before the execute budget is allocated, you can submit an Early Purchase during the Move to Assess or Move to Plan Gate or through a Change Order (guidelines in the appendix).

☐ Facilitate detailed requirements gathering, feasibility studies, assessments, etc. to prepare for determining a solution (these will be led by a Business Analyst (BA) if you have one on the project)

☐ Support Purchasing in developing and sending an **RFx** as needed (details in the appendix)

☐ **Onboard and support any contractors**. If you will have contractors that will not have NWN laptops, they will need access to Virtual Workspace. To get this set up, you will need to request a new project VDI profile. Work with your tech lead, SMEs, engineers and/or IT sponsor to define and file a request to set up this VDI project profile, including: 1) the project name 2) the contractors that need access, and 3) the list of applications requested (there will be one profile for the whole team, so make sure the list of tools is comprehensive for every role!). Note that there may be licensing cost and/or access issues that will need to be negotiated depending on what you're requesting. More information on VDI can be found in the appendix.

☐ Finalize your **full project charter** (form can be found in your Work Detail in Planview)

☐ Determine if an **Alternatives Analysis (AA)** is required (details in the appendix); if so, stop your design process before any decisions are made to write up a thoughtful AA of the project alternatives. You should have enough information that you can properly anticipate costs of different approaches to solve the problem (e.g. 30% design for pipeline projects or proposals submitted to an RFx but no vendor yet selected). To submit an AA, first complete the AA Narrative Form, save it on your SharePoint site, then submit **Alternatives Analysis Gate** request through Planview for review by the AA Committee.

- [ ] Finalize the **budget for the plan phase**, building the needs into your Financial Detail Screen in Planview. Be sure to include contingency. If you need support, work with the PMO accountant.

- [ ] Develop a **schedule for the plan phase** (and beyond if you can!), building major milestones, dates, dependencies, etc. into your Work and Assignments Screen in Planview. If you are leveraging any internal contractors or FTEs (e.g. IT&S resources, SMEs, etc.), you also need to **request those resource roles** by filing Requirements at the top of your schedule for the Plan Phase.

- [ ] Submit **Stage Gate Request** in Planview to **Move to Plan,** which will include a request for Phase budget and link to the full project charter, budget, schedule, risks, etc. It is best practice to also send an email to your sponsors before submitting the gate for awareness.

Engineering Additions

- [ ] Complete the 30-60% design, enough to obtain reliable ballpark costs before submitting the AA
  - Pipeline projects should aim for 30% design
  - Plant or customized projects should aim for 60% design

Facilities Additions

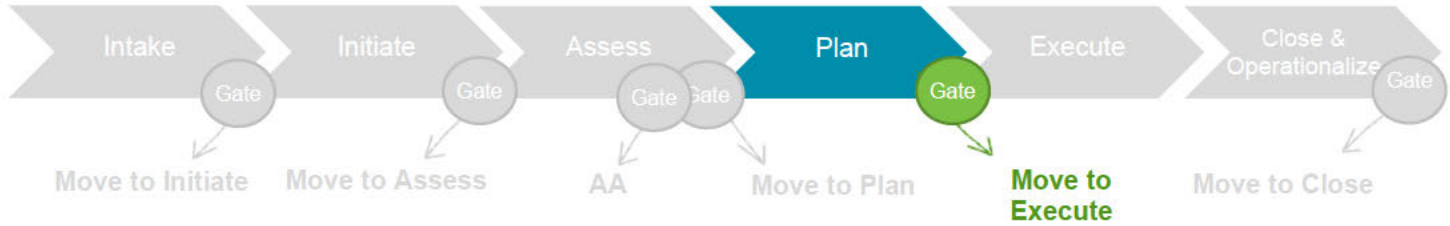
- [ ] Have the architecture team create a preliminary 40% design and the construction team provide the initial price estimate for the work; then facilitate the submission of the AA**.** Note: Land purchases should have an AA completed before any design is completed to review the purchase

IT&S Additions

- [ ] If purchasing is needed, utilize the ITP Checklist to initiate purchase request
- [ ] Before the SOW and/or RFP is developed sit down with your Solution Architect and IT&S Project Sponsor to determine techincal document needs and include them in the SOW/RFP and future project plans
- [ ] Engage Enterprise Architecture to participate in the solution options and design. Ensure they have developed Solution Architecture Diagram and reviewed it in ARB
- [ ] Submit your RFx; after receiving responses but *before* selecting a vendor, submit the AA. Engage the finance team to analyze the benefits and cost of service between on-prem and cloud solutions if applicable Important note: The cost of hours during assess phase are primarily capital, but any time that is spent reviewing the RFP or sitting in presentations for vendors *not* selected need to be charged to O&M.
- [ ] Develop an agreed upon list of relevant technical documents that need to be completed in the project plan, including:
  - Confirm that IT&S Security Operations has completed a design review, if required
  - Once the IT&S Security Operations design review, if required, is completed, confirm an Solution Architecture summary has been developed; ensure your tech lead and architect are working together to channel the project through the TRB and ARB and that the solution has been approved
  - Facilitate the development of technical specs and functional specs (FDS); once complete, share with the appropriate teams including business SMEs, IT&S manager and IT&S Security Operations
  - For all new applications, ensure your tech lead / solution architect has filled out a Business Impact Analysis and Incident Response Plan; check with Information Security and Compliance for questions
  - For new applications, be sure to include a disaster recovery test task in project plan

Plan Checklist

The plan phase is used to fully flesh out the selected solution and define the execution path to achieve the project goals



☐ Manage the **overall project progress**, including:

- Manage project team resources to keep momentum, keeping your requirements up to date for any resources on your project
- Engage purchasing resources as needed
- Complete status reports (monthly during Planning) in Planview
- Carefully manage your budget, including:
    - Before the end of every month, update accruals
    - Track / receive / audit invoices on an ongoing basis and manage costs accordingly
    - Keep your Planview Financial Detail up to date with the latest forecast; on a monthly basis, the system will snapshot a baseline
- Hold regular meetings with the project team and steering committee (see meeting standards); remember to find the right balance of providing the most important information while being sensitive to busy schedules; leverage the project walking deck as a starting place
- Build a detailed Risk and Issue Log in Planview, using our risk standards to assess severity
- Perform contractor performance management as needed

☐ Submit a **purchase request** (more info here) to kick off the purchasing process for any final design or planning costs. Remember that your purchase request cannot exceed your current approved spend. If you need to request an execution purchase before the execute budget is allocated, you can submit an Early Purchase during the Move to Assess or Move to Plan Gate or through a Change Order (guidelines in the appendix).

☐ Finish your **project design,** partnering with key stakeholders and relevant partners (these will be led by a Business Analyst (BA) if you have one on the project). Obtain sign off on any design or requirements documents, and ensure sign off on the **final on the scope of work**.

☐ If the project execution will engage 3rd party vendors for materials, supplies, hardware/software, or services, work with Purchasing to complete the **acquisition process**. Use the approved scope to create a Statement of Work (SOW) for the project; your purchasing buyer will have the latest templated version of the SOW and the latest guidelines regarding purchasing processes, deliverables, and timelines.

☐ If the project will have a deliverable that impacts how employees do their jobs, define impacted audiences and establish a detailed **communication, training and engagement plan**

- If the project has a Change Manager, they'll develop a change management plan; without a CM, refer to the Engagement Planning document to guide your planning
- Leverage the Internal Communications Process guidelines for large projects and NWN's Brand Guidelines to build a communications plan; you can leverage the Communication Plan Template for larger projects. If there are significant communication needs, schedule a meeting with the Communications team to review strategy and assess how involved the internal communications team should be throughout launch

- o If the project impacts how Bargaining Unit employees perform their job, reach out to the Employee and Labor Relations Manager in HR to determine if there are requirements to consider in your Communication Plan/Process
- o If the project impacts the Utility Services or Operations teams, reach out to Technical Training as early as possible to discuss training plans

☐ Align business stakeholders on a **plan for governance and support** once the product is launched
- o If your project leverages endpoint technology (mobile phone, laptop, desktop, tablet, etc.) schedule time with the service delivery manager to review the plan
- o Working with stakeholders, build a RAM/Day 2 RACI for when the project closes
- o Work with business owner and IT to develop a plan for the transition, completing the Operational Support Plan and ensure your tech lead begins the Technical Support Plan

☐ Determine if the project will result in **ongoing O&M expenses** in future years, including any FTEs needed to support the deliverable; if so, estimate those costs and determine the applicant code that will need to budget for this in future years. This information will be entered into your Move to Execute Gate.

☐ Establish **project acceptance criteria** and ensure all key stakeholders are aligned

☐ Build out your **execution project schedule** in Planview to include a detailed task list, resource requirements, duration, dependencies, constraints, milestones and critical path. Through this process, document any assumptions made and update risk log

☐ Submit **Stage Gate Request** in Planview to **Move to Execute,** which will include a request for Execution budget, schedule, risks, etc. You will also be asked to describe ongoing costs, and your general execution approach (how will you make sure to stay on scope/schedule/budget?). It is best practice to also send an email to your sponsors before submitting the gate for awareness.

Engineering Additions

☐ Complete the 90% design and obtain material quotes

☐ Prepare the scope of work, RFP and obtain construction bids

☐ If the project meets the Regulatory Reporting, Filing, and Notification Requirements, work with Code Compliance to notify PHMSA at least 60 days in advance of the start of construction

☐ Complete execution bids and order materials

☐ Finalize permitting plan

☐ Before entering your stage gate request, schedule a planning meeting with your core group to review the plan, and a follow up meeting for approval including the RMC

IT&S Additions

☐ If purchasing is needed, utilize the ITP Checklist to initiate purchase request

☐ If tech scope changes at any point (e.g. different data, new functionality, etc.), re-engage IT&S Compliance and Information Security

☐ If new software is involved, work with tech lead /solution architect to submit a software request via a New Software Request in ITSM (submit as a generic "software request" and then include in the description that you are requesting a new software and it needs to go to EA for approval)

☐ Prepare your transition to operations plan with your tech lead and sponsor; going into execution, the team should understand the ownership / plan for supporting the application

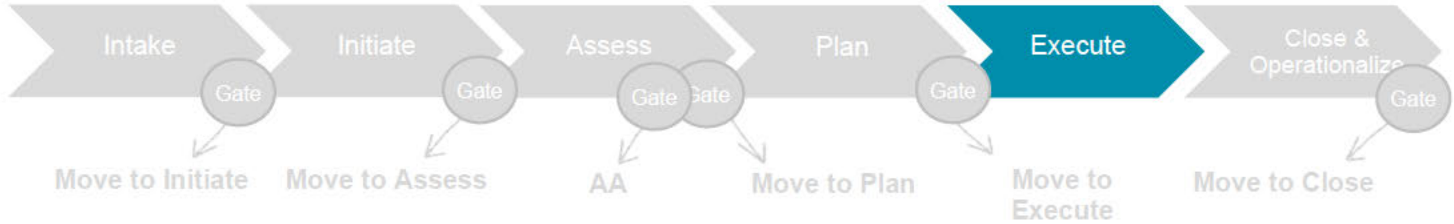
☐ If making changes to an application already under SOX compliance (e.g. SAP ECC, CIS, SAP GRC, Allegro or the I-Series), the tool impacts NWN's financial statements or bringing on a new application, ensure tech lead works with IT&S Compliance and the Business Controls Office to discuss SOX requirements

Facilities Additions

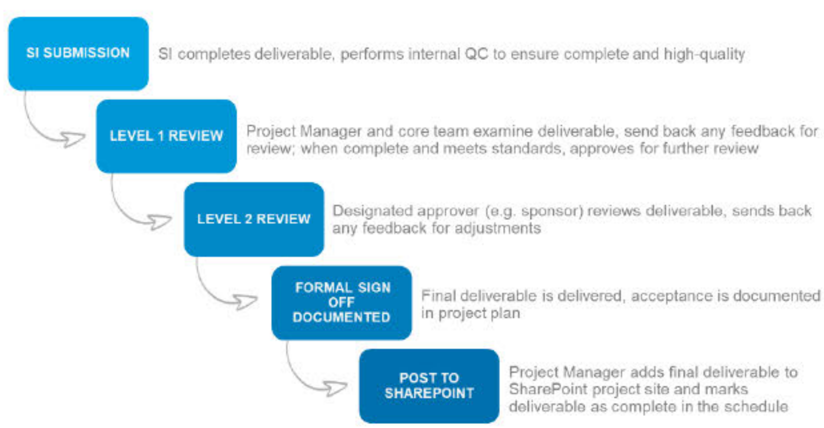
☐ Create a Stakeholder Review Schedule to kick off “4 bites of the apple”, a process to review project progress with stakeholders on a routine basis for alignment

Execution Checklist

This phase is about monitoring and controlling the project, working diligently to rally all project team members to keep momentum and keep the project on budget, on schedule and in scope.



- [ ] Submit a **purchase request** (more info here) to kick off the purchasing process for execution project costs
  - Ideally, your execution purchase request includes incremental year-over-year costs if there are ongoing maintenance for the deliverable
  - Work with Purchasing if updates or additions are needed
- [ ] Send a **kick-off communication** (meeting or email) to steering committee, stakeholders, sponsors and project team that marks the start of execution and outlines key upcoming work; reinforce expectations of key players. Over the course of execution, build a thoughtful communication cadence (refer to the comms guidance for help!) and hold **regular meetings with the project team and steering committee** (see meeting standards and project walking deck); communicate thoughtfully and often, coordinating with communications team on key communications as deployment approaches
- [ ] Manage, monitor and control the **overall project progress**, including:
  - Track progress on schedule, budget, scope and resources on an ongoing basis; proactively raise issues as they arise, always **tracking risks and issues** in Planview; if a change order is needed for scope, schedule, budget or to use contingency (guidance in the appendix), file the **Change Order request** in Planview
  - **Manage project team resources** to keep momentum, keeping your resource requirements in Planview up to date; perform contractor performance management as needed
  - Complete status reports (weekly during Execution) in Planview
  - Carefully **manage your budget**, including:
    - Before the end of every month, update accruals
    - Track / receive / audit invoices on an ongoing basis and manage costs accordingly
    - Keep your Planview Financial Detail up to date with the latest budget forecast; on a monthly basis, the system will snapshot a baseline
  - If there are any significant changes to the project (significant budget changes, new assumptions, additional alternatives identified) or you will be over $1MM with COH and have not filed an AA, work with the PMO director to confirm if you need to submit a new Alternatives Analysis which can be filed using the Change Order process in Planview
  - As deliverables are submitted, they should be **reviewed and approved** by those with accountability and decision authority over the body of work. This is especially critical for System Integrator



deliverables, who should follow a process akin to the graphic to the right

- ☐ **Confirm your in-service date** and determine when you will TECO the project; notify team members that may receive invoices to ensure we are on track to financially close the project
- ☐ Hold a meeting with key stakeholders to **review the acceptance criteria** for the project; agree on if they have been met as an official go/no go before going "live"
- ☐ **Launch** the deliverable! Celebrate a bit.
- ☐ On the exact date that the resulting asset is "Used and Useful" (in-service date, certificate of occupancy, gas flowing), email accounting to TECO the project
- ☐ Reach out to purchasing to communicate that the project is closed
- ☐ Once the product is live, go into your Work Details in Planview and **change the Status to "Prepare for Closure"**, which will walk you through the Close Phase (note that this is a manual step you must do yourself)

Engineering Additions

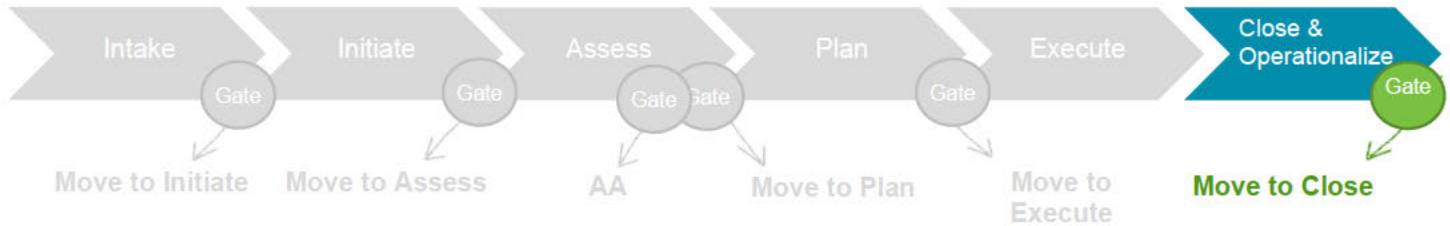
- ☐ Update the operation and maintenance plan, if needed
- ☐ Obtain or organize the QAQC documents

IT&S Additions

- ☐ If purchasing is needed, utilize the ITP Checklist to initiate purchase request
- ☐ Obtain signoff from business and IT stakeholders on a **plan for governance and support** once the project is completed. You'll want two documents finalized: the Technical Support Plan (completed by IT) and the finalized Operational Support Plan (owned by the PM). In addition to the business that will own the product, this may include working closely with Service Delivery on deployment strategy, including Tier 1/Tier 2 support plan, handoff of support RACI, Day 2 support model, knowledgebase articles, access to vendor knowledge base, access to vendor support, escalation paths, etc.
- ☐ Before you go live with any technology changes, ensure your Tech Lead has submitted the request through the **Change Advisory Board (CAB).** This request should be submitted at least 2 weeks beforehand after code has been frozen and testing is complete. The results may influence your launch date depending on other changes in flight. They'll be asked to submit a request through the Self Service Portal that includes a description, reason for the change, scheduled release date, affected configuration items and implementation, back out, communication and test plans. A full overview of the Change Control Procedure and Policy can be found on the Hub.
- ☐ If there are programmatic changes to SAP ECC, CIS, SAP GRC, Allegro or the I-Series, ensure that your Tech Lead is creating **SOX-specific test plans, test scripts and collecting testing evidence** in the project folder; questions can be directed to Enterprise Applications
- ☐ If changes to the original design become necessary, consult with relevant teams (e.g. IT&S Security Operations, IT&S Enterprise Architecture, etc. to ensure potential risks are addressed)
- ☐ If any exceptions to policy are needed, ensure they are filed
- ☐ Ensure applicable **vulnerability scans** are run and findings dispositioned

Close Checklist

Closing is the technical completion of your project; in addition to closing budget, the close phase an opportunity to document lessons learned and ensure we met the project objectives.



- [ ] In Planview's Financial Detail Screen, perform a **final budget true-up** after the final invoice has been accepted
- [ ] **Transition fully to operations**. Coordinate with the owner of the product or asset and the Service Delivery Team (if applicable) to confirm they have everything they need to successfully operate and maintain the asset
- [ ] Hold **lessons learned** sessions
    - The PM or CM should facilitate these sessions. If the program is larger/more complex, experienced significant issues, etc. considering leveraging a third-party CM to ensure unbiased feedback; all project team and key stakeholders should be engaged in the process
    - The sessions should be held in small groups if the group working on the project is more than 5. If less than 5, then should leverage 1:1 sessions. Video or in person is best practice.
    - In addition to meetings to collect this feedback, the PM / CM may leverage an anonymous survey with less than 10 questions to gather feedback
    - Conversations during lessons learned should be forward looking; the facilitator should follow up with questions that draw out what we learned to apply a different approach going forward. The Lessons Learned template can be used as a tool to collect holistic feedback.
    - Summarize results to capture themes. Document summaries in Planview, and in a deck that is presented back to the whole project team, steering committee and/or sponsors
    - Results from these discussions should include action items for what should be adjusted, ideally with owners attached to each (e.g. "Going forward we should aim to have a BA engaged from the start of a project" - assigned to Rustica Carlos and Sean Taylor in the PMO)
    - Confirm that there are no outstanding steps needed to close the project; if so, create a plan to tackle final items
- [ ] Prepare **closing thoughts** (how did this project go compared to plan?) and then file **Move to Close** gate request in Planview; once completed, the project will be marked closed in the system

IT&S Additions

- [ ] Develop **close out presentation** for steering committee
- [ ] Any **information security open items** should be closed or at least have a Plan of Action and Milestones (POA&M) created

Facilities Additions

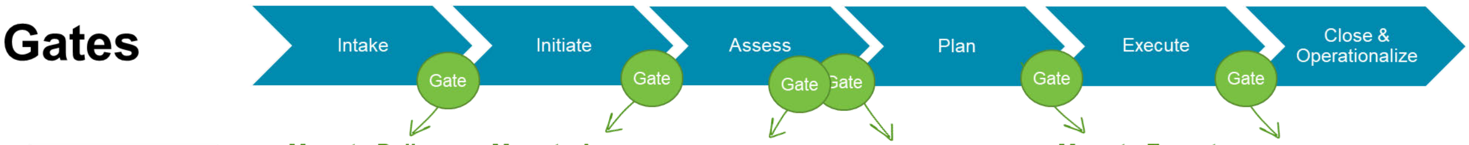
- [ ] Gather O&M Manuals
- [ ] Conduct training on new systems e.g. security, HVAC

Gated Governance

Move To (Phase) Gates

At the end of each phase of the project, we pause to level set our progress through a "Stage Gate", a formal process where key stakeholders review and **approve what was delivered in the last phase and fund the project for the subsequent phase**. This builds consistency, standardized transparency, accountability and documentation that supports PUC requirements. Stage Gates are also a good time to pause and review lessons learned for the previous phase. Here's how it works:

- During a phase, the project team, lead and PM will work on certain screens and content in Planview
- When ready to move to the next phase, the PM will **submit a stage gate request through Planview** That request will then be filtered through a series of approvals; once the approvers have signed off, the next phase of the project begins



	Move to Delivery	Move to Assess	AA	Move to Plan	Move to Execute	Move to Close
What is it?	❑ Summarize and document the PMC decision to select the project; notify partners and officers of the key problem we're trying to solve ❑ Fund the project with $50k to gather resources	❑ Confirm that the initial project charter is complete ❑ Validate that a plan is in place to assess the problem including resources, budget and schedule ❑ Fund the project for the assessment phase	❑ Review the options to tackle the project ❑ Validate that the selected solution as the most efficient and best option and will meet project objective ❑ Confirm the total estimated budget is money well spent to meet the project's objectives	❑ Validate the AA committee decision that the selected option will meet project objectives ❑ Validate the *estimated* total budget is money well spent to meet the project's objectives ❑ Fund the project for the planning phase	❑ Confirm that the project is planned and designed such that it can be executed ❑ Validate the execution budget is money well spent to meet the project's objectives ❑ Fund the execution phase	❑ Confirm that the project has been delivered as promised, fulfilling the value that it pledged
What's included?	Intake Form	Initial Project Charter Assess Budget	Alternatives Analysis	Full Project Charter Planning Budget	Move to Execution Plan Full Budget	Project Closeout Final Budget
Who approves <$1MM?	PMC	PMC → Sponsors	Alternatives Analysis Committee	PMC → Sponsors		
Who approves >$1MM?		PMC → Sponsors → Finance → EC		PMC → Sponsors → Finance → EC		

Note: if a capital project cancelled/stopped at any stage gate, the investment will need to be expensed, following NW Accounting guidelines.

Helpful hints:

- If the request will be at all contentious, socialize it first with the audiences that will receive the request, ensuring they are not surprised and have the information they need to make an educated decision.
- As with anything, be wary of what you write in the approval request – don't include anything that you don't want to see on the front page of the newspaper!
- Once submitted, the approver will see the gate content provided via Planview, and will receive a notification to view the request
- Use the Current Context section of the gate to provide relevant information that isn't otherwise visible (e.g. schedule impacts, ongoing costs, current status of the project, context for recent change orders, etc.)

Early Purchases During Assess or Plan

You have the option to submit an **Early Purchase Request** for execution funding *before* your project is in Execute under the following conditions:

- Emergencies
- Long lead time, non-stock material needs to be purchased
- Financial benefit to early purchase

You have the option to request an Early Purchase while submitting Move to Assess or Move to Planning gate *or* you may request an Early Purchase through the change order process between gates. Note that if a project will need an Alternatives Analysis (AA), it is critical that no purchases are made before an AA is approved. For a full description of the process see the Early Purchase Process Guidelines.

Change Orders

Change Orders are submitted through the Changes tab in Planview for any change to scope, schedule, budget or to use contingency.

Approvers: When a change order is filed, the request is sent to the project's change board (e.g. project sponsor, executive sponsor and likely relevant additional officers or stakeholders); if the project asks for more funds and is a Tier 4 project (or will become one by way of the Change Order), it will also be sent to Finance and then the Executive Committee

Types of Change Orders: below are the triggers that would cause the need for a change order, which align to the type of change order you'll file (note: a change order may be filed for more than one type at a time, so select as many as are applicable):

- **Budget: Forecast Over Budget, Needs More Funding –** Projects require change approval if additional funds are needed for the current phase; upon approval, the request will be sent to accounting/finance to add additional funds to the project
- **Budget: Forecast is Under Budget, Needs to Relinquish Funds –** Projects should file a change order if the forecast shows it is likely to come in *significantly* (e.g. >20%) under the authorized spend amount; upon approval, the request will be sent to accounting/finance to adjust authorized spend in SAP
- **Budget: Project Needs to Use Any Contingency** – Projects require approval from the change board to use contingency; approval of this change will also trigger the accounting / finance team to move the funds from your contingency WBS to the appropriate bucket
- **Budget: 80% of Contingency Used, Needs Final 20% -** Projects require approval from the change board to use the final 20% of contingency since it poses a risk to needing additional funding
- **Budget: Transfer Funds Between Cap & O&M Accounts –** While budget is allocated at the project level and can be distributed among different funding categories, projects require approval if authorized spend needs to be moved between a capital and an O&M account.
- **Schedule: Change to Key Milestones or End Date –** Projects require approval from the change order if major milestones or the project end date will change
- **Scope: Material Scope Change (Add or Delete) –** Projects require approval from the change board if there is a significant change to the scope of work. For instance, if a material scope change would occur if we realized we needed to implement additional security integrations to a selected application or discovered a roadblock in a pipeline route. Each project should have defined core scope and business objectives at the start of the project that are refined as the project moves through initiate, assess and plan – this is what is outlined in your charter, and is the baseline for how scope is measured. Once the project is in *execution*, any deviation from this scope and objectives would require a change order– this would include any new/expanded or reduced functionality, competency or business objectives, even if there are no changes to schedule or budget.

Project Governance

Project Status Reporting

A key part of Project Management is reporting on project health so that all stakeholders are on the same page and allows sponsors to engage in a meaningful and effective manner This ensures more efficient and higher quality project outcomes. This happens through a number of avenues:

PMs are required to file a Status Report for their project Planview (guide here!), which includes a current status assessment and summary, and will pre-populate milestones from the schedule, current forecast from the budget and all risks and issues from the logs. Sponsors are responsible for reviewing these reports on an ongoing basis so that they can help tackle issues as soon as they arise.

Status Report Timing:

- During Initiation, Planning and Assess, status reports are due **monthly** on the first Thursday of the month
- During Execution, status reports are due **weekly** on Thursday

Assessment Criteria:

	Red	Yellow	Green
Cost	Forecast is estimated to exceed authorized spend	Forecast is estimated to utilize 51% to 100% of contingency	Forecast is not estimated to spend over 50% of contingency
Schedule	Major milestone dates are not being met causing critical operational, regulatory or safety impacts OR In-service date will be missed, requiring a change order	Major milestone dates are not met, but there are no critical operational, regulatory or safety impacts AND In-service date is still obtainable with corrective actions	Major milestone dates are being met AND In-service date (often the start of project close phase) is forecasted to be met
Scope	There is a significant change to the original scope that alters cost or schedule	There is a change (addition or reduction) to the original scope, but the change can be absorbed in existing cost and schedule	Scope is being met per baselined project plan
PM Actions	Facilitates meetings with executive sponsors and steering committee Change order is required and provides root cause analysis if needed	Identifies issues Creates change order(s) if needed (WBS for 80% contingency, scope creep, schedule change, etc) Facilitates planning to resolve the issue Works with stakeholders on what conditions would constitute moving to red	Creates WBS change order to start using contingency
Sponsor Actions	Executive sponsor and steering committee determines next steps	Project sponsor acknowledges issue and determines escalation path	No action needed

Monthly Forecasting: In addition, the PM is required to update their forecast at least monthly including:

- *Until July 2021*: Complete the **monthly forecast spreadsheet** by entering values for unapproved (but expected to be spent) budget for the current fiscal year in the Employee Portal on the company's intranet site by the **3rd business day of the month**.
- Keep their Forecast/Actuals Version up to date in **Plainview's Financial Detail**, ensuring it is accurate by the **7th Business Day of the Month**, when we'll snapshot all budgets

Alternatives Narrative/Analysis (AA)

When: The Alternatives Analysis process is completed during the Assess phase for:

- Any projects whose total budget will be >$1MM *including COH*
- Any program (group of projects) who will spend more than $10M (Oregon) or $5M (Washington)

This process is timed to happen once enough information has been gathered to fully understand the requirements, but before any decisions have been made. This timing is critical to ensure we are assessing project alternatives, and the most efficient way to solve the problem at hand.

What: The project team completes the Alternatives Narrative template, saves it on the Project SharePoint site and then submits the AA approval through Planview (guide here!), which will be sent for review to the AA committee (John Sohl, Zach Kravitz, Jorge Moncayo, Tamy Linver). If additional analysis is needed, an Alternatives Analysis may also be requested by the AA committee.

Exemptions: Some projects are exempt from completing an AA; refer to the Alternatives Analysis Guidelines for details. That exemption also needs to be filed in Planview, for approval by the AA committee.

Why: The AA includes important documents providing rationale for the execution of the project, proof of due diligence in selecting the best solution/project for NWN needs, that we are utilizing company resources is the best manner, and finally, assist with rate recovery for our projects. As a regulated utility company, transparency to the public and regulators is ***extremely*** important.

Who: The Business Analyst and Project Manager (for IT projects) or Project Engineer (for engineering projects) takes the lead on developing the Alternatives Analysis with the aid of the potential Business Sponsor or other SMEs

Programs: If a program concept is developed before any projects begin, the program may request to file a single Alternatives Analysis on behalf of the set of programs; upon approval, the projects (no matter the size) will not need to file an individual AA unless the scope or costs significantly shift during the development of the project. In this case, the projects will file an exemption during assess, allowing the AA committee to request additional information on the individual project if necessary.

Best Practices: When developing your potential cost ranges, be aware of the Cone of Uncertainty and that at the time of the analysis, it is possible that the cost range is very wide. This is acceptable so long as that width of range is explained as part of the Cone of Uncertainty, and 2, that the likelihood of the real execution of the project would exceed the range is very low.

Examples: CGI Replacement (IT&S), Mist Instrument and Controls Phase II (Engineering), Warrenton Resource Center (Facilities)

Risk + Issue Management

Definitions: Risks are positive or negative events that might occur that will likely have an impact on the project's scope, schedule or cost. **Issues** are risks that have already occurred.

Expectations: Project Managers are expected to pull the project team together to actively tackle risks for their project. This happens in a continuous process that starts with risk identification followed by evaluation, response and controlling.

All risks and issues must be entered into the project's logs in Planview with enough detail for a stakeholder to understand the issue and how it is being navigated. Risks and issues should be discussed in **every project team meeting** to ensure all stakeholders understand the current landscape and their part to mitigate the consequences.

Risk Identification: Risks are derived from various sources, some of which can be identified before a project starts, and some of which are surprises along the way. Many of these risks or sources are common across projects, so the PM may start with NWN's common risks by project type. These tools can be leveraged as a starting place, but it is the job of the PM to coalesce common *and* unique risks that the project faces.

Risk identification should be conducted on an ongoing basis, but two points of the project are particularly important:

- During the Assess phase, leverage the assessment team to identify underlying risks with the chosen solution
- During the Planning phase, focus on what challenges might come up during execution; best practice is to hold a workshop with your project team to work through identification, evaluation and response plan

Risk Evaluation: As we document risk, we talk about its **probability** and its **impact**; this allows the project team to make thoughtful decisions about potential risks. To make this simple, we can use the following definitions to give a score for both probability and impact:

Probability of Risk Occurring

Level	Probability	Score
High	The risk is likely or certain to occur. Specifically, there is **more than 75%** chance that the risk occurs	3
Medium	There is some likelihood that the risk will occur. Specifically, there is between a **25% and 75%** chance that the risk occurs	2
Low	It is not very likely that the risk will occur. Specifically, there is **less than 25%** chance that the risk occurs	1

Impact If the Risk Occurs

Level		Cost	Schedule	Scope	Quality	Score
High	If the risk occurs, it will have a severe impact on the ability to achieve the project's critical objectives	Cost increases would be beyond the total authorized spend, causing a change order	Key project event or milestone will be delayed by more than 3 months	Scope decrease would have significant impacts on key deliverables	Performance is degraded to the point that the project would not meet its objectives	3
Medium	If the risk occurs, it will somewhat impact the desired results – either crippling a secondary objective or causing a critical outcome to be degraded	Cost increases would dip into contingency funds	Key milestone will be delayed	Scope decrease would impact some core objectives or key deliverables	Performance would be below goal and may have some impacts on project objectives that can be mitigated with work arounds	2
Low	If the risk occurs it will have little or no impact on the project's ability to achieve it's objectives	Cost increases could be managed within the approved budget	No key milestones will be impacted	Scope decrease would not impact core objectives or key deliverables	Requires minor performance trades, but will not significantly inhibit project objectives	1

These numbers should then be evaluated to determine overall exposure, which will drive the project team's mitigation response:

Probability				
	High	3	6	9
	Medium	2	4	6
	Low	1	2	3
		Low	Medium	High
			Impact	

Risk Response and Control

Risk response is perhaps the most important step in risk management; it is important to focus efforts and communications on the most important risks, with targeted and thoughtful mitigation strategies. The risk exposure score will drive how these are tackled.

Red Risk Exposure

- Mitigation Strategy: The mitigation strategy and execution should be assigned to a risk owner. The project team needs to work together to find outlets to avoid or temper the severity of the risk at hand. If the risk is accepted, it's critical that every stakeholder understand the consequences.

- o Disclosure: Risks scored in red must be disclosed on status reports, including mitigation strategy.
- o PM Role: The PM is responsible for communicating and escalating issues and ensuring that all impacted parties understand the possible negative consequences. They are accountable for ensuring the risk reaches the appropriate level of response, but are not always accountable for the mitigation itself.
- o SteerCo and Sponsor Role: For red exposure risks the Sponsors and/or Steering Committee are responsible for making critical risk decisions (e.g. approving *how* are we going to tackle this risk) and accountable for ensuring the mitigation strategy is implemented (e.g. working to identify new resources to support a capacity risk).

Yellow Risk Exposure

- o Mitigation Strategy: Yellow exposure risks should likely have a mitigation strategy, although in some cases accepting the risk may be acceptable. If this is the case, all impacted parties, including sponsors and steerco need to be aware and sign off on the impact.
- o Disclosure: Risks scored in yellow must be actively discussed and managed in the project leadership team meetings.
- o PM Role: The PM is responsible for communicating and escalating risks to the appropriate members in project team; they are accountable for ensuring the risk reaches the appropriate level of response, but are not always accountable for the mitigation itself.
- o Sponsor Role: The Sponsor is responsible for acknowledging risk mitigations, and removing barriers for the risk owner to tackle the mitigation.

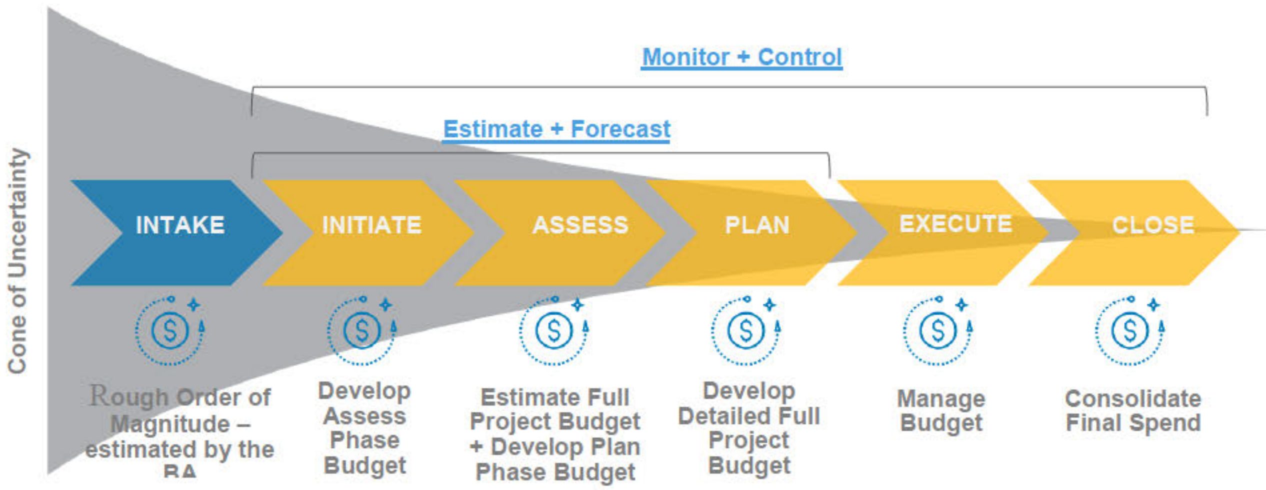
Green Risk Exposure

- o Mitigation Strategy: Green exposure risks need to be monitored, but do not necessarily need an active mitigation strategy
- o Disclosure: Green risks should be part of the risk register but do not need to be escalated.
- o PM Role: The PM is responsible for monitoring the risk and ensuring it does not increase in probability or impact.

As risks occur, the PM moves them into the Planview issues list, which is also monitored to ensure all stakeholders understand the consequences.

Accounting and Budgeting Practices

Project managers are responsible and accountable for maintaining a project's budget – from the estimates generated during the Initiation phase through finalization of the project's actual spends at Project close. The diagram below outlines the high-level Budgeting activities that take place throughout the project's life cycle:



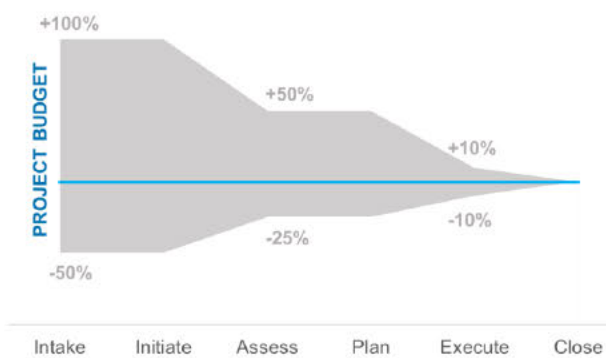
In order to effectively manage budgets, PMs are responsible for tracking and managing internal and external spend and submitting change orders as needed to keep the budget balanced and accurate. Our PMO Cost Accountant closely monitors spending on a month-to-month basis to ensure we're providing enough transparency as a public utility.

Forecasting / Estimation

Project Managers will begin their forecasting at Initiation. At this phase of the project, Project Managers should work closely with stakeholders and Accounting to begin outlining high level project costs; these estimates should become more refined as the project progresses.

Cone of Uncertainty

As you develop your budget, the cone of uncertainty provides the acceptable amount of variance at each stage. Communicate thoughtfully to key stakeholders about the cone of uncertainty. Explain that at this phase in a project, the budget is an estimate with a wide potential variance. This will become more defined as the project unfolds. For a typical project, the variance at each phase is usually:



- **Intake**: When a project is first proposed at Intake, there is a Rough Order of Magnitude (ROM) estimate provided. Given that this estimate is provided before any stakeholders have been engaged or SOWs generated, it is an extremely high-level estimate. At this stage the rough order of magnitude is entered into the Triage form where we expect the variance to fall anywhere from **-50% to +100%** of the eventual project budget; for those projects that do not have much precedent, variance may be even larger.
- **Initiate**: As the project enters the "Initiate" phase, you will develop a budget for the Assess phase – however you will NOT be required to formally estimate total project costs at this juncture.
- **Alternatives Analysis:** At the end of the Assess phase when you submit the AA, the project should have the first solid estimate of full project cost. At this point, some variability is still expected: **-25% to +50%**

- **Plan**: Finally, as you work through the Planning stages you will be further refining your project forecasts. You should be receiving completed RFPs from prospective vendors. These, along with other refined estimates, will allow you to submit your full project budget, which will constitute your project baseline as you enter Execution. This estimate is expected to fall within **+-10%** of your actual spends.

Capital vs. O&M

As you begin to estimate project costs, you should speak with Accounting about setting up your project costs. Project Costs are split between Capital and O&M, and both should be included in your budget for all elements (internal labor, external labor, materials, etc.). The capital asset policy outlines what is considered capital vs O&M, but here is a general guideline:

Item #	Cost Category or Item	O&M (O) / Capital (C)	Notes
1	**Labor**		
1.01	System Integrator Services	C	
1.02	NWN Internal Labor	C	If the employee is normally O&M and is back-filled, or if the employee normally charges to capital. Caveat: The time during assess phase is *primarily* capital, but any time that is spent reviewing the RFP or sitting in presentations for the vendor not selected need to be charged to O&M.
1.03	Data Transformation	O	
1.04	Data Migration	C	
1.05	System Documentation	C	
1.06	Organizational Change Management	O	
1.07	Communications	O	
1.08	Project Management	C	
1.09	Training - Trainer	C	
1.10	Training - Development of end user materials	C	
1.11	Training - Employees receiving end user training	O	
1.12	Process Discovery, Design, Learning	O	Any work to build a new capability or process is O&M
2	**Software**		
2.01	On Premises Licensing	C	Usually this is a one-time expense
2.02	On Premises Maintenance	C	First year or until the project's in-service date if implementation is longer than one year
2.03	Cloud Annual Licensing	C	First year or until the project's in-service date if implementation is longer than one year for expenses greater than $10K; projects that involve cloud and are >1year should meet with accounting for individual review
3	**Hardware**		
3.01	Initial Purchase	C	
3.02	On Premises Maintenance	C	First year or until the project's in-service date if implementation is longer than one year
4	**Miscellaneous Costs**		
4.01	Facilities (including Leasehold improvements and related expenses)	C	Note: this will be for incremental lease expense incurred as a result of the software project
4.02	Employee Awards/Recognition	C	
4.03	Furniture/Equipment	C	
4.04	Miscellaneous Costs	TBD	TBD. Depends on nature of expense. Please consult with Accounting team.

Note: if a capital project cancelled/stopped at any stage gate, the investment will need to be expensed as O&M, following NW Accounting guidelines.

Additional questions around the natural grey areas can be directed to accounting prior to submitting for approvals.

Documenting Project Forecast

Project Managers will build their forecast (first at the individual phase and then for the whole project) in Planview, using their Forecast/Actuals Version (guide here!). These expenses should be broken out by Account (e.g. Professional Services, Labor, Materials, etc.), Capital or O&M and marked with the phase where the funds will be spent. If the PM would like to forecast with more granularity, they have the option of subcategories under each account (but this is not required).

Your authorized spend (budget that you can actually spend against your project) will get approved with each stage gate for the next phase. So as you submit a gate, it is critical that your Forecast/Actuals version reflects the funding you're requesting. Once approved, the request gets sent to Finance and Accounting and they will:

- Set up your project WBS structure in SAP, reflecting the accounts you've developed in your Financial Detail
- Fund the project at the project level under three buckets: O&M, Capital and Contingency
- As actuals come in, they will land on the WBS structure, and pull from the appropriate project level bucket
- The PM should keep their Forecast/Actuals version up to date with the latest, and can then compare that version to the SAP actuals or current authorized spend to ensure the project is on track
- On a monthly basis and at each gate, Planview will snap a baseline of your budget; this can also be used for future comparisons

Labor Charges

Your project team (both internal and contract resources) can track time toward your project. Managers and above are typically excluded – meaning their time does not count toward your budget even if they work on the project.

To build out any phase budget, you'll need to estimate the resource need and associated cost. Planview makes this easy – as you know the resource roles you'll need, add a requirement (guide here!) for that role and phase (e.g. I need a SME from the Business Analytics team for the Assess phase, which runs from 1/1 to 5/12). That requirement will be sent to the Resource Manager to fulfill (assign a person to), but you can also *load* those resource costs into your project budget (guide here!). When you load the cost, it will calculate the amount of time you indicated you needed (% time and date span) and the typical rate for that role and apply it to your forecast. You can refresh this load at any time; once a *person* (FTE or contractor) is assigned, the forecast will load their *actual* rate.

Contingency

Included in your budget is your project contingency, which is used for unexpected project costs. These guidelines should be followed for contingency:

- Calculating Contingency:
    - When building a budget, the PM will request a specific amount of contingency. The amount requested will depend on the risk of the project.
    - Best practice is that for construction and engineering projects contingency is based on the risk register; IT-related and other business projects calculate contingency as roughly 10% of the total budget
    - Once allocated, contingency will have its own WBS. Contingency may not be wrapped into individual WBS elements (e.g. a 10% contingency buffer within materials), but must be contained in one WBS for the project.
- Requesting the Use of Contingency:
    - To use *any* contingency, the PM needs to submit a change order
    - Once approved, funds will be transferred out of contingency into the appropriate bucket

- A change order must also be submitted to release the final 20% of contingency; this will be routed through approval
- When to Use Contingency: If your forecast shows you may go over budget, best practice is to plan on using contingency before requesting new budget.

COH

COH (Construction Overhead) represents indirect capital costs that are applied to capital projects for back office support. NWN has a number of different rates based on the applicant type (SW/HW gets a different rate than Facilities and Engineering; the current rates can be found in a file here). It is applied to current month actuals for the duration of the project. The rates change during the year - this could be an increase or decrease to COH based on what was allocated the previous 11 months.

From a financial perspective, total project costs include: COH, capitalization of property tax, vehicle overhead and AFUDC (Allowance for Funds used during construction). Project managers are *not* responsible for forecasting these costs, only responsible for managing variances against direct costs. However, PMs do need to understand COH to determine if their project will meet the AA threshold when COH is applied to the estimated total cost. In addition, PMs can report on the total project cost including indirect costs through the PowerBI report (coming soon!).

Budget Management

Throughout the entire project lifecycle, PMs must actively manage the project's budget. There are key activities that happen on a monthly basis around month-end that are summarized below; additional detail on these processes are listed below the graphic.

Project Accounting Timeline

The below process is for any typical T&O contract.
For pre-paid, milestone or fixed fee agreements, please discuss with accounting directly to document a plan.

Email
SAP Forecast
Manual Accrual Template
Planview
Perham's Spreadsheet
PowerBI Reports

ACCTING MILESTONES	Sends close schedule and confirms due date SOX report for large POs sent to relevant PMs		AP is closed and accrual entry is posted by 1pm	Actuals finalized in SAP for the previous month by Day 3	Negative balances analyzed		
Business day related to month end that the task is due	**-7**	**0**	**+2**	**+3**	**+4**	**+5**	***ongoing***
PM ACTIONS	Email vendors to understand value of work performed in the current month Review project transaction report and compare to your detailed list of known costs for the month to determine accruals needed	Update SAP with purchase order estimates (or provide to delegate to enter), updating delivery note with estimate and the date Complete SOX report if sent to you (in which case do not file a manual accrual) File a manual accrual for any estimates not entered or previous month invoices still not paid by 5pm on the last day of the month		Run Transaction Report to make sure estimates recorded as expected Update current month's forecast in Planview	Run reports to validate accruals, and actuals; highlight any mis-placed charges. If found, complete the SAP transfer form and email it to Daren Cox Complete monthly forecast in SAP	Complete forecast excel sheet	Ensure you are copied on invoices sent to AP, approve as needed to validate the correct values; ensure they are shared with AP. For engineering and facilities, enter details to MIGO As invoices are paid, ensure estimates are backed out as actuals come in using reports
ESCALATION PATH	Jim Dehning, Marie Guizzotti or team accountant	Jim Dehning, Marie Guizzotti, Leslie Holder (SOX report)	Jim Dehning, Marie Guizzotti	Michael Perham	Michael Perham	Michael Perham, Lory Littlejohn	Lory Littlejohn, Michael Perham

Accruals and Estimates

NW Natural utilizes Accrual Accounting, which means that we record expenses in the month that they were accrued, rather than the month the invoice was received. That means if a contractor is performing work for you in July, and you receive the invoice in August, we should be tracking the costs that happened in July. When we have large purchase orders that have labor components, tracking these costs becomes important – particularly at financially sensitive times like quarter- or year-end.

Accruals are typically performed for two reasons:

- The contractor performed work in the month but invoiced in the next month.
- Material was received in one month but invoiced in the following month. We do not perform accruals for materials that have not yet been received, unless it is a contractual obligation – such as a line heater where we pay 10% at drawings, 40% at materials and 50% at delivery. We'd accrue the 10% when we received the drawings.

There are two ways to perform accruals, estimated receiving and manual accrual:

The goal is to have all accruals go through the **Estimated Receiving** process:

- Before the month ends (ideally <u>3-5 days before month-end</u>), contact your vendors/contractors and ask them to provide an estimate of expenditures for that month. Usually this is a simple email.
- Perform a receipt just like you would with a regular invoice, but include the email from the vendor/contractor or add a short note regarding how you came to that estimate amount as an attachment.
- Update the Delivery Note field with ESTIMATE MM-YY so that A/P knows this is as estimate and that it should not be paid to the vendor. If you don't have access to the PO, you should contact your purchasing partner who can enter an "estimate" on your PO for those costs.
- When the invoice comes in that estimate will reverse and the invoice will be processed in its place.

(Helpful hint: doing this before the end of the month that the services were delivered will save you work later, and ensure we comply with SOX requirements!)

If there is an unavoidable reason that you cannot do an estimated receiving or the estimate is incorrect, the backup option is a **Manual Accrual**:

- Note: If the individual invoices are less than $2000 and the vendor total is less than $5000 for the month, you do not need to file the accrual.
- On the <u>last day of the month</u>, look at what invoices have not yet come in that you expected.
- If there will be trailing invoices for the month that were not previously estimated, submit a <u>Manual Accrual</u> with supporting documentation to Accounts Payable <u>before 5pm on the last day of the month</u>.

After the end of the month passes: If Accounts Payable has been closed for the month and you have not submitted an estimate you will need to submit a manual accrual for un-invoiced costs to Accounts Payable <u>prior to noon on the first work day following the end of the month</u>. In this case, if you do not get an invoice for the services/materials that were accrued you will need to re-accrue every month until that invoice is presented.

Accruals & Estimated Receiving Tricks & Tips:

- When estimating, be sure you are looking at the <u>work date</u> on the invoice, rather than the invoice date itself. The invoice should go against the date that the services were delivered
- It's important for vendors to include the correct PO number

- AP Accounting closes the second day of the month at noon. You MUST get accruals in by the end of the month. Plan accordingly. If you've missed that date, reach out to the Account Payables Supervisor

Auditing Invoices

It is important that as invoices are received, the PM takes the time to review the contents closely and confirms accuracy for goods delivered as well as alignment to original contracting and in alignment with the G24 Policy which covers corporate purchasing and expenditure procedure. This audit should ensure that the goods or services are reviewed for reasonableness before receiving in SAP and submitting for payment – a critical role that the PM plays in having the closest purview to the project. Generally, each invoice should be reviewed to confirm:

- ☐ The goods and services were indeed delivered
- ☐ The Quantity (or hours worked) are correct
- ☐ The Price (or hourly rate) is correct
- ☐ Charges align with the contract
- ☐ If applicable, any travel expenses are in alignment with NWN's travel related guidelines. If travel expenses exist, confirm the expenses are in alignment with the vendor's MSA. Where it is not clear in the MSA, leverage NW Natural's travel policy (80.1).
- ☐ Vendor has provided supporting documentation, if applicable

Ongoing Forecasting

At all times, the PM is expected to understand and grasp the financials of their project including overall spend to date, total project budget and any risks to the project cost.

On a monthly basis, PMs are asked to update their forecasts in Planview, which will be baselined on the **3rd working day of the month**.

In addition, until January 2022, PMs also need to:

- In order to complete the **monthly forecast into SAP**, PMs need to enter in values for approved budget forecast for the current fiscal year in the Employee Portal on the company's intranet site by the **3rd business day of the month** (Note: reference the Glossary to identify the definitions for both Approved and Authorized spends).
- Complete the spreadsheet that the project accountant manages on a monthly basis; this link will be sent to PMs, who will be asked to populate their forecast. To do this:
    - Go to the Hub, then "Employee Portal" in the upper righthand corner
    - Select the Project Manager tab
    - Enter the SAP number for your project, search and select your project
    - This will populate a full authorized spend, actuals YTD and an amount listed per month (based on your last entry) for the remaining fiscal year
    - Download your project information and open the attachment
    - Copy the first line through the end of the year and paste it into the provided forecast document; if you are keeping a manual tally of actuals and forecast, you can compare that content as needed.
    - If there is expected unauthorized spend, add additional information in the "unauthorized spend" line for your project
    - If you have questions on the process, please reach out to the Project Management Specialist or a NW Natural project manager

Pulling Accounting/Budgeting Reports

Your accounting reports can be found in PowerBI; these will capture the full project accounting. Training for these reports can be found here (video) or here (reference guide).

Using PowerBI, you have access to helpful reports. Note that information is not updated real time, but is refreshed overnight.

Project Labor report will represent your internal labor costs, and in many cases, signify when your project team is not inputting their time when they should be for accurate reporting and supporting original budget estimates in this WBS.

Purchase Order by WBS Element can provide a broad look at budget burn with regards to non-internal labor costs. When tracking leading up to project close out, engage with Purchasing, Accounting and your Vendors to determine what invoices have been received, paid, or are in flight.

Project Forecast Summary will provide the monthly actuals for your project for all months that have closed along with monthly forecasts for the future (provided you have entered this information into Planview.

Budget to Actuals Summary will provide a year to date or project to date comparison of your actual cost against budget and authorized spend at the WBS element level. **You are required to download and save this report to your project site at the end of every month.**

Forecast Summary will provide a snapshot with monthly actuals for months that have closed and monthly forecasts for future periods. **You are required to download and save this report to your project site at the end of every month.**

Invoice Tracking
Invoices over the course of a project should be sent directly to Accounts Payable but copy the PM. Whatever the situation, it is the PMs job to track down and keep an eye on each invoice and approve them before they are paid. The PM should approve the payment of all invoices, as well as SMEs.

Change Orders
In managing your budget, you may need to file a change order through the stage gate approval process if you will use contingency and/or exceed your authorized spend. Remember that if you are projected to exceed your authorized spend, you must first use contingency. A change order should be filed under the following budget-related reasons:

- If you will need more funds than are currently allocated to your project
- You have excess funds you need to return to the project
- You need to use contingency
- You will use the last 20% of contingency
- You need to transfer money from O&M to Capital buckets

Tracking O&M + Internal Time
Labor-related O&M is eventually paid by a specific cost center. However, the amount spent / to be spent is still part of your project budget. O&M expenses should be treated in the same manner as your capital budget – you forecast for the costs, work with the Project Accountant to create work orders for each element, and track actuals against your budget leveraging your SAP reports.

Wherever possible, internal resources *should* be tracking time against work orders for project work, even if the time is O&M. This allows us to see and understand the full project spend as well as understand where employee resources are being allocated.

At the end of every month, costs go through "settlement" which passes those costs to an underlying cost center based on how each work order / WBS is set up. With this in mind, it is important to work with the owning department if any O&M projections shift for any of your line items.

Execution O&M	202093-04	TEC...	78,940.00	71,884.80
Execution External Labor (O&M)	202093-04-02	TEC...	32,500.00	43,659.80
51060 Chg Mgr SAP Concur	3592183	REL ...	0.00	43,659.80

Here's what that internal labor O&M settlement will look like in practice:

- If a project leverages a Change Manager whose time is partially O&M, the O&M time for that resource will eventually come back to the PMO's cost center
- If a SME is tracking O&M time, the cost will come back to their department's cost center

How do I Find the WBS Codes Assigned to My Project?
When your project is funded, the project accountant will provide you the WBS structure. Once funded, you can run your project budget report to see the WBS structure.

Misc Expenses
If you have expenses to bill against the project (within your authorized spend), an FTE employee can charge that amount (via P-Card or personally and then with an expense report). They will just need to include the WBS number when filing the expense.

TECO
Technically Complete (TECO) happens at an overall project level at the end of a project.

Note: for projects where products are deployed in phases, we may opt to set up WBSes for each phase, and TECO the in sequence. Talk to the PMO Cost Accountant at the start of the project to set up your project accordingly.

Projects should be marked overall as TECO when the deliverable is “used and useful”. It is critical that this happens on the day it is in service – it impacts our ability to get a return on the investment of the project. Project team and key stakeholders should be informed of plans to TECO the projects and sponsors should approve before completed.

To TECO a project or WBS, email the accounting contact on the day you would like this to happen.

Charges to existing POs and labor charges can still be charged to the project once it is TECOed. Project can remain in TECO stats for roughly 3-6 months before they are “closed” and all the invoices have been paid.

Note that projects cannot be un-TECOed. If you need to change a PO to add funds or need to create a new PO, the team should decide if a new WBS element is needed for issuance of trailing costs.

Final Budget True-Up
Once the project is complete, Project Managers should reconcile their final actual spends with their project baseline and calculate the corresponding variance. This is particularly important when there are trailing invoices. In some instances, you may receive trailing invoices after you TECO a project; this is ok. However, this also means that once final invoices are received, those invoices must be incorporated into the project's final budget as a part of due diligence and final project reconciliation.

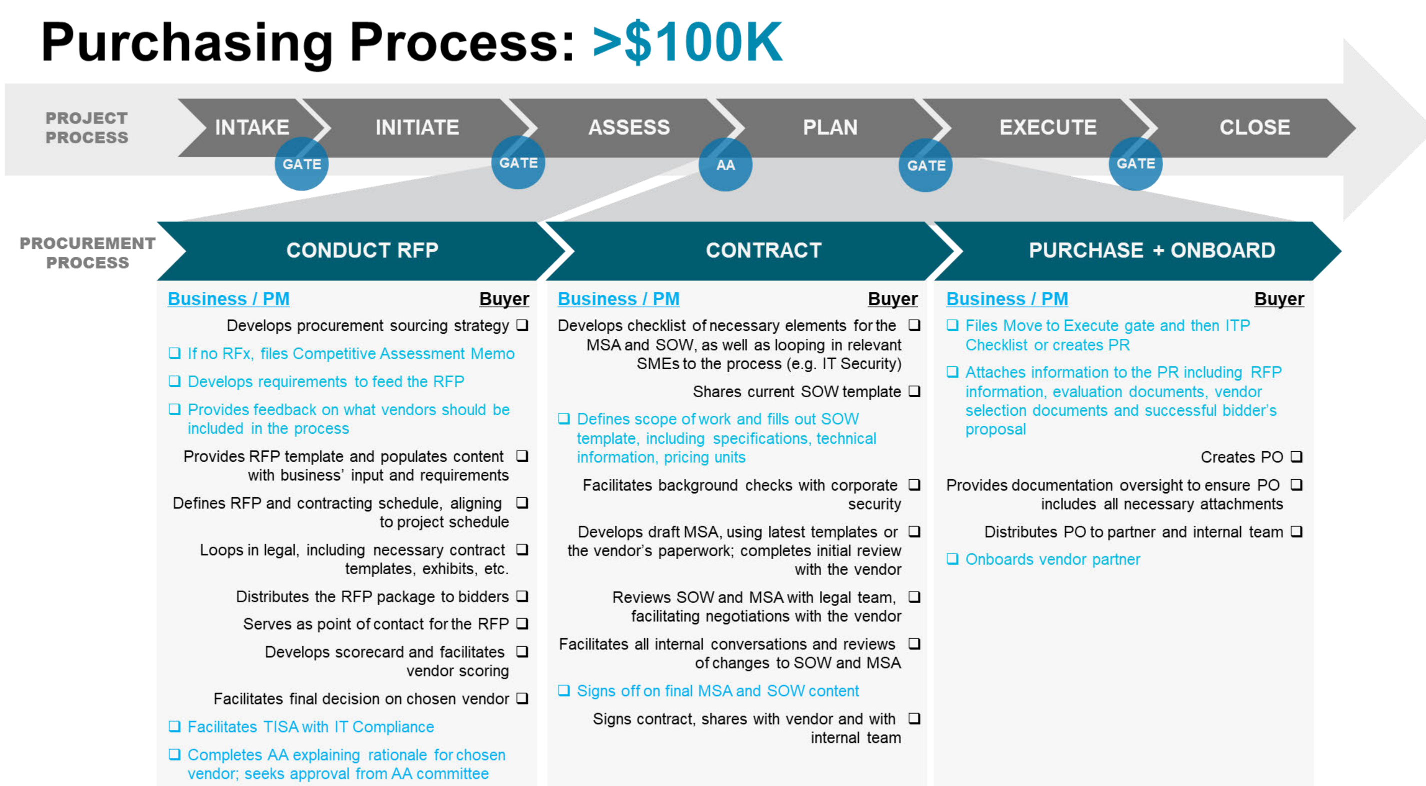
Purchasing Practices

PMs work closely with Purchasing throughout the life of a project. Engage Purchasing early, especially if the plan is to submit a Request for Information/Quote/Purchase, as this indicates a high likelihood for adding new Vendors to our systems and there is a need to build time in the project schedule for these activities to be completed.

Submitting RFx (RFI, RFP or RFQ)

Company Policy I82 Expenditure Authorization Section 6.2 requires that purchases over $100,000 are competitively bid and that exceptions may be made with proper documentation. If there is a reason to skip an RFx, you will need to submit a Competitive Assessment Memo (CAM) explaining the non-solicitation vendor selection decision.

To kick off the RFx process, PM loops in the Buyer and ensures that the Business Analyst, Business Sponsors and SMEs have gathered requirements and finalized scope to feed the functional and business requirements for the RFx exhibits. The Purchasing Agent is responsible for the RFx schedule, RFx package and facilitation of the RFx process internally and externally, including determining appropriate contracts and working directly with Legal (see Contract Risk Review and Routing Policy* for more information). They take the lead in coordinating the Q&A, scoring and bidding process.



New Vendor

When a new vendor is selected, their information must be entered into SAP and other systems before a purchase request can be initiated. The Purchasing Agent is responsible for reaching out to the vendor for appropriate documentation.

The PM might need to get additional discipline-specific information to add a new vendor to NWN's vendor pool. For IT, this may be a TISA Form and a Vendor Performance Verification. The PM is responsible to meet with Purchasing and IT (ideally together) to confirm required documentation/forms.

PR & PO Process

When project work is completed by a vendor or contractor, the Project Manager should follow NWN Purchase Request (PR) and Purchase Order (PO) protocols, outlined below. PR practices, templates and contacts can be found on the Hub.

REQUEST PR	RELEASE PR	SET UP PO	SHARE PO #	SUBMIT INVOICES	PAY INVOICE	TRACK PAYMENTS
Who: PM finds the right contact to initiate a Purchase Request (PR) (see appendix) **How**: Relevant info (vendor, individual, duration, amount of money, relevant Work Order Number or WBS, etc.) is entered into SAP through ME51N to request the PR More info	**Who**: The PR requestor manually emails the appropriate approval chain (see here) **How**: Depending on the requesting department and the amount, the PR approval is sent up the department-specific chain to release it in SAP	**Who**: Purchasing **How**: PR is converted into a Purchase Order (PO) number that ties to the PR **Note**: A SOW has to be created and approved in order for this step to happen	**Who**: Purchasing **How**: When sending the signed SOW back to the vendor, Purchasing includes the PO number with instructions to include it on future invoices	**Who**: Vendors **How**: Vendors send invoices to AP	**Who**: AP + PR Requestor **How**: AP sends the invoice to the person who created the PR to confirm it should be paid Requestor processes the invoice in SAP Requestor sends material doc number back to AP to complete payment **Note**: this is why it is important to have the right requestor, and to set expectations on who should review before payment	**Who**: PM **How**: PM should keep track of which invoices have come in (they should be copied on approvals via the requestor), and compare that to the actuals in reporting; They use this information to enter correct accruals To track individual charges, run the Project Purchase Orders by WBS Element Report More info

Initiating a Purchase Request

- IT&S: Reach out to an FTE IT PM until you become more familiar with the purchasing process. There are several IT requirements that need to be reviewed and accepted prior to submitting the PR. Once ready to submit the PR, reach out to ITprocurement@nwnatural.com with questions and fill out the IT Procurement (ITP) Checklist. When completing this form, a few tips:
  - The ITP Checklist is used to request the purchase of hardware, software and/or services that is IT&S-related for budget purposes. The PM is responsible for completing the ITP Checklist, which then enables the IT and Procurement teams to create the PR and PO.
  - This process needs to be filed any time for any change order, new vendor, increase of a PO amount, etc.
  - The PM will need to complete a unique ITP for each vendor – as each process will create a PO specific to that vendor
  - The ITP checklist can only be completed once funding is approved and funded via the appropriate stage gate request, and requires the SOW to be at least in final draft form (might not be signed yet). The checklist will ask you to include the draft SOW. If you file an ITP before receiving funding approval, your purchasing team cannot process it and it will be put on hold until funding is approved. You can always fill out a draft ITP so it's ready to go, and hold off on submitting it until you have funding.
  - Any purchase request that is >$100K will need an associated RFP or CAM (see the purchasing section). Depending on how much money you are requesting, your ITP will go up to different levels of individuals for approval (e.g., just up to Jim Downing, or all the way up to Frank or Dave).
  - The form itself will ask for information including the vendor details, what type of services are requested, supporting documentation (SOWs, quotes, etc.), confirmation that funding is already complete, target dates and contact names. There's also a section for IT Authorizations, which is a

reminder to the PM that new HW and SW is required to be reviewed by Cybersecurity and Enterprise Architecture before finalizing a purchase.

- Engineering: Work with purchasing to develop RFPs, bids and contractor selection. The PRs are created by PMs or project engineers (or in rare cases a dedicated resource). It is best practice to have a lead engineer set up the PR so that approval triggers automatically go through the appropriate management chain within engineering; the engineer should work closely with the PM to ensure they approve each PR and invoice before it is sent through the payment chain. For detailed instructions on the entire purchasing lifecycle please review this document.
- Facilities: Work with Ebb Zlatnik for details.

Extending a Contractor's SOW

- IT&S: If you need to extend a contractor's SOW, send an email summary to Purchasing detailing the reason for extending the contract, any rate changes, and the new SOW schedule. Include reference to the previous SOW and Purchase Order Number. Reach out to ITprocurement@nwnatural.com to see if an update to the ITP Checklist is needed.
- Engineering & Facilities: Engage your buyer to extend the contractor's SOW; Purchasing can provide the most current amendment form.

Tracking Invoices and Getting Access: As of now, there is not a consistent process for PMs to receive and view invoices. Work directly with the vendors to ask them to copy you on invoices, and provide early estimates to support your accrual estimates. In addition, ask for guidance from:

- Facilities projects: Ebb Zlatnik
- IT&S Projects: ITprocurement@nwnatural.com
- Engineering Projects: JoNell DeMars

Program Management Practices

Definitions: Program Management focuses on the broader strategy, continuous improvement, and benefit realization of a set of projects. Project Management focuses on the specific tasks, deadlines, and tactical execution necessary to achieve the overall program goals. When executed properly, these two practices are complementary.

Within a program, related projects are managed as a group, with a holistic lens to drive toward core objectives. NWN typically formalizes a program when:

- There is a long-term (multi-year) effort that involves significant effort from multiple departments
- The projects result in significant change to one or more departments
- There are multiple projects with a connected goal, such that benefits of managing the collection outweigh managing projects as individual units
- There are multiple projects that have several critical interdependencies

Programs may include larger projects *and* smaller initiatives that lead toward the same goal. PMO purview over those smaller initiatives will be determined on a case-by-case basis. Programs have a distinct start and end to ensure NWN is tracking toward meaningful objectives.

Formalizing a Program:

The Portfolio Management Committee (PMC) is charged with determining if projects align with the above criteria. This can happen:

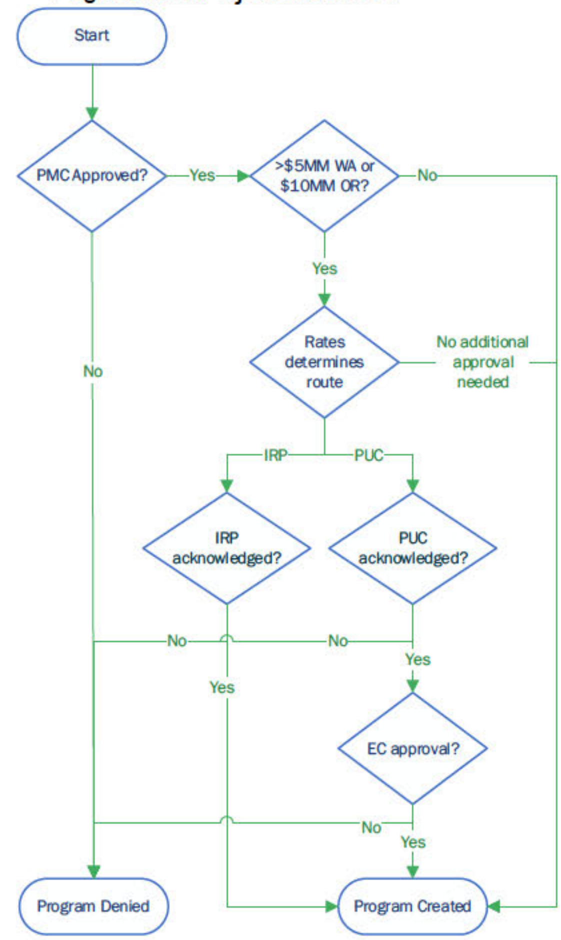
- Proactively: the need for a program is known up front and is approved by the PMC. The program will go through Assess and build the Alternatives Analysis that all subsequent projects will refer to.
- Iteratively: Sometimes, a project will evolve into a program, once the full scope of work is known. This will typically happen during the Assess phase, once requirements and/or design have been broadly finalized. In this case, once the AA has been completed and we have determined a program needs to be created, the existing project will be stopped, and a new program management project initiated for review by the PMC. All projects in the program will refer to the initial AA.
- Retroactively: Occasionally, we will determine that a collection of projects should be managed as a program. In this case, a program management project will be created for approval by the PMC. As this is an administrative action, the program management project will be expedited through PMC and will not require an AA.

To kick off the program (in any of the above scenarios), the Program Manager or Program Sponsor will file an intake form for a "Program Management Project" – the project that will house the program-level charter and documentation as well as the budget requests for any program-level resources. The approval of this project will indicate approval for the overarching program, and the Program Manager or PPM admin will create the Program "shell" in Planview which will tie all the projects together for reporting and management purposes, and connect the program to an officer goal and strategic pillar. Once approved:

- The PMO will assign a Program Manager who will be responsible for developing and overseeing the program
- A Program Change Manager, Program BA, Program Solution Architect, etc. may also be assigned to coordinate efforts across multiple initiatives
- Projects within that program that have been prioritized by the program leadership will be given priority at the PMC
- Projects under programs will still need to be approved through PMC, but will be expedited through the process.
- If new projects arise that tie to a program's objectives, the program leadership will determine if they want to "Accept" projects in based on timing, objectives, depth of overlap, etc.

Note: If the program is >$5MM in Washington or $10MM in Oregon (including Cost of Overhead (COH)), the program <u>may</u> need to be approved by executives and the Public Utility Commission (PUC). Once the intake is approved by the PMC, along with an Alternatives Analyses strategy and approval (either for each project or for the program overall), the Program Manager will work with the AA team and PMC to assess the need for PUC acknowledgement.

- If the program does not require PUC acknowledgement, the program will be approved to proceed with execution
- If the program does require PUC acknowledgement via the Integrated Resource Plan (IRP), it will be routed through the IRP process by the IRP team
- If the program does require PUC review or awareness outside of the IRP, it will be routed through PUC process via the Rates Department
- If PUC acknowledgement is obtained, a final approval by the Executives will be required to proceed with execution



Program Steering Committees: Program-level steering committees are recommended for every program to provide a governance structure, ensure major program initiatives align with business strategy, and develop a plan to complete the workin the most beneficial and efficient manner. The use of program level steering committees requires a program manager to be thoughtful about the role of the committee and the time requirements imposed on its members. Having one group oversee multiple projects with common or correlated goals also provides expedited issue resolution, aligns consensus for approvals and avoids conflicting decision-making between projects.

Program Status: Programs will report their regular status (weekly during execute and monthly during plan), which will be based on the status of the projects underneath the program. That means that the program status will always take the most critical status from its child projects (e.g. if one project is yellow and two are green, the program will be yellow). The summary for the program's status will be based on the holistic view of project process and progress toward program objectives.

Information Flow/Communication: The Program Manager provides status updates to the steering committee and any other necessary parties on a regular basis; this may be via email or in team meetings. Meetings with the executive and/or business sponsor should still be conducted frequently to address changes or issues and keep them abreast of the current standing of the program. The Program Manager can leverage the Program Walking Deck Templates and Planview Program/Strategy Reports to present concise and meaningful information.

Program Schedules: It is critical for a program manager to have a high-level view and understanding of how individual project schedules intertwine. This facilitates conflicting or coordinating milestones, tracking inter-dependencies and shared resources. To ensure this is possible:

- The program manager sets the standards for how schedules should be used and creates a template with consistent milestones within Planview
- Each project manager that is part of a program must use the Program template to track to the program-consistent milestones
- On a regular basis, the Program Manager pulls out project-specific milestones to visualize and analyze a program-wide schedule, leveraging Planview tools
- The high-level schedule is leveraged in program team and executive meetings to reveal any conflicts, dependencies or critical risks; the Program Manager should build a program portfolio to run reports and see connections between projects

Inter-Dependency Tracking: Each project within a program will have dependencies (things they require from external sources to deliver successfully for the project to succeed) and contributions (things the project needs to deliver successfully for other sources to succeed). To effectively manage programs, the Program Manager is responsible for understanding, communicating and escalating inter-related dependencies.

These dependencies / contributions can include any of the following, and all should be assessed:

- **Resource constraints**: critical single-threaded individuals or teams whose skillsets are needed to work on multiple projects in tandem or in sequence and at risk of not being able to meet all the demands of their time
- **Technical or Infrastructure enablement**: a specific product, application, infrastructure, data set, etc. that is required to be stable or complete for other work to succeed
- **Schedules**: A critical milestone that must be completed before a new workstream can begin, or both workstreams must start or finish at the same time
- **Business processes or policy**: A change to a business process, flow or policy that will be impacted by multiple workflows that need to be coordinated

Tracking Dependencies During Initiation:

- Working with relevant groups (e.g. Enterprise Architecture, Lead Engineer, Project PMs, Vendor PMs, etc.), the Program Manager creates a visualization of projects within the program and how they interact using the data from Planview schedules
- The project team creates a list of dependencies, contributions and linked risks, which are entered into Planview
- A final "Dependency Map" is produced to communicate the key dependencies and contributions that exist across the program.
    - This tool is intended to be high-level view of critical dependencies and contributions that can be leveraged for decision making and communication. It is not intended to be detailed tracking of day-to-day task dependencies, which should be accomplished in the project and program schedules.
    - This "map" is reviewed and approved by the core project team, including Project Sponsors
    - The "map" should be reviewed periodically with the Program Steering Committee to keep them in the loop and ensure they are aware of the impacts of any decisions contrary to the program's needs

Ongoing Dependency Tracking:

- Over the course of the program, individual Project Managers are responsible for communicating individual milestones, dependencies and schedules, and tying their Planview Work and Assignments to one another for tracking
- The Program Manager will use the Dependency Map and Planview reports to create a dependency list that tracks individual dependencies.
- Program-level inter-dependencies and risks are owned by the Program Manager, who reviews them in status meetings regularly and escalates as needed, leveraging the initial map and list as a discussion tool

Program Management Records in Planview: The Program Manager is responsible for managing the program shell (milestones, description, status reports, etc.) as well as the Program Management Project record, where risks, issues, changes, program charters, AAs, etc. will be filed on behalf of the program. The Program Management Project record will also go through tier 4 gating process to request budget for any program-level expenses (e.g. Program Manager time).

Appendix

Meeting Standards

Meetings with stakeholders are critical, but it is important that PMs are cautious with people's time. Set up a cadence of meetings that is reasonable for the speed, complexity and importance of your project. For all meetings we expect that the Program/Project Manager:

- **Publishes an agenda** at least 1 business day ahead of time that includes an overall purpose, clear meeting objectives and key decisions needed; these can be standard meeting agendas if they are consistent meeting to meeting. Standard meeting agendas are available on the Hub.
- **Only invites the critical stakeholders** for the agenda at hand; for these stakeholders, make it clear that attendance is mandatory and proxies can be sent in their absence
- **Provides Skype call in information** for all meetings that include employees not working on site
- Ensures the meeting **starts on time and ends 5 minutes early**
- Where needed, steps in to transition side-line conversations to follow-up action items
- For key decisions and risks, leverages the **issues and risk logs** in Planview
- Captures **clear action items** during meeting with owners and due dates as part of the meeting notes (ideally leaving time at end of meeting to review these with all participants to ensure accuracy and reinforce ownership)
- Discusses issues with appropriate personnel or departments prior to steering committee meetings
- Identifies someone to take **detailed notes** and sends them to all attendees after the meeting is over, within 1 business day (see meeting minute template on the Hub).

Defining the meeting's purpose:

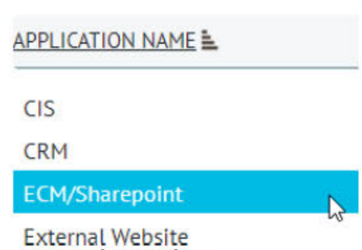
Meeting Type	Description	Example	Participant Involvement
Define	Identify a problem or a solution to a problem Describe the universe of possible options to be considered	Working session	Very High
Feedback	Review options and provide input	Initial strategic direction presentations to Executives	High
Decide	Determine a decision from among a number of options, which could include a recommendation	Program steering committee presentation of possible change management integration options	Medium
Approve	Approve a decision/recommendation made in another meeting.	CFO's signoff on a specific vendor assessment	Low
Inform	Provide information to participants	Project status meeting	Very Low

SharePoint Project Sites

All PMO projects need to have a SharePoint project site, which is where you'll house all of your project documents to share within your team and store key documents. Note that for engineering and construction projects it is also best practice to save key design documents on a separate drive to ensure they are stored for longer time periods to meet regulation requirements.

Requesting a site: To request a SharePoint project site be built, file a Request for Support through the Self-Service Portal (IT&SM Portal).

- In your request, include the following information: Project name, executive sponsor, project manager, project tier, department and SAP number if known
- In the application name section, select "ECM/Sharepoint"



All site owners need to complete the SharePoint training before their first site us up and running

Sections overview: The PM can adapt the project page to meet the needs of the project. By default, your project site will come with the following sections:

- **Contracts:** This document list is where you'll store any official contracts. It is best practice to not allow contractors to have access to this section, which is why it is separated from other document lists
- **Documents**: This list is typically used for all documents that the project team would need access to (e.g. design documents, RFPs, permits, etc.). Please refer to the ECM tutorials to learn how to leverage metadata to make documents easily searchable if your document library will contain many files
- **Project Management**: The PM section is typically used for documents primarily owned by the PM. Best practice is to save important project documentation here including stage gate documentation, change orders, budgets, schedules and status reports.

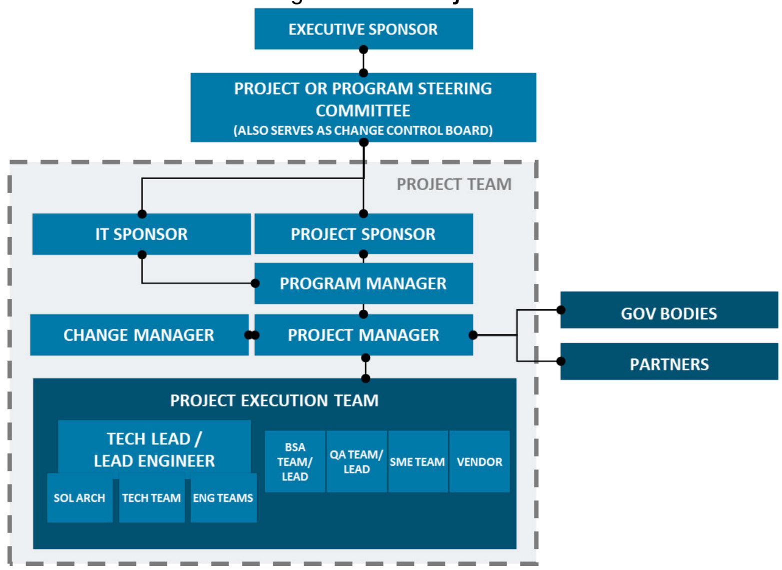
Access: Your core project team and select vendors/contractors should have access to your site. To learn how to grant permissions, review ECM tutorials.

Documentation Requirements: It is critical that PMs store core project documents to meet compliance requirements. Here is a guide to where documents should be stored to ensure they meet retention standards. Each document **should be stored in the correct location** by the start of the next phase. A final review of all documentation also needs to be completed before closing the project.

Document Type	Document Title	Storage Requirement
Stage Gate Documentation	• Exports of Change Baselines (Schedule and Budget) • Alternative Analysis	All final Stage Gate Documents not stored in Planview screens should be stored in your **project SharePoint site** in **Project Management** documents. This will ensure they are stored for the length of time required for compliance.
Project Management Documentation	*(as applicable)* • SOX compliance test scripts • SOX compliance evidence • SOX compliance sign off	Should be stored in your **project SharePoint site** in **Project Management** documents. This will ensure they are stored for the length of time required for compliance.
Financial Reports	• Monthly Project Budget to Actuals Summary • Monthly Project Forecast – Current Fiscal Year	Should be stored in your **project SharePoint site** in **Project Management** documents
Design Documents	*(as applicable)* • Project Survey • Design Files • Plant and Station CAD files	Given the size and storage reequipments, design documents need to be shared on the **project's R:\drive or Q:\drive**
Construction Sketches	*(as applicable)* • Company-drafted constructed sketches	Should be stored in your **project SharePoint site** in **Project Documents**
As-Builts, Work Order Cards and Pressure Test Documentation	*(as applicable)* • As Built Drawing • Work Order Card • Pressure Test Documentation Report	Should be stored in **Electronic Records Viewer (ERV)**
Contracts	*Varies by project*	Contract documents are stored through the Procurement process in SAP and in Purchasing's SharePoint repository (see Contract Routing Policy for reference). In addition, it is best practice for the PM to also save final contracts should be saved in your **project SharePoint site,** under **Contracts**. It is best practice to not allow contractors to have access to this section, which is why it is separated from other document lists.

More information: A full tutorial on SharePoint can be found on the Hub

Project Roles and Responsibilities



Clear governance structure and well-understood roles and responsibilities are a critical component to ensure project success. In conjunction with your RACI and RAPID Use these common definitions to align stakeholders to their role.

Project Manager: The PM is responsible for the successful execution and completion of a project, ensuring project deliverables are met within the agreed upon scope, schedule and budget.

- Recognizes when there are things that happening that could impact scope, schedule and/or budget and proactively address them; filters risks, dependencies, roadblocks and issues
- Ensures the proper allocation of project resources and stakeholder involvement
- Ensures team understands project goals (why the project is happening), scope, timelines, activities and deliverables (usually creates a walking deck that is kept up-to-date)
- Implements and adheres to project governance including creating roles and responsibilities so that team understands who is responsible for what; holds team accountable for their assigned work within timeframes and tracks open action items through closure to ensure completeness
- Provides regular status of project to stakeholders
- Keeps project schedule updated and proactively seeks updates to ensure team is on track; ensures milestones will be met or help team to prioritize their work to meet deadlines
- Manages vendor relationships and contractual deliverables as needed

Project/Program Sponsor: The Project Sponsor makes business decisions for the project or program. They are typically members of senior/director management – those with a stake in the project's outcome and the ultimate owner of the delivered asset.

- Work closely with the project manager, and are kept informed by the PM
- Make key decisions for the project/program; help resolve conflicts and remove obstacles that occur throughout the project and sign off on approvals needed to advance each phase
- Accountable for the project's overall success and ensuring the project delivers its objectives
- Act as the primary point of escalation
- Champions the program across NWN

Executive Sponsor: The Executive Sponsor has ultimate authority and accountability for a project or program. They are typically members of officer/executive management – those with a stake in the project's outcome.

- Accountable for ongoing validation of project priority
- Ensure the project delivers on promised ROI
- Additional point of escalation/approval for issues that cannot be resolved within the core project team
- Champion the project across NWN
- Represent NWN's overall strategy, ensuring the project contributes to NWN's operations and growth

Steering Committee (Project or Program): While the Executive Sponsor holds authority and responsibility for a project or program, a project or program Steering Committee makes decisions beyond a single sponsor's purview.

- Establishes the direction of a project/program and ensures the success of the program/project by providing guidance, necessary approvals and oversight
- Resolves inter-organizational conflicts and prioritization issues and makes critical decisions arising over the course of the program/project
- Provides resources to carry out the project, removes obstacles, reviews performance

- Acts as a link between the project/program and NWN's overall strategic objectives
- Creates an atmosphere of trust and transparency, where teams can openly discuss challenges and escalate potential issues; possesses a "How can I help?" attitude that is approachable / consultative; provide thought leadership for the team
- Balances the needs of their business area with the holistic solution that benefits the entire organization
- Provides visible support throughout the organization and supports change management activities (leads by example)

A project should have a steering committee only if:
- ❑ multiple departments will be substantially impacted by the project, or
- ❑ complex decisions need to be made with impacts on different groups, or
- ❑ the project is high risk and may require coordinated escalations through multiple partners, OR
- ❑ there are multiple connected projects (Program)

Note: If your project has IT components, an IT director should sit on the committee; if you have IT components and no steering committee, you'll want an IT&S Sponsor instead

Program Manager: Responsible for multiple inter-connected projects to support a specific strategic direction.
- Identifies Governance and Project Teams; drives the planning, governance and delivery of the program's output and product
- Identifies, resolves and/or escalates inter-project/program dependencies and risks; ensures project team escalate potential changes that could impact scope, schedule and/or budget
- Ensures good communication and provides cohesion across all projects in the program and supports project managers and teams; keeps all stakeholders informed on a regular basis through written communication
- Juggles priorities (including where shared resources focus and how budgets may need to be reallocated) between all projects to align with the organization's goals
- Directs project managers in order to achieve defined outcomes
- Escalates obstacles to executive (Program Steering Committee) with clear root causes, options (with costs / benefits) and recommendations
- Provides concise and accurate program updates to executives (Program Steering Committee)
- Serves as central point of contact for program questions / clarifications
- Manages stakeholder expectations
- Leads Program Steering Committee meetings
- Often creates longer-term roadmap used to visually depict how the inter-related projects in the program will add specific value to the organization as time progresses

Project Engineer: The Project Engineer acts as a key SME and facilitates the project scope and delivery. They coordinate all engineering activities from design to execution and provide critical input into all core project phases. They are responsible for core project documentation.

Technical Lead: For large, IT-related projects, the tech lead is responsible for leading and coordinating all technical tasks and workstreams. They make technical decision on a project and act as a source of knowledge in the project by gathering and filtering information. They engage all the necessary IT&S resources to successfully complete the project. They work with their teams to identify, organize, communicate, and escalate information necessary for the project's success to the Project Manager.

Business Analyst: On select projects, the Business Analyst uses a set of tasks and techniques to work as a liaison among stakeholder in order to understand the structure, policies, and operations of an organization and to recommend solutions that enable the organization to achieve its goals.

Change Manager: For projects with significant individual impacts, a Change Manager may be assigned. They are responsible for identifying the impact that the project will have on stakeholders, developing a change management plan and building programs that lead to adoption and minimize resistance. This may include tactics like stakeholder engagement, leadership enablement, training, communications, champion engagement, and resistance management.

Project Team Subject Matter Experts (SMEs): SMEs are key stakeholders that provide source information to the team and manage some day-to-day development of the project. They provide expert business understanding of the organization, represent the users and user areas when identifying current or future problems, reviews and confirms requirements for the project, and participates in User Acceptance Testing.

PMO Project Cost Accountant: During Stage Gate, the Project Cost Accountant will create the SAP project number and work breakdown structure (WBS) elements. During the project they will allocate funding as approved by stage and change order. They are also responsible for preparing forecast reports. They also determine what costs will be O&M vs Capital on a project.

Finance: During Stage Gate, Finance will receive the notification of the approved project funding request to allocate funding in SAP according to the budget workbook.

Purchasing: Purchasing is engaged throughout the project lifecycle, especially if the project requires robust and continuous purchasing and/or an RFx (RFP or RFI or RFQ) request. The Purchasing Agent is responsible for creating the purchasing plan and managing the RFx process. They will look to Project Managers to provide the scope of work. See the Purchasing section of this handbook for more information.

Legal: During a Request for Proposal (RFP), Purchasing will engage Legal in the RFP process for the review and negation of service agreements. NW Natural policy (17.1) also requires that contracts >$100K be reviewed financially and legally if any new or updated terms and conditions are introduced. Before engaging in legal and purchasing activities, it is advised to review this policy with both parties to ensure the correct documentation and required approvals are aligned.

Health and Safety: Mostly for Engineering, Facilities, and possible Infrastructure projects: Safety should be engaged as soon as a Project Request Memo has been approved. Safety provides subject matter expertise for the initial project scope, schedule, budget, and determination on whether specific Safety requirements are needed such as the role of a Safety Manager, review and approval of site-specific safety plans, site audits, incident reports, etc.

Environmental Management: Mostly for Engineering, Facilities, and possible Infrastructure projects: Environmental Management should be engaged as soon as a Project Request Memo has been approved. They provide subject matter expertise for the initial project scope, schedule, budget, as well as participation in pre-bid site walk meetings and consulting for governmental affairs engagement.

Risk and Land: Mostly for Engineering, Facilities, and possible Infrastructure projects: Risk and Land should be engaged as soon as a Project Request Memo has been approved. They can provide information on easements, insurance certification, Land and Property Owner-related information, and bonding.

Claims: Mostly for Engineering, Facilities, and possible Infrastructure projects. Safety may be involved in Claims Management. If an accident or injury occurs during the course of the project to a non-NW Natural employee, touch base with the Safety Manager and the Claims Department for assistance.

IT&S Enterprise Architect: For IT-related projects, provides guidance on strategy, standards, roadmaps, and solution architecture across applications, data, and infrastructure aspects of the project. Shepherds project through IT&S Architecture Review Board (ARB) and Technical Review Board (TRB) review and approval processes.

IT&S Solution Architect: For large IT-related projects, the solution architect takes the guidance from EA and creates the required documentation.

RMC: For engineering projects, RMC is responsible for staffing external resources to complete the work.

Understanding NWN's Key Players

As you navigate a project, knowing the right contacts is critical. A full organization chart can be found on SharePoint, but here is an initial lay of the land if you are looking for the right contact in a department you know you'll need to engage. **You will want to start by identifying the manager of the subject matter expert to get resources assigned.**

Accounts Payable will be a key resource for accruals, invoice tracking, etc. Please note that AP is especially busy the last few days and first few days of the month; please avoid reaching out for non-core requests during these time periods. Marie Guizzotti

Business Control Office is involved with any SOX compliance issues; this includes any applications that are SOX compliant (if you're not sure if the tool you're working on is SOX-applicable, double check with the team!) Amanda Faulk

Communications is a key partner if there are large-scale impacts to internal or external audiences. Bring them in early to determine a communications strategy. Michel Gregory

Engineering projects should start with Dan Kizer and Doug Ramsey to find the right contact.

Environmental Management is a key partner if there are any environmental permitting considerations for the project. They should be consulted as soon as there is an idea of a project in this realm (note: required for all facilities and engineering projects starting with the engineering checklist). Mike Hayward

Facilities projects should start by reaching out to the PMO Facility's Sr. Project Manager Philip (Ebb) Zlatnik

Corporate Security (physical security, not to be confused with cyber security) is required for all Facility projects and may also be engaged when there are security considerations for company assets or employees. Jeff Hansen

Utility Operations will often be tapped as a **Facilities Project SME**. Jim Hart

IT&S can play a variety of roles on a project if the initiative has IT components:

IT Compliance is engaged when a TISA form is required. Sohail Ali

IT Security Operations is engaged for a design review if the project meets at least one of the below criteria: Matt Carlson

- Use of Personally Identifiable Information (PII) or Confidential Information
- External facing applications or systems
- Interaction with existing applications or systems already reviewed
- Control systems for pipelines or gas storage facilities
- Information Security review required by a regulatory or oversight body
- Other significant risks identified during the initial security consultation

Service Delivery is involved if a project touches endpoint technology (laptops, mobile devices, etc.). They should be engaged early, potentially trained and engaged with developing a move to support plan. Ryan Montgomery

IT Infrastructure is a key stakeholder if the project involves hardware, servers, permissions, Azure, etc. To find the right resources for your project, first reach out to Paul Saunders

IT Enterprise Applications is a key stakeholder if the project involves software and/or integrations and database support. To find the right resource for your project reach out to Dina Thompson

IT Enterprise Architecture is a key stakeholder for every IT project. To find the right resource for your project, reach out to Mano Mandi

Network is a key stakeholder for any posts, firewalls, telephony, etc. Reach out to Adam Eaglestone to get started

If you are unable to find the right folks to work with, in IT, reach out to Deanna Ricci

Legal provides contract oversight and suggestions (note: required for all facilities projects) Stephen Kelly

Purchasing/Procurement will need to be involved for any Request for Proposal (RFP), Request for Quote (RFQ), Request for Information (RFI) and new vendors. You will likely have an individual Buyer assigned to your project. Purchasing also handles all Purchase Orders (POs). To find the right resource for your project, start with the Buyer Assignment List (*coming soon*!); you can also reach out to David Aimone for IT and Engineering projects or Mary Kay Plass for facility projects.

PMO Cost Accountant needs to be consulted at the start of a project to help determine capital vs O&M expenses; they will also be a resource throughout a project in creating your project structure, funding your budget requests and helping research accounting issues. Michael Perham

Rates & Regulatory should be consulted for any project that will meet or exceed the $1MM to discuss the approach to meeting Alternative Analysis requirements. Zach Kravitz

Risk & Land Steve Walti

Land: facilitates any rental, lease or easements and rights-of-ways on private and public properties. Facilitates the acquisition of Business and ROW licenses.

Risk: should always be consulted to help determine the insurance requirements and levels for procured contractors, Certificates of Insurance, Surety Bonds and Builder Risk Policies.

Safety is a key partner if the project requires "covered tasks" (note: required for all facilities projects). Charlie Emerson

Technical Training should be looped in early to ensure there is capacity to train Utility Services or Utility Operations. Requests for time to be in front of this audience will be channeled through the Training Steering Committee. Final training materials need to be delivered least 10 weeks prior to training, once your project is slotted for a training time. Gabe Cabatic

Glossary of Terms

Accruals ⟹ An estimated and documented dollar amount entered into SAP monthly for work that is is performed but has not yet been invoiced.

Alternative Analysis (AA) ⟹ A document created when a project is initiated that outlines why we need to solve a problem, the possible solutions and why we've selected the solution we chose.

Applicant Code ⟹ Number used to indicate the account that payment is coming from, tied to a specific department and budget bucket (e.g. engineering integrity).

Approval ⟹ The right person or group examining a proposed decision and providing formal sign off on that decision. This could include greenlighting a project to start, approving a request for additional funds, confirming that a project is complete or accepting a shift in scope.

Approved Budget ⟹ Total money initially approved for the project, including contingency.

Architecture Review Board (ARB) ⟹ ARB is a meeting where Enterprise Architecture and the CIO review proposals against NWN's current architectural landscape to assess viability. As a governance and assurance body, they are responsible for any architectural deliverables, impacts and alignment decisions. ARB must be involved when a project is proposed (pre-approval), as a solution is selected and any time the scope of a project changes that impacts IT&S components. Enterprise Architecture is responsible for driving through ARB and TRB processes and requirements and fees information back to the PM. The PM is not responsible for facilitating or executing, but ensures that these checkpoints are included in the project plan.

Authorized Spend ⟹ Total money approved by the company, including contingency and any additions or subtractions via change orders.

Business Analyst (BA) ⟹ The role responsible for identifying needs, eliciting and documenting requirements and designs for improved processes or solutions.

Capital Expenditure (CAPEX) ⟹ The money NWN spends to purchase, build or replace a capital asset. A capital asset is a new solution, construction or total replacement of existing construction This includes deliverables like pipe/meters/roofs/walls, software, implementation costs, project management, year one of maintenance, enhancements if they provide significant new functionality. Additional guidance can be found in the accounting section, or in the capital asset policy on the Hub.

Change Management (CM) ⟹ Change management is a structured process and set of tools for managing the people side of a tactical change such that business results are achieved, on time and on budget.

Change Manager ⟹ Individual responsible for creating and implementing change management strategies and plans that maximize employee adoption and usage and minimize resistance.

Change Order ⟹ A request to accept mid-stream changes to a project's budget, scope or schedule.

Cone of Uncertainty ⟹ The reality that when a project is started, estimates are variable and become more certain the project unfolds. During initiation, cost estimates are likely +/- 100%; by the time we head into execution they are likely closer to +/- 25%.

Contingency ⟹ WBS cost line item representing the money allocated to a project to be used (with approval) for unplanned expenses.

Construction Overhead (COH) ⟹ COH represents indirect capital costs that are applied to capital projects for back office support.

Discipline ⟹ A primary customer group of the PMO; currently defined as IT&S, Engineering and Facilities. Note that other departments also leverage the PMO.

Discretionary/Non-Discretionary ⟹ A definition of when NWN *has* or can choose to do a project. If a project is non-discretionary, NWN has to do the project for compliance or external reasons. If a project is discretionary, it is strategic choice by NWN to complete the project.

Earmark (EM) ⟹ The cost estimate for the entire project.

Executive Sponsor ⟹ The top project advocate and champion, and escalation point for the project, who holds final accountability for the project's success.

Financial Planning Detail ⟹ The Planview tool that project managers use to calculate the total cost of a project including labor, hardware, software, vendors, materials, etc.

Forecast ⟹ Monthly breakdown of expected future spend on the project based on your current understanding of the scope and schedule. This is updated monthly or more in Planview based on any new information that impacts your prior assumptions.

In-Service Date ⟹ The date the change will be live and ready for use ("used and useful"); this is often the first day of the close phase.

IT&S Alignment Team ⟹ A team of officers comprised of Jim Downing, Kim Heiting, Brody Wilson, Frank Burkhartsmeyer, Dave Webber and MardiLyn Saathoff that meets bi-weekly to discuss upcoming IT&S initiatives. This team has first right of approval/decline.

Milestone ⟹ Key event in a project; this likely includes the start or end of phases, approval points and delivery of significant components, services or materials.

Operations & Maintenance Spend (O&M or OPEX) ⟹ Generally, the cost to run and maintain existing assets. There are also often costs incurred while running a capital project that are considered O&M This includes software selection, data conversion, training, year 2+ of maintenance. We do get recovery, just not a return, on all O&M dollars that are responsibly spent. Additional guidance can be found in the accounting section, or in the capital asset policy on the Hub. When in doubt of whether the cost is or isn't O&M, contact the Project Accountant.

Planview ⟹ NW Natural's PPM tool, the home for the full project lifecycle.

Portfolio ⟹ A broad view of all projects across the company or within a discipline for the sake of monitoring and/or prioritization.

Portfolio Management Committee (PMC) ⟹ A group of key strategic business individuals who review proposed ideas, weigh them against company priorities and resources and select priority projects to start.

Program ⟹ Related projects that are managed as a group, with a holistic and strategic lens to allow a company to drive toward core objectives across teams

Project ⟹ A temporary endeavor undertaken to create a unique product, service or result; in our case, projects of a specific size are managed through the PMO depending on their cost and impact on customers or the business

Project Charter ⟹ A required document created during initiation (initial) and plan (final) that defines the scope, resources, cost, schedule and deliverables for the project.

Project Manager (PM) ⟹ An assigned resource who partners with the business and leads the project team to ensure the success of a project.

Project Schedule / Work and Assignments ⟹ The project's tasks, schedules, resources and dependencies.

Project Prioritization Committee (PPC) ⟹ The former group charged with prioritizing projects; replaced with the Portfolio Management Committee (PMC)

Project Sponsor / Business Sponsor ⟹ The primary customer for the project who has a vested interest in the successful delivery of the product and is accountable for its success.

Project Stakeholder ⟹ An individual who is impacted by the outcome of the project.

Project Resource / Project Team Member ⟹ An individual who is needed to play an active role in planning or executing the project.

Risk Register ⟹ A living repository in the project site of potential risks to the project. Each risk will have a ranking of how likely it is to happen, and options for reacting to that risk.

Schedule ⟹ The duration of a project and its defined major milestones.

Scope ⟹ The agreed upon functionality and deliverables of a proposed project, based on the business requirements. The scope is used to define a successful delivery of a project.

SOX Compliance ⟹ The Sarbanes-Oxley Act requires that all publicly held companies must establish internal controls and procedures for financial reporting to reduce the possibility of corporate fraud; For projects impacting CIS, SAP ECC, SAP GRC, Allegro and the I-Series, documentation is critical including Project Charter, project design documents (planned changes to data interfaces, user GUI, security changes), testing scripts and evidence and any data conversion.

Subject Matter Expert (SME) ⟹ An individual who is tasked with providing the business requirements for the project.

Stage Gate ⟹ Critical points in a project where we pause to review and approve. This is managed through a Planview where PMs submit a request with documentation and it is filtered to a defined set of approvers for sign off before moving forward. This process and documentation is especially important for rate case and auditing.

Status Report ⟹ A summary of the project that the PM completes on a regular (weekly or monthly depending on the phase) basis that speaks to the current health of the project.

System Integrators (SIs) ⟹ The contracted partners who provide professional services to support the implementation of a product. They often support the design, configuration, implementation and testing as a new software is launched.

Tier ⟹ A project categorization from 1 (low) to 4 (high) based on the project's cost.

Technical Review Board (TRB) ⟹ TRB is a meeting of IT leaders to inform them of upcoming projects with IT impacts, allowing them to weigh in on resourcing, tactical execution/timing and provide any feedback. Enterprise Architecture is responsible for driving through ARB and TRB processes and requirements and fees information back to the PM. The PM is not responsible for facilitating or executing, but ensures that these checkpoints are included in the project plan.

Technically Complete (TECO) ⟹ Once an asset is deemed "used and useful" (see below) a project is Technically Complete for accounting purposes. After a project is TECOed, the budget cannot be increased but trailing invoices can still be paid with remaining funds.

Used & Useful ⟹ A term used to describe if the expected asset is functioning. To determine if the deliverable is used and useful we ask: Is the asset being used for what it was constructed? For example: Is there gas flowing through the pipe? Is the software or server being used? Do you have a certificate of occupancy?

Work Breakdown Structure (WBS) ⟹ The structure of a project in SAP. For instance, a project may have a "Planning" and "Execution" WBS with nested work items such as "internal labor", "external labor", "materials" etc. More complex projects will have O&M elements (tied to work orders) or separate phases to accommodate staggered rollouts. As costs are estimated and incurred, they are tracked against these line items.

Need more? A detailed glossary of terms can be found on the Hub.

PMO SharePoint Resources

PMO Department Site

Description of Stage Gate Process

Planview PPM

Planview User Guides

Where do I run Budget and Forecast Reports?

ITP Checklist (use the ITP checklist to initiate a purchase request for any IT purchasing needs (hardware, software, professional services, licensing, etc))

Where do I find NW Natural-branded PowerPoint Template?

How do I submit requests for IT support?

NWN PMO Contractor Need to Knows

As a contractor in the PMO, while you are not an employee of NW Natural, you are a critical participant of the project team and the PMO. Please be sure to review NWN's code of ethics that sets expectations for conduct and highlights key compliance standards and policies.

Office Etiquette: Please always be aware of your behavior and how it impacts those around you. Always use common sense, be respectful and put your best foot forward to represent the PMO. Read the Office Etiquette Guide to understand NWN's suggestions for addressing distractions and open-use spaces.

Billing time: Keep track of your hours and where you are spending them. On a regular basis you'll be asked to track time toward projects and/or provide your allocation for each month (time tracking in Planview coming soon!).

Out of Office Practices: If you will be out of the office, let your project sponsors and stakeholders know in advance; depending on the phase of the project, designate a back-up and provide a detailed overview of the project status to that individual. You can also set a delegate in Planview so any lifecycle steps come to them (guide here!). Please be sure to update your out-of-office time on the PMO calendar here. Enter your time as "Name PTO", which will ensure it is correctly coded.

Overtime: Our projects are typically scoped and resources are budgeted based on a 40hr week. That being said, there are times when it is necessary to work overtime. In those cases, your overtime must be approved in advance by your project manager, PMO Director or Specialist. Without prior approval, you run the risk of the overtime hours being denied. This guideline has been shared with our vendors as well.

Flextime and Working from Home: We support flexible working arrangements when projects allow. In order to make this effective, please follow these guidelines:

- Your flexible working arrangement should be consistent (e.g. working from home every Friday). You are expected to be available via email, IM, and mobile while working remotely.
- Your arrangement must be approved by your project manager (or the Director of the PMO, if you are the PM)
- The PMO calendar should be updated to reflect the arrangement and make it easy for people to know where you are. You can access the PMO calendar here. Enter your status as "Name WFH", which will ensure it is correctly coded.
- Project needs trump the flexible working arrangement (e.g. if you are needed onsite, you are expected to be onsite)

Contact List: Please make sure your information is up to date on the department contact list. You can find the list here.

Resource Allocation List: Please make sure your project allocations are up to date in Planview to ensure we can assess our capacity and plan future work.

Building Access: Your badge likely grants you access to the building between 6am and 6pm Monday to Friday.

Meeting Rooms and Meeting Room Etiquette: There are about 80 spaces at 250 Taylor that you can reserve via the Outlook and Evoko reservation systems. A few conference rooms are available only for specific teams or purposes, such as Human Resources and the Board Room. These restricted conference rooms can be reserved only by designated administrators. There are also eight quiet rooms and seven mother's rooms throughout the building, and all of them can be reserved via the Outlook and Evoko reservation systems.

Connecting via Virtual Desktop or VPN

VPN: If you are given a NW Natural computer, you may access the network via VPN using a token. To get set up with VPN, request access through the self service portal (details here); once set up, you will use an app on your phone called RSA to authenticate each session

Remote/Virtual Desktop (VDI): If a contractor does not have a NW Natural computer, they will use Virtual Desktop to access the network on their own computer.

- **To request access for NW Natural Contractors:** Currently the virtual workspace makes the following applications available to External NWN Contractors: Microsoft Office, Skype, SharePoint, web access and RDS connection(s). If the applications currently available do meet your project's needs, please complete the following prerequisites:
    - A NW Natural Active Directory Account
    - An RSA token, for connecting from an external network

  Once you have fulfilled the prerequisites above click here for directions on requesting access to virtual workspace.
- **If you need more access or applications:** The Remote Desktop connection can provide access to other servers or environments that have project or role- specific applications installed. To request additional applications for your contractor please follow this process:
    - Step 1: Log into the ITSM Tool
    - Step 2: Please enter additional application(s) requests.

  Note: Some contractors/projects have numerous or specific application requirements. In such cases, the virtual workspace may not be the right solution, as it does not provide access to all applications available in the NW Natural Software Center. If that is the case, log a service request. Please provide as much detail as possible about what you were trying to accomplish with a virtual workspace solution.

Polices:

- Company Policies
- Standards of Conduct Policy
- Project Management General Procedure
- Code of Ethics

Holidays

NWN recognizes the following holidays: New Year's Day, MLK Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Day after Thanksgiving, Christmas Day

Version Control

Version Number	Author	Date	Summary
1.0	Victoria Barrett	3/13/2020	First version released
1.1	Maura Koehler-Hanlon	4/15/2020	Technical Training and PHMSA additions
1.2	Maura Koehler-Hanlon	5/6/2020	New stage gate email content, clarity on AA timing
1.3	Maura Koehler-Hanlon	5/7/2020	CAB clarification
2	Maura Koehler-Hanlon	5/29/2020	New Intake, Prioritization, Design and PMC process; moved items within phases around to account for the new timing on creating a solution
2.1	Maura Koehler-Hanlon	6/10/2020	Additional detail to Change Orders and CAPEX/OPEX
2.2	Maura Koehler-Hanlon	6/22/2020	Clarification to cancelled projects O&M + contingency WBS structure + project site request process
2.2	Maura Koehler-Hanlon	7/22/2020	Link to purchasing site, SOX team clarity
2.3	Maura Koehler-Hanlon	9/9/2020	Rewrite of budgeting, accounting sections; program additions including updates to R&R, more thorough risk management guidelines, VDI additions
3.0	Maura Koehler-Hanlon	1/13/21	Updates to the PMC process order (triage before prioritization)
3.1	Maura Koehler-Hanlon	3/2/21	Clarification on scope change orders, documentation requirements table, engineering triage additions, purchasing process additions
4.0	Maura Koehler-Hanlon	4/9/21	Full overhaul on: Planview implementation, addition of formal assess phase, changes to budgeting practices, resource management, ITP guidance
4.1	Maura Koehler-Hanlon	6/22/21	Program Management additions for the Planview Phase 2 release
4.2	Maura Koehler-Hanlon	9/1/21	Horizontal approval details, addition of links to "at a glance" summary, lessons learned best practices, operational support plan details
4.3	Maura Koehler-Hanlon	11/24/21	Accrual timeline visual, PowerBI report links, Transition to Operations Link
4.4	Maura Koehler-Hanlon	1/11/22	TISA clarification
4.5	Maura Koehler-Hanlon	2/16/22	Additional guidance for auditing invoices

NW Natural®
General Procedure

Corporate Purchasing and Expenditure Procedure
G-24

[redacted]

Effective date June 30, 2012

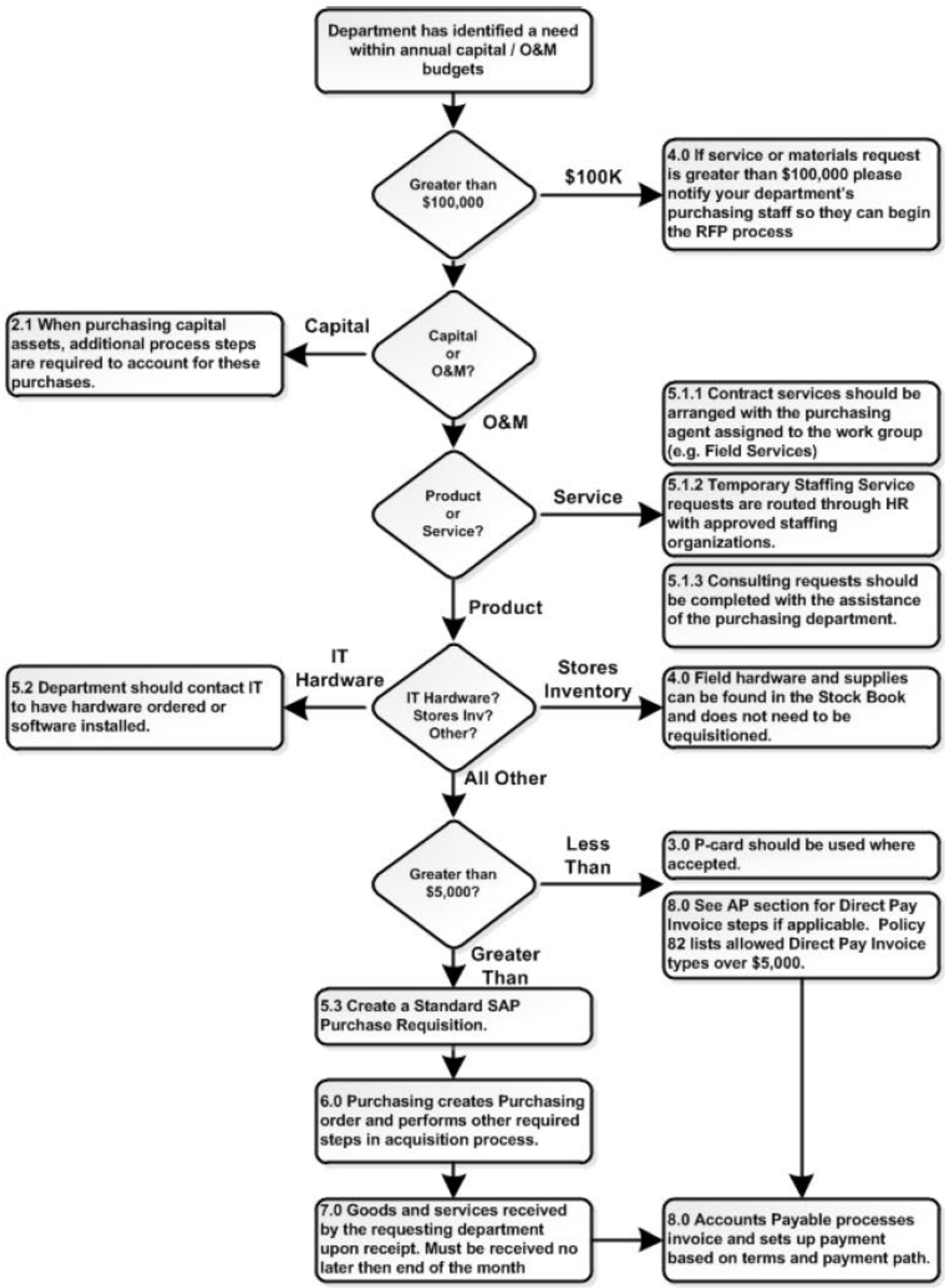
1.0 Purpose:

This procedure illustrates the established business processes that apply when requesting purchases on the Company's behalf. This procedure complements Company Policy I-82. The goal of this procedure is to set forth how departments and cost centers acquire goods and services in the most efficient manner possible while complying with Company policy. By establishing a common understanding of the process steps in the NW Natural Supply Chain, departments can work together more collaboratively and effectively.

The process map in Figure 1 summarizes the different types of purchases made at NW Natural. Each type may have slightly different steps required to acquire the necessary goods or services. The numbers (e.g. 5.x) in the process boxes refer to the paragraph sections below that discuss the different types of purchases. After reviewing the high level process documented in Figure 1 below, you can simply use it to locate the section related to your specific purchase.

2.0 Purchasing Process Overview:

Figure 1. Acquisition Process Flowchart



2.1 Capital Asset Process

Items that will be acquired as part of the capital asset process must use SAP Project Systems (SAP PS). If you are unclear about the definition of a capital asset, please review the NWN Capital Asset Policy (**Policy 83**). SAP PS tracks capital assets from the time of creation to completion. Upon completion, the asset will be entered into the SAP Asset Management (AM) Module. Capital asset process steps are covered in this procedure. These steps are not currently required for operations and maintenance expenditures (O&M). Prior to obtaining authorization to set up a new capital project, the Budget and Finance Department must allocate capital budget dollars to the project or allocate capital dollars to the general project type under consideration. See Table 3 for more detailed process steps.

3.0 Small-dollar transactions: Purchase Card (P-Card) and Expense Reports

3.1 Purchase Card Program

NW Natural's policy is to use P-cards as our preferred payment option for routine, small-dollar items (less than $5,000) unless otherwise stated below. Use of a P-Card enables prompt payment to suppliers and eliminates the cost of creating purchase requisitions and purchase orders for small dollar items.

Table 1. Purchase Card use exceptions

Specific exceptions include:

Capital Assets must be acquired using Project Systems and the general purchase order process.	See Section 2.1
IT hardware and software is acquired by the IT department as a policy of the Company.	See Section 5.2
Services or maintenance work performed on NW Natural's job sites or Company property is acquired using the general purchase order process.	See Section 5.1.1
Pipeline materials or "stores inventory" items such as pipes, valves, meters, etc. are acquired by Stores Staff. (Contact the Stores Department for requisitioning inventory type items).	See Section 4.0 (3)

The Company P-card policy can be found at Policy Index Number 81 – Purchase Cards.

If you have an open purchase order, DO NOT use your P-card to pay for the related item in question. If you receive an invoice from the vendor or Accounts Payable, the proper way to authorize payment is to receive against the purchase order in SAP for the item. (see Section 7.0, "Timely Receiving Process," below) Using a P-card for an item already on a purchase order leads to duplicate vendor payments.

3.2 Employee Expense Reports

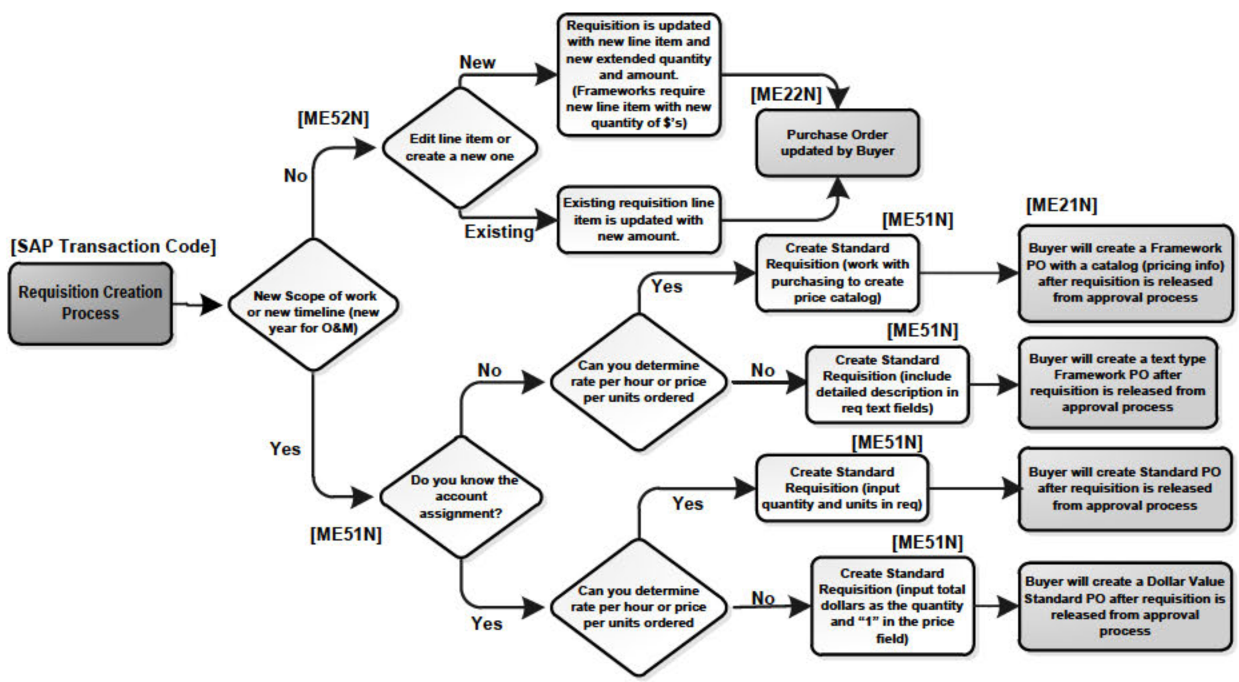
Employees should use P-Cards for business expenses whenever possible. However, when a P-Card is not available or cannot be used for qualified business expenses, then employees may be reimbursed by filling out an Employee Expense Report for items paid with a personal credit card, personal check or cash.

3.2.1 Expense Receipt Procedure (Accountable Plan IRS Requirements):

Whenever possible, employees should use a credit card to pay for business expenditures when the employee does not have a Company issued P-Card. A proof of payment receipt **must** be obtained and submitted with expense reports to support all expenses **of $75 or more and for all lodging expenses incurred**. Employees should obtain and submit all receipts for proper documentation including expenditures under $75 whenever possible. Receipts should be taped to an 8½ x 11 piece of paper to enable them to be scanned by Accounts Payable. Credit card statements are acceptable as proof of payment. For employees that have recurring expenses such as mileage, the employee should keep a business mileage log to substantiate their business miles. A copy of this mileage log should be provided with the receipts and the original copy of the log should be retained by the employee. Requests for expense reimbursement may be disallowed if they are older than 60 days. (see IRS Pub 15.) The NW Natural Policy on Business Travel can be found on the HUB. See Accounting Forms Site on the HUB for Expense Forms.

4.0 Purchase Requisition Overview

Figure 2. Requisition Process Overview



The standard way for departments to request goods and services is through the creation of a purchase requisition in SAP as shown in Figure 2. The requisitioner should understand if a new requisition should be completed for a new purchase request or if a previous purchase request should be edited based on the flowchart in Figure 2. In general, if the requestor is responding to a scope of work change on an existing project or purchase, the existing purchase requisition should be updated. If the requisitioner is buying a new product or starting a new project, a new requisition should be set up. Questions regarding this distinction should be discussed with the Purchasing staff member assigned to their department. Call the Purchasing Department for an updated list of assigned Purchasing staff by function.

Purchase requisitions should be completed and approved in SAP according to the following general process. The requester should contact the Purchasing Department for training materials and/or direct assistance, if needed. To release requisitions (e.g. approve them), the releaser must have the proper authority in SAP. SAP authority is granted by roles according to the levels and release groups in Policy 82. To request and approve access, employees must use the SAP Access Enforcer Portal.

The following steps outline the general requisition process:

1. Identify the business need for goods or services; confirm the cost is in the current year budget or obtain the appropriate approval for unbudgeted expenditures.
2. If the cost of the goods or services could reasonably be expected to exceed $100,000, consult with the Purchasing Department to evaluate the need to competitively bid the purchase before proceeding further. The Purchasing Department will work closely with the requester to facilitate this process. If NW Natural has a sole source relationship with a vendor, the Purchasing Department will require the business unit to complete the Sole Source Agreement Form and have it signed by the department manager.
3. Create a purchase requisition in SAP (Transaction ME51N). As seen in Table 2 below, it is the preference of the Purchasing Department to create standard purchase orders from requisitions. To create this type of purchase order, the requisition must contain the account assignment (e.g. the GL account, cost center and internal order number or WBS) entered into it and the units being purchased along with the corresponding price per unit. This is the preferred type of requisition as it provides the best price and spending controls to the business unit making the purchase. It is not possible for every requisition to be created with the account assignment. In these instances, the requisition is set up with a dollar limit. Pricing for these requisitions should be entered into a service catalog so the receiver has something to validate the pricing against when the item or service is received. On this type of purchase order, the account coding is entered at the time of receipt. In rare cases, the pricing catalog may be too large to enter into SAP and a manual catalog is used outside SAP to validate pricing. This needs to be coordinated with the department completing the receiving transaction. Stock inventory items should be requested from the Stores Department, rather than creating a purchase requisition. The Stores Department creates all purchase requisitions for stores inventory replenishment.
4. The next step in creating a requisition is getting the requisition released (i.e. the authorized approval step) in SAP. Based on the requisition release strategy, the appropriate approver "releases" the purchase requisition in SAP (Transaction ME54N). A detailed list of individuals and their authorized roles is updated regularly on the Hub (Employee Services/Policies and Procedures/Company Policies/82/Appendix A). Note: Currently, the creator needs to manually notify the approver(s) to authorize the purchase requisition in SAP (e.g. by sending them an email). However, all release groups over level 5 (e.g. $500,000) will automatically receive an email for any requisitions that require release. Except in cases of emergency, the approval should occur before goods or services are arranged with a vendor.

Table 2 Types of requisitions/purchase orders by preference

	In order of preference	Standard PO	Framework w/ Pricing	Standard Dollar PO	Free Text Framework
1	Account coding known at time of purchase and unit prices known	Best pricing and spend controls			
2	Account coding unknown at time of purchase but unit pricing is known		Good pricing and spend controls		
3	Account coding known at time of purchase but no unit pricing			Manual pricing controls with spending limit	
4	Account coding unknown at time of purchase and unit pricing is unknown				Manual pricing controls with spending limit

In SAP, released purchase requisitions are reviewed by the Purchasing Department, who then creates and executes a purchase order and follows purchasing best practices. This step formally commits Company funds to the external vendor.

Please remember to obtain proper management approval **before** starting the requisition process. This may require additional steps for certain types of purchases, such as special approval from IT Budget Oversight Committee Charter, special approval for SAP Plant Maintenance Work Order, or special approval from a cost center manager when the cost center is responsible for making the purchase (e.g. the Legal Department). Remember to allow more time for purchases over $100,000 as the Purchasing Department will require an RFP process before a purchase order can be created in most cases.

Receiving advanced authorization for purchases is Company policy.

5.0 Purchase Requisition Creation

5.1 Staffing Requests

5.1.1 Contract Services

A contract service includes retaining a company to provide specific services for the organization. Many times these are recurring in nature. Examples include pipeline locating services or construction services provided in the field. It is important to understand how the vendor will be evaluated with regard to the completion of the service and how this will be communicated to the department personnel required to receive against the resulting purchase order in SAP.

As an example, on a construction project, purchasing might set up the purchase order on a percentage of completion contract. As a result, the department responsible for receiving would receive the amount each month that corresponds to the percentage complete on the project (e.g. $100,000 contract, 10% complete, department would receive $10,000). The department should not wait until the vendor invoices the Company for the $10,000. The invoice should go to Accounts Payable and be paid without being sent to the receiving department first. For this reason, it is important for the department to have a clear understanding with the vendor on how and when they will invoice NW Natural. The vendor needs to have the purchase order number and NW Natural contact information on the face of the purchase order. If the vendor properly includes the $10,000 amount on the appropriate purchase order line item, the invoice will be processed and paid by NW Natural Accounts Payable. In this process, more organization is required during the purchase order set up but this upfront effort makes the process of transacting with the vendor much more transparent and streamlined when work starts.

Note: At the discretion of the legal department, contractors may need to certify as to their independence from NW Natural. Independence issues should be discussed with the department's purchasing contact at the time of vendor selection. Insurance coverage and other considerations are important factors when selecting contract service vendors. These are some of the reasons it is required to work with Purchasing when selecting and using contract services.

Table 3 below describes the process and necessary data elements to create a purchase requisition in SAP. Steps one and two are required for capital expenditures and three through six are required for all requisitions.

Table 3 Requisition Creation Steps

Process Step	Department Responsible	Process Step	SAP Trans. Code / Comments
1 **CapEx**	Project Manager	Establishes project (or uses exiting one) in SAP Project Systems to account for all capital costs of the project. (Work Breakdown Structure "WBS" number(s) is created as part of this step)	CJ20N (Project Builder)
2 **CapEx**	Requesting Department & Accounting/ Budget and Finance	Requests Asset Accounting Analyst to provide project attributes (Applicant Number, AFUDC Rate, COH Rate, etc.). Once complete, Budgeting Staff will establish a budget for the project and will mark the project as "released" so charges can be posted to the project.	CJ20N (see system status)
3 **All**	Requesting Department & Purchasing Department	The Requesting Department should assess early on if the total purchase is likely to be more than $100,000 and if so, they should call their Purchasing contact as soon as possible to start the RFP process. This process can take a few weeks to complete depending on the complexity of the purchasing transaction. Contacting Purchasing early on will help streamline the purchasing process.	

4 **All**	Requesting Department	1. Creates purchase requisitions in SAP: Required information to complete requisition: a. Requisitioner needs to provide: the requested vendor, business purpose, notes for purchasing and approvers, a list of any attached files and a description of item/service to be provided in the header notes of the requisition in SAP b. Quantity (how many in defined units) c. Unit (Unit of measure) d. Valuation Price (price per unit) e. Delivery date (required delivery date) f. Requisitioner (person that requested the purchase requisition) g. Des. Vendor (desired vendor) h. G/L Number i. Cost Center (only used for authorization/reporting on capital assets) j. WBS – Work Breakdown Structure number from Project Systems (from step 1) k. Short description of items or services being purchased (per line on requisition) l. Estimated freight costs, if applicable (add dollar value line item estimate for highest authorized amount)	ME51N Try to make the required delivery dates as close as possible to the actual goods and services delivery data as this will assist in timely delivery and cash management efforts downstream. This applies to both the requisition and purchase order. Attach any related documentation (quotes, drawings, vendor correspondence)
5 **All**	Requisitioner	a. Requests individual(s) with the proper purchase level authority to release the requisition (see Policy 82). System uses Cost Center from step 3.i to authorize purchase requisition *Note: User needs to notify next releaser on the requisition manually using email. Requests for release levels over Level 5 will automatically be emailed to releaser via SAP.*	
6 **All**	Purchasing Department	Works with purchase requisition creator to: a. Select a vendor b. Establish contract if needed c. Create and send purchase order to vendor with applicable terms and documentation	ME21N

7 **All**	Requesting Department	Assigns personnel to receive against purchase order: (Unit/dollars entered into SAP MIGO Screen) Asks purchasing to close purchase order when all items/services are complete. This step is completed automatically if all the lines on the purchase order are fully received against at the time of receipt.	MIGO

5.1.2 Staffing Services

Staffing services include obtaining temporary staffing support from staff augmentation companies to fulfill a temporary need at the Company. Examples would include temporary accounting staff to fill a specific need or staff to work at a community event.

Note: Managers requesting staffing resources should contact the Employment Team in Human Resources before contacting external parties regarding staffing services. The Employment Team has a number of staffing firms that it currently works with and can work with any vendor you may request to acquire special skilled staff but there are steps HR needs to take before this can be set up.
Please see Table 1 Requisition Creation Steps once you are ready to set up requisition.

5.1.3 Consulting Services

Consulting services are short term engagements with organizations that have a specific skill set the Company does not currently employ. This may include the retention of experts that would testify on the Company's behalf in a general rate case filing.

Note: At the discretion of the legal department, contractors may need to certify as to their independence from NW Natural. Independence issues should be discussed with the department's purchasing contact at the time of vendor selection.

Please see Table 3 Requisition Creation Steps once you are ready to set up a requisition.

5.2 IT Hardware and Software Purchases

NW Natural's policy is to purchase all IT hardware and software through the IT Department. The requester can call the IT Help Desk at x4357 to request a Hardware/Software Order Form. The Help Desk can assist in installing needed applications on an employee's computer.

5.3 Purchase Requisition for Products

5.3.1 Standard Purchase Requisition for materials process steps:

Note: After completing a requisition under $500K, the creator must notify individuals with requisition release authority for the assigned cost center so they can release the requisition. Requisitions over $500K are automatically routed to the appropriate individuals with requisition release authority.

Before completing a purchase requisition for a piece of equipment or hardware item, please confirm it is not a Stores item by contacting the purchasing agent for your area or reviewing SAP transaction MM60 to determine if the item is in Stores inventory. If the item is in the Stores inventory you can complete a material request to obtain the item.

Freight/Handling Charges on Purchase Order

Freight and handling charges should be estimated on a separate line item on requisitions where freight/handling charges are anticipated to be over $250. Dollar value units should be used to estimate the amount of freight (e.g. 500 units at $1.00) on a purchase order. Invoices with unauthorized freight charges over $250 will need to be reviewed by the business unit or purchasing agent before being processed by Accounts Payable. This will significantly slow down the payment to the vendor as the requisition will need to be released again and the purchase order set up again by Purchasing. Please put freight line items on the requisition and resulting purchase order to ensure prompt payment of your vendors. Alternatively, freight handling instructions can be entered in to the purchase order header text if special instructions are necessary.

Sales Tax Charges on Purchase Order

Purchasing should include lines for any anticipated sales tax that should be paid by NW Natural for purchases to be shipped to Washington or California. The purchase order header text should specify if the vendor or NW Natural is paying the related sales tax to the taxing jurisdiction. Sales tax information should be included in the text portion of the purchase order so the vendor can see the determination made by NW Natural's Purchasing Department.

5.3.2 Standard purchase requisition with "Framework Type" account assignment

Framework type orders are used to manage vendors for which NW Natural has an on-going relationship. At the time a framework type order is set up, the specific account coding for the goods and services to be purchased is unknown. The process for a framework type order is to enter the account coding (GL Account, Cost Center, Internal Order, WBS and/or Work Order) at the time the goods or services are received.

Framework type orders and the resulting purchase orders should have a price catalog set up with the framework type order that documents the pricing of the items being ordered. Due to the complexity of this type of order, please work with your contact in Purchasing to set up this type of requisition.

The steps in creating a framework type requisition are the same as a standard requisition except for the field changes listed below and a dollar limit replaces the specific items on a standard requisition. As noted above, the account coding is not required at this point in the process.

Configuration changes on a framework type requisition:

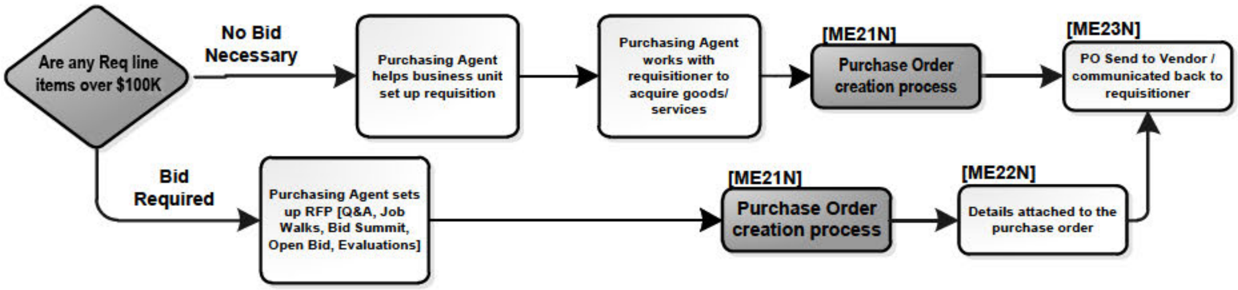
- ☐ Account Assignment Category = X "All aux.acct.assgts."
- ☐ Item Category = D "service"
- ☐ Limits Tab = set limits on items and total purchase requisition value

Switching the above fields to these values will create a framework account assignment type requisition.

6.0 Purchase Order Creation

Once a requisition is fully released, the Purchasing Department will convert the requisition to a purchase order. Depending on the requested amount and type of request, the Purchasing Department will follow different steps outlined in Figure 3 below.

Figure 3. Purchase Order Creation Summary



The Purchasing Department completes a number of business requirements once a requisition is completed and a purchase order is setup.

These activities include:

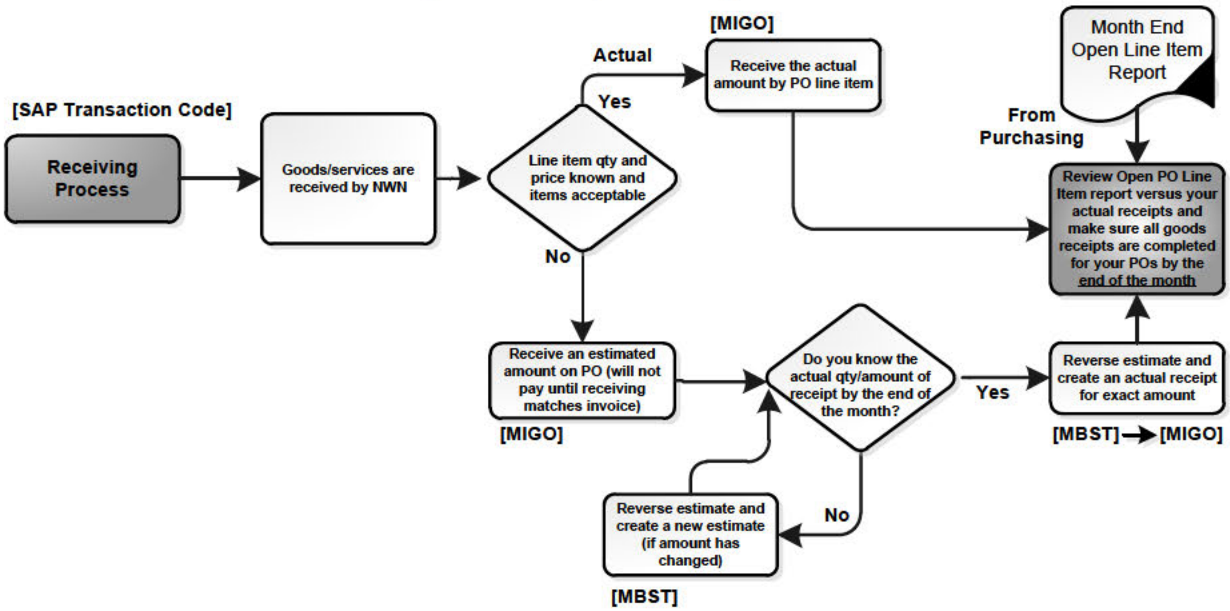
- ☐ **Vendor Performance Management:** For vendors in which we have an ongoing relationship, Purchasing performs periodic performance metrics. It also works with the RMC (Resource Management Center) to preform quality performance reviews. Purchasing is also responsible for ensuring adequate pricing controls on purchase orders larger than $100,000.
- ☐ **Contract Monitoring:** Purchasing monitors all major vendor contracts for insurance coverage performance, bonding coverage levels and independence certification statement documentation requests.
- ☐ **Diversity Spend Goals:** NW Natural has goals related to supporting minority businesses. The Purchasing Department tracks spending by classes in order to report progress on diversity spend levels.
- ☐ **Sustainability Policy Goals:** Environmental stewardship is one of the Company's core values and this is supported by the Purchasing Departments' Policy on sourcing sustainable products and services where possible.

7.0 Timely Receiving

It is very important for departments to be aware of their outstanding purchase orders and what goods and services have been received from the vendors. <u>By the end of each month all receiving activities in SAP should be completed for the goods and services received on open departmental purchase orders.</u> This is because the Integrated SAP ERP System records financial accounting liabilities based on when receiving is completed in SAP. Late or missed receiving transactions directly impact the accuracy of NW Natural's financial statements.

Figure 4 illustrates the receiving process for goods and services. All receiving coordinators should receive individual training from the Purchasing Department before they are requested to fill this roll. All departmental cost centers are required to designate a receiving coordinator as a point person to facilitate the timely receiving of goods and services on the cost center's (department's) purchase orders. Receiving coordinators receive a monthly report from Purchasing that details all the open purchase order line items for their area. This is done to facilitate the timely receiving of all items on a monthly basis. All receiving transactions must be completed by the end-of-business on the last day of the month.

Figure 4. Timely Receiving Process



7.1 Goods Receipt on Standard Purchase Order

Requesting Department

1. Vendor delivers goods and services and items are received in SAP Transactions MIGO:
   Required Fields (data needed to complete)
   a. Header should say "goods receipt, purchase order"; in the selection field enter the purchase order to be received against. Hit execute button.
2. Receiver enters in line item quantity for each line to be received (remember to check the "**item OK**" box).
3. Select the "check" box to check for issues on the goods receipt.
4. If you receive errors, review the items you entered. Check the purchase order detail for available line items.
5. If you do not receive any errors, you can click the "post" button.
6. You will receive a document number when the program posts the goods receipt.

7.2 Goods Receipt on framework type purchase order

Requesting Department

1. Vendor delivers goods and services and items are received in SAP Transactions ML81N **Service Entry Sheet**:
   Required Fields (data needed to complete)
   a. Receiver must enter the corresponding purchase order number.
2. Create service entry sheet. If there is a pricing catalog associated with the PO then the user must select that option in the entry form in ML81N.
3. For a text based service entry sheet, the receiver enters the header text, item

description / service description text, quantity, unit of measure and the gross price of the sheet being entered.

4. Next, the receiver enters the account assignment (GL Number, Cost Center, WBS and/or the order number).
5. The last step is to “Accept” the changes and “Save” the service entry sheet.

8.0 Accounts Payable

When Accounts Payable receives an invoice, it is processed in SAP. For the invoice to be paid there needs to be a purchase order line item that matches the invoice and there must be a receiving document that also matches the amount of the invoice.

Accounts Payable cannot process invoices that are unauthorized or lack the proper documentation to be entered into SAP. Supplier invoices are to be sent directly to Accounts Payable. If an invoice is received outside of Accounts Payable and is not processed in a timely manner, payment cannot be expedited beyond the defined processing times below.

All invoices should be sent directly to NW Natural Accounts Payable:
Email is the preferred method to transmit invoices to NW Natural. Invoices should be in an Adobe PDF format. The departmental contact can be copied on the email that includes the invoice but Accounts Payable should always be sent the invoice directly so amounts can be accounted for and vendors can be paid in a timely manner.

Invoices should be sent to: **NWNAP@nwnatural.com**

If a vendor must send paper correspondence, all invoices and related documents should be mailed to:

NW Natural Accounts Payable
PO BOX 4709
Portland, OR 97208

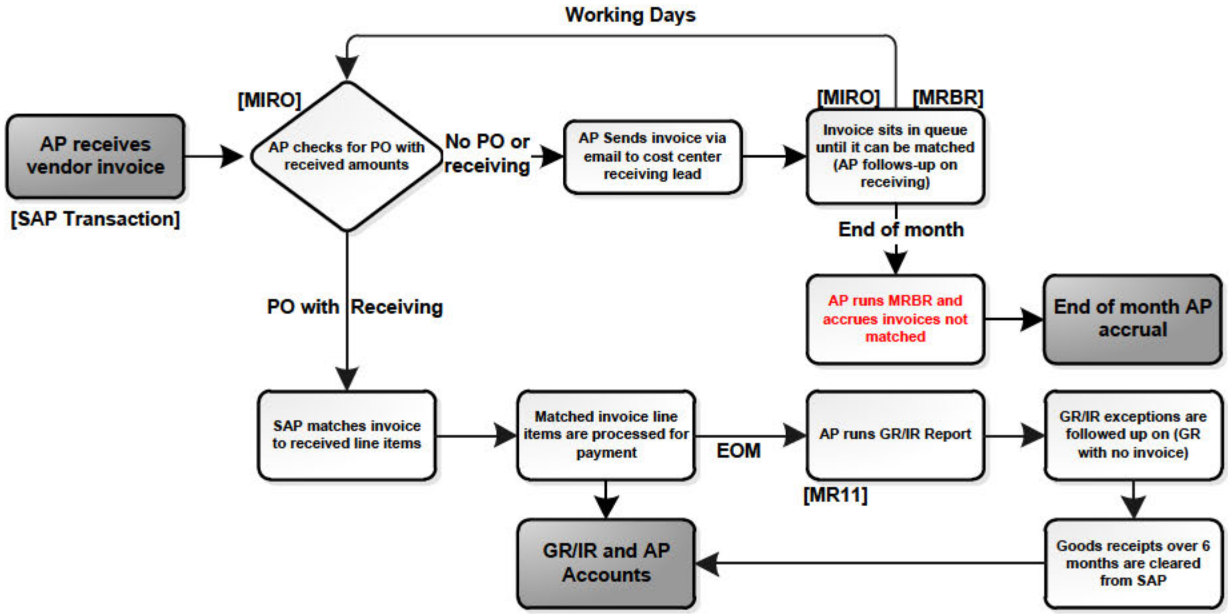
The Accounts Payable Department’s fax number is **503.220.2579.**

The Accounts Payable department is responsible for ensuring that all properly presented invoices, received by the daily cutoff time, are processed for payment. Payment is issued according to the terms in the SAP Vendor Master Record or NW Natural purchase order and the invoice date entered by the Accounts Payable Department.

All invoices must include NW Natural’s purchase order number. Direct pay invoices must have the departmental contact person’s name and/or email address. Invoices lacking this basic information will be returned to the vendor.

Figure 5 illustrates the different steps in the Accounts Payable process. It shows the central role of the purchase order in the process and the need for a receiving coordinator.

Figure 5. Accounts Payable Process



Standard Vendor Terms

Standard vendor terms are "**Net 30 – Destination.**" Payment terms are based on the vendor's invoice date and payment will be processed based on this date. To allow for funds to transfer, payments may be processed a few days prior to the calculated payment date in SAP. No invoice will be processed unless the goods and services have been received by the Company. Exceptions to this standard (Net 30) can be made via a NW Natural Purchase Order and must be approved by the Manager of Purchasing. Vendors with special terms must have a purchase order, as vendors that do not will default back to Net 30 terms. Vendors that are deemed to have a high volume of invoices may be put on a payment program by Accounts Payable. These vendors will have their invoices batch processed once a month. This may delay some vendor payments. Vendors with high volumes of transactions should send a batch of invoices to be received by the 20th of the month. Payments will be issued to the bank on the due date of the payment. If the payment date falls on a weekend or holiday, the payment will be made the previous business day. If an invoice is received with incomplete details and needs to be resubmitted, the terms will be reset based on the corrected invoice date. Accounts Payable will monitor for invoices that are received with invoice dates that are older than a few days. The invoice date on a late invoice may be adjusted by Accounts Payable by contacting the vendor. Accounts Payable will work with vendors and Purchasing in these cases.

Purchase order terms will state that any conflict in payment terms will default to the payment terms on NW Natural's website (http://www.nwnatural.com/uploadedFiles/Terms_and_Conditions6-23-09.pdf) or authorized purchase order.

All vendor master records will be set up in accordance with table below:

Table 4. Standard Vendor Terms

Payment Term	Vendor Type Examples
Due Upon Receipt or Due on a Fixed Date	Taxes (federal, state, local jurisdictions) Rents/lease/maintenance agreements Payroll & benefits (heath, pension, insurance, 401K) Debt maturities & interest payments Dividend payments Charitable contributions Employee reimbursements Down payment/deposits Gas supply invoices
Due Net 15 Days or due on fixed date	Utilities Telecommunication services
Due Net 30 Days (NW Natural Standard) Within 10 Days 2% Cash Discount Within 20 Day 1% Cash Discount	Materials and Supplies Services

Invoice Routing Procedure

Received invoices that have a valid purchase order, but do not have current receiving open line items, will be scanned and emailed to the responsible person for the cost center that authorized the purchase order. It is the responsibility of the cost center's receiving coordinator to receive on the purchase order if it is not already completed. If the purchase order does not have available funds, the department will need to work with their purchasing agent to increase the amount of available funds on the purchase order. Once the purchase order is correct and the item has been received, the responsible user should email "*Accounting A/P" so that the item can be processed and paid.

Special Handling Check Process

Special handling checks are checks that need to be returned to NW Natural so that special remittance can be put with the check when it is mailed to the vendor/payee. This is required in rare cases like tax payments, franchise payments and as part of special programs at NW Natural like "Dollars for Doers" and spot bonus payments. All other payments should be mailed by the bank to the vender per the instructions in the SAP Vendor Master Record. Accounts Payable Manager approval is required to have a vendor marked as "special handling". The bank will return checks that are marked with "Return by Overnight" as their Payment Method Supplement. This field is managed by Accounts Payable in the Vendor Master.

Emergency Check Process

NW Natural's checks are printed by the bank. In very rare circumstances it may be required to print an on-site check. The Accounts Payable Department has the ability to do this but it requires the approval of the Cost Center Officer and the Corporate Controller.

Timing of Payment Overview

The daily transaction cutoff for all payment requests is 12:00 Noon. See Table 5 below for a timing matrix for payment issuance. If a request is received after the cutoff time of 12:00 Noon, Accounts Payable will not process the payment until the next day. Payment cannot be expedited without deviating from the department's normal business processes [See Emergency Requests above for more detail].

Employee reimbursements are only processed via ACH or by check mailed to the employee's home address on record with NW Natural Payroll Department. Expense reimbursements must be received before 12:00 Noon for the employee to receive funds by Day 3 after the request; see the Payment Timing Illustration, Table5, below.

Table 5. Accounts Payable Funding Schedule

	AP receives fundable invoice	AP processes invoice for payment	Check is printed and mailed by bank	ACH Settlement	Wire Settlement	Check back at OPS
Day 1	By Noon					
Day 2		X			X	
Day 3			X	X		(Overnight)
Day 4						X
Day 5						

Direct Pay Procedural Steps:

1. Employee obtains manager approval (some direct payments are preauthorized via Policy 82), completes purchase transaction and instructs vendor to bill NW Natural Accounts Payable. The vendor invoice must include the employee's name or it will be returned to the vendor.

2. Upon receipt of invoice, Accounts Payable routes the invoice to the employee's department. The invoice is stamped and assigned the proper GL Account, Cost Center and/or WBS/Order Number and business purpose. The invoice is then signed by an appropriate approver in accordance with the requisition release strategy (Policy 82).

3. The approver returns the approved invoice to Accounts Payable. Do not return direct pay invoices to Accounts Payable unless goods have been received or services have been rendered and the vendor should be paid. Note: For direct pay invoices, goods and services are considered received when Accounts Payable receives the payment request. Invoices awaiting approval at month end for which the goods or services have been received and with a total value of $2,000 must be manually accrued at the end of the month [Manual Accrual Form]. The receiving department is responsible for filling out the manual accrual form and submitting it to the Accounts Payable Department by the last business day of the month (if they are still holding the invoice). Please do not pay an invoice with your Purchase Card AND send the invoice to Accounts Payable. This can led to duplicate payments on the invoice.

Review:

In order to ensure that this General Procedure continues to reflect current practices, a regularly scheduled review, led by Accounting will be conducted every 3 years unless changes in the law or business supersede this requirement.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 475

475. In reference to NW Natural/400, Kizer/pages 29-30, regarding the three inline inspection (ILI) conversion projects for E08 Springfield at $1.5 million, P31 McMinnville/Lafayette at $3.8 million, and E04 North Eugene at $3.0 million:

a. Please provide a breakout of capital and non-capital costs for the identified projects.

b. For non-capital expense details provided in (a.) above, please identify the one-time expense dollar amount(s) and the recurring cost dollar amount(s) for each project.

c. For any recurring costs identified in (b.) above, please provide a narrative description of the nature of the recurring costs and whether these costs will increase/decrease/remain static over time.

d. Does ILI represent the least cost/least risk option necessary to meet Federal Pipeline and Hazardous Materials Safety Administration (PHMSA) transmission line safety testing requirements? If no, please:

i. Identify the least cost/least risk safety option(s);

ii. The expected cost(s) of the least cost/least risk option(s) for each project; and

iii. A detailed narrative explaining why the Company thinks ratepayers should pay for a more expensive safety testing regimen.

Response:

a. All costs for the three inline inspection conversion projects are capital, including the first inline inspection (ILI) following the pipeline conversion work. These projects are part of our Transmission Plant assets and specifically fall within FERC 367-Mains. As part of the definition of 367, costs incurred to install transmission system mains, including pipe and fitting, are included. Because these projects are converting and replacing pipe for pipeline integrity and safety and it is new pipe, they are capitalizable, along with any inspection of the work completed. ILI costs for all future pipeline inspections are non-capital expenses.

b. N/A, as there are no non-capital expenses with the ILI conversion projects. However, as noted below, the ILI assessments have non-capital expense associated with each ILI after the first ILI is performed. We perform pipeline assessments every seven years, as required by 49 CFR 192.

c. N/A, as no recurring costs are identified in the response to part b.

d. –As discussed below, on balance, ILI represents the least cost/least risk option necessary to meet PHMSA transmission line safety testing requirements. NW Natural generally utilizes two forms of assessment on existing transmission lines – External Corrosion Direct Assessment (ECDA) and Inline Inspection (ILI). Both forms of assessment satisfy PHMSA requirements. In the area of transmission pipeline assessment, ILI is form of assessment that inspects the entire transmission pipeline system and can identify more threats to the pipeline. ECDA as utilized per Code is performed only in High Consequence Areas (HCAs) and Identified sites, thus limiting the assessment to only certain sections of the pipeline. The threats identified by ECDA are limited to threats that are associated with coating damage. Therefore, this ECDA assessment can miss defects such as third-party damage or natural forces damage where the coating was not disturbed, and does not identify any threats outside of the HCA's and Identified sites. ILI assesses an entire pipeline segment, between the pig launcher and pig receiver, and can identify dents or other defects where the coating may not have been disturbed, as well as internal defects such as corrosion and bad pipe seams.

For many of our transmission pipelines, NW Natural will need to invest in pipeline facilities such as pig launchers and receivers and removal of reduced port fittings that prevent passage of cleaning, sizing and inspection pigs for inline assessment. This is a one time investment to upgrade these facilities to allow for inline inspection. ECDA, on the other hand, does not require additional investment and only has operations & maintenance expense associated with each inspection. As noted above, ECDA does not provide the same level of inspection as ILI, and that is why NW Natural has proactively upgraded its transmission facilities in a planful way. Section 2 of NW Natural's 2021 Transmission Integrity Management Plan (TIMP) summarizes the differences in ILI and ECDA inspection technologies. Please refer to **UG 435 CUB DR 3 Attachment 2** for NW Natural's 2021 TIMP. Please refer to **Confidential UG 435 OPUC 475 Attachment 1** for NW Natural's 2021 ECDA to ILI 10 Year Plan, which includes our 10 year plan for execution of proactive ILI upgrades projects. Additionally, our Annual Safety Plan has identified these projects. Please refer to **UG 435 OPUC DR 475 Attachment 2** for NW Natural's 2022 Annual Safety Plan. Each of these documents are routinely assessed and updated.

NW Natural has numerous examples where potentially harmful defects to the transmission pipeline system have been found through the use of ILI. A recent example was in 2019 when NW Natural utilized ILI to assess the Central Coast Feeder (P30). The result of this assessment was the discovery of an immediate defect that was located approximately 18 miles north of Newport, OR which is the nearest HCA to the location of the defect. Upon excavation of this immediate defect, it was discovered that a steel cable was wrapped around the NW Natural transmission pipeline. The force exerted on this steel cable from an unknown source had resulted in a dent in the pipeline with an associated metal loss where the metal had been displaced. Please refer to **UG 435 OPUC DR 475 Attachment 3** which show pictures of this metal loss defect.

Also, with the advancements in ILI technology, NW Natural is utilizing inspection tools that allow NW Natural a greater understanding of the material properties of the transmission pipeline system, which assures NW Natural that the transmission pipeline system is in alignment with original design records. NW Natural believes that projects funded by customers to convert transmission pipelines from ECDA to ILI assessment allow NW Natural to have a better understanding of the transmission pipeline system which results in a safer and more reliable natural gas system.

For the three inline inspection (ILI) conversion projects listed in this request, a majority of the costs is associated with installation of pipeline facilities such as pig launchers and receivers and removal of reduced port fittings that prevent passage of cleaning, sizing and inspection pigs for inline assessment.

After a pipeline is converted to ILI, the costs for the ECDA and ILI assessment are equivalent for the pipeline segment inspected.

- E04 – this pipeline was assessed using ECDA in 2021 to comply with Code reinspection timelines. Therefore, we have recently decided to defer converting the assessment of this pipeline to ILI until a later date. We will reflect that decision in our reply testimony.

- E08 – NW Natural estimates the cost for the ECDA assessment of this pipeline to be $60,000 and the ILI assessment to be $70,000. As noted above, this project is part of our 10-year plan because ILI is a more complete assessment of the pipeline, is able to detect more threats to the pipeline and provides a greater level of safety to the public as this assessment gives NW Natural a better view of the pipeline and the potential defects.

- E31 – NW Natural estimates that the cost for the ECDA assessment for this pipeline is $40,000 and the ILI assessment is $100,000. However, it should be noted that the ECDA assessment will only cover 3.31 miles of this pipeline while the ILI assessment will cover the entire pipeline segment of nearly 14 miles. Therefore, at an assessment level, the ILI assessment is the least cost option. As noted above, this project is part of our 10-year plan because ILI is a more complete assessment of the pipeline, is able to detect more threats to the pipeline and provides a greater level of safety to the public as this assessment gives NW Natural a better view of the pipeline and the potential defects.

2022 SAFETY PROJECT PLAN

OREGON

September 30, 2021

250 SW Taylor Street
Portland, Oregon 97204
503-226-4211

NW Natural®

Contents

1. Introduction

In compliance with the Oregon Public Utility Commission (“Commission” or “OPUC”) Order No 17-084 (“Order”) in Docket UM 1722, this 2021 Safety Project Plan (SPP) outlines NW Natural’s safety project investments for 2022. The SPP includes updated capital and O&M projects and programs and projects that carry over from 2021.

This SPP demonstrates NW Natural’s commitment to pipeline safety by providing insight into NW Natural’s safety activities and identifies NW Natural’s response to regulatory changes that may drive safety program priorities or modify existing programs. In the future if NW Natural seeks approval for a Safety Cost Recovery Mechanism (SCRM), this SPP is intended to expedite the review process of safety investments.

Safety is a core value at NW Natural and we appreciate the opportunity to present this information to the Commission.

2. Background Information

NW Natural is a regulated natural gas utility conducting business in Oregon and southwest Washington. The Company serves ~770,000 customers and owns and operates ~660 miles of natural gas transmission pipeline, and ~14,000 miles of distribution pipelines. In addition, NW Natural operates three energy storage facilities in Oregon – Portland and Newport LNG Plants and Mist Underground Storage.

NW Natural’s pipelines and storage facilities are governed by:

- 49 CFR Part 192 – Minimum Safety Standard – Transmission & Distribution Systems
- 49 CFR Part 193 – LNG Safety Standards
- 49 CFR Part 196 – Protection of Underground Pipelines from Excavations Activity
- Additional OARs (OAR 860-024 – Safety, OAR 860-031 – Pipeline Inspections), and ORSs such as ORS 757.039 – Regulation of hazardous substance distribution and storage operations, and ORS 757.542-993 – One call notification.

In addition to the federal and state regulations identified above, NW Natural’s safety program considers the findings of Oregon House Resolution 3 (HR 3, 2011) which directed the Oregon Seismic Safety Policy Advisory Commission to prepare the Oregon Resiliency Plan with the purpose of identifying recommendations for how Oregon’s critical energy infrastructures could be made seismically resilient against a Cascadia subduction zone earthquake. Upon completion of that work on February 28, 2013, the Oregon Senate passed Senate Bill 33 (SB 33, 2013), which established the Governor’s Task Force on Resilience Plan Implementation (“Task Force”). In October 2014, the Task Force issued a report recommending that the Commission require regulated energy providers to conduct seismic assessments of regulated facilities and recommended that the Commission allow cost recovery for prudent investments related to assessments and mitigation of vulnerabilities identified during those assessments. In October 2018, Governor Kate Brown presented the “Resiliency 2025” plan, titled “Improving Our Readiness for the Cascadia Earthquake and Tsunami” (“Resiliency 2025 Plan”). The Resiliency 2025 Plan follows the 2013 ORP, and outlines six key strategies for the State of Oregon. Its vision is to “protect all Oregonians by ensuring we are prepared to survive and recover from the expected 9.0 magnitude Cascadia earthquake and ensuing tsunami.” The key strategy of the Resiliency 2025 Plan to improve the energy infrastructure is to “develop a plan for the Critical Energy Infrastructure Hub to prevent and mitigate catastrophic failure and ensure fuel supplies and alternate energy sources are available to responders and the public.”

3. Threat Identification – NW Natural’s four highest ranking threats, as identified in the DIMP Plan are:

3.1 Excavation Damage

Excavation damage continues to be the principal threat to NW Natural’s gas distribution system, comprising approximately 86 percent of all recorded leak repairs. Excavation damage is a system-wide threat brought on predominantly by improper excavation practices. NW Natural’s efforts to reduce excavation damages are described below.

3.1.1 Excavation Training and Education:

NW Natural actively engages in training and education for contractors, general public, and other utilities, to promote safe excavation procedures and practices. These efforts include classes on Oregon dig laws, displays at public events, and the use of media including print, radio, television, and internet to promote safety, best practices, and the use of 811.

NW Natural’s Damage Prevention Department works to reduce the number of excavation damages through investigation, cause analysis, and proactively works to identify and support contractors engaging in high-risk construction activity.

3.1.2 One-Call Notification Practices:

NW Natural actively participates in local and state-level Utility Coordinating Councils as well as the One Call Utility Notification board. A primary function of these organizations is to reduce damages to underground utilities through excavation best practices, public awareness, and the use of the Oregon one call system (811).

NW Natural also maintains a robust Public Awareness Program which includes advertising, direct mailing, and public event outreach to increase this awareness.

3.1.3 Locating Practices:

NW Natural is an active member of Oregon’s one call system and responds to all locate requests. Due to the high volume of locate requests this work is contracted. All locating is performed by NW Natural qualified personnel and oversight is performed by Company contract management personnel. In addition, locating activity is included in NW Natural's Quality Assurance program to minimize the incidences of errors, mismarks, and missed due dates.

3.1.4 Incorrect Facility Marking:
Incorrectly marked facilities may be due to underground interference, equipment issues, inaccurate facility maps, or procedural issues. Locating personnel responsible for a mismark receive additional training and are required to re-qualify prior to being allowed to locate gas facilities. Review of mismarks are conducted by supervisor or other qualified personnel and the results are used to identify deficiencies, correct maps, and ensure the facility can be reliably located.

3.2 Material, Weld or Joint Failure

Material, weld, or joint failure is the second largest threat to the NW Natural gas distribution system, comprising approximately 9 percent of all recorded leak repairs. NW Natural is proactive in its efforts to reduce these occurrences, as described below.

3.2.1 Plastic Pipe Installed from 1960s to 1980s:
NW Natural makes every effort to identify all pre-1982 plastic pipe installations, analyze leak histories, evaluate any conditions that may threaten integrity of the pipe, and take appropriate remedial action, including replacement, to mitigate risks to public safety.

3.2.2 Acrylonitrile-Butadiene-Styrene ("ABS"):
NW Natural used ABS in the 1960s to reline or renew existing steel services. These services have been identified for replacement. NW Natural's use of ABS was limited to ½" pipe inserted into existing steel service lines mitigating the industry-identified risk of rock impingement and slow crack growth related to unsuitable backfill material and construction practices.

3.2.3 Plexco Service Tee Celcon Caps:
NW Natural is aware of industry issues regarding Plexco Service Tee Celcon Caps possibly leaking when over-tightened during installation. These caps exist within the gas distribution system and are replaced as found and scheduled for replacement if leaks are identified.

3.2.4 Polyethylene ("PE") Fusion Failure:
NW Natural has a robust training and Quality Assurance/Quality Control program in place to ensure proper PE fusion quality. This program includes testing, biannual qualification, and ongoing training. All PE fusions are visually inspected, and pressure tested prior to being placed in service.

3.2.5 Flat Back Risers:

In 2012 NW Natural identified a type of riser stop valve, internally known as a "Flat Back Riser" that contained components prone to atmospheric corrosion in the coastal areas of NW Natural's service territory. NW Natural identified that corrosion failure on a retaining pin could result in a hazardous leak. NW Natural developed an Accelerated Action Plan to replace these valves in coastal areas.

3.3 Corrosion

Corrosion is the third largest threat to the NW Natural's gas distribution system, comprising less than 2 percent of all recorded leak repairs. NW Natural's efforts to reduce these occurrences are described below.

3.3.1 Pipe Replacement:

The primary driver for external corrosion system-wide is steel pipe. At this time NW Natural's distribution system is approximately 51% coated and cathodically protected steel and 49% polyethylene. During all pipe replacement projects consideration is given to replacing existing steel pipes, valves, and fittings with polyethylene to mitigate the threat of corrosion. In 2015 NW Natural completed the replacement of all known un-coated bare steel buried pipe eliminating the single largest corrosion threat.

3.3.2 Pipe Casings:

Steel casings are primarily used to protect or facilitate the installation of mains and services underground and are fitted with seals to prevent water intrusion, spacers to prevent contact between the casing and gas carrying pipe, and vents.

NW Natural inspects steel casings annually to identify problems such as contact between the casing and gas pipe, or water intrusion. If a “short” or other anomaly is identified a work order is created to address the concern.

At NW Natural the installation of casings has been largely replaced by HDD (Horizontal Directional Drilling) installation. During pipeline improvement projects existing casings are evaluated for replacement by HDD or alternatives.

3.3.3 Atmospheric Corrosion:

NW Natural’s system includes facilities such as risers, regulators, station piping, bridge crossings and other above ground facilities that are susceptible to atmospheric corrosion.

NW Natural’s atmospheric corrosion mitigation plan includes replacement of facilities when appropriate as well as protective coatings such as epoxies, paint, wax, other corrosion resistant materials, and enhanced inspections in locations with an elevated risk of corrosion.

3.3.4 Exposed Pipe Inspections

During normal operations when a buried pipeline is exposed crews inspect the pipe and protective coating for evidence of corrosion, or coating anomalies that can lead to future corrosion. Coating repairs or pipe replacements are completed before the pipe backfilled and placed back in service.

3.4 Equipment Failure

Equipment Failure is the fourth largest threat to the NW Natural gas distribution system, comprising approximately 1 percent of all recorded leak repairs. NW Natural’s efforts to reduce these occurrences are described below.

3.4.1 Valves:

Valves are vital to the safe operation of a gas distribution system. NW Natural has in place a key operating valve inspection and maintenance program to ensure key valves are operable and available for use. Valves that are found to be inoperable, inaccessible, and/or paved over are identified and remediated as necessary.

3.4.2 Pressure Control / Relief Equipment:

NW Natural has an established inspection and maintenance program in place for pressure control/relief equipment to ensure reliable and safe operation.

3.4.3 Mechanical Couplings:

Pipe may pull out from compression couplings due to tensile forces including excavation damage, cyclic fatigue from changes in the temperature of natural gas as a result of the Joule-Thomson effect, ground movement from earthquakes or after heavy rains. Mechanical fitting failures are investigated, tracked, and reported per PHMSA and OPUC requirements.

In the past as an alternative to welding small diameter steel fittings mechanical couplings were sometimes used to install valves and service tees. These types of fittings may develop leaks through the elastomer seal between the coupling and the pipe. NW Natural replaces these fittings with welded steel fittings or polyethylene as discovered during routine operations and maintenance activity.

3.4.4 Other:

Other types of material or equipment failure may occur in the gas distribution system. Failure reports are reviewed to detect trends or patterns that may affect the distribution system.

Many of the safety projects identified in this plan are in direct response to the above threats, and to maintain compliance with safety codes and regulations.

4. Safety Activities Performed by NW Natural

Safety activities at NW Natural can be divided into categories:

4.1 Prescriptive Regulatory Actions – Includes actions which must be performed to meet minimum federal safety standards.

49 CFR 192 includes multiple prescriptive activities, intended to safeguard public safety, and fall into broad categories such as "operations" (Subpart L) and "maintenance" (Subpart M). Most of these activities require inspections at prescribed intervals to confirm that a facility or asset is meeting operational requirements prescribed by federal code. These activities provide the baseline data for other performance-based activities and include, but are not limited to:

- Atmospheric corrosion surveys
- Leakage surveys
- Cathodic protection surveys
- Right of way ("ROW") patrols
- Valve maintenance
- Water crossing inspections
- Odorization
- Odorometer Reads
- Line Marking

- Pressure Regulation Inspection
- Large Meter Inspections
- Record Keeping
- Control Room Management
- Bridgeline Inspections
- Equipment Calibration
- Houseboat Inspections
- Transmission Integrity

The safety activities from this category are prescriptive in nature and are not driven by risk analysis alone. Because these activities are required, they are not discussed further in this SPP, which instead focuses on projects and/or programs identified by NW Natural as essential to enhancing safety and reliability.

4.2 Proactive, Performance-Based Actions

Other sections of 49 CFR 192 include more proactive performance-based risk reduction activities, such as Subpart O – Transmission Integrity Management Program ("TIMP") and Subpart P – Distribution Integrity Management Program ("DIMP"), Damage Prevention, and Public Awareness. These programs focus on mitigating pipeline safety risk.

4.2.1 Transmission Integrity (TIMP)

Transmission Integrity refers to 49 CFR 192 Subpart O-Gas Transmission Pipeline Integrity Management. This federally mandated program covers natural gas transmission pipelines located in High Consequence (HCA) and Moderate Consequence (MCA) areas. NW Natural exceeds code requirements in TIMP to address conditions outside of HCA and MCA's

Activities in this category include baseline assessments and reassessments of transmission lines using in-line inspection ("ILI") and other direct assessment methods. They may also include pipeline replacements and modifications in compliance with integrity management rules, best practices, and relocation of facilities to mitigate threats posed by natural forces such as flooding, land movement, and erosion.

4.2.2 Distribution Integrity (DIMP)

Distribution Integrity is outlined in 49 CFR 192 Subpart P- Gas Distribution Pipeline Integrity Management. This federally mandated program requires operators to create a written Integrity Management Program that takes into consideration: system knowledge, threat identification, evaluation and risk ranking, identification, and implementation of measures to address risk, measurement of results, and reporting.

Activities in this category include projects warranting Accelerated Action ("AA") to address a system integrity risk. These AA projects are identified through risk modeling, industry identified threats, and by subject matter experts within the Company, and include:

- Replacement of vintage plastic services,
- Relocation of facilities under structures,
- Replacement of valves and fittings susceptible to leakage,
- Protection of above grade gas facilities,
- Crossbore investigation, and
- Relocation of distribution gas lines to mitigate threats posed by natural forces such as:
    - Flooding
    - Land movement, and
    - Erosion.
- Enhanced EFV Installation – installation of EFVs on services that were installed prior to the EFV rule issued in 2006
- Dithiazine – a sulfur compound found in natural gas that has been known to cause equipment failure especially in district regulators.

4.3 Safety Policy and Practices

NW Natural also implements risk reduction activities not explicitly required by the federal code. These actions have been identified as prudent safety practices intended to enhance public safety, improve system reliability, and maintain the safe operation of NW Natural's above and below-ground facilities including LNG Plants and underground natural gas storage facilities. These risk reduction actions include:

- Seismic vulnerability assessments of LNG Plants, the Mist Underground Storage Facility, and Transmission Pipeline System as recommended by SB 33 (2013) and consistent with the Governor's Resiliency 2025 Plan
- Accelerated replacement of vintage materials
- Transmission inspection outside of high and moderate consequence areas.
- Development of a PSMS
- Proactive EFV installation
- Locate ticket risk modeling
- Natural forces assessments of NW Natural's transmission system as part of NW Natural patrol and surveillance programs.

5. Projected and Preliminary Costs Presented in this Plan

The 2021 Capital and O&M costs presented in this plan are projected based on current expenditures for each of the identified projects through the end of the year. Costs presented for the significant safety initiatives are preliminary for planning purposes and do not include NW Natural overhead costs. Costs for safety projects under consideration will be presented in future SPPs.

6. 2022 Capital Safety Investment

In 2022, NW Natural estimates it will invest $12 MM in capital to comply with DIMP, TIMP, and other regulations. Significant projects in this category include:

6.1 Springfield Transmission (ILI) (2021-22 estimate of $1.2 MM):

This project involves transition of the Springfield transmission line from direct assessment to ILI. The Springfield transmission line is the primary feed to downtown Springfield and large industrial customers in the area. This pipeline is approximately 3 miles and routed along Harlow Road, which is a major thoroughfare between the cities of Eugene and Springfield. Work on this project in 2021 with planned completion in 2022.

6.2 Pro-active EFV Installations (2022 estimate of $600,000):

On October 14, 2016, the U.S. Department of Transportation's ("DOT's") Pipeline and Hazardous Materials Safety Administration ("PHMSA") adopted code requiring the installation of EFVs or shut-off valves on all new or replaced branched service lines (Docket No. PHMSA-2011-009). While the code requires EFV installations be installed in all new or replaced branched service lines, it did not require retrofitting EFVs on existing services.

NW Natural believes a proactive EFV installation program is a prudent action that can mitigate the consequence of a gas release resulting from excavation damage to a gas service line. NW Natural is implementing a policy to retrofit EFVs on existing gas service lines when the buried portion of the service line is exposed and the work involves the interruption of gas service.

This pro-active EFV program was initiated in 2020 and will continue to be a safety program.

6.3 McMinnville/Lafayette ILI (2022 estimate of $2.6MM):

This project involves the transition of the McMinnville/Lafayette transmission line from ECDA to ILI assessment. The McMinnville/Lafayette transmission line is a 6" transmission main that connects to the Central Coast feeder near Amity, OR and runs north 13 miles to serving the residential and industrial customers of McMinnville. The transmission main terminates in the town of Lafayette north of McMinnville. Design work to modify the pipeline will begin in 2021 with construction starting in 2022; cleaning ILI assessment, data analysis, and remediation activities will continue through 2022.

6.4 North Eugene Industrial Trans (2022 estimate of $2.1M)

This project involves the transition of the North Eugene Industrial transmission line from ECDA to ILI assessment. The North Eugene Transmission line is a 5 mile long 6" and 8" transmission line primarily serving the residential and industrial customers located along the Randy Pape Beltline highway. The line terminates at the Northwest Expressway. Design and preliminary construction work coordinated with City of Eugene public works projects will be done in 2021. Cleaning and ILI assessment activities will continue through 2022 with data analysis and remediation/repairs completed in 2022.

6.5 Underground Storage – Well Integrity (2022 estimate of $3.0 MM)

PHMSA has issued an Interim Final Rule incorporating by reference American Petroleum Institute ("API") Recommended Practice 1171 referred to as the Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs by reference. NW Natural developed a Mist UGS Risk Management plan and has begun work on the program. Work in 2022 will involve assessments of the production casings of 6 storage wells. The assessments will include downhole wireline logging of the production casing strings using both multi-arm caliper and magnetic flux tools to identify deformations and metal loss features.

6.6 Other safety projects and programs (2022 estimate of $2 MM):

Pipeline Replacement due to Seismic/Natural Forces

Portions of NW Natural's distribution and transmission system cross through landslide faults, seismic faults, sensitive areas, and waterways. Due to significant weather events or the passage of time, the integrity of these pipelines may become at risk. When identified during patrols, routine maintenance, or other stakeholder the Integrity Team develops plans to remediate these at-risk pipelines as they are identified.

Valve Isolation Plans

NW Natural is working to develop a strategy for identifying and installing additional valves in the distribution system to assist in the isolation of portions of the distribution system in case of an emergency or third party damage.

Meter Protection Installation

NW Natural will continue installation of guard posts adjacent to meter sets that are determined to be at risk of damage due to vehicle or equipment contact.

Pipeline Modification due to ROW Encroachment

Patrols of NW Natural Pipelines may discover structures or other encroachments built over or adjacent to pipelines that can impact the safe operation or access to a pipeline. This program works with landowners to remediate these encroachments.

Pipeline Material Identification (PMI)

At selected transmission pipeline anomaly remediation sites NW Natural has instituted a process using technology to non-destructively test and acquire data regarding pipe material properties. In addition, when the Transmission Integrity rule went in to effect over twenty years ago NW Natural began keeping short (18”-24” long) sections of pipe for future reference. These spools will be destructively tested to obtain pipe material properties that were not required as part of the original installation documentation. The material data obtained through this program will be stored in the permanent record for each pipe segment.

6.7 ASV/RCV Installation (2022 estimate of $700k)

To assist in the timely and efficient closure of valves on the transmission system, NW Natural is continually identifying locations where ASV/RCV valves can reasonably be installed, or existing valves retrofitted in order to facilitate isolation of the transmission system.

6.8 Historical Capital Expenditure - Safety Project Plan (System Integrity)

The Historical Capital Expenditures below are actual expenditures for each of the presented years.

Year	Expenditure
2015	$17,190,356*
2016	$ 7,772,763
2017	$ 5,925,409
2018	$ 9,699,814
2019	$ 10,231,431
2020	$ 8,900,000
2021	$8,200,000

*Final year of known bare steel main replacement

Historical capital expenditures include:

- Work to modify pipelines to accept inline inspection devices; including removal or replacement of non-piggable fittings and facilities required to launch and receive inline inspection devices.
- Pipeline relocation to mitigate threats including outside forces and natural forces. This work does not include relocations due to utility conflicts, or third-party improvement projects.
- Pipe replacements and testing in compliance with federal and state regulations.

- Ongoing DIMP AA programs/projects such as Vintage Plastic, Guardpost installations, Proactive EFV installations, etc.

7. 2022 O&M Expenditures

In 2022 NW Natural expects to spend $3.4 in O&M to address and comply with DIMP, TIMP, damage prevention, and public awareness.

Activities that reflect expenditures in this category include costs for supplies (office/field), reference materials, education (conferences/workshops), vendor and contract costs associated with transmission assessments, sewer crossbore investigations and remediation, public awareness program materials, advertisements and mailings, and natural forces investigation and remediation. Additionally, this category covers the development, initiation, and execution of studies and consulting fees related to integrity requirements, such as class location studies and third-party geotechnical site evaluations to address and mitigate risk.

O&M also includes some non-capital internal labor in support of NW Natural's system integrity program ("SIP"). These costs include the Integrity Management staff (7 FTE), damage prevention specialists (4 FTEs) involved in damage prevention/investigation, and a public information officer for safety outreach, training, and program administration. The Integrity Management group may also utilize other internal resources in support of SIP activities which includes GIS analysts, Customer Service, Construction, and other subject matter experts. Significant O&M projects include:

7.1 Sewer Crossbore Inspections (2022 estimate of $1.6MM):

The sewer crossbore program involves the visual inspection of sanitary sewers for incidences of gas line crossbores. In installations where trenchless technology was used to install polyethylene pipe, there exists the possibility the gas line was bored through a sewer main or lateral. NW Natural's policy is to expose all foreign line crossings when performing trenchless work. Sewer crossbores typically occur when facility owners fail to locate their pipe, creating a situation where NW Natural is unable to expose facilities during construction. This is an industry-wide threat. Although sewer crossbores are not isolated to gas operators, the consequence when gas lines are involved can be high. This program identifies existing trenchless polyethylene installations and inspects the sewers in the vicinity to identify crossbores.

7.2 Transmission Inline and Direct Assessment Reassessment and Remediation (2022 estimate of $1.3MM):

This work includes the federally prescribed seven-year reassessment of transmission pipelines in HCAs and is comprised of both inline inspection and direct assessment of transmission assets and associated repairs.

7.3 Natural Forces (2022 estimate of $300,000):

Where the threat of natural forces can be mitigated without pipe replacement or rerouting, NW Natural may choose to address the threat through site work. This option is necessary in situations where a reroute is not feasible due to environmental restrictions or where a pipeline serves a critical customer or provides a single feed to a distribution system. Work may include armoring of slopes, re-grading of sites, culvert improvements, and retaining structures to address land movement and drainage issues.

7.4 Damage Prevention (2022 estimate of $800,000):

In compliance with DIMP regulations, and to address the single largest threat to gas facilities, NW Natural maintains a damage prevention department. The department consist of a supervisor and 4 FTE damage prevention specialists whose responsibilities include damage prevention through high risk locate ticket intervention, training, attendance at pre-construction meetings, participation in Utility Coordinating Councils, and support of the 811 One-call system. Damage prevention specialists are also responsible for the investigation, enforcement, and contractor training related to excavation and third-party damage.

7.5 Public Awareness (2022 estimate of $1,050,000):

NW Natural's Public Awareness program meets the requirements mandated in API RP 1162, adopted by reference by PHMSA into Part 192.616(a),(b), and (c). This program promotes public safety through communication and outreach focused on educating customers and the public about natural gas safety. The program includes customer correspondence, mailers, advertisements, community events, mobile phone applications, and brochures to excavators, contractors, public officials, residences and businesses along pipeline rights-of-way and in high consequence areas, floating homes, and schools.

The Public Awareness Plan utilizes television and radio advertising, bill inserts, social media, and events to promote natural gas safety awareness. Targeted outreach and public awareness materials are provided annually to customers near transmission pipelines, as well as contractors, excavators, and first responders within NW Natural's service territory.

7.6 Right-of-Way Encroachments (2022 estimate of $100,000):

Pipeline patrols are used to identify changes in site conditions. An example of such a change is the installation of structures over pipelines, and inside dedicated pipeline rights-of-way, or easements. In some instances, the remediation may involve the relocation of structures and other non-gas facilities.

7.7 Historical O&M Expenditure - Safety Project Plan (System Integrity):

The historical O&M expenditures below are actual expenditures for each of the presented years (not including PSMS, damage prevention or public awareness expenditures).

Year	Expenditure
2015	$4,034,218
2016	$4,889,618
2017	$4,771,267
2018	$4,000,000
2019	$3,052,000
2020	$3,100,000
2021	$2,900,000

Historic O&M expenditure included:

- Regulatory transmission assessments including the investigation and remediation of identified anomalies resulting from inline inspection and external corrosion direct assessment (ECDA).
- Sewer crossbore inspection program.
- Investigation and remediation of natural forces including landslides, flooding, erosion, etc.
- Buildover remediation where structures encroach into pipeline right-of-way.
- Digital conversion of historical facility records to facilitate system knowledge.
- Remediation of difficult to operate valves.
- Maintenance of Integrity Risk model as a result of geographical and system changes.

These above costs do not reflect those related to ongoing maintenance of facilities including right-of-way clearing, patrols, leakage, cathodic protection, and other ongoing routine O&M work.

8. 2022 Significant Safety Initiatives

8.1 Changes in TIMP Assessment Methodology

In 2022 NW Natural will extend the use of inline inspection (ILI) for integrity assessment of transmission pipelines assessed at seven-year intervals. Inline inspection tools have the advantage over direct assessment and pressure testing because they assess the entire pipeline maintaining constant contact with the inner wall providing data allowing for the identification of interacting anomalies such as pipe deformation and metal loss. In 2022 NW Natural will change the assessment methodology of the following pipelines.

The McMinnville/Lafayette Transmission line supporting the City of McMinnville and surrounding areas. The 13-mile-long pipeline is routed along Oregon Highway 99W.

The Springfield transmission line is the primary feed to downtown Springfield and large industrial customers in the area. The 3-mile-long pipeline is routed along Harlow Road.

The north Eugene Industrial Transmission line serving industrial, commercial, and residential customers in north Eugene. The 5-mile-long line pipeline is routed along the Randy Pape Beltline Highway.

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8.2 Pro-active EFV Installations

NW Natural has installed EFVs on all new single-family residential services since February of 1999. In 2006, Federal Code was modified to require the installation of EFVs on all new residential and small commercial services. NW Natural will continue and expand the program installing EFVs on existing residential and small commercial services when the buried portion of the service line is exposed and service to the customer is interrupted. NW Natural believes proactive installation of EFVs is a prudent and pragmatic approach that can mitigate the consequence of an excavation damage to a service line.

9. Safety Projects/Programs Being Evaluated at this Time – Tracking and Traceability

NW Natural is developing a roadmap to meet the proposed requirements of the Plastic Pipe Rule (Docket No. PHMSA–2014–0098). The DOT has designated the Plastic Pipe Rule a "significant rulemaking" due to economic impact; compliance with the Plastic Pipe Rule will require new equipment, software, and process changes by NW Natural to meet tracking and traceability requirements.

When the final rule is issued and the impact of the rule on current operations is understood, the Company will develop a program that will be included in future SPPs.

In compliance with recent Regulatory Mandates involving material verification of steel transmission pipelines NW Natural has implemented a non-destructive material verification program to collect material property data on transmission pipeline assets. This program involves material testing of in-service pipelines during planned work to collect material data including metallurgy that was not required at the time of installation.

NW Natural has also developed a program to destructively test segments of pipeline that were removed from past transmission projects to collect the material property information. Collecting material information from the in-service transmission mains and the destructive tests from the historical transmission mains will allow NW Natural to develop a library of material property data.

10. Cost Benefit Analyses & Alternative Analysis

The performance of a cost benefit analysis and alternatives analysis is difficult in the context of safety programs mandated by regulation. As a result, a cost benefit analysis has not been a primary consideration in this report because these safety projects are mandated by CFR, dictated by industry best practices, or driven by operational requirements. The assigned risk and prioritization for implementing these projects are based on in-depth studies and analysis of NW Natural's transmission and distribution systems as well as plant and storage assets. Studies performed as part of normal operations provide measurable and continual feedback needed to perform safety related work for which there are few practicable alternatives.

Alternative analysis and in-depth studies are useful when they identify threats and risks that can be mitigated or eliminated through the application of performance-based best practices, engineering analysis, operational knowledge, and subject matter experts. Where the Code of Federal Regulations prescribe compliance activity or mandate programs, the use of cost benefit, or alternative, analysis is not warranted.

When a pipeline safety initiative requires a cost benefit or alternative analysis NW Natural may select a qualified external resource to perform the analysis.

11. Legislative Update

11.1 Docket No. PHMSA-2011-0023 - the Safety of Gas Transmission and Gathering Lines

11.1.1 Rulemaking No. 1

Regulatory Mandate – involves MAOP reconfirmation, expansion of assessment requirements outside of high consequence areas, material verification, seismicity, reporting requirements, other related items. This rulemaking was published in October of 2019. NW Natural is in compliance with the rule at this time.

11.1.2 Rulemaking No. 2

Non-Regulatory Mandate – involves repair criteria, integrity management improvements, cathodic protection, and management of change, risk modeling requirements, external corrosion, internal corrosion, risk assessment requirements, safety of launchers and receivers, surveillance after weather events, and other related rules. This rulemaking is on currently on hold.

11.1.3 Rulemaking No. 3

Safety of Gas Gathering Pipelines – involves gathering lines. The rule is currently on hold.

NW Natural will assess the full impact of all new or amended rules once published to understand the impact on operations and engineering practices. NW Natural will update programs and existing safety projects as needed to comply with new mandated requirements.

11.2 Docket No. PHMSA-2016-0016 – Underground Storage Facilities for Natural Gas

On February 12, 2020 the Final Rule incorporating API Recommended Practice 1171 referred to as the Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs by reference was published. NW Natural developed a storage well integrity program in compliance with API 1171 incorporating all required provisions into operations at Mist. NW Natural program is in compliance with the final rule as published.

12. Completed Projects (or scheduled to be completed in 2021)

12.1 Eugene Transmission (ILI) ($3.3 MM - Actual):

This project involved the transition of the Eugene transmission line from direct assessment to ILI. The Eugene transmission line is the primary feed to downtown Eugene and the University of Oregon. This pipeline is approximately 4 miles and is routed along Coburg Road. Work on this pipeline was completed in 2021.

12.2 Underground Storage - Well Integrity ($3.5MM – Actual)

This project involved the re-work and baseline assessment of seven wells in the Mist storage field. The 2021 projects are included in year three of NW Natural's well integrity baseline assessment work that includes down hole assessment of production casing and re-work of well tubing as at regular intervals. The program was developed to meet compliance with PHMSA's adoption of APR RP 1171 - Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. This is a multiyear project planned for completion in 2027.

12.3 South Eugene Transmission (ILI) ($1.4 MM - Actual):

This project involves transition of the South Eugene transmission line from direct assessment to ILI. The South Eugene transmission line is a transmission line from the South Eugene gate that primarily serves the IP Springfield facility and is approximately 6.5 miles in length. Work including station upgrades was completed in 2021. The ILI assessment and remediation of any identified anomalies will be completed in 2021.

12.4 Seismic Vulnerability Assessment and Study of NW Natural's Transmission Line System (2021 estimate of $1MM):

The performance of this assessment and study was completed in compliance with the recommendations of SB 33 (2013) published on October 1, 2014. SB 33 (2013) and in furtherance of the Governor's Resiliency 2025 Plan.

Results of the study will be used to identify projects to replace and/or fortify facilities determined to be vulnerable during events such as a Cascadia subduction zone earthquake. As identified and prioritized, these projects will be included in future SPPs. Future projects will complement existing TIMP mitigation programs, including but not limited to: installation of automatic shut-off valves ("ASVs") or remote control valves ("RCVs"), elimination of bridge crossings, natural forces mitigation work, system reinforcement, and valve installation.

12.5 Underground Storage Integrity – Mist Reliability ($2.2M - Actual):

As part of a mist reliability study and in anticipation of PHMSA's adoption of RP 1171, NW Natural performed inline inspection of four transmission pipelines that transport natural gas between storage wells at Mist into the NW Natural transmission system.

12.6 Labish Shallow Pipe Remediation ($1M - Actual):

As a result of NW Natural's regularly scheduled patrols of the transmission system a 1200' long section of 12" transmission pipe north of Salem was identified as having insufficient ground cover. Due to the depth of the pipe and the farming activities in the area the pipe was replaced. Work was completed in the fall of 2020.

12.7 12" Willamette River Crossing ($1.6M - Actual):

In 2014 an inline inspection was performed on Pipeline S02 from Aurora to Tualatin. This pipeline was primarily 12" in diameter and included a 10" Willamette River Crossing. During the inspection at the river crossing the geometry of the 10" pipe damaged the inspection tool. This project replaced the unpiggagle 10" section with a 12" river crossing allowing the line to be inline inspected. This crossing was installed, and successful ILI assessment completed in 2020.

13. Conclusion

This SPP provides an overview of NW Natural's pipeline safety initiatives and commitment to the safe and reliable delivery of natural gas to the communities we serve. Through its 160-year history, NW Natural has been committed to identifying threats to pipeline safety and taking steps to address and mitigate those threats. Looking forward to the role natural gas will play in our energy future, and as members of the communities we serve, NW Natural recognizes the trust placed on us by our neighbors and customers. NW Natural will continually work to ensure public safety and maintain the integrity of our natural gas system.

UG 435 OPUC DR 475 Attachment 3

Figure #1 P30 Central Coast Feeder North of the Siletz River 2 miles west of Lincoln Beach. Steel cable found wrapped around pipe when excavated.

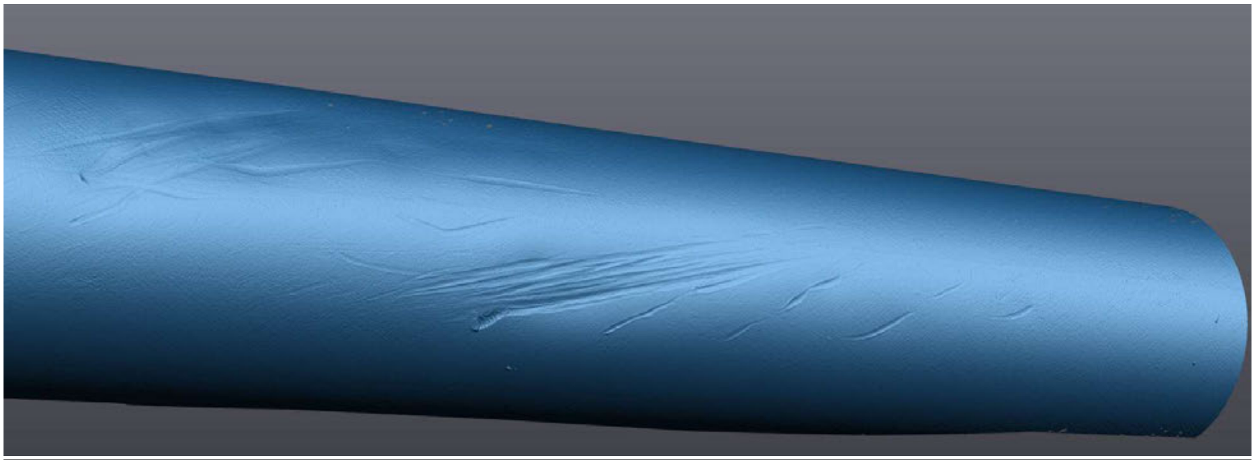

Figure #2 Scanned image of damage caused by cable

Figure #3 Metal loss caused by cable dragging along pipe

<u>Figure #4 Metal displacement caused by cable dragging along pipe</u>

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 476

476. In reference to NW Natural/400, Kizer/page 33 at lines 17-19, and NW Natural/400, Kizer/page 34 at lines 6-7, regarding EFV installations and the Company's requested annual recovery of $0.6 million:

a. Regarding the projected $0.6 million cost for future EFV installations related to the Distribution Integrity Management Program (DIMP), is the Company requesting rate recovery of these costs in this rate filing?

b. If yes, is any portion of the projected EFV installation cost considered "customer requested"?

Response:

a. NW Natural is seeking recovery for EFVs that are installed proactively on existing services between November 1, 2020 through October 31, 2022, and the EFVs forecasted into the test year ending October 31, 2023. These existing services were installed prior to the PHMSA EFV rule that requires the installation of EFVs on all residential services and certain commercial and multi-family building services starting in 2006. NW Natural assembled a list of services meeting that criterion and performed a system wide risk assessment of those services to be retrofitted with EFVs. NW Natural has created an Accelerated Action (AA) for EFV installations as defined in the NW Natural DIMP Plan and will be expanding this program in future years. Please refer to UG 435 CUB DR 3 Attachment 1 Appendix D for the Enhanced EFV Remediation Accelerated Action in the 2021 DIMP Plan.

b. No. None of the costs associated with the Enhanced EFV Remediation program are for customer initiated EFV installations. In compliance with 49 CFR 192.383, NW Natural has a process in place to allow customers to utilize their right to request the installation of an EFV at the customer's expense.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 477

477. In reference to NW Natural/400, Kizer/page 31 at lines 9-14, regarding the Company's requested annual recovery of $2.7 million for Underground Storage Facilities – Well Integrity Program:

a. What specific activities are performed for this annual expense? Please provide a narrative description sufficient to explain and support this ongoing expenditure request.

b. Please provide a breakout of the annual expense by activity type (e.g., $X for down well casing inspection required every Y years).

Response:

To the extent our initial rate case request was unclear, NW Natural clarifies that our rate case request has not sought recovery of costs of our Well Integrity Program beyond October 31, 2022.

Also, please note that the dollar amounts in NW Natural/400, Kizer/page 31 at lines 9-14 are typographical errors and should match the dollar amounts stated in NW Natural/400, Kizer/page 18 at lines 1-5. Therefore, NW Natural/400, Kizer/page 31 at lines 9-14 should read as follows:

Q. Please describe the estimated cost of the Company's Underground Storage Facilities – Well Integrity Program.

A. The estimated total cost of the Company's Underground Storage Facilities – Well Integrity Program in 2022 is $3.7 million or approximately $3.3 million on an Oregon-allocated basis. Similar annual costs are expected to continue for the life of the facility.

Background on Baseline Well Casing Inspections:

On December 19, 2016, PHMSA issued an interim final rule (IFR) establishing regulations for underground natural gas storage facilities (UNGSF). The IFR incorporated by reference RP 1171, “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs” (First Edition, September 2015). The IFR implemented PHMSA’s authority to regulate underground gas storage and the Congressional mandate in section 12 of the PIPES Act to establish minimum safety standards for depleted hydrocarbon reservoirs, aquifer reservoirs, and solution-mined salt caverns used for the storage of natural gas.

After issuance of the IFR, PHMSA considered public comments and a petition for reconsideration of the IFR and modified the minimum safety standards for UNGSFs in a final rule published on February 12, 2020 and effective March 13, 2020. Regarding its impact on Mist Storage, this final rule modifies compliance timelines, revises the definition of a UNGSF, clarifies the states’ regulatory role, reduces recordkeeping and reporting requirements, and formalizes integrity management practices.

Consistent with the final rule, NW Natural will run baseline casing inspection logs on each of its active gas storage wells prior to the March 13, 2027 deadline. In order to run these casing inspection logs, a considerable amount of work needs to be performed to prepare the site for a workover rig, isolate the gas well from the gathering system, and safely deconstruct the well to gain direct access to the production casing. NW Natural anticipates that it will complete the Mist Casing Inspection Program for all 41 of its utility gas storage wells by the end of 2025. As of March 2022, no rule has been issued that clearly addresses a minimum re-inspection frequency for well casing inspections beyond 2027, but we do expect that another rule will be issued to better define these requirements for the underground gas storage reservoirs beyond 2027. The costs for any future inspection program beyond 2027 are unknown at this time.

a. Specific activities that are performed for the wells selected for inspection each year as part of the Mist Casing Inspection Program include the following:

1) Site preparation work for workover rig and equipment
2) Isolation of gas well from topsides gathering equipment and system
3) Rig based work to deconstruct well, inspect production casing, and reconstruct well:
    i. Well kill procedure using bullheading method
    ii. Removal of Christmas Tree
    iii. Installation and testing of Blowout Preventer

iv. Removal of production tubing and bottomhole assembly from well
v. Run casing inspection logs through production casing
vi. Installation and testing of mechanical set packer with work string inside production casing
vii. Installation and testing of two safety valves on top of work string
viii. Removal of Blowout Preventer and tubing head
ix. Installation of new tubing head
x. Installation and testing of Blowout Preventer
xi. Removal of mechanical set packer with work string
xii. Installation of new production tubing and bottomhole assembly
xiii. Fill of inner annulus with kill fluid treated with biocide and corrosion inhibitor
xiv. Testing of new production tubing
xv. Removal of Blowout Preventer
xvi. Installation and testing of new Christmas Tree
xvii. Unload kill fluid from production tubing

4) Topside inspection and mechanical work to reconnect well to gathering equipment and system.

b. Breakout of annual expense by specific activity (based on historical averages on per well basis):

Since 2019 NW Natural has performed well casing inspection activities for five to seven wells per year. Annual expenses for the well inspection efforts are dependent upon the number of wells to be inspected and well type. In 2022, we will perform well casing inspections for four utility wells owned by NW Natural. NW Natural anticipates the average cost of the well rework in 2022 to be approximately $935,000 per well (without COH and contingency). The cost for well casing inspection activities vary by the specific scope of work required for each well. The average cost for well integrity inspection work can be broken down further by a range of percentage of the total well cost as follows:

1) Site preparation work for workover rig and equipment: **2-5%**
2) Isolation of gas well from topside gathering equipment and system: **1-3%**
3) Rig based work to deconstruct well, inspect production casing, and reconstruct well: **75-85%**
4) Topside inspection and mechanical work to reconnect well to gathering equipment and pipeline system: **8-15%**

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 478

478. In reference to NW Natural/600, Downing/pages 11-12, concerning the three Horizon Program development studies conducted by TMG Consulting (TMG), Infosys, and Deloitte:

a. Please provide the Oregon allocated cost for each of the three studies.
b. Are the costs for all three studies identified in (a.) above included in the current rate case?
c. Please explain why three independent studies were necessary.
d. Please explain how/why these studies are prudent and not duplicative in nature.

Response:

a. The Oregon allocated cost for these three studies are (i) TMG Consulting, identified as the CIS Assessment, system cost is $147,007, Oregon allocated amount is $131,248; (ii) Infosys, identified as the SAP study, system cost is $746,050, Oregon allocated amount is $658,389; and (iii) Deloitte, identified as the CIS study, is not currently allocated to state yet because it has not been placed in-service and still remains in construction work in progress (CWIP).

b. Infosys, SAP study, is the only study that is included in the current rate case.

c. Please see response to part (d).

d. These studies were prudent and not duplicative in nature.

    a. NW Natural commissioned a study in 2016 from TMG Consulting ("TMG"), an independent consulting company that specializes in CIS, to develop an application plan and business case for the potential upgrade, enhancement, migration, or replacement of the existing CIS platform. The TMG study recommended that the Company move forward with a CIS replacement strategy within the next several years, and transition to a new solution that allows for external, vendor-provided support and ongoing product upgrades.

    b. Infosys completed a second study in the first quarter of 2019, which provided a reliability assessment of NW Natural's ERP platform and use of

SAP. Infosys evaluated the current and future state of the ERP landscape and set out an implementation strategy and roadmap—accounting for improvement opportunities, potential benefits, success metrics, and high-level cost estimates. The Infosys study recommended that NW Natural move forward with the SAP ERP upgrade as the first step, before turning to the CIS replacement, because the CIS would be developed on the new ERP platform foundation. This order of operations would minimize the need to customize the CIS, while limiting both costs and risks.

c. To challenge and confirm the TMG recommendation with regard to CIS, we commissioned Deloitte to complete a third study in the second quarter of 2019, which provided an additional reliability assessment of NW Natural's CIS platform. This study identified a list of outstanding CIS projects needed to prepare for CIS replacement, verified TMG's conclusion that a CIS replacement is needed, and confirmed Infosys's recommendation that the ERP upgrade take place before the CIS replacement. Knowing that the ERP project would be a multiyear effort, NW Natural needed the confirmation that the current CIS could withstand the next few years. This confirmation was needed because if Deloitte's recommendation was to move forward with CIS project before the ERP, we would need to reassess. Infosys and Deloitte both recommended moving forward with the ERP project first.

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 479

479. In reference to NW Natural/600, Downing/pages 15-16, NW Natural/600, Downing/page 17 at lines 13-18, regarding the need to update the Company's enterprise resource planning (ERP) platform due to SAP ending support for NW Natural's current version of SAP in 2027:

a. Please provide additional explanation supporting why the SAP ERP upgrade is needed now.

b. In Docket No. UG 388, NW Natural/600, Downing/page 8 at lines1-3, the Company stated that it was primarily the 2025 SAP end of support date driving the need to upgrade the ERP platform. If SAP support has been extended from 2025 to 2027, why is it prudent to initiate the conversion to the newer version of SAP now?

Response:

a. NW Natural is upgrading the ERP platform now for several reasons. First, delaying the ERP upgrade would also delay the critically needed CIS upgrade. As detailed in the 2019 Infosys and Deloitte studies, it is important to complete the ERP upgrade before transitioning the Company's existing CIS platform in Horizon 2. Proceeding with the Horizon 1 ERP upgrade will allow the Company to turn to the Horizon 2 CIS upgrade in as timely a manner as possible, while saving on overall costs and avoiding unnecessary implementation risks.

   Second, the cost to upgrade to the new software is likely to increase substantially as the software company's 2027 support deadline approaches. Many different companies (including more than 20 utilities) rely on the existing SAP ECC software package, meaning that many different companies are—or soon will be—in the process of finding and installing replacement systems. This replacement effort requires the use of outside consultants to both perform and help oversee the critical upgrade process. Growing competition for these outside consultants means that waiting could substantially increase the necessary costs.

   Third, it is important to proceed now with the upgrade to the new ERP platform because the existing ERP software has limited functionality. The current system is 13 years old, has a long list of deferred enhancements, and is operationally cumbersome—requiring employees to use multiple applications to complete tasks and relying heavily on manual entries. In addition, the new S/4HANA ERP platform will avoid the need for substantial, costly investments that would otherwise be necessary to sustain the viability of the Company's current ERP platform and other key applications.

b. The Company objects to the data request's characterization of "primarily" as being overly broad under OAR 860-001-0500(2). In Docket No. UG 388, NW Natural/600, Downing/page 8 at lines 7-11, NW Natural stated that it "is upgrading to the new ERP now because: (1) the cost to upgrade to the new software is likely to increase substantially as the developer's 2025 deadline approaches; and (2) the current platform does not adequately support NW Natural's range of business needs that are necessary to serve customers." Notwithstanding this objection, the Company responds as follows:

On February 4, 2020, SAP extended its mainstream support deadline for the current version of NW Natural's ERP from 2025 to 2027. In light of this 2-year extension, NW Natural considered delaying the move to SAP S/4HANA, however, as stated at UG 435, NW Natural/Downing/page 17, lines 1-18, additional analysis supported moving forward with the transition to SAP S/4HANA now. Following SAP's announcement, the Company examined the costs and benefits of delaying the ERP replacement project. As noted above, NW Natural's decision to proceed with the SAP ERP upgrade was driven by (1) the need to support the CIS upgrade because the current platform is antiquated; (2) the likelihood of substantial implementation cost increases as the support deadline approaches; and (3) the inadequacy of the current ERP platform for NW Natural's business and customer-service needs. Delaying the move to SAP S/4HANA would increase the cost and risk of the CIS upgrade, increase the overall costs of the transition, and fail to address the functionality concerns of the existing ERP platform. With these concerns in mind, NW Natural concluded that it was prudent to proceed with the transition to SAP S/4HANA now.

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Request No.: UG 435 OPUC DR 480

480. In reference to NW Natural/600, Downing/page 20, lines 8-18, regarding the $1.85 million in incremental O&M cost savings ascribed to the new SAP ERP platform:

a. Please provide the workpaper(s) and supporting analysis documents used to quantify the incremental O&M savings.

b. How will NW Natural track whether the new ERP platform generates the projected "aspirational savings" for O&M expense?

c. If "aspirational savings" for O&M expense exceed the projected amounts, please explain how the Company will return the additional savings to customers.

Response:

a. Please refer to UG 435 OPUC DR 202 Attachment 2 “Sunsets” tab (system-wide costs), and Confidential UG 435 OPUC DR 205 Attachment 2 for calculations (system-wide costs).

b. The system amount of $1.5 million, $1.35 million Oregon allocated, in cost savings are described in Confidential UG 435 PC DR 205 Attachment 2. These savings reflect identifiable reductions in O&M costs that are currently included in revenue requirement, largely driven by expected improvements to supply chain management and organizational efficiencies. NW Natural has reduced revenue requirement in anticipation of capturing these benefits. The cost savings may take more than one year to harvest but were included as an offset to revenue requirement immediately when the project is included in rates.

   We have also included as an offset to revenue requirement $0.6 million system, $0.5 million Oregon allocated, of reduced costs related to replaced or retired applications. These include removing any remaining depreciation expense from the legacy SAP system and removing sunsetting applications from rates that will no longer be used after Horizon is implemented. This amount is not included as “aspirational savings.”

Business Performance Metrics are in process of being developed by the Horizon 1 Program. These metrics will provide a defined set of business performance metrics that align with Horizon 1's objectives, scope and business case justification and provided recommended calculation, target performance values, suggested data source, and data collection approach. The company will begin measuring its performance post go live.

c. If savings in O&M expense exceeds the projected amounts, customers will benefit from those savings in the Company's next general rate case. In such a case, the Company's base year will reflect those savings, and will consequently be reflected in the test year costs in our next general rate case.

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Data Request Response

Request No.: UG 435 OPUC DR 481

481. In reference to NW Natural/600, Downing/page 21, lines 1-9, regarding the $11.8 million in Oregon allocated ERP replacement avoided costs:

a. Please provide the workpaper(s) and supporting analysis documents used to quantify the Oregon allocated avoided costs.

b. If both the newest version and legacy version of SAP are supported by the vendor, please explain why the legacy version would incur significantly higher vendor support costs compared to the newest version.

Response:

a. Please see UG 435 OPUC DR 481 Attachment 1.

b. If the Horizon 1 project was delayed, the projects listed in UG 435 OPUC DR 481 Attachment 1 would need to proceed forward to address end of life/support applications as well as critical business needs that cannot be delayed further. Not proceeding forward with these projects would increase NW Natural's operational risks as these applications support our compliance activities, inventory management and budgeting. The SAP ERP upgrade project still would have been required; thus, overall costs would be higher. These are high level estimates of the overall project costs provided by external consultants during the SAP study and Horizon 1 Pre-Planning Initiatives.

Process	Project Name	Description	High Level Estimates	Estimated Duration	Details
EAM	PCAD Upgrade		$2,500,000	24 months	External labor plus licenses - $1,500,000; Internal labor - $1,000,000
	Construction Planner Replacement		$1,200,000	6-8 months	Labor - $1,100,000 plus training $100,000
	Advantica Upgrade		$250,000		Project needs to proceed forward due to application being shut down by the vendor
	Mobility Refresh		$510,000	NA	183 devices at $600 each; 6 devices at $3500; 439 devices at $875
	Goods Receiving process	Redefine goods receipt process to streamline steps, reduce manual interaction, include automation, bar code scanning, and use Fiori app to standardize and reduce required steps	$500,000	6 months	Labor - $500,000
	Planning Forecast, MRP, master data management	Establish material requirements forecasting from use of historical consumption and MRP executions. Will include Material master data field standardization and value enhancement to support MRP executions to create purchase requisitions and purchase orders.	$500,000	6 months	Labor - $500,000
	Quality Management Implementation	Implementation of SAP QM to establish inspection requirements for specific inbound inventory. This will include but not be limited to requirements for creation of inspection plans that require collection, scanning, and storage of vendor pressure certification documents.	$600,000	6 months	Labor - $600,000
	Mobility for Inventory Control	Refine Outbound Goods Issue process to streamline steps, reduce manual interaction, include automation, bar code scanning, and use Fiori app to standardize and reduce required steps.	$690,000	9 months	Labor - $630,000; Training - $50,000
	AP Invoice Automation	Implementation of Open Text Vendor Invoice Management for AP invoice automation	$1,270,000	6 months	Labor $1,200,000; software - $70,000
Finance	Budgeting, Planning, Consolidations and Reporting - Phase I – O&M Budgeting and Consolidations	Implementantion of SAP Analytics Cloud and Group Reporting	$3,610,000	12 months	Labor $3,000,000; software - $610,000
Environmental, Health and Safety	EH&S Implementation	Implement incident management	$942,000	9 months	Labor - $850,000; software - $92,000
	Damage and Claims Implementation	Implement the damage and claims capabilities	$640,000	9 months	Labor -$540,000; training - $100,000
	EHS Mobility	Implement Mobility Capabilities for Environment, Health and Safety	$200,000		Labor - $160,000; Training - $40,000
			$13,412,000		
		Oregon Allocated	$11,836,090		

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 482

482. In reference to NW Natural/600, Downing/page 30, Table 1 at line 6:

a. Please clarify that the total Oregon allocated dollar amount for Horizon capital costs of $63.7 million excludes the other IT projects noted in NW Natural/600, Downing/page 2, lines 5-11.

b. If the Horizon Program is primarily a cloud based solution, please provide a detailed response explaining how significant capital costs associated with this project are prudent.

c. Regarding the $8.8 million in "contingency and other costs", have any of the contingent funds been used or are projected to be used? If yes, please provide:

i. A breakout for each specific project cost overrun necessitating the use of contingency funds.

ii. A detailed explanation describing why each cost overrun occurred.

iii. A detailed description of the steps the Company took to manage project costs and adhere to the Company approved project budget.

iv. If the contingency funds are not needed to complete the project, how will the Company remove these costs from this rate case?

Response:

a. The total Oregon allocated dollar amount for Horizon capital costs of $63.7 million excludes the other IT projects noted in NW Natural/600, Downing/page 2, lines 5-11.

b. The Financial Accounting Standards Board (FASB) issued Accounting Standards Update 2018-15 (ASU 2018-15) specifically to address accounting for cloud-computing software. This update requires companies to capitalize certain costs associated with implementing a cloud arrangement. These costs include implementation to get the hosted service set up, configured, and ready for use. Additionally, new software licenses qualify for capitalization as they fall in the category of Bring Your Own License (BYOL). This means we own the licenses and could pull them from the cloud and install locally if we chose to in the future.

The implementation for cloud or on-premise solutions of these applications will still require design, configuration, development, testing and deployment activities to be successful.

c. Contingent funds have been used and are projected to be used.

i. Please see UG 435 OPUC DR 482 attachment 1, column E – Amount of Change. Total approved contingency use through March 31, 2022, is $4,519,671, Column E Row 23.

Total projected contingency use through March 31, 2022 is $975,000, Column E Row 29. Analysis is still underway for scope and work effort; these are estimates provided by our service integrator.

The Horizon Program is still in process and additional items requiring the use of contingency funds may be required. At this point, the project anticipates a need to use the remainder of the contingency funds by October 31, 2022, but are not currently projected or known.

ii. Please see UG 435 OPUC DR 482 attachment 1, column G – Reason for Change.

For the change orders over $1 million dollars, we have attached the change order requests that provide additional details around the explanation of cost overrun. IQGEO change order for $2 million, see UG 435 OPUC DR 482 attachment 2. Reporting change order for $1.5 million, see UG 435 OPUC DR 482 attachment 3.

For the projected change orders, analysis is still underway for scope and work effort; these are estimates provided by our service integrator and will follow our change control process for approval.

iii. The Horizon Program is a multi-tier structured and adhered-to governance model with key leadership providing direction and oversight. Please see attachment UG 435 OPUC DR 482 attachment 4.

The Horizon Program has an established Change Control Process that aligns to the governance model. Please see attachment UG 435 OPUC DR 482 attachment 5.

Below is the Horizon Program meeting cadence directly related to project costs:

1. Weekly review of project costs with NWN program Finance and Accounting
2. Weekly review of contractual obligations and service level credits with NWN program team and NWN legal team
3. Weekly review of change control board
4. Monthly Service Level Agreement metrics review with program team and Accenture
5. Monthly invoice review with Accenture and program Finance and Accounting

6. Monthly review of project costs with program Finance, Accounting, Rates and Regulatory, and Program Executives

7. Quarterly review of projects costs with the Senior Executives and IT&S Alignment Team

Following the Horizon Program governance model, change control process, and meeting cadence describes the process that the Horizon Program follows to manage project costs and adhere to the Company approved project budget.

iv. If contingency funds are not needed to complete the project, the Company is willing to adjust the capital in its compliance filing to the actual amount spent for Horizon, when the project goes into service.

Approved Contingency Costs	Work Stream	Cost Type	Title of Change	Amount of Change	Description of Change	Reason for Change
	Security	Capital	SAP UI Data Masking Software License	$ 13,000	SAP Software (license) costs associated with User Interface Data Masking and Logging	Determined to be required during design phase of the project to ensure access to PII or sensitive data is restricted and monitored
	SAP SW	Capital	SAP UI Data Masking Implementation	$ 191,700	Implementation costs of the User Interface Data Masking and Logging software	Determined to be required during design phase of the project to ensure access to PII or sensitive data is restricted and monitored
	SAP SW	Capital	SAP LAMA Licensing Cost	$ 60,394	SAP Software (license) costs associated with Landscape Management (LAMA) tools	Determined to be required during design phase of the project to enable automated end to end system copy and refresh needed to support testing and training preparation for the project and during operations
	Tech Arch	Capital	SAP CHARM Implementation	$ 68,000	Implementation costs to enable change management controls for SAP	Determined to be required during design phase of the project to enable automated change management for SAP (migration of code from development to production) to support SOX reporting and monitoring
	RTR	Capital	PowerPlan Lessor Module Implementation	$ 42,500	Costs to implement the PowerPlan Lessor Accounting module	Determined to be required during design phase of the project to handle lessor type leases for fixed assets accounting to support ASC842 accounting standard
	EAM	Capital	Clevest changes for truck stock	$ 68,092	Costs to develop an enhancement in scheduling dispatching software	Determine to be required during design phase of the project to handle ability to manage truck stock by resource center which aligns to NWN requirements
	IQGEO	Capital	Mobile geospatial/mapping implementation	$ 2,000,000	Costs to implement mobile geospatial/mapping solution to support execution of field work	Determined to be required during design phase of the project to enable fully integrated field solution inclusive of mapping/geospatial capabilities to support safe field operations
	SCM	Capital	Mobility deployment to Sunset resource center	$ 200,000	Costs to deploy the mobility items (scanners and printers) to Sunset Pipe Yard and Sunset Resource Center	Determined to be required during design phase of the project to support pipe inventory management
	RTR	Capital	Concur modifications	$ 10,905	Costs to modify Concur application to accommodate chart of accounts changes	Determined to be required during design phase of the project to support chart of accounts changes and financial reporting
	EAM	Capital	Clevest mobility enhancement	$ 42,000	Costs to implement an enhancement to enable Clevest integration with mobile mapping solution	Determined to be required during design phase of the project to support integration method required for mobility mapping solution

Approved Contingency Costs	Work Stream	Cost Type	Title of Change	Amount of Change	Description of Change	Reason for Change
	HR	Capital	HR PTO Time Bidding	$ 12,000	Costs to implement an enhancement to manage the field PTO requests capabilities	Determined to be required during design phase of the project to support NWN requirements of managing BU employees PTO requests and adherence to collective bargaining agreement
	PwC	Capital	Adding Ariba and Fieldglass	$ 90,000	Costs to include Ariba and Fieldglass in scope for PwC assessment	Determined to be required for full assessment of business process controls for P2P, Ariba and Fieldglass needed to be included in scope
	IT&S	Capital	Training Environment	$ 4,900	Costs to implement dedicated SAP training environment	Determined to be required during design phase of the project to support project and post project training activities
	HTR	Capital	Hypercare Extension	$ 5,750	Extended post go live support for SuccessFactors compensation module	Determined to be required during hyper care for release 1 to enable continued support to minimize risk
	SCM	Capital	Fieldglass Integrations (SAP)	$ 113,250	Costs to enable integration between SAP and Fieldglass	Determined to be required during design phase of the project to support ability to link invoicing from external service providers with specific work orders for more accurate reporting and reconciliation
	HR	Capital	EC Employee CoA Data Conversion	$ 10,100	Costs to implement SuccessFactors Employee Central work required by the change in employee cost centers driven by the new Chart of Accounts	Determined to be required during design phase of the project due to Chart of accounts changes
	EAM	Capital	Clevest Device Certification	$ 35,000	Costs to certify NWN laptops by Scheduling and Dispatching software vendor	Needed to ensure break fixes are addressed by the software vendor; NWN laptops version currently deployed in the field is not certified for this scheduling and dispatching software
	EAM	Capital	Clevest Enhancement	$ 50,000	Cost to implement an enhancement to enable unplanned and temporary resource schedule changes	Determined to be required during development phase of the project to enable temporary schedule changes
	HTR	Capital	Workforce Custom Reports	$ 2,080	Costs to implement custom reports	Determined to be required during development phase of the project to support time management reporting that could not be met with standard reports
	Reporting	Capital	Reporting Gaps Phase 2	$ 1,500,000	Costs to implement reports required for go live	Determined to be required during design phase of the project - these operational reports were identified as needed to support compliance and regulatory reporting.
Total Capital Implementation Costs				**$ 4,519,671**		

Projected Contingency Costs	Work Stream	Cost Type	Title of Change	Amount of Change	Description of Change	Reason for Change
	HTR/RTR	Capital	HTR/RTR payroll	$ 425,000	Costs to implement automation of payroll accounting postings	Required to support automation of payroll accountings and corrections
	EAM	Capital	Clevest Upgrade	$ 550,000	Costs to implement integration with Clevest and Workforce for resource schedule override	Required to support automation of temporary resource schedule changes without this automation additional manual process that does not exist to day will need to be in place increasing overall risk of errors and reducing efficiencies
Total Projected Capital Change Orders				**$ 975,000**		

HORIZON 1

Edge Systems: IQGEO Change Order Request

October 14, 2021

Edge System: IQGEO Request

Ask: Requesting to utilize H1 contingency funds to support the IQGEO work.

Background:

- Edge Systems are systems that integrate with Horizon 1 applications.
- Approximately 20 edge systems have been identified. Some of these systems require changes within the application itself to accommodate new Horizon 1 design decisions.
- One system, IQGEO, requires new functionality to be developed + updates to existing functionality to support field operations and achieve desired efficiencies.
- A high-level estimate of $1.1M 3rd Party Integrator External Services was made at budget establishment for system integration work.
- IQGEO required effort was significantly underestimated. Scope was not fully known until scope confirmation wrapped up in September and the detail scope + changes required on the IQGEO platform, as well as integrations with Clevest + S4 were confirmed.
- Original assumption was that Clevest would provide further functionality than what was confirmed during scoping confirmation.

Cost: $2.05M

Details:

- **The Gartrell Group = $1.5M**
- **IQGEO = $550k**
- Transfer of funds from Horizon 1 Contingency to IQGEO WBS
- Horizon 1 Contingency total after transfer = $6.25M
- Neither System Integrators costs include Contingency
- NWN Internal labor (approx. costs $255K) absorbed in current H1 spend

Edge System: IQGEO Request

Risks:

- **Not completing this work will leave the field with less functionality than they have today impacting the accuracy of data collection and work completion in the field.**

- **Delaying the start of this work will also impact H1 overall completion timeline as this functionality is required at go live.**

- **Failure to manage schedule and meet tight timelines**.
  - Mitigation: Requesting that IQGEO help support this scope of work, allowing shared responsibilities with IQGEO & Gartrell.
  - Mitigation: Additional Horizon 1 NWN PM to provide oversight.
  - Mitigation: Establishing an integrated project timeline and a standalone Planview project.

- **Given the change impacts from ongoing work (Field Web Mapping) to H1 there is a risk of change fatigue, lack of change delivery ownership, and lack of change consistency as a unified front.**
  - Mitigation: Defining roles and responsibilities up front with Gartrell / IQGEO / NWN / Accenture
  - Mitigation: Aligning with H1 OCM workstream to provide a seamless experience to end users.
  - Mitigation: Minimizing or consolidating changes introduced from now until the July 2022.

Edge Systems: IQGEO Vendor Costs

Future-State Maturity Level by Option	MVP		Recommended		Optimized	
Approximate Cost[1]	$1.81 M		$2.05M		$2.2M	
Scope	Base MapFrame Functionality	Refactor Advantica Retirement	Enable Clevest	Fully Integrate with S4	Extend	**Comments**
Ability to create leak pool drawings linked to ABC leak inspections	●	●	●	●	●	Alternative: Clevest Mock-Up
Service As-Builting[2]	●	●	●	●	●	Alternative: Clevest Mock-Up
* Asset Map Viewer	●	●	●	●	●	Alternative: None
Ability to send IQGeo work artifacts back to S/4 (i.e. as-built pdf)		●	●	●	●	Store as-built pdf to order and enable ERV integration
Refactoring to S/4 (Leak & Inspection Survey, 5.0 Inspections)		●	●	●	●	Partial Alternative: Heath sustains outside of Clevest
* ArcGIS Server to enable Clevest utility map feature layers		●	●	●	●	Alternative: None
Clevest to IQGeo UX Integration (Deeplink)[2]				●	●	Integrate primary field solutions (IQGeo/Clevest)
Refactor Leak & Inspection exception reports to integrate with S/4					●	Optimize follow-up process
Enable Polygon based inspections (descoped)						For future evaluation (FWM 5.1)
Benefits						
Align to future target states (Clevest, S4, IQGeo)	Low	Med	Med	Med	High	Enable work execution cohesion between our core EAM solutions
Fully enable Clevest functionality	Low	Low	High	High	High	Provide map visibility to both crew proximity and core utility assets (pipe, valves, etc.)
Simpler, more cohesive end user experience	Low	Low	Low	Med	Med	Allow field users to be able to easily navigate from Clevest to IQGeo, saving time and effort
Advancement in geospatial strategy goals	Med	Med	Med	Med	Med	As-builting in IQGeo is a big step forward towards our geospatial goals. This will be a temporary hop until we get to as-builting supported by a network connectivity model (network manager)
Lessen the impact to field users by optimizing change and training activities between Horizon and FWM	Med	Med	Med	High	High	Allows us to build logically on FWM training and change efforts, instead of training on one thing and then moving to a very different approach in less than a year
Reduction of risk in delivery timeline	High	Med	Med	Med	Low	Additional scope increases the potential impact on Horizon 1 timelines

Benefits Level: Low, Med, High

1 - Costs represent the System Integrator costs (The Gartrell Group and IQGeo) only. It does not include NWN labor (expected $254K), SW, cloud or contingency.
2 - Scope items in consideration for IQGeo as a vendor (instead of Gartrell)
* - prioritized for immediate start 10/18

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Staff/202
Fieldheim/128

Edge Systems: IQGEO NWN Resources

NWN Resources[1]		
Name	**Allocation increase**	**Cost increase through August 2022** (utilized Grade 23 as an estimate)
Eric Stipe	25% (50% -> 75%)	$33,500
Shivon Van Allen	10%	
Felex Wong	10%	$17,000
Andrew Shepherd	10%	$17,000
Ashley Moran	10%	$17,000
Travis Juhr	10%	$17,000
Richard Treece	10%	$17,000
Joe Mautino	10%	$17,000
Israel Todd	10%	$17,000
Justin Pool	10%	$17,000
David Blan	10%	$17,000
Rebecca Mateo	10%	
Sam Rookstool	10%	$17,000
Margaret Locke	10%	
Ryan Pemberton	10%	$17,000
Derek Van Hoeter	10%	$17,000
PK Kamma	10%	$17,000
	Total	**$254,500**

1 – Only includes incremental changes, not resources that are already fully allocated to Horizon 1. Additional resource requirements that are already allocated are not displayed.

Edge Systems: 3rd Party Budget Overview

3rd Party Budget = $1.1M Original Budget				
Name	**Actuals**	**Forecast**	**Total**	**Notes:**
Ardalyst (COM)	$38,790	$158,820	$197,610	Final bid
Utilities International (UI Planner	$56,015	$100,000	$156,015	Final bid
Planview	$3,897	$17,200	$21,097	Final bid
Insight (Red Hat + Linux Support)	$202,287	$0	$202,287	Final bid
TakuSaku (Sharepoint - Workflows)	$27,000	$13,500	$40,500	Final bid
Accenture (Data Masking - Security)	$8,000	$5,000	$13,000	Final bid
TakuSaku (Sharepoint - Incident)	0	$100,000	$100,000	Still to be confirmed
SAP (Concur)	0	$100,000	$100,000	Still to be confirmed (by 10/22)
Vertex (CIS)	0	$100,000	$100,000	Still to be confirmed (check with Kristin/Roller)
Gartrell Group (IQGEO)	$68,000	$1,488,424	$1,556,424	Waiting on final bid (by 10/22)
IQGEO	0	$528,670	$528,670	Waiting on final bid
Message Broadcast				Meeting next week to review message options; will be asking for ballpark quote
TOTAL:	**$403,989**	**$2,611,614**	**$3,015,603**	
Original Budget:			**$1,100,000**	
Variance:			**$1,915,603**	
Request for Contingency:			**$2,050,000**	

HORIZON 1

Reporting Gaps Phase 2 Change Order Request

March 21, 2022

NW Natural®

Reporting Phase 2 Request

Ask: Requesting to utilize H1 contingency funds to support the Reporting Phase 2 work.

Background:

- Business Analytics conducted a report investigation with SMEs in the business and identified reports required by the business that were not being addressed directly by Horizon 1:
  - Attributed reports to six business groups (RMC/CFS, Gas Supply/Storage, Accounting/Tax/Finance, Engineering, Damages/Claims, Compliance).
  - Facilitated work sessions with managers, supervisors, and SMEs for each group to identify audience, usage, data sources, frequency, and necessity of each report.
  - Held report showcase meetings for Clevest and WorkForce to demonstrate future OOTB functionality available in native reporting, discovered that Clevest will discontinue their Jasper report engine and replace it with Power BI reporting in the next release.
  - IT&S technical SMEs identified technical detail and history available in reports.

Cost: $1.49M

Details:

- **Slalom = $1.5M**
- Transfer of funds from Horizon 1 Contingency to Reporting WBS
- Horizon 1 Contingency total after transfer = $3.78M
- System Integrator costs does not include extra contingency
- NWN Internal labor absorbed in current H1 spend due to shared resources

Reporting Phase 2 Request

Risks:

- Not completing this work will leave the field users with less functionality than they have today impacting the accuracy of data collection and work completion in the field.
- Delaying the start of this work will also impact H1 overall completion timeline as this functionality is required at go live.
- Reports using multiple data sources and existing Power PI reports will need to be refactored / rebuilt in any case due to changes in source data.
- Any reduction of scope will result in broken reports, loss of functionality, and increased O&M load on the business due to manual work arounds.

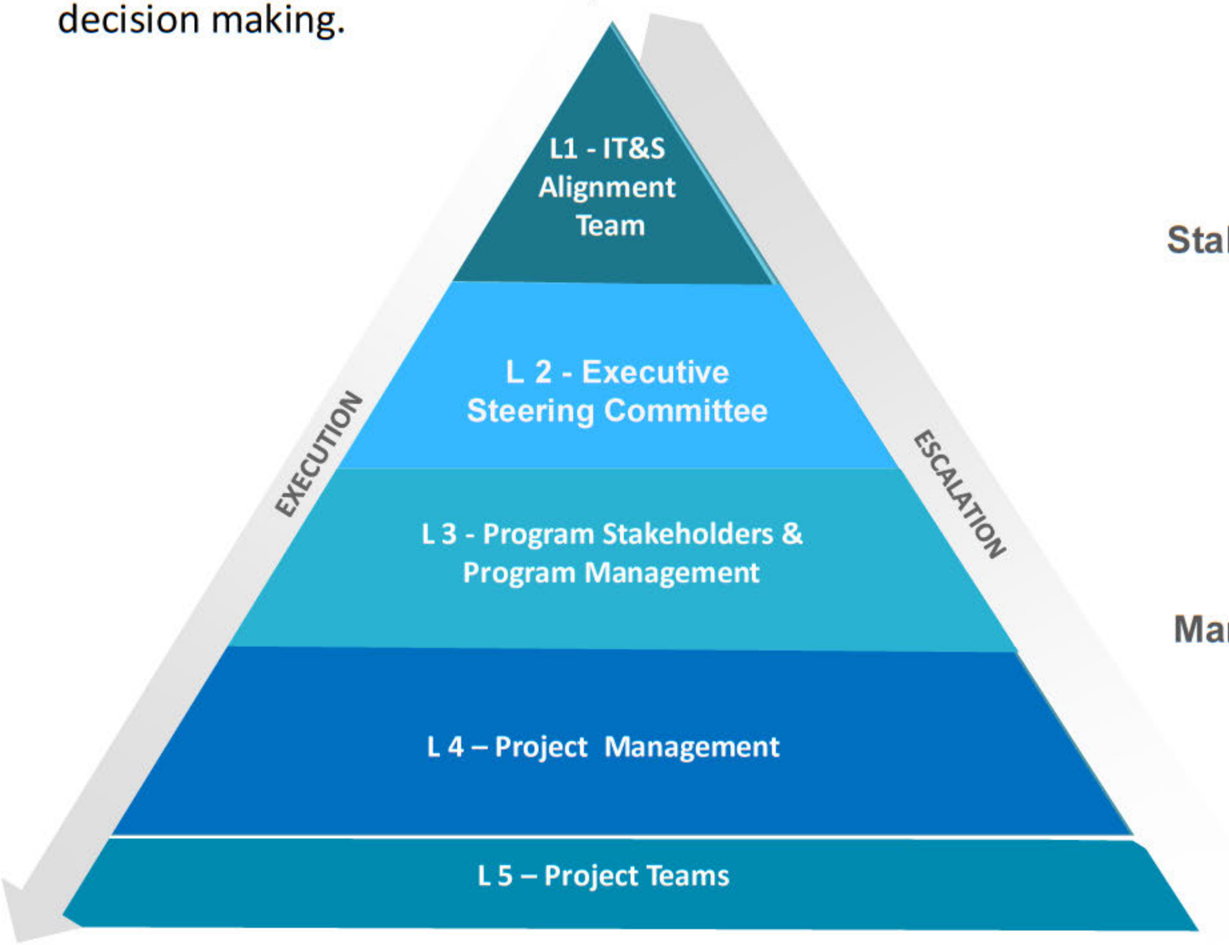
Reporting Gaps 2 – Use Cases

Build working solutions and develop nine (9) use cases (associated with sixty-eight (68) reports) in the new Azure-based EDP with Power BI, leveraging new and existing data sources that are needed at Horizon 1 Go-Live (July 2022):

1. Construction Planner Operations
2. Work and Resource Management
3. Productivity
4. Order Search
5. Emergency Response
6. Schedule Compliance
7. Field Data Completion
8. Cathodic Protection (CP) Inspections
9. Overtime

Program Governance

Our governance framework provides a practice to ensure transformational efforts achieve business alignment, consistency and sustainment. The model contains tools, methods and resources needed for clarity of communications, and transparency of reporting and decision making.



ROLE	RESPONSIBILITIES
IT&S	• Communicates with CEO, stakeholders, and leadership as appropriate
Exec Steering Committee	• Provide vision, goal, strategy, priority, budget, and direction for program • Significant changes to scope, timeline and budget • Provide oversight and guidance to all team members • Resolve non-project related roadblocks • Resolve enterprise level strategic issues as they arise
Program Stakeholders	• Responsible for overall business priorities for the workstreams • Approve deliverables and project completion • Advocate for required process changes within their business areas • Resolve cross functional issues as they arise • Reallocate team member responsibilities as needed to meet project requirements • Communicate with Exec Steering Committee
Project Management	• Accountable for budget and timelines • Coordinate activities across workstreams • Assume responsibility for project execution, all workstream tasks and activities • Represent workstreams in all project activities, deliverables, decisions, and team meetings • Resolve project roadblocks • Provide advice and guidance to the workstreams • Communicate with Program Stakeholders

Docket No: UG 435

Staff/202
Fjeldheim/135

HORIZON 1

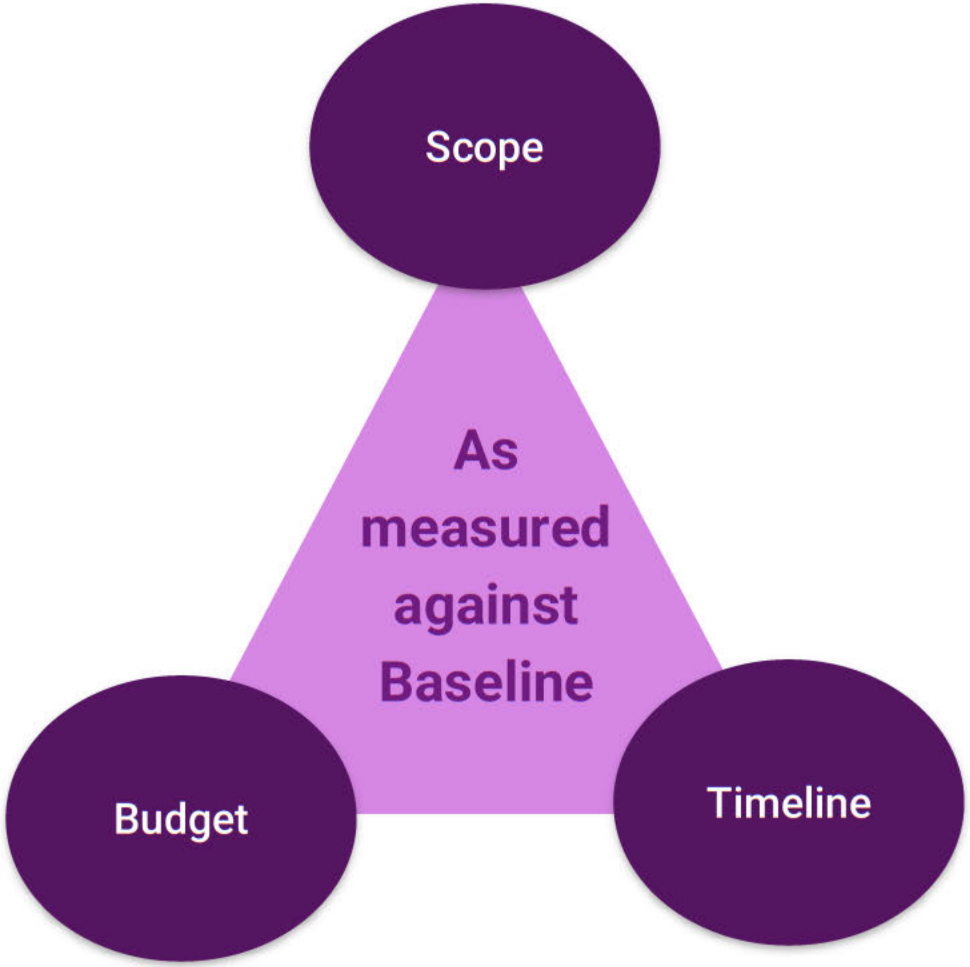
Change Control Process

Change Control Board

Jennifer Chiaratti / Dave Karpinsky

NW Natural®

What constitutes a Change?



Change Request (CR) constitute any proposed modifications during the project in the context of what has already been “agreed & signed off” in one of the project deliverables and can have an impact on the key objectives or constraints of the project.

CR can result from one or more of the following (not exhaustive):

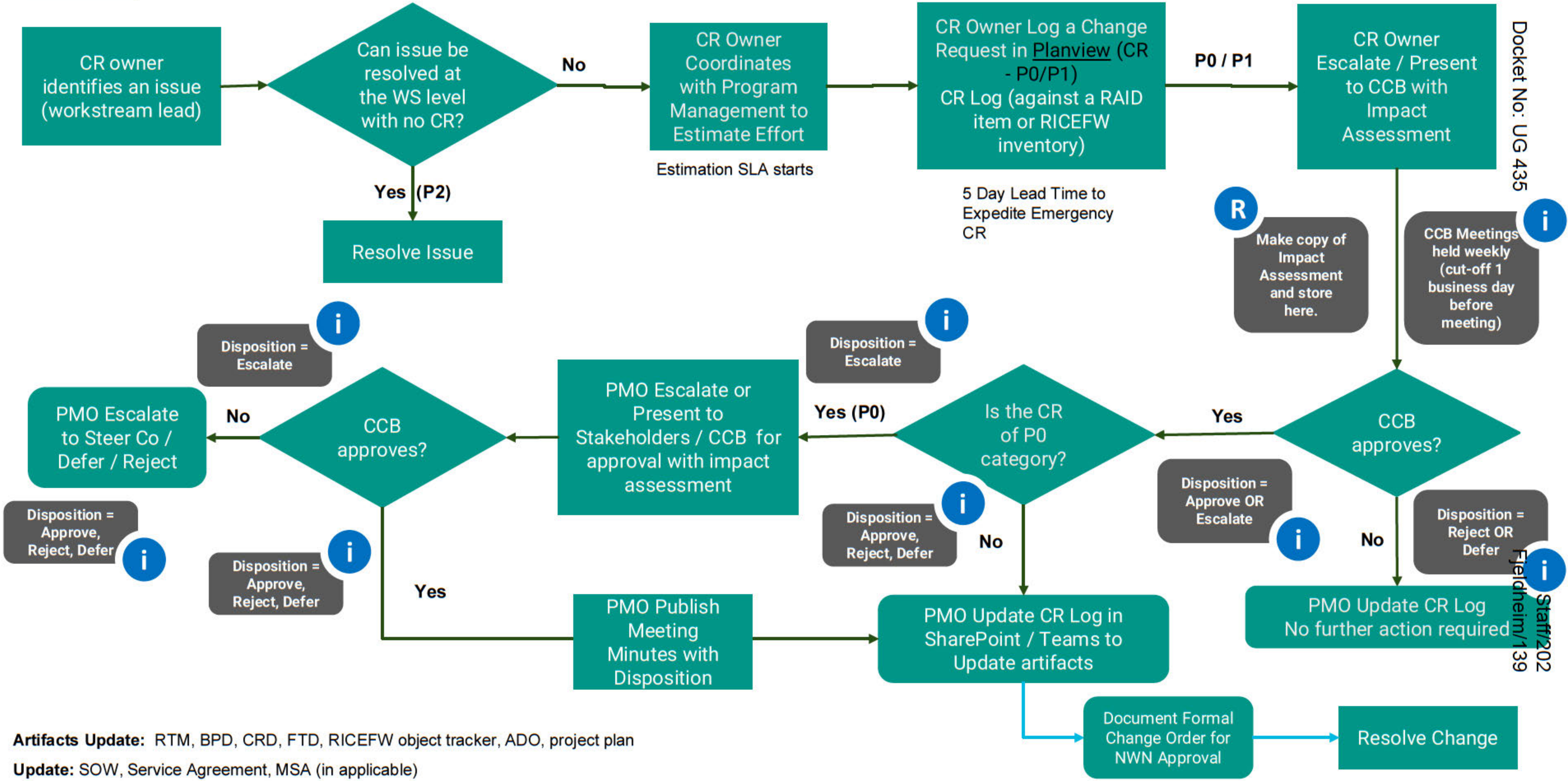
- Change in requirements
- Gaps in design
- Technical limitations identified during build resulting in design changes
- Delayed timelines for certain key activities
- Additional resources required

Who Approves the Change?

- CR's can be submitted by any Leads or PMO
- All work effort or changes to original scope by Phase against a given deliverable must be logged as a CR
- All Extensions or Changes to SAP Core Code will require approval by CCB (2nd level of approval)

Project Levels	Schedule Impact	Scope Impact	Effort/Cost Impact
0 Level of Approval (P2) Workstream Leads (Workstream Solution Architects)	No change to deliverable dates and/or milestones	No changes to scope	No changes to a baseline within the cost / effort
1st Level of Approval (P2) CCB	Set / change deliverable dates and/or milestones. Less than 1 week impact. Workplan date change from baseline, within workstream	Minimum change to scope, no cross functional impact; impacts only one specific team	$\leq$ 40 hours OR $10,000 aggregate work effort against given deliverable for all CRs tied to the same deliverable
2nd Level of Approval (P1) Program Stakeholders (CCB)	Set/change deliverable dates and/or milestones. Less than 2 weeks impact. Workplan date change from baseline, impacting other workstreams due to dependency	Major changes to scope. Cross functional impact	>40 hours and $\leq$ 80 hours OR $20,000 total work effort aggregate given deliverable for all CRs tied to the same deliverable
3rd Level of Approval (P0) CCB > SteerCo (Exec Sponsors)	Set/change deliverable dates and/or milestones AND project phase end date extended over 2 weeks.	Significant changes to scope. Cross functional impact	>80 hours total work effort or greater than $20,000 against given deliverable for given CR

Step 1 – Submission of Change Request

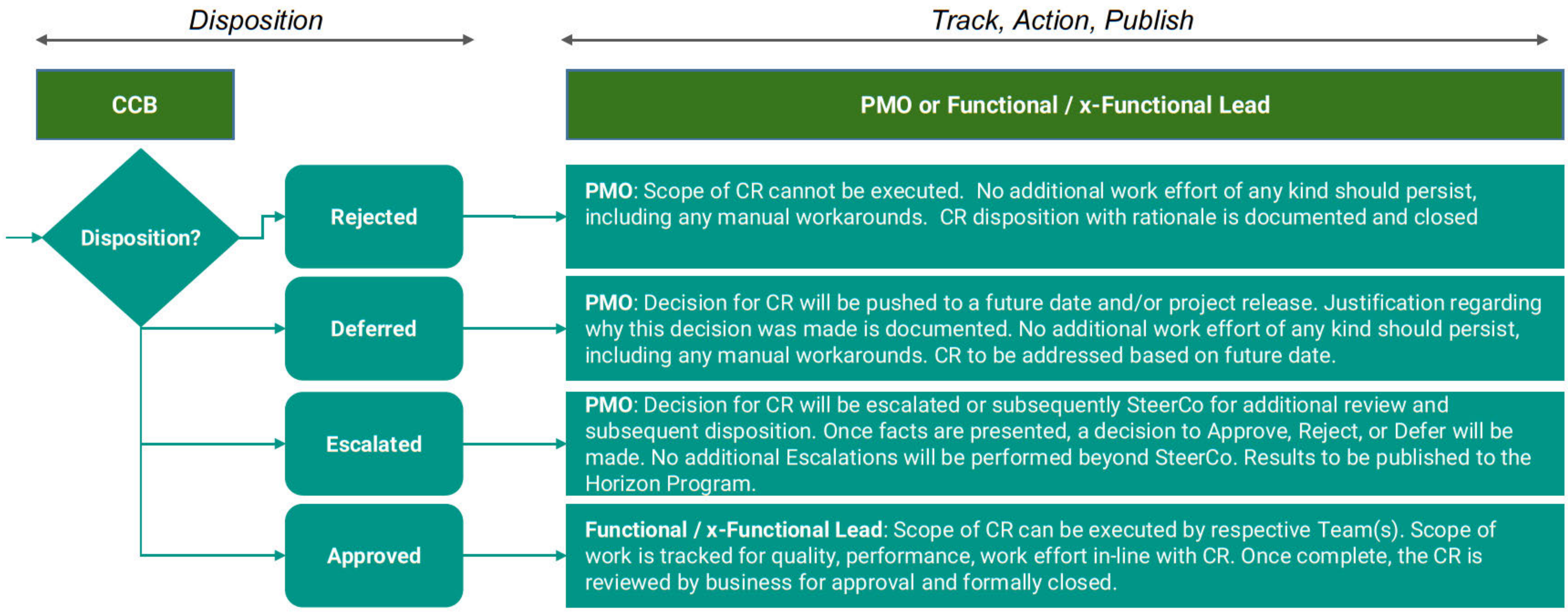


Artifacts Update: RTM, BPD, CRD, FTD, RICEFW object tracker, ADO, project plan

Update: SOW, Service Agreement, MSA (in applicable)

Step 2 – Disposition with Change Control Board

CRs will follow the process shown below for Dispositions from the Change Control Board (CCB):



Change Control Meeting Cadence

Standard CCB Meeting Cadence

- Initially, the CCB will meet weekly each week to review normal Change Requests that are ready for review. Agenda to be sent day before.
- The list of CRs to be reviewed at the next CCB meeting is always available in the CR Log
- If an emergency CR has been submitted, then the CCB shall meet same day as when the emergency CR is ready for review
- As Release gets closer to go live, the frequency of CCB meetings will be increased, as required

Meeting Attendance

- Voting Members:
- ***NWN:*** *Jennifer Chiaratti, Dave Karpinski, Dina Thompson, Joe Sciacca*
- ***Accenture***: Karen Mok (Approval delegate is Rasika Purohit), Joseph Valerio, Leo Muritiba, Joao Assuncao
- Presenters: *CR Owner(s)*: Functional or Horizontal Leads

Emergency Meeting Cadence

- *Definition*: An "emergency CR" is a CR that is time sensitive and must be escalated faster than the arranged review process. Emergency CR's usually result from an unexpected result that must be acted on in less than 5 business days.
- Emergency CR's should be immediately escalated to the CCB. In the event a CR is deemed an emergency, a CCB review meeting can be called immediately to address the issue raised.

Change Request Traceability

Actions required if a Change Request is "Approved" or "Deferred"

Tracking the Deliverable

- If CR is to create a new Configuration or RICEFW object and "Approved" or "Deferred", then a new object will be created in the deliverable tracker with work effort by Complexity and due date by CR disposition.
- If CR is against an existing Configuration or RICEFW object and "Approved" or "Deferred", then a new sub-RICEFW object will be created in deliverable tracker (e.g. RICEFW-A, RICEFW-B, etc.) with representative dates for when the work will begin and work effort by Complexity by CR disposition.

Within Existing Deliverable Document (i.e. does not apply if it is a New CR "Approved") – RTM, BPD, CRD, FTD, RICEFW object tracker, ADO

- With the Revision History of the respective deliverable, the Change Request ID (C-xxxxx generated in Planview) should be included along with the Title of the CR and link to the CR document change to occur
- Notations should be made within the detailed portions of the respective deliverable(s) to reference the Change Request ID (C-xxxxx)

Change Request Use Cases

Description of Change	Impact	Category	Category Rationalization
Add a new column to a RICEFW (design change)	FSD changed. Object development is not complete and the impact is assessed to be minimal	P2	No impact on any of the key constraints
New requirement for an user validation or customization (Scope change)	Good to have. Hence low on priority. Additional effort required is minimal and can be absorbed in the current work plan	P2	Low priority. No considerable impact on the project if change is not approved
Change in customization needed (design change)	Customization is of low complexity and requires minimal additional of effort which can be absorbed in the current work plan	P2	Minimal impact on effort. No impact on budget or critical path
New reporting requirements identified (Scope change)	Reports pertain to statutory reporting. Additional efforts required > 40 hours. Does not impact the critical path	P1	Has a moderate cost impact due to re prioritization of resources. However there is no impact to critical path
Delay in Mock 1 execution (timeline change)	Delays Mock 1 timelines, which risks further test cycle timelines. Replan needed. Critical path not impacted due to buffer days	P1	Timelines are delayed. However critical path is not impacted
Major P0 defect in UAT for a core functionality that requires additional time to be resolved	Go-live delayed	P0	Go live dates cannot be met
Edge System not ready (scope / design change)	The edge system will continue to remain "As Is" and will be handled by a manual process workaround	P0	This will change scope and add to the scope of the future release

Change Request Use Cases

Description of Change	Impact	Category	Category Rationalization
RTR UAT delayed by 1 week (resource / budget change)	While the changes in RTR will be absorbed in subsequent sprints (hence P1), this has impact on <system>, where <system> has conflicting priorities resulting from this delay	P0	Additional resources needed in <system> to align with the RTR UAT timelines
Verily -> EAM integration cannot be completed by RTR	While the basic integration for Consolidation will be still be done in RTR, the BW integration will be done as part of Fincore-R2	P0	Scope is getting changed between releases
A business process related to Intercompany processes will not be ready for SIT1 (timelines)	The business process will be tested in SIT2	P1	SIT1 scope is getting changed

Important Callouts

1. Classification of critically of a CR
   - Whenever there is a use case that falls between P2 or P1, it is advised to treat it as P1
   - For use cases falling between P1 & P0, it is advised to log it as P0
2. CR impacting other pillars or releases
   - In case the CR impacts other workstreams / releases, the team initiating the CR will be responsible for liaising with the other WS teams and incorporating the impacts on the overall impact analysis
   - Other workstreams should log a CR for their work streams as necessary
3. **Once a CR is approved, please ensure that ALL relevant documentation (such as requirements. design, tickets (including related tickets), documentation etc.) has been updated, with revision history populated with the CR #**

Intake form

Intake form to have following:

- Name of Change Request
- Date submitted
- Description
- Propose applicable Deliverables
- Determine if CR will require resources, products, services or Deliverables that are different from original scope
- Type of change request (scope, schedule, budget)
- Assessment – Rationale / Justification
- Impact if not done
- Impact Assessment and Update to SOW, Service Agreement, MSA if applicable
- Alternative options including manual workarounds or post go-live deferral
- Workstream impact
- Identify interdependencies amongst projects, tasks timelines, responsibilities
- Identify amendments to the terms and conditions of existing schedules
- Identify cost of implementing CR
- Identify roles, responsibilities (including timeline, milestones, deliverables, specifications)
- Disposition Status – Approve, Reject, Defer, Escalate
- Date Disposed (within 10 days of logging CR with impact assessment completed)

Changes to Members

Updates

- Dan Chesser moved off project in September 2021 – Joe Valerio is the new named member
- Omar Bell moved off project on 10/31/21 – Rasika Purohit is the new named delegate member for Karen Mok
- James Xu moved off project on 2/28/21 – Leo Muritiba is the new named member

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 483

483. Regarding the Company's response to Staff DR 296, Attachment 1, please confirm:

a. Are any of the projects and associated dollar amounts from the Excel file "UG 435 OPUC DR 296 Attachment 1", Excel Tab "B – D" included in the present rate case filing?

Response:

Yes, the projects and associated dollar amounts in Excel tab “B – D” are included in the present rate case filing.

CASE: UG 435
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203
IS CONFIDENTIAL

Exhibits in Support
Of Opening Testimony

April 22, 2022

CASE: UG 435
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

April 22, 2022

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

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

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. My testimony addresses cost management and efficiencies, escalation, income taxes, taxes other than income, and utility plant.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. What areas of NW Natural's filing are you primarily responsible for reviewing?

A. I have primary responsibility for reviewing cost management and efficiencies, escalation, income taxes, taxes other than income, and utility plant other than information systems and safety related projects. In order to gain additional insight, I reviewed the Company's responses to Staff's Standard Data Requests (SDRs), issued approximately 43 additional data requests (DRs), and reviewed the Company's responses. I also reviewed the responses to pertinent requests issued by other parties in this case.

Q. Are you discussing all of the above issues in your opening testimony?

A. Yes.

Q. Please briefly summarize your conclusions regarding these issues.

A. I recommend revisions of Test Year expenses based on Commission precedent, changes the Company made to its initial filing in errata filings, other updates and corrections proposed by the Company, and Staff's analysis of the estimates and methodologies underlying the Company's filing.

I propose plant in service be limited to property used and useful at the rate effective date, in accordance with Oregon law, and propose other adjustments to rate base resulting from Staff discovery.

Q. Please summarize your proposed adjustments.

A. My proposed adjustments are summarized in the following table.

Adjustment - increase (decrease) in thousands	Revenue	Expense	Rate Base
Issue 1, Escalation		$ 67	
Issue 2, OCAT Deduction For State Income Tax		[redacted]	
Issue 3, Excess Deferred Income Taxes		(100)	
Issue 4, Property Taxes		(47)	
Issue 5, Regulatory Commission Expenses		408	
Issue 6, Plant Test-Year Capital Expenditures		[redacted]	[redacted]
Issue 7, Land and Building Adjustments		(502)	2,843
Issue 8, Excess Budget for District Regulators			[redacted]
Issue 9, Attestations and Other Project Adjustments		TBD	TBD
Issue 10, Property Sales (no revenue requirement effect)			
Total	$ -	$ (2,660)	$ (27,778)

Please note that I may revise my recommendations based on testimony filed by other participants in this rate case.

COST MANAGEMENT AND EFFICENCIES

Q. Please summarize actions taken to mitigate the effects of a rate increase and other efficiencies asserted in the Company's testimony.

A. The Company cites the following mitigating actions:[1]

- Delayed effective date for the updated depreciation study.
- Choosing the lowest point in the range of ROE recommended by the Company's expert witness.
- Requesting an accounting order to extend the depreciable life of Horizon 1 from 5 to 10 years.
- NW Natural's overall capital and O&M expenditures that compare favorably with peer utilities.

The Company also discusses specific savings expected to arise from information technology projects:

- Savings from moving vehicles and equipment from the LNG Facility to the Central Resource Center (NWN/500, Pipes/33).
- Workspace efficiencies and lease savings resulting from the Enterprise and Large Projects Space (NWN/500, Pipes/54).
- Business efficiencies resulting from the Data Analytics and Reporting Implementation (NWN/600, Downing/5-6).
- Ongoing O&M cost savings resulting from the Horizon 1 upgrade, identifiable reductions in O&M costs driven by expected improvements to

[1] NWN/100, Anderson-Kravitz/20-24.

supply chain management and organizational efficiencies (NWN/600, Downing/20).

- Efficiencies of the new IT&S environment (NWN/600, Downing/35).
- Employee efficiencies and improved collaboration capabilities (NWN/600, Downing/43).
- Efficiencies incentivized by pay at risk (NWN/800, Rogers/12 and 14).

Q. Regarding the specific savings asserted, what are Staff's findings?

A. For the most part, the savings are not quantified. In response to Staff DRs, the Company asserts Test Year savings of $51 thousand for 250 Taylor, $1.5 million for Horizon 1, and $600 thousand for software no longer needed.[2]

Otherwise, the Company's responses indicate that savings are either non-quantifiable or future oriented using phrases such as; "there are no savings included in the Test Year", "we expect savings to be present in expense levels of future rate cases", "It is difficult to quantify the efficiencies as they are qualitative in nature", and "cost savings related to efficiencies are not quantifiable at this time, we expect savings to be in expense levels of future rate cases".[3]

Q. What does Staff recommend?

A. Staff recommends the Commission require the Company to report annually regarding the status of further savings that are not quantified in the test year.

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2 UG 435 OPUC DR 205 NWN Response.pdf and UG 435 OPUC DR 206 NWN Response.pdf.
3 UG 435 OPUC DR 205 NWN Response.pdf.

ISSUE 1. ESCALATION

Q. Please provide a summary of the Commission's historical treatment of escalation and the latest available information.

A. The Commission has a long history of express reliance on the All-Urban CPI in its determination of wages and salaries[4] and Staff uses it almost invariably to escalate costs in a general rate case. As the Commission has noted, "the All-Urban CPI measures price changes in a fixed market basket of goods and services in 200 categories, generally including housing, apparel, transportation, medical care, recreation, education, and others to urban consumers."[5] "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."[6]

The most recent release of the All-Urban CPI was the March 2022 report, released February 9, 2022. According to Appendix A of this report, the percentage change for U.S. All-Urban CPI for 2021, 2022, and 2023 are 4.7 percent, 4.2 percent, and 2.2 percent, respectively.

Q. What are the escalation rates stated in the Company's filing?

A. Except for several specific items, non-payroll costs were adjusted using the most current West Region Urban Consumer Price Index ("CPI") as reported in

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[4] *See e.g., In the Matter of Portland General Electric Company Request for a General Rate Revision,* Docket No. UE 197, Order No. 09-020, p. (January 22, 2009) (Commission using All-Urban CPI to escalate wages and salaries); *In the Matter of Northwest Natural Request for a General Rate Revision*, Docket No. UG 132, Order No. 99-697, p. 37 (November 12, 1999) (Same).

[5] *Northwest Natural,* Docket No. UG 132, p. 37, n10.

[6] *Ibid.*, p. 38.

the December 2021 Oregon Economic and Revenue Forecast, published by the Oregon Office of Economic Analysis ("OEA").[7]

These rates are 4.5 percent, 3.9 percent, and 2.4 percent for 2021-2023, respectively.[8]

Q. Do these rates agree with the work papers underlying the Company's filing?

A. Not entirely. Staff's review of the Company's model[9] indicates 4.0 percent was used for 2021 rather than 4.5 percent. However, Staff calculates the impact of this difference to be only $11 thousand dollars as the rate is only applied to the last three months of 2021. The Company's base year includes actual expenditures through September 2021.

Q. Regarding the February All-Urban CPI forecast discussed above, what would be the impact of using those rates?

A. Staff asked the Company to calculate the impact of using the U.S. All-Urban CPI rates of 4.7 percent, 4.2 percent, and 2.2 percent which the Company calculates would result in a net increase in O&M of $67 thousand.[10]

Q. What is the Company's rationale for using the West Region instead of the U.S. All-Urban CPI?

A. The Company states this is because most of the Company's non-payroll expenses (e.g., office supplies, utilities, repairs and maintenance, contractors,

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7 NWN/1200, Davilla/3.
8 NWN/1203, Davilla/41.
9 UG 435 OPUC DR 143 Attachment 1.xlsx.
10 UG 435 OPUC DR 358 NWN Response.pdf.

professional services) are regional purchases (i.e., purchases made within Oregon or southwest Washington).[11]

Q. Does Staff recommend using the All-Urban CPI rather than the West Region CPI even though STAFF'S adjustment results in a slight increase to test year expense?

A. Yes. Staff's use of the U.S. All-Urban CPI is a longstanding practice and coupled with specific adjustments, where justified, provide a conservative yet fair and reasonable test year test year estimate. The fact the use of the All-Urban CPI results in a slight increase for this cost category is not material. What is material is the consistent use of an appropriate escalator year over year. The Commission has observed that 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.[12]

Q. What does Staff recommend?

A. Staff recommends the Commission allow an additional $67 thousand O&M increase to account for the update February U.S. All-Urban CPI rates as discussed above. Staff recommends that Commission reject the Company's proposed use of West Region rates.

[11] NWN/1200, Davilla/9.
[12] *NW Natural Gas Company,* Order No. 99-697, p. 38.

INCOME TAXES

Q. Please summarize the portions of NW Natural's testimony where income taxes are discussed.

A. Income taxes are discussed in the testimony Kyle Walker, NWN/xxx, at pages:

- 14-15 Income Taxes
- 15-16 EDIT
- 24 Deferred Income Tax
- 24 EDIT Rate Base
- 29-30 Gas Reserves Excess Deferred Income Tax

Q. What are the requirements of Oregon law regarding the inclusion of income taxes in utility rates?

A. Income taxes in utility rates are subject to the requirements of ORS 757.269.

> **757.269 Setting of rates based upon income taxes paid by utility; limitation on use of tax information; rules.** (1) When establishing schedules and rates under ORS 757.210 for an electricity or natural gas utility, the Public Utility Commission shall act to balance the interests of the customers of the utility and the utility's investors by setting fair, just and reasonable rates that include amounts for income taxes. Subject to subsections (2) and (3) of this section, amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operations of the utility.
>
> (2) During ratemaking proceedings conducted pursuant to ORS 757.210, the Public Utility Commission must ensure that the income taxes included in the electricity or natural gas utility's rates:
>
> (a) Include all expected current and deferred tax balances and tax credits made in providing regulated utility service to the utility's customers in this state;
>
> (b) Include only the current provision for deferred income taxes, accumulated deferred income taxes and other tax related

items that are based on revenues, expenses and the rate base included in rates and on the same basis as included in rates;

(c) Reflect all known changes to tax and accounting laws or policy that would affect the calculated taxes;

(d) Are reduced by tax benefits generated by expenditures made in providing regulated utility service to the utility's customers in this state, regardless of whether the taxes are paid by the utility or an affiliated group;

(e) Contain all adjustments necessary in order to ensure compliance with the normalization requirements of federal tax law; and

(f) Reflect other considerations the commission deems relevant to protect the public interest.

(3) During a ratemaking proceeding conducted under ORS 757.210 for an electricity or natural gas utility that pays taxes as part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon:

(a) Whether the utility's affiliated group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation;

(b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or

(c) Any other considerations the commission deems relevant to protect the public interest.

(4)(a) Because tax information of unregulated nonutility business in an electricity or natural gas utility's affiliated group is commercially sensitive, and public disclosure of such information could provide a commercial advantage to other businesses, the Public Utility Commission may not use the tax information obtained under this section for any purpose other than those described in this section, in ORS 757.511 and as necessary for the implementation and administration of this section and ORS 757.511.

(b) The commission shall adopt rules to implement paragraph (a) of this subsection that:

(A) Identify all documents and tax information that an electricity or natural gas utility must file in its initial filing in a proceeding to change rates that include amounts for income taxes, recognizing that any party may object to providing such documents on the grounds that they are not relevant; and

(B) Determine the procedures under which intervenors in such proceedings may obtain and use documents and tax information to fully participate in the proceeding.

> (5) As used in this section, "affiliated group" means a group of corporations of which the public utility is a member and that files a consolidated federal income tax return. [2011 c.137 §1]

Q. Please summarize Staff's review of income taxes in this case.

A. Overall, Staff concludes that the Company's provision for tax appears to be correctly calculated for rate making purposes with the exception of the Oregon Corporate Activity Tax (OCAT) and ARAM EDIT estimates as discussed further below, Staff issued a number of data requests and analyzed the Company's responses.[13] Staff's examination and discovery included confirming the federal and state tax rates, flow through of pre-1981 tax benefits, calculation of current and deferred income tax expense, application of tax credits, and the ongoing ratemaking treatment of excess deferred income taxes (EDIT) as approved in prior Commission orders.

Q. Are you proposing adjustments with respect to income taxes?

A. Yes. My proposed adjustments are discussed in issues 2 and 3 below.

[13] NW Natural Responses to Staff Data Request Nos. 345-349.

ISSUE 2. OCAT DEDUCTION FOR STATE INCOME TAX

Q. Please explain how the Oregon Corporate Activity Tax (OCAT) is reflected in the filed case.

A. Expense for the OCAT in the amount of $3.15 million was moved into base rates in the UG 388 case.[14]

The OCAT is included in the Company's initial filing as follows:

- Base year at present raters $3.207 million.[15]
- Test year at NWN's present retail rates $3.339 million.[16]
- Test year at NWN's proposed retail rates $3.658 million.[17]

Q. Overall, does Staff dispute the Company's methodology for calculating the OCAT?

A. No, however Staff notes that the Company includes the incremental OCAT increase due to the proposed increase in base rate revenue. Accordingly, if the Commission approves a rate increase less than this amount then amount of OCAT expense would need to be reduced accordingly.

Q. Is the Company's OCAT expense overstated in the initial filing?

A. Slightly, Staff noted that the increase between text year at present rates and proposed rates is $319 thousand while the Company's detailed model shows

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14 See *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 388, Order No. 20-364, p. 18-19 (Oct 16, 2020).

15 NWN/1308, line 13, column a. Not labeled clearly on NWN/1308; however the amounts match detailed calculations in UG 435 - Exh. 1300 - WP1 - Revenue Requirements Model.xlsx.

16 NWN/1308, line 13, column c

17 NWN/1300 - WP1 - Revenue Requirements Model.xlsx, Proof of CAT in Proposed Total. OCAT increase is subsumed within state excise tax increase of $5.714 million shown on NWN/1302, line 12, column d.

$310 thousand. Staff ascertained that this difference is due to a $7 thousand "plug" figure in the model. In response to Staff DR, the Company states that this is a carryover from its last general rate case, UG 388, and is, in the Company's view, immaterial.[18] Staff would note that this ought to be removed as the revenue model is updated.

Q. Why is the OCAT not included as a revenue sensitive cost in the conversion factor?

A. Inclusion as a revenue sensitive cost has not been explicitly considered by the Commission however it has not been treated as such in the approved rates for NW Natural nor the other investor owned utilities. In Staff's view, including the OCAT as a revenue sensitive cost would be problematic because the effective OCAT rate is not a straight percentage of revenue due to the numerous possible exclusions applicable to the definition of commercial activity and the 35 percent deduction for cost inputs or labor costs.[19]

Q. Regarding state income taxes, does Staff agree with how the Company reflects the OCAT as an expense?

A. No. Staff's review of NWN Exhibit 1308 indicates that the OCAT is not being included as a deductible expense for state tax purposes in the Company's tax provision. In response to a Staff DR, the Company agrees with Staff's understanding that OCAT is a deductible expense and indicates an adjustment

[18] Staff/302, NWN Response to Staff DR 345.

[19] See ORS Chapter 317A and OAR 150-317-1000 through 1500. Staff also notes that the Company's 2020 OCAT tax return has been provided to the parties (NWN Response to Confidential UG 435 AWEC DR 49 Attachment 1.pdf).

of **[Begin Confidential]** [redacted] **[End Confidential]** is appropriate with respect to the amount of state tax in the Company's errata filing.[20]

Q. Does Staff agree with this adjustment?

A. Not entirely. **[Begin Confidential]** [redacted] **[End Confidential]**

However, as the Company has acknowledged that the base rates finally adopted by the Commission in this proceeding will not exceed the revenue requirement amount reflected in its initial filing,[22] the appropriate amount of CAT expense is not to exceed the $3.658 million included in the initial filing.

Q. What does Staff recommend?

A. Staff recommends the Commission reject the Company's proposed correction as discussed above, subject to a final adjustment to reflect the final revenue increase approved in this case.

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20 Confidential UG 435 DR 346 Attachment 1.xlsx

21 The Company's response to Confidential UG 435 DR 346 Attachment 1.xlsx indicates at total state tax amount of **[Begin Confidential]** [redacted] **[End Confidential]**.

22 As stated in errata filing.

ISSUE 3. EXCESS DEFERRED INCOME TAXES

Q. Please briefly describe excess deferred income taxes and the Commission's resolution in NW Natural's recent rate cases.

A. Excess Deferred Income Taxes (EDIT) are deferred taxes paid by customers in rates prior to 2018 that became refundable as a result of the 2017 Tax Reform Act which reduced the Federal corporate tax rate from 35 percent to 21 percent. EDIT can be either protected or unprotected. Protected EDIT can be returned to rate payers no faster than the rate allowed under IRS normalization rules (also known as the Average Rate Adjustment Method or ARAM).

The 2017 Tax Act created three categories of EDIT for NW Natural:

- Protected EDIT
- Unprotected EDIT
- Gas Reserves EDIT

The ratemaking treatment of the unprotected and gas reserves EDIT has been previously resolved in prior Commission orders and need not be repeated here.

Q. Please summarize how the protected or ARAM EDIT is reflected in this case.

A. ARAM EDIT amortization in the amount of $3.0 million is included in Exhibit 1308, line 13, columns (b) and (d) for the base year and test year, respectively.[23] This $3.0 million amount is unchanged from the prior rate case.[24]

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23 NWN/1308, line 13, columns (b) and (d), also include Federal R&D credits of $82 thousand.

24 UG 388_OR2020_Revenue Requirements Model_Settlement - FINAL for Compliance Filing.xlsx and UG 388 - Exh 1000 - WP5 - EDIT Rate Base Adjustment.xlsx.

Q. Why would the ARAM EDIT amortization remain unchanged from the prior rate case?

A. In response to Staff DR 346,[25] the Company provided the ARAM amortization (actuals and estimates) for calendar years 2018 through 2025. The schedule also includes the annual ARAM amortization included in ratemaking (actual and proposed) as well as how these figures track against the cumulative totals.

The $3.0 million is the amount the Company estimates can be returned to ratepayers without exceeding the ARAM "speed limit".

Q. What is the ARAM "speed limit"?

A. The "speed limit" is a term coined by NW Natural in the UG 388 case that simply means the maximum rate that ARAM EDIT benefits can be returned to ratepayers without triggering a normalization violation.[26]

Q. What is a normalization violation?

A. Normalization is a system of accounting used by regulated public utilities to reconcile the tax treatment of the Investment Tax Credit (ITC) or accelerated depreciation of public utility assets with their regulatory treatment. Under normalization, a utility receives the tax benefit of the ITC or accelerated depreciation in the early years of an asset's regulatory useful life and passes that benefit on to ratepayers ratably over the regulatory useful life in the form of reduced rates.[27]

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25 UG 435 OPUC DR 346 NWN Response.pdf, Confidential UG 435 DR 346 Attachment 2.xlsx

26 See *In the Matter of* NORTHWEST *NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, Docket No. UG 388, (October 16, 2020), NW Natural/2500, Borgerson/22.

27 IRS Revenue Procedure 2017-47.

A violation of the normalization rules would, in particular, eliminate NW Natural's ability to use accelerated depreciation for tax purposes which would have significant negative implications for the Company's cash flow.

Q. Please elaborate on the Company's response to Staff's data request regarding ARAM EDIT.

A. As discussed above, the Company has provided its ARAM EDIT estimates through 2025.[28] [**Begin Confidential**] [redacted] [**End Confidential**]

Q. What does Staff recommend?

A. Staff recommends increasing the ARAM EDIT amortization in rates from $3.0 million to $3.1 million thereby decreasing the amount of federal tax expense by $100 thousand per year. This represents a compromise that will return benefits to customers faster while still leaving a reasonable buffer in the cumulative amount returned.

28 Confidential UG 435 DR 346 Attachment 2.xlsx.

TAXES OTHER THAN INCOME

Q. Please provide a summary of the Commission's historical treatment of taxes other than income.

A. The category "taxes other than income" (Other Taxes) typically includes franchise fees, the regulatory fee imposed by the OPUC, property taxes, payroll taxes and other miscellaneous taxes or fees (e.g., the Oregon Dept. of Energy (ODOE) energy supplier assessment (ESA)), incurred by the energy utility. Payroll taxes are included as a component of wages and salaries, which is discussed in a separate section of Staff's testimony.

Franchise fees, along with business or occupation taxes, licenses, and similar exactions or costs, are allowed as operating expenses for ratemaking purposes on the condition these costs do not exceed 3.0 percent of gross revenues for a gas utility.[29] For simplicity, these costs are referred to collectively as franchise fees.

The OPUC fee and ODOE assessment are also included in operating expenses for ratemaking purposes. In rate cases, franchise fees and the OPUC fee are a function of the fee rate multiplied by gross revenues and are called revenue sensitive costs. Additionally, these revenue sensitive fees are included in the conversion factor used to determine the revenue requirement.

The ODOE ESA is an annual assessment based on both the Company's annual business revenues and ODOE's revenue need. This means the ODOE

[29] See OAR 860-022-0040(1). Fees that exceed three percent must be charged to the customers within the *jurisdiction* assessing the fee. (OAR 860-022-0040(6)).

ESA can vary from year to year based on the ODOE assessment dollar amount, year-to-year variations in the Company's gross revenues, and the relative percentage of the Company's annual revenues when compared to the combined annual revenues of all Oregon power suppliers.

Property taxes related to property that is not yet used and useful may not be included in customer rates of a gas utility.[30] Hence, these property taxes are excluded from the Test Year operating expenses. Property taxes related to property that is used and useful are included in Test Year operating expense and are usually forecasted for ratemaking purposes based on historical property tax information.

Q. Please discuss Staff's overall recommendations regarding taxes other than income.

A. Regarding franchise fees and the ODE Energy Supplier Assessment (ESA), Staff notes that application of its methodology from the UG 388 case would have resulted in a higher allowed amount in this case. As Staff's methodology was known to the Company but not used, Staff is not recommending an adjustment.

Regarding property taxes and OPUC fees, Staff's recommended adjustments are discussed in Issues 4 and 5 below.

Regarding all other items in this category, Staff recommends the Commission accept the Company's estimate of other taxes, such as permits

[30] See ORS 757.*355*(1).

and licensing fees, which are forecasted based on an average of the three years ending September 30, 2021.

Finally, Staff's recommendations regarding the Oregon Corporate Activity Tax (OCAT) are discussed in the income tax section of this testimony due to discussion of a related change in the Company's tax provision.

However, Staff notes that Oregon Department of Revenue has stated that the CAT is not an income tax.[31]

[31] "The CAT is imposed on taxpayers for the privilege of doing business in this state. The CAT is not a transactional *tax*, such as a retail sales tax, nor is it an income tax. Oregon's CAT is measured on a business's commercial activity – the total amount a business realizes from transactions and activity in the normal course of business in Oregon": https://www.oregon.gov/dor/programs/businesses/Pages/CAT/CATFAQ.aspx.

ISSUE 4. PROPERTY TAXES

Q. Please summarize how NW Natural has estimated property taxes in the past.

A. In UG 388, Staff concurred with the Company's adoption of a three-year average to develop their property tax rate. Staff proposed an adjustment of ($30) thousand in opening testimony based on how this methodology was applied and recommended truing up to the final net plant.

Q. Please discuss how property taxes have been estimated in this case.

A. The methodology in the Company's initial filing was changed to match Staff's method in the UG 388 case. However, as a result of the Company's errata filing,[32] which occurred on February 28th, estimated net plant at December 2022 was corrected and has increased from $2.068 to $2.119 billion.[33]

Staff notes that the 2019-2021 net plant in Exhibit 1311 was also corrected (an increase) therefore the weighted average rate declined thereby reducing test year property tax expense.

Q. What does Staff recommend?

A. Staff recommends the Commission accept the reduction in property tax expense of ($47) thousand in the errata filing.[34] Staff also recommends that the final property tax expense in this case be adjusted to reflect the actual level of rate base approved.

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32 See NW Natural's Errata *Sheets correcting* two FERC accounts that were excluded from rate base. (Feb 28, 2022.)

33 Errata Exhibit NWN/1311, line 6, column f.

34 $27,124,558 – 27,172,015 = $47,457.

ISSUE 5. OPUC FEE

Q. Please discuss how regulatory commission expense is calculated.

A. In UG 388, the OPUC fee was adjusted to the then effective rate of 0.350 percent. The initial filing in this case uses the then effective rate of 0.375 percent. This effective rate is applied to total operating revenue as shown on Exhibit 1302.

Q. Has the rate changed subsequent to the Company's initial filing?

A. Yes, the rate has increased to 0.430 percent. [35]

Q. What does Staff recommend?

A. Staff calculates the resulting incremental change to the Test Year at Present Rates to be $408 thousand, recommends the Commission approve this increase in expense, and finally, recommends that the conversion factor by updated to reflect the new 0.43 percent rate.

[35] OPUC fee set to 0.43 percent for 2022. See *In the Matter of The Imposition of Annual Regulatory Fees upon Public Utilities Operating within the State of Oregon*, Docket No. UM 1012, Order No. 22-062 (Feb 24, 2022).

UTILITY PLANT

Q. Please summarize the amount and timing of the Company's utility plant in service as proposed in the initial filing.

A. The Company is proposing utility plant in service of $3.562 billion dollars, accumulated depreciation of ($1.483) billion, yielding a net utility plant of $2.079 billion.[36] The Company's testimony indicates this amount is calculated using the 13-month average of monthly averages (AMA) method.[37] Staff review of the underlying work paper indicates this amount is calculated using forecasts of plant in the November 1, 2022 to October 31, 2023 test year. Staff notes that the Company's work paper detailing the increase in rate base is confidential in part.[38]

Q. Please discuss the portion of rate base projections deemed to be confidential.

A. The Company states that "All data past September 30, 2021, or contained therein" is confidential.[39] As stated in the UG 388 case "All forward looking monthly data that has not been disclosed to the public has been deemed confidential."[40]

Q. Please discuss Staff's ongoing objection to a portion of rate base projections being designated as confidential.

36 NW Natural/1301, Walker/1.
37 NW Natural/1300, Walker/24.
38 NWN/1312 - WP1 - Gross Plant and Accum Deprec - CONFIDENTIAL.xlsx.
39 NWN/1300 - WP2 - Revenue Requirement Flow Chart and WP Index.xlsx.
40 UG 388, Staff 200, Fox/2.

A. In Staff's view there is a public policy issue here. Specifically, the Company is seeking the benefit of a forward looking test year and there ought to be a degree of public transparency about how the requested rate base is calculated.

Furthermore, none of the other five investor owned utilities deem the projected portion of rate base in their general rate case filings to be similarly confidential in nature. Also, the analogous work paper in the UG 344 case was not labeled as confidential.[41]

Q. Turning now to the errata filing which occurred on February 28, 2022, please summarize the amount and timing of the Company's revised utility plant in service.

A. The Company's errata includes a revised utility plant in service of $3.633 billion dollars, accumulated depreciation of ($1.502) billion, yielding a net utility plant of $2.131 billion. As noted in the errata filing, this is a $51.7 million increase in net rate base compared to the initial filing; however Staff notes the increase in utility plant before depreciation is $71.6 million.

Q. Does the errata filing represent the entirely of the pending corrections to rate base in the filed case?

A. No. It does not. According to NW Natural, "[t]he errata filing corrects for two accounts mistakenly excluded from the plant projections; FERC 396 (Power Operated Equipment) and FERC 392 (Transportation Equipment)."[42]

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41 Docket No. UG 344 - 200 wp7 - Gross Plant and Accum Deprec.xlsx.
42 NWN Errata filing at 1.

At the time of the filing, Staff noted that a discrepancy still existed between Oregon and Washington for FERC Acct. 389 Land and Land Rights and 390 Structures and Improvements compared to the prior rate case, UG 388. The Company confirmed, via informal inquiry,[43] that the discrepancy was related to Staff's DR 172 and that the Company intended to include the rate base impacts in its reply testimony rather than complicate the errata filing.

Q. Please discuss the Company's overall methodology for developing utility plant estimates.

A. Based on Staff review of the initial filing, the overall methodology can be summarized as follows:

- **Intangible – Software** (FERC Accts. 303.1 to 303.7) are allocated by multiplying system-wide plant balances by Oregon's share of total customers, 88.25 percent.
- **Intangible – Other** (FERC Accts. 301 and 302) are specific to Oregon and Washington with no allocation between states.
- **Production** (FERC Accts. 304.1 to 319) are specific to Oregon. Washington does not have any assets in these accounts.
- **Transmission** (FERC Accts. 365.1 to 367 and Acct. 369) are specific to Oregon. Washington does not have any assets in these accounts.
- **Distribution** (FERC Accts. 374.1 to 387.3) are specific to Oregon and Washington with no allocation between states.

[43] Via email February 24 and March 3, 2022.

- **General** (FERC Accts. 390.1 to 398.5) are allocated using a 3-Factor & Direct method, 88.91 percent to Oregon.
- **Storage and Storage Transmission** (FERC Accts. 350.1 to 363.42, and Accts. 367.21 to 367.26) are allocated based on Oregon's share of Firm Delivered Volumes, 88.95 percent.[44]
- **Land & Structures** (FERC Accts. 389 and 390) are allocated using a more detailed methodology further discussed below.
- **CNG/LNG Refueling Facilities** (FERC Accts. 363.5 and 363.6) are allocated using a 3-Factor method, 88.91 percent to Oregon.

Q. Does Staff propose further adjustments to the errata filing?

A. Yes. Staff proposes to remove plant additions subsequent to the rate effective date and recommends the Commission accept the land and building adjustments provided by the Company in response to DR 172, discussed as issues 10 and 11 below.

Q. Turning now to Staff's prudence review, please summarize the Commission's standard for prudence.

A. The purpose of a prudence review has been succinctly stated by the Commission in prior rate cases. For example, in a 2012 order, the Commission stated:

> *[W]e take this opportunity to clarify the prudence standard in ratemaking. Parties have raised questions about how the Commission applies the prudence standard, particularly with regard to the*

[44] The allocation methodology also includes a specific adjustment to allocate $33 million of the total South Mist Pipeline Extension to Oregon as agreed in a prior rate case. See the Company's Direct Testimony in UG 152 (UG 152/NWN/400 Stinson/20 – 22) and NWN Advice No. OPUC 04-11A.

relevance of the decision-making process that a utility uses to make an investment.

The prudence standard is traditionally used to address the proper valuation of utility investment in rate base. Any investment found to be unreasonable is deemed imprudent and subject to partial or full disallowance. An example of a modem articulation of the prudence standard is as follows:

A prudence review must determine whether the company's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company's managers. The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the task that confronted the company.

Although the Oregon courts have not expressly discussed the applicability of the prudence standard in this state, this Commission has long used the standard when examining utility investments. Through various orders, the Commission has confirmed that prudence of an investment is measured from the point of time of the utility's actions and decisions without the advantage of hindsight, that the standard does not require optimal results, and the review uses an objective standard of reasonableness. [45]

Q. What methods did Staff use to evaluate the prudence of proposed rate base additions in this case?

A. First, Staff reviewed information available in the Company's other dockets such as the most recent Integrated Resource Plan, Affiliated Interest Report, Construction Budget, Results of Operations, and FERC Forms.[46]

[45] See *In the Matter of PacifiCorp* Request *for a General Rate Revision,* Docket No. UE 246, Order No. 12-493 at 25 (Dec. 20, 2012).

[46] Docket Nos. LC 71, RG 8, RG 19, RG 40 and RG 37, respectively.

Second, Staff review the detailed plant projections provided in the initial filing, errata filing, and in response to Staff data requests to determine the timing and amount of plant additions.

Third, Staff requested additional information on projects over $150 thousand dollars and compared the information provided with details of projects discussed in testimony, information in the Company's other filings, and the Company's modeling and projections in this case. Additional data requests were sent following up on specific projects and issues.

Q. Please describe Staff's review of discovery responses regarding utility plant.

A. After reviewing the Company's work papers submitted with the filing, Staff issued data requests in several major groupings with follow up requests based on Staff analysis of the data provided. Staff also reviewed the responses to pertinent requests issued by other parties in this case.

- Capital investments over $150 thousand through September 2021[47]
- Projected capital investments over $150 thousand through October 2022[48]
- Projected non-discrete capital investments[49]
- Land and structures[50]

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[47] Data requests; 169 and 308.
[48] Data requests; 170, 302, and 310.
[49] Data requests; 171 and 303.
[50] Data requests; 172, 304, and 328.

- Major distribution system and storage facility projects[51]
- Allocations, overhead, capital budgeting, and construction work in process (CWIP)[52]
- Miscellaneous[53]

Q. What are Staff's conclusions?

A. Staff has not identified any projects that it believes to be imprudently undertaken. However, Staff does have concerns regarding the reliability of the Company's estimates, especially for projects projected to be placed into service near the rate effective date, and recommends attestations for those projects as further discussed in Issue 12 below.

Staff's conclusions regarding prudence are not final and may change based on evidence presented by other parties.

[51] Data requests; 173-183, 309, SBUA 8, and CUB 3.
[52] Data requests; 164, 165, 166, 167, 168, 305, 306, 307, and AWEC CUB 6-9.
[53] Data requests; CUB 34-35.

ISSUE 6. PLANT TEST-YEAR CAPITAL EXPENDITURES

Q. Please discuss provisions of Oregon's "used and useful" standard.

A. The "used and useful" standard requires the property to be placed into service prior to the effective date of the rates (ORS 757.355).[54, 55] The law applies to all utility plant including plant placed into service before the rate effective date and prior additions to rate base that are no longer used in providing utility service to customers.

Q. Does the Company's filing include plant additions after the rate effective date?

A. Yes. As stated by the Company, average rate base balances were calculated by utilizing monthly forecast amounts to construct a 13-month AMA for all rate base components.[56]

Staff's review of the Company's plant models also confirms that Test Year additions in this case have been included on an AMA basis.

Q. Is this approach consistent with the Company's recent rate case filing?

A. Yes. Both the UG 344 and UG 388 included Test Year plant additions in the initial filing.

54 ORS 757.355 prohibits the inclusion of "property not presently used for providing utility service to the customer."

55 *Pacific Power and Light,* Docket No. UE 210, Order No. 10-022, pp. 14-15 (*"ORS 757.355 prohibits a public utility from collecting in* customer *rates the costs of any property not presently used for providing utility service to those customers" . . . . "Given this evidence, and despite the parties' contentions about specific rate base adjustments, it is clear that the Stipulation will allow Pacific Power to collect in rates only the costs of property presently providing service to customers in conformance with ORS 757.355. We therefore deny ICNU's objection on this point."*)

56 NWN/1300, Walker/24.

Q. How were the requirements of ORS 757.355 resolved in those cases?

A. In UG 344, the stipulating parties agreed to reduce rate base by $33,730,000 to reflect removal of projects that will not go into service until after the rate effective date for that rate increase, November 1, 2018, except that the stipulating parties agreed to include a portion of those capital additions related to customer acquisitions.[57]

In UG 388, the Stipulating Parties agreed, in context of the Comprehensive Stipulation, to a reduction to rate base of $23,290,000, and a reduction to expense of $1,639,000. These reductions reflected removal of projects that will not go into service until after the rate effective date of that rate case, November 1, 2020, except that the Stipulating Parties agreed to not remove a portion of capital additions related to customer acquisitions.[58]

Q. Please quantify the amount of test year additions in the Company's filing.

A. Staff calculates the test year additions included in the three plant models provided by the Company thus far in this case to be **[Begin Confidential]**:

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[57] See *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General* Rate *Revision*, Docket No. UG 344, Order No. 18-419, p. 10 (Oct 26, 2018).

[58] See *In the Matter of Northwest Natural Gas Company, dba, NW Natural, Request for a General Rate Revision*, Docket No. UG 388, Order No. 20-364, Oct 16, 2020 at 4.

Derivation of Test year Average of Monthly Averages (AMA) Change in Net Utility Plant	Intital Filing	Errata Filing	Errata Update DR 302
Utility Plant in Service - October 2022	[redacted]		
Utility Plant in Service - Test Year AMA	(3,561,657,066)	(3,633,271,521)	(3,642,900,789)
Plant in Service Adjustment	[redacted]	[redacted]	[redacted]
Accumulated Depreciation - October 2022	[redacted]	[redacted]	[redacted]
Utility Plant in Service - Test Year AMA	(1,482,632,191)	(1,502,582,155)	(1,504,177,403)
Accumulated Depreciation Adjustment	[redacted]	[redacted]	[redacted]
Change in Net Utility Plant	$ [redacted]	[redacted]	[redacted]

[End Confidential]

Staff estimates the commensurate reduction in test year depreciation expense to be **[Begin Confidential]** [redacted][59] **[End Confidential]**

Q. Please discuss Staff's position regarding capital additions related to customer acquisitions.

A. While Staff recognizes that capital additions related to customer acquisitions have been allowed in the Company's past two rate cases, this is not universal practice nor a settled ratemaking principle in Oregon. The two most recent general rate case filings before the Commission did not request such additions in the test year.[60]

Accordingly, Staff is proposing to remove all test year additions from NW Natural's case including those related to customer acquisitions.

Q. What is Staff's recommended adjustment?

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[59] Staff notes that test year depreciation expense in the initial filing of $111.660 million remained unchanged in the errata update. This is 3.135% of average rate base in the initial filing. ($70,743,347) x 3.135% = ($2,217,804).

[60] UE 394 PGE/200, Tooman-Batzler/3 and UE 399 Pac/100, Steward/9, respectively.

A. As Staff Witness Brian Fjeldheim has included the errata update in Staff's revenue requirement model, Staff recommends an adjustment to remove test year plant in service of ($70.8) million, an accumulated depreciation reduction of ($42.7) million, and a reduction in depreciation expense of ($2.2) million.

ISSUE 7. LAND AND BUILDING ADJUSTMENTS SUBSEQUENT TO THE COMPANY'S ERRATA FILING

Q. Please discuss the background for this adjustment.

A. As discussed above, the Company's response to DR 172 indicates that there are errors in the plant projections for land and buildings. The Company states the nature of the necessary adjustments to be as follows:

> [T]he Company inadvertently entered data into the wrong months in the Land & Structure tab within the "UG 435 - Exh. 1312 - WP1 - Gross Plant and Accum Deprec – CONFIDENTIAL.xlsx" file. Therefore, the Company has overstated capital by $1.05 million.[61]

And,

> [T]he Company inadvertently calculated the structures jurisdictional allocation on book value instead of the gross plant balance and inadvertently included a few nonutility assets. This resulted in understated capital by $2.8 million in the test year as the total structures balance was allocated to Oregon based on the lower allocated percentage of 79.62% instead of 82.13%.[62]

As the additional updates were not included in the errata filing, Staff issued DR 328 requesting the revenue requirement impacts. The Company provided a thorough response to this data request which also included the related changes in rate base.

The Company's proposed adjustments [63] are summarized in the following table (with respect to Exhibit 1302 in the errata filing):

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[61] UG 435 OPUC DR 172 NWN Response.pdf

[62] *Id.*

[63] UG 435 OPUC DR 328 Attachment 1.xlsx and UG 435 OPUC DR 328 Attachment 3.xlsx.

DR 172 and 328 Plant Update (000's)	Land Correction	Structures Correction	Total
Utility Plant in Service - Corrected	$ 3,632,222	$ 3,636,616	
Utility Plant in Service - Errata Filing	(3,633,272)	(3,633,272)	
Plant in Service Adjustment	(1,050)	3,344	$ 2,295
Accumulated Depreciation - Corrected	1,502,582	1,503,084	
Utility Plant in Service - Errata Filing	(1,502,582)	(1,502,582)	
Accumulated Depreciation Adjustment	(0)	502	$ 502
Change in Net Utility Plant	$ (1,050)	$ 2,843	$ 1,793

Revenue Requirment with correction	$ 77,933	$ 78,294	
Revenue Requirment without correction	(78,030)	(78,030)	
Revenue Requirement Adjustment	$ (97)	$ 264	$ 167

Q. What does Staff recommend?

A. As this is correcting an error in the filing, Staff recommends the Commission approve the proposed plant in service increase of $2.3 million, increase in accumulated depreciation of $502 thousand, and increase in depreciation expense of $502.

ISSUE 8. EXCESS BUDGET FOR DISTRICT REGULATORS

Q. What are district regulators and what issue did Staff identify with respect to the Company's budget for district regulators?

A. District regulators are used to regulate gas in connection with distribution system operations other than gas deliveries to customers. Staff identified an unusual spike in PGE's budget for district regulators in 2022 and investigated to determine whether PGE will actually acquire district regulators that it had budgeted for.

Q. Please summarize the Company's budget for district regulators.

[Begin Confidential]

[redacted]

64 UG 435 OPUC DR 166 NWN Response.pdf, CONFIDENTIAL UG 435 OPUC DR 166 Attachment 1.xlsx, CONFIDENTIAL UG 435 OPUC DR 166 Attachment 2.xlsx, Confidential UG 435 DR 166 Attachment 1-Amended.xlsx

[redacted]

[End Confidential]

Q. What does Staff recommend?

A. Staff recommends a reduction of **[Begin Confidential]** [redacted] **[End Confidential]** million in utility plant.

65 Confidential UG 435 DR 307 NWN response.pdf

ISSUE 9. ATTESTATIONS AND OTHER PROJECT ADJUSTMENTS

Q. Please discuss Staff's general concerns regarding how project costs are estimated.

A. The Company's response to Staff DR 173 provides a high level overview of the management process for large projects that includes the following phases; intake, initiate, assess, planning, execution, and close out.[66] The accuracy of estimated cost progresses from a rough order of magnitude in the early phases to increasingly more detail as projects move through planning and execution.

Accordingly, the cost of projects included in the projected rate base can vary from a known final cost for a project already completed to rough order of magnitude estimates for projects in earlier phases, especially projects yet to be constructed and projected to be completed nearer to the October 2022 rate effective date.

With this background in mind, Staff proposes that certain projects be removed from rate base and that the Company provide office attestations for others which, in Staff's view, reflect a significant amount of uncertainty.

Q. Regarding projects specifically discussed in the Company's testimony, what does Staff recommend?

A. Staff recommends officer attestations for the following projects for the reasons stated:

- Kuebler Boulevard Reinforcement Project

[66] UG 435 OPUC DR 173 NWN Response.pdf, page 1.

- o This $24.2 million project is expected to be placed into service in October 2022, just prior to the rate effective date.[67] Further discovery indicates that the $24.2 million figure reflects a rough order of magnitude estimate[68] and includes spending in November and December 2022 for trailing charges.[69]

- Mist Well Rework Program 2022
  - o This $3.3 million[70] project is expected to be placed into service in October 2022, just prior to the rate effective date.[71] Further discovery indicates that no project Planning and Execution budgets were developed prior to the rate case filing and the cost is a rough order of magnitude estimate.72
- Mist Electrical Upgrades Project
  - o This $1.7 million[73] project is expected to be placed into service in October 2022, just prior to the rate effective date.[74] Further discovery indicates that as of December, 2021 the project was in the Planning phase and the Execution phase budget had not been developed.[75]
- Portland LNG Boil Off Compressor Project

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67 NWN/400, Kizer/8.
68 NWN Response to Staff DR 173, page 4.
69 UG 435 OPUC DR 302 NWN Response.pdf, page 2.
70 Oregon allocated.
71 NWN/400, Kizer/17-18.
72 NWN Response to Staff DR 173, page 6.
73 Oregon allocated.
74 NWN/400, Kizer/22.
75 NWN Response to Staff DR 173, page 7.

- This $1.3 million[76] project is expected to be placed into service in October 2022, just prior to the rate effective date.[77] Further discovery indicates that no project Planning and Execution budgets were developed prior to the rate case filing and the cost is a preliminary project estimate.[78]

- Newport LNG Pretreatment Regeneration Project
    - This $5.1 million[79] project is expected to be placed into service in October 2022, just prior to the rate effective date.[80] Although an execution budget was developed prior to the rate case filing,[81] in Staff's view there remains a risk that the project will not be in service prior to the rate effective date.

- Lincoln City Resource Center Project
    - This $15.3 million project is expected to be placed into service in October 2022, just prior to the rate effective date.[82] Further discovery indicates that this amount includes a forecasted $1.1 million of additional capital investments related to the Lincoln City Resource Center project that will be placed in service in November

[76] Oregon allocated.
[77] NWN/400, Kizer/25.
[78] NWN Response to Staff DR 173, page 7.
[79] Oregon allocated.
[80] NWN/400, Kizer/28.
[81] NWN Response to Staff DR 173, page 8.
[82] NW Natural's Errata to Direct Testimony of Wayne K. Pipes (NW Natural/500, Pipes/27) (January 24, 20200). Staff notes the cost stated in the initial filing was $12.3 million and neither the errata filing nor the Company's response to DR 302 provide a cogent explanation of the underlying estimation error.

2022.[83] Staff considers officer attestation essential for this project due to the shifting nature of the Company's estimates and expected final payments after the rate effective date.

Q. Is there an additional error in the filed case that Staff wishes to bring to the Commission's attention?

A. Yes, the Central Resource Center – Phase 1 project was stated in the original filing to be $10.3 million[84] to be completed in December 2021.[85] As a result of further discovery, the Company states the cost is actually $12.4 million and the cost of this facility, along with other structures was incorrectly projected in the Company's modeling. The Company also states that it will update its revenue requirement and exhibits in reply testimony.[86]

As the project is complete and the Company will be providing additional testimony, an officer attestation is not necessary.

Q. Does Staff recommend attestations for certain projects not discussed in the Company's testimony?

A. Yes. As a result of Staff discovery, Staff identified a number of projects that are scheduled to be completed in **[Begin Confidential]** [redacted][87] **[End Confidential]**

83 NWN Response to Staff DR 302, page 2.
84 NWN/500, Pipes/44.
85 NWN/500, Pipes/39.
86 NWN Response to DR 302, page 2.
87 Confidential UG 435 DR 310 NWN Response.pdf. Staff notes this DR was confidential as it relates to confidential portions of the Company's NWN's 2021 New Construction Budget Report,

In Staff's view, there is a significant risk that either the projects will slip and not be completed by the rate effective date or that the final cost of the projects will be materially different from amounts included in the filed case.

Staff recommends officer attestations for the following projects:[88]

- 300-400 Cooler Replacement - $856 thousand.
- 300-400 Header Valve Automation - $692 thousand.
- 300-400 Heavy Piston Upgrade - $462 thousand.
- 300-400 Suction and Recycle Control Valve - $239 thousand.
- GC500 & GC600 Separator Dump Valve Upgrade - $400 thousand.
- Miller Station TI - $556 thousand.
- **[Begin Confidential]** [redacted] **[End Confidential]**

Docket No. RG 19, filed 3/31/21. Identification of the projects themselves resulted from Staff review of UG 435 OPUC DR 170 Attachment 1.xlsx.

[88] Costs are from UG 435 OPUC DR 170 Attachment 1.xlsx unless otherwise noted.

[89] Confidential UG 435 DR 310 NWN Response.pdf, page 6.

[90] These projects are scheduled for execution in **[Begin Confidential]** [redacted] **[End Confidential].**

[91] NW Natural Response to Staff DR 310, page 10.

[92] *Id.*, page 14.

[93] *Id.*, page 15.

[94] *Id.*, page 16.

- 202407 Delta & Green Acres Dist Reg – **[Begin Confidential]** [redacted] **[End Confidential]**
- 202286 Miller Station Level Controller Upgrade – **[Begin Confidential]** [redacted] **[End Confidential]**
- 202438 Mist GC500 Compressor Rebuild – **[Begin Confidential]** [redacted] **[End Confidential]**
- 202437 Mist GC 600 Compressor Rebuild – **[Begin Confidential]** [redacted] **[End Confidential]**
- 202370 Mist GC 500 HMI and Controls Upgrade – **[Begin Confidential]** [redacted] **[End Confidential]**

Q. Please summarize Staff's thinking as to requiring attestations for these projects not discussed in the Company's testimony.

A. The bulleted projects in the previous Q&A sum to just under $9 million dollars in total. Staff believes there is substantial uncertainty regarding the proportion of this aggregate amount that will actually be in service at the rate effective date. Accordingly, Staff feels that individual project attestations are reasonable even though several of the projects are only a few hundred thousand dollars.

Staff witness Brian Fjeldheim recommends attestations and a rate true up mechanism for large information technology projects. His recommendations are specific to those projects only and are unrelated to other plant additions.

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[95] *Id.*, page 17.
[96] *Id.*, page 20.
[97] *Id.*, page 21.
[98] *Id,*, page 21.
[99] *Id*, page 23.

ISSUE 10. PROPERTY SALES

Q. Please summarize the property sales discussed in the Company's filing.

A. Regarding a vacated Astoria property, the filing states that the Company expects to receive proceeds due to customers of $1.0 million for its sale of the Astoria Resource Center property.[100] Regarding a soon to be vacated Lincoln City property, the filing states that the Company is in the early stages of constructing a new facility and expects to complete the new Lincoln City Resource Center and place it into service by October 2022. The Company will begin marketing the existing site for sale in early 2022 but will not complete the sale until the new facility is complete.[101]

Q. Did Staff conduct additional discovery?

A. Yes. Staff issued a general request regarding sales of utility property from 2017-2021 and a specific request regarding how the Astoria proceeds have been reflected in the case.[102] In response, the Company responded that there have been three land parcels sold since 2017, all of which are known to Staff having been the subject of past Commission proceedings.

Q. Has the ratemaking treatment of the Astoria parcel been resolved previously?

[100] NWN/500, Pipes/18.
[101] NWN/500, Pipes/26.
[102] OPUC DR 229 NWN Response.pdf and UG 435 OPUC DR 302 NWN Response.pdf

A. Yes, in Order No. 20-495,[103] the Commission approved the return of the sale proceeds in the 2022 Purchased Gas Adjustment (PGA) on an equal percent of margin basis. At the time of the order, the estimated net gain from the sale was $1.071 million on a system basis and $1.019 million Oregon allocated.

Staff notes that the Company's response to Staff DR 229 indicates a net gain from the sale of $826 thousand on a system basis and $785 thousand Oregon allocated. Staff review of the journal entries[104] filed with the Commission indicates that the actual cash proceeds of the sale were $1,136,268 rather than the $1,400,000 million estimate underlying Order No. 20-495.

Q. What is Staff's recommendation regarding the Lincoln City parcel?

A. As discussed above, NW Natural will begin marketing the existing site for sale in early 2022. Staff recommends that, if the sale proceeds are known or reasonably estimable at the time of the final PGA update on September 15th, the proceeds be returned to customers in the 2022 PGA also.

Q. Does this conclude your testimony?

A. Yes.

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[103] See *In the Matter of Northwest Natural Gas Company, dba, NW Natural, Request for* Authorization *of the Sale of Certain Property Located in Astoria Oregon*, Docket No. UP 410, Order No. 20-495 (Dec 30, 2020).

[104] *Id.* NW Natural's Compliance per Order No. 20-495, Final Journal Entries, filed 1/31/2022.

CASE: UG 435
WITNESS: JOHN FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

April 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME: John L. Fox

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Financial Analyst
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: I hold a Bachelor of Science degree in Business Administration / Accounting from the University of Oregon (1989). I also completed the Certificate in Public Management program at Willamette University (2010).

I have been licensed as a Certified Public Accountant in Oregon since 1991. Maintaining active status has required a minimum of 80 hours continuing professional education every two years.

EXPERIENCE: From 1989 to 1999 I was in general practice with several CPA firms in Southern Oregon and the Mid-Willamette Valley. My tax experience includes individuals, trusts and estates, qualified retirement plans, and extensive corporate, partnership, and LLC work. Accounting experience during this time includes client write up, compilation and review, and significant audit and attest work.

I have been employed in the executive branch of Oregon state government since 1999. My experience prior to joining the Commission staff includes 3 years as a cost accountant, 11 years as a senior budget analyst, and 4 years in an oversight role as a budget team lead.

I have extensive experience in capital construction and financing, complex cost modeling, rate development, fiscal projections, expenditure analysis, and cost control for programs with biennial revenues between $100 million and $300 million.

PRIOR DOCKETS: I have provided testimony as a Staff witness in the following OPUC proceedings; UE 333, UE 335, UE 374, UE 390, UE 391, UE 392, UE 394, UG 344, UG 347, UG 366, UG 388, UG 389, UG 390, UG 433, UM 1992, UM 2004, UM 2026.

CASE: UG 435
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

April 22, 2022

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 164

Please indicate if additional capital asset allocation audits have occurred subsequent to the UG 388 OPUC DR 129.
If so, please provide a copy of the reports.

Response:

No additional capital allocation audits have occurred subsequent to the UG 388 OPUC DR 129 request.

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Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 165

Please indicate if additional Construction Overhead (COH) Study or studies have occurred subsequent to the UG 388 OPUC DR 130.
If so, please provide a copy of the study(s).

Response:

The UG 388 OPUC DR 130 was a five-year lookback at construction overhead. Attached is the latest five-year lookback. Please see “Confidential UG 435 OPUC DR 165 Attachment 1”.

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Rates & Regulatory Affairs

UG 435

Request for a General Rate Revision

Data Request Response

Request No.: UG 435 OPUC DR 166

Please provide the 2021 Capital Budget and 2022, 2023, and 2024 Capital Forecasts in the same format as the as the Company's response to UG 388 OPUC DR 131.

Response:

Please see Confidential UG 435 OPUC DR 166 Attachment 1 for the 2021 Capital Budget and Confidential UG 435 OPUC DR 166 Attachment 2 for the 2022-2024 Capital Forecast, which are in the same format as provided in the UG 388 rate case.

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Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 167

Please provide a list in excel format of all projects included in construction work in process at December 31, 2020 and September 30, 2021. Please include a list of all accounting work orders by project and FERC account. Please identify the date when each project or project component is expected to be placed into service.

Response:

We have provided the project number within the Project listing as of December 31, 2020 and September 30, 2021. Please see UG 435 OPUC DR 167 Attachments 1 and 2.

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Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 168

Regarding the Company's response to UG 344 OPUC DR 201,
a. Please indicate if the UI planner software is still in use.
b. Please update the list of UI planner reports provided in the DR response.
c. If reports are being superseded or supplemented by reports available from the seven IT&S projects listed in Downing, 600/2, please provide a detailed list of such reports and which system they are associated with.
d. Please update the Company's response providing a narrative summary of ad hoc reporting capabilities including data base structure, available reporting tools or software, and who in the company is able to query the data and run reports. Please respond with respect to UI planner and seven new projects.

Response:

a. Yes, UI Planner is still in use.

b. See UG 435 OPUC DR 168 Attachment 1 for an updated list of UI planner reports.

c. No reports are being superseded or supplemented. UI Planner reports are not being superseded or supplemented by reports available for the seven IT&S projects listed in Downing, 600/2. UI Planner is our financial forecast planning tool. We upload accounting/financial information (i.e., actual results) from our SAP systems into UI Planner and perform our forecasting in the UI Planner software. The reports listed in part b are reports within our UI Planner tool only and used by a limited audience for financial planning purposes with a focus on the forecast rather than historical results. Actual accounting and financial results (as opposed to forecasts) currently are loaded into UI Planner from our SAP system that is being replaced by applications within the Horizon 1 project (i.e., one of the seven IT&S projects listed in Downing, 600/2).

d. Regarding UI Planner, the response provided in UG 344 OPUC DR 201 is unchanged. UI Planner is a financial and regulatory software application that provides standard forecast financial statements for financial planning, such as Income Statement, Balance Sheet, Cash Flow, etc., as well as the functionality to build custom reports or views as needed. Within these reports there is the capability to drill down, providing detailed forecast information to the data load level such as the account balance or forecast value for a specific project, and a way to follow data through reports as it is allocated. These reports can be exported to Excel for further analysis offline. Members of the Financial Planning and Budget department can build and run reports, and certain employees within the Tax and Rates and Regulatory departments have access to run reports as well as update forecast assumptions.

The seven new IT&S projects are independent of our forecasting tool. Many of those projects create, capture and house accounting results that may be uploaded into UI Planner for use in our forecasting and financial planning.

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Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 169

Please provide a list in excel format of all discrete capital investments over $150 thousand dollars placed into service each month from January through September 2021 for each FERC account:
a. For the following categories, please include Oregon and Washington:
i. Intangible software
ii. General
iii. Storage and Storage Transmission
iv. CNG/LNG
b. For the following categories, please include Oregon only:
i. Transmission
ii. Distribution
c. For each investment, please include the project name or description with enough specificity for Staff to understand what was purchased.
d. For each investment, please include in the response all coding necessary for further inquiry. Including but not limited to asset numbers, accounting work orders (AWO), project numbers, etc.
e. For specific investments discussed in the Company's direct testimony and exhibits please indicate the exhibit and page number.
f. For each investment, please indicate under which category it is included in the capital expenditure bar chart (Figure 1) presented in testimony (Davilla 1200/25.

Response:

See UG 435 OPUC DR 169 Attachment 1 for items a – f.

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Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 170

Please provide a list in excel format of all discrete capital investments over $150 thousand dollars projected to be placed into service each month from October 2021 through October 2022 for each FERC account:
a. For the following categories, please include Oregon and Washington:
i. Intangible software
ii. General
iii. Storage and Storage Transmission
iv. CNG/LNG b.
b. For the following categories, please include Oregon only:
i. Transmission
ii. Distribution
c. For each investment, please include the project name or description with enough specificity for Staff to understand what is being purchased.
d. For each investment, please include in the response all coding necessary for further inquiry. Including but not limited to asset numbers, accounting work orders (AWO), project numbers, etc.
e. For specific investments discussed in the Company's direct testimony and exhibits please indicate the exhibit and page number.
f. For each investment, please indicate under which category it is included in the capital expenditure bar chart (Figure 1) presented in testimony (Davilla 900/27).
g. Please identify investments included in the 2022 Capital Safety Investment Plan (UM 1900: NW Natural's Annual Oregon Safety Project Plan in Compliance with OPUC Order No. 17-084, pages 8-10, filed September 30, 2021).

Response:

See UG 435 OPUC DR 170 Attachment 1 for response. Investments referred to in DR subpart "g" above are non-discrete projects and, therefore, covered in the Company's response to UG 435 OPUC DR 171.

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Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 171

Please provide in excel format the dollar amount of non-discrete capital investments by projected to be placed into service each month from October 2021 through October 2022 for each FERC account:
a. For the following categories, please include Oregon and Washington:
i. Intangible software
ii. General
iii. Storage and Storage Transmission
iv. CNG/LNG
b. For the following categories, please include Oregon only:
i. Transmission
ii. Distribution
c. For each investment, please indicate under which category it is included in the capital expenditure bar chart (Figure 1) presented in testimony (Davilla 1200/25).
d. For each investment, please indicate under which category it would be included in the categories presented in testimony (Davilla 1200/26-29). Staff notes the discussion of methodology does not match 1:1 with the chart on page 1200/25.

Response:

See UG 435 OPUC DR 171 Attachment 1 for response. As to Staff's note in subpart "d" above, the categories of Damages, Tools and Leakage are grouped into the "Other" category in the chart on page 1200/25. In our response to this DR, we did use "Other - xxx" to separately identify each of those categories.

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 172

Regarding Land and Structures,
a. Please provide a worksheet in excel format showing the individual asset details for land as of Sept 2021 in the same format as last rate case (UG 388 OPUC DR 136 Attachment 1).
b. Please provide a worksheet in excel format showing the individual asset details for structures as of Sept 2021 in the same format as last rate case (UG 388 OPUC DR 136 Attachment 2).
c. Please provide a list in excel format of projected land and building additions by month including October 2021 through October 2022 including the anticipated allocation factor for each. Please provide asset level detail in the same format as the last rate case (UG 388 OPUC DR 136 Attachment 3).

Response:

a. Please see “UG 435 OPUC DR 172 Attachment 1” for land allocation. Please note, the Company inadvertently entered data into the wrong months in the Land & Structure tab within the “UG 435 - Exh. 1312 - WP1 - Gross Plant and Accum Deprec – CONFIDENTIAL.xlsx” file. Therefore, the Company has overstated capital by $1.05 million. The Company will update its revenue requirement in its reply testimony.

b. See “UG 435 OPUC DR 172 Attachment 2” for structures allocation. Please note, the Company inadvertently calculated the structures jurisdictional allocation on book value instead of the gross plant balance and inadvertently included a few nonutility assets. This resulted in understated capital by $2.8 million in the test year as the total structures balance was allocated to Oregon based on the lower allocated percentage of 79.62% instead of 82.13%. The Company will update its revenue requirement in its reply testimony.

c. See “UG 435 OPUC DR 172 Attachment 3” for detail around land and structures, FERC accounts 389 and 390. Large projects are identified by FERC account. Projects titled “Blanket Project Applicant 36” represent smaller projects that have been aggregated to FERC 390 for each forecasted month. There are no forecasted land additions.

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Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 173

Regarding the major transmission, distribution system, and facility storage projects presented in testimony (Kizer, 400/4-25):
a. For each project, please provide the cost details (e.g. materials, labor, contract services, engineering, AFUDC, construction overhead, etc.) as of the date of the Company's final comments in Docket No. LC 71 filed on February 8th 2019. Staff notes the Company's response in UG 388 OPUC DR 137 that a project or budget may not have been created as of that date. Please provide whatever information was available at that time to support amounts included in the IRP filing.
b. Please provide the details of all initial and subsequent changes to the project budgets that occurred from February 8th, 2019 through the Company's initial filing in this rate case.
c. Regarding five projects listed on Kizer, 400/2 as being removed from rates as a result of the Comprehensive Stipulation in docket UG 388, please provide,
i. The cost of the project included in the UG 388 filing.
ii. Project costs incurred as of November 1, 2020
iii. Project costs incurred as of September 30, 2021
iv. The estimated or final cost of the project and the estimated or final date placed into service with a detailed narrative explanation of costs incurred in excess of items i. and ii. above.
d. Although not listed on that page, please provide the same information for the Keubler Rd. project.

Response:

To manage large capital projects, NW Natural follows a Project Management Office process.
A high-level summary of our Project Management Office's process for large projects is as follows:

- Intake: With sponsor support, a project manager applies to our Project Management Office to intake a large project and submits it to the Portfolio Management Committee (PMC). The PMC reviews available funds and internal staff resources to support the project and to prioritize the project within our portfolio of our other large projects (Facilities, IT, Plant).

- Initiate: The project team is authorized to take action to move the project forward. A nominal budget is authorized for internal labor to further identify and develop the scope of resources and funds needed to complete the Assess Phase.
- Assess: The project team works to more fully develop project requirements, assess available options to address the project's needs and determine the alternatives and perform feasibility and front end engineering and design (FEED) studies that lead to identification of the preferred solution. If a significant study is needed to explore various alternatives to a potential solution, the Assess phase is used to take the time for this evaluation. This phase culminates in submission of an Alternatives Analysis. Projects do not advance to the Planning phase until approval of the Alternatives Analysis stage gate. Cost estimates developed at the Assess phase, such as in a FEED study, include some variability on the order of approximately -25% to +50%.
- Planning: The project team focus is to develop design, budget, and schedule for the preferred alternative selected during the Assess phase. The intent is to ensure that the project has a fully defined plan and approach for moving to execution. The Planning phase will have a budget to account for items such as engineering design, exploratory field work, and permits. The Planning phase may experience change orders if additional funds are needed to address Planning phase costs that were not foreseen when the initial Planning phase budget was prepared. The first Execution phase cost estimate is developed during this phase. Pricing for materials, internal labor, external vendors and equipment is collected based on current market conditions and is used to develop the Execution phase cost estimate. Ideally, the level of uncertainty at the end of the Planning phase allows for the development of an Execution cost estimate with reduced variability on the order of approximately -10% to +10%.
- Execution: The project is constructed to completion. Changes to scope and costs are documented by Change Orders. The Execution phase has a budget to account for direct costs necessary for constructing the project and is in addition to funding approved for previous phases. Ideally, the level of uncertainty at the start of the Execution phase allows for development of cost estimates with a range of plus or minus 10%.
- Close out: The project team completes required paperwork associated with the project.

In our Project Management process the rough order of magnitude estimates used for 10-year facility plans, FEED Studies and Initiation and Assess phase work do not include COH and AFUDC, nor do they include detailed labor, equipment and materials estimates. Planning and Execution phase estimates do not include COH and AFUDC. Planning and Execution phase estimates consider labor, external vendor, permitting, equipment and materials costs. Closeout documentation includes the costs for COH and AFUDC charged to the project.

During the IRP process, there is not a budget created yet with COH, AFUDC, etc. To develop estimates for the IRP process for system reinforcements and betterments, we consider proposed pipeline size, installation length and route characteristics to create a rough order of magnitude cost estimate using data from similar projects for the IRP analysis. For projects at Newport LNG, Portland LNG, and Mist, we may commission a FEED study to identify project alternatives and their associated scope and estimated costs. If the system reinforcement or betterment is acknowledged by the Commission in the IRP process, then the project can move forward to the Initiation phase. The Initiation phase is followed by the Assess Phase. A project that was evaluated and acknowledged through the IRP process is granted an exemption to our internal alternative analysis process. The project then moves to the Planning phase, and the project team works to develop the Execution budget.

Below is a summary table of all the major transmission, distribution system and facility storage projects presented in testimony (Kizer, 400/4-25) and their project management status.

Project	**Project Management Status as of February 8, 2019**	**Project Management Status as of December 17, 2021**	**Expected move to Execution month**	**Expected Used and Useful month**
Kuebler Boulevard Reinforcement	Not Initiated - Waiting for IRP acknowledgement	Planning	June 2022	October 2022
Kuebler Boulevard Reinforcement – Partial Construction	Not initiated	Complete	September 2021	October 2022
Toledo Regional Station	Not initiated	Complete	September 2020	December 2020
Mist 300 and 400 Compressor Controls Project	Not initiated	Complete	August 2020	September 2021
Mist Well Rework 2021	Not initiated	Complete	June 2021	November 2021
Mist Well Rework 2022	Not Initiated	Assess	March 2022	October 2022
Mist Corrosion Abatement Phase 4	Not Initiated	Execution	April 2021	March 2022
Mist Electrical Upgrades	Not Initiated	Planning	April 2022	October 2022
Portland LNG PLC Upgrade	Not initiated	Execution	February 2021	April 2022
Portland LNG Boil Off Compressor	Not initiated	Assess	June 2022	October 2022
Newport LNG Pretreatment Regeneration	Not initiated	Execution	June 2021	June 2022

a. As mentioned above, none of the major transmission, distribution system and facility storage projects presented in testimony had full project budget details as of February 8, 2019.

<u>IRP projects as of February 8, 2019</u>

<u>Kuebler Boulevard Reinforcement Project</u>

The Kuebler Blvd Reinforcement Project in NW Natural's 2018 IRP (LC 71) action plan had not been acknowledged by the OPUC as of February 8, 2019 (the OPUC issued Order No. 19-073 on March 4, 2019). As such, the project had not yet entered the Initiation phase and a project budget did not exist.

The Total Project Estimate for the Kuebler Boulevard Reinforcement Project noted in UG 388 OPUC DR 137 was $19.7 million as per NW Natural/400/Karney/Page 35. This figure is the upper end of the range presented in LC 71. At the time LC 71 was filed the proposed pipeline length was approximately 4 miles. The suggested route followed Marion County right-of-way from the State Street / Cordon Road intersection, across Highway 22, along Kuebler Blvd and then across private property owned by the State of Oregon before connecting to our 8-inch pipeline in Turner Road.

b. The details of all initial and subsequent changes to the project budgets that occurred from February 8th, 2019 through the Company's initial filing in this rate case are as follows:

<u>Kuebler Boulevard Reinforcement Project</u>

Between Feb. 8, 2019 and the Dec. 17, 2021 filing of this rate case, the project Planning, Early Purchase and Partial Execution budgets were developed for the Kuebler Blvd Reinforcement Project. Please refer to **UG 435 OPUC DR 173 Attachment 1** for the Planning Budget without construction overhead and a rough order of magnitude estimate of the range of total project costs without and with construction overhead. Please refer to **UG 435 OPUC DR 173 Attachment 2** for the Early Pipe Purchase Change Detail without construction overhead. Please refer to UG **435 OPUC DR 173 Attachment 3** for the Partial Execution Change Detail without construction overhead.

February 2019 Total Project Cost Estimate = $14.1 to $19.7 million with construction overhead.(NW Natural LC71/Page 8.14, Table 8.2)

July 2020 Planning Budget = $1,216,040 without construction overhead. (**Attachment 1**)

July 2020 Total Project Cost Estimate = $14.4-$17.1 million without construction overhead and $20.3 - $24.1 million with construction overhead (**Attachment 1**)

April 2021 Early Pipe Purchase Change Order = $274,400 without construction overhead (**Attachment 2**)

August 2021 Partial Construction Change Order = $640,598 without construction overhead (**Attachment 3**)

December 2021 Total Project Estimate = $24.2 million per testimony (NW Natural/400/Kizer/Page 8).

Toledo Regional Station Project

Between Feb. 8th, 2019 and the Dec. 17, 2021 filing of this rate case, the project Planning and Execution budgets were developed for the Toledo Regional Station Project. Please refer to **UG 435 OPUC DR 173 Attachment 4** for the Planning Budget without construction overhead and **UG 435 OPUC DR 173 Attachment 5** for the Execution Budget without construction overhead. Please refer to **UG 435 OPUC DR 173 Attachment 6** for the final total execution budget with addition of Change Order 01 and Total Estimated Project Costs without construction overhead.

2020 Planning Budget = $445,000, which includes $25,000 for initial planning and $420,000 for long-lead materials, without construction overhead.

2020 Execution Budget = $1,151,431 without construction overhead.

2020 Change Order 01 Budget = $2,014,638 without construction overhead and $2.54 million with construction overhead.

Mist 300 and 400 Compressor Controls Project

Between Feb. 8th, 2019 and the Dec. 17, 2021 filing of this rate case, the project Planning and Execution budgets were developed for the Mist 300 and 400 Compressor Controls Project. Please refer to **UG 435 OPUC DR 173 Attachment 7** for the Planning Budget and **UG 435 OPUC DR 173 Attachment 8** for the Execution Budget.

2020 Planning Budget = $10,000 without construction overhead.

Execution Budget = $3,177,236 without construction overhead.

Total Project Budget = 3,187,236 without construction overhead.

Mist Well Rework 2021 Project

Between Feb. 8th, 2019 and the Dec. 17, 2021 filing of this rate case, the project Planning and Execution budgets were developed for the Mist Well Rework 2021 Project. Please refer to **UG 435 OPUC DR 173 Attachment 9** for the Planning Budget and **UG 435 DR 173 OPUC DR 173 Attachment 10** for the Execution Budget with construction overhead. Note that some of the well rework is funded by non-utility funds so the amount shown in **Attachment 10** ($4,598,440) is larger than the $3,181,023 figure below for the utility well rework funded by utility funds.

April 26, 2021 Planning Budget = $50,000 without construction overhead.

June 12, 2021 Execution Budget = $3,181,023 $3,067,708 without construction overhead.

Total Project Budget = $4,648,440 without construction overhead and non-utility wells included.

Mist Well Rework 2022 Project

Between Feb. 8th, 2019 and the Dec. 17, 2021 filing of this rate case, no project Planning and Execution budgets were developed for the Mist Well Rework 2022 Project. A rough order of magnitude estimate was used for the $3.7 million total project estimate included within testimony (Natural/400/Kizer/Page 18).

Mist Corrosion Abatement Project Phase 4

Between Feb. 8th, 2019 and the Dec. 17, 2021 filing of this rate case, the project Planning and Execution budgets were developed for the Mist Corrosion Abatement Project Phase 4. Please refer to **UG 435 OPUC DR 173 Attachment 11** for the Planning Budget without construction overhead and **UG 435 OPUC DR 173 Attachment 12** for the Execution Budget without overhead.

2021 Planning Budget = $269,424 without construction overhead.

2021 Execution Budget = $2,369,096 without construction overhead.

2021 Total Project Budget = $2,638,520 without construction overhead and $3.2 million with construction overhead.

Mist Electrical Upgrades Project (Phase 1)

Between Feb. 8th, 2019 and the Dec. 17, 2021 filing of this rate case, the project Planning budget was developed for the Mist Electrical Upgrades Project. Please refer to **UG 435 OPUC DR 173 Attachment 13** for the Planning Budget. Please note that the execution forecast capital spend is also shown in **Attachment 13**, but this is not considered a budget.

August 13, 2021 Planning Budget = $195,000 without construction overhead.

As of December, 2021 the project was in the Planning phase and the Execution phase budget had not been developed. The current Total Project Estimate for the Mist Electrical Upgrades Project is $1.9 million as per testimony (NW Natural/400/Kizer/Page 22.)

Portland LNG PLC Upgrade Project

Between Feb. 8th, 2019 and the Dec. 17, 2021 filing of this rate case, the project Planning and Execution budgets were developed for the Portland LNG PLC Upgrade Project. Please refer to **UG 435 OPUC DR 173 Attachment 14** for the Planning budget and **UG 435 OPUC DR 173 Attachment 15** for the Change Order for the Planning Budget. Please refer to **UG 435 OPUC DR 173 Attachment 16** for the Execution Budget.

July 2019 Planning Budget = $450,000 without construction overhead.

July 2020 Planning Budget Change Order = $200,000 without construction overhead.

Execution Budget = $2,290,856 without construction overhead (excludes O&M costs shown in **Attachment 14**.)

Total Project Budget = $2,940,856 without construction overhead.

Total Project Budget = $3.5 million with construction overhead

At the time of the Company's initial filing it was anticipated that the Total Project Costs would be below the $3.5 million Total Project Budget figure above. The current Total Project Estimate for the Portland LNG PLC Upgrade Project is $2.8 million as per testimony (NW Natural/400/Kizer/Page 24.)

Portland LNG Boil Off Compressor Project

Between Feb. 8th, 2019 and the Dec. 17, 2021 filing of this rate case, no Planning or Execution budgets were developed for the Portland LNG Boil Off Compressor Project. A preliminary project estimate was used for the $1.5 million total project estimate included within testimony (Natural/400/Kizer/Page 18.)

Newport LNG Pretreatment Regeneration Project

Between Feb. 8th, 2019 and the Dec. 17, 2021 filing of this rate case, the project Planning and Execution budgets were developed for the Newport LNG Pretreatment Regeneration Project. Please refer **to UG 435 OPUC DR 173 Attachment 17** for the Planning phase budgets and **UG 435 OPUC DR 173 Attachment 18** for the Execution Phase budget. Please refer to **UG 435 OPUC DR 173 Attachment 19** for the Total Project Budget developed.

Total Planning Budget = $1.45 million (includes multiple early purchases) without construction overhead.

June 2021 Execution Budget = $3.4 million without construction overhead.

June 2021 Total Project Budget = $4.85 million without construction overhead

c. For the five projects removed listed on Kizer, 400/2 as being removed from rates as a result of the Comprehensive Stipulation in docket UG 388, please provide:

i. Cost of the project included in the UG 388 filing:
ii. Project costs incurred as of November 1, 2020:
iii. Project costs incurred as of September 30, 2021:
iv. The estimate or final cost of the project and the estimated or final date placed into service with a detailed narrative explanation of costs incurred in excess of items i. and ii. above.

Please note that there are four (not five) projects listed on Kizer, 400/2.

Toledo Regional Station Project

i. Cost of the project included in the UG 388 filing is $1,193,820.
ii. Project costs incurred as of November 1, 2020 are $1,031,840
iii. Project costs incurred as of September 30, 2021 are $2,055,686
iv. The final cost of the project is $2.06 million. The final costs of the project with construction overhead is $2.53 million. The project was placed into service in December, 2020.
The costs incurred in excess of the items above were due to schedule changes and staffing changes leading to project delays related to wildfire activity in the Lincoln City area delaying completion of the project to December 2020. The original budget did not include the cost to replace the station's 16-inch inlet valve. During construction efforts, a third party was brought in to perform Stopple fitting installation, and an additional 16" Stopple fitting was added to address an unplanned valve replacement to replace a valve that was not sealing tight enough to weld downstream. Original welding was planned to be performed with internal resources, but

contract labor was brought in to backfill due to welders being dispatched to other parts of the system for wildfire response.

Mist Electrical Upgrades Project (Phase 1)

i. Cost of the project included in the UG 388 filing is $2,494,990.
ii. Project costs incurred as of November 1, 2020 is $0.
iii. Project costs incurred as of September 30, 2021 is $17,860.
iv. The estimated final cost of the project is approximately $2.4 million with construction overhead. The project is estimated to be placed into service in October, 2022. At this time, costs are not forecasted to exceed the items above.

Mist Corrosion Abatement Project (Phase 4)

i. Cost of the project included in the UG 388 filing is $1,748,470.
ii. Project costs incurred as of November 1, 2020 is $61,414.
iii. Project costs incurred as of September 30, 2021 is $1,984,548.
iv. The estimated final cost of the project is $3.2 million with construction overhead. The project is estimated to be placed into service in March, 2022.

Costs incurred in excess of the items above were due to use of a budget forecast figure from September 2019 in the UG 388 filing that was prepared before the full scope of the project had been determined.

E08 Springfield Transmission ILI Project

i. Cost of the project included in the UG 388 filing is $1,675,910.
ii. Project costs incurred as of November 1, 2020 is $0.
iii. Project costs incurred as of September 30, 2021 is $58,124.
iv. The estimated final cost of the project is $1.5 million with construction overhead. The project is estimated to be placed into service in October, 2022. At this time costs are not forecasted to exceed the items above.

d. Although not listed on that page, please provide same information (requested in part c) for the Kuebler Blvd Reinforcement Project.

Kuebler Boulevard Reinforcement Project

i. Cost of the project included in the UG 388 filing is $19,739,670.
ii. Project costs incurred as of November 1, 2020 is $394,704.
iii. Project costs incurred as of September 30, 2021 is $1,822,660.
iv. The estimated final cost of the project is $24.2 million as per testimony (NW Natural/400/Kizer/Page 8.) The project is estimated to be placed

into service in October 2022. Please refer to **UG 435 OPUC DR 176** for information about the increase in estimated total project costs since the UG 388 filing.

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Request No.: UG 435 OPUC DR 174

Regarding the significant transmission and distribution projects bulleted on Kizer, 400/3, please explain why the Springfield ILI project is not considered to be significant as it was listed on the page prior.

Response:

The E08 Springfield ILI project, and other ILI conversion projects, are significant in that they are presented in testimony (Kizer, 400/29-30) in Section III (Safety-Related Projects).

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Request No.: UG 435 OPUC DR 175

Regarding the major storage projects bulleted on Kizer, 400/3-4, please provide,
a. Project costs incurred as of November 1, 2020
b. Project costs incurred as of September 30, 2021
c. The estimated or final cost of the project and the estimated or final date placed into service

Response:

Mist 300 and 400 Compressor Controls Upgrade Project

a. Project costs incurred as of November 1, 2020 are $908,125 without construction overhead.
b. Project costs incurred as of September 30, 2021 are $3,043,389 without construction overhead.
c. The estimated final cost of the project is $3.3 million without construction overhead and $4.0 million with construction overhead. The project was placed into service in September, 2021.

Mist Well Rework Project 2021

a. Project costs incurred as of November 1, 2020 are $0 without construction overhead.
b. Project costs incurred as of September 30, 2021 are $3,019,137 without construction overhead.
c. The final cost of the project is $3.1 million without construction overhead and $3.7 million with construction overhead. The project was placed into service in November, 2021.

Mist Well Rework Project 2022

a. Project costs incurred as of November 1, 2020 are $0.
b. Project costs incurred as of September 30, 2021 are $0.
c. The estimated final cost of the project is $3.7 million with construction overhead. The project is estimated to be placed into service in October, 2022.

Mist Corrosion Abatement Project (Phase 4)

a. Project costs incurred as of November 1, 2020 are $61,414 without construction overhead.
b. Project costs incurred as of September 30, 2021 are $1.99 million without construction overhead.
c. The estimated final cost of the project is $2.65 million without construction overhead and $3.2 million with construction overhead. The project is estimated to be placed into service in April, 2022.

Mist Electrical Upgrades Project (Phase 1)

a. Project costs incurred as of November 1, 2020 are $67,753 without construction overhead.
b. Project costs incurred as of September 30, 2021 are $99,623 without construction overhead.
c. The estimated final cost of the project is $1.9 million with construction overhead. The project is estimated to be placed into service in October, 2022.

Portland LNG PLC Upgrade Project

a. Project costs incurred as of November 1, 2020 are $360,302 without construction overhead.
b. Project costs incurred as of September 30, 2021 are $1,980,087 without construction overhead.
c. The estimated final cost of the project is $2.2 million without construction overhead. The estimated final cost of the project is $2.7 million with construction overhead. The project is estimated to be placed into service in April, 2022.

Portland LNG Boil Off Compressor Project

a. Project costs incurred as of November 1, 2020 are $0.
b. Project costs incurred as of September 30, 2021 are $0.
c. The estimated final cost of the project is $2.5 million without construction overhead. The estimated final cost of the project is $3.0 million with construction overhead. Please refer to response from DR UG 435 OPUC DR 181 for the latest detailed cost estimate. The project is estimated to be placed into service in October, 2022.

Newport LNG Pretreatment Regeneration Project

a. Project costs incurred as of November 1, 2020 are $89,314 without construction overhead.

b. Project costs incurred as of September 30, 2021 are $1,627,630 without construction overhead.
c. The estimated final cost of the project is $4.85 million without construction overhead. The estimated final cost of the project is $5.82 million with construction overhead. The project is estimated to be placed into service in June, 2022.

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Request No.: UG 435 OPUC DR 176

Regarding the Keubler Boulevard Reinforcement Project,
a. Please provide a detailed narrative explanation of why the project was delayed from fall 2021 to fall of 2022.
b. In Staff's recollection, the project was to be constructed in conjunction with a City of Salem waterline. Please provide a detailed narrative explanation of what efficiencies were lost due to the decision to delay the project and whether the decision to reroute was related to the subsequent completion of the waterline.
c. Please indicate whether the decision to delay the project was related to the project's removal from the UG 388 test year revenue requirement.
d. Please provide the initial and most recent detailed project budgets and any cost benefit analyses that were performed.

Response:

a. The complexity of the pipeline project is the main driver for the project delay from the fall of 2021 to the fall of 2022. The project's complexity was not fully realized when the pipeline route was identified in Docket No. LC 71.

   The Planning phase Charter listed potential project constraints and risks such as Engineering staff resource constraints, easement acquisition, soil conditions and environmental permitting risks. Please refer to **UG 435 OPUC DR 173 Attachment 1** for the Planning phase Charter document. Several of the potential project constraints and risks identified in the Planning phase Charter were realized during the planning phase, leading to a longer planning period than forecasted when testimony was filed at the end of 2019 (UG 388, NW Natural/400/Karney.)

   A pipeline Route Assessment was conducted in Q3 and Q4 2020 to identify feasible pipeline route alternatives to connect the existing 12-inch steel pipeline on State Street to the 8-inch steel pipeline on Turner Road. Please refer to **Confidential UG 435 OPUC DR 176 Attachment 1** for the final version of the Route Assessment, dated November 4, 2021 (noted as "third submittal"). Section 4 of **Attachment 1** (entitled "Addendum") addresses changes made from the initial submittal in late 2020 to the final, third submittal.

The routes identified on the “Route Analysis Exhibit” (Reference **Confidential UG 435 OPUC DR 176 Attachment 1,** Page 22) followed Cordon Road, Kuebler Road, 62nd Ave, MacLeay Rd, Aumsville Highway and Deer Park Drive and varied from 4.3 to 5.7 miles in total length. The route assessment considered issues including construction safety, installation length, construction efficiency, impacts to the public during construction, and accessibility for operations and maintenance. The analysis also considered risks related to impacts of potential environmentally sensitive areas, permit requirements, presence of existing utilities and public infrastructure, and potential for future relocation due to public works projects.

The analysis in the Route Assessment identified more difficult and costly construction conditions than known at the time of the cost estimate presented in the UG 388 proceeding for the 8-inch pipeline route shown in LC 71. Factors adding complexity and cost to the LC 71 pipeline route included: increased traffic control for intersections along the Cordon Road corridor, night work, inability to install pipeline within paved road surface leading to significant environmental permitting for impact to environmentally sensitive areas outside the paved roadway, AC current mitigation requirements to protect buried steel pipeline from high voltage power lines along the east side of Cordon Road, and realization that Cordon Road is an arterial in the City of Salem’s Transportation Plan and slated for widening to five lanes in the future.

The pipeline route between State Street and Turner Road follows public rights-of-way governed by three jurisdictions: Marion County, Oregon Department of Transportation and the City of Salem. Our consultant and engineering staff have had to engage staff from three public agencies during the planning phase to review pipeline route locations, pipe alignment location, separation from edge of pavement and municipal utilities, pavement cut and restoration requirements, traffic control plans, and permitted work hours.

The route identified in LC 71 and the final selected pipeline route cross property owned by the State of Oregon between Kuebler Blvd and Turner Road in order to avoid two crossings of Mill Creek near the Turner Road / Kuebler Blvd intersection. Trenchless construction methods such as horizontal directional drilling (HDD), are preferred to crossing creeks to avoid impacts to waterways and the adjacent environmentally sensitive areas. Mill Creek has a stream bed full of cobbles and boulders, making a trenchless crossing high risk of failure and HDD methods would not be feasible. The selected route to avoid the creek crossing is owned by the State of Oregon. The State of Oregon is in an ongoing partnership with the City of Salem Urban Renewal Department to market the State’s surplus prison property for urban industrial development (Mill Creek

Corporate Center.) Consequently, NW Natural was required to coordinate the easement agreement with both the State and the City of Salem to confirm that the location of the gas pipeline easement across the State property would avoid negative encumbrance to the future development of the property. Easement acquisition negotiations started in Q3 of 2020 and the purchase of the easement concluded on September 15, 2021.

Preliminary design studies were initiated in Q4 2019 and Q1 2020 to aid in route evaluation. Field surveying and geotechnical exploration studies began Q2 of 2020. Our pipeline engineering consultant was selected and started work in Q3 of 2020. Environmental studies began in Q4 of 2020 and permit applications to cross jurisdictional wetlands along the selected pipeline route were submitted to Oregon Department of State Lands (DSL) in September 2021. Permit application review typically can be several months and recently has been longer due to impacts of the COVID pandemic. At this time, the environmental permit application remains in review with DSL and environmental permits continue to be a schedule risk for the project.

b. We do not recall a discussion to construct our gas pipeline with a City of Salem waterline. We are aware that a private third-party constructed a City of Salem 24-inch water main along the paved west bike lane of Cordon Road between State Street and Gaffin Road, approximately 1.4 miles in length, during summer 2020. The City of Salem does permit joint trench construction with their waterlines, and for the 24-inch water main requires 10-feet of horizontal separation between their 24-inch water main and any other public or private utility.

   No efficiencies were lost due to the water main project noted above. During our conversations with Marion County Public Works, the County stated a requirement of approval would be installation of the new 8-inch steel gas main outside of the paved roadway near the edge of right-of-way, in accordance with the County standards for private utilities. This requirement by Marion County was a consideration in the route analysis discussed in part a. above.

c. No, the decision to delay the Kuebler Boulevard Reinforcement Project was not related to the project's removal from the UG 388 test year revenue requirement. As noted in the response to part a, project constraints and risks were recognized during the planning phase leading to a longer planning period than forecasted when the project was added to testimony in Q4 of 2019 (NW Natural/400/Karney.)

d. Please refer to **UG 435 DR 173 part b** for the details of the approved budgets.

As noted in part a. above, the analysis in the Route Assessment **(Confidential UG 435 OPUC DR 176 Attachment 1)** identified more difficult and costly construction conditions than known at the time of the cost estimate presented in the UG 388 case for the 8-inch pipeline route shown in LC 71.

The Route Assessment provided cost estimate ranges for each pipe segment analyzed (Reference **Attachment 1**, Page 6). These cost ranges were utilized as part of the route selection process and confirm that the selected route has comparable construction costs to the shortest pipeline route considering the installation difficulty. The Selected pipeline route is discussed in the Addendum section of the Route Assessment (Reference **Attachment 1**, Page 19). Please refer to Attachment A in the Route Assessment for a map of the pipe segments discussed on Page 6.

A summary of the cost estimate ranges for the Shortest, Longest and Selected pipeline routes is as follows:

Route Alternative	Route Length (miles)	Cost (Low) $MM NO COH	Cost (High) $MM NO COH	Range with current COH = 42% ($MM)
Shortest Route 1 North + Center Route + Route 1 South	4.3	$11.1	$16.6	$15.7 - $ 23.6
Longest Route 2 North + Center Route + Route 2 South	5.7	$13.6	$20.4	$19.3 - $29.0
Selected (See Attachment A)	5.3	$11.4	$16.8	$16.1 - $23.9

The selected pipeline route is shown on Attachment A (Reference **Attachment 1**, Page 21).

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Request No.: UG 435 OPUC DR 177

Please provide the Mist Storage Facility Assessment cited on Kizer, 400/12.

Response:

Please refer to **Confidential UG 435 OPUC DR 177 Attachment 1** for the Facility Assessment Process Improvement and Refurbishment Project for the Mist Storage Plant (Mist Storage Facility Assessment).

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Request No.: UG 435 OPUC DR 178

Regarding the Mist 300 and 400 Compressor Controls Upgrade Project,
a. Please provide a detailed narrative explanation of why the turbine usage rates were inefficient (Kizer, 400/15).
b. Please provide the AECOM Mist Compressor Evaluation Study cited (Kizer, 400/15).
c. Please provide documentation of any cost benefit analysis that was performed regarding the cited alternatives to the control upgrade project (Kizer 400/16)..).
d. Please provide the initial and final detailed project budgets and any cost benefit analyses that were performed.

Response:

a. Section 5 of the AECOM study evaluated the historical operations of the four compressors at Mist. For the period evaluated, the 500 and 600 turbine compressors were the chosen equipment used for compression during the majority of the time. Turbine compressors operate best at maximum capacity, and do not have much ability to turn down, or reduce, their capacity. In order to further reduce the turbine's capacity beyond the turbine's turndown capability, a significant amount of recycling of the discharge gas is needed. This reduces the throughput of the compressor, but is inefficent and uses energy unnecessarily.

   Part of the work being performed by the turbine compressors was to move gas within a loop, rather than moving gas productively downstream into the distribution system. By upgrading and modernizing the 300 and 400 compressors, it was determined that their throughput capacity could be increased and they could handle the plant needs for a larger portion of the injection and withdrawal seasons, thereby allowing the turbine compressors to be used less.

b. Please refer to **Confidential OPUC DR 178 Attachment 1** for the AECOM report, dated June 23, 2020. Please refer to **Confidential UG 435 OPUC DR 178 Attachment 2** for the AECOM report appendices.

c. Section 8 of the AECOM study provided a comparison of lifecycle costs analyses of 4 options. Option 2 had the lowest estimated 25-year Life Cycle Costs in the analysis. As noted in Section 1.5 Option 2 Refurbishment / Overhaul offered lower capital costs when compared to Option 3 Replacement. The Mist 300-400 Compressor Controls Upgrade Project was the first improvement identified as part of the two-fold Option 2 concept discussed in Section 1.5.

d. Please refer to **UG 435 OPUC DR 173 Attachment 9 and UG 435 OPUC DR 173 Attachment 10** for the Planning and Execution Budgets, respectively. The final project cost is estimated to be $3.3 million without construction overhead. Refer to part c above for discussion on the lifecycle costs for the alternatives studied.

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Request No.: UG 435 OPUC DR 179

Regarding the Mist Electrical Upgrades Project,
a. Please provide the Harris Group study (Kizer, 400/20).
b. Please provide a detailed narrative description of each of the project phases and the anticipated cost of each phase (Kizer, 400/21-22).
c. Please provide the initial and most recent detailed project budgets and any cost benefit analyses that were performed.

Response:

a. Please refer to **UG 435 DR 179 Attachment 1** for the Harris Group Study.

b. In Section 4 (Recommended Repairs and Upgrades) of the Harris Group Study, various new projects to improve the Miller Station Electrical System were identified. The projects were grouped into Priority 1 and 2. The Mist Electrical Upgrades Phase 1 project includes all items that were identified as Priority 1 in the study. The Priority 2 projects will be completed in subsequent phase(s).

   The **Mist Electrical Upgrades Phase 1 (Priority 1)** scope of work involves the following improvements:

   • Replace existing 500kVA service transformer with a new outdoor pad mounted 1000 kVA liquid filled transformer.

   • Replace primary switch gear

   • Re-feed circuits from new transformer to MCC-1A

   • Construct new Power Distribution Center (PDC) building with 1200 Amp ATS.

   Per Section 5 of the Harris Group Study, the estimated cost of the Phase 1 (Priority) 1 electrical improvements is \$1.4M to \$1.64M without construction overhead and internal labor. An estimate for Total Project costs for Phase 1 is \$1.9 to \$2.1 million with construction overhead.

   The **future Mist Electrical Upgrades Phase 2 (Priority 2)** scope of work involves the following improvements:

   • Replace Mechanical Building Motor Control Center and Upgrade Feeders

• Provide 1-hour Battery Storage System to Protect from Outages

• Refeed Bruer Site with New Power Cables in Conduit

• Refeed S-100/200 and S-300/400 Buildings from new Motor Control Center

• Demo and Refeed All Equipment in Production Yard

• Provide New Ground-Ring Installation for MCC-1A, South MCC, Mechanical MCC, TEG MCC, PDC DEHY MCC.

• New Energy Storage System

Per Section 5 and the Appendix in the Harris Group Study, the estimated cost of the Priority 2 improvements is $2.3 million without construction overhead. For planning purposes we estimate the total cost for the Priority 2 improvements to be in the range of $2.1 million to $2.8 million without construction overhead and $2.5 million to $3.4 million with construction overhead.

c. Please refer to **UG 435 DR 179 Attachment 2** for the Planning budget.

Planning budget = $200,000 without construction overhead.

A cost benefit analysis was not performed for the electrical equipment recommended for replacement. Section 4 of the Harris Group Study provides recommendations for equipment replacements, system upgrades and system studies due to end of life issues or equipment reaching capacity limits. Upgrades to the electrical equipment is expected to improve plant power system performance and reliability.

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Request No.: UG 435 OPUC DR 180

Regarding the Portland LNG PLC Upgrade Project,
a. Please provide a detailed narrative description of the two dependent components and sub components listed on Kizer, 400/22 including the anticipated cost of each.
b. Please provide the initial and most recent detailed project budgets and any cost benefit analyses that were performed.

Response:

a. The scope of the second listed dependent components (i.e., the buildout of a new, climate-controlled information technology server room with security infrastructure upgrades and network segmentation to remediate a number of cyber security concerns) includes the following work:

   • Build-out and conversion of existing electrical room into a new IT server room.

   • Installation of new server racks and IT/security hardware including switches, servers, hard-drives, and routers.

   • New heating and cooling units for climate control of the room, new entry doors and entry hardware.

   • Electrical panels, transformers and backup batteries (UPS or uninterruptible power supply) to meet IT backup specifications.

   • New monitors and hardware for operator work stations to standardize with other plants.

   • Demolition of the existing telephone and network demarcation closet and demolition of the raised ceiling and replacement of old lights to enable the installation of new electrical routing trays.

   • Addition of security door card readers for physical security.

   The scope of first listed dependent component includes the purchase and installation of a new Programmable Logic Controller (PLC) and a fiber loop ring to match other NW Natural facilities (for example, Newport LNG).

NW Natural bid the project out as a single project to the contractor and did not split the costs among the two components.

b. Please refer to **UG 435 OPUC DR 173 Attachments 14 and 15** for the Planning phase budget and Planning phase change order. Please refer to **UG 435 OPUC DR 173 Attachment 16** for the Execution budget. Please refer to **UG 435 OPUC DR 180 Attachment 1** for the Alternatives Analysis.

Planning Budget with Planning Change Order = $650,000 without construction overhead.

Execution Budget = $2,290,856 without construction overhead (excludes O&M costs shown in **Attachment 16**.)

Total Project Budget = $2,940,856 without construction overhead.

Total Project Budget = $3.5 million with construction overhead

The final total project cost is anticipated to be $2.8 million with construction overhead.

The Alternatives Analysis covers the alternatives considered for this project.

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Request No.: UG 435 OPUC DR 181

Regarding the Portland LNG Boil-Off Compressor Project,
a. Please provide the Sanborn and Head analysis (Kizer, 400/24).
b. Please provide the initial and most recent detailed project budgets and any cost benefit analyses that were performed.

Response:

a. and b. Please refer to **UG 435 OPUC DR 181 Attachment 1** for the Portland LNG Feasibility Assessment Report (FAR), dated February 15, 2022 (Sanborn and Head analysis.) The FAR provides an assessment of the current conditions of the Portland LNG facility with recommendations for equipment upgrades. The boil off compressors are discussed in detail in Section 4.6 of Attachment 1. Please refer to **UG 435 OPUC DR 173** for discussion of initial budget up thru December, 2021.

   NW Natural is currently in the assessment phase for this project and have yet to develop detailed Planning and Execution phase project budgets.

   Section 4.6 of Attachment 1 discusses the alternatives for the boil off compressor and recommends installation of a new oil flooded screw compressor.

   The most recent project budget is based on the cost estimate provided in Attachment 1 for the Portland LNG FAR. Page 27 of the Portland LNG FAR shows an estimated cost of $2,470,000 without construction overhead for a new oil flooded screw boil off compressor constructed in 2026.

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Request No.: UG 435 OPUC DR 182

Regarding the Newport LNG Pretreatment Regeneration Project,
a. Please provide a detailed narrative description of the three key components listed on Kizer, 400/26-27 including the anticipated cost of each.
b. Please provide the initial and most recent detailed project budgets and any cost benefit analyses that were performed.

Response:

Regarding the Newport LNG Pretreatment Regeneration Project,

a. Please provide a detailed narrative description of the three key components listed on Kizer, 400/26-27 including the anticipated cost of each.

The project costs were developed, and bid based upon, the system entirety. Construction costs were evaluated on a discipline basis, such as civil, electrical and mechanical. Total installed costs have not been developed based on the three key components referenced.

To aid in understanding the details below: The Newport LNG pretreatment system is designed to remove contaminants (water, and CO_2) from the feed gas stream to the liquefier, and includes two separate processes: dehydration, and CO_2 removal. Each system consists of pressure vessels (beds) which are filled with a molecular sieve media specifically designed to clean particular components from the natural gas, along with interconnecting piping, control valves, and instrumentation. The dehydration system is designed to remove moisture and mercaptans from the feed gas stream and consists of two beds which alternate between online and regeneration. The CO_2 removal system is a three-bed system and removes CO_2 from the feed gas stream prior to the gas flowing to the liquefaction system. Both the dehydration and CO_2 removal systems include a regeneration system, which uses hot gas to regenerate the bed media, and then cooling gas to remove heat from the regenerated bed, allowing it to eventually be placed back online.

The three key components referred to are in *italics*.

1. *Convert the carbon dioxide adsorber regeneration cooling process to a semi-closed loop system, similar to the carbon dioxide adsorber regeneration heating process.*
   The existing process mixes cooling gas flow from the CO_2 adsorber bed that is in cooling mode with the feed gas stream to the liquefier. With this design, there is some carry over of contaminants which are sent to the liquefier, reducing system reliability and/or availability. The new system design separates the cooling stream from being able to send contaminants into the liquefier. The modified design reconfigures the gas piping and adds a recirculation blower. The modified system will use boiloff gas to cool the cooling bed. The new blower will recirculate a portion of the cooling flow in a semi-closed loop, in order to reduce the net natural gas used in the process.

2. *Install a new regeneration heat exchanger to provide independent heat for the dehydration system regeneration heating.*
   With the existing system, a single heat exchanger is used to supply heat to both the CO_2 regeneration and dehydration bed regeneration processes. This modification installs a new heat exchanger dedicated to regeneration of the dehydration bed, while the existing heat exchanger will continue to supply heat to the CO_2 regeneration. The new, dedicated heat exchanger ensures adequate and efficient heating of the dehydration system during regeneration. The new exchanger also facilitates reuse of regeneration waist gas downstream of the CO_2 beds which is now utilized for regeneration of the dehydration beds, reducing the amount of natural gas required.

3. *Redirect the dehydration system regeneration cooling outlet stream to the fuel gas system.*
   The existing dehydration system regeneration cooling design mixes cooling gas flow into the feed gas stream, increasing the potential for contaminants to be reintroduced into the downstream components. The modified design allows for regeneration cooling flow to be sent to the fuel gas stream, increasing the efficiency and reliability of the liquefier.

b. Please provide the initial and most recent detailed project budgets and any cost benefit analyses that were performed.

Please refer to **UG 435 OPUC DR 173 Attachment 17** for the total budget for the Planning phase, which includes early purchase requests for equipment with long lead times. Please refer to **UG 435 OPUC DR 173 Attachment 18** for the details of the Execution budget and Total project budget.

Please refer to **UG 435 OPUC DR 182 Attachment 1** for the project's Alternatives Analysis.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 183

Regarding the Central Resource Center Project and 250 Taylor Second-Floor Tenant Improvements,
a. Please provide the total anticipated cost of Phase 2.
b. Please confirm or deny that Phase 2 costs are included in utility plant in this case.
i. If confirmed, please provide a detailed narrative explanation of how such costs are projected in the case and a summary of the cost by month placed into service.
c. Please provide the Phase 2 costs both including and excluding the additional square footage avoided by establishing the 250 Taylor Emergency Response Center (Pipes, 500/41) and asserted to fully offset the test year cost of the 250 Taylor Second Floor Tenant Improvements (Pipes, 500/51).
i. Please all internal analysis supporting this assertion.
d. Please provide the FTE associated with the 24/7 Emergency Response Workgroup supervisors and field employees (Pipes, 500/41).
e. Regarding the statement that locating the large project space at Sherwood would utilize space otherwise reserved for emergency operations, Staff notes that the Company discussed using the Sherwood facility as an emergency backup control center (UG 344, Pipes, 500/13),
i. Please provide a narrative explanation of how the Company's emergency plans have evolved since 2017 and why the proposed costs to supplement emergency response at 250 Taylor and the Central Resource Center are not redundant with regard to the Company's investment in Sherwood.
f. Please update the cost analysis provided in the UG 388 case (UG 388 Davilla Exhibit 904) to reflect current costs and square footage used by the Company on the Second floor.
g. Please provide a narrative explanation of how the Enterprise and Large Project space slated to be occupied by the Horizon 1 and 2 project teams (Pipes, 500/53) will be split between O&M and capital cost including the accounting methods employed (e.g. overhead allocation vs. direct charging the projects, etc.)

Response:

a. The total anticipated cost of Phase 2 of the Central Resource Center Project is $8,314,325.

b. Central Resource Center Phase 2 is not included in utility plant in this case.

c. Phase 2 of the Central Resource Center Project was originally planned to include a 17,986 square foot building at a total estimated cost for construction in March of 2023 of $11,375,578. The Company's general contractor, Bremik Construction, estimated this cost in August 2019. The revised Phase 2 scope includes a 6,900 square foot building at a total estimated construction cost for construction in March of 2023 of $8,314,325. This cost was estimated in January 2022.

Please refer to the file, "UG 435 OPUC DR 183 Attachment 1," which compares the estimated Security Operations Center, Emergency Response Center, and Safety Workgroup space Test Year revenue requirement under two scenarios that accommodate these functions through: (1) tenant improvements at 250 Taylor ("Option 1"); or (2) construction of a larger Central Resource Center ("Option 2"). Attachment 1 indicates that the revenue requirement reduction associated with eliminating the additional square footage at the Central Resource Center by choosing Option 1 over Option 2 fully offsets the Test Year costs of the 250 Taylor Second-Floor Tenant Improvements related to constructing the Security Operations Center, the Emergency Response Center, and the workspace for the Safety group.

d. There are six FTEs associated with the 24/7 Emergency Response Workgroup: One supervisor and five emergency response specialists. None of these FTEs are field employees. The emergency response specialists oversee responses to companywide emergency incidents, but do not directly supervise any staff.

e. Emergency response and emergency back up operations are completely separate functions. Emergency response is made up of the supervisor and emergency response specialists that oversee daily / ongoing natural gas emergencies and report to onsite emergencies. The 250 Taylor Operations Center location allows these personnel to quickly respond to emergencies in the Portland Central City area. The Sherwood facility provides back up emergency operations capabilities for Gas Control, Resource Management, Emergency Call Center, Emergency Operations space for our Incident Command Team and Business Continuity Space for other critical business functions should our 250 Taylor Operations Center not be useable. The Sherwood facility was never intended to provide these teams and critical business functions a base for long-term emergency operations and response capabilities for the Portland Central City area.

f. Please see "UG 435 OPUC DR 183 Attachment 2".

g. Tenant improvement is capitalized and amortized as an O&M expense. Both the lease expense and tenant improvement amortization for 250 Taylor are expensed to a 931 FERC account. This FERC account gets an administrative transfer rate of 35% which credits O&M in FERC 922 and transfers that 35% to Capital.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 205

Please provide a narrative explanation, for each item listed below, of whether the efficiencies asserted in testimony can be quantified at this time, the specific FERC accounts where the savings would occur, and the time frame when the savings are expected to be realized. Please specify any savings already included in test year expenses in this case.
a. Pipes, 500/33 – savings from moving vehicles and equipment from the LNG Facility to the Central Resource Center.
b. Pipes, 500/54 – workspace efficiencies and lease savings resulting from the Enterprise and Large Projects Space.
c. Downing, 600/5 and 600/60 – business efficiencies resulting from the Data Analytics and Reporting Implementation.
d. Downing, 600/20 – ongoing O&M cost savings resulting from the Horizon 1 upgrade, identifiable reductions in O&M costs driven by expected improvements to supply chain management and organizational efficiencies.
e. Downing, 600/35 – efficiencies of the new IT&S environment.
f. Downing, 600/43 – employee efficiencies and improved collaboration capabilities.
g. Rogers, 800/12 and 800/14 – efficiencies incentivized by pay at risk.

Response:

a. The Company does not anticipate any direct cost savings associated with the relocation of vehicles and equipment from the LNG Facility to the Central Resource Center, but the relocation will result in better and more efficient use of staff time. Therefore, there are no savings included in the Test Year, and while cost savings related to efficiencies of staff time are not quantifiable at this time, we expect savings to be present in expense levels of future rate cases.

b. The decision to site the Enterprise and Large Projects Space at 250 Taylor will result in improved workplace collaboration as well as potentially reduced travel time for staff who would otherwise need to meet at an offsite location. The Company has quantified the Test Year revenue requirement impacts of (1) tenant improvements at 250 Taylor ("Option 1") compared to (2) sublease space at an offsite location ("Option 2") and found Option 1 to be the least cost option. Please refer to the file, "UG 435 OPUC DR 205 Attachment 1". The lower cost is reflected in the Test Year revenue requirement filed in this case; had the

Company chosen Option 2, the filed Test Year revenue requirement would have been higher, specifically associated with FERC Account 931.

c. At this point we are in the design and build phase of the project. This capability is to provide improved business insights and decision making, beyond the currently available analytics. It is difficult to quantify the efficiencies as they are qualitative in nature. Our initial phase will help lay the foundational set of capabilities and we will begin to see the qualitative improvements in the business decision making process in late 2022 and beyond. Past the test year, we will build upon sophisticated and more advanced analytics in a continuous manner. We will also begin to see the reduced time to produce the analytics after the initial years as we expand the data cataloged and data quality. This will enable us to service our significant back log of reporting and analytics needs of the business.

   Our initial target use cases are strategic in nature and represent critical parts of the business. These use cases target long term gas supply forecast, delinquency and collections to analyze trends, root cause and predictive actions for delinquent accounts, customer analytics for the analysis of improved customer communications across the service channels, safety analytics for improved worker and vehicle incidents and training analytics to evaluate training effectiveness and training curriculum. Overall, business efficiencies will be realized in a continuous fashion, as we increase the data footprint from various data domains, bring together relevant data across various business functions and increase the analytics driven business insights and decision making. We will also increase efficiencies in analytics generation with reduced time and effort to build and deliver them. While cost savings related to efficiencies are not quantifiable at this time, we expect savings to be in expense levels of future rate cases.

d. Please see Confidential UG 435 OPUC 205 Attachment 2 for calculations supporting the system amount of $1.5 million in cost savings described in UG 435 DR 205 Attachment 1. NW Natural has not realized these efficiencies yet, but we have committed to reducing revenue requirement in anticipation of capturing the benefits identified in Confidential UG 435 OPUC DR 205 Attachment 2. In this way, these are “aspirational goals” that may take more than one year to harvest, but they have been included as an offset to revenue requirement immediately when the project is included in rates.

   We have also included cost savings that could be categorized as “eliminating current costs.” These include removing any remaining depreciation expense from the legacy SAP system and removing sunsetting applications from rates that will no longer be used after Horizon is implemented.

e. Please see response to (d) above and the Information Technology and Services table in Confidential UG 435 OPUC 205 Attachment 2.

f. NW Natural today uses Skype for Business for communication and collaboration. In 2021 Skype for Business averaged per month +650 employees scheduling

+6,400 conferences and those had +25,000 participants (again averaged monthly across all of 2021). However, Skype has limitations such as no persistent chat and no direct-link ability to meeting data. This causes “email culture” where files are often sent prior, during, and after meetings. Version control becomes challenging, and people will often request “you email me the most recent copy of that file.” The M365 Implementation Program will implement Microsoft Teams which will further build upon the capabilities of Skype by offering enhanced collaboration technologies such as persistent chat and channels in which participants can directly access data relevant to that meeting. The implementation of Microsoft Teams as part of M365 Implementation Program will provide a more effective and efficient way to share information and thus improve the way employees communicate and collaborate. While cost savings related to efficiencies are not quantifiable at this time, we expect savings to be in expense levels of future rate cases.

g. As stated in the testimony, NW Natural uses our continual pay at risk program to incentivize officers and all employees to operate the gas company in a safe and effective manner while also meeting the needs of our customers. We use measures such as safety rates, the number of preventable motor vehicle collisions, response time for gas odor or emergency calls as well as two different measures of customer satisfaction. Focusing the attention of employees on these critical areas have allowed us to meet customer needs and maintain a low rate of cost for workers’ compensation claims and vehicle repairs. In addition, officer goals such as maintaining a strong positive relationship with our Union partners allows us to work quickly through employee issues. While efficiencies related to the pay-at-risk program may not be directly identifiable, current cost levels in the rate case will have been impacted from past pay-at-risk programs, and the cost levels included in future rate cases will have been affected by the current program.

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 206

Please provide all work underlying the ongoing O&M cost-saving benefits quantified on Downing, 600/30, specifically,
a. A reduction of $0.6 million ($0.5 million Oregon-allocated) related to software that we will no longer needed.
b. $1.5 million ($1.35 million Oregon allocated) in O&M savings that we expect to realize from increased efficiencies.

Response:

a. Please refer to UG 435 OPUC DR 202 Attachment 2, “Sunsets” tab.

b. Please see Confidential UG 435 OPUC DR 205 Attachment 1.

ZACHARY D. KRAVITZ
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NW Natural

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PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

December 6, 2016

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
3930 Fairview Industrial Drive SE
Post Office Box 1088
Salem, Oregon 97308-1088

Re: Northwest Natural's Gas Company's Notice of Property Sale

Pursuant to ORS 757.480(2), Northwest Natural Gas Company, dba NW Natural ("NW Natural" or "the Company"), provides this notice of the sale of a utility owned property ("Notice"). Specifically, NW Natural sold 1,250 square feet of improved land located at NW 30th Ave., Portland, Oregon to Cairn Pacific Acquisition for $45,000 on October 7, 2016. The after-tax gain on sale will be reflected in the property sales balancing account and returned to ratepayers through the Schedule 178 "Regulatory Adjustment Rate" in the 2017-18 Purchase Gas Adjustment (PGA) mechanism. The property was sold in accordance with the terms of a Real Estate Purchase and Sale Agreement, which is attached to this Notice as Attachment A. A recorded copy of the Special Warranty Deed evidencing the transfer of the Property to Cairn Pacific Acquisitions LLC, dated and recorded October 7, 2016, is included with this Notice as Attachment B.

The transfer of the property will not interfere with the Company's ability to access or operate its facilities. Furthermore, the public is not harmed because the Company will continue to be able to fulfill its obligation to provide safe, reliable gas service.

Please address correspondence on this matter to me with copies to the following:

eFiling
NW Natural Rates & Regulatory Affairs
220 NW Second Avenue
Portland, Oregon 97209
Telecopier: (503) 721-2516
Telephone: (503) 226-4211, ext. 3589
eFiling@nwnatural.com

Please call me if you have any questions or require any further information.

Sincerely,

/s/ Zachary D. Kravitz
Zachary D. Kravitz
Associate Counsel
Attachments

REAL ESTATE PURCHASE
AND SALE AGREEMENT
(NW 30th Ave., PORTLAND, OR – Tax ID R307722)

THIS REAL ESTATE PURCHASE AND SALE AGREEMENT (this "**Agreement**") is made by and between **CAIRN PACIFIC ACQUISITION LLC**, an Oregon limited liability company and/or assigns ("**Buyer**"), and **Northwest Natural Gas Company** (collectively, "**Seller**").

Seller is the owner of certain real property located in Multnomah County, Oregon containing approximately 1,250 square feet of improved land located on NW 30th Ave., Portland, Oregon and more particularly described on the attached Exhibit A (the "**Land**"). As used in this Agreement, "**Property**" means collectively the following: (A) the Land and all rights, privileges and appurtenances belonging or pertaining thereto (the "**Real Property**"); (B) all improvements and fixtures located on the Land, if any (the "**Improvements**"); and (C) all assignable development rights related to the Real Property or the Improvements or any part thereof, if any (the "**Development Rights**", all on the terms, covenants and conditions set forth in this Agreement.

NOW, THEREFORE, for and in consideration of the mutual covenants and agreements herein contained and other valuable consideration, Seller and Buyer agree as follows:

1. **Agreement.** Seller agrees to sell the Property to Buyer, and Buyer agrees to purchase the Property subject to and in accordance with the terms and conditions of this Agreement.

2. **Purchase Price Payment.**

(a) **Purchase Price Amount.** The total purchase price for the Property (the "**Purchase Price**") shall be Forty-Five Thousand Dollars ($45,000.00). The Purchase Price shall be payable in cash at Closing (as defined below).

(b) **Earnest Money.** Within three (3) business days after the Effective Date (as defined below), Buyer shall open an escrow with Ticor Title Company ("**Title Company**"), 111 SW Columbia Street, Suite 1000, Portland, Oregon 97201, Attention: Alli Swallow, Phone (503) 219-2179, and shall deposit with Title Company an earnest money note in the amount of Three Thousand Dollars ($3,000.00) (the "**Earnest Money Note**"). Within three (3) business days after the removal of Buyer's Due Diligence Contingency (defined below), the Earnest Money Note shall be converted to cash (the "**Earnest Money**") and shall be deemed non-refundable (except for a default by Seller, casualty, condemnation or any material representation or material warranty of Seller shall not be substantially true and correct at the Closing). The Earnest Money is applicable to the Purchase Price.

3. **Review of Property.**

(a) **Seller's Deliveries.** Within ten (10) days of the Effective Date), Seller shall deliver to Buyer copies of all information, documentation and reports to the extent in Seller's department of Risk and Land's possession pertaining to the Property, including, without limitation, the following (collectively, the "**Seller Documents**"): (a) all plans, drawings, specifications, soils reports, engineering and architectural studies, zoning studies or reports, hazardous waste studies, geotechnical reports, hydrology reports, wetland studies, topographical maps, boundary and ALTA surveys, environmental reports, grading plans, and similar data relating to the Property; (b) copies of all contracts and agreements between

Seller and Seller's consultants relating to the materials addressed in Section 3.1(a), above; and (c) all permits, entitlement documents, zoning agreements, mitigation agreements with any governmental agency, and any traffic studies for the Property or surrounding properties, and all correspondence related thereto. Seller is making the Seller Documents available to Buyer as an accommodation to Buyer. Seller makes no representation or warranty whatsoever as to the accuracy or completeness of the Seller Documents, provided Seller does warrant that any document provided by Seller is a complete copy of such document in Seller's files. Buyer acknowledges that its decision whether to complete the purchase of the Property shall be made solely on the basis of Buyer's own due diligence and not on reliance on Seller's Documents.

(b) **Buyer's Review.** As of the Effective Date, Seller shall provide Buyer and its agents and consultants with access to and entry upon the Property to inspect each and every part thereof to determine its present condition and, at Buyer's sole cost and expense, to prepare such reports, tests and studies, including, without limitation, any tests, geological reports, surveys, hazardous/toxic materials investigations and other physical investigations of, on, or in the Property. Buyer shall not excavate or drill in the Property or alter any improvements or otherwise engage in any invasive activities relating to or testing of the Property without the prior written consent of Seller, which consent may be subject to Seller's reasonable conditions. Buyer shall indemnify and hold harmless the Seller from any mechanics or materialmen's liens filed against the Property as a result of Buyer's entry upon the Property in accordance with this Section 3.2 and with respect to any claims arising out of Buyer's entry to the Property. Before entering the Property to perform testing of any kind, Buyer shall provide Seller evidence of commercial general liability insurance (combined single limit, not less than $1,000,000 per occurrence and $2,000,000 in the aggregate) which policy shall include Seller as an additional insured by endorsement which endorsement shall be referenced in the evidenced of insurance.

(c) **Due Diligence Contingency.** The obligations of Buyer under this Agreement are, at Buyer's option and in its sole and complete discretion, subject to the complete satisfaction or waiver, on or before the date that is forty five (45) days after the delivery by Seller of the Seller Documents to Buyer (the "**Due Diligence Contingency Date**") of the following contingencies (individually and collectively, the "**Due Diligence Contingency**"): (a) the Property and its physical condition, zoning and land use approvals and restrictions, and all systems, utilities, and access rights pertaining to the Property are suitable in every respect for Buyer's intended use; (b) the Seller Documents are acceptable to Buyer; and (c) it is economically feasible for Buyer to own, develop and operate the Property in a manner and upon terms and conditions satisfactory to Buyer. Buyer may, in Buyer's sole discretion, terminate this Agreement at any time, on or prior to the Due Diligence Contingency Date, by written notice to Seller, if Buyer determines that the Due Diligence Contingency set forth in this Section 3.3 will not be satisfied on or before the Due Diligence Contingency Date. If Buyer fails to give notice to Seller that the Due Diligence Contingency has been satisfied or waived on or before the Due Diligence Contingency Date, Buyer shall be deemed to have terminated this Agreement. If Buyer terminates or is deemed to have terminated this Agreement in accordance with this Section 3.3, the Earnest Money Note shall be returned to Buyer. If Buyer terminates this Agreement and Seller is not in default of its obligations under this Agreement, Buyer shall provide Seller with copies (without representation or warranty) of any final third party prepared reports pertaining to the physical condition of the Property.

4. **Title.**

(a) **Conveyance.** Upon Closing, Seller shall execute and deliver to Buyer a special warranty deed (the "**Deed**"), conveying fee title to the Property, subject only to the Permitted Exceptions, if any, approved by Buyer in accordance with Section 4(b) and an exception for such matters that would be shown by a true and correct survey and the Central Assessment Property Tax Exception (as such term is defined below).

(b) **Title Insurance.** At Closing, Seller shall at Buyer's expense furnish to Buyer an ALTA Standard Coverage Owner's Policy of Title Insurance (the "**Policy**") issued by Title Company, insuring title vested in Buyer in the amount of the Purchase Price against any loss or damage by reason of defect in Seller's title to the Property, other than the Permitted Exceptions as determined hereunder. Seller agrees to execute and deliver to Title Company a standard title affidavit. Within five (5) business days after the Effective Date, Buyer shall deliver to Seller a preliminary commitment for the Policy, together with legible copies of all documents referenced or described therein (collectively, the "**Commitment**"). Buyer shall be responsible for securing, at Buyer's sole expense an ALTA survey of the Property (the "**Survey**"). Buyer shall notify Seller in writing of Buyer's approval of any exceptions or other defects shown in the Commitment ("**Permitted Exceptions**") within fifteen (15) days of receipt by Buyer and Buyer's counsel of the Commitment. Seller shall with respect to liens and encumbrances which can be satisfied and released by the payment of money, eliminate such exceptions to title on or before Closing. With respect to other encumbrances or exceptions, Seller shall have no obligation whatsoever to eliminate any encumbrances or exceptions. If Buyer is not satisfied with the condition of title, then on or before the expiration of the Due Diligence Contingency Date, Buyer may, at its sole option, to either: (i) terminate this Agreement, whereupon the Earnest Money Note or the Earnest Money, and any interest accrued thereon shall be returned to Buyer and no party shall have any right or remedy against the other; or (ii) waive its prior disapproval and elect to approve such exception(s) as Permitted Exceptions. If, notwithstanding the foregoing, title to the Property is not insurable subject only to the then Permitted Exceptions and cannot be made so insurable by the Closing Date, Buyer may, at its sole option, terminate this Agreement whereupon the Earnest Money and interest accrued thereon shall be returned to Buyer, or Buyer may waive its prior disapproval and elect to approve such exception(s) as a Permitted Exception, whereupon this Agreement shall remain in full force and effect. If Buyer elects to terminate this Agreement as herein provided, Seller shall pay any cancellation fee charged by the Title Company for the Commitment. Notwithstanding the above or anything to the contrary herein, Buyer acknowledges that the because Seller is a regulated utility, real property owned by Seller is centrally assessed by the Oregon Department of Revenue and that the Commitment and the Deed will contain an exception (which shall be included as a Permitted Exception) substantially similar to the following: "Pursuant to ORS 308.505 through 308.665, the Oregon State Department of Revenue has assessed the subject property along with other real property in Multnomah County which is owned by Northwest Natural Gas Company, and we are unable to aggregate the amount of tax, if any. Due to the power and authority of the Department of Revenue to correct any assessment errors, this property may be subject to additional taxes following a transfer of title" (the "Central Assessment Property Tax Exception").

(c) **[Intentionally Deleted].**

(d) **Condemnation.** In the event that the Property, or any part thereof, is or becomes the subject of a condemnation proceeding before Closing, then Buyer may elect either to: (a) terminate this Agreement, in which event the Earnest Money Note or the Earnest Money and any interest accrued thereon, shall be returned to Buyer and all rights and obligations of the parties hereunder shall cease; or (b) proceed to consummate and Close the purchase of the Property hereunder, in which event the Purchase Price for the Property shall be reduced by the total of any awards or other proceeds received by Seller at or before Closing with respect to any such condemnation proceeding. If Buyer elects to Close and the award or other proceeds have not been received by Seller at or before Closing, then at Closing, Seller shall assign to Buyer all rights of Seller in and to any awards or other proceeds payable by reason of any such condemnation proceeding. Seller agrees to notify Buyer in writing of any condemnation proceedings within five (5) days after Seller learns thereof.

(e) **Risk of Loss.** If, prior to the Closing Date, any part of the Property is destroyed or suffers material damage affecting Buyer's intended use, Buyer shall have the right, exercisable by giving notice of such decision to Seller within five (5) business days after receiving written notice of such damage or destruction or condemnation threat, to terminate this Agreement, in which event the Earnest Money Note or the Earnest Money and any interest accrued thereon, shall be returned to Buyer and all rights and obligations of the parties hereunder shall cease. If Buyer does not timely elect to terminate this Agreement, all insurance and/or condemnation proceeds payable to Seller shall be assigned by Seller to Buyer.

(f) **Development Approvals.** So long as this Agreement remains in effect, Buyer shall have the exclusive right to pursue and obtain all necessary approvals for developing the Property in such manner as Buyer shall deem appropriate in Buyer's sole discretion. Seller hereby grants to Buyer the right to, among other things: (a) enter into discussions and negotiations regarding the Property with all governmental authorities having jurisdiction; and (b) apply in its own name for any plat, permit, rezoning, change in comprehensive plan designation, development agreement, variance or conditional use request, site plan, local improvement district, or other approval which may be required incident to Buyer's planned development of the Property provided in no event shall any of the same be binding on the Property if and until Buyer completes the purchase of the Property. Seller (at no cost to Seller) shall reasonably cooperate with Buyer in connection with applying for any governmental approvals, which cooperation shall be limited to the execution and delivery of any applications as may be reasonably requested by Buyer to the extent that Seller (as the Owner of the Property) is obligated to sign any application for such application to be processed.

5. **Closing.**

(a) **Closing Contingencies.** Buyer's obligation to Close this transaction shall be further conditioned upon all of Seller's representations and warranties set forth in Section 7 hereof being true, correct and complete as of the Closing.

(b) **Royal Oak Property Closing**. Buyer's obligation to Close this transaction shall be conditioned upon Buyer completing purchase of the adjacent 54,885 square foot parcel ("Royal Oak Property") as depicted on Exhibit B. For avoidance of doubt, in such case, Buyer shall not be entitled to a return of its Earnest Money and the Earnest Money shall be released to Seller.

(c) **Escrow.** "**Closing,**" and "**Closing Date**" shall mean the date the Deed for the Property from Seller to Buyer is recorded and Seller is entitled to the delivery of Buyer's funds. Closing shall occur in escrow (the "**Escrow**") will occur on the date that is no later than thirty (30) days after Buyer has completed purchase of the Royal Oak Property, but in no circumstance will the Closing Dated extend beyond two hundred ten (210) days following the Effective Date (the **"Outside Closing Date").** Buyer and Seller shall deposit into the

Escrow all instruments and monies necessary to complete the Closing in accordance with this Agreement, including all instructions and closing statements not inconsistent herewith. Closing shall occur when all Seller deliveries and Buyer deliveries have been made and the Title Company is committed to issue the Policy and the Seller Policy. Buyer shall give Seller not less than fifteen (15) business days' notice of the Closing Date.

(d) **Prorations.** General real property taxes and assessment installments for the current year shall not be prorated as of the Closing.

(e) **Possession.** Buyer shall be entitled to possession on Closing, free and clear of all lease and contracts.

(f) **Costs.** Buyer shall pay: (i) the cost of recording the Deed; (ii) the cost of the Survey; (iii) the cost of the Policy, and any endorsements to the Policy required by Buyer; and (iv) the Title Company's Escrow fee.

(g) **Seller's Deliveries to Closing.** On or before Closing, Seller shall duly execute and deposit into Escrow:

(i) the Deed;

(ii) an assignment of Seller's interests in the Development Rights in the form attached as Exhibit D;

(iii) a certificate in a form acceptable to Buyer that Seller is not a "foreign person" as such term is defined in the Internal Revenue Code; and

(iv) such other documents which Seller is specifically required to deliver to Buyer pursuant to this Agreement or are otherwise reasonably required in order to consummate this transaction.

6. **Seller's Representations and Warranties.** Seller represents and warrants to Buyer that the following facts are true as of the date of Seller's execution hereof and as of Closing, or as of such other dates as may be set forth herein:

(a) **Marketable Title.** Seller owns fee simple title to the Property.

(b) **No Violations and Actions.** The execution, delivery and performance by Seller of its obligations under this Agreement do not constitute a default under any of the provisions of any law, governmental rule, regulation, judgment, decree or order by which the Seller is bound, or by any of the provisions of any contract to which the Seller is a party or by which the Seller is bound or, if Seller is not an individual, by the Seller's declaration of trust, certificate of incorporation, bylaws, limited liability company operating agreement or partnership agreement, as the case may be.

(c) **Liens.** All persons and entities supplying labor, materials, and equipment to the Property have been paid, there are no claims of liens and there are no service contracts applicable to the Property. All contracts for the furnishing of goods, labor, construction or other services to the Property shall be terminated as of the Closing Date.

(d) **[INTENTIONALLY DELETED].**

(e) **[INTENTIONALLY DELETED].**

(f) **Litigation.** There is no litigation, claim, investigation or other proceeding pending or, to Seller's actual knowledge, threatened against or affecting the Property, the use thereof, or the Seller which may become a lien against the Property.

(g) **Hazardous Materials.** Seller has received no written notice that the Property is in violation of any federal, state, local or administrative agency ordinance, law, rule, regulation, order or requirement relating to environmental conditions or Hazardous Materials (**"Environmental Laws"**). For the purposes hereof, **"Hazardous Materials"** shall mean any substance, chemical, waste or other material which is listed, defined or otherwise identified as "hazardous" or "toxic" under any federal, state local or administrative agency law or ordinance including but not limited to the Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. §§ 9601 *et seq.*; the Resource Conservation and Recovery Act, 42 U.S.C. §§ 6901 *et seq.*; the Federal Water Pollution Control Act, U.S.C. §§ 1251 *et seq.*; the Clean Air Act, 42 U.S.C. §§ 7401 *et seq.* or any similar or analogous state or local statute or ordinance, or any regulation, order, rule, or requirement adopted thereunder, as well as any formaldehyde, urea, polychlorinated biphenyls, petroleum, petroleum product or by-product, crude oil, natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel or mixture thereof, radon, asbestos, and "source," "special nuclear" and "by-product" material as defined in the Atomic Energy Act of 1985, 42 U.S.C. §§ 3011 *et seq.*

(h) **Contracts.** Seller has not committed nor obligated itself in any manner whatsoever to sell the Property to any person other than Buyer. Without limiting the generality of the foregoing, no right of first refusal regarding the Property exists. Seller will not, prior to Closing, offer to or enter into any backup or contingent option or other agreement to sell the Property to any other person.

(i) **Leases.** There are no existing Leases with respect to the Property.

(j) **Foreign Person or Entity.** Seller is not a foreign person, non-resident alien, foreign corporation, foreign partnership, foreign trust, or foreign estate, as those terms are defined in the Internal Revenue Code and the Income Tax Regulations promulgated thereunder. At Closing, Seller shall deliver to Buyer a certificate of non-foreign status in form required by the Income Tax Regulations and reasonably acceptable to Buyer.

(k) **Violations of Laws.** Seller has received no written notice that the Property is in violation of any applicable laws.

Buyer's rights to enforce such representations, warranties and covenants shall survive the Closing for a period of one (1) year and shall terminate and be of no further force or effect thereafter and no enforcement action may be brought against Seller after such one year period.

7. **Buyer's Representations and Warranties.** Buyer represents and warrants to Seller that the following facts are true as of the date of Buyer's execution hereof and as of Closing:

(a) **Power and Authority.** Buyer is a limited liability company organized and validly existing under the laws of the State of Oregon. No further action is necessary on the part of Buyer to make this Agreement fully and completely binding upon Buyer in accordance with its terms.

(b) **No Violations and Actions.** The execution, delivery and performance by Buyer of its obligations under this Agreement do not constitute a default under any of the provisions of any law, governmental rule, regulation, judgment, decree or order by which the Buyer is bound, or by any of the provisions of any contract to which the Buyer is a party or by which the Buyer is bound, or by the Buyer's certificate of formation, operating agreement, or other organizational documents, as the case may be.

(c) **As-Is.** Except as expressly set forth in this Agreement and the Deed, Buyer specifically acknowledges and agrees that Property is being sold in an "AS IS" condition and "WITH ALL FAULTS." Except as expressly set forth in this Agreement and the Deed, no representations or warranties have been made or are made and no responsibility has been or is assumed by Seller as to any matters concerning the Property, including, without limitation, the condition of the Property or its value, the environmental conditions of the Property, boundaries, or as to another fact or condition which has or might affect the Property. Buyer acknowledges the possible presence of asbestos materials in or part of the shed on the Property. Notwithstanding any other term or condition of this Agreement, Buyer agrees in connection with its redevelopment of the Property to remove and dispose of the shed in compliance with all applicable laws and regulations governing asbestos handling, removal and disposal, specifically including Environmental Laws.

8. **Events of Default.**

(a) **By Seller.** In the event Seller, without legal excuse fails to Close, Buyer will be entitled in addition to all other remedies available at law or in equity, (i) to seek specific performance of Seller's obligation to Close under this Agreement; or (ii) to terminate this Agreement by written notice to Seller and Title Company and Seller shall pay all of Buyer's actual out of pocket costs incurred in connection with Buyer's due diligence of the Property not to exceed $10,000 in any event. If Buyer terminates this Agreement pursuant to clause (ii) of this Subsection 8 (a), the Escrow will be terminated, the Earnest Money Note, the Earnest Money, and any interest accrued thereon shall immediately be returned to Buyer, all documents will be immediately returned to the party who deposited them, and neither party will have any further rights or obligations under this Agreement, except as otherwise provided in this Agreement except that Seller shall pay any costs of terminating the Escrow and any cancellation fee for the Commitment.

(b) **By Buyer.** If Closing and the consummation of the transaction herein contemplated does not occur as herein provided by reason of any default of Buyer, and Buyer fails to complete the purchase of the Property, Seller may terminate this Agreement by written notice to Buyer. Buyer and Seller agree that it would be impractical and extremely difficult to estimate the damages suffered by Seller as a result of Buyer's failure to complete the purchase of the Property pursuant to this Agreement, and that under the circumstances existing as of the date of this Agreement, the liquidated damages provided for in this Section 9 represent a reasonable estimate of the damages which Seller will incur as a result of such failure. **THEREFORE, BUYER AND SELLER HEREBY AGREE THAT A REASONABLE ESTIMATE OF THE TOTAL DAMAGES THAT SELLER WOULD SUFFER IN THE EVENT THAT BUYER DEFAULTS AND FAILS TO COMPLETE THE PURCHASE OF THE PROPERTY IS AN AMOUNT EQUAL TO THE ALL OF THE EARNEST MONEY. SUCH AMOUNT WILL BE THE FULL, AGREED AND LIQUIDATED DAMAGES FOR THE BREACH OF THIS AGREEMENT BY BUYER, AND AFTER PAYMENT THEREOF TO SELLER, NEITHER PARTY SHALL HAVE ANY FURTHER OBLIGATION TO OR RIGHTS AGAINST THE OTHER.**

9. Miscellaneous.

(a) **General Provisions.** This is the entire agreement of the parties with respect to the Property and supersedes all prior written or oral agreements or understandings. This Agreement may be modified only in writing signed by both parties. This Agreement shall be construed according to the laws of the State of Oregon. The parties have been represented by their respective legal counsel in connection with negotiation of this Agreement, and accordingly waive the rule of construction that this Agreement shall be construed against its drafter. If the date for any performance required hereunder is not expressly stated to occur within a certain number of business days, then such performance shall be determined by calendar days, unless the date for such performance under this Agreement falls on a weekend or holiday, in which case the time shall be extended to the next business day. "Business day" means a day that both national banks and Title Company are open for business in Portland, Oregon.

(b) **Notices.** Any demand, request or notice which either party hereto desires or may be required to make or deliver to the other shall be in writing and shall be deemed given when personally delivered, when delivered by private courier service (such as Federal Express), when received if by telecopy (with a copy by mail) or three (3) days after being deposited in the United States Mail in certified form, return receipt requested, in each case addressed as follows:

If to Seller:	Northwest Natural Gas Company 220 NW 2nd Avenue Portland, OR 97209 Attn: Steve Walti Telephone No.: (503) 721-2447 Facsimile No.: (503) 721-2516
with a copy to:	Northwest Natural Gas Company 220 NW 2nd Avenue Portland, Oregon 97209 Attn: Kat Rosenbaum Telephone No.: (503) 220-2354 Facsimile No.: (503) 721-2516
and to	Bateman Seidel 888 SW Fifth Avenue, Suite 1250 Portland, Oregon 97204 Attn: Chris Gram Telephone No.: (503) 972-9931 Facsimile No.:(503) 972-9951
If to Buyer:	Rob Hinnen Cairn Pacific LLC 1015 NW 11th Avenue, Suite 242 Portland, OR 97209 Telephone No.: (503) 345-6733 Facsimile No.: (503) 444-9017

with a copy to: Brix Law LLC
75 SE Yamhill Street
Suite 202
Portland, OR 97214
Attn: Bradley S. Miller
Telephone No.: (503) 741-2311
Email: bmiller@brixlaw.com

For purposes of notices, either party may change its address to any address that is not a post office box by giving notice to the other in the manner herein prescribed.

(c) **Commissions.** Seller warrants and represents to Buyer that no broker or finder has been engaged by it in connection with the transaction contemplated by this Agreement. Buyer warrants and represents to Seller that no broker or finder has been engaged by it in connection with the transaction contemplated by this Agreement. In the event any other claims for brokers' or finders' fees or commissions are made in connection with the negotiation, execution, or consummation of this Agreement, then Buyer shall indemnify, hold harmless, and defend Seller from and against such claims if they are based upon any statement, representation or agreement made by Buyer, and Seller shall indemnify, hold harmless, and defend Buyer if such claims shall be based on any statement, representation or agreement made by Seller.

(d) **Waiver.** Failure of either party at any time to require performance of any provision of this Agreement shall not limit such party's right to enforce such provision, nor shall any waiver of any breach of any provision of this Agreement constitute a waiver of any succeeding breach of such provision or a waiver of such provision itself.

(e) **[INTENTIONALLY DELETED].**

(f) **Attorneys' Fees.** With respect to any dispute relating to this Agreement, or in the event that a suit, action, arbitration, or other proceeding of any nature whatsoever, including (without limitation), any proceeding under the U.S. Bankruptcy Code and involving issues peculiar to federal bankruptcy law or any action seeking a declaration of rights or an action for rescission, is instituted to interpret or enforce this Agreement or any provision of this Agreement, the prevailing party shall be entitled to recover from the losing party its reasonable attorneys', paralegals', accountants' and other experts' and professional fees and all other fees, costs and expenses actually incurred and reasonably necessary in connection therewith including (without limitation) deposition and expert fees and costs incurred in creating exhibits and reports, as determined by the judge or arbitrator at trial or other proceeding, or on any appeal or review, in addition to all other amounts provided by law.

(g) **Arbitration.** ANY DISPUTE BETWEEN BUYER AND SELLER RELATED TO THIS AGREEMENT, OR THE PROPERTY, OR THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT WILL BE RESOLVED BY ARBITRATION GOVERNED BY THE FEDERAL ARBITRATION ACT AND, TO THE EXTENT NOT INCONSISTENT WITH THAT STATUTE, CONDUCTED IN ACCORDANCE WITH THE RULES OF PRACTICE AND PROCEDURE FOR THE ARBITRATION OF COMMERCIAL DISPUTES OF ARBITRATION SERVICES OF PORTLAND ("**ASP**"). THE ARBITRATION SHALL BE CONDUCTED IN PORTLAND, OREGON AND ADMINISTERED BY ASP, WHICH WILL APPOINT A SINGLE ARBITRATOR. ALL ARBITRATION HEARINGS WILL BE COMMENCED WITHIN THIRTY (30) DAYS OF THE DEMAND FOR ARBITRATION UNLESS THE ARBITRATOR, FOR SHOWING OF GOOD CAUSE, EXTENDS THE

COMMENCEMENT OF SUCH HEARING. THE DECISION OF THE ARBITRATOR WILL BE BINDING ON BUYER AND SELLER, AND JUDGMENT UPON ANY ARBITRATION AWARD MAY BE ENTERED IN ANY COURT HAVING JURISDICTION. THE PARTIES ACKNOWLEDGE THAT, BY AGREEING TO ARBITRATE DISPUTES, EACH OF THEM IS WAIVING CERTAIN RIGHTS, INCLUDING ITS RIGHTS TO SEEK REMEDIES IN COURT (INCLUDING A RIGHT TO A TRIAL BY JURY), TO DISCOVERY PROCESSES THAT WOULD BE ATTENDANT TO A COURT PROCEEDING, AND TO PARTICIPATE IN A CLASS ACTION.

(h) **Waiver of Jury Trial.** BUYER AND SELLER EACH WAIVES RIGHT TO A JURY IN ANY LITIGATION IN CONNECTION WITH THIS AGREEMENT, OR THE PROPERTY, OR THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT. BUYER AND SELLER EACH ACKNOWLEDGES THAT THIS WAIVER HAS BEEN FREELY GIVEN AFTER CONSULTATION BY IT WITH COMPETENT COUNSEL. THIS SECTION 10(g) HAS BEEN INCLUDED ONLY FOR THE EVENT THAT, DESPITE THE PARTIES' INTENTION, THE AGREEMENT TO ARBITRATE DISPUTES IS HELD TO BE INAPPLICABLE, AND NOTHING IN THIS SECTION 10.8 IS INTENDED TO QUALIFY THE PARTIES' AGREEMENT TO ARBITRATE ALL DISPUTES.

(i) **Severability.** If any term or provision of this Agreement or the application thereof to any person or circumstance shall to any extent be invalid or unenforceable, the remainder of this Agreement and the application of such term or provision to persons or circumstances other than those as to which it is held invalid or unenforceable shall not be affected thereby, and each term or provision of this Agreement shall be valid and enforceable to the fullest extent permitted by law.

(j) **Operating Covenants.** Between the date of this Agreement and the Closing Date, Seller shall continue to operate the Property as it has in the past and carry insurance in the same manner as before the making of this Agreement, as if Seller were retaining the Property. In no event may Seller, without Buyer's prior written consent, which consent may be withheld by Buyer in its sole discretion, enter into: (a) any new leases or occupancy agreements for the Property; or (b) any service contracts affecting the Property that are not terminable at the Closing.

(k) **Assignment.** This Agreement shall be fully assignable by Buyer. This Agreement shall bind and inure to the benefit of the heirs, successors, and assigns of the parties hereto.

(l) **No Memorandum.** This Agreement shall not be recorded. Seller and Buyer shall, at Buyer's request, execute and record a short form memorandum hereof. If Buyer relinquishes its right to purchase the Property at any time, Buyer shall execute and deliver to Seller a recordable release of the memorandum.

(m) **Exhibits.** All Exhibits attached hereto are incorporated herein by this reference.

(n) **Effective Date.** For all purposes of this Agreement, the term "**Effective Date**" shall mean the last date upon which both Seller and Buyer have executed and delivered this Agreement.

(o) **Counterparts.** This Agreement may be signed in counterparts, each of which shall be deemed an original and when taken together shall constitute one and the same instrument. The execution and delivery of facsimile or e-mail copies of this Agreement shall be deemed to be delivery of an original signature.

(p) **Confidentiality.** Seller and its representatives shall hold in confidence all data and information obtained with respect to the other or the business of the other, whether obtained before or after the execution and delivery of this Agreement, and shall not disclose the same to others; provided, however, that Seller may disclose: (i) prior to the Closing, to the employees, lenders, consultants, accountants and attorneys of Seller, any such data and information, if such persons agree to treat such data and information confidentially; (ii) on and after the Closing, to the public, the fact that Seller has sold the Property; and (iii) at any time, to governmental officials or other third parties (including the public, respecting information contained in public reports), any such data and information as may be required to comply with Seller's reporting requirements under law. The provisions of this Section 10.16 shall survive the Closing or any termination of this Agreement.

(q) **Statutory Land Use Notice.** THE PROPERTY DESCRIBED IN THIS INSTRUMENT MAY NOT BE WITHIN A FIRE PROTECTION DISTRICT PROTECTING STRUCTURES. THE PROPERTY IS SUBJECT TO LAND USE LAWS AND REGULATIONS THAT, IN FARM OR FOREST ZONES, MAY NOT AUTHORIZE CONSTRUCTION OR SITING OF A RESIDENCE AND THAT LIMIT LAWSUITS AGAINST FARMING OR FOREST PRACTICES, AS DEFINED IN ORS 30.930, IN ALL ZONES. BEFORE SIGNING OR ACCEPTING THIS INSTRUMENT, THE PERSON TRANSFERRING FEE TITLE SHOULD INQUIRE ABOUT THE PERSON'S RIGHTS, IF ANY, UNDER ORS 195.300, 195.301 AND 195.305 TO 195.336 AND SECTIONS 5 TO 11, CHAPTER 424, OREGON LAWS 2007, SECTIONS 2 TO 9 AND 17, CHAPTER 855, OREGON LAWS 2009, AND SECTIONS 2 TO 7, CHAPTER 8, OREGON LAWS 2010. BEFORE SIGNING OR ACCEPTING THIS INSTRUMENT, THE PERSON ACQUIRING FEE TITLE TO THE PROPERTY SHOULD CHECK WITH THE APPROPRIATE CITY OR COUNTY PLANNING DEPARTMENT TO VERIFY THAT THE UNIT OF LAND BEING TRANSFERRED IS A LAWFULLY ESTABLISHED LOT OR PARCEL, AS DEFINED IN ORS 92.010 OR 215.010, TO VERIFY THE APPROVED USES OF THE LOT OR PARCEL, TO VERIFY THE EXISTENCE OF FIRE PROTECTION FOR STRUCTURES AND TO INQUIRE ABOUT THE RIGHTS OF NEIGHBORING PROPERTY OWNERS, IF ANY, UNDER ORS 195.300, 195.301 AND 195.305 TO 195.336 AND SECTIONS 5 TO 11, CHAPTER 424, OREGON LAWS 2007, SECTIONS 2 TO 9 AND 17, CHAPTER 855, OREGON LAWS 2009, AND SECTIONS 2 TO 7, CHAPTER 8, OREGON LAWS 2010.

[SIGNATURE PAGE FOLLOWS]

[SIGNATURE PAGE]

BUYER:

Cairn Pacific Acquisitions LLC,
an Oregon limited liability company

By: Cairn Pacific Holdings LLC
an Oregon limited liability company

By: [signature]
Name: Robert A. Hinnen
Title: Member

Date Signed: April 22, 2016

SELLER:

Northwest Natural Gas Company

By: [signature]
Name: MardiLyn Saathoff
Title: Senior Vice President and General Counsel

Date Signed: April 29, 2016

Exhibit A:	Legal Description of Property
Exhibit B:	Royal Oak Property Site Plan
Exhibit C:	Earnest Money Promissory Note
Exhibit D:	Assignment of Development Rights

EXHIBIT A
TO
REAL ESTATE PURCHASE AND SALE AGREEMENT

LEGAL DESCRIPTION OF PROPERTY

The south 25 feet of Lot 11, Block 10, WILLAMETTE HEIGHTS ADDITION TO THE CITY OF PORTLAND, in the City of Portland, County of Multnomah, and State of Oregon.

EXHIBIT B TO REAL ESTATE PURCHASE AND SALE AGREEMENT

ROYAL OAK SITE PLAN

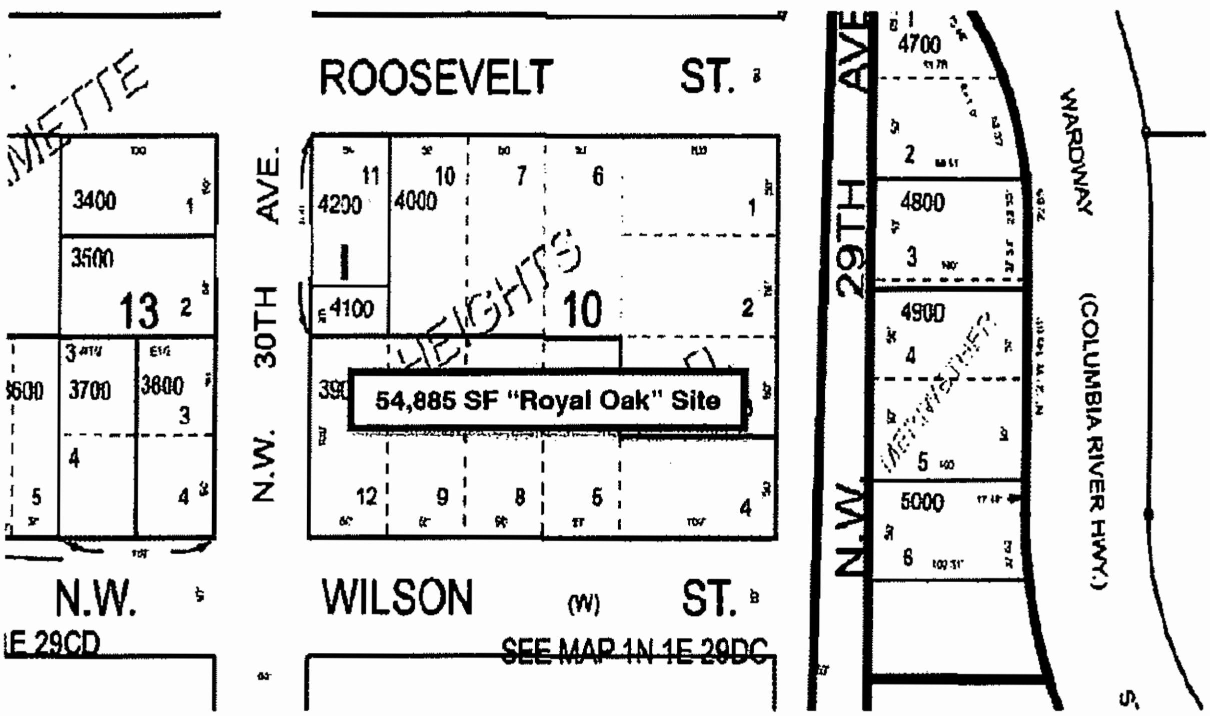

EXHIBIT C
TO
REAL ESTATE PURCHASE AND SALE AGREEMENT

EARNEST MONEY PROMISSORY NOTE

$3,000	Portland, Oregon	April ____ 2016

For value received, **CAIRN PACIFIC ACQUISITIONS LLC**, an Oregon liability company ("**Maker**"), hereby promises to pay to the order of Ticor Title Company, 111 SW Columbia Street, Suite 1000, Portland, Oregon 97201 ("**Payee**"), the principal sum of Three Thousand Dollars ($3,000.00) at such times and in such amounts as set forth in Section 2 of that certain Real Estate Purchase and Sale Agreement, executed by Maker, as Buyer, and **Northwest Natural Gas Company**, as Seller, pertaining to the real property commonly located at NW 30th Ave., Portland, Oregon (the "**Real Estate Purchase Agreement**"). Maker shall be entitled to repay this Promissory Note in whole or in part at any time without penalty or premium.

Maker will pay to any holder of this Promissory Note all reasonable attorneys' fees incurred by such holder in collecting any amount due under this Promissory Note following a default in payment by Maker.

This Promissory Note may be changed, amended or modified only by a writing expressly intended for such purpose and executed by the party against whom enforcement of the change, amendment or modification is sought.

This Promissory Note is delivered pursuant to the Real Estate Purchase Agreement. Maker's liability under this Promissory Note will be extinguished upon the termination (or deemed termination) of the Real Estate Purchase Agreement by Maker pursuant to the terms of such Real Estate Purchase Agreement.

This Promissory Note, and its validity, enforcement and interpretation, shall be governed by the laws of the State of Oregon, without regarding to any principles of conflicts of law.

Cairn Pacific Acquisitions LLC,
an Oregon limited liability company

By: Cairn Pacific Holdings LLC
an Oregon limited liability company

By: ____________________
Name: ____________________
Title: Member

EXHIBIT D
TO
REAL ESTATE PURCHASE AND SALE AGREEMENT

ASSIGNMENT OF DEVELOPMENT RIGHTS

This Assignment of Development Rights (this "**Assignment**") is made and entered into ____________________, 20__, by and between **Northwest Natural Gas Company** ("**Assignor**"), and ____________________________ ("**Assignee**").

For good and valuable consideration paid by Assignee to Assignor, the receipt and sufficiency of which are hereby acknowledged by Assignor, Assignor does hereby assign, transfer, set over and deliver unto Assignee all of Assignor's right, title, and interest in all development rights related to property located on NW 30th Avenue, Portland, Oregon (the "**Development Rights**").

Except as otherwise expressly provided in that certain Real Estate Purchase and Sale Agreement between Assignor and Assignee dated as of April __, 2016, by accepting this Assignment and by its execution hereof, Assignee assumes the payment and performance of, and agrees to pay, perform and discharge, all the debts, duties and obligations to be paid, performed or discharged from and after the date hereof, by the owner under the Development Rights. Assignee agrees to indemnify, hold harmless and defend Assignor for, from and against any and all claims, losses, liabilities, damages, costs and expenses (including, without limitation, reasonable attorneys' fees) resulting by reason of the failure of Assignee to pay, perform or discharge any of the debts, duties or obligations assumed or agreed to by Assignee after the date hereof.

All of the covenants, terms and conditions set forth herein shall be binding upon and shall inure to the benefit of the parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF, Assignor and Assignee have caused this Assignment to be executed on the date and year first above written.

Assignor: **Northwest Natural Gas Company**

By:________________________________

Name:______________________________

Assignee: ________________________________

Multnomah County Official Records
R Weldon, Deputy Clerk

2016-126832

10/07/2016 02:04:44 PM

1R-W DEED Pgs=4 Stn=70 ATKRH
$20.00 $11.00 $10.00 $20.00

$61.00

Recorded by TICOR TITLE 3626082299 ams

After Recording Return To:
Brix Law LLP
75 SE Yamhill Street, Suite 202
Portland, OR 97214
Attn: Bradley S. Miller

Unless a change is requested all tax statements shall be sent to:

Cairn Pacific Acquisitions LLC
1015 NW 11th Ave., Suite 242
Portland, OR 97209

SPECIAL WARRANTY DEED

Northwest Natural Gas Company, an Oregon corporation, which acquired title as Portland Gas & Coke Company, a corporation ("Grantor"), conveys and specially warrants to **Cairn Pacific Acquisitions LLC**, an Oregon limited liability company ("Grantee"), the real property located on NW 30th Avenue, Portland, Oregon, and legally described on Exhibit A attached hereto, free of encumbrances created or suffered by Grantor except as specifically set forth on Exhibit B attached hereto.

The true consideration paid for this conveyance is Forty-Five Thousand and 00/100 Dollars ($45,000.00).

BEFORE SIGNING OR ACCEPTING THIS INSTRUMENT, THE PERSON TRANSFERRING FEE TITLE SHOULD INQUIRE ABOUT THE PERSON'S RIGHTS, IF ANY, UNDER ORS 195.300, 195.301 AND 195.305 TO 195.336 AND SECTIONS 5 TO 11, CHAPTER 424, OREGON LAWS 2007, SECTIONS 2 TO 9 AND 17, CHAPTER 855, OREGON LAWS 2009, AND SECTIONS 2 TO 7, CHAPTER 8, OREGON LAWS 2010. THIS INSTRUMENT DOES NOT ALLOW USE OF THE PROPERTY DESCRIBED IN THIS INSTRUMENT IN VIOLATION OF APPLICABLE LAND USE LAWS AND REGULATIONS. BEFORE SIGNING OR ACCEPTING THIS INSTRUMENT, THE PERSON ACQUIRING FEE TITLE TO THE PROPERTY SHOULD CHECK WITH THE APPROPRIATE CITY OR COUNTY PLANNING DEPARTMENT TO VERIFY THAT THE UNIT OF LAND BEING TRANSFERRED IS A LAWFULLY ESTABLISHED LOT OR PARCEL, AS DEFINED IN ORS 92.010 OR 215.010, TO VERIFY THE APPROVED USES OF THE LOT OR PARCEL, TO DETERMINE ANY LIMITS ON LAWSUITS AGAINST FARMING OR FOREST PRACTICES, AS DEFINED IN ORS 30.930, AND TO INQUIRE ABOUT THE RIGHTS OF NEIGHBORING PROPERTY OWNERS, IF ANY, UNDER ORS 195.300, 195.301 AND 195.305 TO 195.336 AND SECTIONS 5 TO 11, CHAPTER 424, OREGON LAWS 2007, SECTIONS 2 TO 9 AND 17, CHAPTER 855, OREGON LAWS 2009, AND SECTIONS 2 TO 7, CHAPTER 8, OREGON LAWS 2010.

[SIGNATURE PAGE FOLLOWS]

Recorded by TICOR TITLE 3622608 2299 ams

After Recording Return To:
Brix Law LLP
75 SE Yamhill Street, Suite 202
Portland, OR 97214
Attn: Bradley S. Miller

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[SIGNATURE PAGE FOLLOWS]

Dated this 7th day of October, 2016.

GRANTOR: **Northwest Natural Gas Company,**
an Oregon corporation

By: MardiLyn Saathoff

Name: MardiLyn Saathoff

Title: Senior Vice President and General Counsel

STATE OF OREGON)
) ss.
County of Multnomah)

The foregoing instrument was acknowledged before me this 7th day of September, 2016, by MardiLyn Saathoff, as Sr. VP + General Counsel of Northwest Natural Gas Company, an Oregon corporation, on behalf of such company.

OFFICIAL STAMP
RONNA COULTER NEWSOM
NOTARY PUBLIC-OREGON
COMMISSION NO. 941024
MY COMMISSION EXPIRES JULY 19, 2019

Ronna Coulter Newsom
Notary Public for Oregon
My Commission Expires: 9/19/19

EXHIBIT A
Legal Description

The South 25 feet of Lot 11, Block 10, WILLAMETTE HEIGHTS ADDITION TO THE CITY OF PORTLAND, in the City of Portland, County of Multnomah and State of Oregon.

EXHIBIT B
Permitted Encumbrances

1. General and special taxes and assessments, a lien not yet due or payable.

2. Taxes or assessments which are not shown as existing liens by the records of any taxing authority that levies taxes or assessments on real property or by the Public Records; proceedings by a public agency which may result in taxes or assessments, or notices of such proceedings, whether or not shown by the records of such agency or by the Public Records.

3. Facts, rights, interests or claims which are not shown by the Public Records but which could be ascertained by an inspection of the Land or by making inquiry of persons in possession thereof.

4. Easements, or claims of easement, not shown by the Public Records; reservations or exceptions in patents or in Acts authorizing the issuance thereof; water rights, claims or title to water.

5. Any encroachment (of existing improvements located on the subject land onto adjoining land or of existing improvements located on adjoining land onto the subject land), encumbrance, violation, variation, or adverse circumstance affecting the Title that would be disclosed by an accurate and complete land survey of the Land.

6. Any lien or right to a lien for services, labor, material, equipment rental or workers compensation heretofore or hereafter furnished, imposed by law and not shown by the Public Records.

7. Pursuant to ORS 308.505 through 308.665, the Oregon State Department of Revenue has assessed the subject property along with other real property in Multnomah County which is owned by Northwest Natural Gas Company, and we are unable to segregate the amount of tax, if any. Due to the power and authority of the Department of Revenue to correct any assessment errors, this property may be subject to additional taxes following a transfer of title.

   Tax Account No.: R307722

8. Rights of the public to any portion of the Land lying within streets, roads and highways.

9. An easement created by instrument, including terms and provisions thereof;

   Dated: March 19, 1984
   Recorded: May 10, 1984
   Recorder's Fee No.: 84-031744, Book: 1746, Page: 1598
   In Favor Of: Pacific Northwest Bell Telephone Company, a Washington corporation
   For: Underground communication lines, above ground cabinets and other appurtenances

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 302

302. Regarding the file UG 435 OPUC DR 170 Attachment 1.xlsx,

a. Please confirm that the $11.72 million listed for the Astoria/Warrenton Resource center is prior to application of the $1.0 million net sale proceeds discussed on Pipes, 500/18.

i. Please provide a detailed narrative explanation of how the $1.0 million net sale proceeds are being removed from rate base projections in this case.

ii. Please explain how this proposal compares to one that passes back the gain to customers through a credit in the PGA? What are the strengths and drawbacks of both alternatives?

b. Please provide a reconciliation of the following projects (sum total $12.4 million) to the $10.3 million Phase 1 project cost stated on Pipes, 500/44.

i. 202197 Central Pit Fill-In (Phase 1A)
ii. 201799 Central Resource Center
iii. 202198 Central Site Dev (Phase 1B)

c. Regarding the Lincoln City Resource Center, please provide a reconciliation of the $14.2 million total to the $12.3 million project cost stated on Pipes, 500/27.

d. Regarding the Keubler Blvd Reinforcement, please provide a reconciliation of the $21.3 million total to the $24.2 million project cost stated on Kizer, 400/8.

e. Regarding the Mist Well Rework project, please provide a reconciliation of the $6.5 million total to the $3.7 million project cost stated on Kizer, 400/18.

f. Regarding the PLNG Boil Off Compressor and PLNG C3 Boil off Compressor Rebuild projects, please provide a reconciliation of the $2.1 million total to the $1.5 million project cost stated on Kizer, 400/25.

Response:

a) i) The $11.72 million in total Warrenton Resource Center project investment cost is prior to the application of the $1.0 million in sale proceeds from the Astoria property. The revenue requirement calculation includes the $11.72 million without the offsetting $1.0 million gain on property. The Company proposes that the gain on property will be given back to customers through a one-time credit in its next Purchased Gas Adjustment ("PGA") filing.

ii) Please see part “i” above. Mr. Pipes’ testimony did not address how the $1.0 million gain on sale of the property would be provided to customers in rates. The two different methods to provide the benefits to customers, in particular 1) a one-time credit through the PGA; or 2) embed the net gain with the rate base amount of $11.72 million, are a matter of timing differences. In the past, net gains on sale of property are credited back to customers through a one-time credit in the PGA following the closing of the property sale, through the Schedule 178 Regulatory Adjustment Rate.

b) The Company included an incorrect amount for the anticipated cost of the Central Resource Center Phase 1 project in Mr. Pipes’ Direct Testimony at NW Natural/500, Pipes 44. The correct forecasted cost for the three sub-projects that make up Phase 1 is $12.4 million. Please note that the original filed revenue requirement as presented in NW Natural/1300, Walker, as well as associated exhibits and workpapers, reflect an incorrect allocation for structures past October 2021. Although the total cost of the projects were included within the revenue requirement models, the allocation to Oregon was misstated. Please see Confidential UG 435 OPUC DR 302 Attachment 1 for an updated version. This version not only fixes the allocation issue, it also reflects the updates identified in the Company’s revenue requirement errata filing on February 28th as well as OPUC DRs 172 and 328. The Company will update its revenue requirement and exhibits in reply testimony.

c) Please refer to the Company’s *Errata to the Direct Testimony of Wayne K. Pipes Exhibit NW Natural/500 filed December 17, 2021*. This Errata was filed in Docket UG 435 on January 24, 2022. It corrects Mr. Pipes’ Direct Testimony with the correct forecasted cost of Lincoln City Resource Center project of $15.3 million. The Company’s response to UG 435 OPUC DR 170 indicates a cost of $14.2 million for this project because this data request specified that the requested list of discrete capital investments be limited to those investments placed in service from October 2021 through October 2022. The Company forecasts that roughly $1.1 million of additional capital investments related to the Lincoln City Resource Center project will be placed in service in November 2022. The $1.1 million in November 2022 reflects the final payment made for the project. It is customary business practice for the final payment to be made in the month following project completion.

d) The $21.3 million total shown in UG 435 OPUC DR 170 Attachment 1.xlsx reflects funds forecasted to be spent through October 2022. The $24.2 million project cost stated on Kizer, 400/18, reflects total project costs, with approximately $2.9 million planned to be spent after October 2022. As noted in UG 435 OPUC DR 173, page 3 of 10, the Kuebler Blvd Reinforcement Project is proposed to be placed into service in October 2022. The $2.9 million difference reflects spending in November and December 2022 for trailing charges such as pavement restoration and project closeout costs.

e) The $6.5 million total shown in UG 435 OPUC DR 170 Attachment 1 .xlsx reflects spending through October 2022 for the combination of the two Mist well rework projects mentioned on Kizer, 400/16-18, Mist Well Rework 2021 and Mist Well Rework 2022. The $3.7 million project cost stated on Kizer, 400/18, is the total cost for the Mist Well Rework 2022 Project only.

f) The PLNG Boil Off Compressor will be named C4 when it is placed in service. The PLNG C3 Boil Off Compressor Rebuild project is a minor rebuild of the C3 boil off gas compressor, which was originally installed in 1986. (Note: C2 is original to the plant's 1968 construction. EX/C1 is original to the plant's 1968 construction and is the turbo expander). In UG 435 OPUC DR 170 Attachment 1 .xlsx, the $2.1 million total reflects costs for both PLNG boil off compressor projects, whereas the $1.5 million project cost stated on Kizer, 400/25 reflects costs for only the new PLNG Boil Off Compressor Project (C4).

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 303

303. Regarding the file UG 435 OPUC DR 171 Attachment 1.xlsx,
a. Please provide a detailed narrative explanation regarding higher than average projected additions for the following accounts and months.
i. 397.2 OTHER THAN MOBILE & TELEMET, 5-2022, $ 3,413,092
ii. 367 MAINS, 10-2022, $ 6,133,786
b. Please provide all work papers and a detailed narrative explanation of the methodology underlying projections for the following accounts which Staff notes, in aggregate, are nearly double the net additions reported on FERC Form 2 for the past four years (2017-2020).
i. 378 MEASURING & REG EQUIP – GENER
ii. 392 TRANSPORTATION EQUIPMENT
iii. 394 TOOLS - SHOP & GARAGE EQUIPUI
iv. 396 POWER OPERATED EQUIPMENT

Response:

a. Please see UG 435 OPUC DR 303 Attachment 1, which identifies the projects being placed in-service for both FERC accounts identified in part a above. For FERC 397.2, the $3.4 million is primarily the result of $3.3 million being placed in-service for the Voice Radio Project. This is discussed in detail further in NW Natural/600/Downing 5-6. The FERC 367 in-service amount in October 2022 of $6.1 million is primarily the result of In-Line-Inspection (ILI) projects E04 North Eugene Industrial ($2.6 million) and the P31 McMinnville/Lafayette transmission line project ($3.1 million). These projects are discussed in more detail in NW Natural/400/Kizer 29-31.

b. Explanations for increased additions are:

i. 378 MEASURING & REG EQUIP – GENER – There are two factors to this increase in spend. First, in our forecast FERC Account 378 captures the spend internally classified as District Regulators and Service Regulators. All expenses under these Applicants are allocated to FERC Account 378 in UI Planner. In actuals, projects sometimes have assets under those Applicants that are allocated to FERC 376.11, 376.12 and 380 as well as 378. Second, there is a placeholder for unidentified work in the 2022 forecast. Previously, we have not always planned for unidentified spend in this category, so this was a change to improve our forecast. As we go through the budget year, we will evaluate the unidentified placeholder, which was budgeted at $1.8 million (without COH), each forecast cycle and reduce it as work is identified. The combination of proactively planning for unidentified work and having assets being forecasted to hit one FERC Account but depending on the components of the project having actual assets that are allocated to other FERC Accounts, explains why the net additions are higher.

ii. 392 TRANSPORTATION EQUIPMENT - In 2021, NW Natural placed orders for vehicles that had met end of life criteria for replacement. As of December 31, 2021, NW Natural had not yet taken delivery of 31 Transit Vans ($1,511,709 without COH) and a Crane Truck ($233,966 without COH). Supply chain issues for manufacturers have affected the manufacturing and delivery dates. The open purchase order value and additional expenses for the upfit of vehicles (radio & safety equipment installation, application of company logos, etc.) adds an additional $1.85 million to our 2022 Vehicle forecast. Please see detail in UG 435 OPUC DR 303 Attachment 2.

iii. 394 TOOLS - SHOP & GARAGE EQUIPUI – New technology and planned replacement of older equipment has led to a larger capital forecast in 2022 than in previous years. Field Supervisors and Managers worked together to create a list of equipment to purchase. The top 5 items ($850,000 without COH) are listed below.

Item	**2022 Forecast**
RMLD - Additions for ERS, First Responders, on-call vehicles, Supervisors	$ 450,000
Mueller E5 tapping and plugging machines manufacturer parts.	$ 125,000
Speed Shoring Boxes (Non Static Box, by Speed Shore)	$ 100,000
Pit Bull 14 machines	$ 100,000
Squeezers Hydraulic C850 + Pumps	$ 75,000

Please see additional detail in UG 435 OPUC DR 303 Attachment 2.

iv. 396 POWER OPERATED EQUIPMENT - The 2022 forecast is higher than previous years due to new technology and replacement of end-of-life units. 2022 has some equipment needing replacement, including 8 Excavators for $1,050,000, a Dozer for $235,000, and 2 Directional Drills for $470,000 (all without COH). Please see detail in UG 435 OPUC DR 303 Attachment 2.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 304

304. Regarding UG 435 OPUC DR 172 Attachment 2.xlsx, please identify the asset underlying the $594 thousand of non-utility assets noted and explain why these assets are in Account 490 instead of Account 121 Nonutility Property.

Response:

The assets (which go back to 2003 and include signage, an HVAC system and a chain-link fence) are classified in account 390 (not Account 490, as stated in the request) and are currently classified in the system as Non-Utility and are segregated from the Utility assets appropriately. These assets were inadvertently included within the calculation as described in previously submitted UG 435 OPUC DR 172.b, and subsequently removed from that calculation.

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2023
Base Year Twelve Months Ended December 31, 2021
Increase in Revenue Requirement
($000)

NWN/Exhibit 1302
Walker/ Page 1

Line No.		Base Year at Present Rates (a)	Adjustments to Base Year (b)	Test Year at Present Rates (c)	Required Increase (d)	Proposed Total (e)
	Operating Revenues					
1	Sale of Gas	$691,764	$30,250	$722,015	$77,933	$799,947
2	Transportation	16,953	56	17,010	0	17,010
3	Decoupling	(527)	527	0	0	0
4	WARM	6,165	(6,165)	0	0	0
5	Miscellaneous Revenues	3,648	(248)	3,400	0	3,400
6	Total Operating Revenues	718,004	24,420	742,424	77,933	820,357
		435,744				
	Operating Revenue Deductions					
7	Gas Purchased	282,260	13,515	295,775	0	295,775
8	Uncollectible Accrual for Gas Sales	702	11	712	76	788
9	Other Operating & Maintenance Expenses	179,693	19,511	199,204	0	199,204
10	Total Operating & Maintenance Expense	462,654	33,037	495,691	76	495,767
11	Federal Income Tax	12,536	(6,845)	5,691	14,636	20,327
12	State Excise	9,589	(2,538)	7,051	6,061	13,113
13	Property Taxes	23,942	3,179	27,121	0	27,121
14	Other Taxes	26,313	1,391	27,704	2,100	29,804
15	Depreciation & Amortization	93,084	18,576	111,660	0	111,660
16	Total Operating Revenue Deductions	628,118	46,801	674,919	22,873	697,792
17	Net Operating Revenues	$89,886	($22,381)	$67,505	$55,060	$122,565
	Average Rate Base					
18	Utility Plant in Service	3,181,526	450,697	3,632,222	0	3,632,222
19	Accumulated Depreciation	(1,351,426)	(151,156)	(1,502,582)	0	(1,502,582)
20	Net Utility Plant	1,830,100	299,541	2,129,640	0	2,129,640
21	Aid in Advance of Construction	(5,629)	(1,639)	(7,268)	0	(7,268)
22	Customer Deposits	(1,084)	792	(292)	0	(292)
23	Gas Inventory	41,722	(3,524)	38,198	0	38,198
24	Leasehold Improvements	22,980	(673)	22,307	0	22,307
25	Materials & Supplies	14,170	2,366	16,536	0	16,536
26	EDIT Adjustment to Rate Base	8,462	(5,462)	3,000	0	3,000
27	Accumulated Deferred Income Taxes	(412,539)	(9,669)	(422,208)	0	(422,208)
28	Total Rate Base	$1,498,183	$281,731	$1,779,913	$0	$1,779,913
29	Rate of Return	6.000%		3.793%		6.886%
30	Return on Common Equity	7.41%		3.31%		9.50%

Revenue Requirement
$77,933
$78,030
($98)

<< Land Adjustment of $97,710 related to Land Correction

Revenue Change:
10.55%
10.56%
-0.01%

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2023
Base Year Twelve Months Ended December 31, 2021
Increase in Revenue Requirement
($000)

NWN/Exhibit 1302
Walker/ Page 1

Line No.		Base Year at Present Rates (a)	Adjustments to Base Year (b)	Test Year at Present Rates (c)	Required Increase (d)	Proposed Total (e)
	Operating Revenues					
1	**Sale of Gas**	$691,764	$30,250	$722,015	$78,294	$800,309
2	**Transportation**	16,953	56	17,010	0	17,010
3	**Decoupling**	(527)	527	0	0	0
4	**WARM**	6,165	(6,165)	0	0	0
5	**Miscellaneous Revenues**	3,648	(248)	3,400	0	3,400
6	**Total Operating Revenues**	718,004	24,420	742,424	78,294	820,718
		435,744				
	Operating Revenue Deductions					
7	**Gas Purchased**	282,260	13,515	295,775	0	295,775
8	**Uncollectible Accrual for Gas Sales**	702	11	712	76	788
9	**Other Operating & Maintenance Expenses**	179,693	19,511	199,204	0	199,204
10	**Total Operating & Maintenance Expense**	462,654	33,037	495,691	76	495,767
11	**Federal Income Tax**	12,523	(6,851)	5,672	14,704	20,376
12	**State Excise**	9,584	(2,540)	7,044	6,089	13,133
13	**Property Taxes**	23,942	3,193	27,134	0	27,134
14	**Other Taxes**	26,313	1,391	27,704	2,110	29,814
15	**Depreciation & Amortization**	93,084	18,576	111,660	0	111,660
16	**Total Operating Revenue Deductions**	628,100	46,806	674,906	22,979	697,885
17	**Net Operating Revenues**	$89,903	($22,386)	$67,518	$55,315	$122,833
	Average Rate Base					
18	**Utility Plant in Service**	3,184,686	451,929	3,636,616	0	3,636,616
19	**Accumulated Depreciation**	(1,351,817)	(151,266)	(1,503,084)	0	(1,503,084)
20	**Net Utility Plant**	1,832,869	300,663	2,133,532	0	2,133,532
21	**Aid in Advance of Construction**	(5,629)	(1,639)	(7,268)	0	(7,268)
22	**Customer Deposits**	(1,084)	792	(292)	0	(292)
23	**Gas Inventory**	41,722	(3,524)	38,198	0	38,198
24	**Leasehold Improvements**	22,980	(673)	22,307	0	22,307
25	**Materials & Supplies**	14,170	2,366	16,536	0	16,536
26	**EDIT Adjustment to Rate Base**	8,462	(5,462)	3,000	0	3,000
27	**Accumulated Deferred Income Taxes**	(412,539)	(9,669)	(422,208)	0	(422,208)
28	**Total Rate Base**	$1,500,952	$282,853	$1,783,805	$0	$1,783,805
29	**Rate of Return**	5.990%		3.785%		6.886%
30	**Return on Common Equity**	7.39%		3.30%		9.50%

Revenue Requirement:	
$78,294	
$78,030	
$264	<< Change in revenue requirement of $263,974 related to str

Revenue Change:
10.59%
10.56%
0.04%

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 328

328. Regarding the revenue requirement updates propounded in response to Staff DR 172 a. and 172 b.;

a. Please provide the necessary revenue requirement adjustment for each proposed update in the same columnar format and level of detail as the file UG 435 - Exh. 1300 - WP1 - Revenue Requirements.xlsx, Base Year Adjustments worksheet.

Response:

a) As a result of the inadvertent data entry referenced in the response to UG 435 OPUC DR 172-part a, the revised calculated change in revenue requirement is a decrease of $97,710 related to FERC Account 389 - Land. Please see the following workpapers for calculation.

   i. UG 435 OPUC DR 328 Attachment 1.xlsx

   ii. Confidential UG 435 OPUC DR 328 Attachment 2.xlsx

b) As a result of the inadvertent calculations referenced in the response to UG 435 OPUC DR 172-part b, the revised calculated change in revenue requirement is an increase of $263,974 related to FERC Account 390 - Structures. Please see the following workpapers for calculation.

   i. UG 435 OPUC DR 328 Attachment 3.xlsx

   ii. Confidential UG 435 OPUC DR 328 Attachment 4.xlsx

NW Natural®

Rates & Regulatory Affairs

UG 435

Request for a General Rate Revision

Data Request Response

Request No.: UG 435 OPUC DR 345

345. Regarding the file UG 435 - Exh. 1300 - WP1 - Revenue Requirements Model_Errata.xlsx, regarding the work sheet TY Adjustments CAT therein, please explain the $7 thousand plug embedded in the formula within cell G28.

Response:

The "$7 thousand plug" was a carry over from the previous rate case (UG 388) where the Company used the plug to align with the Staff revenue requirement model. The revenue requirement model is a large, dynamic model that has many calculations and complexity. When the Company and Parties settled on a revenue requirement in the last rate case, the Company and Staff were unable to get their two models to completely match due to rounding. Therefore, the Company used an immaterial, $7 thousand plug, to match the models. The Company inadvertently retained the rounding plug from the previous rate case in the current rate case.

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Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 346

346. Regarding Exhibit 1308 Tax Provision,
a. Please explain why corporate activity tax (CAT) expense is not being treated as a deductible expense in the ratemaking state tax calculation.
b. Please provide the anticipated ARAM EDIT amortization for the next three tax years after 2021.

Response:

a. It is our current position, and was our intention in preparing the revenue requirement, that the Oregon Corporate Activity Tax (CAT) be included as a deductible expense for purposes of calculating state income tax. We agree that an adjustment should be made to reflect this. We have prepared, "Confidential UG 435 OPUC DR 346 Attachment 1," which indicates the adjustments we would support to "Exhibit 1308 – Taxes" as included in the Exhibit 1300 Errata filing.

b. Please see, "Confidential UG 435 OPUC DR 346 Attachment 2," which presents ARAM amortization (actuals and estimates) for calendar years 2018 through 2025. The schedule also includes the annual ARAM amortization included in ratemaking (actual and proposed) as well as how these figures track against the cumulative totals.

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Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 347

347. Please confirm or deny that the CAT tax expense was not included as a deductible expense on the Company's 2020 Form OR-20 Oregon Corporation Excise Tax Return nor is anticipated to be deducted on the 2020 return.

a. If confirmed, please provide any supporting information known to the Company that states the CAT tax is not deductible for Oregon tax purposes.

Response:

It is our current position that the Oregon Corporate Activity Tax (CAT) is deductible in determining the Oregon state income tax. This was also our position during the previous rate filing, UG 388, and the approved revenue requirement in that proceeding included the benefit of a deduction for the CAT in determining Oregon state income tax. The CAT expense for calendar year 2020 was reported as a deductible expense on the Company's 2020 Oregon Corporation Excise tax return.

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Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 358

358. Regarding the file UG 435 OPUC DR 201 Attachment 1.xlsx and Exhibit 1203/41, please update the file on a pro-forma basis using the U.S. All Urban CPI rates for 2021-2023 rather than the West Region rates used in the Company's filing.

Response:

UG 435 OPUC DR 358 Attachment 1 illustrates a revised OPUC DR 201 Attachment 1 utilizing instead the All Urban CPI rates for 2022-2023 based on the Oregon Economic and Revenue Forecast March 2022 report. The rates in this most recent report identified the All Urban CPI rate for 2022 as 4.2% and the 2023 rate as 2.2%. This would be compared to the West Region CPI rate used in the filing of 3.9% in 2022 and 2.4% in 2023. The net change calculated is a slight increase to the Test Year O&M by $67K.

CASE: UG 435
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Confidential Exhibits in Support
Of Opening Testimony

April 22, 2022

CASE: UG 435
WITNESS: Ryan Bain

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

April 22, 2022

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

A. I am Dr. Ryan Bain, Ph.D., a Senior Economist employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. In my testimony I analyze and review Northwest Natural's load forecast and resulting sales and transportation revenue forecasts, along with their miscellaneous revenues forecast.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Staff found Northwest Natural's load forecasts to be sound and reasonable after scrutiny with the only adjustment recommended to be a continued discussion of the appropriateness for the future inclusion of a Covid intervention variable for the Commercial Use-Per-Customer (UPC) forecast.

Staff finds NW Natural's miscellaneous revenues forecast to be reasonable.

Q. Is this your final review of these topics?

A. No. I will continue to review this topic and the testimony of other stakeholders and the Company and present my recommendations in my next round of testimony.

ISSUE 1. LOAD AND REVENUE FORECAST

Q. Please summarize the NW Natural's load forecasting methodology.

A. Northwest Natural (or Company) utilizes Autoregressive Integrated Moving Average (ARIMA) models for its load forecasts. Like many other utilities, Northwest Natural breaks down its forecast into two components of load that are forecasted separately: use-per-customer (UPC) and number of customers – where these components can be multiplied to obtain the overall load. Economic and weather variables are used as explanatory variables in the customer count and use per customer models.

Q. What is an ARIMA model?

A. An ARIMA model is a type of regression analysis that can remove trends and seasonality in a data series such that the differences between modeled values and historical actuals can be assumed to have been generated by one unpredictable random process across the entire time series. This characteristic of ARIMA models leaves the modeler reasonably assured that the model is using all available information and that it is appropriate to use for near-term forecasts. ARIMA is an acronym, with "AR" representing the autoregressive term, "I" representing the number of differences taken of the data, and "MA" representing the moving average term.

Autoregression allows the model to use past values of the dependent variable to forecast future values, while the moving average term allows the model to utilize the error generated from past values to predict future values. Differencing the data allows the model to examine the change in the dependent variable, or even the change in the change, as opposed to the level of the dependent variable such that the model exhibits certain well behaved properties.

Q. Does Staff support the use of an ARIMA model for forecasting load?

A. Yes. ARIMA models are used by all Oregon regulated utilities and remain the standard approach. ARIMA models are appropriate for short-term forecasting of natural gas usage because there is often “inertia” in short-term observations and the model can control for certain statistical problems. Staff generally recommends ARIMA models for shorter-term forecasts because of their relative balance between complexity and simplicity. These models are complex enough to handle some of the main concerns when utilizing time-series data like non-stationarity, but also relatively common enough for most regression analysts to have some familiarity. Again, one of the main differences between an ARIMA model and a standard ordinary least squares model is that the ARIMA model allows you to eliminate some effects of a trend that can cause the model’s error to grow over time.

Q. What are the Autoregressive and Moving Average parts of an ARIMA model?

A. These two parts define how much information from previous years is significant in the estimation of the current year. The Autoregressive portion (p) is the number of previous years or lags, of the estimated variable that are included. So, if last year’s value was indicative of this year’s value, but the value from two years ago was not, then the AR portion of the model would include a single lag.

The moving average portion (q) defines the number of lags of the error term. This error term represents the unexplainable noise in the variable, or the difference between the predicted and actual amount. All three variables, p, d, and q are chosen during the model selection process. Many different metrics can be used to identify the optimal number of lags and differences, including the autocorrelation function and partial autocorrelation functions of variables.

Q. Describe how the Company determines the specification of the ARIMA model terms.

NW Natural's witness Mr. Wyman inspects several metrics including the Dickey-Fuller test to determine model stationarity and, on the previous advice of Staff and keeping in best practice, relies on the Akaike Information Criterion (AIC) for determining the final specification of the models' ARIMA components. The AIC metric considers both goodness-of-fit and simplicity in the model selection process to reduce model over-fitting.

Q. Describe the Company's primary explanatory variable for residential UPC forecasts.

A. Northwest Natural uses weather as the primary explanatory variable for UPC forecasts. Weather is broken down into heating degree days (HDD) relative to a 59 degree Fahrenheit base for residential schedules and a 58 degree Fahrenheit base for commercial schedules. The Company uses the most recent 25 years of weather data to establish a historical benchmark for normal weather. Staff supports the Company's use of the 25-year moving average for normal weather as it achieves a balance between minimal variance and ability to capture expected temperature changes due to climate change.

Q. Describe the Company's primary explanatory variable for customer count forecasts.

A. Northwest Natural uses the commercial housing start and growth forecasts from the Oregon Office of Economic Analysis (OEA) as explanatory variables, along with time series models of historical population to forecast customer counts.

Q. Have wildfires resulted in any loss of customers?

A. Yes. The Company reported the loss of 189 services in the year 2020 due to wildfires. 60 services were lost due to the Beachie Creek Wildfire and 129 services were lost due to the Echo Mountain Wildfire.[1]

Q. Has the COVID-19 pandemic resulted in any changes to the companies load forecast methodology?

A. No.[2] Staff inquired with the Company regarding the appropriateness of including an intervention variable into the commercial load forecast to account for a potential break in historical trend. The Company believes that the customer count forecast accounts for pandemic impacts appropriately and cites Avista's testimony in UG 433 highlighting that the most stringent of

1 See Staff/402, Bain/6, NW Natural Response to Staff DR 287.
2 See Staff/402, Bain/9-10, NW Natural Response to Staff DR 439.

pandemic-related restrictions occurred during shoulder and summer months when natural gas is typically lowest. Staff supports a continued discussion on Covid-19 impacts on the load forecast in future rate cases as additional usage data enters the historical record.

Q. Has the Company incorporated any changes in load forecast methodology from the previous general rate case UG 388?

A. Yes. Inputs and data collection remains consistent, but the Company now uses a monthly 'base usage' indicator variable as opposed to the previous annual constant term plus summer usage adjustment term. This results in a model with 13 coefficients as opposed to three, before considering any ARMA terms.

Staff supports this modelling change as it allows for more granular accounting of seasonal changes in usage over the course of the year. Staff supports the continued inspection of variables for explanatory power and the transparent documentation of these changes.

Q. Please summarize the Company's load forecasting results.

A. The Company has forecast roughly 1.1 billion therms total for Oregon usage in the Test Year filed in the Company's opening testimony. This is a roughly 2.3 percent increase from the Company's Base Year deliveries of 1.07 billion therms. The greatest growth is in the interruptible sales schedule of 12.1 percent, while greatest schedule diminution in usage is in the Firm Special Contracts schedule in transportation with a downward projection of 5.7 percent. Overall sales volumes are projected to increase by 4.9 percent, and transportation volumes are projected to decrease by 2.7 percent. See table inset below for additional detail.

Sales Volumes	Actual Therms Sales Base Year	Normalized Therms Sales Test Year	% Diff.
Residential	386,437,175	405,331,797	4.9%
Commercial	227,946,326	237,367,655	4.1%
Industrial Firm	31,661,306	31,170,660	-1.5%
Interruptible	54,493,717	61,092,975	12.1%
Total Sales	700,538,524	734,963,087	4.9%
Transportation Volumes	**Base Year**	**Test Year**	**% Diff.**
Firm	91,657,519	91,754,217	0.1%
Interruptible	201,924,669	195,362,913	-3.2%
Special Contracts - Firm	60,104,860	56,670,178	-5.7%
Special Contracts - Interruptible	13,518,362	13,574,265	0.4%
Total Transportation	367,205,410	357,361,573	-2.7%
Total Deliveries	1,067,743,934	1,092,324,660	2.3%

Sales & Transportation as a % of Total Deliveries

	Base Year	Test Year
Total Sales	65.6%	67.3%
Total Transportation	34.4%	32.7%

Q. Did the Company make any post forecast adjustments?

A. Yes. The Company makes Demand Side Management (DSM) adjustments post forecast as outlined in the Company's 2018 IRP and in the same manner accepted for use in its most recent general rate case, Docket No. UG 388. The post DSM adjusted UPC for the residential class is 633 therms, and 3,807.4 therms for the commercial class.

Q. How did Staff review the Company's forecast?

A. Staff reviewed the workpapers for accuracy and the load forecast overall for reasonableness. Staff appreciates the Company's organization and documentation of its methodology for use in Staff's review. Staff finds the Company's methodology and revised data inputs to be accurate and the forecast to be reasonable. Staff was successfully able to recreate the Company's models and statistical tests for robustness. Staff and stakeholders were additionally able to hold a Microsoft Teams meeting with the Company witness, Mr. Wyman, on March 11, 2022, to ask clarifying questions and review methodology. Staff inquired about specific large residuals generated in the Company's UPC models by weather phenomena shown in NW Natural's response to Staff DR 440. The company highlighted the unusually extreme temperatures falling outside of the 90th percentile of temperature norms for the periods in question and Staff is satisfied with this explanation as the proximate cause of said data abnormalities.[3]

Q. Does Staff have any further comments?

A. Yes. Staff asks that the Company continue to provide a discussion on COVID-19 as it relates to the Company's load forecasts.

Q. How does the resulting revenue forecast compare to UG 388?

A. In UG 388 the total sales and transportation revenue forecast was approximately $434 million, while the revenue forecast in this case is approximately $443 million under current rates multiplied by normalized test year therms sales. While gas sales revenues are projected to increase by

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3 See Staff/402, Bain/12, NW Natural Response to Staff DR 440.

2.3 percent, transportation revenues are projected to decrease by 1.6 percent, netting an overall increase in combined gas sales and transportation revenue of 2.1 percent.

Q. Does Staff recommend any adjustments?

A. No. Staff found Northwest Natural's load forecasts to be sound and reasonable after scrutiny with the only recommendation to be a continued discussion of the appropriateness for the future inclusion of a Covid intervention variable for the Commercial Use-Per-Customer (UPC) forecast.

ISSUE 2. MISCELANEOUS REVENUES

Q. How does Northwest Natural define miscellaneous operating revenues?

A. Northwest Natural defines miscellaneous revenues as those revenues collected by the Company from customer fees collected through Schedule C, Miscellaneous Charges, as well as revenues from property rentals. Costs of service related to Schedule H, curtailment, and entitlement revenues, along with non-utility misc. revenues are not included in the calculation of misc. operating revenues. Curtailment and entitlement revenues are rebated to customers through Schedule 168 per Commission Order No. 20-364.

Q. How do miscellaneous operating revenues affect the revenue requirement?

A. Miscellaneous revenues serve as an offset to revenue requirement. If the Company were to include $2 million in misc. revenues, this $2 million would serve to offset $2 million from the revenue requirement as the Company no longer needs to collect this amount through retail rates.

Q. What level of miscellaneous operating revenues has the Company included in the Base and Test Years?

A. Northwest Natural reports $3.47 million in the Base Year calculation and $3.40 million in the Test Year.

Q. What methodology does the Company use to calculate miscellaneous revenues for the Test Year?

A. In the Company's testimony it states that due to impacts from Covid-19 the Company uses a three-year period ending February 28, 2020, to establish Test Year revenues based on historical data that has not been skewed by the pandemic. "If the amounts for a particular category were trending upward or downward, the most recent year was taken as representative for the forecast. If there was no apparent trend to the historical amounts, a simple three-year average was used."[4] This methodology was accepted for use in UG 388 and yields a similar misc. revenue forecast.

Q. Does Staff propose any adjustments to Test Year miscellaneous revenues?

A. No. Staff does not recommend an adjustment.

Q. Does this conclude your testimony?

A. Yes.

[4] NW Natural/1300, Walker/11-12.

CASE: UG 435
WITNESS: RYAN BAIN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

April 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME:	Ryan Bain
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Utility Strategy and Integration Division
ADDRESS:	201 High Street SE, Suite 100 Salem, OR. 97301
EDUCATION:	Ph.D., Economics (2020) Washington State University B.S., Economics (2009) Texas A&M University
EXPERIENCE:	Prior to joining the Oregon Public Utility Commission as a Senior Analyst in the Utility Strategy and Integration Division, I was employed as an economist with a forensic economics consultancy in the Dallas / Fort Worth area. My peer reviewed published research involves understanding information impacts on national and local agricultural commodity markets, and I have presented research on testing the accuracy of various forecasting methods in the case of agricultural commodities before a meeting of economic professionals.

CASE: UG 435
WITNESS: RYAN BAIN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

April 22, 2022

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 283

283. Please provide complete data and code documentation of the input/output files used to generate the final dataset for the monthly weather normalized use-per-customer ("UPC") forecast described in NWN/1400, so that results can be replicated.

a) The data and programing files used to generate the monthly weather normalized UPC forecasts for each residential and commercial rate schedule. Provide the data using an electronic spreadsheet format with all formulae and cell references intact;
b) The definitions of all variables used to generate the total customer forecast for each schedule;
c) Stata program files showing the monthly customer forecast regression models for each rate schedule;
d) Output of all statistical tests performed to understand the behavior of the error structure of the models.

Response:

As described below, the inputs used to generate the final weather normalized UPC Forecast results were generated in an Excel workpaper. These inputs were imported into a statistical software program called Stata and evaluated using an Autoregressive Integrated Moving Average ("ARIMA") time series model specification. The ARIMA coefficients and forecast prediction results were then exported back into the same Excel workpaper. The requested data and code documentation can be found in the following files:

a) The UPC Forecast usage and weather inputs, as expressed as (1) therm use per premise per day; and (2) heating degree days ("HDDs") per day, are generated in the filed workpaper, *UG 435 - Exh. 1400 - WP2 - OR Normalized UPC Model,* at Tab "UPC Model Inputs." The Stata ARIMA coefficient outputs are copied to *Exh. 1400 - WP2,* at tabs with names ending "Models FINAL." Finally, the ARIMA model predictions, as expressed as UPC per day, are copied to *Exh. 1400 - WP2,* beginning at Cell AG11 in all tabs with names ending "UPC Daily."

b) Please refer to the file, UG 435 OPUC DR 283 Attachment 1, Tab "Index." This tab contains a list of all Stata variables used in the UPC Forecast analysis, as well as a description and (if necessary) comments explaining how or where the variable is generated.

c) There are two types of native Stata files that are included with this response: (1) a .dta file which contains the raw data and variable names; and (2) a .do file which contains the code documentation. Refer to the file, UG 435 OPUC DR 283 Attachment 1, Tabs “Stata .dta” and “Stata .do” for the contents of these files in Excel format. Refer to the files, UG 435 OPUC DR 283 Attachment 2 and UG 435 OPUC DR 283 Attachment 3*,* for the native versions of the .dta and .do files, respectively.

d) Please refer to the Company’s response to UG 435 CUB DR 19 for a summary of the test statistics produced by competing model specifications. These statistics were used to select the number of *p, d,* and *q* terms for each rate schedule modeled for the UPC Forecast.

   Further, please refer to the file, UG 435 OPUC DR 283 Attachment 4*,* for the results of an out-of-sample back cast test analysis that was performed to evaluate the performance of the ARIMA model specification versus a Vector Autoregression (“VAR”) model specification. This analysis tests how well each model predicts actual usage that is left out-of-sample (e.g., when the in-sample data is cut off at May 2018, how well does the model predict against observed actuals through May 2021?). Per UG 435 OPUC DR 283 Attachment 4*,* this analysis found the ARIMA model outperformed the VAR model when comparing performance using a normalized root mean square error (“RMSE”) measure.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 284

284. Please provide complete data and code documentation of the input/output files used to generate the final dataset for the forecasted end-of-period customer counts described on page 13 of NWN/1400, so that results can be replicated.

a) The data and programing files used to generate the monthly customer forecasts for each residential and commercial rate schedule. Provide the data using an electronic spreadsheet format with all formulae and cell references intact;

b) The definitions of all variables used to generate the total customer forecast for each schedule;

c) Stata program files showing the monthly customer forecast regression models for each rate schedule;

d) Output of all statistical tests performed to understand the behavior of the error structure of the models.

Response:

As described below, the inputs used to generate the forecasted end-of-period customer counts were generated in Excel. This forecast was not generated using the Stata statistical software program. The requested data and code documentation can be found as follows:

a) Please refer to the file, UG 435 OPUC DR 284 Attachment 1. Note that the results of the customer forecast are copied to the filed workpaper, *UG 435 - Exh. 1303 - WP1 - Rate Case Margin Model,* Tab “Input - Cust & Use.”

b) Please refer to the file referenced in part (a), tabs “Methodology Description” and “Conversion Forecast.”

c) N/A.

d) There is no additional statistical output beyond the regression results shown in UG 435 OPUC DR 284 Attachment 1, Tab “Conversion Forecast.”

NW Natural

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 285

285. Please refer to “Time Series line: Actuals vs Model Prediction (w/forecast)” on the “Residential Model FINAL” tab of NWN/1400 workpaper titled “UG 435 – Exh. 1400 – WP2 – OR Normalized UPC Model”. Please provide the actual and model estimated values used to generate this graph.

Response:

The referenced graph is produced using the variables named “ALLRESUsePremDay” and “ALLRESUPCPredict,” defined in the file UG 435 OPUC DR 283 Attachment 1, Tab “Index.” The data associated with the variables can either be found in the “Stata .dta” tab of that same file, or in the file UG 435 OPUC DR 283 Attachment 2. The Stata software code that generates this graph is found at Line 50 in UG 435 OPUC DR 283 Attachment 1, Tab “Stata .do,” or in the file UG 435 OPUC DR 283 Attachment 3.

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Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 286

286. Please refer to page 14 of NWN/1400. Please provide more information on how changes in projected load usage are made in the "Industrial Forecast", along with descriptions of how changes in customer accounts are handled. Are any models used in these Industrial Forecasts? If so, please provide all underlying data, inputs, and programming files used to generate these Industrial Forecasts.

Response:

Please refer to the file, Confidential UG 435 OPUC DR 286 Attachment 1, for the Company's Industrial Forecast model used for this rate case. Tab "Block Summary" in this file contains the input data for the filed workpaper, *UG 435 - Exh. 1303 - WP1 - Rate Case Margin Model*, Tab "from Industrial File." Note that account data have been anonymized such that individual customers cannot be identified in order to protect sensitive forward-looking information about expected operations.

The Industrial Forecast uses historical actual data, adjusted based on annual service election changes, and annualized for new (and expected) customer additions or closed customer accounts. Additionally, the Forecast is adjusted based on information the Company's Major Accounts Services team receives from individual customers (e.g., facility expansions, equipment shutdowns for replacement or maintenance, addition or subtraction of shifts, requests for additional service capacity, economic headwinds or tailwinds affecting specific industries, etc.). These adjustments, for instance, can be found on the "Customer Adj" tab of Confidential UG 435 OPUC DR 286 Attachment 1.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 287

287. Please provide an estimate of how many customer meters/accounts were destroyed/lost due to wildfire activity across all schedules for each of the past 5 years (as applicable).

Response:

During the past 5 years 189 services were destroyed during the 2020 Beachie Creek (Santiam Canyon) and Echo Mountain (Otis, Neotsu and Lincoln City) Wildfires.

60 of the destroyed services occurred due to the Beachie Creek Wildfire and 129 of the destroyed services occurred due to the Echo Mountain Wildfire.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 366

366. Please provide the workpaper "NWN 2021 IRP Savings projections.xlsx" identified in workpaper "UG 435 – Exh. 1400 – WP2 – OR Normalized UPC Model.xlsx" under the "DSM Adjustment" tab.

Response:

Please refer to UG 435 OPUC DR 366 Attachment 1 for the file identified as "NWN 2021 IRP Savings projections" in the filed workpaper and tab referenced above.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 438

438. Please provide the Energy Trust of Oregon report containing the DSM estimates ultimately used to adjust the load forecast.

Response:

Please refer to the Company's response to UG 435 OPUC DR 366, which includes an attachment with the Energy Trust of Oregon ("ETO") DSM estimates used to adjust the weather normalized load forecast for this rate case.

For a discussion of ETO's DSM model and an explanation of the methodology, please refer to Chapter 5 of NW Natural's 2018 Integrated Resource Plan.

NW Natural

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 439

439. Please provide a discussion of why the company controls for Covid pandemic impacts in its Misc. Revenue forecasts but does not similarly adjust its commercial load forecasts to account for pandemic impacts.

Response:

The Miscellaneous Revenues forecast includes revenues associated with activities such as service reconnections and field collections. Given the moratorium on these activities during portions of 2020 and the Base Year period, it was appropriate to adjust the Test Year Miscellaneous Revenues forecast to control for the COVID-19 pandemic.

The Company's weather normalized commercial load forecast is built using a use-per-customer forecast ("UPC Forecast") and a customer count forecast. While the UPC Forecast does not control for pandemic impacts, as discussed below, the customer count forecast does in fact account for the impacts associated with the COVID-19 pandemic. The end-of-period customer counts were forecasted based on a methodology that incorporates economic indicators that incorporate the impacts of the pandemic as represented by a measure of change in economic activity. The customer count forecast was also adjusted throughout the pandemic to reflect changes to conditions that can affect customer losses such as length and magnitude of economic aid, and duration of customer collections and shut-off moratoriums.[1]

The UPC Forecast does not control for pandemic impacts, however, for three reasons. First, the Company believes the customer count forecast, as a component of the Test Year commercial load forecast, appropriately accounts for pandemic impacts. Second, on a per commercial customer basis, the Company found that using an explanatory variable to denote the months beginning with the COVID-19 lockdowns in March 2020 through the end of the data series in May 2021 did not produce a statistically significant coefficient to represent pandemic-related impacts.[2] Inclusion of this indicator variable

[1] Please refer to the Company's response to UG 435 OPUC DR 284 for more information about the customer count forecast methodology.
[2] Using other periods to denote the COVID-19 pandemic, such as March 2020 through June 2020 when the pandemic response was in its early stages, similarly did not produce statistically significant coefficients.

also did not result in an overall improvement in model test statistics. The Company hypothesizes this could be due to a number of offsetting factors: Commercial customers that were impacted the greatest ceased service which was reflected in the premise count; other customers kept usage consistent or nearly consistent with the help of state and federal economic aid; some sectors were impacted slightly or not at all; and some customers such as those with commercial meters connected to apartment buildings may have realized load growth as residents worked from home and complied with Oregon's "Stay Home, Saves Lives" order. Third, the state mandated pandemic shut-downs and the most stringent of pandemic-related restrictions occurred during shoulder and summer months when natural gas usage is at its lowest.[3]

[3] Avista outlined this final observation in recent testimony. See: In the Matter of Avista Corporation, Request for a General Rate Revision, Docket No. UG 433 at Avista/800 Forsyth/Page 11: 18-20 (October 21, 2021).

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 440

440. Please provide an explanation for the unusually large residuals from the company model for the months of December 2013 and March 2019. Please also provide any additional information the company may have related to these periods.

Response:

The Company also recognizes that model residuals are larger relative to all (in the case of March 2019) or nearly all (in the case of December 2013) of the other months in the dataset. The Company finds that this is true across both the residential and commercial classes, so it is unlikely that this condition is due to a data issue affecting certain rate schedules.

Note that these periods in question correspond to the Company's financial models for that month, but are based on loads that are read on a cycle basis and will fall on dates that do not necessarily match to a calendar month.

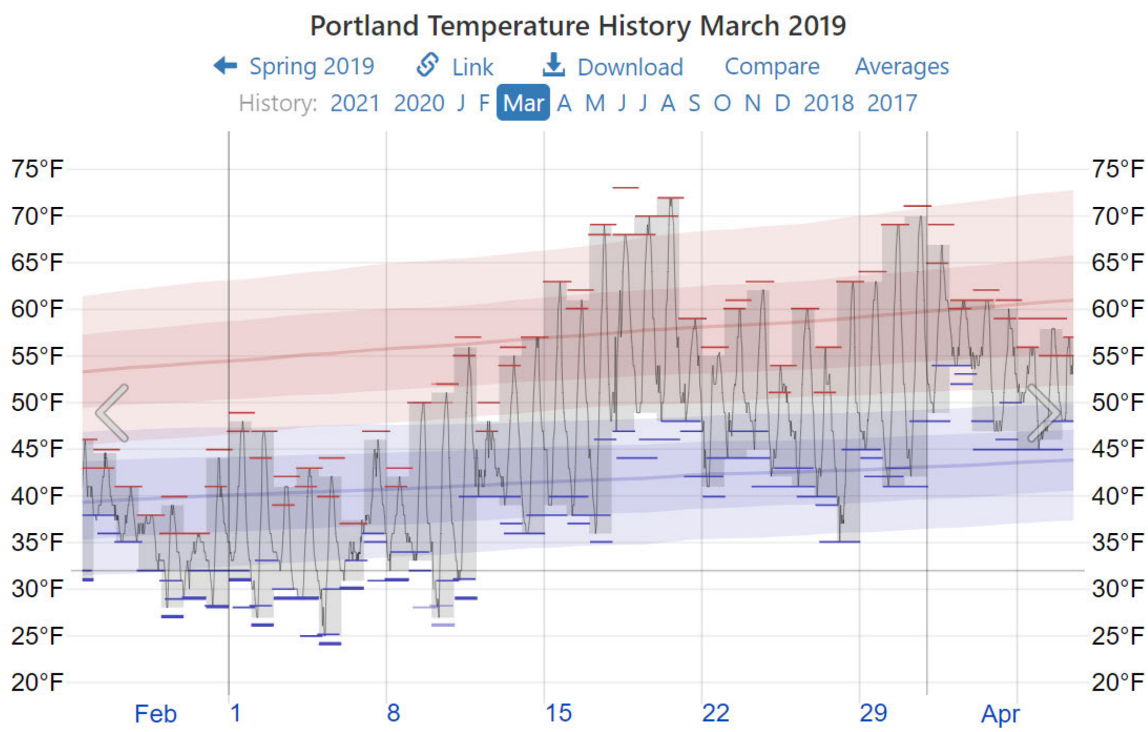
The common characteristic of both periods is that they coincided with unique weather events that, we hypothesize, resulted in underpredictions of actual usage for these months. December 2013 realized the coldest weather in Oregon since 1972, meaning that there were temperature averages that month outside of the 25-year heating degree day ("HDD") normal.[1] The dates that this period occurred (December 3 through 9, 2013) fall within the billing cycles for that period.

The month of March 2019 also realized unusual weather patterns. The first eleven days of the month realized peak lows well above the 90th percentile of average daily lows for that period. This was followed by a warm period from March 17 through 20, 2019 with days of peak highs above the 90th percentile of average daily highs for that period. During this cold stretch, the high temperature only reached above 45 degrees Fahrenheit on four days, meaning many customers' heating appliances were engaged for an entire 24 hour period each day. Since the model uses average daily temperatures to derive HDDs, it is possible that it is not fully picking up the load impacts associated with the persistently low temperatures that were observed in the first half of the month,

[1] See, for example: https://www.oregonlive.com/weather/2014/03/portland_weather_winter_of_201.html.

relative to the more mild temperatures usually observed in March. See Chart 1 below for the high and low temperature data for Portland from March 2019.

Chart 1



The daily range of reported temperatures (gray bars) and 24-hour highs (red ticks) and lows (blue ticks), placed over the daily average high (faint red line) and low (faint blue line) temperature, with 25th to 75th and 10th to 90th percentile bands.

Source: Weather Spark, https://weatherspark.com/h/m/757/2019/3/Historical-Weather-in-March-2019-in-Portland-Oregon-United-States#Figures-ObservedWeather.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 441

441. Please provide all Miscellaneous Revenue data available to the company from February 2020 forward to the most current available. Please also provide five years' worth of data prior to the February 2020 cutoff that the company uses to mark the end of the pre-Covid era.

Response:

Please see "UG 435 OPUC DR 441 Attachment 1.xlsx". As you will notice from February-2015 through February-2020 the miscellaneous revenue balances are consistently in the mid-to high $3.5 to $4.0 million and dropped significantly by half in February 2021 and February 2022 primarily due to the impact of COVID-19. The difference between the pre-COVID-19 balances and balances during the pandemic are largely deferred via the Company's COVID-19 deferral account.

Please note that the Astoria rental income stopped in June 2020.

CASE: UG 435
WITNESS: RYAN BAIN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony
(Electronic)

April 22, 2022

CASE: UG 435
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 500

Opening Testimony

April 22, 2022

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

A. My name is Madison Bolton. I am a Utility and Energy Analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address NW Natural's ("NWN" or "Company") materials and supplies inventory in rate base, rate case expense, and atmospheric testing expense.

I recommend the following adjustments:

Rate base: Materials and Supplies – ($2,366,000)

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following Exhibits:

- Exhibit Staff/501 – Witness Qualifications
- Exhibit Staff/502 – Responses to Staff Data Requests
- Exhibit Staff/503 – Response to DR 260 Confidential Attachment 1

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Materials and Supplies:

Staff finds that the Company's forecasted increase to the account is not consistent with the three-year historical trend from 2019-2021. While Staff is aware of supply shortages and price increases due to the COVID-19 pandemic, without further evidence that prices will grow at the same rate as in 2021, Staff recommends a disallowance to rate base of $2.37M.

Rate Case Expenses:

Staff finds that the Company's rate case expenses align with the historical average and the transactional detail and is consistent with previous rate cases. Staff does not recommend an adjustment.

Atmospheric Testing Expenses:

Staff found that the proposed increase in atmospheric testing expenses is within the historical trend, the transactional detail is consistent, and the Company's vetting process for vendors identifies least-cost, competitive contracts. Staff does not recommend an adjustment.

Please note that I may revise my recommendations based on testimony filed by other participants in this rate case.

ISSUE 1. MATERIALS AND SUPPLIES (NON-FUEL)

Q. Please describe the Commission's ratemaking treatment of "Materials and Supplies."

A. Materials and supplies have been treated as a component of working capital. Working capital is the amount of funds provided by investors to enable the utility to pay its operating expenses prior to the collection of operating revenues from customers and to maintain a normal level of materials and supplies.[1] The Commission has typically authorized natural gas utilities to include an allowance for materials and supplies inventory in rate base to represent working capital.[2]

Q. Please outline NW Natural's proposal for Materials and Supplies in the Test Year.

A. The Company is requesting $16.5M be included in rate base for the Test Year. This represents a $2.37M, or 16 percent, increase from the $14.17M included in the Base Year.

Q. What is the three-year historical average for Materials and Supplies?

A. The average ending monthly balance from 2019-2021 is $13.72M, about three percent less than the Base Year.

Q. What is NW Natural's justification for the Test Year increase?

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1 See *In the Matter of Portland General Electric Company*, Docket UF 2176, Order No. 37112 (Mar. 10, 1960).

2 See, e.g., *In the Matter of California Pacific Utilities Company*, Docket UF 3275, Order No. 77–394 (*June* 13, 1977) and *In the Matter of Cascade Natural Gas Corporation*, Dockets UF 3094, UF 3129, Order No. 74–898 (Nov. 21, 1974).

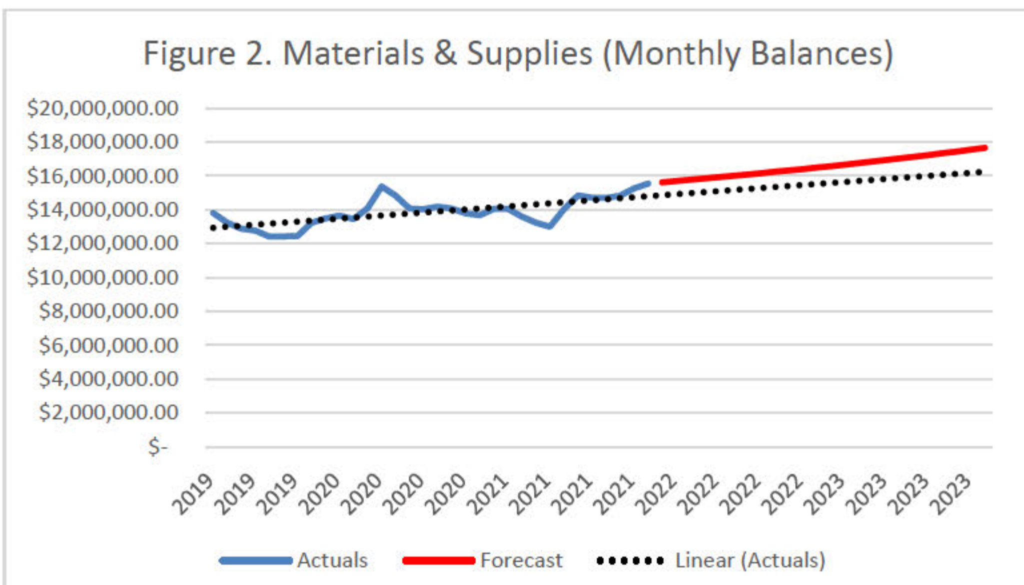
A. In the responses to Staff DR 434 and 435, The Company identifies the COVID-19 pandemic as a hindrance in procurement efforts. As a result of the pandemic, NWN points to increased lead times, labor shortages, transportation issues, inflation, and other factors driving increasing prices.[3] The Company references price increases for seven specific materials and supplies in its response to DR 434[4], demonstrating an average price increase of 49 percent across the seven materials from December 2020-November 2021. While some materials and supplies such as steel pipe and magnesium anodes rose by over one hundred percent, other materials' prices like valves and risers only increased by ten to twenty-two percent. Staff does not know at this time whether the price increases for these seven materials and supplies are representative of prices for all of NWN's materials and supplies inventory.

Q. What is Staff's analysis of the Company's response regarding the justification for an increase in the Test Year?

A. Staff did not find sufficient evidence to accept NWN's linear forecast for the Test Year. While Staff recognizes that the COVID-19 pandemic has impacted inflation and supply chains, the price increases identified in the response to DR 434 are applicable in approximately one year of pricing data. When analyzing materials and supplies monthly balances for multiple years (2019-2021), Staff produced a linear trend-line from 2019-2021 that falls below the Company's forecasts into the Test Year (See Figure 2). Staff finds that while price

3 Staff/502, Bolton/5, NWN Response to Staff DR 435.
4 Staff/502, Bolton/4, NWN Response to Staff DR 434.

increases and supply interruptions were present from 2020-2021, there is insufficient data to support NWN's assumption that these same concerns will lead to prices that will rise at the Company's forecasted rate. The Company's method of tracking prices for common materials and supplies from 2020-2021 identified large price increases during severe supply chain disruption, but does not account for production, shipping, and other supply chain aspects recovering in 2022 as demand increases and pandemic-era restrictions lift. Staff's analysis includes 2019 balances to develop a trend that is not entirely dependent on data during the pandemic. Additionally, Staff notes that the price increases the Company tracked for the seven materials and supplies referenced in the response to Staff DR 435[5] may not be representative of the entirety of NWN's materials and supplies.



Q. What is Staff's recommendation?

5 Staff/502, Bolton/5, NWN Response to Staff DR 435.

A. Staff does not think NW Natural's assumption that materials and supplies costs will continue to grow at the rate experienced during the pandemic for the Test Year is a reasonable one for ratemaking purposes. Staff believes that a more appropriate forecast is obtained by examining an additional year of data. Staff's analysis of monthly balances from 2019-2021 shows a linear trend below the Company's forecast, and without additional evidence demonstrating NWN's costs will continue to grow at the rate observed in 2021, Staff recommends an adjustment of ($2.37MM) for Test Year account total of $14.17MM.

ISSUE 2. RATE CASE EXPENSES

Q. Please describe the Company's treatment of rate case expenses in the test year.

A. The Company did not explicitly provide this information in testimony or work papers, but they did provide an estimate in response to DR 260.

Q. Has NW Natural incorporated rate case expenses into the Test Year?

A. Yes. The Company's response to DR 260 explains the following:

> The forecast is based on prior rate case expense and is estimated to be $350,000 for UG 435. One-third of this expense, or $116,667, is included in the test year forecast. The rate case expenses included in a rate case are not considered incremental. Incremental revenue requirement represents the shortfall of all expenses the Company must recover from the rate case.[6]

Q. Please describe Staff's analysis of NW Natural's rate case expenses.

A. Staff issued data requests to examine historic rate case expenses, transactional detail pertaining to rate case expenses, and the amount of rate case expense incorporated into the Test Year. Staff examined the historic trend of the data as well as the transactional detail relating to the expenses. Staff totaled the transactional expense data for UG 344 and UG 388 and compared the historical values to the Company's forecast. [redacted].

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6 Staff/502, Bolton/1, NWN Response to Staff DR 260.

7 Confidential UG 435 OPUC DR 260 Attachment 1.

Q. Does Staff have any adjustments to the Company's proposed rate case expense?

A. No. The vendor expense summaries appear consistent when compared between past rate cases, with the largest differences attributed to [redacted]. The total estimated expense for UG 435 and the forecasted expense included in the Test Year do not deviate significantly from the historical trend and are reasonably based on the transactional detail for rate case expenses already incurred in UG 435 and past rate cases.

ISSUE 3. ATMOSPHERIC TESTING EXPENSES

Q. Please describe NW Natural's atmospheric testing program.

A. Atmospheric testing (AT) expenses include the cost of compliance with a federal safety mandate to inspect all portions of natural gas pipelines in contact with the air for signs of corrosion. The Company's response to Staff DR 261 explains that NWN engages a third party, Heath Consultants, to conduct atmospheric surveys related to leakage and corrosion.[8] The contract with Heath Consultants became effective January 1, 2020, and ends on December 31, 2022.[9]

Q. Please describe the Company's treatment of atmospheric testing expenses in the Test Year.

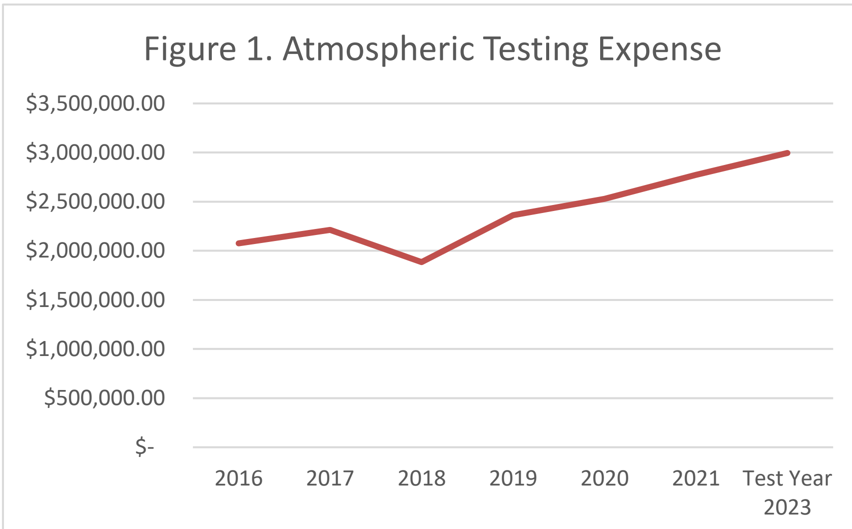
A. NW Natural has a contract with a third party to conduct atmospheric testing. The contract covers multiple years and has an annual increase that results in a $223,000 increase in the Oregon-allocated expense in the Test Year.

Q. Please describe Staff's analysis of NW Natural's proposed atmospheric testing expenses.

A. Staff reviewed NWN's supplemental attachments provided in response to Staff DR 261 which included transaction detail for the contracted leakage and corrosion surveys. Staff also reviewed the yearly total expenditures on atmospheric testing. The Company's proposed Test Year expense follows the historical percent increase associated with contracted survey expenses. The

[8] Staff/502 Bolton/2, NWN Response to Staff DR 261
[9] NW Natural/1200, Davilla/12

increase is mainly driven by rising labor expenses captured in the contract. The expense included in the Test Year is an increase of about 8 percent, which is lower than the average historical percentage increase of 14 percent from 2019-2021, as shown in figure 1.



Q. Is the contract with Heath Consultants reasonable?

A. It appears that it is because it is the result of a competitive process. The Company's responses to Staff DR 436 and DR 437 describe the request-for-proposal (RFP) process used to determine vendors. NWN uses either a three or five-year cycle for vendors before reissuing RFPs.[10] In 2019, NWN conducted an RFP for leakage and atmospheric corrosion surveys where Heath Consultants scored second lowest in pricing and highest in all other categories including execution, safety, training & supervision, technology,

[10] Staff/502 Bolton/7, NWN Response to Staff DR 437.

and resources.[11] Staff is satisfied that the described RFP process appears reasonable and promotes a more competitive contractual agreement for the company.

Q. Does Staff have any adjustments to the Company's proposed Atmospheric Testing expense?

A. No. Staff finds that the proposed increase in the Test Year for atmospheric testing expenses does not deviate from the historical trend and is slightly below the historic percent increase for the previous three years. Staff is satisfied with the competitiveness of an RFP process and its impact on contractual costs.

Q. Does this conclude your testimony?

A. Yes.

[11] Exhibit Staff/502, Bolton/6, NWN Response to Staff DR 436.

CASE: UG 435
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

April 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME:	Madison Bolton
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Utility Strategy & Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	B.A. Carroll College, Helena, Montana Major: Biology, 2017 M.ENV. University of Colorado, Boulder, Colorado Focus: Renewable & Sustainable Energy, 2020
EXPERIENCE:	Since September 2021, I have been employed by the Oregon Public Utility Commission. I currently hold the position of Utility Analyst 2 in the Utility Strategy and Integration Division. From 2019 to 2020 I worked as a graduate research analyst at E Source where I conducted research for utility clientele on large non-residential energy consumers. Additionally, in 2020 I assisted Camus Energy in researching the feasibility of electric grid management software.

CASE: UG 435
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Responses to DR 260, 261, 434-437

April 22, 2022

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 260

260. Please provide a summary by account, vendor and/or expense source, month and year, of the amount of rate case expense incurred and forecasted on an Oregon allocated basis for the UG 435 rate case. Explain for costs included as rate case expenses whether and to what extent these costs are incremental and not already present/recovered in base rates.

Response:

Please see Confidential UG 435 OPUC DR 260 Attachment 1 for rate case expenses by vendor and month for UG 435.

The forecast is based on prior rate case expense and is estimated to be $350,000 for UG 435. One-third of this expense, or $116,667, is included in the test year forecast.

The rate case expenses included in a rate case are not considered incremental. Incremental revenue requirement represents the shortfall of all expenses the Company must recover from the rate case.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 261

261. Please provide transactional line-item account detail for all atmospheric testing expenditures on an Oregon allocated basis by year for the years 2016 through 2021. Please include any available descriptions of each expense. Please provide the data in electronic, Excel format with all formulae and cell references intact.

Response:

The Company engages a third party, Heath Consultants, to perform atmospheric surveys as part of the leakage and corrosion surveys process. We do not perform any atmospheric testing. The testing performed by our corrosion department generally consists of checking cathodic protection levels on buried pipelines and NW Natural does inspect pipe for atmospheric corrosion but not testing. Refer to **UG 435 OPUC DR 261 Attachment 1** for the transactional line-item detail for the costs charged to the leakage and corrosion surveys order, including the atmospheric surveys.

NWN Response to OPUC DR 261 Attachment 1

is filed in electronic format

NW Natural

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 434

434. Please provide an explanation for the proposed increase in materials and supplies inventory from 14.2 million dollars in the Base Year to 16.5 million dollars in the Test Year. Please describe the specific factors that are expected to influence the increase.

Response:

COVID-19 has impacted supply chains all over the world. Specific to NW Natural, we have experienced the following challenges in our procurement efforts:

- Labor shortage issues impacting suppliers and downstream manufacturers
- Shipping & transportation resource challenges
- Raw material sourcing issues with our downstream manufacturers
- Delivery dates missed by suppliers
- Lead times have increased significantly
- Demand increases for critical material items

As a result of these issues, NW Natural has experienced a significant increase in unit pricing due to inflation. In May 2021, we started to track pricing for a handful of commonly used material items. In the table below, December 2020 is the base year and as shown, the price increases over subsequent periods were significant. The full impact of this inflation on our inventory valuation will span a couple years due to the cycling of inventory, which explains the continued increase over the Base Year.

					Increase over Dec 2020		Increase over Dec 2020		Increase over Dec 2020
Material	LTM Usage	Unit	Price Dec 2020	Price May 21	% chg	Price Sept 21	% Chg	Price Nov 21	% Chg
PIPE, PE, 2" - STICK 20 FT - COIL 500 FT	500,000	FT	$ 0.85	$ 1.02	20%	$ 1.08	26%	$ 1.15	35%
ANODE MAGNESIUM, 1#	13,900	Item	$ 17.58	$ 17.70	1%	$ 21.25	21%	$ 41.35	135%
WIRE TRACER, COPPER, YELLOW 12AWG	1,700,000	FT	$ 0.12	$ 0.18	50%	$ 0.18	50%	$ 0.18	50%
RISER, FLEX, 1/2" CTS X 3/4" NPT,30',PE	3,900	Item	$ 48.25	$ 50.32	4%	$ 52.84	10%	$ 52.84	10%
VALVE, BALL, F X F, 150 ANSI, 2"	400	Item	$435.80	$439.10	1%	$ 439.10	1%	$ 529.88	22%
VALVE, BALL, THRD X THRD, 175 PSIG, 3/4"	17,000	Item	$ 11.89	$ 12.28	3%	$ 12.28	3%	$ 13.53	14%
Pipe, Steel, FBE Coated, FBE, 8"	2,300	FT	$ 28.71	$ 35.20	23%	$ 42.09	47%	$ 57.35	100%
		Weighted Avg.			15%		21%		49%

Rates & Regulatory Affairs
UG 435 Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 435
435. Please explain why materials and supplies inventory has increased from 2018 to 2021. Please describe the specific factors that have influenced the increase.
Response:
COVID-19 has had a significant impact on supply chains during the past couple years. Specific to NW Natural, we have experienced the following challenges in our procurement efforts:

- Labor shortage issues impacting suppliers and downstream manufacturers
- Shipping & transportation resource challenges
- Raw material sourcing issues with our downstream manufacturers
- Delivery dates missed by suppliers
- Lead times have increased significantly
- Demand increases for critical material items

In addition to the impact of inflation on inventory valuation, as explained in the Company's response to UG 435 OPUC DR 434, several suppliers have given notification of supply shortage due to the issues mentioned above. In response, NW Natural has increased safety stock levels to minimize stock out events and impact on field operations.
A few examples are as follows:
Poly Pipe – Dura Line, a significant supplier of poly pipe in the utility industry, stopped production in 1Q21 due to quality control issues. This event left many utility companies searching to locate alternative sources, which added demand on alternative suppliers, including Chevron, which is NW Natural's supplier. Lead times for Chevron have increased from two weeks to 32 weeks for some items. To minimize risk to operations, NW Natural has increased its safety stock levels over time.
PVC Pipe – in 4Q20, we received notification from our supplier that the manufacturer was experiencing a resin shortage and would not be processing any orders at that time. Fortunately, our supplier was able to place orders for NW Natural to support ongoing operations but also increase safety stock levels over time. The resin issue is getting better, but not fully resolved
Meter Set Assemblies - Suppliers have had a difficult time with sourcing regulators, a key component of the meter set assembly. Honeywell is the key Supplier of regulators and is having sourcing issues with a few critical key components. To minimize stock-out issues, we have been trying to build up safety stock levels. This issue has not been resolved and continues to be a problem

NW Natural

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 436

436. Please describe how NW Natural verifies that the price for Heath Consultant's atmospheric surveying is competitive or the lowest cost option.

Response:

NW Natural conducted an RFP in 2019 for leakage survey and atmospheric corrosion survey.

Heath Consultants pricing was the second lowest out of five submittals, and Heath Consultants scored the highest in all other categories (i.e., execution, safety, training & supervision, technology and resources). As a result, Heath Consultants was the clear overall winner for the award.

NW Natural

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 437

437. Please explain how often NW Natural compares prices or seeks bids from third parties other than Heath Consulting for atmospheric surveying work.

Response:

NW Natural uses an RFP process to determine the award by an award matrix. NW Natural has a three-year cycle and five-year cycle for our vendors.

CASE: UG 435
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503

NWN Response to OPUC DR 260
Confidential Attachment 1

April 22, 2022

NWN Response to OPUC DR 260 Confidential Attachment 1

is filed in electronic format

CASE: UG 435
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony

April 22, 2022

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

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

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/601.

Q. What is the purpose of your testimony?

A. I provide background, analysis, and recommendations regarding the Company's Test Year expense for wages, salary, incentives, and full-time equivalents (FTE). I also address the Company's Test Year expense for customer account, customer services, sales expenses as well as some miscellaneous Operation and Maintenance(O&M) expenses.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. WAGES, SALARIES AND FTE

Q. Please provide a summary of the Commission's historical method for determining the amount to include in a utility's revenue requirement for wages, salaries, incentives, and overtime expense.

A. The Commission's methodology has many components. The Commission determines the appropriate level of wages and salaries for employees in the Test Year using its three-year wage and salary (W&S) model to estimate union and non-union payroll levels for energy utilities.[1,2] The model determines an appropriate level of Test Year expense and capital investment for wages and salaries by escalating the Company's base year wages and salaries by annual changes to the All-Urban CPI (for non-union) or negotiated increases (for union) and applying a sharing mechanism between the wages and salaries determined by the W&S model and the wages and salaries proposed by the utility.

To determine the appropriate amount to include in revenue requirement for incentives paid to employees, the Commission's policy is to disallow 100 percent of officers' bonuses because they are typically based on increased

[1] *In the Matter of Northwest Natural Request for a General Rate Revision*, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999); and *In the Manner of PacifiCorp* dba Pacific Power *Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 102 (December 18, 2020).

[2] *See Pacific Power & Light*, Docket No. UE 116, Order No. 01-787 at 40 (September 7, 2001); *Northwest Natura*l, Order No. 99-697 at 43; *In the Matter of the Application of Portland General Electric Company for Approval of Customer Choice Plan,* Docket No. UE 102, Order No. 99-033 at 61 (January 27, 1999); and *In the Matter of the Revised Tariff Schedules for Electric Service in Oregon filed by Portland General Electric Company,* Docket No. UE 88, Order No. 95-322 at 10 (March 29, 1995).

earnings, which benefit shareholders.[3] 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.[4]

Finally, the Commission determines the appropriate ratio of expense and capital to apply to the total forecasted compensation and applies it to determine what compensation expense that is included in Test Year expense and what compensation is included rate base.

Q. Please explain how Staff used the Three-Year W&S model to arrive at its recommendation for wage and salary levels for the Test Year.

A. As a starting point for determining non-union wages for each employee class, the W&S model uses the utility's actual wage, salary, and overtime levels as they existed three years prior to the Test Year.[5] For example, a 2022 Test Year would require a Base Year of 2019. From there, the Base Year wages and salaries are adjusted by a year-over-year escalation of expenses using the All-Urban CPI for each of the three subsequent years to establish a forecast of Test Year wage and salary levels.[6]

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3 See *Northwest Natural,* Order No. 99-033 at 62; and *In the Matter of the Application of US West Communications, Inc. Application for an Increase in Revenues*, Docket No. UT 125, Order No. 97-171 at 74-76 (May 19, 1997).

4 *See PacifiCorp*, Order No. 20-473 at 97; *Northwest Natural,* Order No. 99-697 at 44-45; and *PGE,* Order No. 99-033 at 62.

5 See *Northwest Natural,* Order No. 99-697 at 43.

6 *Ibid*.

In effect, the model calculates the average salary based on the Company's actual Base Year calendar payroll (2020), divided by the actual Base Year FTE (2020), then escalates the average by the annual changes to the All-Urban CPI for 2021, 2022, and 2023. Once the escalated amount is determined, it is compared to the Company's Test Year figures.[7] At this point the sharing principle is applied, wherein Staff adjusts its forecasted amount to allow the Company to share 50/50 the lesser of the difference between the model forecast and the amount the Company has included in its Test Year or a 10 percent band around Staff's projection.[8]

For non-union wages, the W&S model incorporates actual market-based data by using historic wages and adjusting for inflation using the All-Urban CPI index.[9] The Commission has consistently validated the All-Urban CPI to adjust historic wages and salaries as "adjusting payroll levels by changes in inflation provides employees the same real level of compensation as in the base year and provides an incentive to companies to minimize labor costs."[10] Further, the methodology of equally dividing between ratepayers and shareholders the difference between the utility's Test Year forecast and the forecast obtained by the model allows for some adjustments to reflect changes in market conditions without allowing unchecked escalation.[11]

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[7] Ibid.
[8] Ibid.
[9] Ibid.
[10] Ibid.
[11] *PGE,* Order No. 95-322 at 10.

For union wages, the W&S model again starts with actual wages three years before the Test Year. Rather than escalating the wages using All-Urban CPI, wages are escalated using negotiated wage increases as set forth in union contracts, and Staff's final adjustment incorporates any sharing between the Company's Test Year forecast and the forecast obtained under the W&S model.[12] In Order 20-473 (2020) in PacifiCorp's general rate case, the Commission rejected Staff's proposed 50/50 sharing between Staff's Test Year determination of expense for union wages and salaries and the Company's projection. The Commission concluded that the arms-length nature of the negotiations regarding wages was sufficient protection for ratepayers.[13]

Q. Please summarize Company's proposal for wages, salaries, incentives and overtime expense in this case.

A. The Company's 2023 Test Year includes $106 million in wages and salaries (base pay), $11.5 million in incentive compensation, and $6.8 million in overtime.[14] While the Company's initial testimony reported a total of $11.3 million in incentives, the Company corrected their Non-Exempt Restricted Stock Units (RSU) amounts to $437,254.[15] The Oregon allocation factor is 100 percent with a O&M/Capital split of 59.8/40.2.[16]

12 *See Northwest Natural,* Order No. 99-697 at 43.
13 See *PacifiCorp,* Order No. 20-473 at 94.
14 NW Natural/800, Rogers/5, 17.
15 Staff/602, Cohen/4, NWN Response to Staff DR 265, Tab 267/269, Footnote 2 (electronic spreadsheet).
16 Staff/602, Cohen/1, NWN Response to Staff DR 93.

FIGURE 1: INCENTIVES FROM COMPANY TESTIMONY

Original	Executive	NBU
Short Term Incentive		
O&M	526,519	4,550,462
Capital	466,688	2,987,243
	993,207	7,537,705
State Allocation	88.29%	89.26%
OR Utility Short Term Incentive Comp	876,910	6,727,889
OR LTIP (O&M)	2,109,952	145,372
OR Stock Expense (O&M)/RSUs	1,276,553	135,547
OR Pay At Risk	**4,263,415**	**7,008,808**

Corrected	Exec	NBU		Total
OR LTIP	2,109,952	145,372		2,255,324
OR RSUs	1,276,553	437,254	*	1,713,807
OR Short Term Incentive	876,910	6,727,889		7,604,799
Total	**4,263,415**	**7,310,515**		**11,573,930**

*See DR 265 Tab 267/269 foonote 2, Company corrects non-exempt RSUs to $437,254

The Company states it removed half of the officer short-term incentives associated with net income from its proposed Test Year.[17] However, also included in the Test Year Operations and Maintenance expense is $1.9 million of stock expense, which includes the employee stock purchase plan as well as $2.3 million of the Long-Term Incentive Plan for Officers and key employees.[18] With respect to officer incentives capitalized in plant since the effective date of NW Natural's last general rate increase (November 1, 2020), Staff included incentives in the last two months of 2020 and the entirety of 2021. Staff calculates Northwest Natural's proposed Revenue Requirement includes total officer incentives capitalized in plant for that period at $954 thousand.[19]

Q. How does the Company determine the compensation for employees?

[17] NW Natural/800, Rogers/5.
[18] NW Natural/1200, Davilla/18.
[19] Staff/602, Cohen/8, NWN Response to Staff DR 344 (electronic spreadsheet).

A. NW Natural testifies that it uses third party survey data completed in 2020 to ensure base pay midpoints are at the median of comparable companies for Non-Bargaining Unit (NBU) employees. Bargaining Unit (BU) employee pay is determined through a negotiated process that uses comparable market survey data and union contracts as points of comparison for setting wage steps. The Company uses compensation data provided by independent compensation consultant Pay Governance to set officer pay.[20]

In addition to base pay, the Company offers the following incentives:

- Goals Incentive Program: Offered to NBU non-officer employees for those who meet or exceed their annual performance objectives.
- Employee Stock Purchase Plan: Allows employees to purchase common stock at 85 percent of closing price.[21]
- Executive Annual Incentive Plan: Short-term incentive program or cash-payments for Officers that is based on a weighted formula of 70 percent Company Performance Factor (71.43 percent Net income and 28.57 percent Operations) and 30 percent Priority/Individual Goals (which includes a Return on Invested Capital (ROIC) component).[22]

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[20] NW Natural/800, Rogers/4.
[21] NW Natural/800, Rogers/9-11.
[22] NW Natural Schedule 14A Proxy Statement, April 15, 2021, https://www.sec.gov/Archives/edgar/data/1733998/000119312521117464/d45834ddef14a.

- NBU Short-Term Incentive Plan: Offered to non-officers and is based on customer service, company growth and public and employee safety goals.[23]
- Long-Term Incentive Plan (LTIP): Qualifying officers and key NBU employees are eligible for the LTIP which comes in the form of stock, restricted stock, restricted stock units, stock options or performance shares.[24] Officers receive 35 percent of their compensation in the form of Restricted Stock Units and 65 percent in the form of Performance Shares. RSUs vest over four years if Return-on-Equity performance threshold is met while performance share awards are based on achieving ROIC threshold, three-year Cumulative Earnings-per-Share (EPS) and a modifier based on Relative Total Shareholder Return (TSR).[25] The three-year cumulative EPS as well as the Relative TSR were chosen "to align executives' interest with shareholders interest."[26]

Q. What adjustments did the Company make to its actual 2020 Base Year salaries and wages to forecast the 2023 Test Year?

A. To project its Test Year, the Company escalates its 2021-year end NBU employee salaries by 4.6 percent in 2022 and 4.35 percent in 2023. This

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23 NW Natural/800, Rogers/9-11.
24 NW Natural 10-k, Fiscal Year Ended 12/31/21, https://www.sec.gov/ix?doc=/Archives/edgar/data/1733998/000173399822000005/nwn-20211231.htm.
25 NW Natural Schedule 14A Proxy Statement, April 15, 2021, https://www.sec.gov/Archives/edgar/data/1733998/000119312521117464/d45834ddef14a.
26 *Ibid.*

includes merit increases of 4 percent and 3.75 percent with an additional 0.6 percent to reflect promotions and equity adjustments. Salary increases are also influenced by CPI Western increases of 4.5 and 3.9 percent in 2021 and 2022. Based on union contracts, bargaining unit employee salary is escalated 3.5 percent June 2021 and every June 1st thereafter until the end of the contract in 2024. Union increases include an additional 0.8 percent to account for movement throughout the training steps. Officers were escalated by the same percentages as NBUs with other updates to officer salaries who were paid below the competitive range of market data.[27]

Wages, Salaries, Overtime & FTE Recommendation

Q. What is Staff's recommendation for Test Year wages and salaries including and overtime?

A. Staff, consistent with the W&S model, starts with a Base Year (2020) that is three years prior to the Test Year, and escalates to the Test Year using All-Urban CPI (CPI) rates, which are 4.7 percent for 2021, 4.2 percent for 2022, and 2.2 percent for 2023.[28] Staff escalates BU or union salaries and wages in the same manner as the Company, applying a rate of 3.5 percent for 2021, 2022 and 2023 based on collective bargaining increases.[29]

Staff then applied the sharing principle to its and the Company's projected 2023 test year amounts. The sharing principle, which allows the Company to

27 NW Natural/800, Rogers/5-6.
28 Oregon Economic & Revenue Forecast March 2022, Volume XLII, No. 1, Table A.4, page 37, https://www.oregon.gov/das/OEA/Documents/forecast0322.pdf.
29 NW Natural/800, Rogers/6.

share 50/50 the lesser of the difference between the Company's and Staff's calculated projections, or a 10 percent band around Staff's calculated projection, makes a reduction to Staff's projection. Because of the high inflation via the CPI, Staff's projection for Exempt, Non-Exempt and Union base salaries is slightly higher than the Company's, with one exception: Officer salaries. Staff has a small adjustment to Officer salaries of $28 thousand O&M and $19 thousand rate base.[30]

FIGURE 2: W&S MODEL ADJUSTMENTS

Description	Officers	Exempt	Non Exempt	Union
Actual Base Payroll (2020) calendar year	3,327,706	48,746,541	1,016,008	41,913,501
Ave. # of Employees (FTE) (2020)	10	445	14	539
Average Salary	339,903	109,600	72,452	77,825
Allowable % Increase	1.11	1.11	1.11	1.11
Ave. # of Employees (FTE) (Test Year)	10	464	15	537
Projected Payroll	3,653,037	56,653,435	1,241,068	46,331,658
Test Period Payroll	3,748,341	56,179,500	908,243	45,224,165
Total Difference for Sharing	95,304	-	-	-
10% Band - Allowable	365,304	-	-	-
50% Sharing of Lesser of Difference or Band	47,652	-	-	-
Staff Proposed Level	3,700,689	56,179,500	908,243	45,224,165
Net Payroll Adjustment	(47,652)	-	-	-

Q. Does Staff have an adjustment for Overtime?

Staff has adjustments for Union Overtime, split between $544,144 expense and $365,796 rate base. Staff calculates a $1.2 million between Staff's projection ($5.6 million) and the Company's ($6.8 million). Staff's calculation was based on the Company's union escalation rates of 3.2 percent per year.

30 See Staff/604, Staff electronic work paper UG 435 Exhibit 604 Wage and Salary Model CONF, tab 3-year W&S.

After the sharing principle is applied, the model suggests an adjustment of half of the initial difference of $544 thousand O&M and $365 thousand rate base.[31]

FIGURE 3: OVERTIME ADJUSTMENT

Description	Officers	Exempt	Non Exempt	Union	Total
Actual Overtime (2020)	-	-	12,356	5,081,152	5,093,508
Average No. of FTE (2020)	10	445	14	539	1,007
Average Overtime per FTE	-	-	881	9,435	
Allowable % Increase	-	-	1.1150	1.1087	
Staff Proposed Level FTE for Test Period	10	464	15	537	1,026
Projected Overtime	-	-	15,093	5,616,743	5,631,836
Test Period Overtime	-	-	6,358	6,807,521	6,813,878
Total Difference	-	-	-	1,190,778	1,182,042
10% Band - Allowable	-	-	-	561,674	
50% Sharing of Lesser of Difference or Band	-	-	-	280,837	
Staff Proposed Level	-	-	6,358	5,897,580	5,903,938
Net Payroll Adjustment	-	-	-	(909,940)	(909,940)
O&M Expense as % of Payroll Exp	1	1	1	1	-
O&M Expense Adjustment - System wide	-	-	-	(544,144)	-
Oregon Allocation Factor	1	1	1	1	1
O&M Expense Adjustment - Oregon	-	-	-	(544,144)	(544,144)
Rate Base as % of Payroll Exp	0	0	0	0	1
Rate Base Adjustment - System wide	-	-	-	(365,796)	(365,796)
Rate Base Adjustment - Oregon	-	-	-	(365,796)	(365,796)

Q. Does Staff have an adjustment for FTE?

A. Staff does not have an adjustment for FTE. The Company's FTE count remained flat, never increasing over 3.5 percent since 2018 and Staff is satisfied with the Company's justification for year-over-year FTE changes.[32]

FIGURE 4: FTE

Description	2018	2019	2020	2021	TY
Total System	1,118	1,110	1,124	1,113	1,151
Oregon	998	997	1,007	992	1,026
OR % Change		-0.09%	1.02%	-1.54%	3.42%

Incentives

[31] See Staff/604, Staff electronic work paper UG 435 Exhibit 604 Wage and Salary Model CONF, tab 3-year OT.

[32] Staff/603, NWN CONF Response to Staff DR 340 (electronic spreadsheet)

Q. What does the Company propose for employee incentives?

A. As noted earlier, the Company includes $11.5 million in incentives in its testimony[33] but only $8.5 million in its response to Staff DR 92. The discrepancy is due to Standard Data Request 92 reporting only paid cash compensation whereas the $11.5 million includes non-cash elements such as stock units.[34] Staff's count of incentives is also slightly higher at $11.7 million due to our inclusion of $174 thousand in Employee Stock Purchase Plan (ESPP) dollars.

FIGURE 5: STAFF CALCULATED INCENTIVES

Stock Expense including ESPP	**2,030,585**		Exec	NBU
RSUs	1,843,494		1,373,151	470,342
ESPP	187,092		7,035	180,057
OR Allocation	92.97%		92.97%	92.97%
OR Stock Expense/RSUs including ESPP	1,887,738		1,283,092	604,645
Total LTIP Expense	$2,554,429		2,389,777	164,652
OR Allocation	88.29%		88.29%	88.29%
OR LTIP	2,255,324		2,109,952	145,372
Short Term Incentives	8,530,912		993,207	7,537,705
OR Allocation	0.89		88.29%	0.89
Total OR Short Term Incentives	7,604,799		876,910	6,727,889
All Incentives			4,269,954	7,477,906
NW Natural Testimony			Exec	NBU
OR LTIP			2,109,952	145,372
OR RSUs			1,276,553	437,254
OR Short Term Incentive			876,910	6,727,889
Total			4,263,415	7,310,515
Difference (ESPP)			6,539	167,391

Staff thought it appropriate to include the ESPP since it was included in the Company's O&M Test Year FERC allocation summary within the total stock expense total of $2,030,585 (or $1.9 million Oregon) and specifically

[33] NW Natural/800/Rogers/17.
[34] Staff/602, Cohen/10, NWN Response to Staff DR 361.

mentioned in the Company's testimony as part of the stock expense in Operations.[35] The Test Year O&M FERC Allocation also included $2,554,429 in the Long-Term Incentive Plan in the Test Year.[36]

The total breakdown in OR allocated numbers showed $1.3 million in Stock Expense/RSUs and Employee Stock Plan for Officers and $605 thousand for NBU employees.[37] $2.1 million of Officer Long Term Incentives are also included alongside $145 thousand for NBU employees. Finally, short term incentives consist of $876 thousand for Officers and $6.7 million for NBU employees.

Q. Does Staff propose an adjustment to incentives?

A. Staff proposes excluding 100 percent of Officer incentives ($4.3 million) and half of non-Officer incentives ($3.7 million) for a total of $8 million ($4.8 million O&M and $3.2 million capital) based on the Commission's long-standing policy.[38]

FIGURE 6: INCENTIVES ADJUSTMENT

	Officers	Exempt	Non Exempt	Union	Total
Test Period Incentive	$4,269,954	$7,395,531	$82,375	$0	$11,747,860
Staff Proposed Level	$0	$3,697,766	$41,187	$0	$3,738,953
Net Payroll Adjustment	($4,269,954)	($3,697,766)	($41,187)	$0	($8,008,907)

35 Staff/602, Cohen/2, NWN Response to Staff DR 143 Attachment 1, tab O&M TY FERC Allocation Summary cell R12 (electronic spreadsheet), NW/Natural/1200/Davilla/18.
36 Staff/602, Cohen/2, NWN Response to Staff DR 143 Attachment 1, tab O&M TY FERC Allocation Summary cell S12 (electronic spreadsheet).
37 Staff/602, Cohen/4, NWN Response to Staff DR 265 Attachment 1 (electronic spreadsheet).
38 See Staff/604, Staff electronic work paper UG 435 Exhibit 604 Wage and Salary Model CONF.

The Commission's policy in disallowing 100 percent of officers' bonuses and 50 percent of non-officer bonuses is based on the conclusion these percentages of bonuses for each type of employee are typically based on increased earnings, which benefits shareholders.[39] While the Company's removal of half of its Officer Short-term incentives is a step in the right direction, its inclusion of LTIP and any portion of the Executive Annual Incentive Plan deviates from Commission policy as they are by design meant to benefit shareholders.[40]

Q. Please summarize all of Staff's adjustments to Salaries, Wages, Overtime, and Incentives.

A. Staff proposes $5.6 million of reductions to O&M and $2.6 million to Capital which includes reductions to:

- Wages & Salaries of $28 thousand O&M and $19 thousand Capital;
- Incentives of $4.8 million in O&M and $3.2 in Capital (Test Year);
- Overtime of $544 thousand in O&M and $365 thousand Capital;
- Officer Incentives in Plant of $954 thousand Capital (from 2020 and 2021); and
- Smaller adjustments to payroll taxes ($85 thousand) and depreciation ($113 thousand).[41]

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39 *See PGE,* Order No. 99-033 at 62; and *US West*, Order No. 97-171 at 74-76.
40 NWN Natural Schedule 14A Proxy Statement, April 15, 2021, https://www.sec.gov/Archives/edgar/data/1733998/000119312521117464/d45834ddef14a.
41 See Staff/604, Staff electronic work paper UG 435 Exhibit 604 Wage and Salary Model CONF.

FIGURE 7: W&S ADJUSTMENTS

Description/ Account No.	Company-Wide: Company Filing	Company-Wide: Staff	Company-Wide: O&M Adjustment	Company-Wide: Capital Adjustment	OR- Allocated: O&M Adjustment	OR- Allocated: Capital Adjustment
Wages & Salaries	$ 106,060	$ 106,013	$ (28)	$ (19)	(28)	(19)
FTE Adjustment	$ 59,880	$ 59,880	$ -	$ -	-	-
Incentives	$ 11,748	$ 3,739	$ (4,789)	$ (3,220)	(4,789)	(3,220)
Overtime	$ 6,814	$ 5,904	$ -	$ (366)	(544.14)	(365.80)
Payroll Taxes					**(85)**	
Depreciation O&M Adjustment Associated with Capital Adjustment					**(113)**	
Incentives in Plant						**954**
Total OR - Allocated Adjustments					**(5,560)**	**(2,650)**

Q. Does Staff have any further comments regarding executive compensation?

A. Staff is aware of public comments the Commission has received regarding executive compensation. Staff notes that the majority of executive compensation flows through Incentives which are 100 percent removed as per Commission policy.[42]

[42] NW Natural Schedule 14A Proxy Statement, April 15, 2021, See Summary Compensation Table, https://www.sec.gov/Archives/edgar/data/1733998/000119312521117464/d45834ddef14a.

ISSUE 2. CUSTOMER ACCOUNT, CUSTOMER SERVICE AND SALES EXPENSES

Q. Please describe customer account and customer service expenses.

A. Customer account 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. Customer Service expense is recorded in FERC accounts 907, 908, and 910 (excluding 909 Informational and Instructional Advertising Expenses, which was analyzed separately). These expenses are for Supervision, Customer Assistance, and Miscellaneous Customer Service. Uncollectibles and Advertising have been reviewed separately in Staff/200/Fjeldheim and Staff/1000/Jent. Finally, FERC accounts 911-917 are comprised of other Advertising, Demonstration and Selling, and Misc. Sales Expenses.

Q. Does the Commission Staff have a standard for how Customer Account, Customer Service and Sales expenses are treated for ratemaking purposes?

A. Rule 860-026-0020 Standards Governing Promotional Activities and Concessions mandates that all promotional activities be just, reasonable, prudent, economically feasible and beneficial to both the utility and its customers. Sales and marketing (including advertising) expenses are prohibited from being posted in customer account or customer service expenses in keeping with Order No. 99-033. Sales and Marketing Costs must demonstrate reasonableness and consumer benefits to be present in rates.[43]

Staff reviews expenses per appropriate use per FERC account. Staff also reviews transaction-level data to ensure expenses relate to activities such as responding to customer requests, inquiries, and safety concerns, resolving customer complaints, extending service to new customers, and providing information about safety and service issues.

FIGURE 8: CUSTOMER ACCOUNT, SERVICES AND SALES 2020-TY

FERC	FERC Category	OR -allocated	OR -allocated	2021-2020	OR -allocated	TY-2021
		2020	2021	% Change	Test Year	% Change
901	Supervision (of Customer Accounting and Collecting Activities)	1,730,217	1,848,583	7%	2,029,213	10%
902	Meter Reading Expenses	898,142	989,930	10%	1,083,393	9%
903	Customer Records and Collection Expenses	14,276,363	16,278,091	14%	17,329,108	6%
904	Uncollectible Accounts	687,610	881,776	28%	-	-100%
907	Supervision (Customer Service Activities)	-	-		-	
	Customer Accounts Expenses	17,592,332	19,998,380		20,441,714	
908	Customer Assistance Expenses	2,562,328	2,446,711	-5%	2,820,423	15%
909	Informational and instructional advertising expenses	2,082,809	2,758,377	32%	2,900,950	5%
910	Misc Customer Service and Information Expenses	239,215	154,485	-35%	201,346	30%
	Customer Service Expenses	4,884,352	5,359,573		5,922,720	
911	Sales Expenses Operation & Supervision	103,038	81,156	-21%	58,796	-28%
912	Demonstration and Selling Expenses	1,661,554	1,866,316	12%	2,052,618	10%
913	Advertising Expenses	428,108	556,553	30%		-100%
	Sales Expenses	2,192,700	2,504,026		2,111,413	

Q. Please describe the Company's customer account and customer service expenses in the Base Year and historically.

[43] *PGE, supra*, Order 99-033 at 63.

A. For Customer Account expenses (FERC accounts 901-905), the Company reported a Base Year Oregon allocated total of approximately $20 million, which included $13 million in labor costs.[44] When compared to 2020, most expenses have increased in the Base Year.[45] The Company attributes these increases to additional FTE and year over year increases in payroll for Supervision and Meter Reading (901-902) as well as a $2.3 million increase by payment vendor Paymentus in Customer Records (FERC 903) which is discussed in the Miscellaneous O&M section.[46] Fluctuations in Customer Service Expenses (FERC 908-910) are attributed to non-payroll expenses for postage, printing and professional services in Advertising (FERC 909) as well as a decrease due to the addition of an automated process for handling customer and supplier interactions in Misc. Customer Service (FERC 910).[47] Staff's examination of DR 153, which lists transactions from 2019-2021 confirms the above changes.

Sales Expenses & Supervision (FERC 911) saw a decrease of 21 percent, largely due to decreased payroll and overhead. Demonstration and Selling Expenses (FERC 912) recorded increases, mainly due to Professional Services, Dealer Relations, Corporate Identity and Other Contract Work. Staff audited the expenses related to professional services, dealer relations,

[44] Staff/602, Cohen/5, NWN Response to Staff DR 276 Attach 1 and Attach 2 (electronic spreadsheets).
[45] Staff/602, Cohen/3, NWN Response to Staff DR 153 Attach 1 (electronic spreadsheet).
[46] Staff/602, Cohen/6, NWN Response to Staff DR 278.
[47] Ibid.

corporate identity and other contract work. FERC account 913 is related to advertising and is covered in Staff/1000/Jent.

FIGURE 9: FERC 911 AND FERC 912 INCREASES 2020-BASE YEAR

FERC 911	Cost element name	2020	2021
	CONFERENCE TRAVEL	84	
	DUES/MEMBERSHIP		882
	EMPLOYEE AWARDS	187	125
	MEALS AND ENTERTAIN	75	24
	NON EMPLOYEE GIFTS		74
	OFFICE SUPPLIES	80	49
	P CARD UNCODED CHARG		-
	PAYROLL OVERHEAD	34,235	27,439
	SALARY BONUS PAYROLL	22	
	SALARY PAYROLL	59,130	45,371
	VACATION, SICK & HOL	9,224	7,193

FERC 912	Cost element name	2020	2021
	PROFESSIONAL SERVICE	28,169	319,508
	SALARY REGULAR	740,508	813,717
	DEALER RELATIONS	28,148	95,690
	CORPORATE IDENTITY	98,061	153,465
	OTHER CONTRACT WORK	5,620	33,227
	REBATES	41,166	65,984
	MATERIALS	297	19,994
	MATERIALS - CONS INV		4,480
	SMALL TOOLS		2,975

Q. Does Staff have any adjustments to these accounts?

A. Staff has several adjustments across FERC accounts 908 and 912, related to the Base Year increases in Corporate Identity, Dealer Relations, and Professional Services. Customer Assistance (FERC 908) Dealer Relations' expense went up over eight-fold from 2020 to the 2021 base year (from $5 thousand to $45 thousand).[48] As branding and building industry events have spurious benefits for consumers, Staff proposes the following adjustment of ($41,112) before escalation.[49]

48 Staff/602, Cohen/12, NWN Response to Staff DR 364 Attach 1 (electronic spreadsheet).
49 *Ibid.*

FIGURE 10: ADJUSTMENT TO FERC 908 DEALER RELATIONS

Cost element name	Purchase order text	Name of offsetting account	Fiscal Year 2020	2021
DEALER RELATIONS		A/P - CONCUR		3,718
		A/P ACCRUED INV	389	(4,832)
		AIR SUPPLY INC		2,678
		BRANDING PLUS LLC	194	
		BUILDING INDUSTRY ASSOCIATION		439
		DEFD REVENUE	1,054	
		FIRST CALL HEATING AND COOLING CO	176	
		GLAVIN DEVELOPMENT LLC	4,442	
		HOME BUILDERS ASSOCIATION		8,170
		JEFFREY TAMBURRO		367
		NORTHWEST NATURAL GAS CO		1,927
		PMT PROC CASH CLEAR	(878)	
		SPADA PROPERTIES INC		248
	2021 Bolt Branding Event	GR/IR		25,036
	Parade of Homes (2021)	GR/IR		7,467
			5,377	45,218
		Adjustment Amount before escalation		41,112

FIGURE 11: FERC 912 CORPORATE IDENTITY, DEALER RELATIONS & PROFESSIONAL SERVICES

Sum of OR Allocated FERC	Cost element name	Fiscal Year 2020	2021
912	CORPORATE IDENTITY	98,061	153,465
	DEALER RELATIONS	28,148	95,690
	PROFESSIONAL SERVICE	28,169	319,508
912 Total		**154,378**	**568,664**

In Demonstration and Selling Expense (FERC 912), cost elements such as Corporate Identity, Dealer Relations and Professional Services were responsible for most of the expense increases. Corporate identity is comprised of event sponsorships, sports sponsorship, home builder association events, block parties, shopping sprees, and trade ally appreciation events with the highest ticket items being a Timbers game and Thorns game as well as an event at the Lot at Zidell Yards.[50] Staff proposes a reduction of $153,043 thousand in base year Corporate Identity expense in FERC 912. Staff has excluded the $422 of meals and entertainment adjustments proposed in this area in Staff/1200/Rossow.

FIGURE 12: FERC 912 CORPORATE IDENTITY

Sum of OR Allocated			Fiscal Year	
FERC	Cost element name	Purchase order text	2020	2021
912	**CORPORATE IDENTITY**		67,033	37,132
		2020 Bolt Safety Event	7,735	
		2020 Lane Cty Home Imprv Show		4,109
		2021 Sponsorship The Lot at Zidell Yards		26,510
		Thorns 2021		19,882
		Timbers 2020 sponsorship	23,293	
		Timbers 2021		65,833
	CORPORATE IDENTITY Total		**98,061**	**153,465**
912 Total			**98,061**	**153,465**

Sum of OR Allocated				Fiscal Year
FERC	Cost element name	Document Header Text	Name	2021
912	CORPORATE IDENTITY	Kloor:May expenses	door prize for golf	49
912	CORPORATE IDENTITY	Nelson:Paul Willocks P-ca	sponsorship of coffee cart at BIA Golf Tournament	374
912 Total				422.78
			Excluding ME adjustment	153,043

Items in Dealer Relations consist of sponsorships, galas, payments to the Home Builders Associations, home tours and other related activities.[51] As ratepayers receive little benefit for these activities, Staff recommends a reduction of $92,482 after excluding the $3,207 of meals and entertainment adjustments in this area.

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[50] Staff/602, Cohen/12, NWN Response to Staff DR 364 Attach 1 (electronic spreadsheet).
[51] Ibid.

FIGURE 13: FERC 912 DEALER RELATIONS

Sum of OR Allocated			Fiscal Year	
FERC	Cost element name	Purchase order text	2020	2021
912	DEALER RELATIONS		22,401	73,121
		2021 Gala & Auction - HBF		5,744
		2021 Sponsorship The Lot at Zidell Yards		8,837
		HBA - Invoices for 2019 Sponsor/Events	5,525	
		HBA Q3 Sponsorship		5,744
		Temporary workers	223	2,245
	DEALER RELATIONS Total		**28,148**	**95,690**
912 Total			**28,148**	**95,690**

Sum of OR Allocated				Fiscal Year
FERC	Cost element name	Purchase order text	Name	2021
912	DEALER RELATIONS		Charity Contribution	44.14
			ORACCA Golf dinner	714.69
			Salem HBA Golf lunch	440.39
			Sponsorship for NARI Annual Golf Tournament	397.65
			Trade Ally appreciation	768.78
		Temporary workers	Catering salem golf	168.25
			Labor salem golf	673.61
912 Total				**3,207.52**

Excluding ME adjustment	**92,482.67**

Finally, after reviewing expenses in Professional Services in FERC 912, Staff recommends the removal of all expenses related to branding or furnace campaigns, or $262 thousand before escalation.

FIGURE 14: FERC 912 PROFESSIONAL SERVICES

Sum of OR Allocated			Fiscal Year	
FERC	Cost element name	Purchase order text	2020	2021
912	PROFESSIONAL SERVICE		28,169	19,136
		2021 Bolt Branding Event		42,463
		2021 Fall Furnace Campaign		49,103
		2021 Fall Hearth Campaign		38,581
		2021 Summer FAU Campaign		42,079
		2021 Winter Furnace Campaign		51,981
		2021 Winter Hearth Campaign		38,342
		Addl fund needed for diff in amt needed		-
		Add'l funds for amended SOW		2,079
		Staffing Srv - Stephanie Frisch		10,773
		Staffing Srv - Stephanie Frisch continue		13,189
		Staffing Srv-Frisch August		11,488
		Temporary workers		294
	PROFESSIONAL SERVICE Total		**28,169**	**319,508**
		Adjustment before escalation		262,549

Q. What are Staff's final adjustments to Customer Assistance and Demonstration and Selling Expenses?

A. After escalating the adjustments by the All-Urban CPI for 2022 and 2023, Staff's proposal is to remove $584,841 in the Test Year from Customer Assistance Expenses (FERC 908) and Demonstration and Selling Expenses (FERC 912) as detailed below.

Q. Why does Staff propose to escalate Base Year expenses by the All-Urban CPI?

A. The Commission has a long history of relying on the All-Urban CPI and Staff uses it almost invariably to escalate costs in a general rate case. As the Commission has noted, "the All-Urban CPI measures price changes in a fixed market basket of goods and services in 200 categories, generally including housing, apparel, transportation, medical care, recreation, education, and others to urban consumers."[52] "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."[53]

[52] *Northwest Natural,* Order No. 99-697, p. 37, n10.
[53] *Ibid.*, p. 38.

FIGURE 15: ADJUSTMENTS WITH ESCALATION

Account	Adjustments	2021	2022 CPI-U	2023 CPI-U
			4.2%	2.2%
908	Dealer Relations	41,112	42,839	43,781
912	Corporate Identity	153,043	159,471	162,979
912	Dealer Relations	92,482	96,366	98,486
912	Professional Services	262,549	273,576	279,595
			Total	584,841

ISSUE 3. MISCELLANEOUS O&M EXPENSE INCREASES

Q. Please explain the Company's individual increases to O&M.

A. The Company lists several items that were not escalated by the CPI but by expected increases in contract costs. Staff reviewed Company work papers and contracts to ensure these costs were appropriately estimated. Staff examined the following expenses:

Paymentus: An increase of $57 thousand (Oregon) due for electronic bill payment services. Accordingly, test year transactions are expected to grow by 4.5 percent annually.[54] The Company trended total payment volume based on customer growth rate as well as a bankcard usage rate of 34 percent.[55]

Locating, Inc.: An increase of $807 thousand (Oregon) based on increased prices per locate (2.25 percent in 2022 and 10 percent in 2023) as well as a 4.5 percent annual growth increase in the number of locating units.[56]

Heath Consultants: The contractual rate per foot of inspection for the survey service will increase 2 percent annually throughout the three-year contract. There is also a projected 25 percent increase in unit cost starting in 2023 due to rising labor costs. The combined effect is an increase of $223 thousand (Oregon). In addition, the Company is required to inspect its Business Districts annually per the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. Business Districts

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54 NW Natural/1200, Davilla/11.
55 Staff/602, Cohen/2, NWN Response to DR 143 Attach 1 (electronic spreadsheet).
56 Staff/602, Cohen/9, NWN Response to Staff DR 352 Attach 2 (electronic spreadsheet).

are gas mains or services where the public regularly congregates. Heath Consultants has projected an increase of $1.4 million (Oregon) related to the necessary inspections.[57]

The Company also has projected an increase of $226 thousand in severance based on a three-year average (2019-2021).[58] Finally, the Company is including $1.9 million in stock expense as well as $2.3 million of Long-Term Incentive Plan.[59] These items have been discussed in the Wages, Salary, and Incentive section.

Q. Does Staff have any adjustments in this area?

A. Staff does not have any adjustments.

Q. Does this conclude your testimony?

A. Yes.

57 NW Natural/1200, Davilla/11.
58 Staff/603, NWN CONF Response to Staff DR 356 Attach 1 (electronic spreadsheet).
59 NW Natural/1200, Davilla/17.

CASE: UG 435
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement

April 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME:	Heather Cohen
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Arts, Political Science Fordham University, New York, NY Master of Public Policy American University, Washington, DC.
EXPERIENCE:	I have been employed as a Senior Financial Analyst by the Oregon Public Utility Commission since January 2020 in the Energy, Rates and Finance Division. I currently perform a range of financial analysis duties related to natural gas, electric and water utilities, with a focus on operations and maintenance. I have worked on the following general rate and power cost dockets: UG 388, UG 389, UG 390, UE 374, UE 390, UE 391, UE 394 and UW 184. I have ten years of professional level budget and fiscal analysis experience. I was previously employed as a Budget Analyst with the Oregon Department of Education (ODE), where I was the lead analyst for the Early Learning Division (ELD) which includes the federal \$97M Child Care Development Fund (CCDF) and \$37M Preschool Promise program. Prior to ODE, I was a Senior Financial Analyst for the state of Texas's Department of Family and Protective Services and Health and Human Services. Before that, I was a Project Manager for the University of Southern California where I directed data collection and analysis, staffing and deliverables for a \$1.2M federal grant related to the provision of mental health services in Los Angeles County. Prior to USC, I was a Senior Budget Analyst for the City of New York responsible for the \$1B expense budget of the Administration for Children's Services (ACS).

CASE: UG 435
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Exhibits in Support
Of Opening Testimony

April 22, 2022

NW Natural®

Rates & Regulatory Affairs

2022 OR GRC

2022 Oregon General Rate Revision

Data Request Response

Request No.: 2022 OR GRC OPUC SDR 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:

Test Year labor expenses expressed as percentages:

O&M	59.8%
Capital	40.2%

Oregon Test Year labor expense represents 89.1% of Total Company labor expense.

NWN's Response to Staff Data Request 143

Is

Filed in electronic format

NWN's Response to Staff Data Request 153

Is

Filed in electronic format

NWN's Response to Staff Data Request 265

Is

Filed in electronic format

NWN's Response to Staff Data Request 276

Is

Filed in electronic format

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 278

278. Company's response to DR 163 shows very large changes from 2020 – 2021 expenses in most areas of Customer Accounts and Customer Service (FERC 901-903), 909-910. Please provide an explanation for these variances.

FERC	FERC Category	System 2020	OR -allocated 2020	System 2021	OR -allocated 2021	2020 - 2021 % change
901	Supervision (of Customer Accounting and Collecting	1,960,822	1,730,217	2,094,963	1,848,583	7%
902	Meter Reading Expenses	1,017,646	898,142	1,121,648	989,930	10%
903	Customer Records and Collection Expenses	16,156,223	14,276,363	18,421,531	16,278,091	14%
907	Supervision (Customer Service Activities)	256	-		-	
908	Customer Assistance Expenses	2,916,819	2,562,328	2,785,206	2,446,711	-5%
909	Informational and instructional advertising expense:	2,360,120	2,082,809	3,125,635	2,758,377	32%
910	Misc Customer Service and Information Expenses	271,432	239,215	175,290	154,485	-35%

Response:

The Company objects to, and does not accept, the characterization in the data request that the noted changes are "very large." Notwithstanding this objection, the Company responds as follows:

FERC 901 – System year over year increase of $134k is payroll related with one additional FTE on average in 2021 as well as normal year over year increases in salaries and benefits.

FERC 902 – System year over year increase of $104k is payroll related representing normal year over year increases in salaries and benefits including more overtime and lower costs charged out of FERC 902.

FERC 903 – The system year over year increase of $2.3M is due to the additional Other Contract Work costs related to the billing and payment vendor Paymentus. Please refer to further the Company's explanation of these variances at **UG 435 OPUC DR 279**.

FERC 909 – System year over year increase of $766k included total payroll expense increase of 7% year over year and a non-payroll increase of $708k across advertising, postage, printing, and professional services. The Company incurred additional advertising and media related expense during 2021, the Base Year, in response to increasing concerns regarding its carbon emissions, increased investments in digital advertising, as well as lower advertising and media costs in 2020 due to the pandemic. The increased advertising delivered facts about RNG supply, sources, carbon reduction benefits for customers as well as NW Natural's plan for acquiring it.

FERC 910 – System year over year decrease of $96k, related to costs incurred for the Customer Order Management ("COM") Project in 2020. This project replaced an outdated, homegrown software system encompassing order management and NW Natural's interactions and relationships with current and prospective customers and trade allies (known as a customer relationship management system, or "CRMS"). The previous, outdated system has been replaced by a streamlined, automated process for handling interactions with customers, trading partners (such as equipment suppliers), municipalities, and prospective customers. The COM project was completed and placed into service in June 2020, and therefore the related O&M costs did not recur in 2021.

NWN's Response to Staff Data Request 344

Is

Filed in electronic format

NWN's Response to Staff Data Request 352

Is

Filed in electronic format

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 361

361. Company's responses in DR 267 and DR 268 appear to be contradictory and are provided below for ease of reference. Please reconcile and explain whether there is or is not consistency between these two responses and refile the Company's response to either of these data requests as appropriate.

Request No.: UG 435 OPUC DR 267

267. The Company seeks full recovery of long-term incentives for Officers and employees which include restricted stock units (RSUs) and Performance Shares, is this correct?

a. Please breakdown the dollar amounts tied to long-term incentives, separately for Officers, Exempt and Non-exempt.

b. Please breakdown the dollar amounts of RSUs and Performance Shares within long-term incentives, separately for Officers, Exempt and Non-exempt.

Response:

Correct. The Company is seeking full recovery of long-term incentives for Officers and employees which does include restricted stock units (RSUs) and Performance Shares (Long Term Incentive Compensation).

See UG 435 OPUC DR 265 Attachment 1, tab DR 267 269 for breakdown of both RSU and LTIP by Officers, Exempt and Non-exempt.

Request No.: UG 435 OPUC DR 268

268. Please reconcile the amounts in question 4 parts a and b with Exempt and Non-Exempt amounts of $6,641,122 and $73,972 in the Test Year and $6,737,316 and $74,084 in the Base Year) in DR 92.

Response:

UG 435 SDR 92 includes incentive or bonus cash paid or expected to be paid to employees for short-term incentives. RSUs and Performance Shares are long-term incentives and therefore were not included in UG 435 SDR 92.

Response:

The Company's responses in DR 267 and DR 268 are not contradictory or inconsistent with each other. UG 435 OPUC SDR 92 which is being referenced in UG 435 OPUC

DR 268 asks specifically to include “actual paid cash compensation” and, as such, is interpreted by the Company to exclude incentive compensation that is awarded not as cash but as stock units. This is in line with how the Company has historically answered SDR 92.

Request No.: 2022 OR GRC OPUC SDR 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 FTEs 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.

NWN's Response to Staff Data Request 364

Is

Filed in electronic format

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 603

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 21-461

(Electronic format)

Exhibits in Support of Opening Testimony

April 22, 2022

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 604

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 21-461

(Electronic format)

**Exhibits in Support
of Opening Testimony**

April 22, 2022

CASE: UG 435
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700
REDACTED

Opening Testimony

April 22, 2022

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

A. My name is Curtis Dlouhy. I am a Senior Economist employed in the Rates, Finance & Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address issues related to NW Natural's pensions and post-retirement medical expenses.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. I find that the Company's pension expense is overstated due to using an Expected Return on Assets (EROA) that is uncommonly low when compared to other pension plans and not supported by the actual performance of its pension plan over the last decade. I find that this same discrepancy is found in the discount rate the Company uses to project its benefit obligation for its pension and post-retirement medical benefit plans.

I recommend raising the Company's EROA up to 7.0 percent to better match the EROA used by large pension plans used by utilities and state governments in California and Oregon. I further recommend raising the discount rates used in the Company's pensions and post-retirement medical benefits calculations by 25 basis points to capture the rise in interest rates since the Company filed its rate case.

The total effect of these adjustments lowers the Company's system-wide pension expense by $6.79 million, or $6.31 million on an Oregon-allocated basis. Of the total system-wide change, $5.10 million is due to the adjustment to the EROA while $1.69 million is due to the adjustment to the discount rate. Raising the Company's discount rate for its post-retirement medical expenses reduces the Company's post-retirement medical expense by $58,000 system-wide, or $54,000 on an Oregon-allocated basis.

Please note that I may revise my recommendations based on the testimony filed by other participants in this rate case.

ISSUE 1 – PENSION AND POST-RETIREMENT MEDICAL EXPENSES

Q. Please summarize the Company's proposals concerning retirement and post-retirement medical expenses.

A. The Company proposes a total Test Year post-retirement medical expense of $1.3 million, which constitutes an increase of approximately $200,000 from the Base Year.

The Company also proposes a total Test Year pension expense of $7.0 million, which is a decline of approximately $9.0 million from the Base Year. This $7.0 million amount is subdivided into $1.3 million of non-service expenses that is categorized as O&M, and $5.7 million that is system service expense. This latter category is allocated between O&M and capital based on the payroll work mix.[1]

Q. What is the Company's total proposed pension expense and what is causing the decrease in pension expenses?

A. The Company's proposed pension expense is $7.0 million in the Test Year Companywide, which constitutes a decrease of $9.0 million from the Base Year.

Based on the Company's confidential response to SDR No. 59, there are a host of factors, sometimes offsetting, that contribute to this overall decrease in the pension expense. Factors that lower the overall test-year pension expense include:

[BEGIN CONFIDENTIAL]

[1] NWN/1200, Davilla/17.

[redacted]

[END CONFIDENTIAL]

Factors that raise the overall test-year pension expense include:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Please explain how these parameters are relevant when calculating pension expenses and give a broad description of pension expenses.

A. Pension expenses, known formally as FAS 87 expense, can be positive or negative. These expenses are most commonly calculated based on a few main components:

- Fair value and funded status of the plan;
- Service cost;
- Interest cost;
- Recognized Gain or Loss;
- EROA; and
- Discount rate.

Increases to the service cost and interest cost ultimately raise overall pension or post-retirement medical expenses. The EROA and the discount rate are percentages that broadly reflect market conditions, future benefit obligations, and how the trust will perform in the market. While the fair value of the plan, recognized gain or loss, service cost, and interest cost are largely predetermined by the choice and operation of the plan, the EROA and discount rate are items that the Company has a lot of discretion in choosing when projecting pension future expenses. I will discuss both the EROA and discount rate in greater detail later in my testimony.

The above parameters and discussion are also relevant when calculating the Company's post-retirement medical expenses, known as the FAS 106 expense, as well. As previously pointed out, the FAS 87 and FAS 106 expense can be positive or negative. In both the FAS 87 and FAS 106, a negative expense means that the trust is in good financial health and draws in more revenues from its investments than it needs to pay out. Likewise, a positive expense means that funds are being drawn from the account faster than they are being recovered, meaning that additional contributions are needed to maintain the trust.

Q. Do you believe that this reduction in pension expenses is sufficient?

A. No. Although the Company has indeed reduced its pension expenses by quite a lot, this reduction does not accurately project test-year expenses based on the Company's historical expenses and current market intuition.

Q. Please explain.

A. As stated previously, the two main prospective levers that the Company can use to calculate the pension expense are the discount rate and the EROA. I find that the Company's EROA underestimates the Company's actual and projected market returns the Company and is among the lowest among Oregon-regulated utilities and that the increase in the Company's discount rate falls well short of the increase in interest rate yields seen in the market.

Q. Please briefly discuss what the discount rate is and how it influences the overall pension expense.

A. The discount rate is the expected market interest rate for the relevant asset or portfolio of assets by which to discount future pension obligations. It is one component that is used to calculate the present value of a portfolio that provides a stream of revenue. An increase in the discount rate decreases the present value of the projected future pension obligations, which ultimately lowers pension expenses.

Q. What analysis have you done to check whether the Company's discount rate is appropriate?

A. To determine whether the Company's discount rate is appropriate, I compared the Company's discount rate to the market yield of bonds that have a similar risk profile to the assets held in Northwest Natural's pension plan, namely the yields on Corporate AA-rated bonds. I also compared the Company's choice of a discount rate to the discount rate used by its Oregon-regulated utility peers.

Q. How does Northwest Natural's discount rate on its pension plan compare to the discount rate implied by the market?

A. While it would be naïve to assume that the Company's discount rate for its pension plan perfectly tracks the return for Corporate AA-rated bonds, comparing the change in the discount rate between the beginning of Northwest Natural's base year of 2021 and the test year of 2022, to the change in the Corporate AA-rated bond yield can serve as an informative proxy. In this testimony as well as past testimony on this subject, I use this proxy to determine whether it appears that the Company's change in discount rate is moving in the same direction as the market and whether the magnitude of the change is roughly in line with the market.

Between the base year and the test year, the discount rate rose from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent, a change in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** basis points.[2]

When comparing the change in discount rate from Base Year to Test Year, I will treat the market yield in the beginning of 2021 as a suitable comparator to the base year and the yield one month before the filing of this testimony as the Test Year. On Monday, January 4, 2021, the yield for Corporate AA-rated bonds was 1.42 percent. This rose to a market yield of 3.17 percent on December 17, 2021, constituting a change in 175 basis points. This change can be seen in Figure 1, where I plot the change in the Corporate

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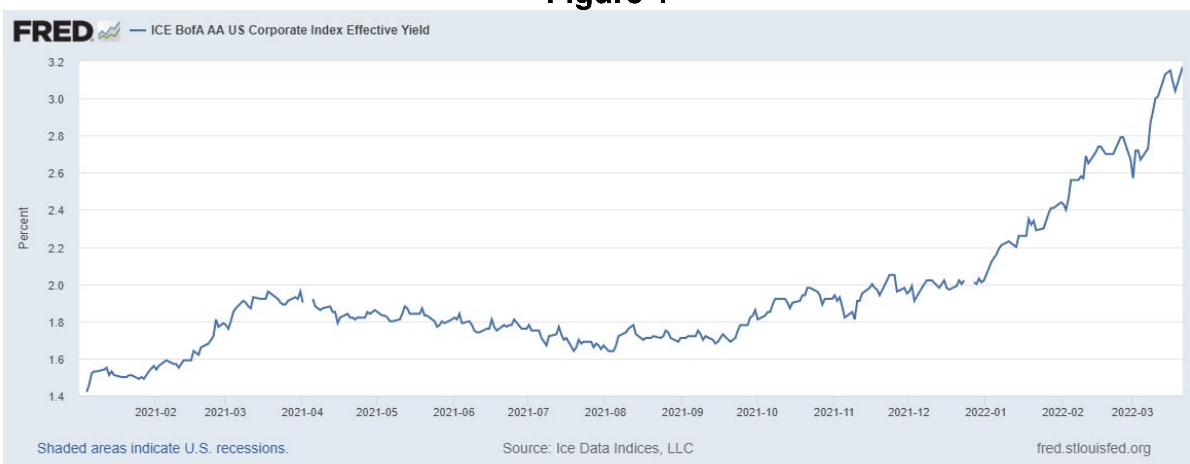
2 Staff/704, Dlouhy/1.

AA-rated bond yields over the time period discussed above. Although I use the beginning of 2021 as the base year for this comparison, it should be noted that any choice of date in 2021 to serve as the proxy for the Test Year would lead to a change of at least 100 basis points between the Base Year and Test Year.

Figure 1



This is suggestive that Northwest Natural's proposed change to the discount rate is at least moving in the right direction, if not necessarily the right scale. To dig deeper into this second question of the scale of the change, we can turn to the broader bond market trends to see if this change continues to seem warranted and if the scale appears correct and to Northwest Natural's Oregon-regulated peers' discount rates.

Q. Do you have reason to believe that the scale of Northwest Natural's change to its discount rate is correct based on other market news?

A. No. In Staff Exhibit 703, I include a recent article from the Wall Street Journal detailing the Federal Reserve Bank's recent decision to raise interest rates by

25 basis points and plan to continue to raise them in the future.[3] The article discusses that the Federal Reserve continues to raise its rates throughout 2022, which means that the increase in bond yields presented shown in Figure 1 is likely to be sustained.

Q. What changes do you recommend the Company make to its discount rate?

A. I recommend raising the Company's discount rate by another 25 basis points to match the rise in the interest rates enacted by the Federal Reserve in March after the Company filed its rate case.

Q. The Company's discount rate would only rise by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] basis points if your recommendation is adopted but the market interest rate has risen by 175 basis points. Why do you recommend such a conservative increase?

A. I recommend only a 25-basis point increase to the discount rate for a few reasons. First, my recommendation matches the 25 basis points increase to the interest rate by the Federal Reserve that has occurred since the Company filed its rate case. Second, my suggested change brings the utility's discount rate up to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent, which would keep Northwest Natural's discount rate reasonably in line with its peers, as can be seen in Table 1.

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[3] Staff/703, Dlouhy/1.

Finally, global uncertainty makes properly forecasting interest rates a much more difficult task, meaning that a less conservative increase in the discount rate may ultimately prove to be too bold and lead to an avoidable forecast error to the Company's forecast of benefit obligations. This uncertainty has been reported and can be seen in the second article contained in Exhibit 703.[4] By keeping the increase to the discount rate at just 25 basis points, my recommended change closes the evident gap between the Company's proposed parameters and reality while maintaining a greater level of certainty that my recommendation remains warranted should market volatility continue.

Q. What effect does an increase to the Company's discount rate by an additional 25 basis points have on the Company's test-year pension expense?

A. Based on the Company's response to SDR No. 60, an increase by an additional 25 basis points decreases the Company's system-wide costs by $1.689 million. This translates to $1.570 million on an Oregon-allocated basis.

Q. What analysis have you done to conclude that the Company's EROA is inappropriate?

A. I conclude that the Company's EROA of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[5] percent is inappropriately low after comparing the EROA to other Oregon-regulated utilities, other large pension plans, and to its actual returns of its pension plan over the last several years. The EROA that the

4 Staff/703, Dlouhy/3.
5 Staff/704, Dlouhy/1.

Company uses for its pension plan is well below almost all of its peers in Oregon and the EROA used by the California Public Employees' Retirement System (CalPERS). Further, the EROA has a long history of underestimating the Company's actual Return on Assets (ROA), a trend which I expect to continue into the future if no changes are made to the Company's suggested EROA.

Q. Why is the Company's assumed EROA important?

A. Funding to pay the pension cost of the Company can come from at least two sources: ratepayers and investment returns.[6] To the extent funding can come from investment returns that reduces the share of the pension cost that must come from ratepayers.

Q. How does the Company's EROA compare to the EROA of other Oregon-regulated utilities?

A. The Company's discount rate and EROA can be found in Table 1. As you can see, the Company's EROA of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent is lower than the majority of its Oregon-regulated utility peers and lower than the mean EROA used by Oregon-regulated utilities excluding Northwest Natural of 6.22 percent. Given the small sample size of Oregon utilities, this may be warranted if there is a trend of pension plans outside of the utility space that are seeking out less risky investments than this sample. However, as evidenced by CalPERS, this is not the case.

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[6] The Company could make cash infusions into the pension fund that are ultimately recoverable to some degree through rates charged to ratepayers.

Table 1: Pension EROAs and Discount Rates for Oregon-Regulated Utilities[7]

Company	Utility Type	EROA	Discount Rate
Cascade*	Gas	5.40%	2.64%
Avista	Gas	5.40%	3.25%
[redacted]			
PacifiCorp	Electric	6.00%	2.50%
Portland General	Electric	6.88%	2.64%
Idaho Power	Electric	7.40%	2.80%

Q. What EROA is used by CalPERS?

A. CalPERS uses a long-term EROA of 7.0 percent, as evidenced by the article contained in Staff Exhibit 703.[8] The article goes on to say that this EROA is average of state and local government retirement funds, meaning that Northwest Natural's **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent EROA is truly a large outlier. This uncommonly low EROA could be justified if the Company's actual return on assets appear to match its EROA, but once again this is not the case.

Q. How does the Company's EROA compare to its actual ROA?

A. The Company provided the actual ROA every year from 2010 until 2021 in response to Staff Data Request No. 282.[9] The geometric mean of the Company's actual ROA **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent. This constitutes a staggering **[BEGIN**

7 All EROA and discount rates except for Northwest Natural are pulled from each utility's February 2022 SEC 10K filing.

8 Staff/703, Dlouhy/10.

9 Staff/702, Dlouhy/3.

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]** basis point difference between the Company's EROA it proposes to use in this rate case.

Q. If the EROA is forward looking, why should the Company's EROA be corrected based on past results?

A. While it is true that the EROA is forward looking and markets fluctuate, the Company's past experience is still indicative of its pension's future performance.

Further, it would take a single year return of zero percent in 2022 to cause the Company's average actual ROA from 2010 to 2022 to dip below the 7.0 percent value I recommend in this rate case.

Q. Are there any other forward-looking measures that support raising the Company's EROA for its pension plan?

A. Yes. In the Company's own testimony on Cost of Capital, it claims that it requires a market return of 9.50 percent ROE based on its own estimation.[10] In its estimation of its CAPM and ECAPM, the Company states that it expects a risk-free rate of 2.40 percent and a market risk premium of between 7.25 percent and 8.61 percent.[11] This translates into an expected market return of 9.65-11.06 percent.

Based on this, adjusting the Company's EROA up to 7.0 percent for its pension plan is not just reasonable, but also easily attainable if the market is returning as strong as it claims in its Cost of Capital testimony. Adjusting the

[10] NWN/300, Villadsen – Figueroa/7.
[11] NWN/300, Villadsen – Figueroa/53.

Company's EROA to 7.0 percent is also in line with Staff's recommended ROE of 9.0 percent, which was partially motivated by a CAPM that was built upon a market return varying from 6.36 percent and 8.24 percent.

Q. What changes do you recommend be made to the Company's EROA?

A. I recommend that the Company adjust its EROA to 7.0 percent. This value matches both the average value used by state and local government retirement plans and the median value of other Oregon-regulated utilities. This constitutes an increase of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** basis points to its filed EROA, which is still comfortably below the Company's recent actual returns and gives the Company plenty of leeway if their impressive pension returns are not sustained in the future.

Q. How does changing the Company's EROA to 7.0 percent affect the Company's pension expense in this rate case?

A. By scaling up the values provided in the Company's response to Staff DR No. 60 up **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** basis points, changing the Company's EROA to 7.0 percent would reduce the Company's pension expense by $5.10 million on a system-wide basis and $4.74 million on an Oregon-allocated basis. I checked to see if this number is accurate by manually calculating the money generated based on the Company's proposed EROA provided in response to Staff DR No. 59 and tracking the other costs down to a final pension expense. The differences between the two methods are quantitatively small.

Q. What have you done to analyze the Company's post-retirement medical benefit expense?

A. In a typical general rate case, the bulk of my analysis is spent on the portfolio of assets used to fund the post-retirement medical benefits. Unlike most Oregon-regulated utilities, Northwest Natural does not fund its post-retirement medical benefits with a portfolio of assets.[12] While this is uncommon for Oregon-regulated utilities, the Commission has not taken issue with it in the past. The Company still projects its benefit obligations using a discount rate, so I will still analyze the Company's choice of a discount rate.

Q. Do you find any reason to make an adjustment to the Company's post-retirement medical benefits?

A. Yes. Much like the Company's discount rate used to project expenses for its pension plan, the Company's chosen discount rate for its post-retirement medical benefits is also artificially low, which incorrectly inflates the cost of the plan for Oregon ratepayers. I recommend raising the discount rate for the Company's post-retirement medical expense by 25 basis points for the same reasons as I described concerning its pension plan. Table 2 shows the discount rates utilized by other Oregon-regulated utilities. In this case, Northwest Natural has the lowest discount rate of all its peers.

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[12] Staff/702, Dlouhy/5.

Table 2: Post-Retirement Discount Rates for Oregon-Regulated Utilities[13]

Company	Utility Type	Discount Rate
Cascade*	Gas	2.66%
Avista	Gas	3.27%
[redacted]		
PacifiCorp	Electric	2.50%
Portland General	Electric	2.92%
Idaho Power	Electric	2.70%

Q. What is the effect of this adjustment?

A. Using the Company's response to SDR No. 60, a 25 basis point increase to the Company's discount rate for its post-retirement medical lowers its system-wide expense by $58,000, or $54,000 on an Oregon-allocated basis.[14]

Q. Please summarize your adjustments to the Company's pension expense and post-retirement medical benefit expense for this section of your testimony.

A. On an Oregon-allocated O&M basis, I recommend reducing the Company's pension expense by $6.31 million and the Company's post-retirement medical benefits expense by $54,000.

Q. Does this conclude your testimony?

A. Yes.

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13 Northwest Natural's discount rate was pulled from Confidential Attachment A to Staff DR No. 59. All other utility's EROAs were pulled from their most recent SEC 10k filings.

14 Staff/702, Dlouhy/1.

CASE: UG 435
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualifications Statement

April 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME:	Curtis Dlouhy
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Rates, Finance, and Audit Division
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	PhD, Economics University of Oregon Eugene, OR Master of Science, Economics University of Oregon Eugene, OR Bachelor of Arts, Majors: Economics, Mathematics Nebraska Wesleyan University Lincoln, NE
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) since June 2020 in the Energy Rates, Finance, and Audit Division. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues. I have provided analysis and expert testimony in various contested cases including UG 388, UG 389, UG 390, UE 374, UE 390, UE 391, UE 394, UG 433, and UG 435 (ongoing). Prior to working for the Commission, I was employed by the University of Oregon as a graduate employee where I taught classes in Intermediate Microeconomics, Industrial Organization and Antitrust Economics. My PhD dissertation covered various topics in fossil fuel markets ranging from coal mine closure, dispatchable electricity choices under carbon taxes and coal transport via railroad. While completing my PhD, I provided cost and economic analysis for the Graduate Teaching Fellows Federation as a member of their contract bargaining team.

CASE: UG 435
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Non-Confidential Data Responses in Support Of Opening Testimony

April 22, 2022

Thousands, except percent	Change in Assumption	Impact on Retirement Benefit Costs	Impact on Retirement Benefit Obligations	OR Allocated Impact on Benefit Obligation	Related FAS
Discount rate:	-0.25%				
Qualified defined benefit plans		$ 1,767	$ 17,934	$ 16,673	87
Non-qualified plans		14	282	262	87
Other postretirement benefits		60	867	806	106
Expected long-term return on plan assets:	-0.25%				
Qualified defined benefit plans		911	N/A	N/A	87

Thousands except percent	Change in Assumption	Impact on Retirement Benefit Costs	Impact on Retirement Benefit Obligations	OR Allocated Impact on Benefit Obligation	Related FAS
Discount rate:	0.25%				
Qualified defined benefit plans		$ (1,689)	$ (16,982)	$ (15,788)	87
Non-qualified plans		(14)	(269)	(250)	87
Other postretirement benefits		(58)	(824)	(766)	106
Expected long-term return on plan assets:	0.25%				
Qualified defined benefit plans		(911)	N/A	N/A	87

The estimates are based on the same data, assumptions, methods and provisions as used for the December 31, 2020 year end disclosures except for the following:

Discount rates as of August 31, 2021	
Qualified defined benefit plan	2.60%
Non-qualified plan	2.25%
Other postretirement benefits	2.53%

For the Qualified defined benefit plan:	
Market value of assets as of August 31, 2021	$ 399,195,685
Assumed asset return assumption from August 31, 2021 through December 31, 2021	0.00%
OR Allocated Percent (FERC 926)	92.97%

Census data was updated to January 1, 2021
Expected contributions are based on the minimum requirements under the American Rescue Plan Act of 2021

2022 Expense Estimate - Baseline

Thousands except percent

	Discount rate	Expense	Benefit Obligation	OR Allocated Benefit Obligation
Qualified defined benefit plans	2.60%	$ 7,168	$ 519,086	$ 482,594
Non-qualified plans	2.25%	667	11,041	10,265
Other postretirement benefits	2.53%	1,098	28,652	26,638

Pension (ASC 715 / FAS 87)								
At December 31	2017	2016	2015	2014	2013	2012	2011	2010
Projected Benefit Obligation*	$ 449,660	$ 423,506	411,792	451,149	362,385	403,978	362,909	314,460
Fair value of plan assets	$ 287,924	$ 257,714	249,338	279,164	267,062	249,603	215,970	219,014
Actual return on assets	$ 40,308	$ 12,593	(9,599)	19,958	22,872	26,683	(6,684)	24,651
Benefits paid	$ (29,527)	$ (18,688)	(34,346)	(18,356)	(17,112)	(16,550)	(16,606)	(16,949)
Funded status	$ (161,736)	$ (165,792)	(162,454)	(171,985)	(95,323)	154,375	(146,940)	(95,446)
Accumulated Benefit Obligation^	$ 410,251	$ 386,981	-	-	-	-	-	-
Funded ratio	64 03%	60.85%	60.55%	61 88%	73.70%	61.79%	59.51%	69.65%
Service cost	$ 6,760	$ 6,742	7,730	6,682	7,990	7,462	6,416	5,989
Interest cost	$ 16,870	$ 17,115	17,116	16,948	15,272	16,052	16,785	16,651
Expected return on assets	$ (20,433)	$ (20,053)	(20,676)	(19,495)	(18,721)	(19,082)	(17,867)	(18,207)
Amortization of transition asset	$ -	$ -	-	-	-	-	-	-
Amortization of prior service cost	$ 127	$ 230	230	230	230	230	230	230
Recognized gain/loss net periodic	$ 14,802	$ 13,238	16,372	9,822	16,744	14,482	107,308	6,740
Net periodic pension cost (income)	$ 18,126	$ 17,272	20,772	14,187	21,514	19,144	16,295	11,404
Company's contribution to plan	$ 19,430	$ 14,470	14,120	10,500	11,700	23,500	20,245	10,000
Discount rate for benefit obligation	3.54%	4.03%	4 24%	3.88%	4.75%	3 87%	4.50/4 52	5.49%/5.46%
Discount rate for annual expense	4.03%	4.24%	3 88%	4.75%	3.87%	4.50/4.52	5.46/5.49	6 00%/5.97%
Long-term rate of return on assets	7 50%	7.50%	7.50%	7 50%	7.50%	7.50%	8.00%	8.25%
Actual rate of return on assets	15.64%	5.05%	-3.44%	7.47%	9.16%	12.35%	-3.05%	12.25%
Beg Bal - FV of Plan Assets	257,714	249,338	279,164	267,062	249,602.67	215,970	219,014	201,312

* Projected Benefit Obligation is an estimate of the present value of pension liabilities, inclusive of projected future wage increases. Accumulated Benefit Obligation is a measure of the present value of pension liabilities without such increases. Projected Benefit Obligation is the GAAP measure of the liability, and is thus used to calculate funded ratio.

^ Accumulated Benefit Obligation is not projected in models received from NW Natural's actuaries. ABO n/a for 2015-2010 consistent with prior filing.

Variation on estimated Long-term Rate of Return and actual:	Actual returns varied from estimated long-term rate of return on assets due to market volatility.

OPEB (ASC 715 / FAS 106)								
At December 31 ($ thousands)	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**
Projected Benefit Obligation*	28,927	29,395	31,049	32,073	28,754	33,034	30,049	27,676
Fair value of plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Actual return on assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Benefits paid	1,751	1,850	(2,262)	(2,040)	(2,051)	(2,250)	(2,159)	(1,510)
Funded status	(28,927)	(29,395)	(31,049)	(32,073)	(28,754)	(33,118)	(30,049)	(27,676)
Accumulated Benefit Obligation*	28,927	29,395	-	-	-	-	-	-
Funded ratio	-	-	-	-	-	-	-	-
Service cost	341	391	526	482	657	592	614	588
Interest cost	1,142	1,175	1,180	1,253	1,157	1,267	1,404	1,436
Expected return on assets	-	-	-	-	-	-	-	-
Amortization of transition asset	-	-	-	-	-	411	401	411
Amortization of prior service cost	(468)	(468)	197	197	197	197	197	196,773
Recognized gain/loss net periodic	695	705	554	221	726	435	289	131,347
Net periodic pension cost (income)	1,710	1,803	2,457	2,153	2,744	2,902	2,915	2,764
					-	-	-	-
Company's contribution to plan	1,737	1,732	2,017	1,871	1,895	1,971	1,962	1,476
Discount rate for benefit obligation	3.44%	3.85%	4.00%	3.74%	4.45%	3.56%	4 33%	5.16%
Discount rate for annual expense	3.85%	4.00%	3.75%	4.45%	3.56%	4.33%	5.16%	5.78%
Long-term rate of return on assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Actual rate of return on assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

* Projected Benefit Obligation is an estimate of the present value of pension liabilities, inclusive of projected future wage increases. Accumulated Benefit Obligation is a measure of the present value of pension liabilities without such increases. Salary is not a determinant of benefits earned under the post-retirement medical (OPEB) plan, and thus these figures are identical.

Variation on estimated Long-term Rate of Return and actual:	Actual returns varied from estimated long-term rate of return on assets due to market volatility.

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 419

419. Please provide a narrative description discussing why the Company's Post-Retirement Medical Benefits plan is not supported by a portfolio of assets.

Response:

NW Natural's other post-employment benefit plan (OPEB) is an unfunded plan. OPEB plans differ from defined benefit plans in that they are not required to be pre-funded. The Company makes annual contributions each year to the plan to pay for retiree benefit payments owed.

NW Natural does own life insurance policies valued at approximately $8.7 million. Of this amount approximately $8 million were purchased to fund retiree medical benefits for NBU employees. These policies are not held in a trust and therefore are called Company Owned Life Insurance ("COLI") policies.

CASE: UG 435
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 703

Relevant News

April 22, 2022

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Dlouhy/1

https://www.wsj.com/articles/feds-mester-says-50-basis-point-rate-rise-is-on-table-for-central-bank-11648049088

CENTRAL BANKS

Fed's Mester Says 50-Basis-Point Rate Rise Is on Table

The Federal Reserve Bank of Cleveland president said rate rises are about cooling excessive demand in an otherwise strong and healthy economy

Loretta Mester in Washington, D.C. in February 2020. She is a voting member of the rate-setting Federal Open Market Committee.

PHOTO: MELISSA LYTTLE/BLOOMBERG NEWS

By Michael S. Derby
March 23, 2022 11:24 am ET

Federal Reserve Bank of Cleveland President Loretta Mester said Wednesday that the U.S. central bank will need to front load its rate rise campaign with aggressive moves, but she doesn't think this path will send the economy into recession.

To get the federal funds target rate range to 2.5% by year-end, "I think we're going to need to do some 50-basis-points moves," Ms. Mester said in reference to the possibility the central bank will raise rates by half percentage point increments, rather than in more-common quarter percentage point increases.

Ms. Mester is a voting member of the rate-setting Federal Open Market Committee. She spoke to reporters Wednesday after a speech on Tuesday in which she said getting very high levels of inflation back under control is the Fed's paramount concern. Last week, the

Staff/703
Dlouhy/2

FOMC boosted the fed-funds rate target range from near zero levels to between 0.25% and 0.50% and penciled in further increases on the way to a rate of around 2% by year-end.

On Monday, Fed leader Jerome Powell spoke and signaled his openness to 50 basis point increases should he believe they'd be necessary.

Ms. Mester told reporters that rate rises are about cooling excessive demand in an otherwise strong and healthy economy, and that this rebalancing should not have a painful impact, as many observers now fear.

"I don't have concerns that the rate increases are going to push the economy into recession, just because the underlying momentum is so strong, and there's excess demand in the economy right now," Ms. Mester said. "I am optimistic that we can do what we're intending to do, which is get inflation under control" with higher rates and taking steps to lower the size of the Fed's currently $9 trillion balance sheet.

Write to Michael Derby at michael.derby@wsj.com

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Justin Ho | Mar 18, 2022

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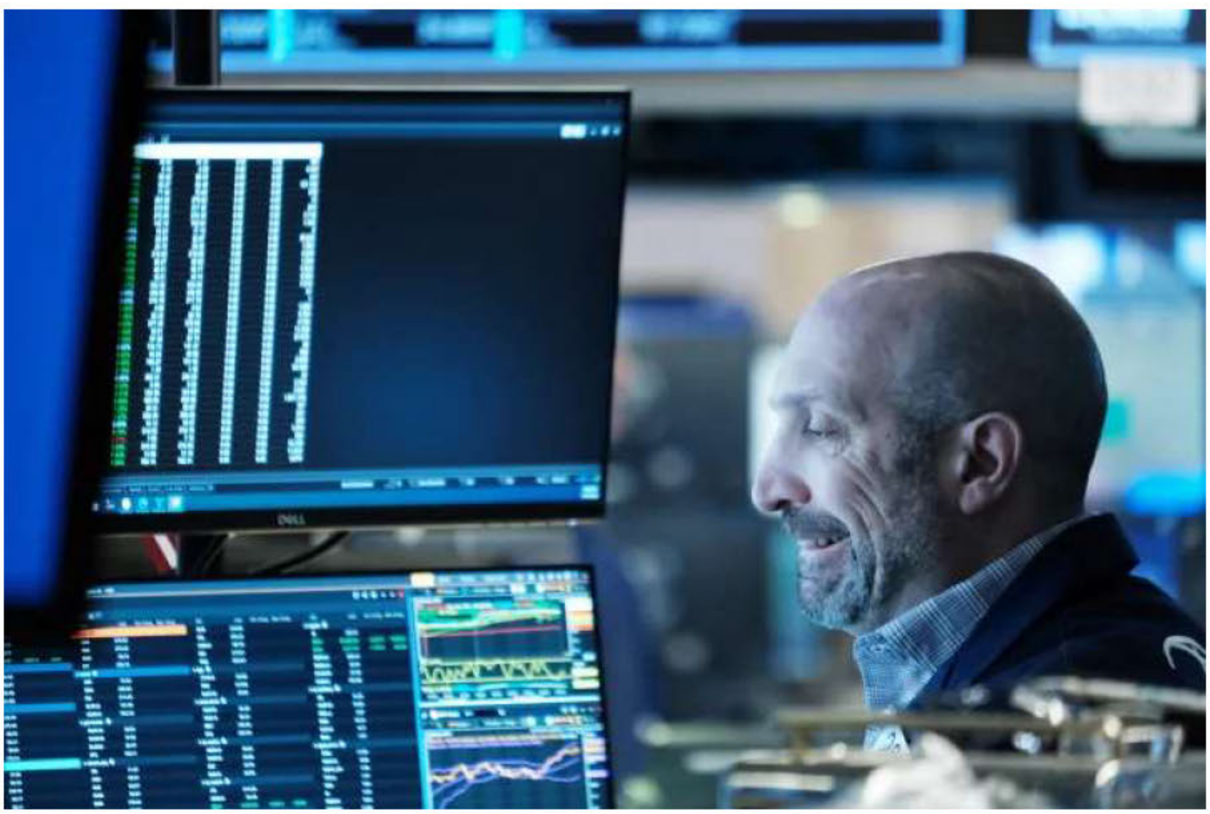

Traders work on the floor of the New York Stock Exchange (NYSE) on March 16, 2022 in New York City. Spencer Platt/Getty Images

Staff/703
Dlouhy/4

The daily ups and downs of financial markets tell us what bets market participants are placing on the future. But right now, markets are dealing with a lot of uncertainty caused by Russia's invasion of Ukraine – and they are reacting accordingly.

One key question for investors is what will happen if Russia's invasion escalates.

In addition to the devastating human toll, "that certainly could impose an economic hardship, certainly across Europe to a greater extent than it already has," said Mark Luschini, chief investment strategist at Janney. "And even on a more global basis."

What if Russia's invasion pushes oil prices even higher? What about wheat prices? What if that makes inflation even worse? And what if that drags down the global economy?

"The margin for error, given the amount of things that are sort of worrying investors at the moment, is quite wide," Luschini said.

While investors can bet based on their hunches about the future, the market as a whole is reacting to what's happening now.

Staff/703
Dlouhy/5

"There's a lot of stuff happening," said Ian Dew-Becker, a finance professor at Northwestern University. "Every day [Russia's invasion] goes on, we learn a little bit, right? It lasts at least one day longer. And so it's the learning, that causes prices to move."

And lately, stock prices have been moving a lot, up and down.

Dew-Becker said that kind of market volatility means that there's a lot going on that's changing investors' minds.

"We don't know," he said. "So some days we get good news. Some people are less pessimistic, but certainly something bad could happen tomorrow, and that could bring prices back down."

People usually don't like not knowing. Investors typically react to volatility by moving money into assets they see as safer, said Winnie Cisar, global head of strategy at CreditSights.

"Things like U.S. treasury markets, investment grade corporate credit," she said.

That strategy happened at the outset of the invasion. But Cisar said treasury and corporate bond markets have been getting more volatile, too.

"And what we're actually observing, is that investors are parking their cash in cash. In money market funds," Cisar said. "The places where they're guaranteed not to actually lose anything because of market volatility."

Cisar said that's probably going to continue until investors get back to feeling comfortable putting their money at risk.




Staff/703
Dlouhy/6

When risk and uncertainty abound, investors move to government bonds in a "flight to safety"

Higher prices, more risk: How Russia's war on Ukraine is likely to affect the global economy

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Pension Cash Dwindles, Risking Liquidity Crunch

by Heather Gillers – WSJ – Nov. 22, 2021

Cash allocations have dropped to a seven-year low, with pensions seeking greater returns in private markets.

CalPERS plans to invest more in private markets
and keep less cash on hand to meet its target.

Bigger **private-market bets**, **inflation** fears and a **surge of retirees** are putting **public retirement funds** at **risk** of a **cash crunch** that would **force them** to **sell assets at losses to pay pension checks**.

Cash allocations have **dropped** to a **seven-year low** at the funds that manage more than $4.5 trillion in retirement savings for America's teachers, police and firefighters. **Public pension funds**, which have **increasingly turned** to **illiquid private markets** to drive up returns, are **now aiming** to **keep** about **0.8%** of their **holdings in cash**, according to data from the Boston College Center for Retirement Research.

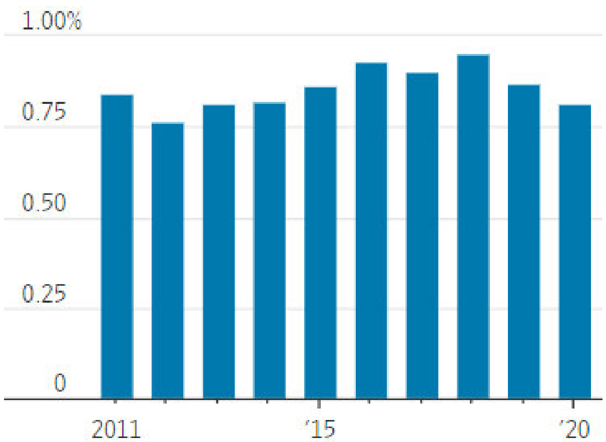
These funds are managing a **juggling act** faced by many institutional and household investors who want to put their money to work but also want easy access to it in a pinch.

"The first report I look at every day is our cash report," said Jonathan Grabel, investment chief of the **$75 billion Los Angeles County Employees Retirement Association**, which aims to keep 1% of its assets in cash. "We have plenty of liquidity across the portfolio, but you **never know when** and **if markets** are **going to seize up**."

Low on Cash

Facing inflation fears and high return expectations, pensions have reduced the share of assets they aim to keep in cash.

Average pension cash allocation target



Source: Boston College Center for Retirement Research

Mr. Grabel's fund in May reduced its target allocation to investment-grade bonds to 12% from 19% and increased the amount it wants to keep in private equity, infrastructure, and illiquid credit to a combined 29% from 16%. The **fund's long-term expected annual return** of **7% is** the **average for state and local government retirement funds**, according to the National Association of State Retirement Administrators.

The **$496 billion California P**ublic **E**mployees' **R**etirement **S**ystem, despite **aiming for** a slightly more conservative **6.8%, still plans** to invest more in private markets, borrow against up to 5% of the fund, and **keep less cash on hand**, to meet that target, under a plan the board approved this month.

Meanwhile, smaller pension funds serving school employees in Ohio, city workers in Illinois and other public employees across the country are putting more of their money into real estate, private equity or private debt.

Public pension funds have hundreds of billions of **dollars less on hand** than the amount they will need to cover promised benefits after two decades of underfunding, unrealistic demands from public-employee unions, and losses during the 2007-2009 financial crisis.

Over the same period, their cash-flow margins have thinned **as retirees** have **multiplied relative to** the **number** of **current workers**. In **Connecticut**, for example, more than a **quarter** of the **state workforce** are **eligible to retire between June 2020 and June 2022**, Boston Consulting Group found.

Public pension funds have historically been able to access cash when **equity** markets faltered by selling bonds. But **over** the past **two decades**, **fixed** income **portfolios shrank to 24% of assets from 33%**, according to the Boston College data, as falling rates turned bonds into a drag on returns. **Now inflation threatens** to **further erode** the **value of fixed-income investments**.

But assets that promise rapid growth – from **common stocks to complex alternative investments** – also **carry** the **risk of losses when sold into rocky markets or before maturity**. After the Pennsylvania Public School Employees' Retirement System last year decided to shrink its private equity allocation, in part to increase liquidity, consultants warned that selling assets early would mean accepting an **average discount** of **15%** of **net asset value**.

Some growth strategies can also require sudden diversions of cash in the form of capital calls and margin calls, often at inconvenient times.

When markets cratered in **2008**, some of the **biggest U.S. pension funds sold stocks** to **raise cash and fund capital calls** from private-equity firms. In the aftermath many, including CalPERS and the California State Teachers' Retirement System reviewed their allocations to alternatives.

A CalPERS spokesman said the fund has improved liquidity management since the financial crisis and as a result was able to take advantage of low prices during the market dislocation in March 2020 at the start of the Covid-19 pandemic.

CalPERS staff said at a meeting earlier this month that the fund uses a dashboard to closely monitor liquidity, which is a measure of how easily holdings can be converted to cash without losses. The retirement fund, which is the nation's largest, **eliminated** its **target** of **holding 1%** of its **assets in cash** as part of the new asset allocation approved this month, which takes effect July 1, 2022.

Finding a **strategy that can accomplish what bonds once did**, providing **yield** in **good times** and **accessible cash** in **bad**, is "**not** a problem with an **easy** solution," said Ash Williams, who recently retired as executive director and chief investment officer of the State Board of Administration, which manages investments for the Florida Retirement System.

"Everybody's wrestling with this same thing," he said.

CASE: UG 435
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 704

Confidential Data Responses in Support Of Opening Testimony

April 22, 2022

Exhibit 704

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 21-461

CASE: UG 435
WITNESS: Moya Enright

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

April 22, 2022

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

A. My name is Moya Enright. I am a Senior Economist employed in the Rates, Finance and Audit (RFA) Division of the Public Utility Commission of Oregon (OPUC or Commission). 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 this testimony?

A. First, I am responsible for the analysis of two Cost of Capital (CoC) issues, Capital Structure, and Cost of Long-Term (LT) Debt.

In addition to these subjects, my testimony will deal with the Company's proposed recovery of costs related to the Williams Pipeline Outage, Gas Inventory and Gas Storage Costs included in the filing, and Affiliate Interest transactions.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your recommendations regarding each issue.

A. I recommend adopting NWN's proposed 50 percent Common Equity – 50 Percent Long-Term (LT) Debt capital structure, and recommend a Cost of LT Debt of 4.258 percent. I recommend denying NWN's request to defer costs relating to the Williams Pipeline Outage. I do not recommend adjustments to the Company's filed gas inventory, gas storage expenses, or affiliate interest transactions.

Please note that I may revise my recommendations based on testimony filed by other participants in this rate case.

ISSUE 1. CAPITAL STRUCTURE

Q. What is your recommendation for a capital structure in this case?

A. I recommend a capital structure of 50.0 percent Common Equity and 50.0 percent LT Debt.

Q. Please explain the basis of your recommendation.

A. My recommendation is based on my analysis of actual and projected capital structure, as summarized in Exhibit Staff/802, Enright/1. This exhibit includes data provided by NWN in response to Staff DRs, data from NWN's Annual 10-K SEC filing, and data pulled from S&P Global Market Intelligence (S&P), a reliable third-party source.

My recommendation is appropriate because it reflects the Company's actual capital structure, and it is consistent with a Commission-preferred balanced "optimal debt to equity ratio," ensuring that rates are not higher than necessary.[1]

Further, my recommendation corresponds with capital structures previously authorized for the Company,[2] and NWN's request in this filing.[3]

---

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

2 A 50 percent Common Equity – 50 percent LT Debt capital structure was approved in each of the most recent NWN General Rate Cases. *See In the Matter of Northwest Natural Gas Company, dba, NW Natural, Request for a General Rate Revision*, Docket No. UG 388, Order No. 20-364 (October16, 2020); and *In the Matter of Northwest Natural Gas Company Request for a General Rate Revision*, Docket No. UG 344, Order No. 18-419 (October 26, 2018).

3 NWN/100, Anderson-Kravitz/17.

ISSUE 2. COST OF LT DEBT

Q. Please summarize your recommendation for NWN's Cost of LT Debt.

A. I recommend a Cost of LT Debt of 4.258 percent. This value represents the cost of servicing all outstanding and forecasted LT debt, as of the 2023 test year.

Q. How have you calculated NWN's Cost of LT Debt?

A. I started by compiling a comprehensive table of NWN's outstanding and forecasted LT Debt as of the 2023 test year, using independent data sources including Bloomberg, S&P, and the Company's Annual SEC 10-k filings. This table appears in Exhibit Staff/803, Enright/1.

To compile this table, I first identified the Company's outstanding debt using Bloomberg, tracking individual debt issuances using their unique CUSIP numbers.[4] I exported the details of each issuance from the database, including critical details such as coupon rates and outstanding debt amounts. I then cross-referenced the data against the Company's latest SEC filing and the records available through S&P. As a final step, the data included in the table was confirmed by NWN through discovery as being fully accurate.[5]

Using the fully comprehensive table of NWN's LT Debt as of the Test Year, I calculated the yield to maturity of each debt issuance and the Company's carrying cost of long-term debt.

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4 A CUSIP number is a nine-character alphanumeric code, which identifies financial securities. The acronym "CUSIP" is derived from the Committee on Uniform Security Identification Procedures, a committee of the American Bankers Association.

5 See Exhibit Staff/803, Enright/4, Confidential Attachment 1 to NWN's response to Staff DR 126.

Q. NWN provided a table of LT Debt in its initial filing. Why not use that?

A. Staff's approach of independently compiling a table of LT Debt is beneficial because it ensures that a clear and impartial record is created. Publicly available information can provide valuable insight and aid with the verification process. For example, the Company's SEC filing includes standardized information, in contrast to a General Rate Case for which no such standardized model exists, and some information may be missed.

Staff's thorough research ensures that when the Cost of LT Debt is calculated, it fully encapsulates the Company's debt issuances, permitting Staff and the Commission to place their full confidence in the integrity of the data therein.

Q. Did you make adjustments to the table you compiled to reflect the anticipated composition of NWN's LT debt in the 2023 test year?

A. Yes. I have made specific adjustments to NWN's current LT Debt holdings to reflect the Company's anticipated debt structure in 2023. These changes include:

- Incorporating forecasted debt issuances **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**
- Excluding the current portion of LT Debt.[6]

Q. How did you forecast interest rates for forecasted debt issuances?

---

[6] The current portion of LT Debt includes any debt maturing within one year of rate effective date, acting as a counter to the forecasted debt issuances.

A. Because there is no third-party forecast of future utility issuance costs, I forecasted the expected interest rates for future debt issuances using a synthetic forward interest rate. My calculation is shown in Exhibit Staff/803, Enright/2.

A synthetic forward interest rate is made up of the market's forecast of US Treasury (UST) interest rates, and the spread between A-Rated Utility bonds and USTs. The "spread" is the difference in borrowing costs for A-Rated utilities compared with less risky USTs.

I first surveyed forward US Treasury (UST) interest rates over a five-week period and calculated the average forecasted rate during that period. By taking this approach, I ensured that volatility within the month did not bias the forecast, as might have happened if the forecasted rate as observed on a single day was used. The second step of this process involved calculating the spread between A-Rated Utility bonds and USTs. Finally, I added the spread over UST to the forecasted UST interest rate for like maturities, resulting in the forecasted interest rate for NWN's debt issuances **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Why is Staff's approach using a synthetic forward interest rate appropriate?

A. Staff favors the approach described above because liquidity in the UST market is high. The large number of buyers and sellers of these securities increases the accuracy of the forecast. The addition of the spread adjusts the forecast to reflect borrowing costs typical of other utilities issuing first mortgage bonds with comparable credit ratings to NWN.

Q. Did you prepare a debt maturity profile for NWN?

A. Yes. Staff's debt maturity profile is presented in Exhibit Staff/803, Enright/3. This exhibit reflects NWN's outstanding LT Debt during the test year[7] and reflects the Company's forecasted issuances.

Q. What did Staff observe when preparing the debt maturity profile for NWN?

A. Staff's debt maturity profile graphic highlights **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Why is a concentration of LT Debt problematic?

A. Ideally, a Company's debt maturity profile should include an even distribution of debt maturities. By evenly distributing debt maturities, a Company reduces its exposure to refinancing risk in the future,[8] for example:

1. The risk of interest rates being higher than expected during the refinancing period,[9] forcing the Company to refinance the maturing debt at a higher-than-expected cost;

---

[7] Excluding the current portion of LT Debt, as detailed in Footnote 6.

[8] Refinancing risk refers to the possibility that an individual or company would not be able to replace a debt obligation with new debt at a critical time for the borrower.

[9] The period in which the Company has a large concentration of debt maturing

2. The risk that the Company may experience a negative market reaction to its need to refinance a large amount of debt within a short window; and
3. The risk that a short-term dip in the Company's credit rating during the refinancing period would cause an outweighed increase the Company's borrowing costs.

Q. What maturities did Staff model for the Company's proforma debt issuances?

A. Staff bases its recommended cost of LT debt on what Staff believes is a reasonable mixture of seven-, 10-, and 30-year debt to avoid **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Staff notes that in this GRC, the Commission will set the "cost" of LT Debt, but not require that the debt be issued with any specific term, and accordingly the Company will be free to issue debt as it sees fit and as opportunities arise. As 30-year term debt usually has the highest cost, it is reasonable to assume that the company may issue a LT Debt with a blend of maturities in the future, and hence Staff's recommendation represents a better estimate than the Company's **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Staff's debt maturity table, found in Exhibit Staff/803, Enright/3, compares the debt concentrations resulting from Staff's recommended approach and the Company's request, and illustrates that Staff's approach greatly reduces debt maturity concentrations **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Does Staff's LT Debt table reflect discounts or premiums, debt issuance costs, and hedging losses and gains?

A. Yes. The table fully encompasses discounts or premiums, debt issuance costs, and debt insurance costs. Staff has tied each individual cost back to the associated issuance and calculated the net proceeds of each debt issuance. The net proceeds of each debt issuance are used to calculate the Yield to Maturity of that issuance, which feeds into Staff's calculation of LT Debt carrying costs.

[BEGIN CONFIDENTIAL] [redacted].[10]

[redacted],[11] [redacted] **[END CONFIDENTIAL]**.

Q. What is Staff's summary recommendation for NWN's Cost of LT Debt?

A. Staff recommends a Cost of LT Debt of 4.258 percent. This recommendation is supported by comprehensive analysis by Staff and is therefore a value in which the Commission can place high confidence.

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10 See Exhibit Staff/802, Enright/4, Confidential Attachment 1 to NWN's response to DR 126.
11 See Exhibit Staff/802, Enright/4, Confidential Attachment 1 to NWN's response to DR 126.

ISSUE 3. WILLIAMS PIPELINE OUTAGE

Q. Please summarize this issue.

A. This issue relates to an event on December 20, 2020, in which a vehicle collided with the gate station operated by Williams Pipeline, causing significant damage to the facility. The incident resulted in approximately 5,710 customers in the central Columbia River Gorge area losing natural gas service, 4,241 or 74.3 percent of whom were in Oregon.[12]

Q. Did the Company file an application to defer costs associated with this incident?

A. Yes. The Company filed a deferral application on December 21, 2020, docketed as UM 2139, requesting to defer $569,348 on an Oregon basis ($766,559 in system costs) representing Oregon's 73.4 percent share of affected customers. The Company's deferral application has not yet been reviewed by the Commission.

Q. Please summarize the Company's proposal in this filing.

A. The Company proposes to recover $652 thousand from Oregon customers (including interest) and to amortize this amount over a one-year temporary rate through a separate Adjustment Schedule, starting November 1, 2022, on an equal percent of margin basis to all customers after the revenue requirement has been allocated in this case.[13]

Critically, the Company currently has **[BEGIN CONFIDENTIAL]**

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[12] NWN/1000, Shampine/1 and NWN/1000, Shampine/8.
[13] NWN/1300, Walker/Page 30.

[redacted] **[END CONFIDENTIAL]**.[14] The Company has indicated that if it receives insurance proceeds from the claims filed, it will credit back customers the amount of the proceeds.[15]

Q. How did Staff analyze this issue?

A. Staff's first concern was whether the incident was significant enough to warrant a deferral. Staff also reviewed the total costs incurred and reviewed itemized breakdowns of the costs and investigated the Company's efforts to recover the costs of the incident through its own and the driver's insurance.

Q. Does Staff believe that the incident was significant enough to warrant a deferral?

A. No. Commission precedent allows deferred accounts to be "used sparingly"[16] to "address costs that are hard to forecast or arise from extraordinary and unanticipated events; implement legislative mandates or unique ratemaking mechanisms; and encourage utility or customer behavior consistent with regulatory policy."[17]

When reviewing a request to defer, the Commission exercises its discretion[18] as to whether or not it should authorize the creation of the deferred account, and decision has historically been based on two interrelated factors:

---

14 Exhibit Staff/804, Enright/9-12, NWN's Confidential response to Staff DR 232.
15 NWN/1300, Walker/Page 31.
16 *In the Matter of the Staff of the Public Utility Commission Request to Open an Investigation Related to Deferred Accounting,* Docket No. UM 1147, Order 05-1070, p. 2 (Oct. 5, 2005).
17 *Id.*
18 ORS 757.259(2) provides that "the commission by order may authorize a deferral," not "must."

1. The type of event that caused the deferral, meaning the reason for the deferral, distinguishing between "risks that can be predicted to occur as part of the normal course of events, classified as stochastic risks," versus "risks that are not susceptible to prediction and quantification, classified as scenario risks,"[19] and
2. The magnitude of the event's effect, generally meaning the impact to the utility.[20]

In Order No. 04-108, the Commission explained that stochastic risks – risks that are reasonably predictable and quantifiable – are not appropriate for deferral unless the Commission finds that the magnitude of the financial impact to the utility is substantial enough to warrant deferral.[21]

Q. Is the William's Pipeline Outage a stochastic risk or a scenario risk?

A. The William's Pipeline Outage is a stochastic risk. Both the predictability and the quantifiability of the risk of damage to the Company's facilities is demonstrated by the Company having **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[22]

Q. If the William's Pipeline Outage was not a predictable and quantifiable stochastic risk, would the magnitude of the event large enough to warrant a deferral of the costs incurred by the Company?

---

19 Docket No. UM 1147, Order 05-1070, p. 3.
20 *Id.*, p. 3.
21 *Id.*, p. 2.
22 Exhibit Staff/804, Enright/9-12, NWN's Confidential response to Staff DR 232.

A. No. The Company's net operating revenue in Oregon in the 2020 calendar year was $91,087,000, resulting in an 8.56 percent Return on Equity.[23] The Company's requested Oregon deferral of $569,348 amounts to nine basis points of Return on Equity in 2020.

As detailed below in Figure 1, the Company expects to receive **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]**. In the best-case scenario, the proceeds of insurance *will more than cover* the deferrable costs of the incident, while the worst-case scenario leaves $159,669 of the requested Oregon deferral costs unrecovered ($217,533 total system), representing approximately just two basis points of Return on Equity. This is not the magnitude of an impact that might qualify for a deferral.[24]

Q. Please provide a breakdown of the Company's outstanding insurance claims.

A. The Company has pursued multiple avenues for recovering its costs through insurance:

1. The Company has **[BEGIN CONFIDENTIAL]** [redacted]

---

23 *In the Matter of Northwest Natural Gas Company, dba, NW Natural Annual Earnings Review Report*, Docket No. UG 40), NW Natural ROO filed April 30, 2021.

24 *See e.g., In the Matter of Portland General Electric Company Application for the Deferral of Storm-Related Restoration Costs*, Docket No. UM 1817), Order No. 19-274, p. 10 (Commission finding the financial impact of 36 basis points ($8 million) of PGE's ROE is neither substantial nor material and is thus insufficient to warrant deferral for either a stochastic or scenario event).

[redacted] [BEGIN CONFIDENTIAL].[25]

2. The Company [BEGIN CONFIDENTIAL] [redacted] [BEGIN CONFIDENTIAL].[26]

3. [BEGIN CONFIDENTIAL] [redacted] [BEGIN CONFIDENTIAL].[27]

Staff has summarized the costs incurred by the Company, and its insurance coverage in Confidential Figure 1 below.

[BEGIN CONFIDENTIAL]

[25] Exhibit Staff/804, Enright/9-12, NWN's Confidential response to Staff DR 232.
[26] Exhibit Staff/804, Enright/9-12, NWN's Confidential response to Staff DR 232.
[27] Exhibit Staff/804, Enright/9-12, NWN's Confidential response to Staff DR 232.

Confidential Figure 1 – Amounts Recoverable from Insurance[28]

[redacted]

[END CONFIDENTIAL]

Q. Please summarize Staff's position on the William's Pipeline outage.

A. Staff finds that the William's Pipeline Outage is not appropriate for a deferral because it does not satisfy the Commission's discretionary criteria for deferral. The event was reasonably predictable and quantifiable, demonstrated by **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]**. The impact of such an event must be substantial to meet the Commission's criteria. The total amount at issue in the deferral request is equal to eight bp of NWN's authorized ROE, and the amount at issue after it is offset with the Company's guaranteed insurance proceeds is equal to two of authorized ROE. Both amounts fall considerably short of what is required by the Commission to trigger a deferral. For these reasons, Staff recommends the Commission address NWN's request to defer the Williams Pipeline Outage costs in this docket and deny the

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28 Exhibit Staff/804, Enright/9-12, NWN's Confidential response to Staff DR 232.

request.

In the event the Commission is inclined to grant the deferral, Staff recommends the Commission delay addressing the amortization of the deferral until after the Company's insurance claim has been resolved. Although the Company has promised to credit the proceeds of its insurance claims back to customers,[29] adopting such an approach would remove the Company's incentive to push for a larger reimbursement of its costs from its insurer.

[29] NWN/1300, Walker/Page 31.

ISSUE 4. GAS INVENTORY

Q. Please describe the gas inventory issue.

A. Gas inventory or storage gas consists of two components, “cushion gas” and “working gas inventory.” Cushion gas is permanently retained in storage to maintain operational pressure and prevent water deterioration in an underground storage reservoir. Cushion gas levels remain constant unless there a major expansion is completed. Working gas is the gas that flows in and out of a storage reservoir, or Liquid Natural Gas (LNG) tank, to serve customer loads, and changes every month based on injections and withdrawals.

Q. Please summarize NWN’s and Staff’s proposed rate treatment of NWN’s stored gas costs.

A. NWN included a total of $38,198,000[30] in Oregon allocated stored gas in the Test Year rate base, of which $20,205,697 is “cushion gas” and $17,992,094 is “working gas.”[31]

Staff supports including the cost of working gas and cushion gas inventory in rate base and recommends adjusting the amount included in the Test Year as proposed by NWN.

Q. Please summarize the Commission’s historical treatment of gas storage in rate base.

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30 NWN/Exhibit 1312, Walker/1.
31 NWN workpaper “UG 435 - Exh. 1312 - WP2 - Other Rate Base Items”, tab “Cushion Gas”.

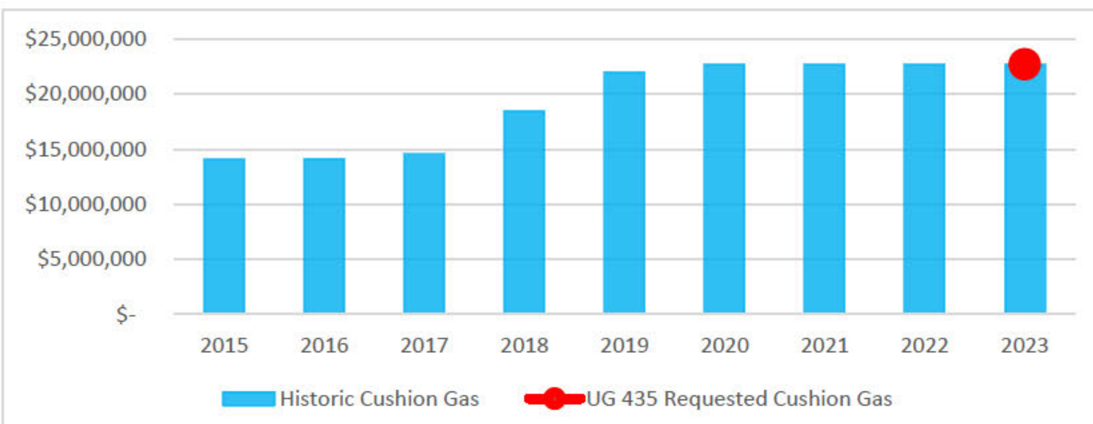
A. All three regulated gas utilities serving in Oregon currently include stored gas costs in rate base due to stipulations reached by the parties and adopted by the Commission.[32]

Q. Please explain how Staff analyzed cushion gas costs in rate base.

A. Staff expects cushion gas volumes to remain constant unless there is a major expansion of storage. Typically, the value of cushion gas value is based on its cost when injected into the facility and should change very little in the absence of expansions.

The proposed dollar value of cushion gas included in the filing and the historic value of the Company's cushion gas is summarized in Figure 2.

Figure 2 - $ Value of Historic vs Requested Cushion Gas



Staff is satisfied that the $20,205,697 of cushion gas included in the filing is appropriate, given that it is consistent with the cushion gas held in the most recent history.[33]

[32] See e.g., *In the Matter of Northwest Natural Gas Company, dba NW Natural, Recovery of Carrying Costs on Working Gas Inventory*, Docket No. UM 1651, Order No. 13-349, p. 5 (September 30, 2013)(Commission adopting stipulation including Northwest Natural Gas Company's working gas inventory in rate base).

[33] Docket No. UG 388, Staff/300, Fjeldheim/3.

Q. Please explain how Staff analyzed working gas costs in rate base.

A. Staff analyzed historic data provided by the Company in response to Staff DRs and in the Company's supporting work papers.[34] Staff learned that the Company used the model "Sendout" to predict its gas prices and storage volumes by month for each storage asset. The requested $17,992,094 in working gas represents Oregon's share of the 13-month average of monthly averages (AMA) of the predicted inventory value in the test year.[35]

Consistent with previous practice in recent filings, Staff calculated the dollar amount for the working gas inventory in rate base using the most recent full calendar year, the 13-month AMA, a three-year calendar annual moving average, a three-year AMA average, and a six-year calendar average (2016 – September 2021). The proposed dollar value of working gas included in the filing, and the historic value of the Company's working gas is summarized in Figure 3.

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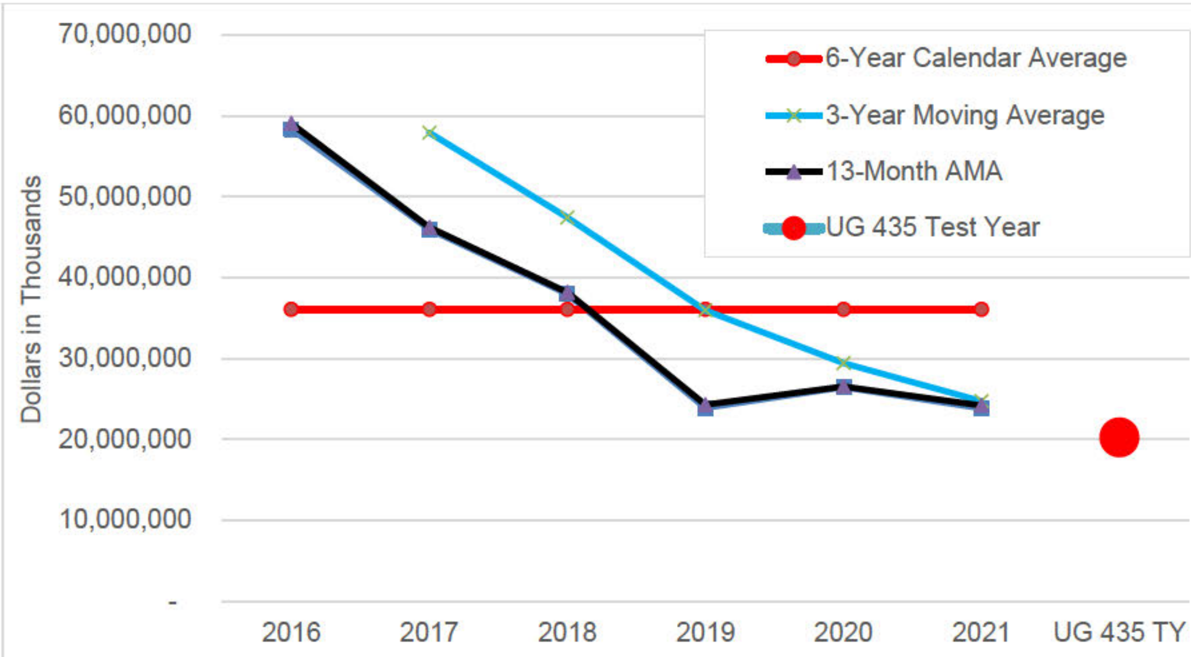
[34] NWN workpaper Walker's filed work paper "UG 435 - Exh. 1312 - WP2 - Other Rate Base Items" and Staff/804, Enright/13-14, Confidential Attachment 1 to NWN's response to AWEC DR 14.

[35] Exhibit Staff/804, Enright/13-14, Confidential Attachment 1 to NWN's response to AWEC DR 14.

Figure 3 - $ Value of Historic vs Requested Working Gas[36]



Q. Is the expense of purchased gas included in the filing?

A. No. Purchased gas costs are included in the total revenue calculation for presentation only. A direct and equal offset is included within the gas costs section, removing the costs from base rates. All purchased gas costs flow through the Company's Purchased Gas Adjustment (PGA).[37]

Q. Does Staff propose an adjustment to the Company's gas inventory?

A. No. Staff proposes no adjustments on this issue.

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36 Values presented on a total system basis. 2021 "annual average" value includes data through end of September 2021.

37 Exhibit Staff/804, Enright/5, NWN's response to Staff DR 207.

ISSUE 5. GAS STORAGE OPERATING EXPENSE

Q. What is "gas storage operating expense"?

A. NWN's gas storage operating expenses of the Company's underground and LNG storage facilities. The storage facilities allow NWN to store lower summer-priced natural gas to be used in the winter during high demand or peak day events. Like transportation, unneeded gas storage capacity can be optimized by selling into a future higher priced market.

NWN records gas storage operating expenses in Federal Energy Regulatory Commission (FERC) Accounts 816 through 847, as detailed in the Company's filing.[38]

Q. Please summarize NW Natural's proposal related to "gas storage operating expense."

A. NWN is proposing to include $6,636,754 of gas storage operating expenses in the Test Year on an Oregon basis ($7,459,697 total system basis). The Company's forecasts for gas storage expenses were developed using Base Year expenses. Non-payroll expenses were escalated into the Test Year by the proposed Consumer price Index (CPI) rate, while payroll expenses have the same payroll assumptions applied (i.e., pay increase, benefits, etc.) as all other areas of the Company.[39]

Q. Please summarize the Commission's historical treatment of "gas storage operating expense."

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[38] NW Natural/1201, Davilla/Page 1. A full description of 18 C.F.R. FERC Gas Accounts can be accessed here: www.ecfr.gov/current/title-18/part-201.

[39] Exhibit Staff/804, Enright/6-7, NWN's response to Staff DR 210.

A. Staff was unable to identify an order whereby the Commission specifically addresses its policy regarding the proper amount of "gas storage operating expense" to include in rate base.

Q. Please explain how Staff analyzed the Company's gas storage operating costs.

A. Staff analyzed historic data provided by the Company in response to Staff DRs and in the Company's supporting work papers.[40] Staff reviewed the Company's historic gas storage operating costs and calculated both a six-year calendar average and three-year moving average of historic costs. The proposed dollar value of gas storage costs included in the filing, and the Company's historic gas storage costs are summarized in Confidential Figure 4.

Confidential Figure 4 – $ Value of Historic vs Requested Gas Storage Costs

[redacted]

[40] Exhibit Staff/804, Enright/1-2, Attachment 1 to NWN's response to Staff DR 143, and Exhibit Staff/804, Enright/6-8, Confidential Attachment 1 to NWN's response to Staff DR 210.

Q. Does Staff propose an adjustment to the Company's gas inventory?

A. No. Staff proposes no adjustments related to this issue.

ISSUE 6. AFFILIATE INTEREST CHARGES

Q. Please explain the Commission's historical treatment of cost allocation among affiliates.

A. The Commission's historical treatment of cost allocation among affiliates is pursuant to OAR 860-027-0048 (Allocation of Costs by an Energy Utility), which addresses the allocation of costs between an energy utility and its affiliates, outlining how transactions should be recorded. OAR 860-027-0048 also states that an energy utility must keep a current Cost Allocation Manual (CAM), with detailed methodology on how costs are allocated between affiliates on file with the Commission. The rule also requires that the Allocation Manual shall be "filed yearly as an appendix to the Affiliated Interest Report required under OAR 860-027-0100."[41]

Q. How, generally, does NWN allocate costs among its affiliates?

A. According to NWN's CAM, "the approach to allocating costs is to directly assign costs when applicable and to allocate costs based on the primary cost driver of the common cost, or relevant proxy, and to ensure that unauthorized subsidization of unregulated activities by regulated activities, and vice versa, does not occur." The CAM also states that "goods or services provided by the utility to an affiliate are provided at the higher of cost or market price," which is in accordance with OAR 860-277-0048.

Typical affiliated transactions that occur between NWN and its affiliates include:

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[41] OAR 860-027-0048(6).

- Direct charges of NWN's payroll and administrative expense for affiliate use of NWN's staff;
- Payments between NWN and affiliates for tax expense or benefit;
- Annual allocation of indirect charges per the CAM;
- Direct charges for office space used by NWN's non-regulated affiliates;
- Vendor payments made by NWN on behalf of affiliates; and
- Equity distributions/contributions and dividends between NWN and affiliates.[42]

Q. Please summarize Staff's analysis of the Company's affiliate interest charges.

A. Staff requested transactional level detail to review cost allocation between the Company and its affiliates and non-regulated entities. Staff reviewed the Company's 2020 affiliated interest report,[43] including its MSA and CAM as well as transactions between NWN and its affiliates. NWN did not propose any changes to its CAM in this filing.

Staff's review focused on ensuring allocation factors are calculated and applied correctly and in adherence with cost allocation principles outlined in NARUC's cost allocation manual and referenced above.

Q. Does Staff propose an adjustment relating to this issue?

A. No. Staff proposes no adjustments related to this issue.

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42 Staff/804, Enright/3-4, Confidential Attachment 1 to NWN's response to Staff DR 199.

43 The Company's 2021 Affiliated Interest Report and Cost Allocation Manual is expected to be filed in Docket No. RG 8 on or around April 30, 2022. See Exhibit Staff/804, Enright/3, NWN's response to Staff DR 199.

Q. Does that conclude your testimony?

A. Yes.

CASE: UG 435
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualifications Statement

April 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME:	Moya Enright
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Certified Energy Risk Professional, 2021. Global Association of Risk Professionals. M.Sc. Political Science, 2015. University of Amsterdam. M.Sc. Investment, Treasury and Banking, 2011. Dublin City University. B.A. International Business and Languages, 2008. Dublin City University through a joint curriculum with École Supérieure de Commerce de Montpellier.
EXPERIENCE:	Senior Utility and Energy Analyst at OPUC since January 2019. Energy Trader for Meridian Energy from 2015 to 2019. Meridian Energy is a power generator and retailer operating both in New Zealand and Australia. Trading and Operations Analyst at Tynagh Energy from 2011 to 2013. Tynagh Energy is an independent power producer operating in the Republic of Ireland. Senior Electricity Market Controller at EirGrid from 2008 to 2011. EirGrid is the Irish electricity Transmission System Operator. It operates the Single Electricity Market for the Republic of Ireland and Northern Ireland. Accounts Assistant roles from 2004 to 2008, including Audit Intern at KPMG in Northern Ireland.

CASE: UG 435
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Exhibits in Support
Of Opening Testimony

April 22, 2022

CONFIDENTIAL

[redacted]

CAPITAL STRUCTURE
Staff Proposes:

50% LT Debt
50% Equity

S&P Capital IQ PRO

Northwest Natural Holding Company | Capital Structure Summary
NYSE:NWN (MI KEY: 4057132; SPCIQ KEY: 292047)

[redacted]

[redacted]

Confidential Staff Exhibit

**“Confidential
Attachment A to DR 38”**

is filed in electronic format.

Staff Exhibit

“Attachments 1 - 4 to DR 442”

is filed in electronic format.

CASE: UG 435
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 803

Exhibits in Support
Of Opening Testimony

April 22, 2022

Table of Long-Term Debt
(Staff Compiled)
CONFIDENTIAL

[redacted]

CONFIDENTIAL

Interest Rate Forecast For
2022 and 2023 LT Debt Issuances
CONFIDENTIAL

[redacted]

[redacted]

Confidential Staff Exhibit

**“Confidential
Attachment 1 to DR 126”**

is filed in electronic format.

CASE: UG 435
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 804

Exhibits in Support
Of Opening Testimony

April 22, 2022

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 143

143. Please provide the underlying data for the Utility Employee Base Pay (Wages and Salaries) (Oregon Allocated FTEs) Table 1 cited in NW Natural/800/Rogers page 5. Please provide all data in electronic workbook format with all cell formulae and references intact.

Response:

See UG 435 OPUC DR 143 Attachment 1, excel tab SDR 92 Summary, excel cells U14:U17 for the data that matches Table 1. UG 435 OPUC DR 143 Attachment 1 can be used to trace back to the underlying data.

Staff Exhibit

“Attachment 1 to DR 143”

is filed in electronic format.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 199

Regarding the Company's confidential Affiliated Interest Report and Cost Allocation Manual:
a. Please provide a copy of the confidential 2020 Affiliated Interest Report and Cost Allocation Manual.
b. Please provide a copy of the confidential 2021 Affiliated Interest Report and Cost Allocation Manual as soon as practicable.

Response:

a. A copy of the confidential 2020 Affiliated Interest Report and Cost Allocation Manual, and its confidentially filed exhibits are included at **Confidential UG 435 OPUC DR 199 Attachments 1-3** which was filed on April 29, 2021, under RG 8.

b. The 2021 Affiliated Interest Report and Cost Allocation Manual is expected to be prepared and filed under RG 8 on or around April 30, 2022.

Confidential Staff Exhibit

**“Confidential
Attachment 1 to DR 199”**

is filed in electronic format.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 207

With regard to gas supply expenses:
a. Please indicate whether gas supply expenses are included in the Test Year. "gas supply expenses" includes any of the items listed under section (c) of this DR.

b. If yes to section (a), please provide a narrative explanation of how the expenses are forecasted for the test year, providing copies of all underlying data used in the forecast in electronic workbook format, and providing references to where the forecast appears in the Company's workpapers.

c. If yes to section (a), please provide, in a single electronic spreadsheet format, for each calendar year from 2011 through 2020, and monthly through 2021, the Company's gas supply expenses, as well as a breakdown of the expenses into:
i. purchased gas expenses,
ii. other gas purchases,
iii. natural gas storage transactions,
iv. gas used for products extraction,
v. other gas expenses.

In response to section (c), please separately identify any related labor expense and provide results separately for total company and for Oregon.

Please provide only those categories included in the Company's filing in this response (excluding categories which flow through the PGA).

Response:

a. Gas supply expenses are included within the revenue requirement for presentation only. A direct and equal offset is included within the gas costs section. Therefore, gas supply expenses are not being recovered in this case.

b. n/a

c. n/a

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 210

With regard to gas storage expenses:
a. Please indicate whether gas storage expenses are included in the Test Year. Please provide a separate response for each of the following gas storage expense types:
i. Underground gas storage,
ii. LNG gas storage, and
iii. Other gas storage.
b. If yes to section (a), please provide a narrative explanation of how gas storage expenses are forecasted for the test year, providing copies of all underlying data used in the forecast in electronic workbook format, and providing references to where the forecast appears in the Company's workpapers. Please provide a separate response for each of the gas storage expense types listed under section (a).
c. If yes to section (a), please provide, in a single electronic spreadsheet format, for each calendar year from 2011 through 2020, and monthly through 2021, the Company's gas storage expenses. Please provide a separate response for each of the gas storage expense types listed under section (a), as well as a breakdown of the expenses into:
i. supervision and engineering,
ii. fuel,
iii. other equipment, and
iv. other expenses.

In response to section (c), please separately identify any related labor expense and provide results separately for total company and for Oregon.

Please provide only those categories included in the Company's filing in this response (excluding categories which flow through the PGA).

Response:

a. Yes, gas storage expenses are included within the Test Year.
   i. Underground gas storage activities are recorded to FERC O&M account 816 through 834.
   ii. LNG gas storage activities are recorded to FERC O&M account 844 through 847.
   iii. Other gas storage activities are recorded to FERC O&M account 840.

b. Yes, gas storage expenses are forecasted for the Test Year and these amounts are calculated in the O&M model submitted in “UG 435 OPUC DR 143 Attachment 1.xlsx”. The total amounts included in the Test Year can be found in the Exhibit – O&M worksheet in cell E112. The underground gas storage expenses can be found in cell E21, LNG gas storage expenses in cell E35, and other storage expenses in cell E26. The non-payroll forecasts for the Test Year were developed by taking the Base Year expenses and escalating them into the Test Year by using the proposed Consumer price Index (CPI) rate, which is calculated in the “Under the “Dept Non-Payroll Forecast” worksheet.

   Similar to non-payroll, all payroll expense is calculated in the O&M model submitted in “UG 435 OPUC DR 143 Attachment 1.xlsx” and it is getting the same payroll assumptions applied (i.e. pay increase, benefits, etc.) as all other areas of the Company. Further detail is discussed in Melinda B. Rogers’ testimony Exhibit 800.

c. Please see “Confidential UG 435 OPUC DR 210 Attachment 1.xlsx”.

Confidential Staff Exhibit

**“Confidential
Attachment 1 to DR 210”**

is filed in electronic format.

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 232

NW Natural/1300, Walker/Page 31, lines 8 – 15, which provides some information on insurance claims to recover the cost of the incident.

a. Please provide a narrative explanation of the process by which the Company issued insurance claims, including detail of how liability for, and the value of, damage is determined.

b. Please provide a list of all related insurance claims in electronic workbook format. For each claim, also include the following detail:

i. Name of party (individual and/or Company) against which the claim was filed,

ii. Value of the claim in US dollars,

iii. For each insurance policy being claimed against, the coverage limit in US dollars for the policy for the specific item being claimed,

iv. In any case where the coverage limit for the policy for the specific item being claimed is lower than the value of the claim, please indicate whether further compensation will be sought from the liable party, outside of the insurance policy.

v. Underlying issue / asset / other,

vi. Status of the claim, e.g. open, pending, closed,

vii. An estimate of the date on which the claim is expected to be finalized, and

c. Please provide a narrative explanation of how employee and/or attorney time spent on insurance claims related to this incident is accounted for in this filing.

Confidential Response:

[redacted]

[redacted]

[redacted]

[redacted]

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 AWEC DR 14

14. Reference "UG 435 - Exh. 1312 - WP2 - Other Rate Base Items", Tab "Cushion Gas", Cell "F130": Please provide workpapers supporting the hardcoded value of $20,227,200 in the referenced cell.

Response:

Cell "F130" in the referenced work paper addresses working gas. Please see Confidential UG 435 AWEC Attachment 1 for the Test Year 13-Month AMA working gas amount of $20,227,200 (cell "U47" on the "Oct21 Storage Summary" tab). The attached includes output from Sendout which predicts gas prices and storage volumes by month for each storage asset.

Confidential Staff Exhibit

"Confidential Attachment 1 to AWEC DR 14"

is filed in electronic format.

CASE: UG 435
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

April 22, 2022

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

A. My name is Bret Farrell. I am a Utility and Energy Analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/901

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address Northwest Natural's (NWN) test year expense for Operations and Maintenance (O&M) Expense (Non-Labor), Administrative and General (A&G) Expense (Non-Labor), and Maintenance of General Plant. I recommend the following adjustments:

- O&M – ($415,623)
- A&G – ($745,499)

Q. Do the findings and recommendations in your testimony represent Staff's final determinations in this case?

A. No. Staff's findings and recommendations are subject to change after review of other parties' testimony.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. OPERATIONS AND MAINTENANCE EXPENSE (NON-LABOR)

Q. What is the Company's proposed Test Year expense for distribution operations and maintenance?

A. NWN is proposing to increase non-labor operations and maintenance expenses from $14.7 million in the Base Year to $18.1 million in the Test Year. This represents an increase of more than $3.4 million, or 23 percent.[1] The Company testified that it determined its Test Year expense by, "escalat[ing] general non-payroll costs using year-over-year rates of change in the forecast of the West Region Urban CPI as reported in the December 2021 Oregon Economic and Revenue Forecast, published by the OEA[,]" and applying the factors on January 1, 2022 and January 1, 2023.[2]

The Company also identified several items where the growth projection was greater or lesser than using CPI and adjusted these items with their specific increase or decrease. Adjustments made to the Base Year non-labor operations and maintenance expenses are comprised of the following four distinct adjustments:

- **Escalation: $882,593**
- **COVID-19 Normalization: $40,367**
- **FERC 874, Contracted Locating Services: $806,467**
- **FERC 874, Contracted Survey Services: $1,647,827**

1 Exhibit Staff/902, Farrell/1, NWN Response to Staff Data Request No. 143.

2 NWN/1200, Davilla/3.

Q. Please describe your review and analysis of NWN's O&M expenses.

A. My analysis focuses on non-labor O&M expense, except for O&M expense for FERC Account 874, Contracted Locating Services and Contracted Survey Services. These expense items are addressed by Heather Cohen.[3] Further, other Staff reviewed certain cost categories within the O&M accounts that are commonly adjusted in a general rate case. These include memberships, dues, donations, meals, entertainment, gifts, airfare, lodging, travel, and awards. Their conclusions and recommendations regarding their analyses can be found in their testimony.

For my analysis, I examined historical trends, transactional detail, and NWN's proposed escalation adjustment.[4] Staff first reviewed the non-labor distribution O&M expenses for the years of 2014 through 2021.[5] This review included looking at trends, historical transactional details, and the response to Staff DR 201 provided by NWN.[6] Staff initially looked at the annual increase in non-labor distribution O&M expenses for the past eight years to determine whether the proposed increase in the test year is consistent with historical increases. Staff also reviewed transaction details from the base year and preceding two years to ensure expenditures are justifiable for normal utility operations.

3 See Staff/600, Cohen.
4 Exhibit Staff/902, Farrell/1, NWN Response to Staff Data Request No. 143.
5 Exhibit Staff/903, Farrell/1, Staff Adjustment Workpaper.
6 Exhibit Staff/902, Farrell/3, NWN Response to Staff Data Request No. 201.

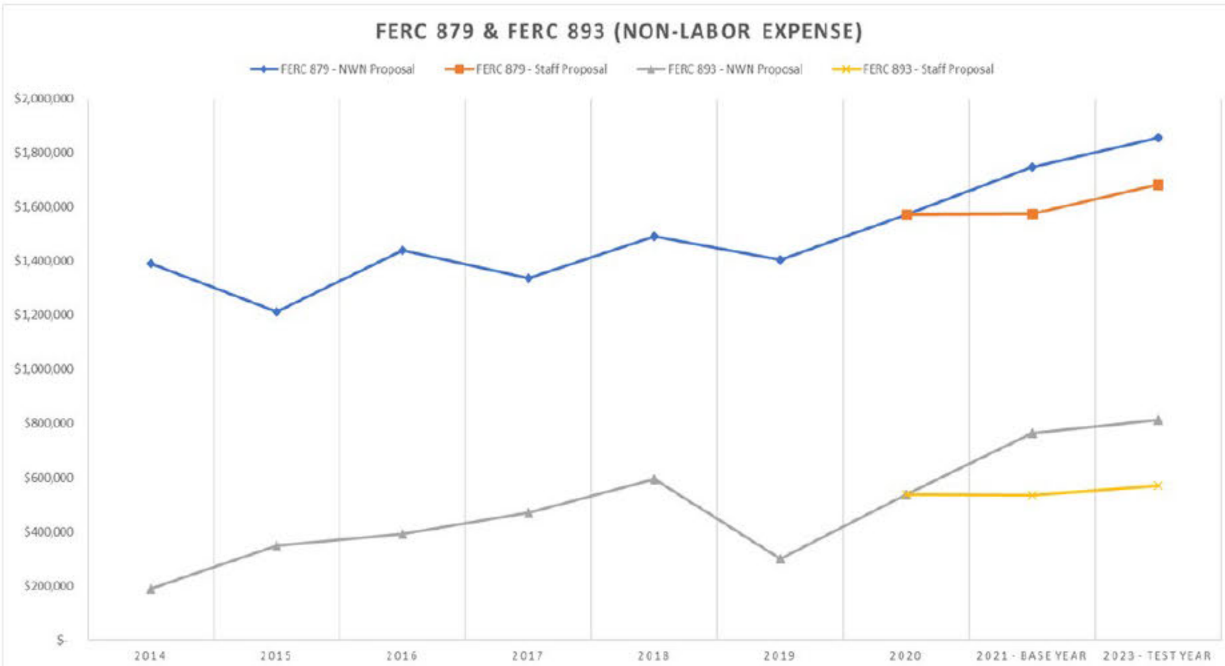
Staff first reviewed the non-labor distribution O&M expenses for the years of 2014 through 2021.[7] This review included looking at trends, historical transactional details, and the response to Staff DR 201 provided by NWN.[8] Staff initially looked at the annual increase in non-labor distribution O&M expenses for the past eight years to determine whether the proposed increase in the test year is consistent with historical increases. Staff also reviewed transaction details from the base year and preceding two years to ensure expenditures are justifiable for normal utility operations.

Q. What does Staff conclude from its review?

A. Based on its review, Staff finds the proposed Test Year expense for FERC Account 879 (Customer Installation Expenses) and 893 (Meters & House Regulators) to be unreasonably high. Accordingly, Staff proposes an adjustment reducing the Test Year expense for by $415,623. To arrive at this adjustment, Staff averaged the expense of the Base Year 2021 and the two preceding years and scaled up to the Test Year using the All-Urban CPI, as published by the State of Oregon Office of Economic Analysis (OEA) in their March 2022 forecast (4.2 for 2022, 2.2 for 2023).[9] Chart 1 shows NWN's proposal alongside Staff's recommended adjustment.

7 Exhibit Staff/903, Farrell/1, Staff Adjustment Workpaper.
8 Exhibit Staff/902, Farrell/3, NWN Response to Staff Data Request No. 201.
10 Exhibit Staff/903, Farrell/1, Staff Adjustment Workpaper.

Chart 1



In looking at the percentage change in non-labor expense from 2020 to the Base Year 2021, Staff notes that FERC Account 879 and FERC Account 893 saw non-labor expense increase 11.2 percent and 42.4 percent, respectively.[10] In contrast, the All-Urban CPI that Staff generally uses to escalate costs for purposes of ratemaking only increased by 4.7 percent over that period.

Q. Does NWN state the cause of the increase in expense?

A. Yes, in response to Staff DR 404, the Company stated the following reason for the increase in FERC Account 879: "The non-labor expense for FERC Account 879 increased from 2019 to 2021 due to an increase in vehicle equipment charges. The vehicle equipment charges follow the payroll of the employees

10 Exhibit Staff/903, Farrell/1, Staff Adjustment Workpaper.

using the vehicles and the increase is in line with the 18% increase in the respective payroll."[11]

In response to Staff DR 405, the company provided the following explanation for the increase in non-labor expense for FERC Account 893:

> The non-labor expense increase for FERC account 893 from 2019 to 2021 is due to Meter Shop temporary testing, hauling, and testing and ERT (encoder receiver transmitter) recycling needed to replace an increased number of meters that are outside performance standards. Please refer to further discussion of the replaced meters at the Company's response to UG 435 OPUC Confidential DR 301.[12]

Q. Why does Staff propose this adjustment?

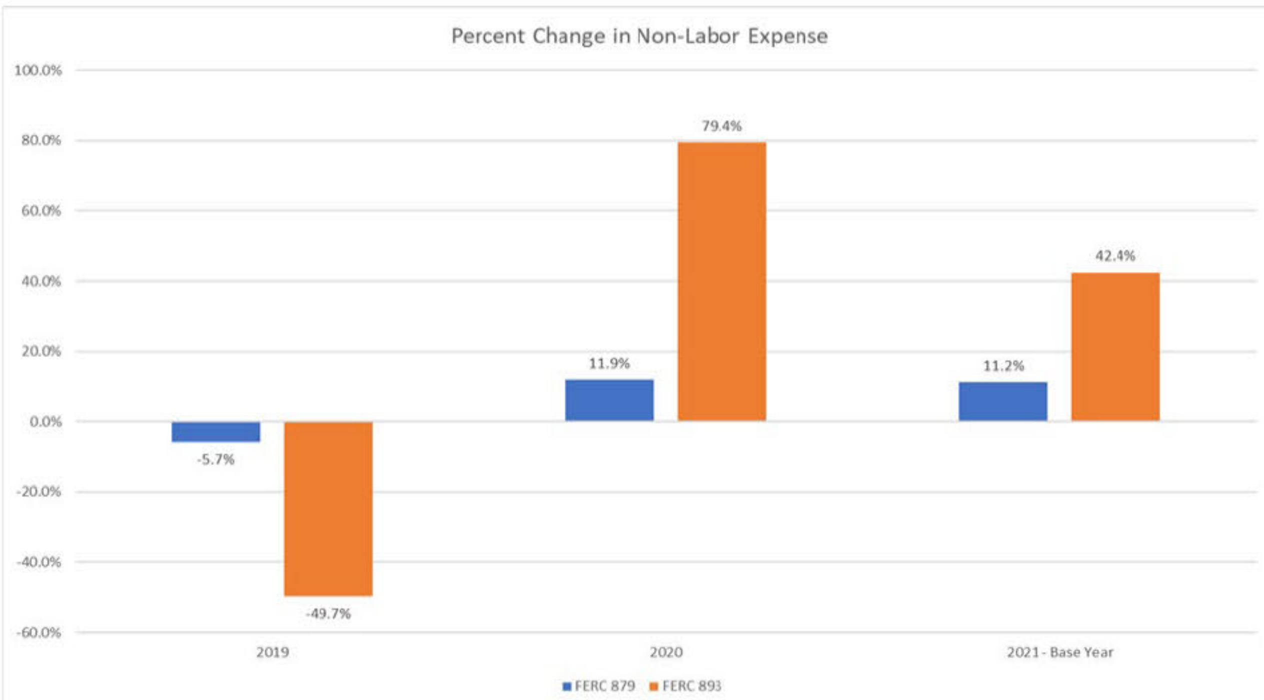
A. Staff believes that the increase in expense for the cost elements identified by NWN in DR 404 and DR 405 deviate significantly from the historic expense trend, and therefore represent an artificially high starting point to determine reasonable expense for the Test Year. Staff examines historical expense data to identify typical year-over-year growth for cost elements and compare historically typical changes in expense to that of the change in expense leading into the base year. It is not unreasonable to assume that a utility may experience outsized increases in expense in certain years due to unanticipated or infrequent costs, such as those costs identified by NWN in DR 404 and 405. Here however, Staff believes it is unrealistic to assume the outsized increase in the costs at issue are representative of a base level of costs. Accordingly, Staff believes it is necessary to use a three-year average as a means of

[11] Exhibit Staff/902, Farrell/5, NWN Response to Staff Data Request No. 404.
[12] Exhibit Staff/902, Farrell/6, NWN Response to Staff Data Request No. 405.

"smoothing-out" these steep increases in expense. Using a three-year average normalizes the Base Year expense and provides a more reasonable starting point from which to escalate the costs for the Test Year.

Chart 2 shows the year-over-year percentage increase in FERC Account 879 and FERC Account 893 non-labor expense since 2019.[13]

Chart 2



Q. What are the escalation rates used in the Company's filing?

A. NWN's proposed escalation adjustment uses the West Region CPI estimate as reported in the December 2021 Oregon Economic and Revenue Forecast (3.9 percent for 2022 and 2.4 percent for 2023).[14]

Q. What does Staff recommend for an escalation factor?

13 Exhibit Staff/903, Farrell/901, Staff Adjustment Workpaper.
14 Exhibit Staff/902, Farrell/1, NWN Response to Staff Data Request No. 143.

A. It is Staff policy[15] to use the Consumer Price Index – All Urban Consumers for the U.S. (CPI, Urban U.S.) as published by the State of Oregon Office of Economic Analysis (OEA) for year over year escalation. As noted above, Staff used the All-Urban CPI to escalate Staff's modified Base Year expense for Customer Installation Expenses and Meters & House Regulators to a recommended level of Test Year expense. However, as the escalation factors used by the Company filing are somewhat less than the latest published index for the All-Urban CPI, Staff does not propose an adjustment to Test Year expense for FERC Accounts 870-878, 880-892, 894 based on escalation.

Q. What is your recommendation?

A. Staff recommends an adjustment of ($415,623) to Test Year non-labor O&M expense in order to normalize the test year expense for FERC Accounts 879 and 893.

[15] In the Matter of Northwest Natural Gas Company, dba, NW Natural, Docket No. UG 132, Order No. 99-697, page 9 (November 12, 1999).

ISSUE 2. ADMIN AND GENERAL EXPENSE (NON-LABOR)

Q. Please describe the expenses included in this issue.

A. The Company uses discrete internal "Cost Element" codes to book a range of administrative and general (A&G) expenses. Non-Labor A&G expenses are recorded in FERC Accounts 921 – 922, 928, 930, 931.

Q. What A&G FERC accounts did NWN include in its Test Year?

A. NWN included A&G FERC Accounts 921, 924-926, 930-931, and 935 in their Test Year expense. I reviewed non-labor expenses in FERC Accounts 921-922, 930, 931, and 935. My analysis of FERC Account 935 is separately analyzed in my *Issue 3. Maintenance of General Plant*. Other Staff reviewed certain cost categories within these A&G accounts that are commonly adjusted in a general rate case. These include advertising, promotions, memberships, dues, donations, meals, entertainment, gifts, airfare, lodging, travel, and awards. Their conclusions and recommendations regarding their analyses can be found in their testimony.

Q. Please provide a summary of the Company's filed proposal for this issue.

A. NWN is proposing to increase non-labor administrative and general expenses from $37.6 million in the Base Year to $54.8 million in the Test Year. This represents an increase of $17.2 million, or 46 percent.[16] The Company in its filing states that:

> The Company escalated general non-payroll costs using year-over-year rates of change in the forecast of the West

[16] Exhibit Staff/902, Farrell/1, NWN Response to Staff Data Request No. 143.

> Region Urban CPI as reported in the December 2021 Oregon Economic and Revenue Forecast, published by the OEA. These escalation factors were applied on January 1, 2022, and January 1, 2023. The Company also identified several items where the growth projection was greater or lesser than using CPI and adjusted these items with their specific increase or decrease.[17]

Adjustments made to the Base Year non-labor administrative and general expenses are comprised of the following five distinct adjustments:

- **Escalation: $2,224,902**
- **COVID-19 Normalization: $617,218**
- **FERC Account 921, Information Technology & Services: $13,984,293**
- **FERC Account 921, OR Rate Case Legal Fees Rate Adjustment: ($88, 257)**
- **FERC Account 931, 250 Taylor Lease Exp.: $621,223**

My analysis focuses on historical A&G expense trends, transactional detail, and NWN's proposed escalation adjustment to non-labor A&G expense. Other Staff reviewed the remaining adjustments, and their conclusions and recommendations regarding their analyses can be found in their testimony.

Q. Please describe your review and analysis of NWN's A&G expenses.

A. Staff reviewed the non-labor components of FERC Accounts 921 (Office Supplies and Expenses), 922 (Administrative expenses transferred credit), 928 (Regulatory commission expenses), 930 (Miscellaneous general

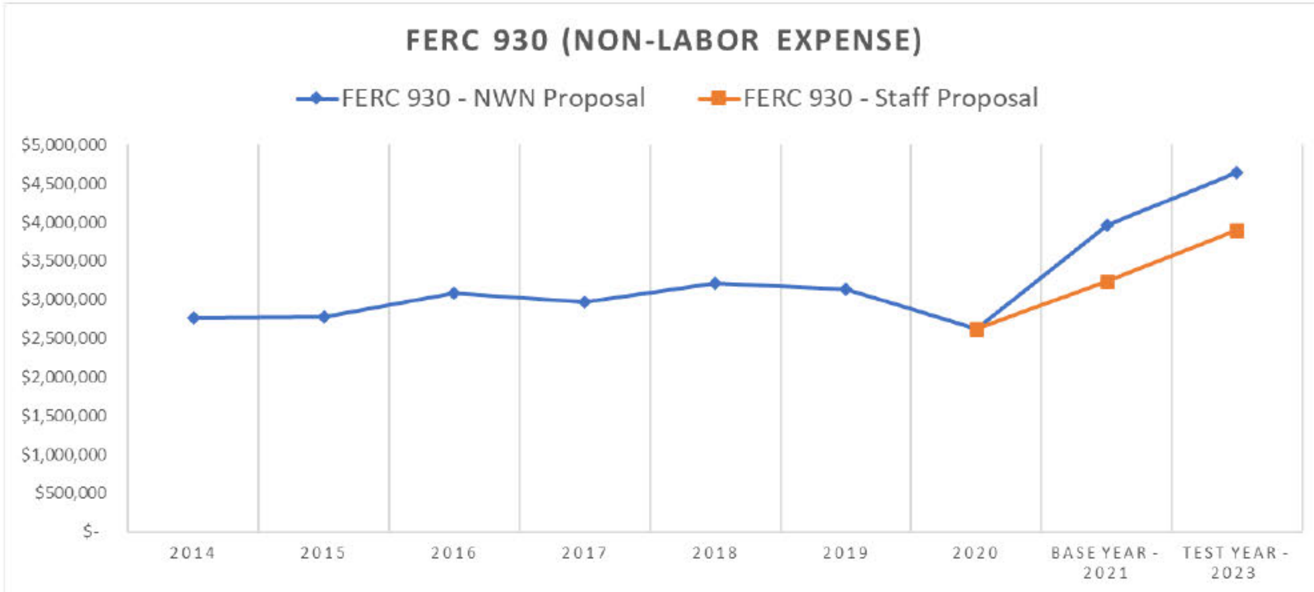
[17] NWN/1200, Davilla/Page 3.

expenses), and 931 (Rents) for reasonableness. This review included looking at trends, transactional details, and the NWN work paper provided in response to Staff DR 201.[18] Staff initially looked at the annual increase in non-labor A&G expenses for the past eight years to determine whether the proposed increase in the test year is consistent with historical increases. Staff also reviewed transactional details from the base year and two preceding years to ensure expenditures are justifiable for normal utility operations.

Q. What does Staff conclude from its review?

A. Based on its review, Staff finds the proposed Test Year expense for FERC Account 930 (Miscellaneous General Expenses) to be unreasonably high. Accordingly, Staff proposes an adjustment reducing the Test Year expense by $745,499. To arrive at this adjustment, Staff averaged the expense of the Base Year 2021 and the two preceding years and escalated to the Test Year using the All-Urban CPI, as published by the State of Oregon Office of Economic Analysis (OEA) in their March 2022 forecast (4.2 percent for 2022 and 2.2 percent for 2023). The following chart shows NWN's proposal alongside Staff's recommended adjustment.[19]

[18] Exhibit Staff/902, Farrell/3, NWN Response to Staff Data Request No. 201.
[19] Exhibit Staff/903, Farrell/1, Staff Adjustment Workpaper.



In looking at the seven years preceding the Base Year, Staff notes that non-labor expenses for FERC Account 930 remained relatively stable with an annual average percent change of -0.4 percent. From 2020 to the Base Year 2021, however, non-labor expense for FERC Account 930 increased 51 percent.[20] In contrast, the Consumer Price Index that Staff generally uses to escalate to Test Year costs, only increased by 4.7 percent over that period.

Q. Does NW Natural state the cause of the increase in expense?

A. Yes, in response to Staff DR 408, the Company stated that the three main causes of the increase were as follows:

1. The Company's recording of COVID-19 cost savings of $729 thousand. In accordance with UM 2068, the Company calculated and recorded cost savings related to COVID-19 against the COVID-19 deferral to reduce the deferral. As the cost savings represent costs that were not actually

[20] Exhibit Staff/903, Farrell/1, Staff Adjustment Workpaper.

incurred, the Company selected to record these to FERC Account 930.2 General Miscellaneous Expenses.

2. Research and development (R&D) spending increased $250 thousand due to increased investments.

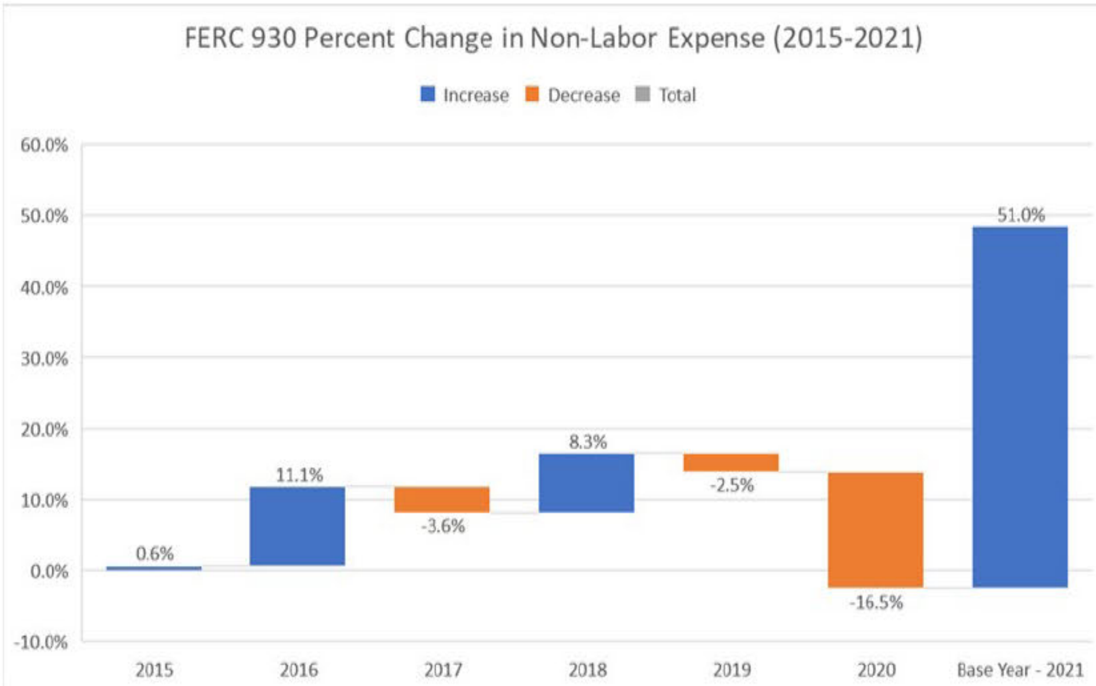
3. Director's fees increased $230 thousand due to the addition of two Board Directors in 2020.[21]

Q. Why does Staff propose this adjustment?

A. Staff believes that the increase in expense for the cost elements identified by NWN in DR 408 deviate significantly from the historic expense trend, and therefore represent an artificially high starting point to determine reasonable expense for the Test Year. As previously noted in my testimony, Staff examines historical expense data to identify typical year-over-year growth for cost elements and compare historically typical changes in expense to that of the change in expense leading into the base year. It is not unreasonable to assume that a utility may experience outsized increases in expense in certain years due to unanticipated or infrequent costs, such as those costs identified by NWN in its response to Staff DR 408. In these instances, however, Staff believes it is necessary to use a three-year average as a means of "smoothing-out" these steep increases in expense. Using a three-year average normalizes the Base Year expense and provides a more reasonable starting point from which to escalate the costs for the Test Year.

[21] Exhibit Staff/902, Farrell/7, NWN Response to Staff Data Request No. 408.

The following chart shows the year-over-year percentage increase in FERC 930 non-labor expense since 2015.[22]



Q. What are the escalation rates used for non-labor A&G expense?

A. As previously noted, NWN's proposed escalation adjustment uses the West Region CPI estimate as reported in the December 2021 Oregon Economic and Revenue Forecast (3.9 percent for 2022 and 2.4 percent for 2023).[23]

Q. What does Staff recommend for an escalation factor?

A. It is Staff policy[24] to use the Consumer Price Index – All-Urban Consumers for the U.S. (CPI, Urban U.S.) as published by the State of Oregon Office of Economic Analysis for year over year escalation. However, as the escalation factors used in the Company's filing are somewhat less than the

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22 Exhibit Staff/903, Farrell/1, Staff Adjustment Workpaper.
23 Exhibit Staff/902, Farrell/1, NWN Response to Staff Data Request No. 143.
24 *Northwest Natural*, Order No. 99-697, page 9.

latest published index, Staff does not propose an adjustment for FERC Accounts 921 – 922, 928, and 931 based on escalation, other than as noted above.

Q. What does Staff recommend?

A. Staff recommends an adjustment of $745,499 to Test Year non-labor A&G expense to normalize the Test Year expense for FERC Account 930.

ISSUE 3. MAINTENANCE OF GENERAL PLANT

Q. What is the Company's proposal for non-labor maintenance of general plant expense?

A. NWN is proposing to increase non-labor maintenance of general plant expense from $2.7 million in the base year to $2.9 million in the Test Year. This represents an increase of roughly $200,000, or 6.1 percent.[25] The Company in its filing states that:

> The Company escalated general non-payroll costs using year-over-year rates of change in the forecast of the West Region Urban CPI as reported in the December 2021 Oregon Economic and Revenue Forecast, published by the OEA. These escalation factors were applied on January 1, 2022, and January 1, 2023. The Company also identified several items where the growth projection was greater or lesser than using CPI and adjusted these items with their specific increase or decrease.[26]

Adjustments made to the base year non-labor maintenance of general plant expense are comprised of the following two distinct adjustments:

- **Escalation: $159,468**
- **COVID-19 Normalization: $5,618**

My analysis focuses on historical maintenance of general plant expense trends, transactional detail, and NWN's proposed escalation adjustment to non-labor maintenance of general plant expense. Other Staff reviewed the remaining adjustments, and their conclusions and recommendations regarding their analyses can be found in their testimony.

[25] Exhibit Staff/902, Farrell/1, NWN Response to Staff Data Request No. 143.
[26] NWN/1200, Davilla/Page 3.

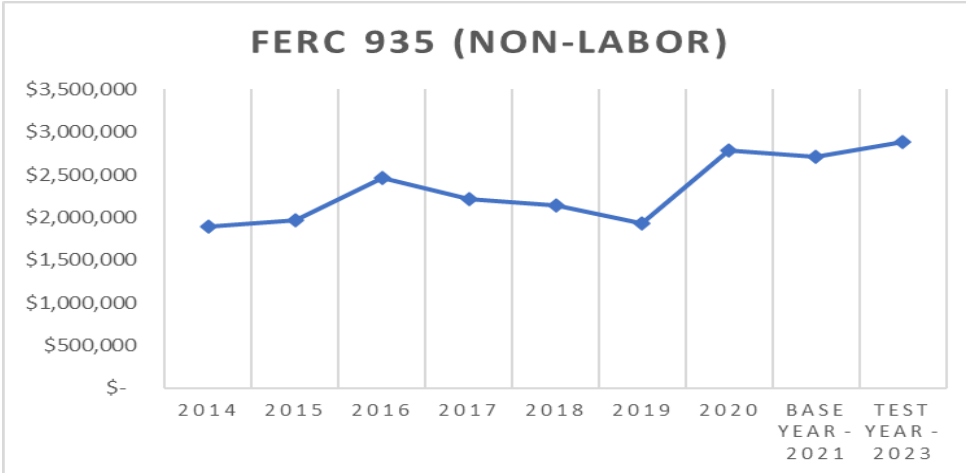
Q. Please describe your review and analysis of NWN's Maintenance of General Plant expenses.

A. Staff first reviewed the non-labor maintenance of general plant expenses for the historical base years of 2014 through 2021.[27] This review included looking at trends, historical transactional details, and the work paper provided by NWN in its response to Staff DR 201.[28] Staff initially looked at the annual increase in maintenance of general plant expenses for the past eight years to determine whether the proposed increase in the test year is consistent with historical increases. Staff also reviewed transaction details from the base year expense and preceding two years to ensure expenditures are justifiable for normal utility operations.

Q. What does Staff conclude from its review?

A. Upon review of historical non-labor maintenance of general plant expense data, Staff notes that FERC Account 935 averaged 6.8 percent annual growth since 2014. The following chart shows the historic trend of maintenance of general plant expense.

27 Exhibit Staff/903, Farrell/1, Staff Adjustment Workpaper.
28 Exhibit Staff/902, Farrell/3, NWN Response to Staff Data Request No. 201.



Staff finds that the overall trend of non-labor maintenance of general plant expense to be historically in line with the appropriate all-Urban CPI growth rate, and therefore the base year 2021 does not represent an artificially high starting point with which to escalate expense.

Q. What is your recommendation?

A. Staff recommends no adjustment to non-labor maintenance of general plant Test Year expense.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 435
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualification Statement

April 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME:	Bret Farrell
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Strategy Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	BA Economics, Illinois State University, Normal, IL MS Applied Economics, Illinois State University, Normal, IL
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since April 2019. I initially began work at the Commission in the Universal Service and Regulatory Analysis Division and later transitioned to the Strategy Integration Division upon its inception. My work prior to the Commission included working as a graduate research assistant at Illinois State University's Institute for Corruption Studies.

CASE: UG 435
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support of Opening Testimony

April 22, 2022

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 143

143. Please provide the underlying data for the Utility Employee Base Pay (Wages and Salaries) (Oregon Allocated FTEs) Table 1 cited in NW Natural/800/Rogers page 5. Please provide all data in electronic workbook format with all cell formulae and references intact.

Response:

See UG 435 OPUC DR 143 Attachment 1, excel tab SDR 92 Summary, excel cells U14:U17 for the data that matches Table 1. UG 435 OPUC DR 143 Attachment 1 can be used to trace back to the underlying data.

OPUC DR 143 Attachment 1 is provided in Electronic Format

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 201

Please refresh the file UG 388 DR 282 CONF Attachment 1.xlsx with data for the current case in the same format and level of detail.
a. To the extent not included in the file above, please provide all work papers underlying the base year forecast O&M adjustment in the file UG 435 - Exh. 1300 - WP1 - Revenue Requirements Model.xlsx, Base Year Adjustments.
b. To the extent not included in the responses above, please provide an analysis, by FERC account, of the difference between the base year and test year O&M as presented in Exhibit 1307. Please disaggregate the analysis to clearly show increases in the specific categories discussed on Davilla, 1200/3-4, specifically,
i. O&M payroll costs
ii. O&M non-payroll costs
iii. O&M other cost adjustments
iv. Amounts inflated using the West Region Urban CPI
v. Other O&M adjustments calculated specifically for the test year.
vi. Base year payroll cost adjustments through the test year.

Response:

a. See UG 435 OPUC DR 143 Attachment 1 for like file to UG 388 DR 282 CONF Attachment 1. The $19.511M O&M adjustment from the Base Year to the Test Year can be calculated by taking the OR Test Year amount found in the O&M TY FERC Allocation Summary tab cell AC139 less the OR Base Year amount found in the O&M BY FERC Allocation Summ tab cell AN 139.

b. See UG 435 OPUC DR 201 Attachment 1 for a table that disaggregates the $19.511M O&M adjustment by FERC account.

OPUC DR 201 Attachment 1 is provided in Electronic Format

NW Natural

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 404

404. Please:
a. Explain why non-labor expense for FERC account 879 increased 24.4% from 2019-2021.
b. Justify these expenses providing an explanation on how they benefit the Oregon ratepayer.

Response:

a. The non-labor expense for FERC 879 increased from 2019 to 2021 due to an increase in vehicle equipment charges. The vehicle equipment charges follow the payroll of the employees using the vehicles and the increase is in line with the 18% increase in the respective payroll.

b. The vehicle equipment charges are part of the total customer installation expenses of FERC 879 for work on customer premises and, thus, benefit our customers.

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 405

405. Please:
a. Explain why non-labor expense for FERC account 893 increased 155.5% from 2019-2021.
b. Justify these expenses providing an explanation on how they benefit the Oregon ratepayer.

Response:

a. The non-labor expense increase for FERC account 893 from 2019 to 2021 is due to Meter Shop temporary testing, hauling, and testing and ERT (encoder receiver transmitter) recycling needed to replace an increased number of meters that are outside performance standards. Please refer to further discussion of the replaced meters at the Company's response to UG 435 OPUC Confidential DR 301.

b. These costs are incurred to ensure customer meters are at the appropriate performance standards. These processes promote accuracy and consistency across all of the customers, thus benefitting them.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 408

408. Please:
a. Explain why non-labor expense for FERC account 930 increased 26.13% from 2019-2021.
b. Justify these expenses providing an explanation on how they benefit the Oregon ratepayer.

Response:

a. The non-labor expenses for FERC account 930 increased from 2019-2021 due primarily to the Company's recording of COVID-19 cost savings of $729 thousand. In accordance with UM 2068, the Company calculated and recorded cost savings related to COVID-19 against the COVID-19 deferral to reduce the deferral. As the cost savings represent costs that were not actually incurred, the Company selected to record these to FERC 930.2 General Miscellaneous Expenses.

   Research and development (R&D) spend increased $250 thousand due to increased investments.

   Directors fees increased $230 thousand due to the addition of two Board Directors in 2020 as previously described in UG 388 NW Natural/900/Davilla/Page 15.

b. The COVID-19 cost savings reduce the incremental COVID-19 costs being deferred and, therefore, benefit our customers.

   R&D spend has proven to be an important initiative that benefits our customers and the general public by supporting the safe and efficient delivery and utilization of natural gas by contribution to operational efficiency and safety improvements in designing, construction, inspecting, maintaining and repairing utility assets, as well as the safe and efficient utilization of natural gas in end-use applications.

   NW Natural customers will benefit through the identification, development and implementation of operational products, systems, procedures, and services that improve the safety, extend the life, reduce the cost, and protect the natural gas distribution system. They will also benefit from the development of improved natural gas end-use technology that is safe, more efficient, more reliable, and more effectively meets the specific customer's needs. Investments made include continued improvements to the efficiency of condensing furnaces, testing of combination solar/thermal water heating, and supporting commercialization of industrial super boilers.

CASE: UG 435
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 903

Work paper showing adjustment calculations for O&M and A&G

April 22, 2022

Staff work paper showing adjustment calculations for O&M and A&G is filed in electronic format.

CASE: UG 435
WITNESS: Julie Jent

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1000

Opening Testimony

April 22, 2022

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

A. My name is Julie Jent. I am a Utility Analyst employed in the Telecom/Universal Services and Regulatory Analysis Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Did you prepare any exhibits?

A. Yes. My witness qualification statement, which details my educational background and work experience can be found in Exhibit Staff/1001. My non-confidential supporting documents and excel spreadsheets can be found in Exhibit Staff/1002 and my confidential supporting documents and excel spreadsheets can be found in Exhibit Staff/1003.

Q. What is the purpose of your testimony?

A. I discuss my review of several categories of Northwest Natural Gas Company's (NWN, NW Natural or Company) Test Year expense, including expenses for advertising, promotional activities and concessions, current medical, other insurance, and Directors and Officers (D&O) Insurance.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Staff's recommendations are as follows: Issue 1 (Advertising Expenses) – a total adjustment to the Oregon allocated total of $(1,000,063); Issue 2 (Promotional Activity and Concessions) – no adjustment for FERC 913; Issue 3 (Current Medical and Health Insurance) – no adjustment; Issue 4 (Insurance (Non-Medical) and Risk (Non-Medical)) – no adjustment; Issue 5 (D&O Insurance) – a total adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIDIAL]**. Please note that my recommendations may change after reviewing testimony and analysis by other parties.

ISSUE 1. ADVERTISING EXPENSES

Q. Does the Commission have a standard means of determining how advertising and promotional expenses are treated?

A. Yes, it does. OAR 860-026-0022 sets out how advertising expenses should be addressed in a rate case. This rule defines advertising expenses as, "expenses for communications which inform, influence, and/or educate customers."[1] A key difference between an "advertising expense" and a "promotional activity" is that advertising expenses are specifically described as communicating a message to customers and chargeable to FERC Account 909, while promotional activities are meant to promote the utility's product to a wider audience and chargeable to FERC Accounts 911, 912, 913 or 916.[2] Utility advertising expenses are grouped into five categories:

Category "A" – Energy efficiency or conservation advertising expenses that do not relate to a Commission approved program, utility service advertising expenses, and utility information advertising expenses;

Category "B" – Legally mandated advertising expenses;

Category "C" – Institutional advertising expenses, promotional advertising expenses and any other advertising expenses not fitting into Category "A," "B," or "D";

Category "D" – Political advertising expenses and non-utility; and

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1 OAR 860-026-0022 (1)(a).
2 OAR 860-026-0010.

Category “E” – Energy efficiency or conservation advertising expenses that related to a Commission-approved program.[3]

OAR 860-026-0022(3) specifies that for ratemaking purposes:

- Category "A" expenses are presumed to be just and reasonable to the extent that expenses are twelve and one-half hundredths of 1 percent (0.125 percent) or less of the gross retail operating revenues determined in the rate proceeding.
- Category "B" expenses are presumed to be just and reasonable.
- Category “C” expenses can be included in rates, but the utility shall carry the burden of showing that any advertising expenses in this category are just and reasonable.
- Category "D" expenses are presumed to be not just and reasonable.
- Category "E" expenses may be capitalized and are subject to a prudence review.

Q. How did Staff perform its analysis of NW Natural’s proposed advertising expenses?

A. Staff reviewed transactional accounting detail for the expenses included in Category A and B for which the Company is seeking recovery in rates. NW Natural stated that although they have budgeted $600,000 for Category C expense during the Test Year, they have not included these in rates.[4] NW Natural reports they are not requesting recovery Category C expenses and

[3] OAR 860-026-0022(2).
[4] Staff/1002, NWN Response to SDR 104.

did not book expenses for Category D or E expenses for 2019-2021.[5] Staff also reviewed data submitted regarding advertising expenses for other companies and read through the budget rationale detailed in the full testimony submitted by NW Natural.

Q. Please provide a summary of NW Natural's Test Year expense for advertising.

A. The Test Year Oregon allocated total was $2,900,950[6], a five percent increase from the Base Year, which is 2021.[7] However, the increase from 2020 to 2021 was 32 percent.[8]

FIGURE 1: FERC ACCOUNT 909 CHANGE OVER TIME

	System	Oregon	% Change OR
2016	$2,066,898	$1,818,870	
2017	$2,835,510	$2,495,249	37%
2018	$2,693,434	$2,370,222	-5%
2019	$2,917,936	$2,575,082	9%
2020	$2,360,120	$2,082,809	-19%
2021	$3,125,635	$2,758,377	32%
Test Year	$3,287,191	$2,900,950	5%

Q. Were there discrepancies in the accounting data NW Natural provided to Staff for FERC Account 909?

A. Yes. Figure 2 demonstrates that while the discrepancies for the Base Year (2021) are due to updated figures that were submitted more recently in

5 Staff/1002, NWN Response to DR 152.
6 Staff/1002, NWN Response to Staff SDR 58(a) Attachment 1 (electronic spreadsheet).
7 Staff/1002, NWN Response to Staff DR 153 Attachment 1 (electronic spreadsheet).
8 Staff/1002, See Staff electronic work paper UG 435 Exhibit 1002 Non-Confidential Figures for an excel page dedicated to each figure with the sources listed and calculations intact.

NWN Response to DR 153 Attachment 1, the other years' discrepancies in the Oregon allocated columns have no identified justification.

FIGURE 2: DISCREPANCIES IN FERC ACCOUNT 909

	2019		2020		2021	
	System	*Oregon*	*System*	*Oregon*	*System*	*Oregon*
SDR 58 Attach. 1	$2,917,936	$2,585,875	$2,360,120	$2,087,058	$3,658,205	$3,228,370
DR 153 Attach. 1	$2,917,936	$2,575,082	$2,360,120	$2,082,809	$3,125,635	$2,758,377

Q. Were there discrepancies in the number of customers as reported by NWN?

A. Yes. NWN response to DR 273 Attachment 1 listed the operating revenue and number of customers from 2015 to the Test Year for NW Natural alongside that of PGE and PacifiCorp. NWN Response to DR 424 listed just the Oregon customer counts for those same years. In theory, these should provide the same customer totals for each year. Staff believes the latter number submitted in DR 424 is an over-count of the number of customers.[9]

FIGURE 3: DISCREPANCIES IN CUSTOMER TOTALS

	2015	2016	2017	2018	2019	2020	Test Year
DR 273 Attach. 1	631,852	640,508	650,402	659,959	669,564	679,693	709,107
DR 424	637,402	645,883	656,031	665,771	675,380	684,153	715,573

Q. How do the Company's advertising expenses compare to historical trends when categorized under the OAR 860-026-0022 categories mentioned above?

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[9] Staff/1002, NWN Response to DR 273 Attachment 1 (electronic spreadsheet) and NWN Response to DR 424

A. The percent change from 2020 to 2021, the Base Year, is nearly twice that of the percentage change from 2019 to 2020 for the two categories of advertising that NW Natural is including in revenue requirements: Categories A and B.

FIGURE 4: CHANGES IN TOTAL SYSTEM ADVERTISING CATEGORIES

	Category A			Category B		
	System	*Oregon*	*% Change OR*	*System*	*Oregon*	*% Change OR*
2019	$1,860,595	$1,641,975		$985,426	$869,639	
2020	$1,622,701	$1,432,034	-13%	$717,341	$633,053	-27%
2021	$2,037,460	$1,798,058	26%	$1,068,711	$943,137	49%
Test Year	$2,093,000	$1,847,073	3%	$1,224,000	$1,080,180	15%

Q. How do the numbers above compare with the formula in OAR 860-026-0022 for Category A allowed expenses for Oregon specifically?

A. See Figure 5. The Test Year request for Oregon allocated is $1,847,073[10] (equivalent of $2.60 per customer[11]), nearly double what the gross retail revenue-based formula allows for, $1,019,914 ($1.44 per customer).

FIGURE 5: TEST YEAR FORMULA VS. REQUEST TOTALS FOR CATEGORY A

	NWN	Formula			Request		
	Operating Revenues	*CAT A Oregon Allocation Formula (0.125%)*	*Customers*	*CAT A Per Customer*	*CAT A Oregon Allocated (Requested)*	*Customers*	*CAT A Per Customer*
Test Year	$815,931,184	$1,019,914	709,107	$1.44	$1,847,073	709,107	$2.60

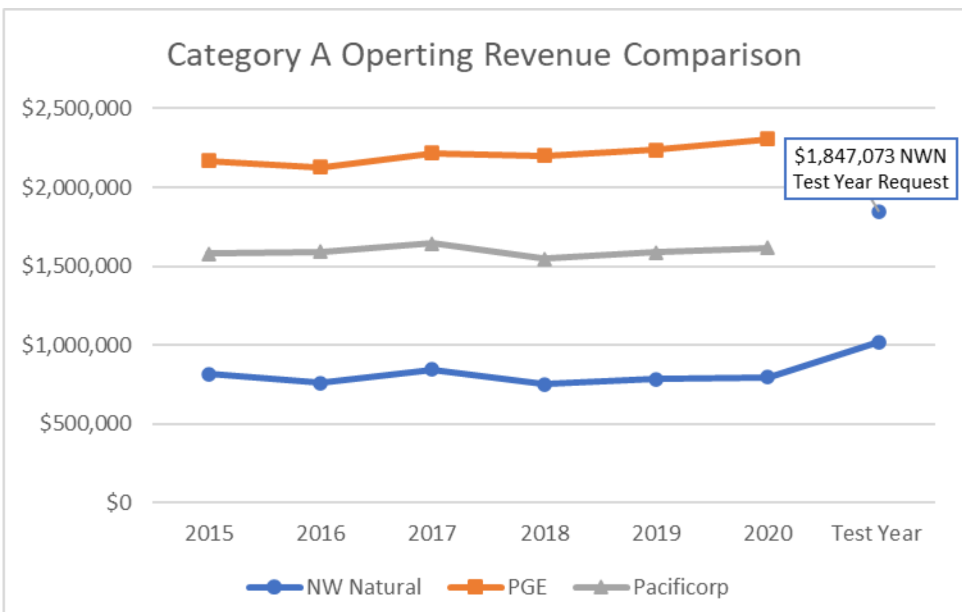
Q. How does NW Natural's Category A advertising expenses compare to that of PGE and PacifiCorp?

10 Staff/1002, NWN Response to DR 248 Attachment 1 (electronic spreadsheet) and NWN Response to DR 274 Attachment 1 (electronic spreadsheet).

11 NW Natural/900 Beck/3-4.

A. The amount NWN is requesting for the Test Year is $1,847,073 ($2.60 per customer). This is on par with 2020 formula amounts for PGE of $2,307,603 ($2.56 per customer) and that of PacifiCorp $1,617,139 ($2.68 per customer).[12] However, NW Natural's 2020 operating revenue was only 35 percent of PGE's and 49 percent of PacifiCorp's. This dramatic increase is demonstrated in Figure 6 where the solid lines demonstrate the formula based operating revenue for Category A expenses.[13]

FIGURE 6: CATEGORY A EXPENSE PER CUSTOMER COMPARISON BASED ON 0.125% OF OPERATING REVENUE



Q. Please explain NW Natural's budget for their Renewable Natural Gas Advertising Program, referred to as the "Less We Can" Project.

12 Staff/1002, NWN Response to DR 273 Attachment 1 (electronic spreadsheet) and NWN Response to DR 422.

13 Staff/1002, NWN Response to DR 273 Attachment 1 (electronic spreadsheet).

A. NW Natural spent approximately $399,784 in the Base Year on environmental advertising associated with the “Less We Can” project, which is 22 percent of total Category A advertising expenses for 2021 on an Oregon allocated basis.[14]

Q. Please explain if and how Staff reclassified any of the Category A Expenses.

A. Staff’s assessment indicates that about $190,320[15] of advertising expense that NWN has classified as Category A “utility information advertising expense” is misclassified because the expense is properly classified as Category C “institutional advertising expense” or “promotional advertising expense.” Under OAR 860-026-0022(1)(g) utility information advertising expenses “means advertising expenses, the primary purpose of which is to increase customer understanding utility systems and the function of those systems, and to discuss generation and transmission methods, utility expenses, rate structures, rate increases, load forecasting, environmental considerations, and other contemporary items of customer interest[.]” In contrast, institutional advertising expenses are for advertising, “the primary purpose of which is not to convey information, but to enhance the credibility, reputation, character, or image of an entity or institution.” And, promotional

[14] Staff/1002, NWN Response to DR 254 Attachment 5 (electronic spreadsheet); For an explanation of the connection between the RNG program and the purposes of advertising expenses expressed in Commission rules, please see NW Natural/900, Beck/3, Lines 5-7, Beck/ 6, Lines 16-21, Beck/13, Line 13, and Beck/16, Line 2.

[15] Staff/1002, NWN Response to DR 155 Attachments 1 (electronic spreadsheet), 3 (MP4 format), and 4 (MP4 format).

advertising expenses are those for which the primary purpose is to communicate with respect to an energy or large telecommunications utility's promotional activities or promotional concessions.

Q. What is Staff's assessment of NW Natural's proposed adjustment for Category A expenses?

A. Staff concludes that advertising expenses for NW Natural's Renewable Natural Gas program, should be reclassified from Category A to Category C expense. These expenses are for two different television ads and are $124,221[16] and $66,099[17] respectively. The Test Year expense budget for Category A is listed as $1,847,073. Staff recommends removing these classifications, scaled by the Urban CPI ($202,676), which brings the Test Year budget for Oregon allocated down to $1,644,397.[18] Staff then recommends adjusting further to the amount that is presumed reasonable under OAR 860-026-0022(3), which is 0.125 percent of operating revenue. This results in a total adjustment of $(827,159) and a Test Year expense of $1,019,914 for Category A Advertising.

Q. Why does Staff propose to disallow the portion of NW Natural's Category A expense that exceeds what is presumed reasonable under OAR 860-026-0022(3)?

16 Listed as document number 1012339867 in NWN Response to DR 155 Attachment 1.
17 Listed as document number 1012449135 in NWN Response to DR 155 Attachment 1.
18 Staff/1002, See Staff electronic work paper UG 435 Exhibit 1002 Adjustments Escalated (electronic spreadsheet).

A. As noted above, NW Natural's spending on Category A expenses is on par with much larger utilities. NW Natural must be mindful of the impact of this spending on customer rates. NW Natural has not justified the steep increase to its Category A expenses or the need for advertising that exceeds what is presumed reasonable under OAR 860-026-022.

Q. Regarding the Category B advertising expenses, what is the standard for reviewing these expenses in a rate case?

A. A utility's expense for Category B is presumed to be just and reasonable.

Q. What is Staff's assessment of NW Natural's proposed adjustment for Category B expenses?

A. For ease of discussion, I display Category B's recent history of advertising costs that was provided earlier.

	Category A			Category B		
	System	*Oregon*	*% Change OR*	*System*	*Oregon*	*% Change OR*
2019	$1,860,595	$1,641,975		$985,426	$869,639	
2020	$1,622,701	$1,432,034	-13%	$717,341	$633,053	-27%
2021	$2,037,460	$1,798,058	26%	$1,068,711	$943,137	49%
Test Year	$2,093,000	$1,847,073	3%	$1,224,000	$1,080,180	15%

Staff notes that from 2019 to the Test Year, Category B advertising has increased from $869,639 to $1,080,180, or an increase of 24 percent. Alternatively, the average of the 2019 to 2021 Category B advertising is $815,276. Assuming that is a 2020 "value", escalating to 2023 yields a value of $907,276.[19]

[19] Staff/1002, See Staff electronic work paper UG 435 Exhibit 1002 Adjustments Escalated (electronic spreadsheet).

In testimony, NWN states that the primary source of new Category B expenses since NW Natural's 2020 general rate revision is focused on damage prevention, emergency preparedness awareness and education and that this advertising is primarily done through their contract with Culver Company.[20]

Staff finds their expenses with this vendor were stable in 2019 and 2020 but increased by more than 50 percent in the Base Year.[21] There is no evidence to support the reasonableness of this steep increase in expenses. Accordingly, Staff believes the presumption of reasonableness in OAR 860-026-022(3) is overcome. Staff believes determination of Test Year expense should take into account amounts spent for Category B advertising in the years before and after the Base Year to smooth out the anomalous increase in the Base Year. As noted above, this modification results in Test Year expense of $907,276. Accordingly, Staff recommends an adjustment of $(172,904) to NW Natural's proposed Test Year expense of $1,080,180.[22]

Q. What is the total adjustment to advertising?

A. Staff recommends adjusting overall advertising expenses downward by $1,000,063.

[20] NW Natural/900 Beck/18-19
[21] Staff/1002, NWN Response to DR 152 Attachments 1-3 (electronic spreadsheets).
[22] Staff/1002, NWN Response to DR 274 Attachment 1 (electronic spreadsheet).

ISSUE 2. PROMOTIONAL ACTIVITY 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]ction by an energy or large telecommunications utility or its affiliate with the objective of increasing or preventing a decrease in the quantity of the energy or large telecommunications utility's service used by present and prospective customers; inducing any person to use an energy utility's service rather than a competing form of energy[.]

OAR 860-026-0015 defines promotional concession as:

> [A]ny consideration offered or granted by an energy or large telecommunications utility or its affiliates to any person with the object, express or implied, of inducing such person to select or use the service or additional service of such utility, or to select or install any appliance of equipment designed to use such utility service.

Examples of promotional concessions include rebates, provision of free goods or services, or providing financing for a natural gas appliance at a lower-than-market interest rate. [23] Utilities are required to file a description of all promotional concession expenses with the Commission before making them.[24] 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.[25]

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[23] OAR 860-026-0015(2).
[24] OAR 860-026-0025(1).
[25] 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.[26]

Q. Has the Company filed its proposed promotional concessions report with the Commission?

A. Yes. The Company filed a report in Docket No. RG 31 on November 30, 2021. [27] In the filing, the Company reported a plan to spend up to $3,302,897 on promotional concessions in 2022. The RG 31 filing for the previous year, 2021, stated that "All campaign costs will be accounted for below-the-line, in FERC Accounts 912 or 913, in accordance with OAR 860-026-0010".[28] In addition, they filed transactional accounting data for FERC Accounts 911-913 for 2021.

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[26] OAR 860-026-0020.

[27] Staff/1002, NW Natural's Report of 2021 Promotional Concession Campaigns and NW Natural's Report of 2022 Promotional Concession Campaigns

[28] This statement was not included in the Report for 2022.

Q. Has the Company included any promotional concessions and activities in the base year?

A. Staff is not aware that NWN has included the cost of promotional concessions in the Test Year. NW Natural has included promotional activities expense, however. Promotional expenses were not allocated to just one FERC account. Follow-up data request responses by NWN indicated that they had $402,596 worth of actual expenses for the promotional activities in 2021 charged to FERC Accounts 908, 910, and 912. [29] Expenditures for promotional activities and concessions included in the Test Year for Oregon totaled $527,056. [30] These accounts are detailed and adjusted for in Staff/600/Cohen.

Q. Has the Company included any promotional concessions and activities for the Test Year in FERC Account 913?

A. No. The total in FERC Account 913 for promotional concessions and activities for the Base Year was $453,005, the largest purchase in the Base Year in Account 913 was for the Street of Dreams, $75,454.[31] There was no amount included in FERC Account 913 for the Test Year.[32]

Q. What are Staff's findings regarding promotional activities and concessions specifically charged to FERC 913?

A. Staff finds that no adjustment is needed for this Account for the Test Year.

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29 Staff/1002, NWN Response to DR 421.
30 Staff/1002, NWN Response to DR 433.
31 Staff/1002, NWN Response to SDR 57 Attachment 1 (electronic spreadsheet); This expense is further described in Staff/1002 NWN Response to DR 433.
32 See Cohen/600 and Staff/1002, NWN Response to DR 433 and DR 421 for additional information on promotional concessions and activities.

ISSUE 3. CURRENT MEDICAL AND HEALTH INSURANCE

Q. Please describe the Company's request regarding employee benefits.

A. NW Natural included $16.4 million in medical (only) benefits for the Test Year. [33] The expense includes costs for both bargaining (union) and non-bargaining (non-union) (NBU) employees and is roughly split between the two groups. This is a 3.5 percent total increase over the Base Year and a 0.2 percent increase on a per-FTE basis.[34] There is an FTE increase from 1,170 as of September 30, 2021, to 1,187 in the Test Year. Benefit plan premiums are typically shared between the Company and the employees. The share that NBU employees pay for the CDHPs has remain unchanged at 85 percent employer/15 percent employee since those plans were introduced in 2013.[35] For the related FERC Account, 926, Figure 7 details the change from the previous Base Year to the current Test Year and calculations were either omitted or were $0 for previous years.[36]

FIGURE 7: FERC 926 (EMPLOYEE PENSION AND BENEFITS)

	Total Regulated Utility Service	Total included in Filed Rate Case	% Change for Total included in Rate Case
Base year 2	$46,949,071	-	
Base year 1	$26,530,671	-	
Base Year	$21,463,010	$ 20,454,784	
Test Year	$15,166,369	$ 14,601,100	-28.62%

33 NW Natural/800 Rogers/Page 18.
34 *Ibid*
35 Staff/1002, NWN Response to DR 239.
36 Staff/1002, NWN Response to SDR 058 Attachment 1 (electronic spreadsheet).

Q. Please discuss Staff's analysis of this issue.

A. Staff performed a four-year trend analysis for the health coverages for which NW Natural provided data in SDRs 064-067. The following table illustrates the Company's medical benefit costs for the Base Year, the preceding two years, and the Test Year amounts for Oregon allocated totals.[37]

FIGURE 8: OR ALLOCATED TOTALS FOR CURRENT MEDICAL

UTILITY-OREGON	Test Year	Base Year	%Change BY to TY	Base Year - 1	Base Year - 2
	10/31/2023	*12/31/2021*		*12/31/2020*	*12/31/2019*
Medical/Dental	$17,062,371	$16,366,066	4.3%	$16,364,508	$15,493,746
401(k)	$5,082,828	$4,642,610	9.5%	$4,415,973	$3,699,104
Group Life Insurance	$153,514	$135,006	13.7%	$124,461	$126,930
Retiree Life Insurance	$123,503	$118,833	3.9%	$124,984	$149,335
Long-Term Disability	$658,337	$560,002	17.6%	$546,600	$513,299
Other: STD, FMLA, EAP, FSA	$153,082	$144,865	5.7%	$146,702	$143,319
Total	$23,233,635	$21,967,382	5.8%	$21,723,228	$20,125,733

Q. Please describe the analysis performed by Staff.

A. Staff typically recommends employer/employee sharing of premium costs at the industry average, however NWN's premium contribution is already aligned with this average (83/17 for single employees).[38] As of now, the requested increase appears appropriate given the historical trend.

Q. Please state Staff's proposed adjustment.

A. Staff does not propose any adjustments to FERC Account 926 for current medical and health insurance expenses.

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[37] Staff/1002, NWN Response to DR 240 Attachment 1 (electronic spreadsheet).
[38] 2021 Employer Health Benefits Survey | KFF.

ISSUE 4. INSURANCE (NON-MEDICAL) AND RISK (NON-MEDICAL)

Q. Does the Commission have a standard means of determining how insurance expenses are treated?

A. Yes. During a rate case, Staff will examine a company's current premiums and remove any costs that are attributed to non-operating and non-regulated operations. This adjustment is performed by examining the purpose of the premium and identifying operations, which are non-operating and nonregulated in nature. When a premium does not maintain a specific breakdown between utility and non-utility operations, Staff will apply the utility's "non-utility" allocation factor (typically as cited in the utility's Cost Allocation Manual) to shared premiums. Staff will not normally escalate insurance costs by the CPI because insurance premiums are market driven. Staff will examine market increases/decreases from websites such as marketscout.com to verify any proposed increases by the utility.

Concerning uninsured losses, Staff examines a utility's actual uninsured losses related to automobile liability, general liability, and workers' compensation over the previous five-year period. For each year of losses, the losses are escalated using the CPI-U, to obtain equivalent year losses. Staff will then calculate the five-year average of the losses, escalate the average to the test year and compare to the Company's Test Year amount. In UE 197, the Commission adopted this principal to set uninsured losses at an escalated five-year average adjusted for inflation (Order No. 09-020 at 20).

Q. Which documents did Staff review regarding the Company's property insurance and additional risks?

A. Staff reviewed the Company's response to SDRs 057, 058, 246 along with confidential responses to 068-075 and 245. In addition, Staff reviewed non-medical insurance in NW Natural/1200, Davilla/14, for a special adjustment in lieu of escalation insurance and NW Natural/1200, Davilla/18, for an adjustment to Operations and Maintenance (O&M) claims and damages.

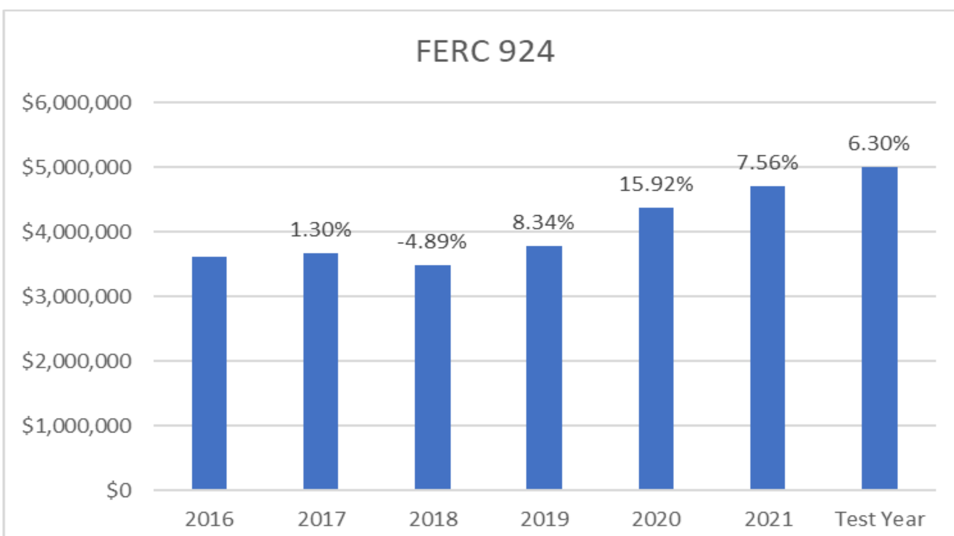
Q. Are there discrepancies in the data submitted by the Company?

A. Yes. The Company's original filing for FERC Account 924 appears to lead to some discrepancies. In NW Natural/1201, Davilla/1, at line 75, NWN is showing Base Year expenses for insurance costs (FERC Account 924) totaling $4,176,078 on a total company basis and $3,712,958 for the OR allocated amount. In NW Natural/1202, Davilla/1 at line 75, the FERC Account 924 entry for total system and OR allocated matches up with total system amount of $5,005,510 but misses on the OR allocated amount and has $4,450,407 instead of $3,712,958. NWN never corrected this figure in the actual filing. When I compare these numbers to the 2021 data NWN supplied in their response to Staff DR 275, Attachment 3 ($4,708,962 for FERC Account 924), they clearly do not match the filing for the OR allocated amount. Then there is a third dollar amount in the insurance reconciliation tab from the Confidential Staff DR 453 Excel file, which shows 2021 insurance premiums of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. What is the Company's proposed Test Year expense for property insurance?

A. For the Test Year, the OR allocated total for FERC Account 924 (property insurance) was $4,450,407, which is a 20 percent increase from the Base Year.[39] However due to data discrepancies, NW Natural's testimony[40] projected a nine percent increase from the Base Year to the Test Year for FERC Account 924 (Property Insurance) and their response to DR 275 Attachment 3, only showed a six percent increase.[41]

FIGURE 9: 924 SYSTEM TOTALS AND PERCENTAGE CHANGE FROM PREVIOUS YEARS[42]



Q. Please explain what other types of insurance were reviewed.

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39 Staff/1002 NWN Response to SDR 58 Attachment 1 (electronic spreadsheet) and NWN Response to DR 275 Attachment 3 (electronic spreadsheet).

40 NW Natural/1200, Davilla/14

41 Staff/1002; as stated in NWN Response to DR 246 and DR 275 Attachment 3 (electronic spreadsheet).

42 Based on NWN Response to DR 275 Attachment 3 (electronic spreadsheet).

A. In addition to property insurance, Staff reviewed documents related to, liability insurance, terrorism insurance, workers' compensation insurance, and other risk management insurance. Please see CONF Figure 10 for a list of these various types of insurances and a chart comparing premiums for these insurances over the last three years. The Company's insurance policy is from each year's October 15 to October 15 and they are unable to predict what losses for a future event would be, therefore a three year average was entered.[43]

FIGURE 10: OR ALLOCATED TOTALS FOR INSURANCE AND RISK PREMIUMS

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Is Staff proposing an adjustment involving any of these types of insurances?

A. No. In reviewing the premiums paid for each different type of insurance, Staff concluded the Company's decision to carry these types of insurance

43 Staff/1003, Staff electronic work paper UG 435 Exhibit 1003 Confidential Figures for an excel page dedicated to each confidential figure with the sources listed and calculations intact.

coverage is prudent and that the insurance premiums appear reasonable as they have fluctuated only slightly from year-to-year.[44] Because of the competitive nature of the insurance industry, it is Staff's position that premiums paid to protect the utility, and ultimately customers, from high dollar casualty losses represents a prudent business decision and that no adjustment is necessary.

[44] Staff/1003, NWN Response to SDR 69 Attachment 1 (Confidential) (electronic spreadsheet).

ISSUE 5. D&O INSURANCE

Q. What is D&O insurance?

A. Directors and Officers insurance is liability insurance payable to the directors and officers of a company, or to the organization itself, as reimbursement for losses or advancement of defense costs in the event an insured suffers such a loss as a result of a legal action brought for alleged wrongful acts in their capacity as directors and officers. Such coverage can extend to defense costs arising out of criminal and regulatory investigations and trials as well. Intentional illegal acts, however, are typically not covered under D&O policies.

Q. Please explain the standard adjustment to D&O insurance expense as it relates to NW Naturals request.

A. Staff has routinely recommend removal of 50 percent of Excess D&O liability insurance as a shareholder cost.[45] This methodology has been followed by Staff in previous dockets in both electric and natural gas utility general rate cases and approved by the Commission.[46] This adjustment is shown in Staff Exhibit 1003.

Q. Please explain the rationale for this standard adjustment procedure.

A. D&O insurance protects senior management in the event that they are sued, whether by customers, shareholders, or others in conjunction with the performance of their duties. Customers, who have no say in electing or

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[45] *In re* Portland *General Electric Company*, OPUC Docket No. UE 197, Order No. 09-020 at 19-20 (Jan. 22, 2009).

[46] *Ibid*.

appointing a Utilities Directors or Officers, should not be held financially responsible for providing 100 percent of the insurance coverage against business decisions or improprieties by management which results in lawsuits. Additionally, a large number of claims are brought by shareholders, customers should not have to pay the full costs of total D&O insurance. The excess insurance should be considered a joint shareholder/customer cost. Moreover, in an article published in *The University of Chicago Law Review,* Professors Tom Baker and Sean J. Griffith of Columbia and Fordham law schools state, “the dominant source of D&O risk, both in terms of claims brought and liability exposure, is shareholder litigation.”[47] So much so that Professors Baker and Griffith, “[t]reat the central purpose of D&O insurance as providing coverage against shareholder litigation.”[48]

Q. Does the Company include the cost of D&O insurance premiums by year?

A. Yes. The Company’s D&O insurance premiums totals **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. However, **[BEGIN CONFIDENTIAL]** [redacted]

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47 Baker, Tom & Griffith, Sean. (2006). Predicting Corporate Governance Risk: Evidence from the Directors' and Officers' Liability Insurance Market. *University of Chicago Law Review*. 74.

48 *Ibid.*

49 Staff/1003, NWN Response to SDR 74 Attachment 1 (Confidential) (electronic spreadsheet).

[redacted] **[END CONFIDENTIAL]**

Q. Does the Company include D&O insurance expense in its Test Year expense?

A. Yes. As stated in NWN Confidential Response to DR 450, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. Are there discrepancies in the data provided?

A. Yes. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

[BEGIN CONFIDENTIAL] [redacted]

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50 Staff/1003, NWN Response to DR 450 (Confidential); Corrected numbers for Oregon Allocated totals for base years 3-6 are included in Staff/1003 NWN Response to DR 451 Attachment 1(Confidential) (electronic spreadsheet).

51 Staff/1003, NWN Response to DR 453 Attachment 1 (Confidential) (electronic spreadsheet).

52 Staff/1003, NWN Response to DR 449 (Confidential); NWN Response to DR 247 Attachment 1 (Confidential) (electronic spreadsheet).

[redacted] [END CONFIDENTIAL]

When looking at the system allocated total in NWN's response to DR 275 Attachment 3, the total for FERC 925 in 2021 is listed as $126,712; for 2020 it is listed as $319,672; and, for 2019, it is listed as $217,866. The FERC 925 account totals listed in NWN's response to SDR 58 Attachment 1 were listed as $220,650 for 2021, -$11,405 for 2020, and $116,812 for 2019. The only common number between these two different DR responses was for the test year, which totaled $214,531 for FERC 925.

NWN did not appear to take care in differentiating between Northwest Natural Holding Company, Northwest Natural Gas Company, and the OR allocated portion of Northwest Natural Gas Company.

Q. Briefly describe your recommendation related to D&O Insurance.

A. NW Natural included in its filed case **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on an Oregon allocated basis for D&O Insurance expense for the test year.[55] This amount represents the sum of the first, second, and third excess D&O liability premiums, and the Broad Form Side A-Difference in Conditions (DIC) premiums. Staff recommends that 50 percent of the total cost of all layers of D&O Insurance be removed from

53 Staff/1003, NWN Response to DR 453 (Confidential)

54 Staff/1003, NWN Response to DR 453 Attachment 1 (Confidential)

55 As stated in Staff/1003 NWN Response to DR 452 (Confidential). [redacted]

A&G, which is consistent with Commission past practice, as described below. Based on Staff analysis, removing 50 percent of D&O Insurance would result in an Oregon-allocated adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[56]

Q. What is Staff's proposed Adjustment?

A. Staff proses to adjust D&O premiums **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Does this conclude your testimony?

A. Yes.

[56] Staff/1003, Jent (Confidential).

CASE: UG 435
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualifications Statement

April 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME: Julie Jent

EMPLOYER: Public Utility Commission of Oregon

TITLE: Utility Analyst 2
USRA

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: I have a Bachelor of Science from Berea College in Political Science where I concentrated on economics and the regions of Eastern Europe and Southeastern Asia. I also hold a Masters of Integral Economic Development Policy specializing in the public sector and econometrics.

EXPERIENCE: I have been employed as a Junior Financial Analyst by the Oregon Public Utility Commission since June 2021 in the Telecommunications and Water division. Within telecom, I work with colleagues and telecom companies on issues relating to OUSF funding and the transition to a new cost model. Within energy, I currently perform a range of financial analysis duties related to natural gas, electric, and water utilities, with a focus on operations and maintenance. However, UG 435 is my first general rate case docket. I was previously employed as an Analyst with the Executive Office of the President (EOP), where I worked as part of a team on education funding. Prior to EOP, I was an Economic Consultant for the U.S. Conference of Catholic Bishops.

CASE: UG 435
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Non-Confidential Exhibits in Support
Of Opening Testimony

April 22, 2022

NW Natural®

Rates & Regulatory Affairs
2022 OR GRC
2022 Oregon General Rate Revision
Data Request Response

Request No.: 2022 OR GRC OPUC SDR 104

For the questions below related to advertising expense, please see the definitions and descriptions in OAR 860-026-0022. For questions related to promotional activities or concessions, please see OAR 860-026-0015 & 0022 including references to the appropriate testimony and / or exhibit pages;
a. Please identify the Category A advertising expense included in the Test Year; including references to the appropriate testimony and / or exhibit pages;
b. Please provide a work paper that shows the calculation of the Category A limit provided in OAR 860-026-0022 (3) (a);
c. If the Test Year Category A advertising expense exceeds the OAR 860 026-0022 (3) (a) limit, please provide support for including the additional expense in rates;
d. Please identify the Category B advertising expense included in the Test Year; including references to the appropriate testimony and / or exhibit pages;
e. For any Category C advertising expense included in the Test Year revenue requirement that is associated with a promotional activity or a promotional concession program, please provide a summary table that includes:
i. A description of the activity or program, and justification for inclusion into rates;
ii. A breakout of the related expense by labor and
iii. The FERC and internal utility account to which the expense will be booked and include references to appropriate exhibit pages.
f. Please identify any other budgeted advertising expense for the test year that will NOT be included in base rates, including below-the-line or nonutility expense, or advertising expense expected to be collected through a tariff. Please include how the expense is allocated between the categories identified in OAR 860-026-0022(2). Please describe the activities and associated expense (broken out by labor & non labor) associated with marketing research and sales activities (include fuel switching and retention of customers) that is included in the test year. Please include references to the testimony and exhibits, and to which FERC and internal utility accounts this expense is booked.

Response:

a. Category A expenditures identified for the test year total $2.60 per customer (NW Natural/900, Beck/4).

b. The calculation allowed by OAR 860-026-0022(3)(a) would have been $1.44 per customer during the test year 2022/23:

NW Natural Proposed Operating Revenue = $815,931,184
Category A allowed – 0.125%

(Calculation = $815,931,184 x .00125 = $1,019,914)

Test Year number of customers = 709,107
Category A per customer = $1.44

(Calculation = $1,019,914/709,107 = $1.44)

c. Support for the proposed Category A advertising expense is provided at: *(NW Natural/900, Beck/3).*

d. Category B expenditures identified for the test year total $1,080,000; *(NW Natural/900, Beck/20-22)*

e. None of the Category C expenses are included in rates.

$600,000 in marketing and advertising activities are budgeted in Category C for the Test Year period, none of which will be included in base rates. See below for activities and account numbers planned for this category expenditure. All activities are designed to aid in retention of customers. It is noted below which activities are labor and non-labor and which are designed to encourage the use of high-efficiency natural gas products over in-efficient alternatives.

Budget Activity	**Internal #**	**FERC #**	**Test Year $**
Department Expenses (non-labor)	502400 11550	913-20000	$ 9,000
Department Expenses (labor)	502100 11550	913-20000	$ 90,000
Home shows / Event Support (non-labor, retention & showcase high-efficiency products)	507500 11550	913-26000	$ 96,000
Professional Services / Research / Writing / Design (labor & non-labor, fuel switching)	505100 11550	913-26000	$ 67,500
Media - Production (labor & non-labor, fuel switching)	505100 11550	913-26000	$ 112,500

Media – TV, Digital, Streaming (non-labor, retention & showcase high-efficiency products)	505200 11550	913-26000	$	225,000
			$	600,000

f. $80,000 is budgeted for below the line for district advertising, promotional concessions, incentives and sponsorships. See below for activities
and account numbers planned for this category expenditure.

Budget Activity	Internal #	FERC #		Test Year $
District Advertising (non-labor, retention & fuel switching)	505200 11550	416-04080	$	30,000
Sponsorship support (non-labor, retention & fuel switching)	507500 11550	416-04080	$	35,000
Special promotion incentives (non-labor)	505100 11550	416-04080	$	15,000
			$	80,000

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 152

152. Please provide transactional line-item accounting detail for Category A, Category B, Category C, Category D, and Category E advertising expenditures for calendar years 2019, 2020 and 2021. Please label each transaction with the appropriate category (A, B, C, D, or E) and include any available descriptions of each expense. Please provide the data in electronic, Excel format with all formulae and cell references intact.

Response:

Please see UG 435 OPUC DR 152 Attachments 1-3 for the response. Please note, NW Natural did not book expenses to Category D or E for 2019, 2020 and 2021.

Attachment 1 to NWN Response to Staff SDR 58(a) is filed in electronic format only

Attachment 1 to NWN Response to Staff DR 153 is filed in electronic format only

Staff Electronic Work Paper titled Non-Confidential Figures is filed in electronic format only

Attachment 1 to NWN Response to Staff DR 273 is filed in electronic format only

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 424

424. See DR 248 attachment 1. How many customers do you have for each of the years listed in this attachment (2015 to 2021 and the test year)?

Response:

Please see the table below for the Oregon customer counts from 2015-2021 and the Test Year:

Year	Oregon Customer Counts
2015	637,402
2016	645,883
2017	656,031
2018	665,771
2019	675,380
2020	684,153
2021	691,805
Test Year (ending date October 31, 2023)	715,573

Attachment 1 to NWN Response to Staff DR 248 is filed in electronic format only

Attachment 1 to NWN Response to Staff DR 274 is filed in electronic format only

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 422

422. What was the final test year expense for Category A and Category B advertising in NWN's previous three rate cases?

Response:

Please see the table below for rate case proposed amounts and final rate case outcome.

Year	**Rate Case Proposal**	**Final Rate Case Outcome**
2012 (UG 221)	$2,117,240	$1,819,377
2018 (UG 344)	$2,506,500	Black box. Undetermined.
2020 (UG 388)	$2,765,700	$2,415,700

Attachment 5 to NWN Response to Staff DR 254 is filed in electronic format only

Attachment 1 to NWN Response to Staff DR 155 is filed in electronic format only

Attachment 3 to NWN Response to Staff DR 155 is filed in MP4 format only

Attachment 4 to NWN Response to Staff DR 155 is filed in MP4 format only

Staff Electronic Work Paper titled Adjustments Escalated is filed in electronic format only

Attachment 1 to NWN Response to Staff DR 152 is filed in electronic format only

Attachment 2 to NWN Response to Staff DR 152 is filed in electronic format only

Attachment 3 to NWN Response to Staff DR 152 is filed in electronic format only

NW Natural®

250 SW Taylor Street
Portland, OR 97204
503-226-4211
nwnatural.com

VIA ELECTRONIC FILING

November 23, 2020

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: RG-31—NW Natural's Report of 2021 Promotional Concession Campaigns

In accordance with OAR 860-026-0030, NW Natural submits this letter as notice of the promotional concessions that NW Natural plans to offer during the 2021 calendar year.

Each campaign may include one or more offers as set forth in the Company's Tariff P.U.C. Or. 25, at Schedule 200 "Promotional Concessions," and more specifically within one or more of these promotional areas:

200-2 General Merchandise Sales Program
200-3 Equipment Sales Promotions
200-4 Cooperative Advertising Program
200-5 Showcase Developments
200-8 Promotions for Company-Offered Products and Services

The campaign description and associated budget is as follows:

- **Hearth/Water Heat Campaigns**
    - The program budget is up to $849,272.

- **HVAC Campaigns**
    - The program budget is up to $1,577,219.

- **Residential Builder Program and Campaigns**
    - This campaign includes residential new construction and multifamily programs.
    - The program budget is up to $1,104,119.

- **Dealer Relations Campaigns**
    - The program budget is up to $230,499.

- **Cooperative Advertising Program**
    - The program budget is up to $20,000.

- **Retail Program Campaign**
  - Incentives for qualifying fireplace or stove inserts ($45,000). Energy Trust matching dealer contribution $200 each.
  - Ongoing event promoting tankless water heaters ($2,000). Additional Energy Trust dealer contribution – instant rebate offered on all Sensei models.
  - Spring and Summer free delivery of grills and BBQs ($5,000).
  - The total program budget is up to $52,000.

For most campaigns, participating dealers or trade allies will offer customer incentives for installing the promoted, natural-gas fired appliances. The Company pays participating dealers or trade allies an incentive for the sale of promoted, natural-gas fired products.

All campaign costs will be accounted for below-the-line, in FERC accounts 912 or 913, in accordance with OAR 860-026-0010.

This notice contains a comprehensive list of the Company's 2021 planned promotional concessions. If additional campaigns are added during the year, the Company will separately notice the Commission in accordance with OAR 860-026-0030.

Please feel free to call should you have questions.

Sincerely,

/s/ Rebecca T. Brown

Rebecca T. Brown
Regulatory
Compliance

cc: Mary Widman, Portland General Electric
Etta Lockey, PacifiCorp

NW Natural®

250 SW Taylor Street
Portland, OR 97204
503-226-4211
nwnatural.com

VIA ELECTRONIC FILING

November 30, 2021

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: RG-31—NW Natural's Notice of 2022 Promotional Concession Campaigns

In accordance with OAR 860-026-0025 and -0030, NW Natural submits this letter as notice of the promotional concessions that NW Natural plans to offer during the 2022 calendar year.

Each campaign may include one or more offers as set forth in the Company's Tariff P.U.C. Or. 25, at Schedule 200 "Promotional Concessions," and more specifically within one or more of these promotional areas:

200-2 General Merchandise Sales Program
200-3 Equipment Sales Promotions
200-4 Cooperative Advertising Program
200-5 Showcase Developments
200-8 Promotions for Company-Offered Products and Services

The campaign description and associated budget is as follows:

- **Hearth/Water Heat Campaigns**
  - The program budget is up to $574,875.

- **HVAC Campaigns**
  - The program budget is up to $1,067,625.

- **Residential Builder Program and Campaigns**
  - This campaign includes residential new construction and multifamily programs.
  - The program budget is up to $1,214,747.

- **Dealer Relations Campaigns**
  - The program budget is up to $298,000.

- **Cooperative Advertising Program**
  - The program budget is up to $20,000.

- **Retail Program Campaign**
    - Incentives for qualifying fireplaces, stoves, or inserts - $48,000. Energy Trust matching dealer contribution $200 each.
    - Energy Trust instant rebate on tankless water heaters - $2,000
    - Spring and Summer free delivery offer on grills - $5,000
    - The total program budget is up to $55,000.

- **Vision 2050: Destination Zero Customer Promotion**
    - Program budget for online game $7,500.
    - Program budget for prizes up to $10,150.

This notice contains a comprehensive list of the Company's 2022 planned promotional concessions. If additional campaigns are added during the year, the Company will separately notice the Commission in accordance with OAR 860-026-0025 and -0030.

Please feel free to call should you have questions.

Sincerely,

/s/ Rebecca T. Brown

Rebecca T. Brown
Regulatory Compliance

cc: Mary Widman, Portland General Electric
Matthew McVee, PacifiCorp

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 421

421. Does the Company engage in any Promotional Activities in the state of Oregon?
a. If so, please identify all references to Promotional Activities in Company workpapers and testimony.
b. Please identify each promotional item the Company conducted in Oregon and describe the benefits produced and available to customers.

Response:

a. Yes, NW Natural engages in Promotional Activities within our service territory in the state of Oregon.

The table below shows the promotional concessions campaigns in the 2021 actual expenses.

Account	Account #	Vendor	Description	Amount	Amount total	OR %	OR $
Professional Services	**505100**				**304,803.75**	**0.878466727**	**267,759.95**
		Infinity Direct	Marketing agency expense. Infinity Direct is an agency that assists NW Natural in creation of messaging, managing the data for unserved premises and production/printing of direct mail material sent to prospective customers.	251,415.00		0.878466727	220,859.71
		Optimizer	Expense related to creation of an online consumer space heating equipment operating cost comparision tool. Optimizer is a data analysis firm that was contracted to create the verifiable operating cost calculations for this tool.	15,000.00		0.878466727	13,177.00
		Outright/DRD Creative	Expense related to creation of an online consumer space heating equipment operating cost comparision tool. Outright is the agency that created the webtool that will be used by customers to enter home heating variable (unique to their premise) and test outcomes for various scenarios of gas and electric space heating.	35,265.00		0.878466727	30,979.13
		Dale Headrick	Contractor used to create design and layout for marketing materials.	1,380.00		0.878466727	1,212.28
		Laurie Christine Harquail	Writer contracted to create copy for cost comparison tool web interface	693.75		0.878466727	609.44
		Stephen Michael Cox	Writer contracted to create copy for campaign materials	1,050.00		0.878466727	922.39
Postage	**502800**				**149,239.86**	**0.878466727**	**131,102.25**
		USPS	Postage for direct mail materials sent to prospective customers	149,239.86			
Advertising Coop	**505200**				**4,250.00**	**0.878466727**	**3,733.48**
		Jacobs Heating	Coop expense for HVAC dealer. Used for website content linking to NWN page.	250.00		0.878466727	219.62
		Pacific Air Comfort	Coop expense provided to HVAC dealer for radio ad campaign in Coos Bay	4,000.00		0.878466727	3,513.87
		TOTAL		**458,293.61**			**402,595.69**

Table A

b. Before providing the detail and justification for these Promotional Activities expenses, it is important to first explain the general nature of the activities.

What is the nature of the activities?

Promotional Activities expenses include printing, postage, data management and creative development of direct marketing campaigns. These campaigns explain rebates, credits and discounts offered by Energy Trust of Oregon, contractors, equipment manufacturers, retailers and NW Natural. Additionally, the campaigns suggest income-qualified programs that assist residents in acquiring high-efficiency space and water heating equipment that can reduce operating cost. The direct marketing materials clearly outline the features and benefits of natural gas and explain verifiable energy cost savings, comfort, resilience benefits, performance, efficiency and convenience that gas amenities offer. These materials help prospective customers make informed decisions about natural gas service. Additionally, messaging to existing customers about offers from contractors, manufacturers and ETO help to encourage customers to upgrade to higher efficiency equipment. Finally, the materials provided assurances to consumers about Covid-related protocols that contractors utilized to ensure the safety of residents during visits to the home.

Also, in 2021, NW Natural undertook a project to create a consumer-facing space heat operating cost comparison web tool. Expenses related to this project are included in the Promotional Activities. These include web tool development, analysis tool calculation coding for equipment scenarios and layout/copy expense paid to Outright, Optimizer and Harquail.

Accounts charged for Promotional Activities

In the RG 31 the Promotional Activities expenses are described and grouped by the seasonal and equipment-related campaigns. Hearth/Water Heat, HVAC (furnace), Residential Builder programs, and Coop Ad programs are listed. Dealer Relations expenses are explained in the response to UG 435 OPUC DR 365 and are not explained in the response to UG 435 OPUC DR 421.

As shown in Table A above, the Promotional Activities expenses are charged into accounts for Professional Services (including creative development, layout, data management, analysis and production), Postage (metered through USPS) and Advertising Coop (paid to dealers).

1. Professional Services FERC 908 and 912 Account 505100
    - **Infinity Direct** – As noted in Table A above, Infinity Direct is an agency that assists NW Natural in creation of messaging, managing the data for unserved premises and production/printing of direct mail material sent to prospective customers. This agency facilitates the campaign planning.

Their services include analysis of results, identification of prospective customers by premise, identification of prospect attributes as they relate to the need for specific information and messages, production of the mailed collateral and coordination of the delivery to USPS. As described in the customer benefits described below, this is a necessary service for homeowners and Infinity Direct is invaluable in the facilitation of the campaigns. Therefore, this is a recoverable expense.

- **Optimizer and Outright** – As noted in Table A above, these two vendors were contracted to create the space heating cost comparison tool. When published, the cost comparison tool will enable customers and non-customers to enter the basic variables about their home, location, energy provider and equipment options (electric and gas). The tool will display relative operating costs. These results will sometimes show gas space heating to be more affordable but will also show results (in various scenarios) where electric space heating may be more affordable. It is unbiased to fuel type and calculates the accurate operating cost information that will enable residents to make informed decisions about equipment. As a website tool that is useful to all customers (existing and future) this is a recoverable expense.

- Creative resources (**Headrick, Harquail and Cox**)—These contractors write copy and create layouts that are used for collateral (both printed and web-based). It is important that material be clearly understood and easy to access. Therefore, prudent use of these contractors adds the value that makes this a recoverable expense.

2. Postage FERC 908 and 912 Account 502800
   - Expense paid to **USPS** for metered postage of direct mail pieces to prospective customers.

3. Advertising Coop FERC 912 Account 505200
   - **Jacobs Heating & Cooling**—this nominal expense ($250) was paid to a contractor who agrees to create content and weblink from their website to material on NW Natural's site. This link directs website visitors to information about offers and steps to new add gas service if needed.
   - **Pacific Air Comfort**—this expense was paid as coop to a Coos Bay HVAC dealer who collaborated and shared expense with NW Natural to run a radio campaign explaining the benefits of high-efficiency gas equipment and services that are offered by the dealer. Coop expenditures, in general, strengthen the relationship between NW Natural and the partner, help facilitate better understanding of the partner

services and extend the reach for important messages intended for existing customer and prospective customers. Therefore, this expense is recoverable.

Generally, how do these activities benefit customers and why are the expenses considered recoverable?

The process of providing credible marketing information to prospective customers who look to NW Natural as a trusted authority is a distinctly valued service.
Consumers, especially those with oil heated homes, need reliable information in order to make informed decisions about long-term fuel choice decisions about their homes. NW Natural marketing provides that critical information, especially regarding operating costs, efficiency, non-energy benefits like comfort, resilience, and convenience, as well as complete listing of potential Energy Trust rebates, manufacturer incentives, income-qualified offers, contractor discounts and NW Natural rebate incentives. It should be noted that NW Natural rebate incentives are agreed to be non-recoverable shareholder expense and have not been included for recovery in the UG 435 filing.

Under law, NW Natural has an obligation to prudently serve new customers who request new service for a premise. Part of fulfilling that obligation is to provide information to prospective customers about the value of gas space heat, water heat and cooking. Marketing campaigns serve that function by communicating information about gas amenities and by communicating the steps that a prospective customer should take to order and install gas service in the home.

Existing customers may benefit from the addition of new customers to the system by spreading fixed system costs across a broader base of customers and reducing the per customer burden of those costs. NW Natural marketing activities combine to create high levels of customer service as measured through J.D. Power and other customer satisfaction indices.

Customers can expect efficient ordering processes, dependable tradespeople, helpful information about natural gas equipment features and safely installed services. Marketing campaigns provide this information—along with gas equipment information—and create piece of mind in prospective customers who then become actual customers of NW Natural. Costs associated with establishing this superior level of service and communicating accurate information should be recoverable.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 433

433. Please provide:
a. A list of expenditures for promotional activities and concessions charged to accounts during the test year; and
b. A description of all programs related to sales promotion included in the test year.

Response:

a. List of expenditures for promotional activities and concessions

First, it is important to note how promotional activities and concessions are defined in the context of utility work. The expenses are grouped in four categories: Administrative Marketing expenses, Trade Relations expenses, Advertising expenses, and Rebates. The expenses with account type are summarized and listed in Table A below.

Administrative Marketing expenses are part of the overall facilitation of marketing efforts. The expenses include travel, meals, education, dues/memberships, mileage, supplies, parking and other costs associated with running the department.

Trade Relations (also listed as Dealer Relations) are related to overall development and strengthening of partnerships with builders, developers, HVAC contractors, dealers, plumbers, architects and engineers. Some expenses are directly related to support of activities that showcase gas, provide education and promote membership in relevant trade associations. For instance, purchases of innovative gas equipment for builder showcases, homebuilder open houses for gas homes, and trade association education seminars are critical to our partnerships. Trade Relations have been covered in depth in the Company's response to UG 435 OPUC DR 365.

Advertising expenses include printing, postage, data analysis, copy writing and creative development of direct marketing campaigns. These conversion campaigns explain rebates, credits and discounts offered by Energy Trust of Oregon (ETO), contractors, manufacturers, retailers and NW Natural. The direct marketing materials clearly outline the features and benefits of natural gas and explain verifiable energy cost savings, comfort, resilience benefits, performance, efficiency and convenience that gas amenities offer. These materials help prospective customers make informed decisions about natural gas service. Additionally, messaging to existing customers about offers from contractors, manufacturers and ETO help to encourage customers to upgrade to higher efficiency equipment and take advantage of income-qualified offers. Advertising expenses have been covered in depth in the Company's response to UG 435 OPUC DR 421.

Rebates—the incentives paid by NW Natural to new customers—are *not recoverable in rates and have not been included for recovery in the UG 435 filing*.

Category	Account type	FERC numbers	Account numbers	Total System Value	OR Allocation %	OR Expense	Comments
Administrative Marketing				**23,533.00**		**20,672.96**	
	Travel	908; 912	512200; 513100	1,778.00	0.878466727	1,561.91	mostly travel within territory
	Meals	908; 910; 912	512100; 503300	4,486.00	0.878466727	3,940.80	
	Education	908; 912	501100	267.00	0.878466727	234.55	
	Dues/Membership	908; 910; 912	501900	14,401.00	0.878466727	12,650.80	membership in trade associations
	Parking	912	504700	178.00	0.878466727	156.37	
	Office Supplies	912	503000	2,423.00	0.878466727	2,128.52	
Trade Relations				**121,998.00**		**107,171.18**	detailed in UG435 DR365
	Home showcase	912	504600	24,521.00	0.878466727	21,540.88	
	Education	908; 912	504600	15,230.00	0.878466727	13,379.05	
	Public events	908	504600	38,500.00	0.878466727	33,820.97	
	Support of trade groups	912	504600	18,966.00	0.878466727	16,661.00	
	Partnership development	912	504600	14,731.00	0.878466727	12,940.69	
	Builder signage	908; 912	524100	500.00	0.878466727	439.23	
	Logo items	912	504600	9,550.00	0.878466727	8,389.36	hats, masks, shirts
Advertising Expense				**454,442.00**		**399,212.18**	detailed in UG435 DR421
	Agency	908; 912	505100	304,803.00	0.878466727	267,759.29	
	Postage		502800	149,239.00	0.878466727	131,101.50	
	Printing		503100	400.00	0.878466727	351.39	collateral material

Table A

b. Description of all programs related to sales promotion

We interpret this question as relating to a description of marketing efforts. NW Natural engages in a variety of programs related to marketing communications and programs. The term "marketing" describes a broad range of activities. It can generally be thought of as the portion of the utility operations that is involved in outreach to and education of potential customers, as well as the on-boarding of customers into the utility system.

The staff question may too narrowly define the concept of "sales promotion" relative to the programs in which the utility engages. For example, program efforts to provide information and support to the homebuilder trades do not have an overt "sales" objective or approach but are part of a larger effort to support the inclusion of natural gas amenities in new construction. In this particular example, NW Natural works through the new construction channel to make sure that customers' interests in gas homes are appropriately represented in the market.

Here is a list of marketing programs and communication efforts conducted by NW Natural:

1. **Direct marketing campaigns to prospective customers**
These campaigns (with planned expenditures noted in the docket RG 31 filing) are typically organized by product categories such as fireplace, HVAC (furnace), and water heat. The communication is administered through direct mail letters and postcards to prospective non-customers. The campaigns are supported by helpful website information including a web-based Gas Availability tool to let prospects know if they can get gas service at their home as well as a contractor referral page pointing them to reliable gas equipment installation dealers.

   As noted previously, the campaign materials explain rebates, credits and discounts offered by Energy Trust of Oregon, contractors, equipment manufacturers, retailers and NW Natural. Additionally, the campaigns suggest income-qualified programs that assist residents in acquiring high-efficiency space and water heating equipment that can reduce operating cost.

2. **Bill inserts to existing customers**
These inserts promote offers from various dealers in the service territory to NW Natural customers. Additionally, ETO rebates and other offers are communicated in the bill inserts. Such offers promote higher levels of equipment efficiency and communicate the value of natural gas service.

3. **Partnership development**
NW Natural engages in a variety of efforts designed to strengthen partnership with trade partners who help provide gas service to customers. The varied assortment of stakeholders contacting NW Natural during the process to serve our mutual customers includes builders, developers, HVAC contractors, fireplace dealers, plumbers, remodelers, architects, and engineers (together, referred to as "tradespeople"). It is vitally important that NW Natural maintain productive relationships. Through regular communication and collaboration, our employees clearly communicate issues of safety and compliance with regulatory policies when connecting gas services. Working with these stakeholders helps uphold NW Natural's high levels of customer service, which benefits customers.

4. **Home showcases and support for new construction**
Developers, builders and new construction home buyers have a choice of fuel used to heat the space and water in their homes, i.e., heat pumps, ductless mini-splits, heat pump water heaters, tankless gas water heaters or gas furnaces. Over the years, NW Natural has promoted natural gas as the fuel of choice for home builders and home buyers. Market research shows that

preference for gas amenities is very high and we attempt to ensure that builders are supplying gas homes to the prospective customers who want them. NW Natural also supports the homebuilder industry through association membership drives, education, and event support.

Home showcases such as Lane County Tour of Homes, Marion Polk County Tour of Homes and Street of Dreams demonstrate to the public the true value of gas (operating cost, efficiency, comfort and convenience). In the case of Street of Dreams, the homes are rated with the ETO Energy Performance Score and are able through communication of the results, display of features and signage to show the high levels of efficiency available in gas homes. Home buyers have very strong interest in gas amenities and these demonstration homes reinforce the value. Additionally, NW Natural supports the builders and the associations that continue to build with gas and provide the amenities that buyers want. NW Natural supplies demonstration products to various home showcases. For example, in the 2021 Street of Dreams, NW Natural supplied the homes with the battery backup devices that allow tankless water heaters to operate for several days during a power outage. Communication about this feature educates customers about the resilience benefits offered by natural gas equipment.

5. Multifamily program

NW Natural uses available information about upcoming multifamily developments. The NW Natural team engages with developers, architects and engineers to determine the best solutions to serve their projects with gas infrastructure.

Attachment 1 to NWN Response to Staff SDR 057 is filed in electronic format only

NW Natural®

Rates & Regulatory Affairs

UG 435

Request for a General Rate Revision

Data Request Response

Request No.: UG 435 OPUC DR 239

What decisions led to the trend to increase the share that employees pay for their medical plans?
Is the declining share that NW Natural is expected to pay for employees plans a trend that you see moving beyond 2022 and 2023?
If this trend is expected to continue, what data is there to show the need to recoup costs despite NW Natural recouping costs by having employees pay more (NW Natural 800, Rogers 18-19).

Response:

There were several key reasons that led to NW Natural's decision to increase the share that NBU employees pay for the PPO and HMO medical plans. The share that NBU employees pay for the CDHPs has remain unchanged at 85% employer/15% employee since we introduced those plans in 2013.

A CDHP is generally a more affordable plan for both employees and employers because more of the costs are incurred when care is needed rather than paying upfront and possibly not utilizing the benefit fully. For this reason, NW Natural had an interest in encouraging employees to select one of the CDHPs. The cost share for the PPO and HMO plans had remained unchanged at 80% employer/20% employee since at least 2006 but with costs increasing much faster for these plans compared to the CDHPs, NW Natural was paying considerably more for employees on the PPO and HMO plans compared to the CDHPs, despite paying 85% of the CDHP premium. By introducing a three-year plan to gradually change the cost share, we wanted to encourage migration to the CDHPs and for those who chose to stay on the PPO or HMO plans, we would bring the amount paid by the company closer together amongst the four plans. Finally, with the closure of the retiree medical plans in 2007 (NBU) and 2009 (BU), we wanted to find another way to help set up our employees for success with their medical expenses in retirement. A CDHP, coupled with a Health Savings Account, is an excellent way to do that. Making the cost share structure for the CDHPs more attractive compared to the PPO and HMO plans has encouraged movement to the CDHPs and as a result, more of our employees now have HSAs which they will be able to use in retirement for medical expenses.

The three-year plan to adjust the cost share for the PPO and HMO plans started in 2021 and will end in 2023. We have no plans to extend it beyond 2023.

Attachment 1 to NWN Response to Staff DR 240 is filed in electronic format only

Attachment 3 to NWN Response to Staff DR 275 is filed in electronic format only

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 246

Please provide a narrative description as to why the Company expects a three percent increase from the base year to the test year in FERC account 924 given the savings discussed in NW Natural 800.

Response:

Please note that the savings was discussed in NW Natural 1200, not NW Natural 800 as the question states. NW Natural's testimony (NW Natural/1200, Davilla/Page 14) projected a nine (9) percent increase in the Test Year for FERC Account 924 (Insurance). The property insurance premiums increased in response to the hardened insurance market conditions, increasing real property values and related improvements, and rising replacement costs.

CASE: UG 435
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1003

Confidential Exhibits in Support
Of Opening Testimony

April 22, 2022

Staff Electronic Workpaper titled Confidential Figures is filed in electronic format only

Confidential Attachment 1 to NWN Response to Staff SDR 69 is filed in electronic format only

Confidential Attachment 1 to NWN Response to Staff SDR 74 is filed in electronic format only

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC Confidential DR 450

450. [START CONFIDENTIAL] [redacted] END CONFIDENTIAL]

Response:

[redacted]

[redacted]

[redacted]

Confidential Attachment 1 to NWN Response to Staff DR 451 is filed in electronic format only

Confidential Attachment 3 to NWN Response to Staff DR 453 is filed in electronic format only

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC Confidential DR 449

449. [START CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Confidential Response:

[redacted]

Confidential Attachment 1 to NWN Response to Staff DR 247 is filed in electronic format only

NW Natural

Rates & Regulatory Affairs

UG 435

Request for a General Rate Revision

Data Request Response

Request No.: UG 435 OPUC Confidential DR 453

453. [START CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Response:

[redacted]

[redacted]

[redacted]

Confidential Attachment 1 to NWN Response to Staff DR 453 is filed in electronic format only

Protected Information Subject to
General Protective Order

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate
Revision
Data Request Response

Request No.: UG 435 OPUC Confidential DR 452

452. [START CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Response:

[redacted]

[redacted]

CASE: UG 435
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Opening Testimony

April 22, 2022

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

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

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss my review of the depreciation rates used to calculate the depreciation and amortization expenses and accumulated depreciation (depreciation reserve) in Northwest Natural's (NW Natural, NWN, or Company) revenue requirement for this rate case, as documented by the Company witness, Kyle T. Walker, in NW Natural/1300. 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 an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/1102, NWN's Response to Staff Data Request (DR) No. 124.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Please note that I may revise my recommendations based on testimony filed by other participants in this rate case.

1. In the UG 435 general rate case, NWN used the depreciation rates that were determined based on 2015 data and authorized in OPUC Order No. 18-007, UM 1808.
2. NWN filed a new depreciation study in December 2021(docketed as UM 2214) to update the industrial asset depreciation rates to comply with ORS 757.140, which requires each public utility to carry a proper and adequate depreciation account and to conform its depreciation accounts to the rates determined by the Commission, and OAR 860-027-0350, which requires each energy utility to file with the Commission an updated depreciation study at least once every five years.
3. Staff does not take position at this time on NWN's decision to exclude the changes in revenue requirement associated with the updated depreciation rates in this general rate case. However, Staff opposes NWN's proposal to delay the effective date of its update to depreciation rates and to have a single-issue rate case at the end of 2023 to update depreciation expense in retail rates.
4. Staff has proposed no adjustment to depreciation expenses and reserves in UG 435 because the depreciation rates that NWN used to calculate the expense and accumulated depreciation reserve in the revenue requirement are consistent with the rates that were authorized in Order No. 18-007, and the depreciation and reserve in the revenue requirement are properly

recorded.

5. Staff made no adjustment to the Company's calculation of AFUDC, because the Company's AFUDC calculations meet Federal Energy Regulatory Commission (FERC) and Oregon regulatory requirements.

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]

The statement above defines depreciation from a valuation perspective. From an accounting perspective, depreciation is the allocation of the cost of fixed assets less net salvage to accounting periods, which is a capital recovery concept. From a ratemaking perspective, both the valuation (rate base) and accounting (capital recovery) concepts of deprecation are important.

Q. Do Oregon statutes address utility depreciation rates?

A. Yes. ORS 757.140(1), states in relevant part:

> Every public utility shall carry a proper and adequate depreciation account. The Public Utility Commission shall ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility. The rates shall be such as will provide the amounts required over and above the expenses of maintenance, to keep such property in a state of efficiency corresponding to the progress of the industry. Each public utility shall conform its depreciation accounts to the rates so ascertained and determined

[1] NARUC, *Public Utility Depreciation Practices*, p.318 (1996).

> by the commission. The commission may make changes in such rates of depreciation from time to time as the commission may find to be necessary.

Q. How are utility property depreciation rates determined?

A. To develop depreciation rates, it is necessary to estimate: (1) the combination of survivor curve[2]-service life (Curve-Life) of utility property, and (2) the net salvage[3] (Gross Salvage – Cost of Removal) ratio. Based on these two fundamental depreciation parameters (and other required elements, such as asset value, asset remaining life, and depreciation method) the depreciation rates are derived.

Q. Why do we need to use authorized depreciation rate results for the revenue requirement calculation?

A. To compute the revenue requirement (RR), which is measured by cost-of-service, a basic formula is followed:

RR = O&M Expense + "Depreciation" + Taxes + Return% x Rate Base

- Depreciation expense & reserve in UG 435 is derived by (Depreciation rate) x (plant in service) x (allocation factor, if any).
- Depreciation expense represents a large percentage of total operating expenses. The deferred income taxes, rate base, and cost of capital are all affected by the depreciation. Therefore, to calculate depreciation expense

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[2] "Survivor curves" are curves that show the number of units or cost of a given group which is surviving in service at given ages. The survivor curves were developed by the Engineering Research Institute of Iowa State University. These curves are frequently referred to as "Iowa Curves."

[3] Net Salvage. The gross salvage of the property retired less the cost of removal. This will be negative, if the cost of removal exceeds the gross salvage.

and reserve, we must use the Commission authorized depreciation parameters.

Q. Has NWN explained the primary drivers for the investment increase?

A. Yes. NWN explains that the primary drivers of the increase in capital investment, and consequently in the depreciation expense, are:

- Substantial investments in the safety and reliability of our distribution system and operations;
- IT&S systems and applications becoming obsolete and the need to modernize those systems to cloud-based architecture;
- Constructing safe, seismically resilient regional resource centers;
- Addressing capacity constraints on the system;
- Complying with the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) requirements; and
- The routine systematic replacement of assets that have reached the end of their useful lives.

Q. What depreciation rates did NWN use in its Test Year revenue requirement?

A. The current depreciation rates for the Company were authorized by OPUC Order No. 18-007. In Order No. 18-007, the Commission specified the Curve-Life and Net Salvage parameters for each FERC plant account, from which the depreciation rates are derived for each account.

Q. Has NWN filed a depreciation study with the Commission updating the depreciation rates approved in 2018?

A. Yes. NWN filed two depreciation studies in December 2021, one for its North Mist Plant and the other for all other assets. The Commission has opened two dockets to review the studies, Docket Nos. UM 2213 (North Mist) and UM 2214. Both have procedural schedules that will result in final Commission orders in October 2022, prior to the rate effective date of this general rate case.

NWN asks that the update to depreciation rates for its North Mist plant be effective January 1, 2023, to coincide with an update to its Schedule 90 for Firm Storage Service – No Notice Withdrawal. NWN asks that the update to all other depreciation rates at issue in UM 2214 be effective on November 1, 2023. Accordingly, NWN has based its revenue requirement in this general rate case on depreciation rates approved in 2018.

Q. Given that the Commission will issue a final decision on the recently filed depreciation rates prior to the rate effective date for this general rate case, why has NWN based its test year depreciation expense on depreciation rates approved in 2018, rather than on the updated depreciation rates in the 2021 depreciation study?

A. NWN asserts that the impact of updating the depreciation rates to those in its 2021 study is an increase to the revenue requirement of approximately $8 million. Based on this assumption of a rate increase, NWN states that it does not want to include an increase to depreciation expense in its proposed revenue requirement in order to reduce the rate increase. Accordingly, NWN proposes to delay the effective date of the update to depreciation rates in Docket No. UM 2214 until November 1, 2023. NWN also proposes to have a single-issue rate case in 2023 to allow an update to retail rates on or around November 1, 2023, to incorporate the impact of the of the November 1, 2023, change to depreciation rates.

Q. If NWN did not want to update its depreciation rates to be effective until November 1, 2023, why did NWN file a new depreciation study in December 2021?

A. NWN is required, by Commission rule to file a depreciation study every five years and did not seek a waiver. It filed its last depreciation study in 2016 and accordingly, was required to file another depreciation study in 2021.

Q. Have the depreciation rates for the UM 2214 case been determined?

A. Not yet. Currently, the UM 2214 case is under Staff review. It is too early to tell at this time if the rates overall would increase or decrease depreciation expense. Based on the hearing schedule, the target Commission decision date is September 23, 2022.

Q. How did you analyze the Company's proposed depreciation expense, and what information did you review?

A. To confirm that the depreciation expense was properly calculated using the authorized depreciation parameters in Commission Order No. 18-007, Staff, in data requests to the Company, asked for calculations for "Depreciation Expense" and "Total Accumulated Depreciation" in Excel format with cell reference links and formulae intact, along with other supporting work papers.

Upon going through the work paper that was filed by NWN with the Company, Staff verified the Company's calculations.

1. Staff reviewed several data files and checked the reference links, formulae, and calculations provided in these files.
2. Staff reviewed how the Company calculated depreciation expense using the rates authorized in Order No. 18-007.
3. Staff verified how the Company forecasted depreciation expenses.
4. Staff reviewed how the Company calculated the depreciation expense and depreciation reserve adjustments.
5. Staff sent data requests to NWN to review and clarify the worksheet data and gain a better understanding of NWN's filing.

ISSUE 2. DEPRECIATION RESERVE

Q. Describe the Depreciation & Amortization Reserve.

A. Depreciation reserve is Accumulated Depreciation, at a point in time, the total amount of recorded depreciation, retirements, gross salvage, cost of removal, and other adjustments. As with depreciation expense, the unamortized balance of the associated assets generally appears in rate base and earns a return at the allowed rate.

Amortization, like depreciation, relates to intangible assets, such as computer software and regulatory assets. Reserves are affected by depreciation expenses, amortization expenses, retirements, gross salvage, cost of removal, and other adjustments. If depreciation expense was changed, the accumulated depreciation and amortization should be changed accordingly.

Q. Describe the depreciation effect on the revenue requirement of a utility.

A. NARUC, in its “Public Utility Depreciation Practices” manual on “Depreciation Expense and Its Effect on the Utility’s Financial Performance – Revenue Requirement” states:

> 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 addition, deferred income taxes, rate base, and cost of capital are all affected by the depreciation practices of a utility.[4]

[4] NARUC, *Public Utility Depreciation Practices,* p.195 (1996).

Q. What is the relationship between depreciation and revenue requirement?

A. Under cost of service regulation, revenue requirement refers to the revenues the utility must earn to recover the costs of providing utility service and the opportunity to earn a reasonable return on its capital investment. To compute the revenue requirement (RR), a basic formula is followed:

RR = Operating & Maintenance Expenses + Depreciation Expenses + Rate of Return% x (Rate Base).

In this formula, "Depreciation" (meaning the gross value of the utility's property less the accumulated depreciation of utility property) is one of the largest line items in the cost of service; therefore, "Depreciation" is important as both an annual expense and as a reduction of rate base.

Q. How are depreciation parameters used in determining the utility's revenue requirement?

A. In a general rate case filing, the depreciation expense is calculated by using the Commission's authorized depreciation parameters, from which depreciation rates are derived (in this case, those rates set forth in Order No. 18-007), and in traditional FERC classification of Natural Gas Storage and Processing Plant, Distribution Plant, and General Plant assets.

Accumulated Depreciation is the cost of the investment in gross plant that is recovered as Depreciation Expense. Accordingly, the depreciation expense is accumulated and is subtracted from the gross plant to reduce the remaining investment to be recovered. The remaining balance is the Net Book Plant. The net book plant represents the portion of gross plant that is not depreciated.

Q. What were the depreciation and amortization expenses and accumulated depreciation reserve that the Company originally filed in its revenue requirement?

A. The depreciation and amortization expenses and accumulated depreciation reserve are listed below:

1. In the filing, NWN asked for a total of $111.7 Million (Depr/Amort Exp)
2. In the filing, NWN asked for a $1,503 Million (Accumulated Depr Reserve)
3. The Oregon Jurisdiction 12-Month Test Year Ending October 31, 2023, will have:
   - Plant Depreciation & Amortization Expense Increased to $111.7 Million
   - Accumulated Depreciation and Amortization in Rate Base Decreased to ($1,503 Million)

Q. Have you proposed any adjustments on NWN's depreciation expense in the UG 435 rate case filing?

A. No. I made no adjustments because I found that:

1. The depreciation rates that NWN used to calculate the expense and accumulated depreciation reserve in the revenue requirement are consistent with the rates that were authorized in Order No. 18-007.
2. The depreciation and reserve in the revenue requirement are properly recorded.

Q. Please explain if the depreciation expense in this testimony is final.

A. No. If any adjustments are made from Plant-In-Service and the cost allocation factor between states (which are being reviewed by other Staff witnesses), the Company's final depreciation expense and accumulated depreciation would be changed accordingly.

Q. What are your concerns with NWN not using the updated depreciation rates in UM 2214 for purposes of book accounting as well as the UG 435 general rate case?

A. NWN should comply with the Commission order in Docket No. UM 2114 as to when the new depreciation rates go into effect for book accounting purposes. In principle, the new depreciation rates should apply promptly for book purposes. The reasons are as follows:

The purpose of a depreciation study is to measure the asset mortality characteristics, to use the characteristics to determine appropriate rates for accrual of depreciation and depreciation reserve. To accomplish this, depreciation expense should match the consumption of the facilities. Such matching ensures that financial statements accurately reflect the results of operations.

The matching concept is known as "intergenerational customer equity." Intergenerational customer equity means the costs are borne by the generation of customers that caused them to be incurred, not by some earlier or later generation. This matching is required to ensure that charges to customers reflect the actual costs of providing service. In short, to be fair and reasonable, we should be clear, cost of service, cost causer pays.

Also, the importance of updating depreciation rates and accurately recording depreciation is particularly important in light of its significant impact on customers' rates. For example, NARUC in Public Utility Depreciation Practices (page 195) states:

> 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 addition, deferred income taxes, rate base, and cost of capital are all affected by the depreciation practices of a utility.

With respect to application of updated depreciation rates in UG 435, Staff does not have a position at this time as Staff has not completed its review of the depreciation rates under review in Docket No. UM 2114. If the new depreciation rates authorized in Docket No. UM 2214 would result in a reduction in overall depreciation expense, Staff believes this benefit should be immediately passed on to customers in this rate case. However, Staff does not intend to attempt to compel NW Natural to include in this rate case any increase to depreciation expense that may result from the new depreciation rates authorized in Docket No. UM 2214. If the Company chooses to absorb the increased depreciation expense associated with newly authorized depreciation rates rather than including that additional expense in revenue requirement in this case Staff will not object.

Q. The Company proposes a single-issue rate case by tracking in the new depreciation rates in November 2023. Do you support a single-issue rate case in this instance?

A. No. Staff does not support a “tracker” or single-issue rate case where the tracking is proposed to take place so long after the general rate review. Single-issue ratemaking proceedings are disfavored by the Commission because allowing recovery of certain costs without concurrent review of other elements of the revenue requirement means the resulting rates are not reviewed for overall reasonableness.[5]

Q. Would Staff object to NWN incorporating the depreciation rates approved Docket No. UM 2214 into this general rate case?

A. No. However, Staff notes that if the updated depreciation rates authorized in UM 2214 result in an increase to depreciation expense, there is a question of whether ultimately, the rate increase approved in this UG 435 rate case can exceed the proposed rate increase that was noticed at the beginning of this proceeding.

Q. Has Staff confirmed NWN’s testimony regarding the revenue requirement impact of its updated depreciation rates in its 2021 depreciation study.

A. Staff has not. However, Staff is reviewing the proposed rates in Docket No. UM 2214.

Q. In Docket No. UM 2213, NWN asks to delay updating depreciation rates for its North Mist Plant until January 1, 2023, to coincide with a scheduled

[5] *See e.g., In the Matter of* Cascade *Natural Gas Company,* Docket No. UM 2026, Order No. 20-015, p. 10 (November 15, 2020).

update to its Schedule 90 for Firm Storage Service – With No Notice Withdrawal. What is the Company's proposal on this issue?

A. According to Kyle Walker's (from NWN) email response to Staff on January 3, 2022, "The North Mist assets (UM 2213) are not included in the NWN asset portfolio (UM 2214). We conducted two separate studies for a few reasons. North Mist (Schedule 90) assets benefit only one customer (PGE). PGE pays 100% of the depreciation for those assets. Also, we are proposing that the revenue requirement impact from the studies become effective at different times. We proposed to make the effective date November 1, 2023, for the NWN portfolio of assets to mitigate rate increases in 2022."

Please note, the intent of UM 2213 is to establish depreciation parameters for North Mist Plant. The two major parameters of a depreciation study are (1) survival curve-projection life and (2) net salvage percent. In UM 2213, the updated depreciation parameters should be retrieved from UM 2214 (UM 2214 is the NWN total system depreciation study) for each of the corresponding FERC accounts. This is why it is important for the Commission to determine the depreciation parameters first in UM 2214.

ISSUE 3. AFUDC

Q. What is Allowance for Funds Used During Construction (AFUDC)?

A. AFUDC is defined as the cost of money used during construction. AFUDC is capitalized as part of Plant in Service. The purpose of AFUDC is a regulatory method of compensating a utility for the financing costs it incurs during construction of new facilities.

Q. Did you analyze the Company's calculation of its AFUDC rates?

A. Yes. I reviewed the company's calculation of its AFUDC rates. I sent out Data Request Nos. 122-125 and asked the Company to explain in detail whether the Company's calculation of its AFUDC rates complies with the FERC AFUDC rate formulas and accounting requirements.

Q. What is the historical treatment of AFUDC?

A. The historical treatment of AFUDC includes:

1. AFUDC is a non-cash reporting item accrued until such time as Construction Work in Progress (CWIP) is closed and transferred to a Plant in Service account.
2. In Oregon, the Rate Base excludes CWIP, non-utility property, and plant held for future use (it is not yet used and useful, i.e., plant that is still under construction and not yet in service).

Q. What information you have reviewed and analyzed?

A. Based on NWN's testimony and data responses, I reviewed and analyzed following components:

1. FERC's two formulas for calculating maximum allowable AFUDC rates.

   The formula and elements for the computation of the allowance for funds used during construction shall be:

   Ai = s*(S/W)+d*(D/D+P+C)*(1-S/W) = Gross allowance for borrowed funds used during construction rate

   Ae = [1-S/W]*[p*(P/D+P+C)+c*(C/D+P+C)] = Allowance for other funds used during construction rate

   S = Average short-term debt

   s = Short-term debt interest rate

   D = Long-term debt

   d = Long-term debt interest rate

   P = Preferred stock

   p = Preferred stock cost rate

   C = Common equity

   c = Common equity cost rate

   W = Average balance in construction work in progress, less asset retirement costs related to plant under construction

2. Authorized Rate of Return - NWN used the OPUC-authorized rate of return (6.965 percent) in the AFUDC calculation.

Q. Has FERC granted a waiver to modify the existing AFUDC rate calculation?

A. Yes. On June 30, 2020, FERC granted a 12-month waiver to modify the existing AFUDC rate calculation beginning March 2020, in response to the

Coronavirus (COVID-19) emergency. The waiver allows using a methodology to remove distorting effects of temporary increases in the amount of current period short-term debt needed in response to the COVID-19 emergency by using an average of historical short-term debt balances for the year ended 2019. All other aspects of the calculation remain unchanged. On September 23, 2021, this waiver was extended through March 31, 2022.

Q. Have you sent FERC's COVID-19 relief order to NWN for its consideration?

A. Yes. On January 24, 2022, I sent an email to the company and asked if FERC's COVID-19 relief order applies to NWN. If it did, they could recalculate AFUDC rates and send an update.

On January 26, 2022, NWN sent an email response back to me. Kyle Walker, NWN Manager of Rates and Regulatory Affairs said, "I've worked with our Plant Accounting team to get you some answers. I'll answer them in the same manner you lay them out below:

1. The Company did not utilize the 12-month waiver because it did not impact the AFUDC rate.
2. For the time stated we have been in AFUDC debt only, as our average short-term debt balances exceeded our CWIP balance, so our AFUDC debt rate is based solely upon our average short term debt rates.
3. We calculate on an annual basis whether we will have AFUDC Debt or AFUDC Debt and Equity. Once we've determined that at the beginning of

the year, we follow it throughout the year. However, monthly we calculate the actual AFUDC Debt or Equity rate."[6]

Q. Have you made adjustments to NWN's AFUDC filing?

A. No. The Company's AFUDC calculations meet FERC and Oregon regulatory requirements.

Q. Are your findings and recommendations in this testimony final?

A. No. My findings and recommendations could be changed after reviewing other parties' testimony.

Q. Does this conclude your testimony?

A. Yes.

[6] Staff/1102, January 26, 2022, e-mail from Kyle Walker to Ming Peng.

CASE: UG 435
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualifications Statement

April 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME: Ms. Ming Peng

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Econometrician
Energy Rates, Finance, and Audit Division

ADDRESS: 201 High Street SE, Suite 100
Salem, OR 97301

EDUCATION & TRAINING:

M.S. Applied Economics
University of Idaho, Moscow

B.S. Statistics
People's University of China, Beijing

CRRA Certified Rate of Return Analyst in 2002
Society of Utility and Regulatory Financial Analysts

Depreciation studies – the Society of
Depreciation Professionals

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing

400+ credit hours on 30+ training topics in the public utility industry

EXPERIENCE: 1/11/1999 – Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 23 years. My roles include:

Expert Witness, Case Manager, Principal Analyst, Econometrician, Economist, Utility Analyst, and Policy Analyst:

I have testified in various formal state hearings and performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in the public utility industry.

Principal Analyst and Case Manager, Settlement Lead/Negotiator for Depreciation Ratemaking:

I have served as a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) for the past 12 years. In this role, I've had a strong focus on Depreciation Rate Determination (fixed cost allocation, and capital recovery). I was also a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) during this time period.

In this position, I investigated, analyzed, and calculated energy asset retirement cost and impact, as well as power plant decommissioning cost and impact, on customer rates. I reviewed, calculated, and analyzed fixed asset depreciation and proposed depreciation parameters for each of FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants. The energy sources I have worked on Steam/Coal, Hydraulic, Natural Gas, Wind, Solar, and Geothermal.

My analyses of "Power-Plant-Shutdown" activities (accelerated plant retirement, and decommissioning cost recovery) include the following cases:

1. PGE closes Boardman Coal-fired plant (UM 1679 & UE 215).
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246).
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under the ORS 757.734 – Recovery of investment in Klamath River dams in OPUC UE 219.
4. Idaho Power Valmy Coal-fired power plant Shutdown (UE 316).
5. PGE Colstrip Coal-fired power plant Shutdown (UM 1809).

I conduct case investigations and analyses on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are: (1) PacifiCorp (serves 6 states), (2) PGE, (3) Northwest Natural Gas (NWN), (4) Idaho Power, (5) Avista Corp (Washington), and (6) Cascade Gas (CNG, Montana).

Lead Analyst and Case Manager on Financial Dockets:

Prior to my current position, I was a Lead Analyst and Case Manager for cost of debt capital for nine years. I reviewed market risks, derivatives and hedging, debt issuance, and stock flotation. My analysis directly informed utility and energy policy.

I advised the Commission on over 60 financial dockets. The Commission incorporated all of my recommendations into final orders.

I was certified by the Society of Utility and Regulatory Financial Analysts as a Certified Rate of Return Analyst in 2002.

Public Utility & Policy Analyst:

Rulemaking: I have formulated energy regulation rules for utility performance incentives and cost-of-service regulation.

Energy Utility Merger & Acquisition: I have testified in formal state hearings involving utility mergers & acquisitions. I conducted Acquisition Premiums & Credit Risk Analysis and testified on behalf of the Commission in MidAmerican Energy Company's application to purchase PacifiCorp. I also reviewed Scottish Power's earlier purchase of PacifiCorp, and PGE's emergence from Enron after the Enron bankruptcy.

Integrated Resource Planning (IRP, Least Cost Planning): I provided comments to the Commission for decision making on Boardman to Hemingway (B2H), a 500-kV transmission power line, which included a cost and benefit list, a pros and cons list, alternatives, and the relevant legal risks. I also provided comments on utility's IRPs, such as total cost for power generation, power capacity (MW) replacement cost, avoided cost for free fuel, and emission trading cost.

Clean Energy – Dollar Impact on Customer Rates: I analyzed and calculated the rate impact and comparative advantage of clean energy. I built the portfolio optimization models to analyze the coal-fired generating capacity replacement.

General Rate Cases: I have been a part of *almost every energy rate case* since I joined the Oregon PUC on 1/11/1999. Historically, my review included fuel price forecasting, property sales, load forecasting, weather normalizations, cost of debt, and capital structures. Currently, my reviews are focused on depreciation and reserve, and AFUDC Capitalization Policy.

Survey Sampling Design: Results of my statistical sampling design and sampling procedures are incorporated into my revenue requirement testimony in Commission Docket No. UM 1288.

Auditing, Interest Rate, Late Payment: I audited cost of capital and financial components. My survey report and analyses are published annually for Oregon (UM 779).

Survey for Market Competition & Economic Policy: I conducted and wrote the report on Telecommunications, “Market Competition and Economic Policy Survey Analysis” for House Bill 2577. This report has been published on the OPUC web annually for 15 years.

Mentor in the ICER - International Confederation of Energy Regulators: I was selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. My “Mentoring Topics” focus on Incentive Regulation; Rate and Economic Impacts of “Cost-of-Service” regulation in the U.S. and “Price-Cap Performance Based Regulation” in Europe; Cost of Capital, Energy Demand and Price Forecasting Modeling; Least Cost Planning; Regulatory Policy; and Renewable Energy issues within regulated rate structures.

CASE: UG 435
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1102

Exhibits in Support
Of Opening Testimony

April 22, 2022

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 124

For AFUDC Accounting (Allowance for Funds Used During Construction-AFUDC, Construction Work-in-Progress-CWIP), please fill out the attached computational tables DR 124 Attachment A with calculation formulas for years from 2016 to 2022 individually. The tables should identify a) the sources of funds, b) the amount or balance of such funds, c) the applicable cost rates for such funds, d) Construction Work-in-Progress CWIP, and e) the relative weight that should be given to those sources of funds in (e) the derivation of the AFUDC rates.

Response:

Please see the UG 435 OPUC DR 124 Attachment A. We have updated the values where appropriate. The AFUDC calculation as provided by Staff does not match how the Company calculates AFUDC. We have made modifications to tab 2022 to agree with the forward-looking calculation methodology.

The derivation of the AFUDC rates are provided by month in UG 435 OPUC DR 124 Attachment 3.

NW Natural calculates the AFUDC entry using an automated program within the general ledger system that produces thousands of line items each month. AFUDC is applied to previous month's ending balance plus half of current month's Construction Work in Progress (CWIP) expenditures. Certain non-cash items are excluded from the AFUDC calculation.

The forecast periods are calculated in the long-term planning forecast system, UI Planner. The methodology of the AFUDC forecast calculation complies with the FERC methodology for AFUDC by utilizing short-term debt rates until CWIP exceeds the short-term borrowing. UG 435 OPUC DR 124 Attachments 1 and 2 are the summary outputs for the years 2021 and 2022 input into an annual FERC AFUDC spreadsheet format. The 2021 and 2022 attachments agree to the analysis produced in the long-term planning forecasting system.

CASE: UG 435
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Opening Testimony

April 22, 2022

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

A. My name is Paul Rossow. I am a Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1201.

Q. What is the purpose of your testimony?

A. I reviewed two main areas of Northwest Natural Gas Company's (NW Natural or Company) proposed Test Year expenses: Memberships and Dues, and Meals and Entertainment. From that review, I recommend an adjustment to Test Year expenses. The proposed adjustments I recommend are derived from review of multiple data responses, analysis of NW Natural 2021 Operations and Maintenance (O&M) non-payroll transactions for FERC Accounts 500 through 935, and Commission policy regarding Memberships expense.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. I recommend reducing expenses associated with Memberships and Dues/Meals and Entertainment by ($969,912). This recommendation is based on reviewing NW Natural's filing as well as responses to Staff Data Requests relating to dues, memberships, meals, entertainment, and miscellaneous operation and maintenance expenses. My adjustment applies long-standing Commission practices for these area of company activities. The ($969,912) is comprised of a ($443,905) adjustment to Oregon allocated test year associated with conferences, subscriptions, memberships and dues; and meals and entertainment expense of ($526,007).

Please note that I may revise my recommendations based on testimony filed by other participants in this rate case.

ISSUE 1. MEMBERSHIPS AND DUES

Q. Please provide a summary of the Company's proposal for memberships and dues.

A. NW Natural's forecast of Test Year expense for memberships and dues starts with actual expenses for January through September 2021 and forecasted expenses for the remaining three months of 2021. NW Natural then adjusts these amounts to include projected changes for the Test Year expenses. NW Natural did not provide narrative testimony specifically addressing memberships and dues. However, the Company's response to Staff Data Request 138 Attachment 1 (DR 138), provided an amount of $979,930 for an Oregon allocated forecasted Base Year and an Oregon allocated forecasted Test Year amount of $788,946.[1] Noted in NW Natural's response to Staff's Standard Data Request 90 Attachment 1 (SDR 90), is that the decrease in expenses between the Base Year and Test Year represents NW Natural's decision to no longer record subscription services and conferences to its dues and membership cost element number 501900 as of 2021.[2]

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

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1 Staff/1202, Rossow/1, NWN Response to Staff DR 138.

2 Staff/1202, Rossow/2, The note in NWN's response to SDR 90 states "The actual costs recorded to the memberships and dues account in 2021 are comprised of the following additional categories. Going forward the non-memberships and dues costs should not occur in this account."

utility's revenue requirement (RR), primarily because some or all of the organizational activities are:[3]

- Not necessary for utility service,
- Primarily to promote the company within the community,
- Do not benefit customers, or
- Would not be recoverable in rates if done by the utility itself.

Based on these principles and Commission practice Staff recommends recovery of dues and memberships for:

1. Industry Research Organizations (e.g., Gas Technology Institute) at 100 percent, except where organizations perform redundant services;
2. National and Regional Industry Trade Organizations (e.g., American Gas Association) at 75 percent, on the basis that certain activities are promotional or lobbying in nature or otherwise do not benefit customers;[4] and

[3] *In* the *Matter of Revised Tariff Schedules filed by Pacific Northwest Bell Telephone Company (PNB)*, Docket No. UT 43, Order No. 87-406, p. 40 (March 31, 1987) ("Only expenditures necessary for furnishing utility service should be reflected in rates. As a result, stockholders are responsible for charitable donations, community affairs expenditures, and non-professional dues." (citations omitted).

[4] *See e.g., In the Matter of Revised Tariff Schedules File by Northwest Natural Gas Company for a* General *Rate Increase*, Docket No. UG 81, Order No. 89-1372 (October 18, 1989) ("Trade associations provide valuable research and other services to utilities. They also engage in promotional activities of a type that may not be recoverable from ratepayers. So an apportioning between ratepayers and stockholders is appropriate. The Commission has in the past generally allowed 75 percent of trade association dues to be passed on to ratepayers by Oregon utilities. The Commission will apply that policy in this case. However, Staff pointed out that significant expenditures by the AGA were related to promotional and marketing activities. The Commission is concerned about that and will disallow a greater portion of trade association dues in the future if an excessive proportion of an association's expenditures are for such activities.").

3. 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 benefit customers.

Q. Please explain your analysis for the memberships and dues adjustment.

A. Staff's analysis included review of NW Natural's memberships and dues expenses recorded to FERC Accounts 820 through 935 provided in electronic spreadsheet format in responses to SDR 90 Attachment 1, Data Request 136 Attachment 1, DR 138, and Data Request 163 Attachment 1 (DR 163). Utilizing responses to SDR 90 and DR 163, Staff developed a Workbook[5] to establish an Oregon allocated 2021 Base Year of actual dues and membership expenses amounting to $1,036,463. Staff then searched and sorted through conferences, subscriptions, dues, and memberships expenses by using several column headings titled "Cost Element Name", "FERC Account", "Fiscal Year", "Period", "Manually added Classification", "Name of Offsetting Account", and "Name" provided by the Company.

Next, Staff used NW Natural's Oregon allocated 2021 transactional data for non-payroll expenses for each FERC account and escalated to approximate the test year expense by applying the All-Urban Consumer Price Index (CPI) of 4.2 percent and 2.2 percent,[6] respectively, to arrive at the test year adjustment.

5 Staff/1202, Rossow/3.
6 See the Oregon Economic and Revenue Forecast, March 2022, Volume XLII, No. 1, Release Date February 9, 2022.

Staff usually approximates the Company's Test Year amount for its disallowance by escalating the proposed adjustment with the CPI factors.

Keeping with Commission policy regarding conferences, subscriptions, dues, and memberships for organizations in the energy utility industry, Staff recognized 100 percent of the projected expenses associated with industry research organizations. The Western Energy Institute is one such organization.

Staff applied a disallowance of 25 percent of the expenses associated with national and regional industry organizations on the basis that certain levels of activities of such organizations are lobbying or promotional in nature, or otherwise do not benefit customers. This disallowance represents a sharing of interests between stockholders and customers in these organizations. An example of this type of organization is the American Gas Association, which advocates and promotes the benefits of natural gas

Finally, Staff applied a disallowance of 100 percent of the expenses associated with technical, commercial, economic development organizations, and transactions without enough description to clearly identify the name of the Organization.

Q. What was the result of Staff's analysis for memberships?

A. Staff's analysis results in an escalated Oregon allocated Test Year disallowance to conferences, subscriptions, dues, and memberships of ($443,905).

ISSUE 2. MEALS AND ENTERTAINMENT AND MISCELLANEOUS OPERATIONS AND MAINTENANCE EXPENSES

Q. Please explain the Commission's historical treatment of O&M non-payroll discretionary expenses.

A. O&M non-payroll discretionary expenses include expenses for items such as awards, birthday cards, food, 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.[7] 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. Please provide a summary of the Company's filed proposal for O&M expenses.

A. NW Natural proposes including $199.2 million of O&M in the 2023 Test Year on an Oregon allocated basis.

Q. Did the Company propose an adjustment for meals and entertainment, awards, gifts, travel, and similar discretionary expenditures?

A. Yes. NW Natural included an adjustment to normalize for the impacts of COVID-19 during the Base Year on meals and entertainment, refreshments,

[7] *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).

business travel, conference travel, and education. This adjustment increases the total expense Test Year expense to an amount of $850 thousand, and the Oregon-allocated amount of $755 thousand.

Q. Please describe Staff's analysis of the company's proposal for O&M non-payroll expenses.

A. Staff reviewed NW Natural's response to SDR 57,[8] to identify any O&M non-payroll discretionary expenses that appear to be excessive, without sufficient business purpose, or not related to the provision of safe and reliable energy to customers. In the Company's response to SDR 57, the Company provided its 2021 O&M non-payroll transactional expenses in Excel format. The accounting data includes several fields, including FERC accounts, transaction descriptions, vendor name, currency amount, and general ledger account descriptions. From this spreadsheet, Staff created a workbook to aid in Staff's analysis of O&M non-payroll discretionary expenses. Staff filtered the data by transaction description and highlighted the results. The selected expenditure types were Books and Magazines, Corporate Identity, Dealer Relations, Employee Awards, Materials, Meals and Entertainment, Mileage Reimbursement, Miscellaneous, Non-Employee Gifts, Office Supplies, Parking, Postage, Professional Service, Refreshments, and Rents and Maintenance.

Staff reviewed the meals and entertainment expenses to determine whether they benefit customers or are discretionary and should be shared

[8] SDR No. 57 requested the Company to provide information for all non-payroll expenses recorded in all FERC accounts for the base year.

between customers and shareholders according to Commission policy.[9] The Commission has historically agreed with Staff that such discretionary expenses are not required to provide safe and adequate service to customers. Additionally, Commission policy does not require customers to support causes through natural gas rates that customers do not necessarily support.[10]

Items Staff found to have no benefit to customers, Staff excludes at 100 percent. Those expenses Staff believed benefitted both customers and shareholders, Staff excluded at 50 percent. Once Staff determined the amount removed based on 2021 dollars, Staff escalated using CPI factors of 4.2 percent and 2.2 percent, year over year for 2022 and 2023, respectively, to arrive at the test year adjustment.[11] Staff escalated using the CPI factors, which is commonly proposed by Staff for O&M non-payroll expenses.

Q. Would you please explain your adjustment

A. Yes. For example, within the selected expenditure types, Staff noted transactions related to expenses described as: Awards, Beverages, Coffee, Dinner, Gift Cards, Lunch, Meals, and Meeting that Staff recommend excluding 50 percent.

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9 Examples of key words Staff used to search transactions included candy, gum, b-fast, bfast, dessert, party, balloon, bereavement, flower, meal, Christmas, floral, recognition, appreciation, food, award, going away, cake, birthday, b-day, snack, coffee, donut, doughnut, bowling, golf, blazer, ball, ticket, prize, gift, dinner, lunch, supper, wine, breakfast, diner, restaurant, napkins, photo, xmas, flight, hotel, airfare, air fare, air, travel, parking, luggage, baggage, shuttle, motel, taxi, lodging, and airport.

10 See *Portland General Electric Company,* Docket No. UE 197, Order No. 09-020, p. 16 ("We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders.").

11 The data in the Company's non-confidential response to Staff Data Request No. 57 is too voluminous to include as an exhibit. However, Staff does include discretionary O&M cost data showing the FERC account totals for each account as Exhibit Staff/1202, Rossow/4.

For those expenses that have no benefit to customers as originally described in NW Natural's response to OPUC Standard Data Request 57, Staff excludes at 100 percent. Staff noted transactions related to expenses described as: Holiday gift for country clubs, Contractor rewards program, Event Winner, Wine glasses, Donation, and Sporting events.

Q. What was the result of Staff's review for these expense types?

A. After reviewing O&M non-payroll 2021 Oregon base year expenses, Staff identified ($840,224) of expense that should be excluded at 50 percent, which equals ($420,112). Staff identified ($75,450) of expenses that should be 100 percent removed. Staff used the CPI factors mentioned above in escalating the ($420,112) and the ($75,450) to the 2023 Test Year, results in a decrease to the Oregon Test Year expense of ($526,007).

Q. What is Staff's total adjustment?

A. Staff's total adjustment is a decrease to the Oregon Test Year expense of ($969,912) for O&M non-payroll expenses.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 435
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualifications Statement

April 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME:	Paul Rossow
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Energy Resources & Planning Division
ADDRESS:	201 High Street SE Suite 100 Salem OR 97302-1166
EDUCATION:	Professional Accounting and Computer Application Diplomas, Trend College of Business 1987
EXPERIENCE:	I have been employed with the Public Utility Commission of Oregon as a Utility Analyst since October of 2002. Current responsibilities include research issues relating to energy utilities. I have actively participated in regulatory proceedings in Oregon, including UE 147, UE 167, UE 170, UE 179, UE 180, UE 197, UE 210, UE 213, UE 215, UE 217, UE 233, UE 246, UE 262, UE 263, UE 283, UE 335, UE 374, UE 394, UG 152, UG 153, UG 181, UG 186, UG 201, UG 221, UG 246, UG 284, UG 344, UG 347, UG 388, UG 389, UG 390, and UG 433. 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: UG 435
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1202

Exhibits in Support Of Opening Testimony (Electronic)

April 22, 2022

CASE: UG 435
WITNESS: MICHELLE SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Opening Testimony

April 22, 2022

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

A. My name is Michelle Scala. I am a Senior Utility Analyst employed in the Strategy 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/1301.

Q. What is the purpose of your testimony?

A. My opening testimony discusses Staff's analysis into NW Natural's programs and efforts centered on equity, affordability, and customer assistance; decoupling and weather adjusted rate mechanisms; and rate spread and rate design proposals.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. EQUITY, AFFORDABILITY, AND CUSTOMER ASSISTANCE

Q. Please briefly describe Staff's analysis into NW Natural's equity, affordability, and customer assistance issues.

A. Staff conducted a general review of NW Natural's current and planned initiatives to promote equity and affordability in NW Natural (Company) rates and program offerings. More specifically, Staff reviewed the Company's testimony and other publicly available information describing NW Natural's:

- Community and Equity Advisory Group;
- Arrearage Management Program;
- Energy Affordability Act implementation efforts; and
- Other sources of customer assistance.

Staff also made a number of data requests to the Company in an effort to further assess the cost effectiveness and qualitative benefits associated with these programs and initiatives.

Q. Equity has not traditionally been identified as a distinct issue addressed by Staff in rate case testimony, what is the reason for calling it out here?

A. Staff has made an intentional decision to bring this critical pillar of just policy to the foreground. Staff analysis of programs intended to serve customers has thus been done through an equity lens aimed at evaluating the Company's efforts to recognize and address under-served and marginalized individuals and groups, and to identify and potentially eliminate barriers.

The lack of equity and inclusion in the energy industry has been highlighted in recent years by multiple channels throughout the public and private sectors. In 2020, the United States Department of Energy's Office of Economic Impact and Diversity launched its Equity in Energy Initiative.[1] This initiative is designed to expand the inclusion and participation of individuals in underserved communities such as minorities, women, veterans, and formerly incarcerated persons, in all the programs of the Department of Energy and in the private energy sector. Highlighted as critical pieces are energy affordability and low-income community energy solutions.

In Oregon, the State Legislative Assembly passed the Energy Affordability Act, House Bill (HB) 2475 (Act) in an effort to enhance equity considerations in the utility regulatory space and promote inclusion of environmental justice advocates in Commission processes. HB 2475 was signed into law in 2021. The measure created new provisions and amended ORS 756.010, 757.072, and 757.230 to include definitions for "environmental justice" and environmental justice communities" in ORS governing the Commission and utilities it regulates.

Section 2 of the Act amends ORS 757.230 to allow consideration of differential energy burdens on low-income customers and other economic, social equity, or environmental justice factors that affect affordability for certain classes of utility customers in rate design.

Section 3 of the Act provides intervenor funding agreements for organizations that represent low-income residential customers and residential customers of environmental justice communities. Section 7 of the Act allows

[1] Equity in Energy™ | Department of Energy.

the Commission to address the mitigation of energy burdens through bill reduction measures, including, but not limited to, demand response or weatherization.

The Federal Equity in Energy Initiative and Oregon Energy Affordability Act are two examples of changing attitudes in the energy industry. Staff's analysis, while always pillared to ensure Oregon utility customers have access to safe, reliable, and high quality utility services at just and reasonable rates, has similarly evolved to provide a more overt space for equity.

Q. How has this "evolution" impacted Staff's analysis of NW Natural's UG 435 proposal?

A. Generally, Staff endeavored to identify how the Company has accounted for and prioritized equity in its programs and proposals. There are several dimensions to equity in action, some of which have been memorialized in publications such as a 2019 white paper by the Urban Institute and supported be the Energy Trust of Oregon.[2] In this document, researchers highlighted that equitable energy practices should:

1. Demonstrate an understanding the historical legacies of disparities;
2. Have a detailed awareness of populations that were affected by past disparities and of new populations that may be negatively affected by a planned intervention, i.e., service, program, agency, or institution;
3. Include the perceptions and insights from all recipients or stakeholders at all levels of interventions' design, staffing, management, and execution;

[2] https://www.urban.org/research/publication/state-equity-measurement.

4. Ensure that the processes for eligibility and application for a service are not exclusionary;
5. Track differences in service outputs that indicate underlying disparities; and,
6. Measure disparate impacts between groups, including ongoing outcome differences.

Separately, the American Council for an Energy-Efficient Economy (ACEEE) presents four dimensions of energy equity: procedural, distributional, structural, and transgenerational, which it describes "can improve decision making, change how benefits and burdens are distributed, and address current barriers."[3] Further, equitable energy policies often improve energy access and affordability, procedural justice, economic participation and community ownership, and health and environmental impacts.

Applying equity dimensions to analyze every issue is not always simple, and often with established utility programs, the requisite data for this type of assessment has not been collected. However, part of Staff's approach has been to identify where such gaps exist and recommend conscious applications of qualitative and quantitative equity metrics into new and existing utility programs.

Q. In what ways has NW Natural demonstrated fostering equity in Company practices?

[3] Energy Equity | ACEEE.

A. In the Company's opening testimony, NW Natural credits itself with a long history of community involvement throughout its service territory and having a commitment to diversity, equity, and inclusion (DEI).[4] On the Company's website, NW Natural includes a page dedicated to providing visitors information on how the Company makes DEI part of its business. One such way is through the use of a DEI Council. NW Natural started the DEI Council 20 years ago to help the Company prioritize the inclusion and equity of underrepresented groups in our company and community. The work of the DEI council includes the use of Employee Resource Groups (ERGs), which provides opportunities for employees to contribute directly to DEI and workplace culture.

Externally, the Company describes a strategy focused on building partnerships, providing financial support, and ensuring equitable access to natural gas programs and services. Staff finds this strategy evidenced by some specific examples such as a demonstrated focus on language accessibility via the expansion of the Spanish Resource Team in the Company's Customer Contact Center and addition of a full-service Spanish language interactive voice response phone system; flexible program offerings to accommodate unique needs situations such as the Crisis Grant afforded in NW Naturals Schedule R, Residential Arrearage Management program; and robust and thoughtful outreach to a diverse set of stakeholders and community members when developing and marketing assistance programs.

[4] NW Natural/100, Anderson-Kravitz.

Most recently, NW Natural has begun work to establish the Community Equity and Advisory Group (CEAG). According to the Company, "[t]he CEAG will be comprised of a broad panel of representatives from community-based organizations (CBOs) who can share their expertise and knowledge of the experiences of the communities they serve."[5] The CEAG is intended to advise the Company on system planning processes and other NW Natural programs and initiatives. NW Natural provides three primary objectives of the CEAG to:

1. Facilitate inclusive discussions;
2. Provide perspective on social, economic, racial, tribal, and environmental equity, and assist in identifying best practices and solutions for improving and expanding equity; and,
3. Be a resource for communities to understand the regulatory and policy environment of the utility.[6]

Q. What progress has the Company made with the CEAG at this point in time?

A. NW Natural initiated work on the CEAG in August 2021 and formally announced the development of the CEAG in late September of the same year. The activity has been extensive and ongoing, however, no incremental costs related to the CEAG have been expended at this time. The Company stated it is still in the process of developing cost estimates and anticipates the major cost categories to be the member stipends and third-party facilitator. A

[5] NW Natural/100, Anderson-Kravitz/7-8.
[6] *Id*.

summary of CEAG work to date is provided in the Company's response to OPUC Staff DR 368 and most recently includes planned CEAG member compensation updates, confirmation of ten organizations to participate, and a request for consultant services to review external candidates and solicit recommendations from peer institutions.[7]

Looking forward, NW Natural expects to host a kickoff meeting with CEAG members, engage external stakeholders on CEAG launch and development, and finalize operating agreements, charters, and terms of service for the CEAG.

Q. How has NW Natural gone about selecting members for the CEAG?

A. The Company stated that the CEAG is populated by a broad panel of representatives from CBOs that serve seniors; urban, rural, and coastal communities; non-native English speakers; housing insecure and houseless individuals; BIPOC and LGBTQ+ communities; and individuals with low incomes; as well as representation from Oregon and Washington to align with the community needs and policy requirements of each state. Internal membership will have representation from across the Company.

Terms will run for a length of two years with opportunity for renewal and align with the calendar year. Some members of the inaugural group may be appointed to a three-year term to serve as a resource for new members.

Recruitment will take place each year in the two months prior to identified term dates. If and when a position opens outside of normal terms of service,

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7 Staff/1302; Scala/1-5, NWN Response to OPUC Staff DR 368.

NW Natural in consultation with the CEAG and a third-party facilitator may choose whether to fill the position before normal recruitment periods. As the convener of the CEAG, NW Natural will determine final appointments to the CEAG.

Q. Has the Company made any proposals related to the CEAG in this general rate case proceeding, UG 435, at this time?

A. No. Staff's purpose in investigating and testifying on the CEAG and other equity initiatives in the Company is to highlight ways the utility is or is not making dedicated space for DEI dimensions in its internal and external practices.

Q. Did Staff find any relevant gaps relating to equity in action within its analysis of NW Natural?

A. Like many peer utilities, NW Natural does not currently collect demographic information or data on customer attributes that might inform analyses of socioeconomic, racial, or regional inequities. In response to an OPUC Staff data request,[8] the Company indicated that information like demographics, income level, dwelling type, or household size was collected from customers.

Staff notes that its request was for any data collection efforts related to low-income metrics; so based on how the Company responded, Staff is unclear whether or not the Company has this information from sources other than directly from customers (e.g. purchased data for marketing purposes). The

[8] Staff/1302, Scala/96, NWN Response to OPUC DR 382.

Company has also expressed hesitation about collecting demographic data, most often citing concerns with security, storage, and customer experience.

While Staff recognizes these concerns, Staff finds that community representatives and advocates frequently express a need for and value to demographic data collection and do not believe optional inquiries to collect such data would compromise the customer experience. Further, Staff has highlighted the move towards demographic data collection from utility customers in its published HB 2475 guidance in Docket No. UM 2211. The purpose of this is to improve the capacity for, at a minimum, targeted outreach, informed program design and evaluation, and equity assessments.

Fortunately, NW Natural has initiated a Low-Income Needs Assessment (LINA), as noted in opening testimony.[9] The Company stated that it plans to use the LINA findings to understand the current customer needs on the NW Natural system and ultimately share results stakeholders to help inform HB 2475 implementation. The LINA is being performed with a third-party consultant and is expected to be completed in July 2022. In the Company's response to OPUC DR 385, Attachment 3, the Company provides the LINA RFP, where NW Natural specifies goals, deliverables, and minimum inclusions.[10]

Staff is hopeful that completion of the LINA and a commitment to maintaining this data for relevancy on an ongoing basis may provide the

[9] NW Natural/100, Anderson-Kravitz/9.
[10] Staff/1302, Scala/102-104, NWN Response to OPUC DR 385, Attachment 3.

solution to a lack of demographic and income data collected to date. At the very least, the LINA findings may fill the informational void for NW Natural until data collection practices and minimum expectations are fleshed out in the UM 2211 process or related rulemaking.

Q. The titular issue of this testimony is "Equity, Affordability, and Customer Assistance Programs." How do all these intersect?

A. Earlier in this section of testimony, Staff referenced HB 2475, the Energy Affordability Act, and how some of the most significant changes brought on by the measure were to provide authority to the Commission to consider differential energy burdens on low-income customers and other economic, social equity, or environmental justice factors that affect affordability for certain classes of utility customers. Historic and systemic social inequities have had lasting effects on the affordability of energy. At a high level, customer assistance programs must be designed and administered equitably in order to properly address affordability.

Q. What programs does the Company offer to mitigate energy burden and promote affordability for its customers?

A. NW Natural provides assistance to customers to reduce energy burden through a variety of income-qualified bill assistance and energy efficiency programs. The Company's low-income bill assistance programs are the Oregon Low-income Gas Assistance program (OLGA) and supplemental low-income assistance program, Gas Assistance Program (GAP). NW Natural's low-income weatherization program is the Oregon Low-Income Energy Efficiency program (OLIEE). Both OLGA and OLIEE are funded through public purpose charges (Schedule 301). GAP is funded by NW Natural shareholders, employees, retirees, and customers. The first $60,000 in donations are matched by shareholders each program year. GAP is also the recipient of some grants and donations in the community and benefits from promotional fundraising through bill inserts, newsletters, social media, and community events.

The programs are intended to complement and be additional to federal funding available through the Low-Income Home Energy Assistance Program (LIHEAP). NW Natural works with local Community Action Partnership (CAP) agencies to distribute these funds to income-qualified customers. The Company's response to OPUC Staff DR 383 provided tables showing OLGA, OLIEE, GAP, and LIHEAP annual benefit metrics since 2002.[11] A summary of 2020-2021 benefit metrics is shown in Table 1, below.

Table 1. 2020-2021 NWN Low-Income Assistance Program Summary

	Number of Customers served	Average Payment per household	Payments to Customers	
OLGA	5,044	$ 445	$ 2,243,670	
GAP	1,135	$ 108	$ 122,029	
LIHEAP	2,337	$ 405	$ 946,145	
	Homes weatherized	**Reimbursed Measure Costs**	**Reimbursed Health, Safety, and Repairs**	**Estimated Therms Saved**
OLIEE	341	$ 1,561,476	$ 156,805	60,394

[11] Staff/1302, Scala/97-101, NWN Response to OPUC DR 383.

On March 22, 2022, the Company received approval to continue and expand its Residential Arrearage Management Program (AMP) that was first implemented in 2021 as a financial relief measure to residential customers during the height of the COVID-19 pandemic.[12] The original program offered four grant options that could be utilized in any combination and provide up to $1,200 in assistance to customers. Initial funding was authorized at $6,167,000, of which the majority has been expended on the $300 no-match instant grant since May 3, 2021. The new terms include an increased funding authorization of approximately $3.1 million, including $750,000 set-aside for income qualified customers; an increase to the total participation dollar cap; and an additional low-income instant grant option (LIIGO) for energy assistance (EA) recipients.

NW Natural is expected to further expand this program to allow customers to self-certify income eligibility in order to access the LIIGO regardless of EA history. Staff also recommended the program, which has been available to all NW Natural customers since its initial inception, be narrowed to those who self-certify their household income at or below 300 percent of the federal poverty level (FPL). The intent of this narrowing would be to target funds based on need and promote equity considerations in terms of access to benefits and overall affordability. The Company plans to continue targeted outreach to customers with the highest balances and longest

[12] *See* Docket No. ADV 1373, NWN Advice No. 22-01.

standing balances, as well as to communities with known low-income attributes.

Looking forward, the Company is currently working on a bill discount program that was previewed with stakeholders on March 30, 2022, and filed in April 2022 with an effective date of November 1, 2022. The program aligns closely with the income-qualified bill discount program approved for Portland General Electric (PGE) as Schedule 18 in Docket No. ADV 1365, effective April 15, 2022. Like the PGE program, NW Natural's proposed program is expected to have a three-tiered discount structure available to customers whose income falls at or below 60 percent of the state median income (SMI).

Q. Has the Company proposed any programs or initiatives to address energy burden in the current proceeding, UG 435?

A. NW Natural has not proposed a program to address energy burden in UG 435.

Q. Does Staff have any concerns that nothing additional has been proposed in this rate revision?

A. Staff is satisfied that the Company is taking meaningful steps toward equity, affordability, and customer assistance programs. Staff finds that the Company recognizes, despite a history of operating in DEI spaces, equity must come to the foreground and equitable business practices and program designs are part of a continuous evolution. The Company's upcoming bill discount program will be complementary to many of the assistance programs listed above. The LINA findings and outcomes of the HB 2475 investigation in Docket No. UM 2211 are expected to inform the development of future low-income programs; and, the Company continues to move forward with the CEAG, which will inform multiple activities and major decision points at the utility through an equity lens.

All of these endeavors, including the differential rate proposal, have been formally announced to stakeholders with targeted implementation schedules and engagement strategies. Thus, Staff makes no recommendations regarding the UG 435 proposal with regard to additive equity, affordability, and customer assistance programs at this time, but is supportive of efforts by the Company to continue to apply equity in action, mitigate energy burden, and pursue meaningful data collection and analysis strategies in this space.

Q. Does this conclude your testimony on this subject?

A. Yes.

ISSUE 2. DECOUPLING AND WEATHER ADJUSTED RATE MECHANISM

Q. Please describe the Company's partial decoupling mechanism.

A. According to a 2005 study that was conducted as directed in the Commission order authorizing decoupling, a primary goal of NW Natural's partial decoupling mechanism, also referred to as the Distribution Margin Normalization (DMN) mechanism, is to reduce the uncertainty around NW Natural's distribution fixed cost recovery.[13] NW Natural recovers a portion of its fixed costs through volumetric rates. During each rate case, rates are set based on an assumption of gas-use per customer. If, on average, the customers consume the expected amount of gas, the Company will recover all fixed costs. If customers use less gas than predicted, the Company may not recover all of its fixed costs.

The difference between actual use and expected use per customer has two components, weather related and non-weather related. NW Natural addresses non-weather related differences through the decoupling mechanism. The decoupling mechanism tracks a portion of the under-collection or over-collection of revenues in a deferred account. The decoupling mechanism then recovers revenue shortfalls and refunds excess revenues by adjusting the per-therm rate the Company charges for gas every 12 months.

Generally, NW Natural's decoupling mechanism breaks the link between earnings and consumption by removing the Company's incentive to increase usage for profit. The mechanism employs a use-per-customer (UPC)

[13] Staff/1302, Scala/6-89, NWN Response to OPUC DR 370, Attachment 1.

decoupling calculation, which adjusts margin revenues to account for the difference between actual and expected customer volumes.

The partial decoupling mechanism is defined in NW Natural's tariff, Schedule 190, where the Company also specifies the applicable rate schedules and most recently effective temporary rate adjustments. Rate changes associated with Schedule 190 are contemporaneous with rate changes for the Purchased Gas Adjustment. The currently effective Schedule 190 was approved in NWN Advice No. 21-07, effective November 1, 2021. The baseline UPC is measured in therms and calculated at 685.5 for residential customers; 2,900.7 for Commercial Schedule 3 customers; and, 33,786.6 for Commercial Schedule 31 customers. Starting November 1, 2021, NW Natural is authorized to amortize the residential deferral credit of $4,438,450 over a one-year period.

The proposed commercial deferral balance authorized for amortization over the next PGA year is an additional amount to be collected from customers of $1,060,539. To amortize this balance, NW Natural requested a temporary rate adjustment of -$0.01089 per therm for residential Rate Schedule 2, $0.00542 per-therm for commercial Rate Schedule 3, and $0.00625 per-therm for commercial Rate Schedule 31. This was approved by the Commission and included in the current Schedule 190 tariff.

Q. How is the decoupling mechanism impacted by the Company's proposal in the general rate case proceeding, UG 435?

A. The Company describes how its proposal includes removing the decoupling amount produced by the mechanism in the Base Year.[14] This adjustment effectively creates no decoupling revenues in the Test Year, since test period revenues have been developed with newly created UPCs, normalizing usage that will become the baseline for the decoupling mechanism at the rate effective date of this proceeding.

This change is standard for general rate case proceedings; however, the components used to derive baseline usage in the final rate case calculations must also be used in the decoupling mechanism. This will ensure the decoupling mechanism will calculate adjustments consistent with customer volumes and revenue approved in the rate case. Thus, to the extent there are changes to the heating and baseload coefficients impacting the UPC values used in the decoupling mechanism, proposed calculations are subject to change.[15] Details of Staff's review of the UPC Forecast and potential modifications can be found in Staff Exhibit 400.

Q. Has the Company proposed any changes to the functionality of the partial decoupling mechanism in this general rate case proceeding?

A. No.

Q. Does Staff have any concerns with whether or not NW Natural's decoupling mechanism is performing as intended?

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[14] NW Natural/1300, Walker/11.

[15] *See* Staff/400 Bain/3-9; Staff has not proposed any changes to the load forecast at this time but has requested additional discussion that may result in future adjustments.

A. For the most part, Staff is satisfied that the mechanism itself is working as intended. In a review of past Schedule 190 adjustments, Staff found the mechanism has resulted in credits to residential customers since 2018 consisting of generally nominal adjustment amounts. The largest residential adjustment under the mechanism was in 2012, where residential customers saw a $0.04166 per therm surcharge as a result of Schedule 190. Commercial customer adjustments have been relatively low as well, with surcharges generally at or below $0.06 per therm, and have been small credits in recent years. Given these minimal historic adjustments, Staff has not identified any major concerns with decoupling in the context of rate impacts to customers at this time.

However, Staff is concerned that the difference in usage between new customers coming on NW Natural's system and existing customers is too large to ignore. Failure to distinguish between new and established customer usage may overstate the impact of lower average use per customer under certain conditions. For example, under declining use per new customers, and an increased number of customers, the decoupling mechanism may cause significant over-collection of fixed generation revenue. In PGE's 2013 general rate case, Docket No. UE 262, the Commission adopted a stipulation that created a secondary monthly fixed charge for customer accounts that exceed the test period customer accounts. This secondary fixed charge was calculated by taking 76 percent of the final PGE residential customer Monthly Fixed Charge per customer. The fixed monthly charge and the secondary fixed monthly charge are updated in general rate cases, and the secondary fixed monthly charge is established as a percentage factor multiplied by the fixed monthly charge. The percentage factor is the average of the annualized consumption for new (connecting) residential PGE customers during a two-year period, compared to the final forecast PGE Schedule 7 use per customer in the rate case test period. The purpose of this change was to reflect the pattern of declining usage for new connections.

In a data request to the Company, Staff asked NW Natural to provide the average annual and monthly usage for an established residential customer location and a new residential customer location.[16] The Company's response assumed "new" locations as a new service put into place in the last ten years (beginning 2012 through 2021).[17] From Staff's perspective, a ten year bracket for new installations may not quite capture what Staff envisioned as "new," however it may be that Staff needs to better understand the Company's rationale for using these parameters. Regardless, according to the Company's response, even ten-year (or less) customer UPC is only around 76 percent of a location that established service prior to 2012 (Table 2).[18] It is possible that this difference may be more pronounced if "new" locations were narrowed to those established in the last year; however Staff does not have that data at this time.

16 OPUC DR 454.
17 Staff/1302, Scala/108, NWN Response to OPUC DR 454, Attachment 1.
18 *Id.*

Table 2. Current Average Weather Normalized Annual and Monthly Usage, by the Residential Location Types: New and Established[19]

		(Therms) UPC Load New Location	(Therms) UPC Load Established Location
	Month		
1	Jan	81.20	106.96
2	Feb	70.44	89.77
3	Mar	61.23	78.94
4	Apr	42.15	55.36
5	May	23.76	32.60
6	Jun	14.51	20.75
7	Jul	10.36	15.38
8	Aug	9.24	13.59
9	Sep	11.06	15.77
10	Oct	30.02	39.98
11	Nov	58.46	75.91
12	Dec	81.64	106.35
Current Annual UPC:		**494.06**	**651.37**

New location is defined for the purposes of this analysis as a new service put into place in the last ten years (beginning 2012 through 2021).
Established location for the purposes of this analysis is any service established prior to 2012.

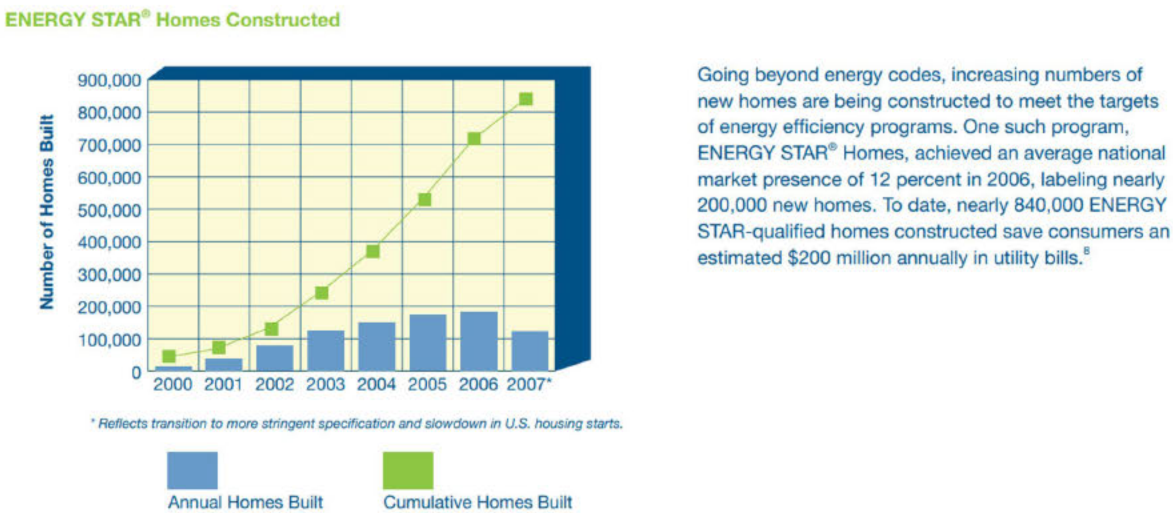
Q. What other evidence has Staff found related to declining UPC values?

A. Staff's analysis revealed other sources, local and national, in support of declining UPC trends for customers overall. For example, in a review of the Company's 2005 third-party decoupling report,[20] residential customer UPC declined by 170 therms between 1993 and 2004. In a 2008 report from the United States Department of Energy,[21] the authors show positive trends related to the number of energy star homes being constructed between 2000 and

19 *Id.*
20 Staff/1302, Scala/6-89, NWN Response to OPUC DR 370, Attachment 1.
21 United States Department of Energy, Energy Efficiency Trends in Residential and Commercial Buildings (Energy Efficiency Trends in Residential and Commercial Buildings).

2007. In that same report, it states that as of October 2008, approximately 840,000 energy star qualified homes (Figure 1).

Figure 1. Energy Star Homes Constructed 2000-2007[22]



In 2021, the number of energy star certified homes and apartments in the United States tripled to approximately 2.36 million.[23] Other relevant findings discussed in the USDOE report[24] include the following:

- From 1985-2004, the energy intensity of the residential sector decreased by nine percent as measured by energy use per household;
- Total residential energy use – which has grown along with the number and size of homes and "plug loads" – has been partially offset by reduced energy intensity per home (Figure 2 and Figure 3); and

22 *Id.*
23 ENERGY STAR Partner Locator | New Homes | ENERGY STAR.
24 United States Department of Energy, Energy Efficiency Trends in Residential and Commercial Buildings (Energy Efficiency Trends in Residential and Commercial Buildings).

- State building codes are increasing energy efficiency.

Figure 1. Average Size of New Homes and Average Number of People per Household

Since 1980, housing units in the United States have grown larger, while the number of occupants per home has decreased. Fewer people have been taking up more space, due to such factors as higher incomes, smaller families, and deferred marriage.

Figure 2. Energy Use Intensity and Factors in the Residential Sector

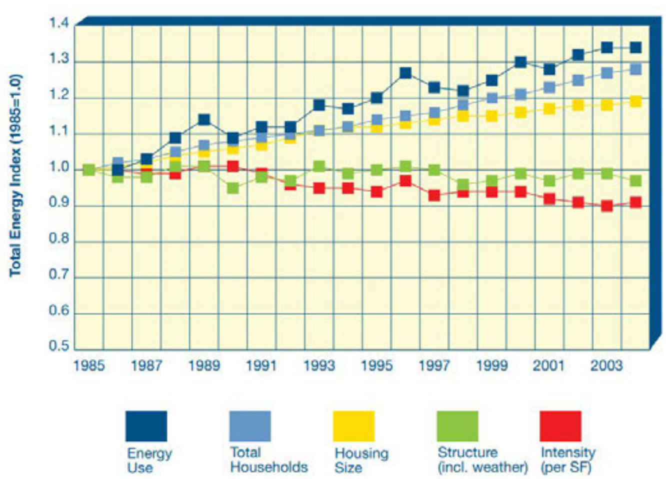


Figure 19 is an index for total energy consumption, number of households, house size, a combined structural component that captures many of the "other explanatory factors," and energy intensity over the period from 1985 to 2004. The number of households increased over this period from 86.8 million to 110.7 million (27.5 percent), while energy consumption increased from 14.7 quads to 19.7 quads. Residential energy consumption, measured as total energy (i.e., including electricity losses), increased overall by about 34 percent. Consumption declined in 1990, 1997, 1998, and 2001, years of mild winter weather. The overall effect of non-efficiency-related changes has been to increase energy use by about 15.5 percent. The residential energy intensity index, based on energy use per square foot, has generally trended downward since 1985, with the greatest declines observed in the early part of the 1990s.

6 The methodology and data for the energy intensity indicators were developed by a laboratory-university team comprising the Pacific Northwest National Laboratory, Stanford University's Energy Modeling Forum, Argonne National Laboratory, Oak Ridge National Laboratory, and Lawrence Berkeley National Laboratory under contract to the U.S. Department of Energy.

Q. How does Staff interpret these findings in terms of declining UPC?

A. Staff finds the analysis as clear evidence that new customers tend to have lower UPC than established customers.

Q. Has Staff discussed this concern with differences between new and established customer usage in prior NW Natural rate cases?

A. Yes. This issue was brought up by Staff, in part, in Docket No. UG 344.[25] There, Staff recommended that only the number of customers forecasted in base rates be decoupled. Staff presented its position in the following testimony:

> New customers tend to have lower baseline use than existing customers due to stricter building code standards, which are independent of the Utility's energy efficiency policy. Extending decoupling to new customers beyond those forecasted in the rate case results in the following problems:
>
> 1. The decoupling adjustment will consistently be in NW Natural's favor due to the average use of new customers being small relative to the average use of existing customers.
> 2. The decoupling mechanism will compensate NW Natural for building code improvements and other forms of energy savings that are independent of both NW Natural and the Energy Trust.
> 3. The revenue associated with new customers will exceed the incremental cost of new customers because the average cost of serving all customers is higher than the incremental cost of serving an additional customer.
>
> These problems arising from NW Natural's proposal generally harm customers, while allowing the utility to recover more than the approved revenue requirement.[26]

This specific issue was not addressed further in subsequent testimony, stipulations, or Commission order. Decoupling in Docket No. UG 344 was resolved through a stipulation that was approved in Commission Order No. 18-419.

Q. Is Staff proposing a change to the mechanism at this time?

A. Yes. In coming up with proposed changes, Staff has taken into consideration:

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25 Docket No. UG 344, Staff/700, Kaufman/71-73.
26 Docket No. UG 344, Staff/700, Kaufman/71-73.

1. The Commission precedent set in PGE's general rate case docketed as UE 262, when similar concerns regarding new versus established customers were made;
2. NW Natural's declining customer demand;[27]
3. NW Natural's active efforts to acquire new customers via engagement with builders and residents to install natural gas service as observed on their website and in the community;
4. Increasing numbers of new homes being constructed to meet the targets of energy efficiency programs; and
5. Evidence that use per customer tends to be lower for newly established customers.[28]

To this end, Staff finds it is appropriate for the Company to distinguish between new and established customers in decoupling calculations.

Q. What precedent or discussion has Staff reviewed on how a bifurcation of customer groups might be achieved?

A. Staff's discussion in Docket No. UG 344 presented one possible remedy: that decoupling only apply to the number of customers forecasted through the Test Year in base rates. The Company opposed this proposal, arguing that without aligning customers and the Company on energy efficiency, the Company would be going against its own low carbon goals.[29] Staff is not opposed to continuing the practice of including all customers in the decoupling adjustment calculation;

27 *Id.*
28 Staff/1302, Scala/108, NWN Response to OPUC DR 454, Attachment 1.
29 UG 344 NW Natural/2000, Walker/19.

however Staff finds it prudent for the Company to modify the decoupling mechanism to distinguish baseline use-per-customer for new versus existing customers. Doing so would more accurately reflect lower usage associated with new customers and mitigate the risk of over-collection from the Company. Staff recognizes it is likely that bifurcating the decoupled customer group by "new" and "existing" would increase the baseline UPC for existing customers and would like to continue discussions with the utility on what the implications of this change may be.

In PGE Docket No. UE 262, Staff posed similar arguments for such a bifurcation, pointing to the results of a commissioned decoupling study that found use per customer is decreasing over time as a result of decreased use by existing buildings and decreased use by new construction. Staff presented a proposal for reducing potential over collection of fixed costs in the decoupling mechanism related to this disparity among customers. There, Staff posited that the Company calculate two distinct monthly fixed charges per customer (MFCPC). The proposed methodology scaled secondary MFCPC from the base or primary MFCPC in order to reflect the observation that new connections place significantly less burden on existing system than preexisting connections.

To achieve this in the annual decoupling adjustment, PGE assumes that the load forecast included in the most recent general rate case is accurate on a "per customer" basis, since it represents the embedded customers at that time. Then for any customer counts that exceed the count from the general rate case that established the baseline, the secondary fixed charge is used because it assumes new customers are a result of new construction and more energy efficient.

Similar conclusions can be made in the case for new NW Natural customers, and so a similar, albeit tailored, approach to modifying the decoupling mechanism is likely appropriate.

Q. How would Staff tailor these approaches for its proposal in the current proceeding?

A. Staff references the existing Schedule 190 Partial Decoupling Mechanism tariff and proposes that after the mechanism calculates the difference between normal and actual heating degree days (HDD) for each district (and performs the necessary normalization), it should use the results from two separate models for new and established customers that develop separate UPC forecasts and per therm variances for each group. The third step of the calculation would utilize distinct per-therm customer variances for new versus established customers and multiply by distinct corresponding customer counts.

Q. Does this apply to all customer classes subject to the mechanism?

A. No. Staff is inclined to limit this bifurcation to the residential UPC to the extent that commercial customer usage is less homogenous than residential usage, and new construction commercial customers in particular may have significant variance depending on commercial square footage.

Q. Does Staff's proposal specify how the Company should define new versus established customers?

A. Under the PGE decoupling mechanism, any customer counts that exceed the baseline established in the most recent rate case are considered to be new customers. In NW Natural's response to Staff's data request regarding new versus established customers, the Company used a ten-year threshold. Staff favors the above baseline approach for the purposes of its initial proposal; however, Staff will continue to discuss with NW Natural and other parties how to best define new versus established customers for the purposes of this modification.

Q. Does Staff have any other comments related to this proposal?

A. Yes. Staff would like to acknowledge some of the conclusions drawn in the Company's third-party decoupling report[30] as they relate to this proposal, specifically, the section where the analysis responds directly to an OPUC inquiry as to how usage and revenues associated with new connects compare to the base usage and revenues assumed in the mechanism. The report provides the following response based on its analysis:

> Section 4.4 presents the limited information that we have to answer this question. We have seen mixed evidence, indicating that residential new connections and commercial conversion customers tend to have lower usage levels than existing customers, while commercial new construction customers have higher usage than existing customers. However, a number of other factors could be affecting this analysis (e.g., small sample size for commercial new connections; and changes in building codes, building materials, and appliance efficiency levels in residential housing). In addition, our review of NW Natural's methods for evaluating new connections and conversion customers revealed that DMN revenue adjustments are not included. Based on this, we conclude that NW Natural has not "gamed"

[30] Staff/1302, Scala/6-89, NWN Response to OPUC DR 370, Attachment 1.

> the DMN mechanism with respect to new connections customers.

Staff finds it may be useful to clarify that the report's statements are not inconsistent with the justification provided in the Staff proposal to bifurcate customer groups. To be clear, the proposal to bifurcate the residential customer group into old and new connections is not to mitigate concerns about the Company "gaming" the mechanism, but to address the evidenced usage differences between new and existing residential customers, thereby reducing the likelihood of over-collections.

Q. Please describe the Company's Weather Adjusted Rate Mechanism (WARM).

A. WARM is the Company's weather normalization mechanism. According to NW Natural's Schedule 195 tariff, WARM was adopted by the Commission in Docket No. UG 221, Order No. 12-408 and modified in Commission Order No. 16-223 in Docket No. UM 1750. The inception of WARM was in Docket No. UG 152, Order No. 03-507, where the Commission adopted a partial stipulation establishing and defining the terms of the program.[31]

Functionally, WARM stabilizes collection of fixed costs for residential and commercial customers. WARM adjusts billings based on temperature variances compared to average weather and is applied from December through May of each heating season. Generally, the mechanism is intended to smooth out fluctuations in winter bills caused by weather variances. WARM

[31] Northwest Natural Gas Company (Docket No. UG 152), Order No. 03-507 (August 22, 2003).

calculates a bill adjustment that offsets the effect that colder or warmer-than-average winter temperatures have on customers' gas use. If weather is colder than average, WARM will lower the billing rate; if weather is warmer than average, WARM will increase the billing rate. Prior to the implementation of the WARM program, NW Natural's recovery of its fixed cost was largely dependent on the volume of gas sold. While fixed costs remain fairly constant, the revenue to cover them varied widely from year to year depending on the weather.

The WARM adjustment is subject to caps and floors when applied to the monthly bill. For residential customers, the maximum increase or credit for WARM on the monthly bill is $12.00 or 25 percent of the usage charges of the bill, whichever is less. For commercial customers, the maximum increase is $35.00 or 25 percent of usage charges, whichever is less. Any amounts not applied to a customer's bill during the WARM period due to the caps and floors will be deferred until the following PGA. By deferring all WARM adjustments that exceed the caps and floors, the Company spreads the rate impact of the deferrals over 12 months simultaneously with the PGA process.[32]

WARM is NW Natural's default billing method, meaning customers must "opt-out" of the program if they do not wish to participate. If a customer elects to opt-out, their election is rolled over every year until such time that customer may choose to elect back into the WARM program. WARM election changes

[32] *See In the Matter of Public Utility Commission of Oregon, Investigation into NW Natural's WARM Program,* Docket No. UM 1750, Order No. 16-223 (June 20, 2016).

for active customers must happen before September 30 every year. New customers may opt out of WARM during the heating season within 30 days of receiving their Welcome Packet.[33] Current WARM participation, by Schedule, is shown in Table 3, below.

Table 3. NW Natural WARM Customer Participation[34]

Rate Schedule	# of Accounts	# opt out	# enrolled (%)
02R	630107	46591	583516 (92.6%)
03R	1514	154	1360 (89.8%)
03C	57477	4545	52932 (92.1%)
Total	689098	51290	637808 (92.6%)

Q. How is WARM impacted by the Company's proposal in the general rate case proceeding, UG 435?

A. The Company states that the proposal updates NW Natural's rate mechanisms by removing the WARM revenue related to the Base Year.[35] The Test Year is based on normal weather and therefore no WARM amount is applicable to that period. This change is standard for general rate case proceedings.

In the same context described earlier in the decoupling section of this testimony, the components used to derive baseline usage in the final rate case calculations must also be used in WARM. To the extent there are direct or indirect changes to the relevant WARM inputs in Staff's load forecast position, proposed WARM updates are subject to change and should ultimately reflect the final load forecast used to set rates.

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33 Staff/1302, Scala/92-93, NWN Response to OPUC DR 373.
34 Staff/1302, Scala/91, NWN Response to OPUC DR 372.
35 NW Natural/1300, Walker/11.

Q. Has the Company proposed any changes to the functionality of WARM in the general rate case proceeding, UG 435?

A. No.

Q. Does Staff have any concerns with whether or not WARM is performing as intended?

A. No. NW Natural states that the mechanism continues to function as designed and allows the company to separately identify and collect revenues to cover the fixed costs from the revenues which cover "truly usage-related costs."[36]

In a review of past Schedule 195 adjustments, Staff found the mechanism has historically resulted in nominal adjustments for both Residential and Commercial customers enrolled in the program. All rate adjustments for WARM have been less than half a cent. Given these minimal historic adjustments, Staff does not identify any major concerns with WARM in the context of rate impacts to customers at this time.

Staff finds that testimony from parties in previous NW Natural rate cases where WARM is addressed show support for the mechanism. In Docket No. UG 221, the NW Energy Coalition highlighted the benefits of the mechanism to customers and NW Natural and stated that "the WARM adjustment is an important tool for providing revenue stability and generally protecting customers from wide swings in costs due to weather."[37] In Docket No. UG 344, CUB stated that narrowing seasonal bill variances for customers

36 Staff/1302, Scala/94-95, NWN Response to OPUC DR 375.
37 *See* Docket No. UG 221, NW Energy Coalition/100, Hirsh/6.

can be helpful and that the terms of the adjustment do not create harm to customers or violate the principle against retroactive ratemaking.

Staff finds that the current terms of the WARM program continue to provide these benefits to customers and the utility. To this end, Staff is not proposing any modifications or additional investigation into WARM at this time; however, Staff remains attentive to potential evolutions of the WARM program that may be necessary to ensure the terms and resulting adjustments are just and reasonable for affected customers.

Q. Does this conclude your testimony on this subject?

A. Yes.

ISSUE 3. RATE SPREAD & RATE DESIGN

Q. Please briefly describe the Company's rate spread proposal in this proceeding.

A. The Company has filed an incremental revenue requirement of approximately $78 million. This amount reflects the original $73.5 million included in the initial filing, and an additional $4.6 million identified in the February 28, 2022, errata filing that explained how the Company mistakenly excluded two FERC accounts from rate base: FERC Account 396 (Power Operated Equipment) and FERC Account 392 (Transportation Equipment). Correction of this error resulted in an incremental increase to rate base of $51.7 million, which corresponds to an incremental increase to revenue requirement of $4.6 million.[38]

The Company proposes to spread incremental revenue requirement in such a manner that is responsive to the results of the Long-Run Incremental Cost (LRIC) study across all rate classes.[39] As a general take-away, the results of the LRIC show that under the current rate structure, residential and small commercial customers are being subsidized by larger industrial and commercial customers. In other words, residential and small commercial customers are underpaying relative to their cost-of-service, while larger

[38] Although the subsequent errata filing added approximately $4.6 million to the incremental revenue requirement proposed by the Company, as the Company states in its response to OPUC DR 474, "the Company understands that the base rates finally adopted by the Commission in this proceeding will not exceed the revenue requirement reflected in its initial filing." As such, Staff's analysis uses the original incremental revenue requirement for the purposes of illustrating the effects of Staff's rate spread proposal.

[39] NW Natural/1400, Wyman/48.

industrial and commercial customers are overpaying. The proposed rate spread endeavors to bring rates closer to parity based on the LRIC findings, thus increasing rates for residential and small commercial customers while decreasing rates for the schedules found to be overpaying; however, the Company makes use of adjustment caps and floors to reduce overall volatility between current and proposed rates.

Q. Does Staff agree with the use of the LRIC as a basis for the Company's rate spread?

A. Yes. Staff supports the use of the LRIC as a baseline resource for rate spread proposals. As a general matter, pricing and customer cost allocations should reflect long-run-incremental cost-causation as much as possible. Table 4 illustrates the Company's LRIC study-indicated parity ratio at present rates for each schedule.

Table 4. NWN LRIC Study Parity Ratio at Present Rates, by Schedule[40]

RATE SCHEDULE	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF
LRIC Study Determined Parity Ratio	0.95	0.95	1.19	0.85	1.46	1.63	1.53	2.20
RATE SCHEDULE	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI
LRIC Study Determined Parity Ratio	1.57	2.20	2.46	2.11	1.16	2.16	2.49	1.89

A strict LRIC-based target allocation of margin costs to the various customer schedules would be the outcome of allocating shares of embedded

40 NW Natural/1400, Wyman/43.

cost categories to customer schedules strictly in proportion to their respective shares of LRIC costs for the respective categories. However, as described by the Company in NW Natural/1400, Wyman/46, “rate spread (and rate design) tends to deviate from [the] strict application of cost study results, given such a change in the short-run would violate principles of rate shock and smoothing, neither of which are in the Company’s or the customer’s interests.”[41] Staff is in agreement with the Company’s position that rate spread must balance the interests of rate equity with rate volatility and strict adherence to the results of an LRIC for rate spread could (and in this instance does) conflict with such a balance.

Evolutions to the rate spread cost allocation from the LRIC can avoid the burden of imposing an increase to a particular customer schedule that is unacceptably out of line with the overall increase, and avoid allowing some schedules to receive a rate decrease in the context of a significant increase being imposed on most of the other customer schedules. This “deviation” appears particularly appropriate in the context of the Company’s UG 435 proposal, such that the results of the LRIC results would implement a margin increase of 22.2 percent for residential and between 22.4 percent to 37.2 percent basic commercial rate classes while the large commercial, industrial, and transportation rate classes would receive margin decreases of up to 53.3 percent.[42]

41 NW Natural/1400, Wyman/46.
42 Staff/1303, Scala/1, NW Natural/1401 WP6 – Long-Run Incremental Cost Study (LRIC) Model.

While such a spread would result in rate parity across the classes, the impact to customers in terms of price signals, affordability, and reasonableness would be substantial. Further, as highlighted by the Company,[43] the Commission has provided some precedent on how it may regard disparities between equity and parity in rate spread, stating that even when rates may be misaligned relative to cost-of-service, "[a]bsent compelling evidence that warrants more immediate action, however, we are not inclined to raise some rates while reducing others."[44]

Q. Staff mentioned NW Natural made use of caps and floors to minimize rate shock related to spreading the incremental revenue requirement proposed by the Company. Please provide additional detail on how this was done.

A. NW Natural witness Wyman describes the application of caps and floors to spread the proposed increase to revenue requirement as follows:

1. Apply a cap equal to 1.05 times the overall incremental margin increase of 16.5 percent to the rate schedules with an LRIC study indicated parity ratio below 1.0 at present rates. This cap, equal to a 17.3 percent margin increase, applies to RS 2 Residential, RS 3 Commercial, and RS 27 Dry-Out. Retain this cap for revenue allocation for these schedules.
2. Apply a floor equal to 0.50 times the overall incremental margin increase of 16.5 percent to the rate schedules in the Industrial and Transportation

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43 NW Natural/1400, Wyman/48.

44 *See In the Matter of AVISTA CORPORATION, DBA AVISTA UTILITIES' Request for a General Rate Revision,* Docket No. UG 284, Order No. 15-054 (February 23, 2015).

rate classes. This floor, equal to a roughly 8.3 percent margin increase, will be adjusted with the final step of this methodology.

3. After the cap and floor have been applied, allocate the remaining revenue requirement to the Large Commercial Sales rate schedules only, on an equal percent of margin basis.

4. Adjust the floor such that the RS 31 and RS 32 rate classes, as well as the RS 3 Industrial schedule, keep the same LRIC study indicated parity ratios relative to each other.

5. Apply the lower floor and reallocate the remaining revenue requirement to the Large Commercial Sales rate schedules only on an equal percent of margin basis.[45]

Table 5 illustrates the parity ratio achieved when the parameters described above are applied to the results of the LRIC.

Table 5. Parity Ratio at NWN UG 435 Proposed Rates[46]

Schedule	02	03CSF	03ISF	27R	31CSF	31CTF	31ISF	31ITF	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI	33T
Parity Ratio	0.96	0.96	1.09	0.86	1.41	1.50	1.40	2.02	1.52	2.03	2.27	1.95	1.12	1.99	2.29	1.74	1.00

Q. How does this requested increase to revenue requirement and proposed rate spread impact each rate class?

A. The Company describes the effects generally as, RS 2 Residential, RS 3 Commercial, and RS 27 Dry-Out rate schedules will receive a revenue spread slightly greater than an equal percent of margin share calculated across all rate schedules. The industrial and transportation rate classes will all receive a

[45] NW Natural/1400, Wyman/49.
[46] Staff/1303, Scala/2, NW Natural/1402 WP-1 Rate Spread Proposal Methodology.

revenue spread less than an equal percent of margin share. The large commercial sales rate schedules will also receive a revenue spread less than an equal percent of margin share, but at a higher rate relative to the industrial and transportation rate classes.[47] Table 6 illustrates the revenue requirement increase and total percentage of margin increase, by class, as proposed by the Company.

Table 6. NWN UG 435 Proposed

Incremental Revenue Requirement Impacts by Schedule

Rate Schedule	Total Proposed Revenue Requirement Increase	Proposed Margin Increase
02	$ 52,494,153.05	17.3%
03CSF	$ 16,091,665.29	17.3%
03ISF	$ 155,173.45	7.2%
27R	$ 81,757.01	17.3%
31CSF	$ 1,063,027.54	12.9%
31CTF	$ 71,095.58	7.2%
31ISF	$ 234,533.26	7.2%
31ITF	$ 10,421.02	7.2%
32CSF	$ 1,528,892.88	12.9%
32ISF	$ 178,388.21	7.2%
32CTF	$ 74,240.38	7.2%
32ITF	$ 477,070.90	7.2%
32CSI	$ 287,294.48	12.9%
32ISI	$ 239,647.44	7.2%
32CTI	$ 38,101.16	7.2%
32ITI	$ 439,391.94	7.2%
33T	$ -	0.0%
Total	$ 73,464,853.58	16.5%

[47] NW Natural/1400, Wyman/51.

Q. As part of this rate spread methodology, is the Company proposing to make changes to its base customer charges?

A. No. NW Natural proposed to apply all of the revenue changes to the volumetric rate for each customer rate schedule and block.[48]

Q. Did the Company indicate whether or not the rate spread would materially change in the event of a decrease to its proposed revenue requirement?

A. In response to Staff data requests,[49] the Company provided updated versions of the Company's filed work paper[50] assuming a scenario where the proposed incremental revenue is reduced by 10; 25; and 50 percent. The Company assumed the reduction would be associated with a proportional decrease in total rate base across the functional categories: General, Services, Distribution, Transmission, and Storage. This resulted in little movement of each rate schedule's parity ratio at present rates, as shown in the "Delta" tab, because rate base was reduced for every schedule at roughly the same overall proportion that makes up the parity ratios under the filed revenue requirement. To this end, the Company does not adjust the overall rate design or the caps and floors that apply to the methodology.

Q. What findings has Staff made regarding the Company's LRIC in this proceeding?

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48 NW Natural/1400, Wyman/51.

49 Staff/1302, Scala/106-107; 109-110, NWN Response to OPUC DRs 397 and 457, including attachments.

50 Staff/1303, Scala/2, NW Natural/1402, WP1- Rate Spread Proposal Methodology.

A. Staff provides its analysis and recommendations of the LRIC in Staff Exhibit 1600. Generally, Staff is satisfied with the manner in which NWN has performed its LRIC study and is in agreement with the overall findings that residential and small commercial customers are being subsidized by larger industrial and commercial customers. Staff has proposed two adjustments with regard to the LRIC in Staff Exhibit 1600[51] related to the Maximum Daily Demand Value (MDDV) and the Company's allocation of system core mains. The adjustments are minimal, but bring most schedules closer to parity (Table 7).[52]

Table 7. Comparison of Staff's and NWN parity ratio at present rates[53]

Schd	**02R**	**03C**	**03I**	**27R**	**31CSF**	**31CTF**	**31ISF**	**31ITF**	**32CSF**	**32ISF**	**32CTF**	**32ITF**	**32CSI**	**32ISI**	**32CTI**	**32ITI**
NWN	0.95	0.95	1.19	0.85	1.46	1.63	1.53	2.20	1.57	2.20	2.46	2.11	1.16	2.16	2.49	1.89
Staff	0.95	0.95	1.17	0.85	1.46	1.59	1.48	2.06	1.58	1.99	2.27	1.91	1.18	2.09	2.67	1.77

The discussion contained further in this section describes how Staff may propose to deviate from strict adherence to LRIC results in the interest of a balanced rate spread that is equitable to customers. Staff changes to the rate spread proposal will result in further adjustments to the parity ratios depicted above.

Q. Does Staff have any concerns with how the increased incremental revenue requirement is spread across customer schedules in terms of reasonableness?

51 Staff/1600, Gibbens/7-13.
52 Staff/1600, Gibbens/3, Table 1.
53 *Id.*

A. Yes. Staff believes that the Company's "balance" of parity and equity in its current rate spread proposal does not take into account all the necessary considerations for residential impacts. While Staff agrees with the general principle of moving toward rate parity, Staff feels a more gradual approach is necessary given other rate adjustments within and outside this proceeding, which were not addressed in the Company's initial filing. For example, Staff is recommending the amortization of COVID-19 deferrals,[54] which is borne primarily by the residential class. NW Natural has also filed its HB 2475 deferral, which includes future use of an automatic adjustment clause that will recover costs, again, primarily from the residential class.[55]

While all customer classes will be subject to the cost recovery in both the COVID-19 and HB 2475 deferrals due to non-bypassability terms in the relevant Commission Order[56] or law, Staff anticipates limitations will be placed on recovery from nonresidential customers. Further related to HB 2475, Staff has some concerns with how rate increases experienced by residential customers as a result of this proceeding will impact the effectiveness of the Company's income qualified bill discount program. In the Company's testimony, the percent increase to an average customer bill for the residential class is approximately 11.8 percent (Table 7).[57]

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[54] Staff/1500, Dlouhy-Fox-Storm/37.
[55] *See* Docket No. UM 2233.
[56] *See In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into the Effects of the COVID-19 Pandemic on Utility Customers,* Docket No. UM 2114, Order No. 20-324 (October, 20, 2020).
[57] NW Natural/1400, Wyman/54.

Table 7. Combined Incremental Revenue Requirement and Average Bill Increase for all Rate Components, Firm Sales Customers Only[58]

Rate Schedule	Revenue Req. Increase		Pct. Increase to Avg. Cust. Bill*
02 R	$	57,281,490	11.8%
27	$	89,717	10.8%
03 C	$	17,702,462	10.3%
03 I	$	193,909	4.3%
31 C Firm Sales	$	1,223,195	7.8%
31 I Firm Sales	$	307,385	4.0%
32 C Firm Sales	$	1,805,198	6.8%
32 I Firm Sales	$	248,611	3.5%
Total All Schedules**	$	81,829,258	

* The average customer bill impact figure calculation excludes pipeline capacity charges for RS 31 and RS 32 rate classes, and thus the rate impacts for these schedules are overstated.
** The proposed margin revenue increase is based on volumetric billing rates rounded to the fifth decimal as necessitated by the Company's tariff. Therefore, there may be a small discrepancy with the indicated revenue requirement presented in NW Natural/1300, Walker. The total represents all rate schedules, not just the ones presented in Table 4 above.

Combined with the aforementioned cost recoveries, customers enrolling in the bill discount program may ultimately receive very little change to their monthly energy burden. Finally, Staff also notes that in a review of the Company's response to a Staff data request,[59] it appears that since 2004, on a net percentage basis, the residential class has experienced the greatest average monthly increase relative to other rate schedules. All things considered, Staff finds that the balance between equity and parity would be served by making some consideration based on the extent to which residential customer bills are expected to increase in 2023 beyond the cost categories in NW Natural's UG 435 proposal.

58 *Id.*
59 Staff/1302, Scala/105, NWN Response to OPUC DR 389, Attachment 1.

Q. Does Staff have a rate spread proposal to mitigate these concerns?

A. Yes. Staff proposes the following methodology to spread the final incremental revenue requirement determined in this proceeding:

- Apply a cap equal to 1.01 times the final overall incremental margin increase to RS 2 Residential. Retain this cap for revenue allocation for these schedules;
- Apply a cap equal to 1.05 times the final overall incremental margin increase to RS 3 Commercial and RS 27 Dry-Out. Retain this cap for revenue allocation for these schedules;
- Apply a floor equal to 0.72 times the final overall incremental margin to the rate schedules in the Industrial and Transportation rate classes;
- Adjust the floor such that RS 3 Industrial Sales Firm and RS 32 Industrial Transportation Interruptible equal to 0.84 the overall incremental margin increase; and
- After all the caps and floors have been applied, allocate the remaining revenue requirement to the Large Commercial Sales rate schedules only, on an equal percent of margin basis.

Staff utilized the Company's proposed rate spread methodology as an initial baseline and adjusted the caps and floors to achieve a more gradual approach to parity and endeavors to reduce the rate impacts to residential customers resulting from this proceeding. Staff acknowledges that the effect of a cap less than the proposed 1.05 for the residential class will increase the total share borne by the non-residential customer classes, and comparatively reduce the degree of adherence to long-run-incremental cost-causation; however, the proposed rate spread will still allow the majority of schedules to move closer to parity while also taking relevant equity concerns into considerations.

Q. How does Staff's proposal impact the percentage of margin increase to customers?

A. Staff's proposed rate spread should be applied to whatever the final overall incremental margin increase to customers would be. To this end, the incremental margin increase to customers will depend on the final incremental revenue requirement in this proceeding. For illustrative purposes, Table 8, below shows the percent of margin increase by rate schedule and resulting parity ratio based on the Staff proposed rate spread. The table applies Staff's proposed caps and floors to the LRIC baseline, as modified by Staff Exhibit 1600. This scenario further assumes the (unlikely) outcome that NW Natural is awarded the total incremental revenue requirement as originally filed of $73.5 million.[60]

[60] Staff's analysis uses the original incremental revenue requirement for the purposes of illustrating the effects of Staff's rate spread proposal.

Table 8. Percent of Margin Increase and Parity Ratio

Staff Proposal[61]

Rate Schedule	Total Proposed Revenue Requirement Increase	Proposed Margin Increase	Margin Revenue at Proposed Rates	Parity Ratio (Unit Parity = 1.0)
	$	%	$	%
02	$ 50,494,376	16.7%	$ 353,237,922	0.96
03CSF	$ 16,091,665	17.3%	$ 108,895,293	0.97
03ISF	$ 297,491	13.9%	$ 2,439,262	1.13
27R	$ 81,757	17.3%	$ 553,265	0.87
31CSF	$ 1,286,759	15.6%	$ 9,548,560	1.48
31CTF	$ 116,675	11.9%	$ 1,097,967	1.54
31ISF	$ 384,892	11.9%	$ 3,622,023	1.45
31ITF	$ 17,102	11.9%	$ 160,937	2.01
32CSF	$ 1,850,674	15.6%	$ 13,733,158	1.60
32ISF	$ 292,753	11.9%	$ 2,754,945	1.92
32CTF	$ 121,836	11.9%	$ 1,146,534	2.24
32ITF	$ 782,921	11.9%	$ 7,367,661	1.90
32CSI	$ 347,760	15.6%	$ 2,580,600	1.04
32ISI	$ 393,285	11.9%	$ 3,701,004	1.66
32CTI	$ 62,528	11.9%	$ 588,417	4.69
32ITI	$ 842,380	13.9%	$ 6,907,059	1.08
33T	$ 0	0.0%	$ 0	1.00
	$ 73,464,854	**16.5%**	**$ 518,334,605**	

[61] Staff/1303, Scala/3, Staff OT UG 435 Proposed Rate Spread WP.

Q. What other issues has Staff investigated with regard to whether or not additional changes are needed to improve NW Natural's rate spread and/or rate design?

A. Staff began initial inquiries into the following rate spread/rate design issues to determine whether additional proposals should be made:

- Actual curtailment activity for interruptible customers;
- Allocation methodology for mains and storage costs;
- Seasonal rates; and,
- Cost distinctions between single and multi-family residential customers.

Q. Does Staff make any proposals based on its initial findings?

A. Staff is not making any proposals related to these issues at this time; however, Staff would like to continue to explore potential modifications related to cost allocation for interruptible customers and cost distinctions between single and multi-family residential customers. Staff finds its inquiries into the allocation methodology for mains and storage costs as well as seasonal rates were reasonably addressed by the Company in discovery.[62]

Q. Please explain why Staff is recommending continued inquiry into interruptible customers and multi-family rates.

A. In response to a Staff data request inquiring as to the frequency of curtailment for interruptible customers, NW Natural provided a table showing that actual curtailment events are few and with the exception of 2018 and 2019, tend to

[62] Staff/1302, Scala/112-114; 115; 116, NWN Responses to OPUC DR 459, 460, and 461.

impact very few of customers actually receiving interruptible rates.[63] Interruptible customers are assessed fewer service charges against their usage and thus receive continuous benefit under that schedule. The Company will also make adjustments that are favorable to interruptible customers, such as that described in NW Natural/1400, Wyman/32 where gas storage plant cost allocations were reduced to acknowledge the possibility of service interruptions that could coincide with a winter peaking event.[64] In Staff/1600, Staff proposes to adjust the system core mains allocations to reflect the fact that interruptible customers are seldom, if ever, interrupted.

Additionally, Staff has recommended that at least one interruptible rate schedule be subject to an adjusted floor in the proposed rate spread. This proposal would increase the affected interruptible schedule's percent of margin increase. However, to the extent cost allocation determinations over-estimate the effect of potential curtailments in other ways, it may be necessary to revisit other elements of impacting how interruptible schedules are treated in rate spread and rate design.

Regarding cost distinctions between single and multi-family residential customers, Staff is interested in exploring whether or not the Company should separate pricing for multi-family residential customers. This was pursued in both the PacifiCorp UE 374 general rate case and more recently the Portland General Electric UE 394 general rate case. In both instances, the proposals

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63 Staff/1302, Scala/111, NWN Response to OPUC DR 458.
64 NW Natural/1400, Wyman/32.

decrease the multi-family basic charge and increase the single-family basic charge. While the arguments in favor of such a change may differ between gas and electric utilities, Staff is endeavoring to understand whether there are fixed costs to the utility that vary significantly enough to pursue a modification.

NW Natural provided that the current $8.00 fixed base monthly charge is one piece of the Schedule 2 rate mechanism the Company uses to collect a portion of the fixed cost component of its overall authorized revenue requirement. The other piece is the volumetric rate, which is used to collect the remainder of the fixed cost component as well as the variable component of the overall authorized revenue requirement.[65]

The Company states that multi-family residential customers can fall under the following rate schedules depending upon the circumstances of their dwelling. Specifically:

1. The standard Schedule 2 Residential Sales Service for individually metered customers;
2. Schedule 4 Residential Multi-Family Service for customers that reside in Participant Multi-Family Buildings; and
3. Residents of multi-family buildings with natural gas service that is master metered under a commercial rate schedule who are not directly charged by the utility and are not utility customers.[66]

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65 Staff/1302, Scala/117-118, NWN, Response to OPUC DR 463.
66 *Id.*

Service under Schedule 4 is offered for eligible new construction multi-family developments through its Multi-Family Program. The basic charge rate for this schedule is based on a cost of service analysis for a specific type of eligible new construction multi-family development.[67] The Company further expressed that it does not see any benefits to adjusting Schedule 2 at this time, as multi-family dwellings tend to use less natural gas, and therefore pay less compared to single-family residences during the heating season when the volumetric portion is the largest component of most bills. NW Natural also revealed that for residents of multi-family buildings with natural gas service billed under a master meter on a commercial rate schedule, there would be no impacts if Schedule 2 were adjusted.[68]

Staff finds the information provided in response to the initial inquiry helpful although not determinative at this time. Staff wishes to perform further discovery and engagement with the utility and intervening parties as to whether or not a change is warranted. Staff is concerned that the Schedule 4 option is relatively narrow and does not afford customers in older multi-family dwellings the same opportunity for cost savings. Similarly, with regard to the Company's statement that the change would have no effect on master metered customers, Staff does not have the requisite information to know if the number of customers under this arrangement represents the majority of multi-family dwelling customers. To this end, Staff agrees with the Company that more

[67] *See* Docket No. ADV 576, NWN Advice No. 17-03.
[68] Staff/1302, Scala/117-118, NWN Response to OPUC DR 463.

information is needed to make an informed assessment of how parties might proceed with a potential adjustment to the current Schedule 2 rate structure.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 435
WITNESS: MICHELLE SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

Witness Qualifications Statement

April 22, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME:	Michelle Scala
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Strategy Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	BA Economics, University of Hawaii, Manoa; Honolulu, Hawaii BA Political Science, University of Hawaii, Manoa; Honolulu, Hawaii
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 Energy Rates, Finance and Audit Division and later transitioned to the Strategy Integration Division upon its inception. I have over nine years of experience in policy analysis and program evaluation for state and local government. 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. Prior to that I was employed at the Hawaii State Legislature as the Senior Analyst to the Senate Committee on Ways and Means. I have worked on the following general rate revision dockets: UG 388, UE 394, and UG 433.

CASE: UG 435
WITNESS: MICHELLE SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support of Opening Testimony

April 22, 2022

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 368

368. Referring to NW Natural/100 Anderson-Kravitz/Pages 7-8:

a. Please provide a timeline and description of any activity and engagement NW Natural has performed related to the Community and Equity Advisory Group. The timeline should include any past, ongoing and forecasted activity.

b. Please describe whether NW Natural has expended any funds related to the CEAG at this time or has identified cost categories and estimates. Where applicable, please describe the source of funding and cost recovery expectations.

c. Please describe how NW Natural plans to identify, nominate, and elect members to the CEAG.

d. Please describe the ways in which NW Natural will commit to being "responsive and accountable to the CEAG."

e. Please describe:

i. The CEAG's role, if any, in the Company's clean energy transition;

ii. Whether this group parallels the electric utilities' obligation to create a Utilities Community Benefits and Impacts Advisory Group, as described in Section 6 of House Bill 2021 and how.

iii. If NW Natural plans to coordinate the work of the CEAG with partner utility advisory groups and how.

f. Please include a column describing any new project/program initiated in that year and the anticipated benefit(s) and objectives(s) to be provided to customers as a direct result of the project/program.

Response:

a. ***Please provide a timeline and description of any activity and engagement NW Natural has performed related to the Community and Equity Advisory Group. The timeline should include any past, ongoing and forecasted activity.***

August – September 2021

- Internal scoping: survey 11 internal departments to uncover shared and individual priorities; document feedback; socialize with internal departments; confirm representation from internal departments to participate in CEAG
- Review peer practices from PSE, Avista, Energy Trust, PGE, etc.
- Develop content for CEAG charter, bylaws, eligibility requirements and timeline

- Establish electronic location for cross-functional team to access documents
- Identify potential organizations for membership; research communities served and alignment with criteria for membership
- Hold internal kickoff meeting; review materials drafted to date
- Announce development of CEAG at 9/29 Technical Working Group meeting
- Identify core project team: Executive Sponsors, Project Sponsor, Community Partnerships Manager, and Project Specialist

October – December 2021

- Present concept overview to executive leadership; secure approval to move forward with full support of executive leadership.
- Begin formal recruitment for CEAG membership; conduct outreach and interview meetings
- Launch facilitator bid process: draft RFP and application to submit, solicit recommendations on candidates, draft scope of work, meet with internal purchasing, draft MOU template
- Meet with Ezell Watson (PUC) and discuss CEAG high level, including: DEI program at PUC; recommendations for third-party facilitators; suggestions for ongoing engagement; and DEI-centered coalition-building amongst utilities and PUC and CBOs
- Present update on CEAG activities at 12/9 Technical Working Group meeting (OPUC, WUTC Staff, ETO, peer utilities, AWEC, NWGA, others)

January – March 2022

- CEAG member activity: Share updates on compensation ($5,000/year/organization) and estimated time requirements (30 hours/year); continue recruitment (10 organizations confirmed to date); respond to inquiries
- Consultant activities: Send invitation to apply for third-party consultant role to external candidates; solicit recommendations from peer institutions; review responses; conduct first and second-round interviews
- Provide updates to internal team (ongoing)

Q2 – Q4 2022

- Hire consultant; hold meetings to review documents, vision, risks, strategies, priorities etc.
- Hold kickoff meeting with CEAG members
- Continue providing updates to internal team and leadership; solicit ideas and recommendations for quarterly meeting topics
- Engage with other external stakeholders on CEAG launch and development
- Continue conversations on CEAG-focused coalition with utility peers
- Finalize CEAG operating agreement, charter and Terms of Service with active participation, feedback and recommendations from members and the third-party consultant. Terms will be finalized by members and reevaluated periodically.

b. ***Please describe whether NW Natural has expended any funds related to the CEAG at this time or has identified cost categories and estimates. Where applicable, please describe the source of funding and cost recovery expectations.***

NW Natural has not expended incremental costs related to the CEAG at this time. We are still in the process of developing cost estimates and anticipate the major cost categories to be the member stipends and the third-party facilitator. NW Natural anticipates including these costs in the HB 2475 proposed in docket UM 2233.

c. ***Please describe how NW Natural plans to identify, nominate, and elect members to the CEAG.***

The CEAG will consist of a broad panel of representatives from community-based organizations (CBOs) that serve seniors; urban, rural and coastal communities; non-native English speakers; housing insecure and houseless individuals; BIPOC and LGBTQ+ communities and individuals with low incomes; as well as representation from Oregon and Washington to align with the community needs and policy requirements of each state. Internal membership will have representation from across the Company.

Terms of Service: Terms will run for a length of 2 years with opportunity for renewal and align with the calendar year. Some members of the inaugural group may be appointed to a three-year term to serve as a resource for new members.

Open Positions & Recruitment: Recruitment will take place each year in the two months prior to identified term dates. If and when a position opens outside of normal terms of service, NW Natural in consultation with the CEAG and a third-party facilitator may choose whether to fill the position before normal recruitment periods. As the convener of the CEAG, NW Natural will determine final appointments to the CEAG.

Internal activities include:

- Candidates have been identified through outreach to employees either directly or via their direct management. Employees are then nominated and or self-selected to participate.
- Criterion for membership includes:
    - Approval by supervisor/manager based on anticipated hours required for participation
    - Ability to represent a department(s) and or project team
    - Adherence to NW Natural's operating guidelines for the CEAG; these guidelines are to be reviewed, revised and finalized by the CEAG and third-party consultant.

External activities include:

- NW Natural worked to provide diverse coverage of populations through the recruited CBOs.
- The first round of recruitment was conducted via direct (email and or phone call) outreach to CBOs by internal members of the CEAG, as well as employees whose roles intersect with community engagement activities. Approximately 40 organizations were engaged in this round of recruitment.

- CBOs that indicated interest were invited to a one-on-one meeting/call with the core CEAG planning team. Following these informational sessions, CBOs presented the opportunity to their organizations to assess interest in and capacity for participation.

d. ***Please describe the ways in which NW Natural will commit to being "responsive and accountable to the CEAG."***

NW Natural is committed to an authentic and effective process. A core tenet of the group is to solicit ideas and encourage engagement from underrepresented populations—avoiding the pitfalls of DEI work that can be transactional and performative. Quarterly meetings will center on concrete, actionable asks of the advisory group—an approach that demands clear expectations, thoughtful planning and ongoing dialogue. Engaging a third-party consultant is another important tool to ensure responsiveness and accountability to members of the CEAG.

A priority for the CEAG is to finalize content that defines the CEAG operating agreement, charter, code of conduct, member responsibilities, and logistics for sharing documents and materials. NW Natural and CEAG members will adhere to the following principles during meetings, communications, and other CEAG activities:

- Actively participate in the group
- Be open to diverse experiences and opinions
- Practice active listening
- Be courteous towards all members and participants
- Understand and respect the role of the facilitator
- Foster effective meetings including silencing electronic devices, muting audio while not speaking, and adhering to agendas and meeting times

Additionally, NW Natural will commit to an agreed upon process of documentation as well as response to advisory items brought forward by the CEAG. NW Natural will utilize best practices and guidance from the third-party consultant to develop these processes. A few mechanisms that will be employed include:

- Recording and reporting out summaries of meetings; Provided by both NW Natural as well as the third-party consultant and could include a third summary/report out by an external CEAG member (TBD by the CEAG)
- Third-party consultant will take unbiased meeting notes and share with all members of the CEAG after each meeting
- Utilization of impartial mediation as needed
- Summary reports quarterly from NW Natural to the CEAG and vice versa
- A core NW Natural team as well as a third-party consultant will be available for communication with CEAG members
- Training and resources to CEAG members to enable understanding (at a high level) of the regulatory and policy environment in which NW Natural must operate, and to what extent NW Natural has the ability to influence particulars of the energy system and or planning process

e. ***Please describe:***

i. ***The CEAG's role, if any, in the Company's clean energy transition;***

We intend to use the CEAG to help guide NW Natural and ensure that the clean energy transition does not cause undue or disproportionate impacts on historically underserved communities. Plans and decision-making are more informed if they are based on the input of those they impact—not just a subset of the population—and so diversifying the voices, lived experiences and perspectives that inform our practices is a necessary step to serving all of our customers better.

ii. ***Whether this group parallels the electric utilities' obligation to create a Utilities Community Benefits and Impacts Advisory Group, as described in Section 6 of House Bill 2021 and how.***

The CEAG is an extension of existing community engagement priorities at NW Natural and a natural outgrowth of our commitment to improving energy equity and easing energy burden for our most vulnerable customers. We look to peer utilities as valuable resources for lessons learned and best practices. That said, the CEAG is not specific to one policy; rather, the intent is to be iterative, member-informed and influence woven throughout the company.

iii. ***If NW Natural plans to coordinate the work of the CEAG with partner utility advisory groups and how.***

The intention of NW Natural's CEAG is to look at a more holistic picture of the Company and its programs versus a narrow scope which many advisory groups employ. To that end, NW Natural is open to coordination of work with partner utility advisory groups, however, this is yet to be defined. NW Natural is seeking to build a coalition around community engagement and energy equity, as one entity cannot engage with all communities nor solve all issues related to energy equity on its own. Moreover, the Company is also mindful of the limited resources and/or staff time community organizations have available to put to these efforts. NW Natural believes a coalition could be effective in identifying and implementing intersections and efficiencies to achieve shared goals.

f. ***Please include a column describing any new project/program initiated in that year and the anticipated benefit(s) and objectives(s) to be provided to customers as a direct result of the project/program.***

The CEAG was initially identified as a need by the IRP team; but we see the advisory group's influence and impact extending beyond system planning decisions and being integrated into other efforts throughout the company, including low-income programs, renewable resource development and philanthropic investment.

CHRISTENSEN
ASSOCIATES
ENERGY CONSULTING

Economic Analysis and Consulting

A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural

by

Daniel G. Hansen
Steven D. Braithwait

March 31, 2005

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Table of Contents

1. INTRODUCTION AND BACKGROUND

Traditional rate-of-return regulation may create incentives for energy utilities that are counter to public policy objectives. In the case of natural gas, this occurs in large part because utilities have costs that are both fixed and variable, but collect revenue to recover those costs primarily through volumetric prices (*i.e.*, retail $/therm prices applied to consumers' energy consumption). To recover their fixed costs, including their allowed return on capital, utilities typically forecast the total amount of energy they expect to sell in a given period, and set a price that will recover the appropriate amount of revenue toward fixed costs on the planned level of sales. This process tends to produce the following outcomes:

- The utility has an incentive to under-forecast sales for the rate-making period, thus increasing the retail price and improving the opportunity to recover fixed costs. The regulatory agency has a corresponding interest in over-stating sales forecasts, which would lead to lower prices. The resulting contrast in incentives typically leads to contentious rate cases.
- Variation in consumers' energy consumption due to factors such as unexpected weather conditions causes variation in both consumers' bills and the utility's net revenue (*i.e.*, revenue toward fixed-cost recovery).
- Once rates are set, the utility has a disincentive to take actions to encourage their customers to adopt energy efficient practices that may result in lower sales, as this will reduce their net revenues, and thus their ability to recover their fixed costs.

Consequently, utilities and regulatory agencies in a number of states have experimented with alternative mechanisms designed to alter some of the above incentives and outcomes. In 2002, the Oregon Public Utilities Commission (Commission) approved a Distribution Margin Normalization (DMN) mechanism for Northwest Natural Gas Company (NW Natural). As part of the Order, the Commission also approved NW Natural's proposal for Public Purposes Funding to support low-income bill payment assistance, low-income weatherization assistance, and enhanced energy efficiency programs. Finally, the Order imposed service quality standards on NW Natural, specifying penalties associated with violating specific service quality measures.

The Commission Order implementing DMN required NW Natural to submit an independent study regarding the effectiveness of the mechanism. The study will contribute to the process of determining whether to continue DMN beyond September 30, 2005. NW Natural has retained Christensen Associates Energy Consulting, LLC (CAEC) to perform this study, and has expanded the scope of the study to also include a partial evaluation of the Weather Adjusted Rate Mechanism (WARM) as well as a comparison of the combination of DMN and WARM to a full decoupling mechanism.

The report is organized as follows. Section 2 provides an overview of DMN, including a description of the calculations and its expected incentive effects. Section 3 provides a similar overview of WARM. Sections 2 and 3 focus on *theoretical* evaluations of DMN and WARM, or what we would expect to happen given the calculations contained in the mechanisms. Section 4 presents data and analysis regarding the effects of DMN, including revenue effects, changes in marketing efforts, organizational changes, financial effects, and service quality issues. Section 5 compares DMN to other rate mechanisms that may be able to achieve similar goals. Section 6 provides a summary and conclusions, including answers to the specific questions raised by the Commission in Order 02-634.

2. OVERVIEW OF DISTRIBUTION MARGIN NORMALIZATION[1]

2.1 Description of Mechanism

A primary goal of DMN is to reduce the uncertainty around NW Natural's distribution fixed cost recovery. That is, because distribution fixed costs are recovered through volumetric rates that are established based upon an expected level of sales, deviations from expected usage (caused by weather, economic conditions, price changes, random variations, etc.) will affect the amount of fixed costs recovered. In addition, by ensuring that the utility recovers its fixed costs regardless of customer usage levels, DMN reduces the utility's disincentive to promote energy efficiency. The DMN mechanism agreed to in Oregon is limited to "decoupling" revenues associated with 90% of the non-weather induced variation in usage for residential and commercial customers.

2.1.1 Elasticity Adjustment

There are two ways in which DMN affects revenues: the *elasticity adjustment* and the *deferral component*. The elasticity adjustment adjusts margin recovery for the effects that changes in retail tariff prices are expected to have on use per customer (*e.g.*, customers are expected to reduce consumption if natural gas prices increase). To understand the elasticity adjustment, consider an example in which the retail price increases over a particular time period. The elasticity adjustment mechanism first adjusts original "baseline" use per customer downward (using a price elasticity value specified in the tariff) to account for the fact that customers are expected to reduce usage when prices increase. This reduction in baseline usage is then used to calculate the increase in the dollar per therm margin required to keep the allowed fixed cost recovery constant on a per-customer basis. This new margin value is then passed through to the standard tariff, which in this example implies increasing the per therm rate. Ultimately, the change in the baseline use per customer value produced by the elasticity adjustment also affects the deferral component of DMN, which is described in detail later in this section.

The revenue effects of the elasticity adjustment alone are described in Equations 1a through 1c.[2]

Equation 1a: Elasticity Adjustment Revenues = $(M' - M) * Q^{A,M}$

[1] This mechanism has also been referred to as the Partial Decoupling Mechanism (PDM) and the Conservation tariff.

[2] For simplicity, we represent the calculations in the first year after a rate case, so that the initial margin (M) and baseline use per customer (QPC^B) are determined in the rate case. In practice, each year's DMN adjustment uses the baseline use per customer and margin values from the previous year.

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Equation 1b: $M' = M * QPC^{B} / QPC^{B,P} + \Sigma_i M_i * QPC^{B}_{i} / QPC^{B,P}$

Equation 1c: $QPC^{B,P} = QPC^{B} * [(P/P^{B} - 1) * \varepsilon_d + 1]$.

Where,

M = initial margin for recovery of fixed costs in the standard tariff;
M' = the adjusted margin resulting from the elasticity adjustment;
$Q^{A,M}$ = metered natural gas consumption in therms;
QPC^{B} = baseline use per customer, initially determined through a rate case;
$QPC^{B,P}$ = price elasticity adjusted baseline use per customer;
M_i = margin components approved subsequent to the most recent rate case;
QPC^{B}_{i} = baseline use per customer at the time that M_i was approved;
P = total dollar per therm tariff price for the coming year (excluding the elasticity adjustment to margin);
P^{B} = baseline total price per therm, initially determined through a combination of a rate case and the calculations resulting from the purchased gas cost adjustment; and
ε_d = the class-specific price elasticity stipulated in the Order (-0.172 for residential customers and -0.110 for commercial customers).

Equation 1a shows that the total revenue effect associated with the elasticity adjustment equals the change in margin times the total metered consumption. Equation 1b shows how the margin is affected by the elasticity adjustment. The margin is adjusted so that the product of baseline use per customer and the margin remains constant (*i.e.*, so that the total margin contribution per customer remains constant). The summation term in Equation 1b accounts for any additions to allowed margin since the rate case that established the baseline. Equation 1c shows how the baseline use per customer is adjusted for price changes. This is accomplished by determining the percentage change in price, multiplying it by the price elasticity in order to obtain the percentage change in baseline quantity, and applying this percentage change to the baseline use per customer.

2.1.2 Deferral Component

Equations 2a and 2b show the calculations contained in the deferral component, which is the part of the DMN revenue adjustments that is intended to compensate NW Natural for conservation efforts (and stabilize fixed cost recovery more generally).[3]

Equation 2a: DMN deferral amount = 90% * $[(QPC^{B,P} * C) - Q^{WN}] * M'$

Equation 2b: $Q^{WN} = Q^{A,S} + C * \beta * (HDD^{N} - HDD^{A})$.

Where,

[3] This simplified description does not consider many complicating factors that have arisen in practice, such as the modifications to the baseline quantities due to the reclassification of customers following the last rate case.

$QPC^{B,P}$	=	baseline use per customer adjusted for price elasticity effects;
M'	=	the per therm margin, adjusted for price elasticity effects;
Q^{WN}	=	weather normalized sendout therms for the residential or commercial class;
$Q^{A,S}$	=	actual sendout therms for the residential or commercial class;
C	=	the number of customers in the residential or commercial class;
β	=	a parameter representing the change in therms per customer per change in heating degree day (HDD), as contained in the WARM tariff;
HDD^{N}	=	normal heating degree days for the billing period, using a base of 59 degrees for residential customers and a base of 58 degrees for commercial customers; and
HDD^{A}	=	actual heating degree days for the billing period, using a base of 59 degrees for residential customers and a base of 58 degrees for commercial customers.

These calculations are made each month. The resulting surcharges or refunds accumulate in a deferral account, and are collected or refunded through rates in the following year (which begins on October 1).

The weather normalization of actual usage shown in Equation 2b is performed using methods developed in NW Natural's most recent rate case. Heating degree day (HDD) data are adjusted ("cycle-ized") to match the timing of the billing data. The normal weather measure is a district-weighted average for the 25 years ending in 2000. The weather normalization method adjusts actual usage (measured on a sendout basis) for the expected difference in usage between normal and actual weather conditions.

2.2 Expected Risk Effects

In this section, we discuss the risk properties of DMN. For this purpose, we define "risk effects" as the changes in revenue flows due to changes in the outcomes of uncertain variables. We consider four sources of uncertainty that create risk in NW Natural's fixed cost recovery and customer bills: weather, natural gas prices, economic conditions, and other random factors.

DMN does not change the risk associated with uncertainty in weather conditions, as the usage amount used to calculate deferrals is weather normalized.

Changes in natural gas prices affect the amount of natural gas that customers will use. Therefore, the risk that NW Natural faces with respect to gas price uncertainty is that when prices rise, customer usage levels decrease, reducing fixed cost recovery. At the same time, the price increase causes customers' bills to increase (as long as any reductions in usage are not offset by the increase in the gas price). Because both NW Natural and its customers are made worse off by increases in natural gas prices, the fact that DMN reduces this risk for NW Natural means that the risk is shifted to customers. However, the component of DMN that shifts this risk is the elasticity adjustment, over which there appears to be no dispute with respect to its appropriateness. That is, various parties' views regarding the efficacy of DMN seem to hinge on their opinion of the decoupling mechanism, not the elasticity adjustment.

DMN has the *theoretical* potential to shift economic risk from NW Natural to its customers. For example, in a period of declining economic conditions (*e.g.*, an increasing unemployment rate) customers may reduce usage in an attempt to reduce their bills due to income constraints. However, the DMN deferral component would increase customer bills (in the following year), thus reducing the amount of bill reduction that customers can achieve. While the possibility of this form of risk shifting exists in theory, our analysis in Section 4.3 indicates that this problem does not appear to exist in practice in NW Natural's service territory (*i.e.*, the analysis of residential and commercial use per customer indicates that they do not appear to be significantly affected by changes in economic conditions).

Controlling for weather conditions, natural gas prices, and economic conditions, some residual variation can be observed in use per customer that must be due to other uncertain factors. (The analysis in Section 4.3 indicates that the residual variation in use per customer is small relative to the variation explained by weather and natural gas prices.) For these other factors, DMN reduces risk for both NW Natural and its customers. That is, the reduction in the variability of revenues under DMN leads to more certainty (*i.e.*, less risk) for both NW Natural and its customers. However, because the customers experience a DMN rate adjustment as a change in the volumetric price in the *following* year, DMN does not reduce their *current* cash flow risk. For example, when usage exceeds baseline levels, customers' current bills reflect the over-payment of distribution costs. They are not "paid back" for the over-recovery until the following year. Therefore, while customer bill risk is reduced over long periods of time (*i.e.*, their "wealth" risk is reduced), customers may not perceive their risk reduction to be significant.[4]

In theory, DMN should be effective in reducing the variability of distribution cost recovery. By design, the effectiveness of DMN in accomplishing this task has been reduced in two ways (relative to full decoupling or fixed/variable rates). First, weather-induced variations in fixed cost recovery are eliminated from the adjustment mechanism through the weather normalization of usage. Second, only 90% of the remaining margin variability is covered by the deferral component of DMN. Therefore, NW Natural retains all weather-related variability and 10% of non-weather related variability in distribution fixed cost recovery from customers on DMN.[5]

In testimony supporting decoupling, NW Natural has asserted that the risk reduction to NW Natural caused by DMN is mirrored by a corresponding reduction in risk to its customers. For example, when NW Natural over-recovers revenue, its customers over-pay, thus providing the opportunity to reduce risk for both parties. This assertion is valid with respect to weather risk (which is addressed by full decoupling, which was the topic of NW Natural's testimony) and risk due to the other non-price and non-economic factors. The theoretical potential for DMN to shift economic risk from NW Natural to its

[4] Another reason that customers may not perceive a large reduction in their risk is that DMN covers only the distribution portion of the bill and not the energy costs. Therefore, DMN adjustments will tend to be small in proportion to the total bill regardless of when they are applied.
[5] Note that WARM addresses weather-related variations in revenue toward distribution cost recovery.

customers is not supported by empirical analysis (see Section 4.3), and the shift of natural gas price risk from NW Natural to its customers that is caused largely by the elasticity adjustment is accepted by both Commission Staff (through its support of a stand-alone elasticity adjustment) and NW Natural.

2.3 Expected Incentive Effects

DMN has the potential to produce a number of incentive effects. Four potential NW Natural incentive effects are addressed in this section, followed by a discussion of the effect of DMN on customer incentives.

2.3.1 Reduced Disincentive to Promote Conservation

Prior to the introduction of DMN, NW Natural had a strong disincentive to promote energy efficient appliances and general conservation efforts. This was due to the fact that any conservation that occurred (*i.e.*, any reductions in natural gas sales from the levels on which retail rates were based) reduced the amount of distribution cost recovery.[6] In fact, NW Natural benefited by promoting load growth because it could achieve excess distribution cost recovery whenever usage levels exceeded the levels used in setting retail rates. By reducing the link between sales and distribution revenues, DMN should be effective in reducing NW Natural's disincentive to promote conservation. However, it does not eliminate the disincentive completely, as NW Natural continues to retain 10% of any non-weather related over- or under-recovery of distribution costs.

The change in incentives with regard to conservation has a less appealing aspect. That is, NW Natural has asserted that direct use of natural gas is itself energy efficient. This is based on the idea that using electricity generated from natural gas is less efficient than using the natural gas directly in applications such as cooking, space heating, clothes drying and water heating. However, with DMN, NW Natural has a reduced incentive to promote fuel switching among current customers. For example, prior to DMN, if a customer converted to a natural gas water heater, NW Natural's revenues increased through the standard tariff. With DMN, the 90% of the increase in revenues is offset by a customer refund generated through the deferral component (though only a very small percentage of this refund will go to the customer that converted the water heater). It could be that in the absence of DMN, NW Natural's incentives to promote these conversions were too high (by causing conversion customers to pay increased fixed costs as well as natural gas energy costs), but the *change* in incentives caused by DMN could cause NW Natural to reduce its efforts to promote conversions that it has advocated as being energy efficient.

2.3.2 New Customer Connections

The DMN deferral mechanism incorporates a baseline use per customer measure that is intended to represent the average usage of the customers in the class (adjusted for responses to changing prices). Because of this, DMN gives NW Natural a short-term

[6] Lost revenue adjustments were in place prior to DMN. These compensated NW Natural for reductions in revenues attributed to some programs, such as the residential high-efficiency furnace program. Section 5.3.2 presents a discussion of the effectiveness of lost revenue adjustments in reducing disincentives to promote energy efficiency.

incentive to provide new connections to low usage customers. Each additional customer that is smaller than average generates surcharges through the deferral mechanism that result in additions to NW Natural's net revenues.

At the time DMN was approved, NW Natural agreed that it would not modify its main extension policies in response to DMN. One way to remove this potential incentive regarding new customer connections is to apply DMN only to existing customers. This would maintain non-DMN incentives for new connections customers, who would only be included in DMN adjustments following the next rate case. However, an offsetting effect of removing new connections customers from DMN is that it might make NW Natural more resistant to altering building codes to improve energy efficiency and reduce their incentive to promote the use of high efficiency appliances in new construction. Section 4.4.3 contains a more complete discussion of new connections.

2.3.3 Uncollectible Accounts

A concern was communicated to us regarding whether DMN affects NW Natural's incentive to pursue uncollectible accounts. An examination of the calculations in Section 2.1 reveals that uncollectible revenues are unrelated to the DMN mechanism. That is, because uncollectible revenues do not flow into the DMN deferral mechanism, we conclude that DMN does not have undesirable incentive effects in this area.

2.3.4 Customer Service

Two factors lead us to believe that the DMN Order does not present negative incentive effects with respect to the provision of customer service. First, the Commission implemented service quality standards and penalties as part of the Order approving DMN. Second, although NW Natural is a monopoly provider of natural gas services in its territory, it does compete with other fuels to serve customers. This fact, combined with the fact that the DMN deferral mechanism compensates NW Natural based on the *current* number of customers in the class, leads us to conclude that DMN provides NW Natural with the same incentive to attract and retain customers. A related concern has been expressed to us that DMN may provide NW Natural with a disincentive to resolve outages in service. The thinking behind this concern is that DMN compensates NW Natural for reductions in usage that occur during outages (while under standard rates, NW Natural loses revenues until the outage is repaired). Given NW Natural's competitive concerns and the fact that natural gas outages can present a significant safety hazard, we do not believe that this effect will exist in practice. Section 4.6.2 provides additional discussion of this issue.

2.3.5 Incentives on Customer Behavior

Regarding the incentive effects of DMN on customer behavior, there is only one minor effect to consider. That is, relative to standard tariffs, DMN may slightly reduce customers' incentives to independently conserve energy (and conversely, DMN slightly decreases the cost of increasing consumption). In the absence of DMN, customers are "over-paid" for conservation efforts, as they pay less fixed distribution cost in addition to the reduction in their energy cost.[7] By ultimately reducing the amount of this over-payment by 90%, DMN reduces the aggregate incentive for customers to conserve.

However, the effect is likely to be very small in practice because the revenue effects of *individual* customer conservation efforts are spread across the *entire* customer class, and delayed until the following year. That is, in the month that the conservation activities are undertaken, the conserving customer receives the full "over-payment" of fixed distribution costs through the standard tariff rate. The shortfall in revenues that this produces is added to the tracking account (with a 10% reduction), deferred until the following year, and recovered through an increase in rates to the *entire* class. Therefore, the conserving customer only re-pays its avoided distribution costs in proportion to its share of total class usage in the following year. Because of this dilution effect, the incentives for individual customers to conserve energy is largely unaffected by the presence of DMN.

2.4 Possibilities for Gaming the Mechanism

In order to implement DMN, NW Natural and the Commission must agree to certain parameter values, including:

- Price elasticity values for residential and commercial classes;
- Definition of normal weather;
- Weather sensitivity parameter (used to weather normalize use per customer); and
- Baseline use per customer for residential and commercial classes.[8]

Each of these parameters introduces the potential for "gaming" the outcome, by which we mean that parties may have an incentive to influence the calculations in order to produce an outcome that is more favorable to customers or the utility.

This gaming issue must be considered from two perspectives: DMN as a stand-alone mechanism; and DMN in combination with WARM. That is, as we will point out, some of the ways in which DMN outcomes might be influenced are countered by an offsetting effect from WARM, thus reducing or eliminating the incentive to game the parameter value.

2.4.1 Price Elasticity Values

The primary effect of setting the price elasticity incorrectly is that it changes the amount of revenues that flow through the deferral accounts, which leads to a reduction in the extent to which distribution revenues are adjusted for price effects (because deferrals are subject to the 90% factor). Note that if the 90% factor were removed, the price elasticity value would have no effect on total revenues collected or refunded; errors in the price

[7] Environmental organizations argue that the "over-payment" does not exist because energy prices do not account for all of the costs that energy use imposes on society (in terms of environmental impacts).
[8] There is an additional gaming concern with respect to new customer connections, which is discussed in Section 2.3.2.

elasticity would simply shift dollars from the elasticity adjustment to the deferral component.[9]

However, because of the 90% factor, only small revenue effects are associated with setting the price elasticity incorrectly. Table 2-1 shows the net revenue effect associated with increasing or decreasing prices when the elasticity value is too high or too low.

Table 2-1: DMN Revenue Effects of Setting the Price Elasticity Incorrectly

	Price Increase	**Price Decrease**
ε_d too low	Surcharge too low	Refund too low
ε_d too high	Surcharge too high	Refund too high

To better understand this table, we will walk through the reasoning associated with the upper left cell ("surcharge too low"). For this example, assume that normal weather conditions occur. When the base tariff price increases, use per customer is expected to decrease. When this happens, DMN produces surcharges to customers that should make NW Natural whole for the lost margins. However, if the elasticity value is set too low (*e.g.*, suppose the true elasticity is -0.3, but it is set at -0.172 for DMN calculations), the use per customer is assumed to fall by less than it actually will. This causes the per therm margin to be set too low, reducing the revenues from the elasticity effect shown in Equation 1a. Offsetting this effect is the fact that, because baseline use per customer is too high, the deferral component will produce surcharges to customers (that would not have existed had the baseline usage been adjusted correctly). In the absence of the 90% factor applied to deferrals, the error in the deferrals would exactly offset the error in the elasticity adjustment. However, because of the 90% factor, total surcharges to customers end up being too low, resulting in lost distribution cost recovery for NW Natural.

Examining each cell of Table 2-1 leads to the following conclusions with respect to gaming the price elasticities: if prices are expected to increase, customers will benefit if the price elasticity is set too low and NW Natural will benefit if the price elasticity is set too high. Conversely, if prices are expected to decrease, customers will benefit if the price elasticity is set too high and NW Natural will benefit if the price elasticity is set too low.

The magnitude of this incentive is relatively small, and would disappear completely if the 90% factor were eliminated. The gaming effects of this parameter are unaffected by the presence of WARM.

2.4.2 Normal Weather Definition

The definition of normal weather in the form of heating degree days (HDD^N) is required for the DMN deferral calculation. To evaluate the effects of setting HDD^N incorrectly,

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[9] In the absence of the 90% factor, the price elasticity value would change the *timing* of revenue recovery, but not the *level* of revenue recovery. That is, revenues recovered through the elasticity adjustment come from current bills, while revenues recovered through the deferral component come from bills in the following year.

assume that the weather sensitivity parameter (β) is set correctly and actual heating degree days (HDD^A) are at their true normal value. Setting HDD^N too low (the equivalent of assuming that winters will be too warm) leads to a consistent over-adjustment of use per customer for weather, producing surcharges to customers. Conversely, setting HDD^N too high (the equivalent of assuming that winters will be too cold) leads to a consistent under-adjustment of use per customer for weather, producing refunds to customers. Therefore, all else equal, customers benefit when normal weather is set too cold, and NW Natural benefits when normal weather is set too warm.

The incentive to influence the definition of normal weather is dramatically reduced when DMN is combined with WARM. This is discussed in more detail in Section 3.4.

2.4.3 Weather Sensitivity Parameter (β)

The weather sensitivity parameter determines how much use per customer is assumed to change as weather conditions (HDDs) change. Currently, the same values are used in DMN and WARM, and they were estimated as part of the load forecasting process undertaken during the UG-152 rate case.

The effect of errors in setting β depends upon whether HDD^A is above or below the assumed value of HDD^N, as shown in Table 2-2.

Table 2-2: Revenue Effects of Errors in Setting the Weather Sensitivity Parameter

	$HDD^A < HDD^N$	$HDD^A > HDD^N$
β too low	Surcharges	Refunds
β too high	Refunds	Surcharges

Consider the result when β is set lower than its true value and winter weather is warmer than normal (represented by the top left cell in Table 2-2). Warm winter weather reduces actual use per customer below baseline values. If β is too low, the weather adjustment does not bring the weather-adjusted actual use per customer all the way up to baseline use per customer, which produces a surcharge to customers through the deferral mechanism.

Therefore, the way in which β might be influenced depends upon the forecast of weather conditions, or equivalently, whether the definition of HDD^N was influenced upward or downward. If winter weather is expected to be warmer than normal (or if it is expected to be normal, but HDD^N has been set too high), customers benefit if β is set too high and NW Natural benefits if β is set too low. Conversely, if winter weather is expected to be colder than normal (or if it is expected to be normal, but HDD^N has been set too low), customers benefit if β is set too low and NW Natural benefits if β is set too high.

As with the incentive to influence the definition of normal weather, the incentive to influence the weather sensitivity parameter is dramatically reduced when DMN is combined with WARM (and the incentive would be eliminated if the 90% factor on the deferral component of DMN were to be removed).

2.4.4 Baseline Use per Customer

Baseline use per customer is initially established through a rate case. Because of the methods associated with standard ratemaking (see Section 1), there is a history of contentiousness between regulators and utilities in determining forecast customer usage. In standard ratemaking, regulators can *reduce* customer rates by pursuing high short-term forecasts of customer usage, and utilities can *increase* rates by pursuing low forecasts of customer usage. (That is, once the revenue requirement is determined, rates are set by dividing revenue by forecast billing determinants.) The presence of DMN reduces these incentives, as the deferral component will tend to produce refunds to customers when baseline use per customer is set too low, and surcharges when baseline use per customer is set too high.

In the absence of DMN, any factor that is included in the forecast of customer usage that must itself be forecast (or assumed) can be manipulated to the benefit of either customers or the utility. In particular, note that forecasting customer usage requires an assumption regarding normal weather conditions. This provides a further incentive for the regulator to promote a normal weather definition that is too cold, as this will produce a baseline use per customer value that is too low, and lead to persistent refunds to customers. The incentive for the utility is the opposite.

Baseline use per customer and the baseline margin rate are jointly determined. If baseline use per customer is set too low, the margin rate will be set too high. Therefore, there are offsetting effects associated with influencing baseline use per customer. Setting baseline use per customer too low will lead to a margin rate that is too high, increasing revenues from the standard tariff. However, it will also lead to persistent refunds to customers through the DMN deferral mechanism.

In the absence of the 90% factor in the deferral mechanism, these two effects exactly offset one another, removing contentiousness over the value of baseline use per customer. In this case, the only effect of setting baseline use per customer incorrectly is that the change in revenues with respect to changes in usage (not due to weather or expected price effects) will be too high or too low because the margin rate will also deviate from its correct value. However, this does not benefit either customers or NW Natural on average, and all parties should be better off by setting the correct baseline value, ensuring that the revenue adjustments are of the appropriate magnitude.

2.5 Potential Improvements in the Mechanism

2.5.1 Methods of Refunding or Collecting Deferral Account Funds

Currently, DMN recovers revenue shortfalls or refunds excess revenues by adjusting the per-therm rate for the following year. There are two potential problems with this approach. First, it introduces the potential for customers to be credited or charged an incorrect share of the revenue adjustment. This would occur whenever a customer's share of total usage differs between the two years. Second, by rolling the adjustment into the per-therm rate, DMN alters the price signal to customers (albeit only slightly), changing the marginal incentives for increasing or decreasing usage.

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An alternative that would address both of these concerns would be to calculate, for each month, the dollar amount that each customer should be credited (charged) based on current usage. That is, the calculation of the deferral amount would be identical to the current method. However, instead of calculating a change to the per-therm rate for the coming year, the deferral adjustment would be credited or charged to customers in a lump sum adjustment based on their share of class usage in that month.

There would then be several options for refunding (collecting) the deferral amounts. First, the credits (charges) could be applied to customers' current bills, which would have the added benefit of reducing cash flow risk for customers. Second, the credits (charges) could be refunded (collected) in a lump sum at the end of the year. However, customers may not find this alternative appealing in years in which they pay a large lump-sum charge. Third, the refunds (collections) could be spread across the twelve months of the following year.

It is possible that this alteration to DMN would increase the administrative costs of the rate. However, given the complexity of WARM, we believe that NW Natural's billing system would be able to accommodate the proposed changes. In addition, these changes would make DMN more visible to customers. Currently, DMN adjustments to rates are not separately listed on customer bills, which has reduced awareness of the mechanism and therefore (we expect) has reduced the number of customer service issues associated with DMN. Changing the way in which DMN adjustments are allocated and refunded (or recovered) will likely increase the awareness of DMN, which could lead to increased customer service expenses.

2.5.2 Incomplete Coverage

Removing the 90% factor applied to the deferral component would improve DMN's incentive properties (*i.e.*, it would further reduce NW Natural's disincentive to promote energy efficiency) and eliminate some incentives to game DMN parameter values. Given that this factor can help or harm customers (*i.e.*, it reduces both surcharges and refunds), it does not seem to serve any useful purpose and should be eliminated.

2.5.3 Complexity

Especially in combination with WARM, DMN is a complex mechanism to understand and communicate to others. A full decoupling mechanism, which produces nearly identical total revenue effects to the combination of DMN and WARM, requires the setting of fewer parameters, and is much more easily explained and understood. A more detailed discussion of the tradeoffs between DMN, WARM, and full decoupling is contained in Section 5.

3. WEATHER ADJUSTED RATE MECHANISM

3.1 Description of Mechanism

The Commission approved WARM in 2003 as a means of reducing weather-related risk for both NW Natural and its customers. That is, fixed distribution costs are recovered through volumetric rates, and customer usage is sensitive to weather conditions. Therefore, in cold winters when usage is above expected levels, NW Natural over-recovers distribution costs and customers' bills are higher than usual. Conversely, in mild winters, NW Natural under-recovers distribution costs and customers' bills are lower than usual. Because NW Natural's exposure to weather is the opposite of its customers (*i.e.*, when NW Natural is made worse off by weather, its customers are better off), mechanisms such as WARM can reduce risk for both parties. In 2004, WARM was altered in two ways. First, limits were placed on the size of the WARM adjustment in any one month (though the full adjustment is still recovered in subsequent months). Second, the calculation of the WARM adjustment was altered so that it is determined on a customer-specific basis instead of a class-wide basis. The description below is of the current form of WARM.

A discussion of WARM in this report is appropriate because the combination of WARM and DMN produce effects that are very similar to full decoupling, which was the initial proposal of NW Natural (in place of DMN). In addition, some aspects of DMN (*e.g.*, incentives to game parameter values) can only be fully understood by introducing WARM effects.

Equation 3 shows the formula used to calculate the WARM adjustment (prior to the application of maximum bill change provisions). It is calculated for each customer based on their billing cycle usage and weather data from the closest available weather station (among the eight established district weather stations used by NW Natural).

Equation 3: WARM Adjustment = $\Sigma_d \, (HDD^N{}_d - HDD^A{}_d) * \beta * M$.

In this equation, d indexes the days of the customer's billing month; $HDD^N{}_d$ is normal heating degree days (HDDs) for day d of the billing month, based on a 25-year average ending in 2000; $HDD^A{}_d$ is the actual heating degree days for day d of the billing month; β is the weather-sensitivity parameter (an estimate of the change in customer usage with respect to a one unit change in HDDs); and M is the distribution margin in dollars per therm.

β is statistically estimated as part of the class load forecasting process. Its units are in therms per HDD, and the same value for β is used for all customers within a class. For residential customers, the WARM adjustment is capped at the lesser of $12 or 25% of the volumetric portion of the bill. For commercial customers, the WARM adjustment is capped at the lesser of $35 or 25% of the volumetric portion of the bill. However, the portion of the WARM adjustment that exceeds the cap is collected in subsequent months. While WARM is the default service for residential and commercial customers, customers may opt out of the program.

3.2 Expected Risk Effects

From NW Natural's perspective, WARM is an effective means of reducing weather-related distribution cost recovery risk provided that few customers decide to opt out of the program. The effect of the opt-out provision upon NW Natural's risk depends upon the characteristics of the customers that opt out relative to those of the class. A more detailed discussion of the effects of the opt-out provision is included later in this section. Under the assumption that no customers opt out of the program, WARM will be effective in reducing NW Natural's weather risk provided that β accurately reflects the average customer response to weather variations, and that the definition of normal weather is correct.[10]

From a customer perspective, WARM is a less effective tool for reducing risk. This is because β is set on a class-wide basis and is constructed in units of therms per HDD. Thus, the amount of risk coverage varies across customers. Customers who are smaller or less weather sensitive than the class average are *over-insured* by WARM.[11] Conversely, customers who are larger or more weather sensitive than the class average are *under-insured* by WARM. The added provisions that cap the amount of the WARM adjustment in any month do not alter our conclusions about over- or under-insurance because the total WARM adjustment is collected from each customer in subsequent months. In Section 3.5 below we discuss the potential value of re-designing the weather adjustment parameter so that it is in units of *percentage* changes in therms per HDD.

3.3 Expected Incentive Effects

The WARM program does not alter NW Natural's behavioral incentives. This is because WARM affects only weather-related fluctuations in distribution revenues, and weather is out of NW Natural's control. The incentives to promote conservation, load growth, the addition of new customers, and the provision of high quality customer service are not affected.

WARM also does not affect participating customers' incentives. WARM may provide customers with benefits through a reduction in their bill variability, but the customers' marginal cost of changing usage levels is not affected by WARM.

3.4 Possibilities for Gaming the Mechanism

Neither the Commission nor NW Natural has an incentive for β to deviate from its true value. (This is true whether WARM is considered by itself or in combination with DMN.) Setting the value correctly ensures that the WARM adjustments have the appropriate magnitude. A value that is too high introduces more weather risk (relative to the "correct" value of β) for both NW Natural and its customers (on average). Setting β too low leads to an adjustment that under-insures NW Natural and its customers (on average).

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[10] However, if DMN and WARM use the same definition of normal weather, the errors in the revenue recovery for DMN and WARM due to an incorrect definition of normal weather largely cancel out. This reduces the incentive to "game" the definition of normal weather.

[11] Because WARM only intends to cover the risk associated with distribution fixed cost recovery, it is unlikely that customers will be over-insured against the weather risk associated with their *entire* bill. That is, any over-insurance on the distribution component will likely be smaller than the remaining weather risk on the energy component of the bill.

When WARM is considered by itself, the Commission and NW Natural have an incentive to manipulate the definition of normal heating degree days. Setting HDD^N below its "true" value leads to a situation in which, on average, WARM produces refunds to customers. (If HDD^N equals its true value, WARM will, over time, benefit neither NW Natural nor its customers.) Conversely, if HDD^N is set above its true value, WARM will tend to increase customers' bills.

However, when WARM is evaluated in combination with DMN, the incentive to game the definition of normal heating degree days is dramatically reduced, provided that both programs use the same definition. An example will help to illustrate this effect. To simplify the example, the timeframe of the analysis is reduced to one month and we will assume that the residential class consists of only one customer who uses 100 therms in normal weather conditions. Furthermore, we will assume that there is no price change (and therefore no elasticity adjustment to the baseline quantity), and that the customer does not deviate from its non-weather related usage. Consider the following case, in which the tariff value for HDD^N is higher than the true value, and actual heating degree days (HDD^A) match the true value:

"True" $HDD^N = 400$
Tariff $HDD^N = 500$
$HDD^A = 400$
$\beta = 0.1958$
$M = \$0.42569$

In this case, both the "true" WARM and DMN adjustments are zero. That is, weather is at normal conditions and there is no non-weather related usage change, so the mechanisms do not affect revenue collection. However, because the tariff contains an incorrect value of HDD^N, both DMN and WARM lead to non-zero adjustments, as shown below.

DMN deferral amount = 90% * $(QPC^{B,P} - Q^{WN}/C) * M * C$
$Q^{WN} = Q^{A,S} + \beta * \Sigma_d (HDD^N{}_d - HDD^A{}_d) = 100 + 0.1958 * (500 - 400) = 119.58$
DMN deferral amount = 90% * (100 – 119.58) * \$0.42569 * 1 = -\$7.50
WARM adj. = $\Sigma_d (HDD^N{}_d - HDD^A{}_d) * \beta * M$ = (500 – 400) * 0.1958 * \$0.42569 = \$8.34

These equations show that, while WARM over-collects by \$8.34, DMN offsets 90% of the over-collection, so that the net over-collection is only \$0.83. Assuming that the intended distribution margin recovery is equal to $Q^{B,P} * M$ = \$42.57, the over-collection amounts to only about 2% of the distribution revenue requirement, versus about 20% when considering WARM by itself. This demonstrates how the combination of DMN and WARM reduces the incentive to game the definition of normal weather.

This example highlights an additional incentive problem caused by setting HDD^N too high. That is, given that customers may opt out of WARM, setting HDD^N too high provides customers with an opportunity to game rates. If the customer realizes that WARM is established in way that consistently produces surcharges to their bills, they will rationally opt out of the program. This decreases the effectiveness of WARM in reducing weather risk, and negates the offsetting effects of DMN and WARM described above. In the example above, if the customer opts out of WARM, the $7.50 refund produced by DMN remains, but the offsetting surcharge of $8.34 generated by WARM is lost, leaving NW Natural with reduced overall revenues. (Alternatively, if HDD^N were set too low, rational customers would not opt out of WARM, as its persistent refunds would offset the persistent surcharges created by DMN, which does not allow them to opt out.) This example therefore highlights the beneficial effects of combining DMN and WARM in terms of compensating for inaccuracy in the program parameters.

3.5 Potential Improvements in the Mechanism

The use of a class-wide value of β reduces the economic value of WARM for many customers, increasing the potential that customers will opt out of WARM. NW Natural's benefits from WARM decline when customers opt out of WARM.

Two options exist for addressing this problem. First, NW Natural could continue to use a class-wide value of β, but instead calculate it as a *percentage* change in the usage per HDD. This would address the customer size problem (that small customers tend to be over-insured by WARM in its current form). For example, if β were expressed in percentage terms, smaller customers would experience lower WARM adjustments to their bill than under the current system.

The second option is to calculate *customer-specific* values of β for use in calculating the WARM adjustments. (These could either be in percentage or level terms.) This approach would address two problems: the inaccurate treatment of customers with respect to size, and the inaccurate treatment of customers with respect to weather sensitivity. Calculating customer specific β parameters would also have the effect of automatically excluding non-weather sensitive customers from the WARM program.

CAEC has developed software that is capable of calculating customer-specific values of β.[12] The software requires twelve months of billing data for a customer in order to estimate β, and screens are used to weed out "bad" estimates. Therefore, if WARM is modified to use an algorithm such as this, the program would be limited to customers with sufficient billing data (at their current site) and for whom the statistical model provides a reliable estimate of weather sensitivity.

A more complete analysis of the implications of modifying the WARM program will be performed in a subsequent report.

4. EVIDENCE OF DMN EFFECTS

Sections 2 and 3 presented theoretical discussions of the expected effects of DMN and WARM. This section explores the extent to which evidence may be found that is consistent with the theoretically expected effects of DMN. In addition, this section discusses the three programs funded by the Public Purposes Funding approved along with

[12] The software has been used to calculate offers for fixed bill programs.

DMN: the Energy Trust of Oregon administered energy efficiency programs (specifically, the residential high-efficiency furnace program), the Oregon Low-Income Energy Efficiency Program (OLIEE), and the Oregon Low-Income Gas Assistance Program (OLGA).

4.1 "Back Cast" of DMN Financial Effects from 1993 to 2004

The financial effects of DMN can be divided into two categories: the price elasticity effect and the deferral component. The price elasticity effect is equal to the change in the per therm margin multiplied by total class usage. That is, as natural gas prices increase, the baseline usage is adjusted downward and the dollar per therm margin is adjusted upwards, so that the margin multiplied by baseline usage per customer remains constant (all else equal). This portion of the adjustment is intended to adjust revenues for changes in use per customer that occur because of changes in energy prices.

The deferral component is intended to adjust revenue recovery for 90% of the non-weather driven fluctuations in use per customer. Deferral revenues can be caused by changes in use per customer due to conservation efforts, an imperfect price elasticity adjustment, or simply random factors. The deferral amount is calculated as 90% of the difference between the price-adjusted baseline usage and the weather-adjusted actual usage, multiplied by the adjusted dollar per therm margin.[13] Table 4-1 below shows the dollar amounts associated with these two categories of revenue effects by customer class for the first two full years of DMN.

The first year of DMN, October 2002 through September 2003, contained large revenue effects because of the need to "catch up" with respect to substantial price increases (and therefore substantial load decreases) since the previous rate case. The following year, October 2002 through September 2003, experienced much smaller revenue adjustments because the baseline values were based on a rate case that concluded in 2003.

Table 4-1: Revenue Effects of DMN Mechanism: October 2002 through September 2004

Time Period	Customer Class	Elasticity Effect ($000)	Deferral ($000)	Total ($000)
Oct. 2002 to Sep. 2003	Residential	7,665	3,093	10,758
	Commercial	2,529	1,573	4,102
	Total	10,194	4,666	14,860
Oct. 2003 to Sep. 2004	Residential	940	-788	152
	Commercial	335	91	426
	Total	1,275	-697	578

Notes: positive values indicate surcharges to customers and negative values indicate refunds to customers.

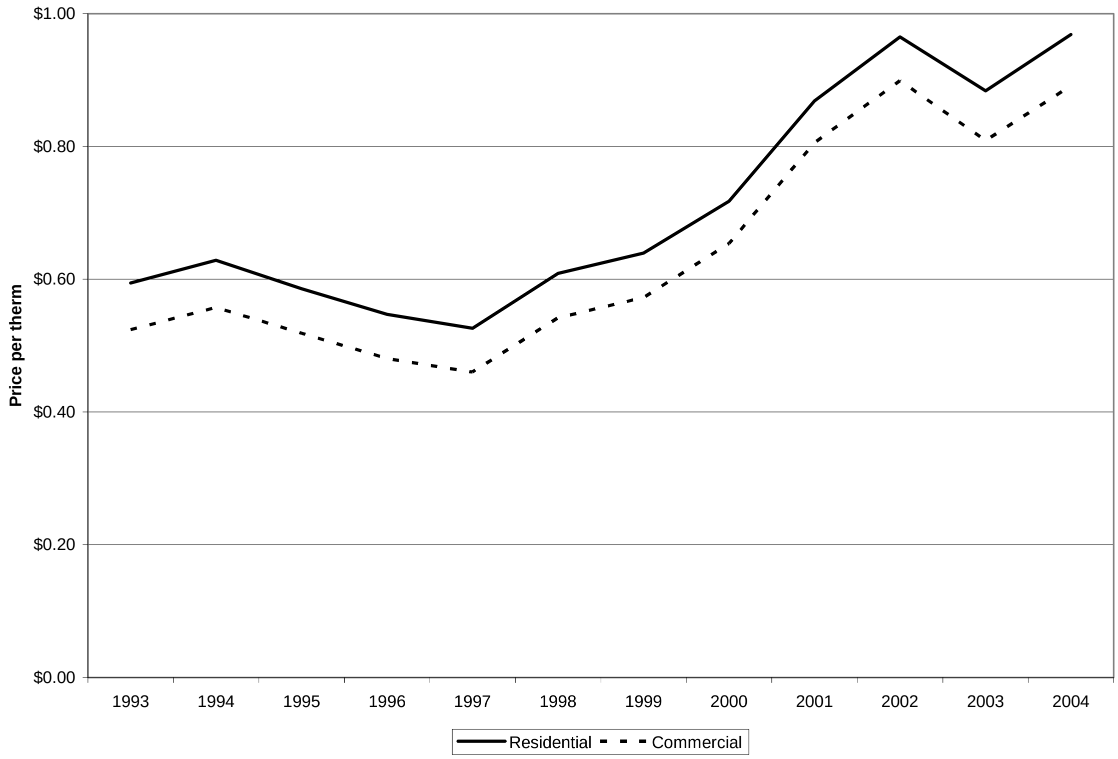
[13] Section 2.1 specifies the elasticity adjustment and deferral component in equation form.

Because DMN was approved relatively recently, there is a limited amount of direct experience to examine. In order to determine how DMN might function under a wider range of possible outcomes (*e.g.*, when prices are decreasing as well as increasing), we performed a "back cast" of DMN financial outcomes using annual data from 1993 through 2004. That is, we calculated the amounts of the price elasticity adjustment and deferral amounts for each of those years, at the price and weather conditions in those years, and using 2000 values of price and use per customer as baseline values. In order to facilitate this simulation, we made the following simplifying assumptions:

- We used annual data (*i.e.*, from January through December) as opposed to October through September monthly data.
- For the commercial class, we used Schedule 3 prices throughout instead of blending the price across the applicable commercial schedules. These prices are used to determine the percentage change in price that, combined with the price elasticity, determines the adjustment to baseline use per customer and margin rate.
- "Normal Weather" was defined as the average HDD value across the 12-year sample timeframe. This allows us to ignore issues about the "correct" definition of normal weather, as we use the *ex post* actual average value for this time period.
- Calendar year 2000 was set as the baseline year for use per customer (which is then weather normalized). Using 2000 as the baseline year allows us to examine DMN effects in years of flat or rising use per customer (prior to 2000), as well as declining use per customer (after 2000)
- The baseline dollar per therm margin was set as the October 2002 through September 2003 actual value, or $0.34055 for residential customers and $0.21692 for commercial customers. These values were simply used to provide an appropriate scale for the financial outcomes.
- The price elasticities and β coefficients (which define the change in use per customer per change in HDD and were used in weather normalization) are based on the values used in the actual DMN (and WARM) calculations. Specifically, the residential price elasticity is -0.172, the commercial price elasticity is -0.110, the residential $\beta = 0.1958$, and the commercial $\beta = 0.7669$.

Figure 4-1 shows the residential and commercial prices for each year. Using a base year of 2000 for this analysis allows us to examine outcomes when the price is below the baseline value (prior to 2000) and above the baseline value (after 2000).

Figure 4-1: Residential and Commercial Prices: 1993 to 2004



Figures 4-2 and 4-3 show the annual DMN revenue adjustments for the residential and commercial classes, respectively. The results for each year consist of three bars. The first bar shows the deferral revenues, the second bar shows the price elasticity adjustment, and the third bar shows the total DMN revenue adjustment (*i.e.*, the sum of the other two bars).[14] Positive values indicate surcharges to customers and negative values represent refunds to customers. Notice that there are no DMN adjustments for the year 2000 because it is the base year.

Figure 4-4 shows residential and commercial weather-normalized use per customer. In both cases, use per customer is declining over time, with 2000 as a transitional year between high and low values. This is reflected in the DMN revenue adjustments shown in Figures 4-2 and 4-3, in which pre-2000 adjustments are negative (refunds to customers), and post-2000 adjustments are positive (surcharges to customers).

[14] A spreadsheet containing the underlying data and calculations is available from the authors.

Figure 4-2: Simulated Residential DMN Revenue Adjustments: 1993 to 2004

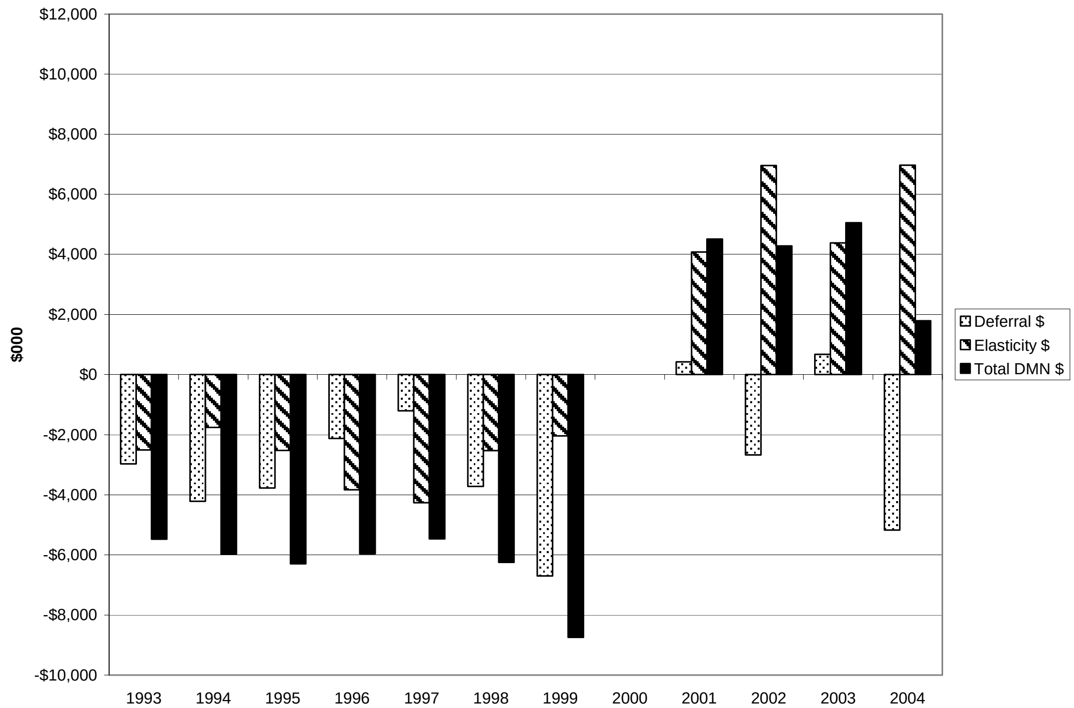


Figure 4-3: Simulated Commercial DMN Revenue Adjustments: 1993 to 2004

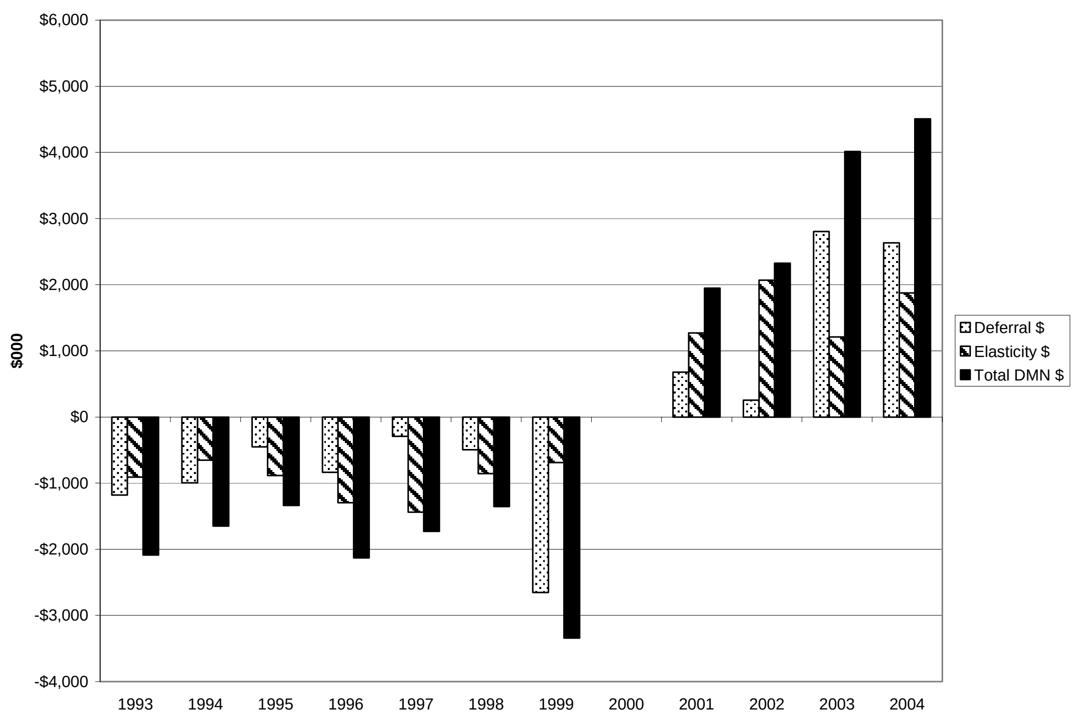
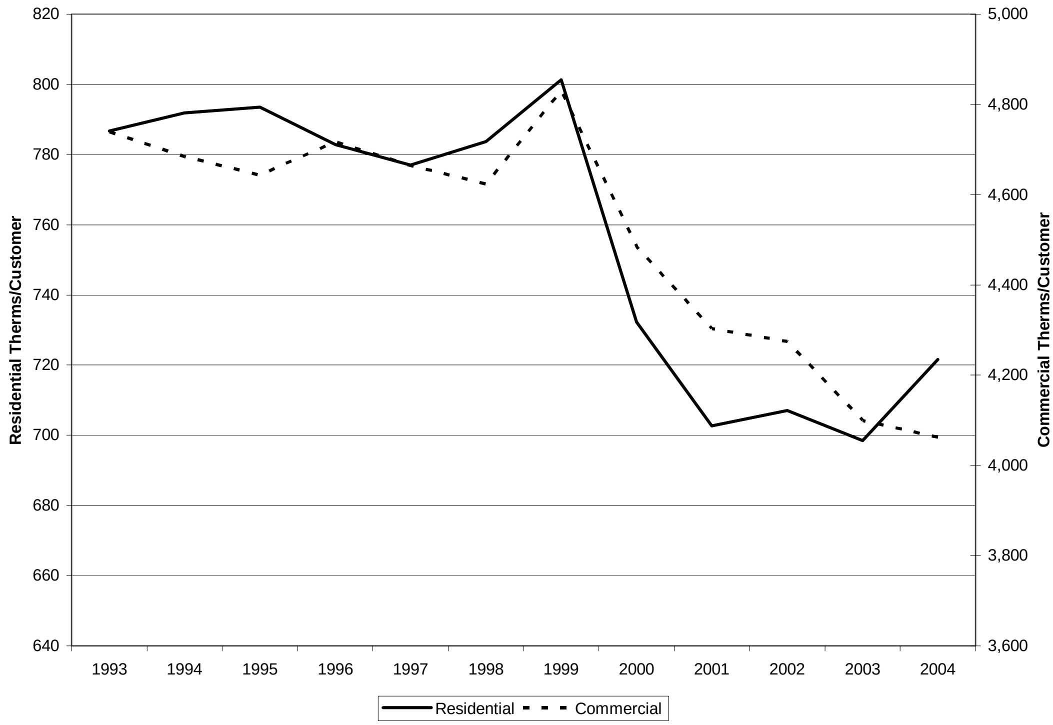


Figure 4-4: Residential and Commercial Weather-Normalized Use per Customer: 1993 to 2004



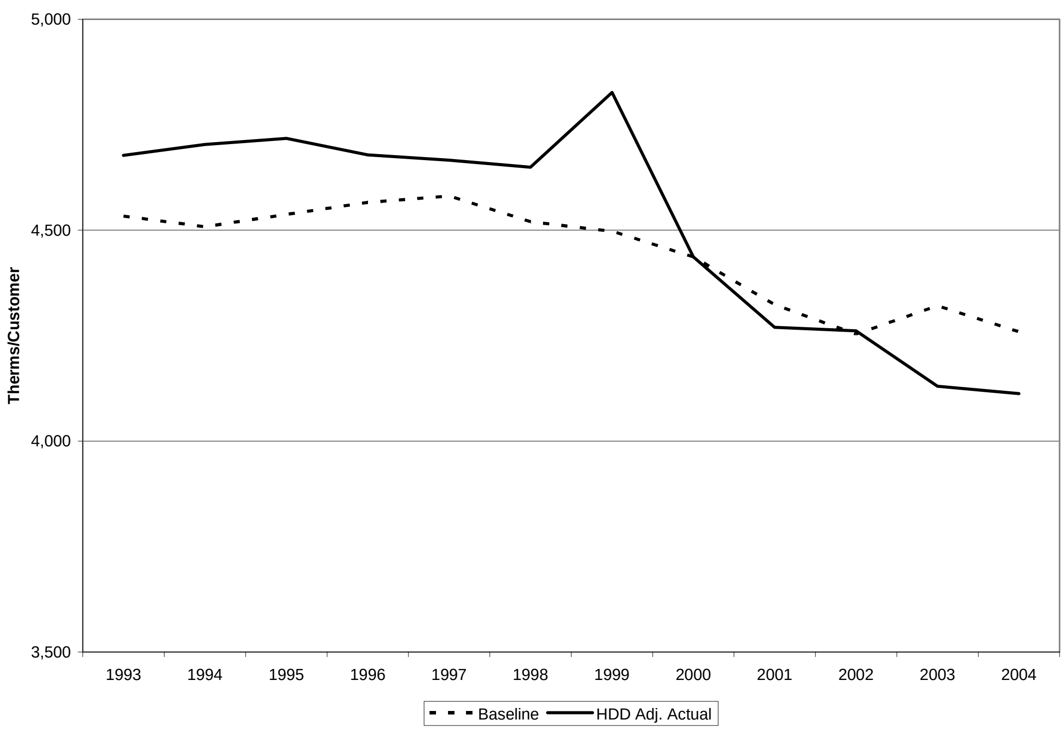
An examination of the margin recovery per customer with and without DMN shows that DMN reduces the variability. For residential customers, DMN reduces the standard deviation of per-customer margins across the simulated years by 30%. For commercial customers, DMN reduces the standard deviation of per-customer margins across the simulated years by 42%. This is the effect that we expected to observe, and the magnitude indicates the effect of implementing DMN instead of full decoupling, which would produce a 100% reduction in the standard deviation of per-customer margins.

One surprising aspect of Figures 4-2 and 4-3 is the size of the deferrals with respect to the elasticity revenue adjustments. That is, we might expect that the price elasticity adjustment would account for the majority of the revenue effects associated with the change in use per customer, leaving a relatively small amount to be "cleaned up" by the deferral mechanism. However, in several years (*e.g.*, 1993 and 1994), the deferral revenues actually exceed the elasticity adjustment revenues.

A closer inspection of the DMN calculations reveals a potential explanation for this effect. Figures 4-5 and 4-6 illustrate the price-adjusted baseline use per customer and weather-adjusted actual use per customer for the residential and commercial classes, respectively. The two figures tell a similar story, with price-adjusted baseline use per customer lying below weather-adjusted actual use per customer in the early years (in

Figure 4-5: Residential Price-Adjusted Baseline and Weather-Normalized Use per Customer: 1993 to 2004

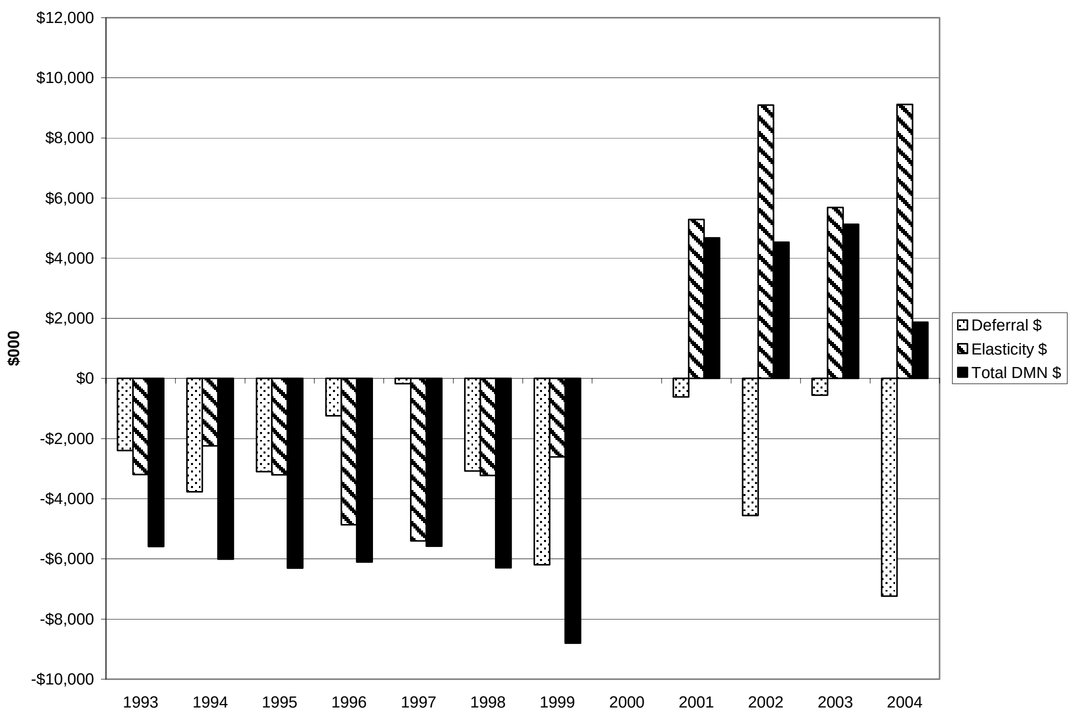
Figure 4-6: Commercial Price-Adjusted Baseline and Weather-Normalized Use per Customer: 1993 to 2004



which prices are low relative to 2000). This could indicate that the stipulated price elasticity values are too low (in absolute value). That is, under the assumption of a higher price elasticity, the usage changes would be larger for a given price difference. This would have the effect of bringing the baseline curves closer to the weather-adjusted actual curves.[15]

We estimated the price elasticities that would minimize the difference between price-adjusted and weather-normalized actual use per customer for each class.[16] Figures 4-7 and 4-8 show the deferral and price elasticity revenue adjustments using the "calibrated" price elasticity values.

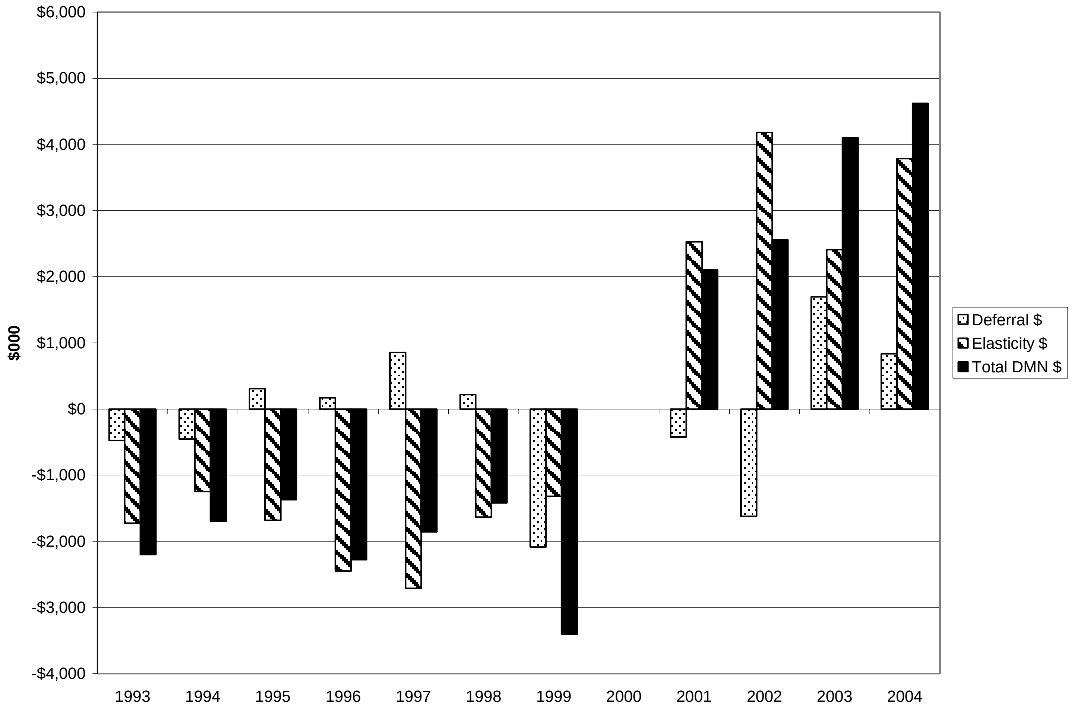
Figure 4-7: Simulated Residential DMN Revenue Adjustments Using Calibrated Price Elasticity: 1993 to 2004



[15] The weather-adjustment parameter (β) is another potential culprit. Our research indicates that "errors" in the value of β contribute to the high level in deferrals in the residential class, but not in the commercial class.

[16] This was done by setting the price elasticity to minimize the sum of squared differences between price-adjusted baseline and weather-adjusted actual use per customer. The weather-adjustment parameters (β) are held at its tariff values for this exercise.

Figure 4-8: Simulated Commercial DMN Revenue Adjustments Using Calibrated Price Elasticity: 1993 to 2004



A comparison of Figure 4-7 to Figure 4-2 (the initial residential deferral and price elasticity adjustment revenues); and of Figure 4-8 to Figure 4-3 shows that calibrating the price elasticity value tends to increase the size of the price elasticity revenue adjustment compared to the deferral amounts. This effect is larger in the commercial class, in which the price elasticity calibration produced a larger change in the price elasticity. The calibrated residential price elasticity is -0.221, compared to the stipulated value of -0.172; and the calibrated commercial price elasticity is -0.213, compared to the stipulate value of -0.110. Note that these values were created to illustrate how the DMN revenue adjustments change as the price elasticity changes. While we believe that this section provides an indication that the stipulated price elasticities may be too low, we do not necessarily recommend using this calibration method to revise the price elasticities. A more reliable method would be estimate the price elasticities directly from historical data, including use per customer, price, and weather data.

4.1.1 Conclusions

We draw two primary conclusions from this analysis. First, DMN revenue adjustments produce adjustments in the intended direction. That is, when non-weather adjusted use per customer increases (primarily because of a response to price decreases), DMN produces refunds to customers. Alternatively, when non-weather use per customer decreases (primarily because of a response to price increases), DMN leads to surcharges to customers. This has the effect of reducing the variability in margin recovered per customer.

The second conclusion that we take from this analysis is that NW Natural and the Commission should investigate whether the price elasticity values should be modified. There is some indication from this analysis that they are set too low (in absolute value), which could lead to relatively large deferrals. Setting the price elasticities "correctly" will minimize deferrals and prevent the 10% slippage of revenues built into DMN (which can work for or against customers).

4.2 Comparison of Revenue Variability across Natural Gas Utilities

One goal of DMN is to reduce the variability of commercial and residential distribution revenues. The Commission Staff requested an examination of NW Natural's revenue variability compared to that of a representative sample of utilities. The sample used here corresponds to the sample used to determine return on equity in NW Natural's last rate case (UG-152). It consists of the following utilities:

1. AGL Resources
2. Atmos Energy
3. Cascade Natural Gas
4. Energen
5. Laclede Gas
6. Nicor
7. NW Natural Gas
8. Peoples Energy
9. Piedmont Natural Gas
10. SEMCO Energy
11. Southwest Gas
12. WGL Holdings

The data were obtained from annual reports and SEC 10-K filings available on the corporate websites. The following information was collected for the years 1993 through 2004 (in most cases, not all years were available):

- Number of residential accounts (expressed either as the number of customers at year-end, or average number of customers during the year)
- Number of commercial accounts (expressed either as the number of customers at year-end, or the average number of customers during the year)
- Residential natural gas sales (expressed in either MDth or MMcf)
- Commercial natural gas sales (expressed in either MDth or MMcf)
- Residential operating revenues
- Commercial operating revenues
- Annual heating degree days

Appendix Table A1 contains all of the data that we were able to collect for the sample utilities. Figures 4-9 through 4-11 present comparisons of the variability of various measures across the utilities. Figure 4-9 compares residential and commercial operating revenues across utilities, expressed as a coefficient of variation (*i.e.*, the standard deviation of revenues divided by the mean, which facilitates comparisons across utilities of different sizes). Eleven of the twelve utilities had sufficient data for inclusion in this figure, though the period of available data varies across utilities.

Figure 4-9: Variability of Residential and Commercial Operating Revenues

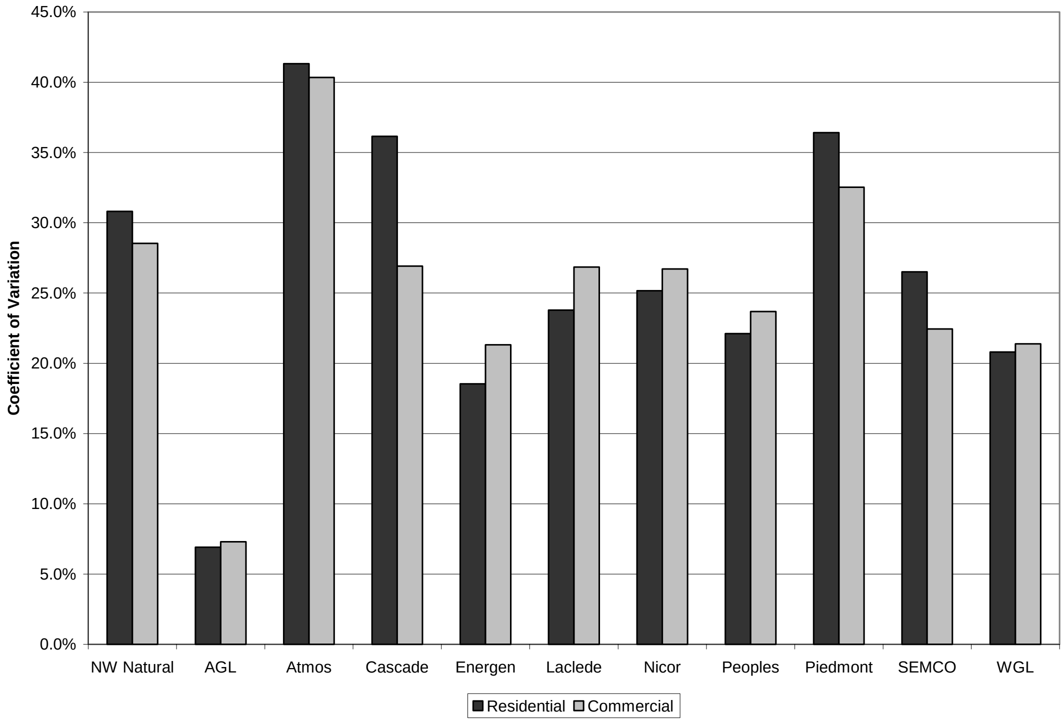


Figure 4-10 compares the variation of residential and commercial sales per customer across utilities. This comparison removes tariff price differences, allowing for an examination of variability differences that are driven only by fluctuations in use per customer. Because several utilities do not report the number of customers by rate class, only eight of the twelve utilities are included in this figure.

Figure 4-11 examines the variation in heating degree days (HDD) across utilities. This is a potentially useful comparison because weather is a primary driver of fluctuations in use per customer across years. In this case, we express variability as the standard deviation of annual HDD.

The information presented here provides mixed evidence regarding NW Natural's revenue variability as compared to other utilities. In terms of class operating revenues, NW Natural's variability is among the highest of the group. However, an examination of the underlying drivers of revenue variability in Figures 4-10 and 4-11 (sales per customer and heating degree days, respectively) reveals that NW Natural's variability is toward to low end of the sampled utilities.

Figure 4-10: Variability of Residential and Commercial Sales per Customer

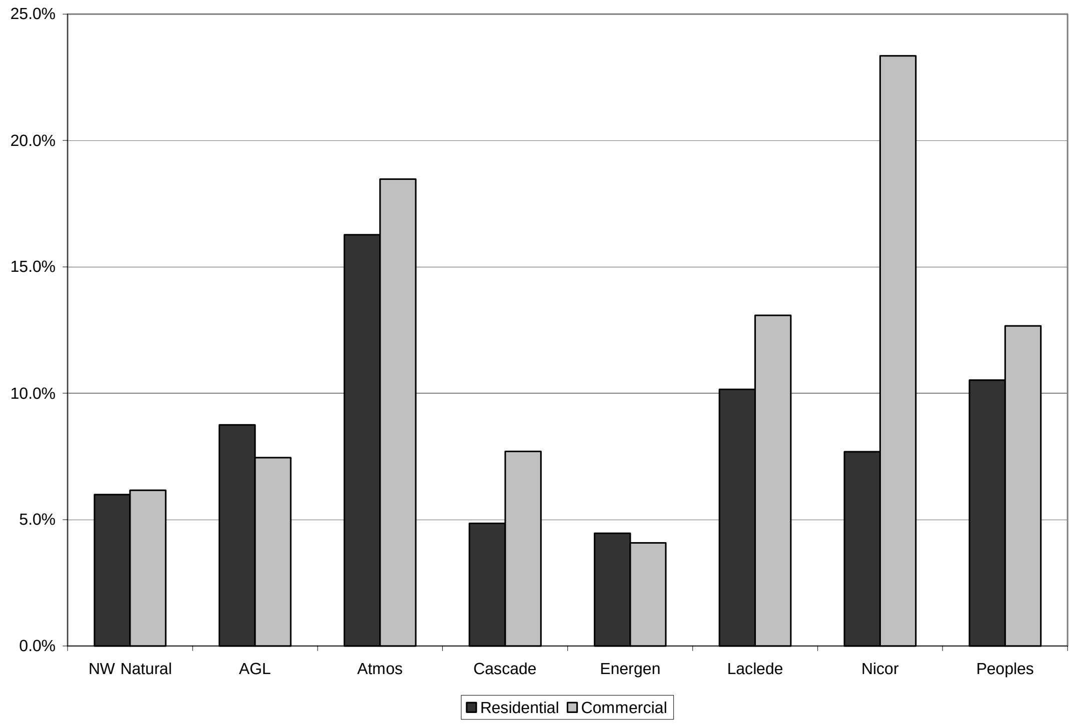
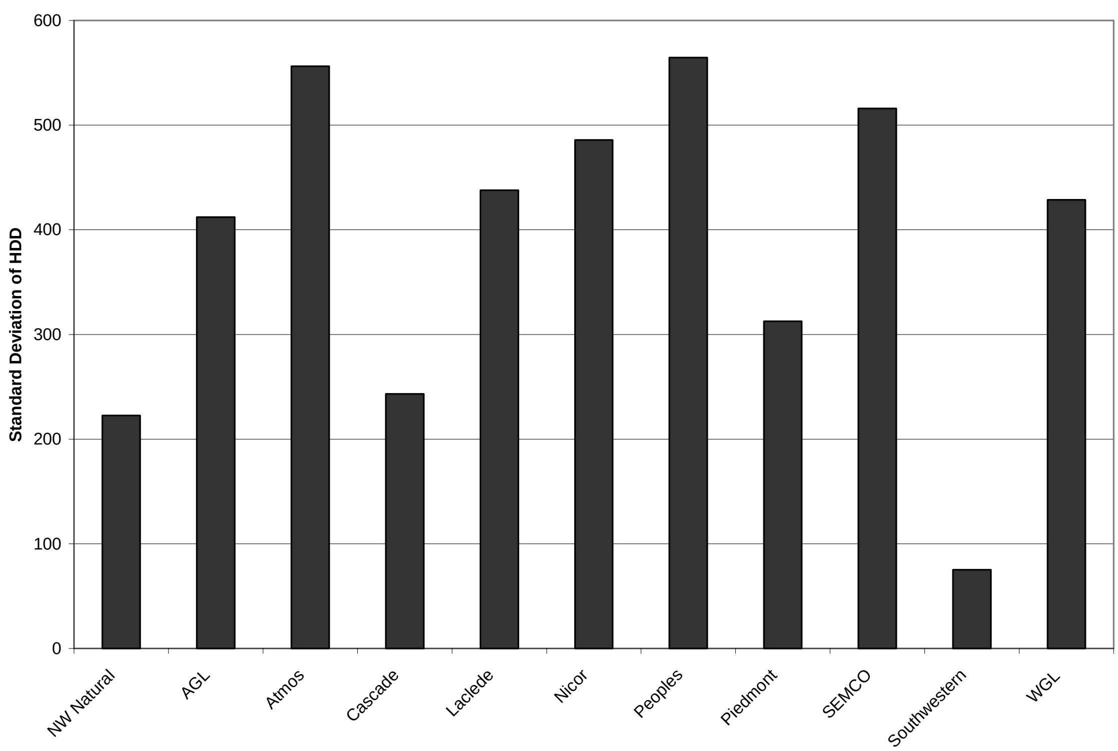


Figure 4-11: Variability of Heating Degree Days



This discrepancy appears to be due to NW Natural's relatively high growth in the number of customers. That is, as the number of customers increases, revenues increase as well. This increases the standard deviation of revenues over the sample time frame. To illustrate this point, note that three utilities had a higher standard deviation of residential revenues (shown in Figure 4-10): Atmos Energy, Piedmont Natural Gas, and Cascade Natural Gas. These same three utilities are the only utilities that had a higher growth rate in the number of residential customers than NW Natural during the sample period.

Note that the variability in use per customer is most relevant in the context of DMN. That is, the majority of the DMN revenue adjustments are due to fluctuations in use per customer. DMN affects revenues associated with a change in the number of customers only to the extent that the average size of new connections customers differs from the baseline use per customer. Therefore, based on the information in Figure 4-10, we conclude that NW Natural has a lower than average variation in distribution fixed cost recovery due to fluctuations in usage per customer.

4.3 Econometric Analysis of Use per Customer

The Commission Staff requested that we investigate the share of DMN revenue adjustments that are attributed to conservation, price elasticity effects, and economic activity. Unfortunately, because changes in use per customer are not directly assigned to these categories, this task cannot be accomplished using a simple accounting exercise. For example, if use per customer goes down during a time in which both the retail price and the unemployment rate increases, we must perform a statistical study to determine the relative influences of these factors.

This section performs that statistical study using historical data to assess the sources of variations in annual use per customer from 1993 through 2004. The results will allow us to infer the major sources of DMN revenue adjustments.

We examined residential and commercial customers separately. The analysis was conducted using ordinary least squares (OLS) regression analysis, which is a statistical technique that estimates the effect that *independent* (or explanatory) variables have on a *dependent* variable, which in this case is use per customer. The independent variables that were considered include:

- Annual heating degree days (HDD)[17];
- Price in dollars per therm;
- Oregon unemployment rate;
- Cumulative units adopted under NW Natural's High Efficiency Furnace (HEF) Program (used in the residential analysis only); and
- A time trend variable to account for changes over time in building codes, housing types, or appliance stock.

[17] HDD is calculated using a 59 degree base for residential customers and a 58 degree base for commercial customers. We use the weighted average HDDs across NW Natural's seven districts, where the weights are set according to each district's share of total customers.

Tables 4-2 and 4-3 present the OLS coefficient estimates for residential and commercial customers, respectively. Three sets of results are presented for each customer class, which differ according to the independent variables that were included in the regression equation. The model used in the first column of each table includes all independent variables, the model used in the second column excludes the time trend variable, and the model used in the third column includes only the weather and price variables (*i.e.*, HDD and price).

Table 4-2: OLS Estimates of Residential Usage per Customer from 1993-2004

Variable	**All Variables**	**No Time Trend**	**Only HDD, Price**
	(1)	**(2)**	**(3)**
HDD	0.166** (0.040)	0.152** (0.033)	0.161** (0.028)
Price	-173.0 (108.8)	-151.4 (99.3)	-224.4** (34.0)
Unemployment Rate	-4.392 (12.386)	1.759 (7.700)	n/a
HEF Adoptions	0.0011 (0.0036)	-0.0011 (0.0013)	n/a
Time trend	-6.226 (9.539)	n/a	n/a
Constant	475.3** (107.0)	449.1** (95.0)	472.0** (83.9)
R-squared	0.921	0.915	0.907

Notes: The number of observations = 12. The dependent variable is residential use per customer in therms. Standard errors are in parentheses. ** denotes that the variable is statistically significant at the 5 percent level. * denotes that the variable is statistically significant at the 10 percent level.

4.3.1 Residential Results

As Table 4-2 shows, the independent variables explained a very high percentage of the variation in residential usage per customer, with R-squared values ranging from 0.907 to 0.921.[18] Weather, represented by HDD, was a statistically significant determinant of usage per customer in each column. The estimated coefficient for HDD is interpreted as follows: a one unit increase in annual HDD leads to an increase in residential therms per customer of about 0.16.

[18] R-squared values range from zero to one, with zero indicating that the model has no explanatory power, and one indicating that the model explains all of the variation in the dependent variable.

Table 4-3: OLS Estimates of Commercial Use per Customer from 1993-2004

Variable	All Variables	No Time Trend	Only HDD, Price
	(1)	(2)	(3)
HDD	0.983** (0.180)	1.004** (0.177)	0.979** (0.169)
Price	-939.3* (476.5)	-1,299.7** (271.5)	-1,431.1** (202.2)
Unemployment Rate	-36.39 (41.82)	-30.71 (40.99)	n/a
Time trend	-17.78 (19.23)	n/a	n/a
Constant	2,970.1** (482.3)	2,997.1** (477.1)	2,954.1** (461.9)
R-squared	0.927	0.918	0.912

Notes: The number of observations = 12. The dependent variable is commercial use per customer in therms. Standard errors are in parentheses. ** denotes that the variable is statistically significant at the 5 percent level. * denotes that the variable is statistically significant at the 10 percent level.

The price per therm, unemployment rate, and cumulative HEF adoption variables were highly correlated with the time trend variable, which makes the interpretation of their coefficients somewhat more complex. That is, the time trend variable is intended to pick up exogenous changes in use per customer over time (*i.e.*, those changes that cannot be directly attributed to weather, price, economic conditions, or NW Natural conservation efforts). However, because natural gas prices and HEF adoptions increase steadily during the analysis time period (this is true to a lesser extent for the unemployment rate), it is difficult for the regression model to differentiate changes in use per customer that might be attributed independently to any one of the factors.

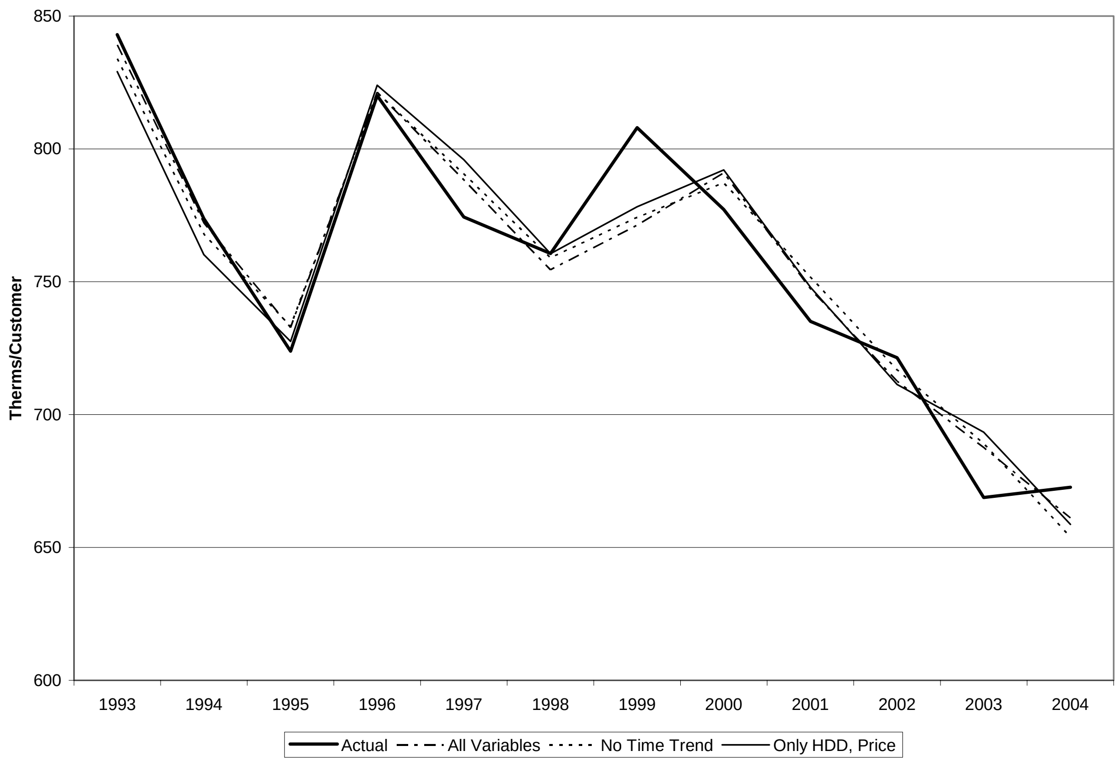
In the full specification, shown in column 1 of Table 4-2, the price variable was the non-weather variable closest to meeting the standard definition of statistical significance.[19] The HEF adoptions coefficient does not have the sign predicted by theory (the result implies that residential use per customer increases as HEF adoptions increase), and is not statistically significant. The coefficient on the Oregon unemployment rate has a very high standard error, and is therefore not statistically significantly different from zero. The time trend coefficient is negative (implying that usage per customer has been declining over time, all else equal), but is not statistically significant.

[19] In regression analysis, the statistical significance of estimated coefficients is evaluated as follows: the null hypothesis is that the estimated coefficient is equal to zero. This hypothesis is tested using the *t*-statistic, which is calculated by dividing the coefficient by its standard error. Using the *t*-statistic, the number of observations, and the number of variables included in the model, the *p-value* is obtained, which is the probability of observing the outcome if the null hypothesis is true. For example, when evaluating a coefficient, a p-value of 5 percent means that there is only a 5 percent chance that we would observe the estimated coefficient if the true value is equal to zero. Traditionally, a 5 percent p-value threshold is considered highly statistically significant, and a 10 percent p-value threshold is considered to be marginally statistically significant.

In an attempt to disentangle the effects of these variables, we first excluded the time trend variable, the results of which are contained in column 2. When we did this, the standard errors of estimated coefficients for price, the unemployment rate, and HEF adoptions all decreased, indicating an increase in the statistical significance of the estimated coefficients. However, aside from the significant HDD coefficient, only the price coefficient was close to being statistically significantly different from zero. Because of this, we include column 3, which shows the results when only HDD and price were included as independent variables. Notice that the R-squared value did not drop substantially, with over 90% of the variation in residential use per customer explained by only these two variables.

Figure 4-12 illustrates the high explanatory power of these regression equations. The bold line shows actual residential use per customer from 1993 through 2004. The three remaining lines show the values predicted by the regression equations. That is, each point in the figure was calculated by multiplying the estimated coefficients by the actual values for the included variables (*e.g.*, HDD or the price) and adding the estimated constant. Each of the three regression models closely tracks actual use per customer. In particular, notice that including variables beyond HDD and the price does not produce large changes in the predicted values.

Figure 4-12: Actual versus Predicted Residential Use per Customer



4.3.2 Commercial Results

As Table 4-3 shows, the results for the commercial customers resemble those of the residential customers in that the independent variables explained a very high percentage of the variation in use per customer. (R-squared values range from 0.912 to 0.927.) In addition, weather was a statistically significant determinant of use per customer in each of the three estimated models. The estimated coefficient for HDD is interpreted as follows: a one unit increase in annual HDD leads to an increase in commercial therms per customer of about 0.98.

The commercial customer data displayed the same high correlation between the time trend and the non-weather independent variables as the residential customer data. We performed a similar set of regression models in an attempt to determine the drivers of use per customer. (However, there is no commercial class equivalent to HEF adoptions.) Among the non-weather variables in the full specification, shown in column 1 of Table 4-3, only the price coefficient is (marginally) statistically significant (though the coefficient on the unemployment rate and the time trend have the theoretically predicted or expected sign).

When we excluded the time trend variable in column 2, the estimated coefficient for the price variable was highly statistically significant, while the estimated coefficient for the unemployment rate did not improve (in terms of an increase in the ratio of the coefficient to its standard error, which is referred to as the *t-statistic*). Because of this, we included column 3, which shows the results when only HDD and price are included as independent variables. Notice that the R-squared value does not drop substantially, with over 90% of the variation in commercial use per customer explained by only these two variables.

Figure 4-13 parallels Figure 4-12, illustrating the high explanatory power of these regression equations. The bold line shows actual commercial use per customer from 1993 through 2004 and the three remaining lines show the values predicted by the regression equations. Once again each of the three regression models closely tracks actual use per customer, and including variables beyond HDD and the price does not lead to large changes in the predicted values.

4.3.3 Implications of the Results

We draw three major conclusions from this analysis.

1. Weather (HDD) and price were the major drivers of changes in residential and commercial use per customer over the time period of the analysis. Table 4-4 illustrates the magnitudes of these effects. The upper portion of the table shows that residential use per customer (unadjusted for weather, prices, or economic conditions) has dropped from 843 to 673 therms per year between 1993 and 2004. Based on our regression estimates, we attribute 51 percent (or 86 therms) of this change to differences in weather conditions, and 49 percent (or 84 therms) to an increase in the price. According to this simple decomposition, there is virtually no change in use per customer that is not explained by changes in weather and prices.

Figure 4-13: Actual versus Predicted Commercial Use per Customer

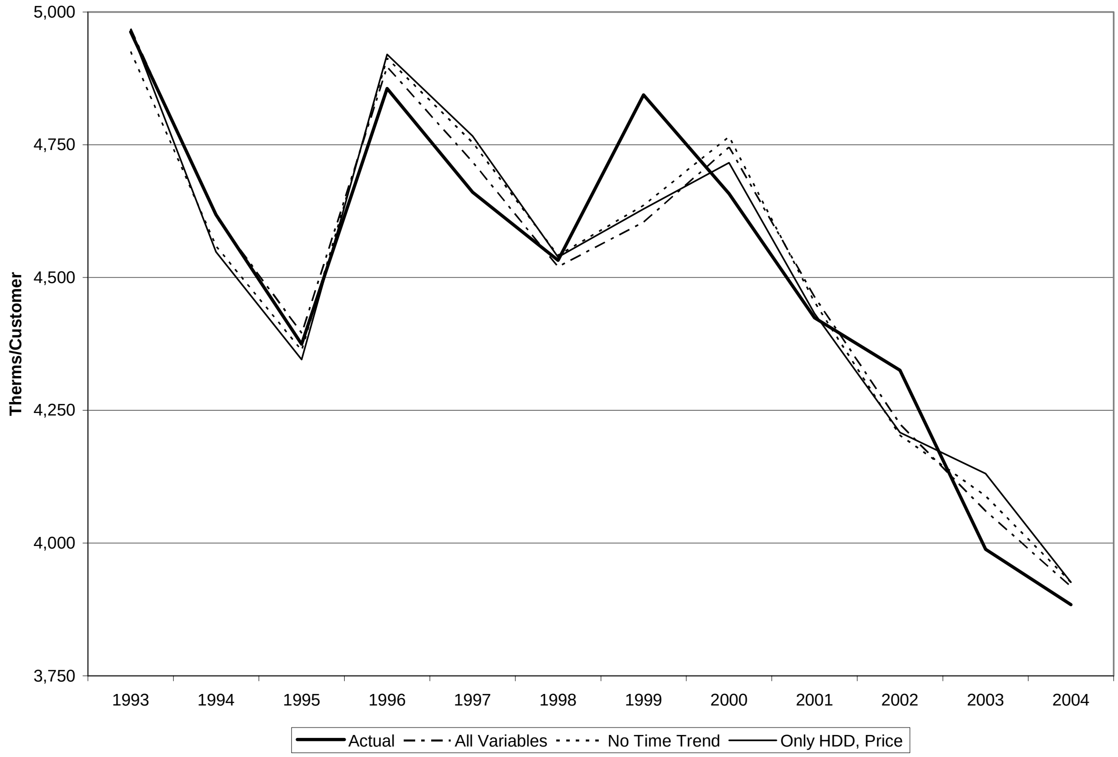


Table 4-4: Breakdown of Change in Use per Customer for Residential and Commercial Classes

Residential	Use per Customer (therms)	HDD	Price ($/therm)
1993 Value	843	3,048	$0.594
2004 Value	673	2,511	$0.969
Change in variable	-170	-537	$0.375
Impact on Use/Cust.	--	-86	-84
% Explained	--	51%	49%
Commercial			
1993	4,963	2,822	$0.524
2004	3,884	2,297	$0.891
Change in variable	-1,079	-525	$0.367
Impact on Use/Cust	--	-514	-526
% Explained	--	48%	49%

The lower portion of the table presents similar results for the commercial class, with differences in weather conditions and an increase in the price explaining a high percentage (97 percent) of the reduction in commercial use per customer.[20] DMN is intended to adjust distribution revenue recovery for non-weather changes in usage per customer (which this analysis indicates consists of price effects and unexplained changes), and WARM adjusts distribution revenue recovery for weather-induced changes in customer usage.

2. Economic conditions, represented by the unemployment rate, did not have a statistically significant effect on residential or commercial use per customer. This is an important result, as it indicates that there is little potential for DMN to shift economic risks from NW Natural to its customers. While the possibility of such a shift exists in theory, the data indicate that the problem is not significant in NW Natural's service territory.

3. The High Efficiency Furnace program did not significantly affect overall average residential use per customer. This result may be explained by NW Natural's estimate that the HEF program produced a 2.4 million therm reduction in total residential usage from 1996 to 2002, which represented only 0.1% of total residential usage over that period. A logical conclusion from this result is that since the HEF program was the most prominent NW Natural conservation initiative during the sample period, NW Natural sponsored conservation was not a major driver of the need for DMN.

4.4 NW Natural Behavior with DMN

The Order approving DMN requires that the independent review address whether DMN affected NW Natural's company culture or operating practices. This will help the Commission to determine whether NW Natural is sincere (and effective) in its efforts to promote conservation. In this section, we address the Commission's requirement by examining NW Natural's marketing efforts, the performance of the residential high-efficiency furnace (HEF) program, a comparison of new connections to existing customers, NW Natural's relevant compensation practices, changes in NW Natural's organizational structure, and third-party views on NW Natural's behavior with DMN. In addition, we interviewed NW Natural employees and third parties (appliance distributors and the NRDC) to provide additional information about changes in NW Natural's culture and business practices.

4.4.1 Marketing Efforts

One way that NW Natural can demonstrate whether it is committed to promoting conservation is through its marketing efforts. We reviewed NW Natural's allocation of marketing resources from 2000 through 2004 in order to evaluate whether a change occurred following the implementation of DMN.

[20] We did not include the other independent variables in this analysis because their estimated coefficients were not statistically significant.

NW Natural allocates its advertising budget to three categories, labeled A, B, and C. They are defined as follows:

Category A: Energy efficiency, conservation, and service information (including rate or account information).
Category B: Safety communication and advertising.
Category C: Promotional advertising and communications to non-customers, or image advertising.

Table 4-5 shows how NW Natural has allocated its Consumer Information budget across these categories from 2000 through 2004. The table shows that resources were shifted away from Category C (promotional and image advertising) and towards Categories A and B beginning in 2001. By 2002, when DMN was approved, the share of Category C had dropped to approximately 20 percent.

Table 4-5: Consumer Information Budget Shares by Category: 2000 through 2004

Year	Category A	Category B	Category C
2000	25%	1%	74%
2001	54%	1%	45%
2002	68%	10%	22%
2003	73%	6%	21%
2004	60%	23%	17%

We also received copies of all marketing materials produced by NW Natural from 2000 through 2004. We reviewed and categorized each print and radio advertisement. Table 4-6 shows the number of advertisements in each category by year. We defined the categories as follows:

- *HEF program*: directly discusses rebates and incentives associated with the residential high-efficiency furnace program;
- *Energy tips*: describes ways that customers can save money by reducing usage;
- *Direct use conservation*: makes the case that direct use of natural gas is an act of conservation;
- *Safety*: warnings about digging or what to do when you smell gas;
- *Load growth*: includes promotions for fireplaces, furnace conversions (primarily from oil), and water heater conversions;
- *Image*: includes general messages (*e.g.*, Black History Month), and messages that provide general support for the use of gas (*e.g.*, clean, efficient, less costly); and
- *Payment options, other regulatory*: includes information about payment options, UNITY, and regulatory notices of changes in rates.

The information provided by this table is limited by the fact that it does not indicate how intensively each item was advertised (*e.g.*, how many times a radio spot was run). However, based only on the number of advertisements, it does appear that NW Natural shifted away from load growth messages (*e.g.*, converting oil furnaces or installing gas fireplaces) and toward promoting high-efficiency furnaces.

Table 4-6: Number of Print and Radio Advertisements by Category and Year: 2000 to 2004

Category	**2000**	**2001**	**2002**	**2003**	**2004**
HEF Program	1	10	10	7	4
Energy tips	0	0	0	0	3
Direct use conservation	1	4	5	7	2
Safety	1	3	4	10	11
Load growth	8	2	3	3	1
Image	3	10	9	5	5
Payment options, other regulatory	0	1	2	1	5

There are at least three potential causes for the shift in marketing resources shown in Tables 4-5 and 4-6. First, in UG-132 the Commission clarified its policy with respect to recovery of advertising expenses. Under these rules, image advertising expenses (Category C) carry no presumption of reasonableness. However, expenses in Categories A and B are presumed to be reasonable up to an allowed amount. It is possible that NW Natural shifted its marketing strategy away from image and promotional advertising and toward conservation advertising simply to ensure recovery of the advertising expenses. (In interviews, NW Natural has denied that this was a significant motivating factor in shifting marketing resources.) This explanation is made less plausible by the fact that Category C expenditures comprised a high percentage of the total in 2000, *after* the UG-132 Order was issued in November 1999.

A second potential explanation for the shift away from Category C advertising is that NW Natural was responding to customers who were upset by rapidly increasing prices. That is, by providing information about energy efficiency, NW Natural may have assisted customers in alleviating bill increases caused by rising prices. This can benefit NW Natural by improving the competitiveness of its product (or the *perception* of the competitiveness of the product, to the extent that not everyone is interested in a high-efficiency furnace).

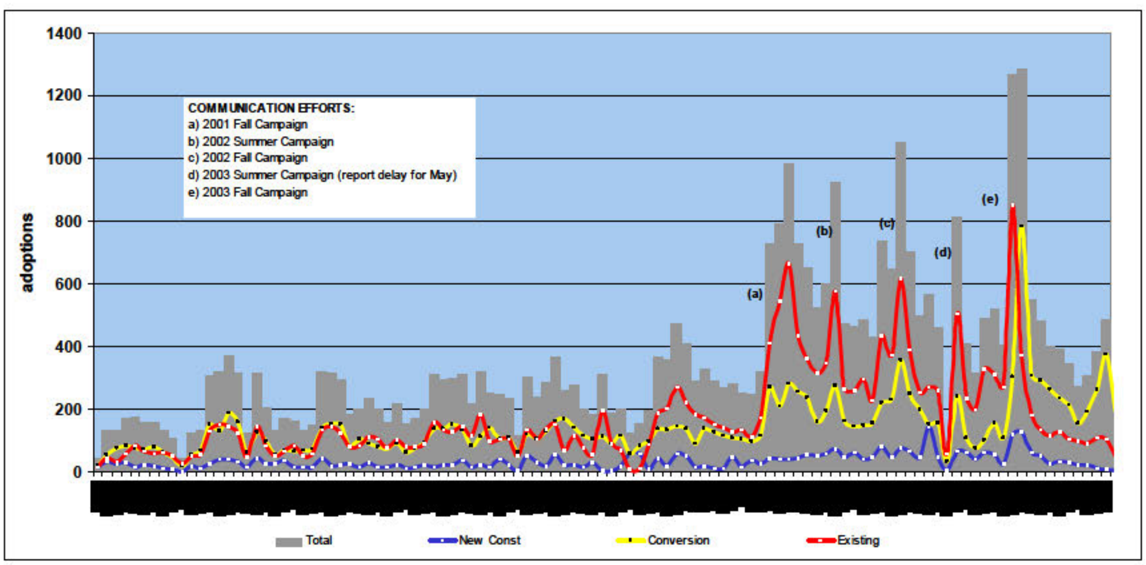
The final potential explanation for the shift away from Category C advertising is that NW Natural responded to the changing incentives provided by DMN. This explanation is made less plausible by the fact that the shift in resources began in 2001 and not in 2002, when DMN was approved by the Commission. However, both CEO Mark Dodson and Kim Heiting, Director of Consumer Information & Internet Services stated in interviews that NW Natural made the decision to behave *as though* they had DMN in 2001. This decision was made in part because it was “the right thing to do” and in part because it helped to address customers’ needs in a time of rising prices.

This section demonstrates that NW Natural shifted marketing resources toward promoting conservation beginning in 2001. We do not have enough information to state definitively whether the primary motivation for this shift was a response to a change in the allowed recovery of advertising expenses, a desire to address customer concerns about rising natural gas prices, or a response to a change in incentives provided by DMN.[21]

4.4.2 High-Efficiency Furnace Program Performance

The high-efficiency furnace (HEF) program, which began in 1995, provides residential customers with incentives to adopt high-efficiency furnaces. Prior to DMN, NW Natural was compensated for HEF adoptions through a lost revenue adjustment (called the "Cost Resource Adjustment," in which NW Natural was compensated for lost margins on a case-by-case basis using estimated therm savings). NW Natural changed its approach for managing and promoting this program in October 2001, when it began coordinating more closely with HVAC distributors and packaged rate-funded rebates, distributor-funded rebates, and the Oregon Residential Energy Tax Credit. This approach dramatically increased HEF adoption rates. On October 1, 2003, the administration of the Public Purposes funded rebate program was transferred to the Energy Trust of Oregon. Figure 4-14 below shows monthly HEF adoptions from 1995 through 2004.

Figure 4-14: Monthly HEF Adoptions: 1995 through 2004



[21] Note that NW Natural does not differentiate its marketing in Oregon from its marketing in Washington (except with respect to specific incentives that are only offered in one state), despite the fact that NW Natural has DMN in Oregon, but no equivalent rate mechanism in Washington. In interviews with us, NW Natural stated that the reason for this is that Washington customers represent a small share of NW Natural's total customer base, so it would be more costly to tailor a marketing message to them than it is to endure lost margins from any conservation that is spurred by marketing that is intended for Oregon customers.

Figure 4-14 shows that HEF adoptions increased noticeably when NW Natural modified its approach in October 2001, and that HEF adoptions spike following targeted promotions.

Information from distributors reinforces this evidence of the success of the HEF program. We spoke with Mike Dawson, Northern Regional Manager at Gensco and Glen Bellshaw, Director of Marketing at Airefco. Mr. Dawson provided confidential data comparing the percentage increase in sales of high-efficiency furnaces between 2000 and 2001 (when NW Natural modified the HEF program) in Oregon to Seattle/Tacoma, Eastern Washington, and Montana/Idaho. The percentage increase in HEF sales in Oregon was more than twice the average increase across the other three regions. Mr. Dawson also indicated that according to tracking data from Trane (the primary manufacturer of high-efficiency furnaces sold by Gensco), Oregon has the highest share of HEF sales (as a percentage of total furnace sales) in the nation by a substantial margin. Mr. Dawson attributes this directly to NW Natural's efforts to promote the HEF program.

Mr. Bellshaw provided confidential data comparing the share of high-efficiency furnace sales as a percentage of total furnace sales in Washington and Oregon during 2003 and 2004. His data show that Oregon's share of high-efficiency furnaces is 3.75 times higher than the share in Washington. (The exact percentages by state are confidential.) Mr. Bellshaw attributes this difference to NW Natural's and the Energy Trust's efforts to promote the HEF program. In theory, this comparison could be tainted by the fact that Oregon offers a tax credit for high-efficiency furnaces, while Washington does not. However, Mr. Bellshaw reports that the HEF adoption rates in Cascade Natural and Avista service territories are much closer to the reported Washington share than the Oregon share (which is dominated by NW Natural results). Given this, he concludes that, by itself, the state-level tax credit does not explain the difference in HEF adoption rates between Washington and Oregon.

The increased success of the HEF program began in 2001, prior to the approval of DMN. NW Natural claims that they made a corporate decision to behave as though DMN was in place in 2001, in part because they were looking for ways to help customers who were facing increasing rates. In addition, we note that they were covered by a lost revenue adjustment, which would compensate them for improved program performance (except to the extent that the increased attention given to energy efficiency may have produced more general conservation efforts on the part of consumers).

Finally, we point out that despite the dramatic increase in HEF adoptions, the HEF program has had a modest effect on total residential therms consumed. According to NW Natural estimates, the cumulative HEF adoptions from 1996 through 2004 accounted for approximately a 1% reduction in 2004 residential consumption. The largest single-year effect occurred in 2002, in which 2002 HEF adoptions reduced that year's residential consumption by approximately 0.2%.

4.4.3 Comparison of New Connections to Existing Customers

In approving DMN, the Commission forbade NW Natural from "gaming" the mechanism with respect to new connections. In theory NW Natural could derive short-term gains from DMN by connecting customers whose expected usage is below the baseline use per customer level. This is because NW Natural would receive revenues as though the customer used the baseline levels.

NW Natural provided data that compares existing customers to new connections in 2004, shown in Table 4-7 below. The data are an update of results presented on page AA-3 of NW Natural's 2004 Integrated Resource Plan, and they represent weather normalized annual use per customer for Portland customers.

Table 4-7: Comparison of Existing Customers to New Connections in 2003 (weather normalized annual therms per customer)

Category	Residential		Commercial	
	Annual Use	Share of Customers	Annual Use	Share of Customers
Existing Customers	749	97.9%	4,521	99.0%
New Construction	737	1.5%	7,276	0.6%
Conversions	582	0.6%	3,152	0.5%

The residential results indicate that new connections tend to have lower consumption rates than existing customers. These results should be interpreted with some caution, as factors such as changes in building materials, building codes, and appliance efficiency levels could contribute to the observed differences between existing and new connections customers. The evidence for commercial customers is mixed, with new construction usage rates far exceeding the usage rates of existing customers, but conversion usage rates well below usage rates of existing customers. The large differences in use per customer across the commercial categories is likely due to small sample sizes in the new construction and conversions categories combined with the fact that commercial use per customer can vary considerably depending upon the size of the establishment and nature of the business. (That is, when a small sample is taken from a population with high variance, the mean of the sample is not a very reliable indicator of the population mean.)

In addition to receiving the data shown in Table 4-7, we reviewed the methods that NW Natural uses to assess new connections customers and apply its main extension policy. These methods forecast usage for potential customers based on home characteristics and expected appliance conversions. Using this forecast, the expected profitability of the customers is determined using the standard tariff rates. The revenue effects of DMN are not considered in this calculation.

The data presented in this section present the possibility that NW Natural has discriminated in its new connections in the residential class. However, based on our review of NW Natural's methods for assessing new customer connections, and given the number of other factors that could be affecting the results shown in Table 4-7, it appears to be unlikely that NW Natural has been gaming the DMN mechanism with respect to new connections.

4.4.4 Cultural and Organizational Effects

We have already discussed how DMN reduces NW Natural's disincentive to promote energy efficiency. This section addresses whether this incentive change affected NW Natural's compensation practices, organization (*i.e.*, staffing changes), public stance with regards to energy efficiency, or non-regulated business activities.

4.4.4.1 Compensation Practices

This section explores the extent to which NW Natural's compensation practices reveal whether NW Natural is committed to achieving the intended goals of DMN (*i.e.*, shifting away from promoting load growth and toward promoting conservation and energy efficiency, while providing high quality customer service).

Regarding customer service, employees at all levels of NW Natural are eligible for bonuses that are awarded based on several criteria. All employees receive the same percentage bonus. Among the criteria used to determine the level of the bonus is a measure of customer satisfaction.[22] In addition, each member of the management team in Utility Services has individual performance goals and measures related to customer satisfaction. This team includes Kim Heiting (Director of Communication Services), Tamy Linver (General Manager of Consumer Services), Susan Dodge (General Manager of Customer Field Services), Barry Stewart (Manager of Customer Account Services), and Chuck Muehleck (Manager of Customer Billing Services).

NW Natural also has individual employee incentives that are more directly related to DMN. In 2003 and 2004, these incentives were associated with developing and maintaining a relationship with the Energy Trust of Oregon. Employees that were affected by these incentives included Grant Yoshihara (who has overall responsibility of NW Natural's relationship with the Energy Trust), Kim Heiting (who is responsible for integrating Energy Trust messaging with NW Natural's information delivery), and Steve Bicker (who is responsible for contract negotiations and development of policies with the Energy Trust).

Because of an evolution of NW Natural's relationship with the Energy Trust that focused more on "tactical execution," the individual incentives changed somewhat in 2005. Several additional employees were given goals/measures that related to the Energy Trust, including Tamy Linver (who became responsible for the overall Energy Trust working relationship), Tim Abshire (Manager of Program Development), and three program managers responsible for working directly with Energy Trust staff to develop all of NW Natural's residential and commercial programs.

[22] There is some dispute regarding the effectiveness of group incentives such as this. That is, the incentive for any one person to improve performance is diminished by the fact that the rewards generated from the increase in effort must be shared with everyone, even those who did not exert effort to improve performance).

The goal measurements associated with the incentives described above include a mix of quantitative and qualitative assessments. As an example, NW Natural tracks quantitative measures such as referrals to the Energy Trust, High-Efficiency Furnace adoptions, responses to a specific customer satisfaction survey question on "providing programs and incentives for high efficiency equipment," the number of programs, and the effectiveness of programs. The mix of these measures used for a specific employee depends on the employee's role. Employees with primarily management roles have more qualitative goals associated with building the relationship with the Energy Trust. Measurement of this is typically based on more anecdotal evidence (*i.e.*, receiving positive comments from Energy Trust leadership or Commission Staff).

An additional compensation policy that appears to have been affected by DMN is ending the use of commissions for Consumer Services conversion representatives, which had been used from the mid-nineties into 2004. Grant Yoshihara, NW Natural's Director of Utility Services, had the following comments on this policy:

> When we realized that the commission structure would potentially present the wrong incentives (promote added load), we began evaluating different options. We did not find anything in the traditional incentive pay category that seemed to work, so we moved toward using the performance goals and measures approach that applies to all of our other non-bargaining employees. In order to make this transition, we also needed to complete another major activity - consolidation of the residential and commercial call centers - that impacted the allocation of work between the call center staff and the conversion representatives. We completed this consolidation in the fall of 2004. Given the fact that the incentive compensation system for the conversion representatives had monthly targets and incentives for the calendar year, we decided to wait until the completion of the calendar year before changing the compensation structure for the conversion representatives.

The existence of the compensation practices described in this section indicates that NW Natural has made some efforts to create and maintain a successful relationship with the Energy Trust, and that it recognizes that DMN reduces the incentive to promote load growth.

4.4.4.2 Organizational Changes

In order to learn about how NW Natural's organization may have changed following the implementation of DMN, we submitted the following request to NW Natural: "*Please describe any organizational changes that took place after DMN was in place. These include position additions and subtractions; department expansions, contractions, or reassignments (in terms of reporting structure).*" We received the following response.

> Organizational restructuring and reassignment of work in sales and service functions began in 2002, just prior to the implementation of DMN. The primary objective of this realignment has been to better integrate and leverage resources in

the sales, customer assistance, and customer service areas. The utilization of resources in terms of O&M expense has shifted along with staffing adjustments and resolution of accounting allocations as was agreed to in the 2002 rate case settlement.

Significant organizational changes that have occurred between the beginning of 2002 and present include the consolidation of Customer Account Services Call Center capacity into two locations (initiated in 2001), consolidation of Consumer Services Call Center capacity (customer assistance) into one virtual network (initiated in late 2004), and shifting of Energy Efficiency program resources for transitioning services to the Energy Trust and supporting the Oregon Low Income Energy Efficiency Program (OLIEE) and the Oregon Low Income Gas Assistance Program (OLGA). Smaller adjustments include the consolidation of all research activities (customer service and satisfaction, market and benchmarking), and realignment of sale and service functions from three market segments (residential, commercial, and industrial) to two segments (mass market and major accounts).

During the three-year period from the beginning of 2002 to beginning of 2005, staffing generally declined in sales/marketing areas, and increased in customer assistance and customer service areas as the customer base grew by 10 percent. While some of this was due to adjustments in accounting practices that transferred staff and expense from sales/promotions to customer assistance, a total net reduction in sales/promotion and customer assistance of 17 FTEs occurred. Most recently, the overall management of sales and service activities was consolidated into a new division, Utility Services.

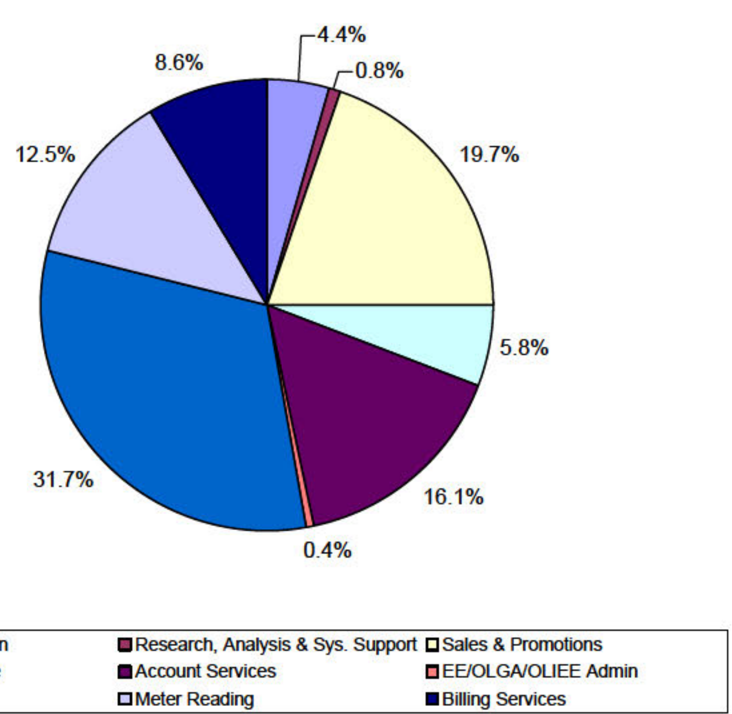
The table shown below identifies the allocation of resources in terms of full time equivalents (FTE's) by functional activity at the beginning of 2002 (actual) and beginning of 2005 (budgeted). A description of the change in staffing is shown for each activity. Also shown below in two charts are the distribution of O&M expense by activity for actual full year 2001 and budget 2005.

Staffing Resource Allocation by Functional Activity
2001 versus 2005

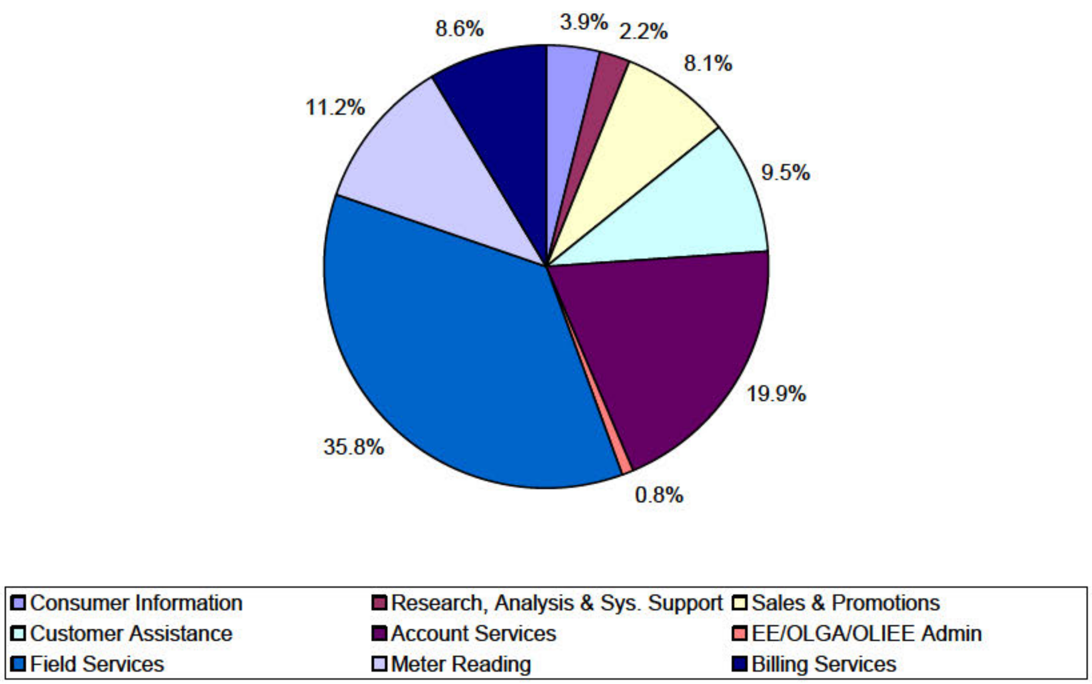
Department or Functional Activity	Description	2002 FTE's	2005 FTE's
Consumer Information & Internet Services	In 2001, staff focus was more concentrated on delivering product benefit and added load communication and advertising designed to help reduce the impact of consumption declines and support conversions. Although the staff level remains consistent, the 2005 work product and funding allocation has moved from a focus on added load and image advertising to a message concentration on energy efficiency, service and safety education.	1.5	1.5
Research, Analysis, & Systems Support	Research efforts were centralized and expanded to include a dedicated customer satisfaction analyst. Additional staffing was added to provide systems support and market analysis.	3.0	6.5
Sales and Promotions	Marketing, sales, and promotions staffing was reduced and reassigned following the 2002 rate case settlement. Accounting adjustments based on time tracking studies submitted as part of the rate case supported some reallocation of expense between sales/promotions and customer assistance. Program development activities for development of existing customer service programs were added in 2004.	67	20.5
Customer Assistance (Acquisition)	Customer assistance staffing (performing functions related to customer acquisition) were consolidated into two market segments for improved efficiency. Portland call centers were consolidated to provide first call resolution service for serving new customers.	18	44
Customer Account Services	Increased staffing is primarily attributable to call center staffing additions to meet increased customer call volumes related to customer growth and higher retail gas prices, consistent with approvals received in the 2002 rate case.	93	113
Energy Efficiency, Oregon Low Income Energy Efficiency, and Oregon Low Income Gas Assistance	Programs added as part of DMN and Public Purpose Funding settlement. Only administrative expenses are shown in the O&M expense distribution charts.	2	3

Department or Functional Activity	Description	2002 FTE's	2005 FTE's
Customer Field Services	Staffing increases to support field service activities has been primarily to handle growth in the customer base. Higher volumes of credit/non-payment customer calls due to higher gas prices has been absorbed through efficiency improvements.	145.5	151
Meter Reading	Despite significant customer growth, a decline in meter reading staffing requirements has resulted from improved route design and adjustments, and improvements in PGE-NWN joint meter reading performance.	74.5	71.5
Customer Billing Services	Staffing increases to support billing activities have been primarily to handle increased bill volume, more complex billing arrangements, and meet Sarbanes Oxley requirements. Mass market and major account billing activities were also consolidated for management and oversight purposes.	13	18.5

2001 Cost Distribution



2005 Cost Distribution



[End of NW Natural's response to CAEC's request. Note that the 2001 and 2005 cost distribution figures are most easily interpreted when viewed in color.]

The most notable changes between 2002 and 2005 are the reduction in full-time employees (FTEs) in sales and promotions, and the increase in FTEs in customer assistance and customer account services. According to Grant Yoshihara, NW Natural's Director of Utility Services, approximately 50% of this shift was an accounting shift based on the results of a time tracking study. (That is, the shift in resources was made to reflect the how time was already being spent by employees.) The remaining 50% of the shift in resources represented a change in focus away from sales and promotions and toward customer service. According to Mr. Yoshihara, this reallocation was part of a larger effort to get sales personnel to coordinate more closely with service personnel.

4.4.4.3 Nexus Home Analyzer

Recently, NW Natural paid approximately $250,000 to install the Nexus Home Analyzer on its website. It allows residential customers to answer a few simple questions about their home (*e.g.*, the number of rooms, the fuel used for space heating, etc.) and then provides information about the sources of energy usage and ways that customers can conserve energy. By raising awareness about how customers use energy, this is an effective tool in promoting general conservation. In the absence of the incentives provided by DMN, NW Natural would not likely have offered this service to its customers.

4.4.4.4 Public Stance on Energy Efficiency

There are several ways in which NW Natural has taken steps to publicly support energy efficiency and conservation. CEO Mark Dodson and others at NW Natural have presented their experiences under DMN, including the benefits of conservation and energy efficiency, at a number of conferences and forums. Mr. Dodson was quoted in a February 2005 *American Gas* article titled "It's Now Easier Being Green: Some natural gas utilities are working to separate their financial health and energy sales" as saying: "We think we have an obligation. Not only a moral obligation to conserve energy, but also a more basic obligation to each customer to try to keep their bills as low as possible." Further reinforcing his public stance in favor of conservation, Mr. Dodson serves as the co-chair of the Governor's Advisory Group on Global Warming in Oregon. The Oregon Department of Energy website lists the objective of this group as follows:

> The purpose of the advisory group is to develop a strategy to reduce Oregon's greenhouse gas emissions both in the short term and over the long term. The strategy will be coordinated with the West Coast Governors' Global Warming Initiative. The Governor requested the strategy by September 2004.
>
> The climate change strategy for Oregon will provide long-term sustainability for the environment, protect public health, consider social equity, create economic opportunity, and expand public awareness. The Advisory Group will make recommendations to Governor Kulongosk.

Based on actions such as these, Ralph Cavanagh of the NRDC called NW Natural the top energy efficiency advocate in the industry. In our interview with him, Mr. Dodson pointed out the difficulty that he would face should DMN be taken away. On the one hand, he has taken a public stance supporting the benefits of conservation. However, in the absence of some form of decoupling, NW Natural shareholders would be harmed by conservation. Mr. Dodson used this example to indicate the harm that can be caused by what he referred to as inconsistent regulation.

4.4.4.5 Non-Regulated Business Activities

According to NW Natural CFO David Anderson, non-regulated activities account for only about 3% of assets, and the risk reductions afforded by DMN and WARM did not affect non-regulated activities. Changes in non-regulated revenues in recent years are primarily related to the proposed (and abandoned) merger with PGE and Mist natural gas storage.

4.4.5 Third Party Views on NW Natural Behavior with DMN

We spoke with four people in order to get a different perspective on NW Natural's actions with DMN:

- Ralph Cavanagh of the Natural Resources Defense Council (NRDC);
- Margie Harris, Executive Director of the Energy Trust of Oregon;
- Mike Dawson, Northern Regional Manager of Gensco;

- Glen Bellshaw, Director of Marketing at Airefco;
- Bob Jenks, Executive Director of the Citizens' Utility Board;

The input that we received from these individuals consistently indicated that NW Natural is sincere in its commitment to promote conservation efforts, specifically in the form of high-efficiency furnaces. Mr. Cavanagh believes that through public presentations by CEO Mark Dodson,[23] NW Natural has demonstrated that it is the leading advocate of energy efficiency in the industry. Mr. Cavanagh reported to us that "I have never seen this level of public enthusiasm by a utility CEO on the conservation benefits of decoupling or the importance of expanded involvement in energy efficiency by natural gas utilities (at NW Natural or anywhere else)."

Ms. Harris described the Energy Trust's current relationship with NW Natural in very positive terms. She acknowledged that there were initial difficulties in forming a working relationship with NW Natural, in particular in the area of data transfers, which produced problems that took about one year to resolve. However, at this point Ms. Harris notes that NW Natural:

- is very responsive to the Energy Trust,
- has increased the number of "touch points" (*i.e.*, individuals that work with the Energy Trust), and
- has regular meetings with the Energy Trust.

In addition, as a customer of NW Natural's she has also noticed an increase in the inclusions of a conservation message in collateral advertising and bill inserts.

There are a couple of areas in which Ms. Harris believes that NW Natural could improve. First, she would like to see NW Natural be consistent in including the Energy Trust in its conservation-based messaging. This would reinforce the partnership that NW Natural and the Energy Trust have formed. Second, she believes that NW Natural could do a better job of diversifying its conservation efforts beyond the residential class. (While NW Natural and the Energy Trust have recently initiated a commercial energy efficiency program, Ms. Harris believes that programs could be expanded to industrial customers as well. However, doing so could present NW Natural with a financial concern, as DMN does not cover industrial customers.)

Section 4.4.2 above contains the information provided by Mr. Dawson and Mr. Bellshaw that indicates that NW Natural's efforts have increased HEF adoptions. Mr. Bellshaw said that NW Natural has changed its attitude about how they do business with contractors, creating a more open process. Mr. Dawson echoed this point, saying that NW Natural is more active in dealing directly with distributors, and that NW Natural has been effective in providing "warm" sales leads to his company.

[23] Some examples of public presentations are: joint presentations by Mr. Dodson and Mr. Cavanagh to the National Association of Regulatory Utility Commissioners and to a joint workshop of the Washington and Oregon Commissions; and Mr. Dodson's keynote address at Bonneville Power Association's Fall 2004 Regional Energy Efficiency conference.

No one among Mr. Cavanagh, Ms. Harris, Mr. Dawson, and Mr. Bellshaw believed that there were any negative aspects of DMN with respect to its effect on NW Natural's actions, though Mr. Cavanagh commented that DMN could be improved by adopting NW Natural's original proposal for full decoupling, which Mr. Cavanagh believes would be less complex and more effective.

Bob Jenks, the Executive Director of the Citizens' Utility Board of Oregon, believes that DMN has been good for consumers. He provided the caveat that his support for DMN is due to the Public Purposes Funding rather than the incentives provided by DMN. That is, he has seen decoupling implemented in the past (for PGE and PacifiCorp) without a change in corporate commitment to conservation. The funding provided by the Public Purposes charges provides tangible support for energy efficiency programs and bill payment assistance. Aside from that caveat about decoupling, Mr. Jenks believes that NW Natural has been supportive and helpful to the Energy Trust in promoting energy efficiency programs.

Taken together, we believe that the views expressed to us indicate that NW Natural takes its commitment to promoting energy efficiency seriously. Mr. Cavanagh's statements show the extent to which NW Natural has linked its corporate image with energy efficiency through public presentations. Ms. Harris, representing an organization dedicated to promoting energy efficiency, believes that NW Natural has made significant efforts to work with her organization to further its goals. Finally, two representatives from appliance distributors provide a front-line account of the effect that NW Natural's (and, since October 2003, the Energy Trust's) efforts have had on high-efficiency furnace sales.

4.5 Financial Data

The Commission Staff requested that we provide information regarding financial effects of DMN on NW Natural. The Commission agreed with us that it would be difficult to attribute changes in financial outcomes specifically to DMN (given the large number of other factors that can affect stock prices, interest rates, etc.). Therefore, this section primarily contains data for various financial indicators over time (lines of credit, bond ratings, stock prices, etc.), but it does not include any formal analyses that attempt to assign changes in financial indicators to DMN or other potential causal factors.

4.5.1 Lines of Credit

NW Natural secures lines of credit in order to protect itself against variations in cash flow. This section describes how the terms of the lines of credit have changed from October 1998 through September 2004. Table 4-8 shows how the lines of credit have changed each year, including the total dollar amount of the credit lines and the average fees associated with them.

Table 4-8: NW Natural Lines of Credit: October 1998 through September 2004

Date	Total Amount of Credit Lines ($ millions)	Basis Point Fees
10/1998 to 9/1999	$100	8.18
10/1999 to 9/2000	$120	8.38
10/2000 to 9/2001	$120	7.50
10/2001 to 9/2002	$150	8.40
10/2002 to 9/2003	$150	10.63
10/2003 to 9/2004	$150	9.50

Beginning in October 2002, NW Natural began securing half of its credit line for a two-year commitment, and the other half for a one-year commitment. Prior to this date, all of its credit line was secured for one-year. Because two-year lines of credit are more costly, an increase in the basis point fees occurred at this time. According to David Anderson, NW Natural's current CFO, this change in strategy reflects an increase in NW Natural's risk management sophistication, bringing them in line with industry best practices. He reported that the change was not related to DMN.

4.5.2 Bond Ratings and Bond Issuances

There has been only one change in NW Natural's bond rating since 1995, which was an increase in the S&P bond rating from A to A+ in 2004. NW Natural has issued 15 long-term bonds since 1999. Table 4-9 below shows the year the bond was issued, the year the bond is due, and the interest rate paid by the bond.

Table 4-9: NW Natural Bond Issuances: 1999 through 2004

Year Issued	Year of Maturity	Interest Rate
1999	2001	6.62%
1999	2002	6.75%
1999	2019	7.63%
2000	2030	7.74%
2000	2025	7.72%
2000	2030	7.85%
2000	2010	7.45%
2001	2006	6.05%
2001	2011	6.665%
2002	2007	6.31%
2002	2012	7.13%
2003	2032	5.82%
2003	2033	5.66%
2004	2010	4.11%
2004	2023	5.62%

According to CFO David Anderson the presence of DMN and WARM contributed to NW Natural attaining a score of "1" on S&P's business risk profile (in which 1 = best risk profile and 10 = worst risk profile). This rating has two effects. First, it allows NW Natural the flexibility to carry a lower share of equity in its capital structure if it chooses. Second, a favorable business risk profile rating allows NW Natural the flexibility to maintain a lower debt-service coverage ratio if it chooses.

4.5.3 Stock Offerings

Table 4-10 shows the dollar amounts associated with stock offerings and repurchases from 1993 through 2004. These data are taken from NW Natural's annual 10-K filings to the SEC in the "financing activities" section of the consolidated statement of cash flows. Note that we have pooled redeemable preferred stock and redeemable preference stock retired in the "Preferred Stock Retired" column.

Table 4-10: NW Natural Stock Issues and Repurchases: 1993 to 2004 ($000)

Year	Common Stock Issued	Common Stock Repurchased	Preferred Stock Retired
1993	$5,720	$0	$11,177
1994	$5,847	$0	$1,091
1995	$39,569	$0	$1,163
1996	$5,690	$0	$1,091
1997	$6,465	$0	$1,320
1998	$52,384	$0	$930
1999	$5,356	$0	$935
2000	$4,826	$2,441	$814
2001	$5,157	$5,792	$750
2002	$6,872	$0	$25,750
2003	$8,349	$0	$8,428
2004	$48,153	$0	$0

4.5.4 Comparison of NW Natural Stock Prices to an Index of Utilities

All else equal, markets place a higher value on companies that have more stable profits. DMN has this effect in theory, as it reduces the variability of fixed cost recovery. Presumably because of this, the Commission expressed an interest in comparing NW Natural's stock price to an index based on a representative sample of utilities. The sample used here corresponds to the sample that was used to determine return on equity (ROE) in NW Natural's last rate case (UG-152). It consists of the following utilities (the stock ticker symbol is in parentheses):

1. AGL Resources (ATG)
2. Atmos Energy (ATO)
3. Cascade Natural Gas (CGC)
4. Energen (EGN)

5. Laclede Gas (LG)
6. Nicor (GAS)
7. NW Natural Gas (NWN)
8. Peoples Energy (PGL)
9. Piedmont Natural Gas (PNY)
10. SEMCO Energy (SEN)
11. Southwest Gas (SWX)
12. WGL Holdings (WGL)

Data were collected from Yahoo! Finance, which publishes historical monthly stock prices adjusted for dividends and splits. The stock price index was calculated as the average (unweighted) stock prices of the utilities in the sample (excluding NW Natural). Figure 4-15 shows the adjusted monthly stock prices for NW Natural and the index of utilities from January 1993 through January 2005. The two series track one another quite closely, which is surprising given that the stock prices of the utilities comprising the index vary substantially. Figure 4-16 shows the adjusted stock prices for all twelve utilities, with NW Natural's data in bold. (This figure must be viewed in color to be able to identify the individual utilities. The figure's legend identifies the data using each company's stock ticker symbol.)

Figure 4-15 shows that NW Natural's stock price increased relative to the index around the time that DMN was approved (in August 2002). Shortly thereafter, NW Natural's stock price reverted to a level closer to the index. During 2003 and early 2004, NW Natural's stock price once again increased relative to the index. This gain was largely maintained through January 2005.

These figures simply show the stock prices for NW Natural and a set of comparable utilities. A number of factors could have affected stock prices over this time period, and because of this we do not claim to provide explanations for changes in the stock prices over time. However, it does appear that NW Natural's stock price increased relative to the index around the times that DMN and WARM were approved.

Figure 4-15: Monthly Stock Prices for NW Natural and an Index of Utilities

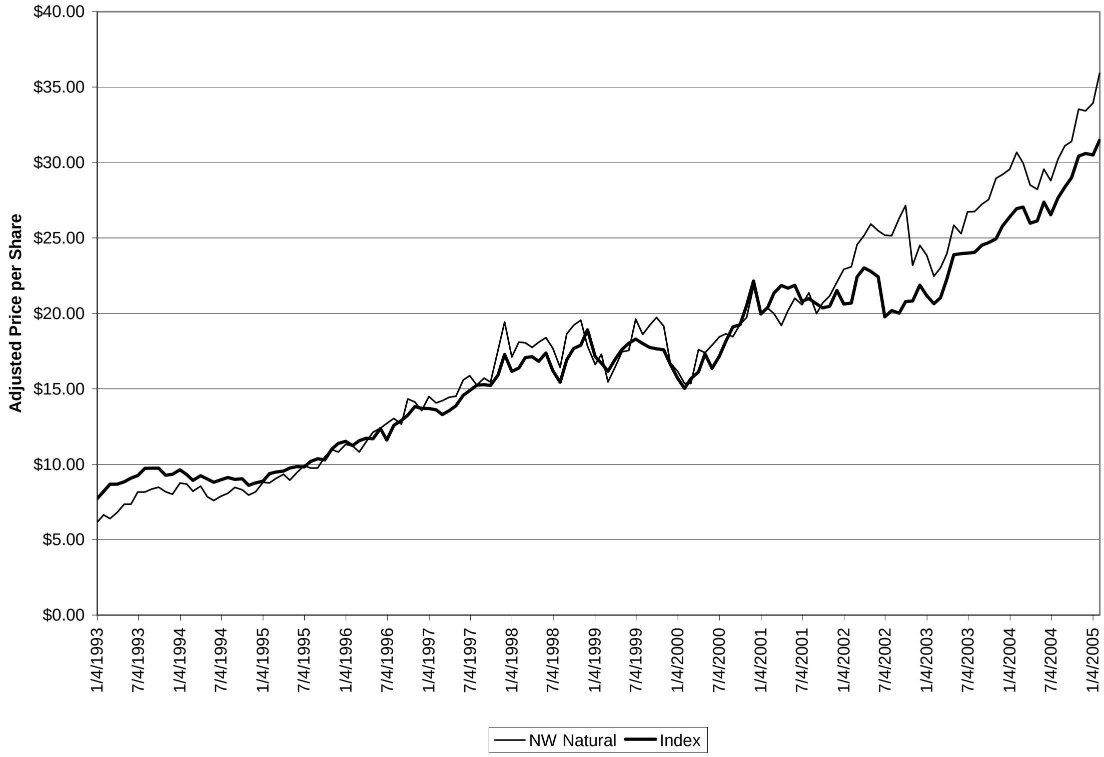
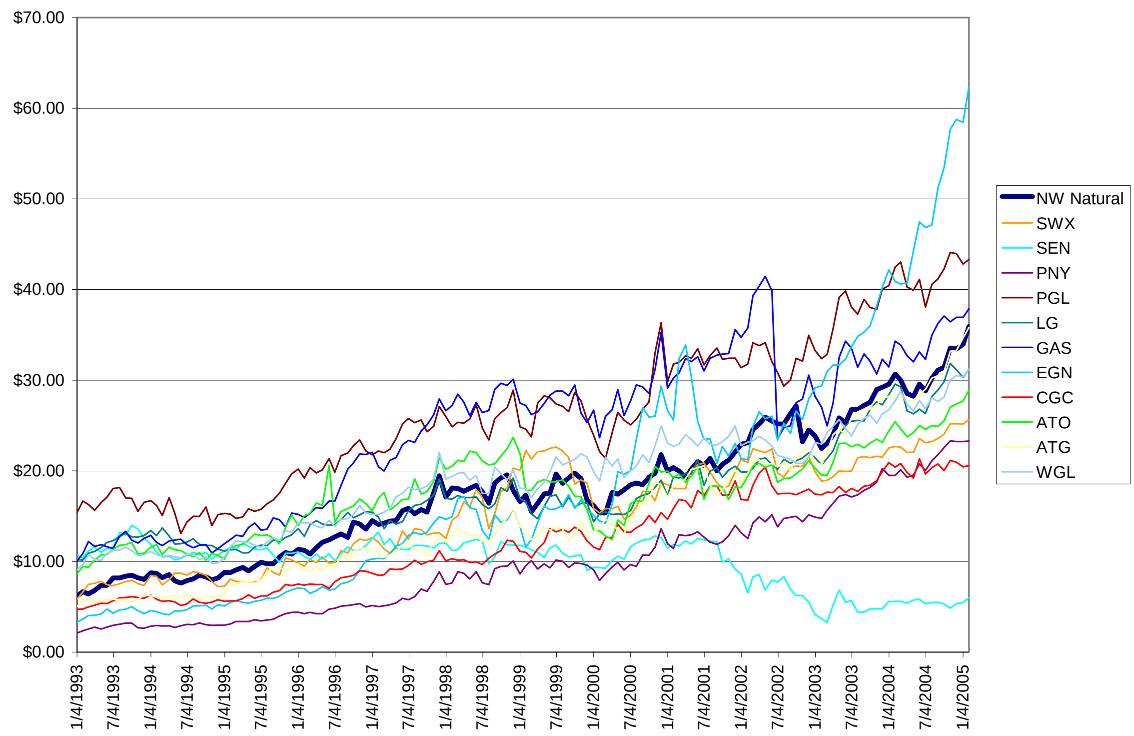


Figure 4-16: Monthly Stock Prices for Twelve Natural Gas Utilities



4.5.5 Reports to Rating Agencies

Commission Staff suggested that we examine NW Natural's reports to rating agencies to see how NW Natural portrays the benefits of DMN and WARM. These reports tend to contain the following elements:

- Tables of financial data;
- Bullet points containing financial highlights (not present prior to 2001); and
- The SEC 10-K annual filing.

To get an idea of how these reports treat DMN and WARM, it is useful to compare the financial highlights from 2003 to those of 2001. The following bulleted text is reproduced from NW Natural reports to rating agencies.

2003 Financial Highlights

- Earnings of $1.76 a share, vs. $1.62 a share in 2002
  - Oregon general rate case contributed $0.09 a share in additional revenues
  - Earnings of $0.17 a share from Gas Storage, vs. $0.14 in 2002
  - Earnings of $0.08 a share from Oregon decoupling mechanism, $0.05 a share from WARM, vs. $0.04 a share from decoupling in 2002
  - Earnings of $0.12 a share from gas commodity savings and off-system sales, vs. $0.28 in 2002
  - Electric generation market contributed no earnings in 2003, vs. $0.11 a share in 2002
  - Higher earnings for pension, health benefits and insurance reduced earnings in 2003 by $0.12 a share
  - Results in 2002 included charges equivalent to $0.33 a share for PGE transaction costs written off
- Cash from operations (before working capital changes) of $102 million, vs. $121 million in 2002
- Utility investments of $125 million, vs. $80 million in 2002
- Net increase in long-term debt of $35 million, vs. $49.5 million in 2002
- Net decrease in preferred and preference stock of $8 million, vs. decrease of $26 million in 2002

2001 Financial Highlights

- Diluted EPS from continuing operations of $1.88 a share compared to $1.79 in 2000
- Weather 3 percent colder than average, but 2 percent warmer than 2000; depressed consumption per degree day reduced earnings by $0.26 a share
- Margin revenues up 5 percent despite depressed consumption patterns
- Storage services added $0.08 a share to earnings
- Electric generation provided $0.11 a share
- Gas commodity savings provided $0.11 a share

These financial highlights show that the presence of DMN and WARM is included, along with their effects in terms of earnings per share. However, DMN and WARM do not appear to receive an unusual amount of attention in the reports. For example, in the 2003 Financial Highlights, the Oregon rate case is listed before DMN or WARM, and its effects on earnings per share are higher.

4.6 Service Quality Issues

4.6.1 Data on Frequency and Nature of Complaints

NW Natural did not report any customer complaints directed specifically at the DMN mechanism. This is likely because rate adjustments caused by DMN are not separately listed on customer's bills. NW Natural reported that there were some complaints generated by the Public Purposes Funding, but they did not provide details.

The Commission provided the "verbatim" complaints (text of letters, e-mails, or transcriptions of telephone calls) associated with UG-143. Twenty-six such complaints were lodged with the Commission between September 2002 and January 2003. The nature of the complaints was uniform, with customers questioning the appropriateness and/or legality of imposing Public Purposes Funding charges on their bills. The complaints were based on the customer's belief that the Public Purposes Funding is taxation without representation, a socialist/communist redistribution of income, and/or forced charitable giving. None of the complaints specifically mention rate adjustments due to the DMN mechanism. (Again, we would not expect them to, as the adjustments are not separately listed on bills.) These negative comments are counter-balanced by the positive comments that we received regarding the value of the funding from the Citizens' Utility Board and community action and planning (CAP) agencies, which indicated the high value of OLIEE and OLGA funding generated by the Public Purposes charges to their organizations.[24] We do not attempt to evaluate the relative importance of the twenty-six complaints (which Deborah Garcia of Commission Staff regards as a significant number of complaints relative to the number of complaints received on other issues) and the benefits derived by the recipients of OLGA and OLIEE funds.

4.6.2 Frequency and Duration of Outages

The Commission Staff raised the possibility that DMN could reduce NW Natural's incentive to address customer outages. That is, if a customer service outage occurs, the DMN deferral mechanism will compensate NW Natural for any lost margins due to a reduction in sales. We requested that NW Natural provide information on the frequency and duration of outages before and after DMN. We received the following response:

> The requested information is unavailable. It is exceptionally rare for NW Natural to experience service interruptions to its customers. In the

[24] The CAP agency representatives that indicated the high value of the Public Purposes funding were: Judy Schilling, Energy & Emergency Assistance Coordinator for Washington County; Karrie Durie of the Community Action Team; Jacque Meier, Weatherization Manager for Clackamas County; Terry Weygandt of the Community Services Consortium; Margaret Davis of the Mid Columbia Community Action Council; and Joan Ellen Jones, Weatherization Manager for Washington County.

highly unlikely event of a service outage, NW Natural has an Incident Command System (ICS) in place to provide a coordinated response ensuring public safety and restoration of service at the earliest possible moment. In almost every circumstance, NW Natural is able to restore service the same day, if not sooner.

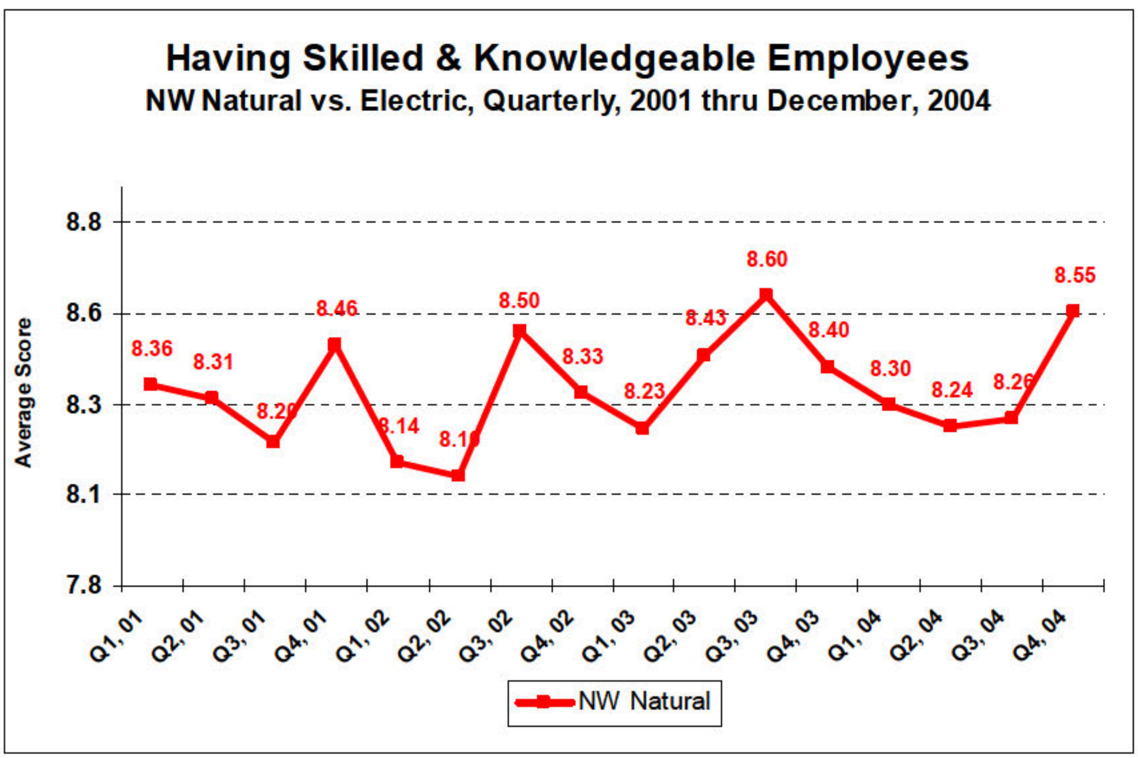
While we do not have direct data to verify the fact that service interruptions have not changed with the introduction of DMN, the customer service ratings data described in the next section indicates that it is unlikely that a problem has arisen in this area. In addition, it is intuitively implausible to us that the small financial incentive associated with delaying repair of an outage would outweigh the customer service costs and the risk of litigation from allowing unsafe circumstances to persist.

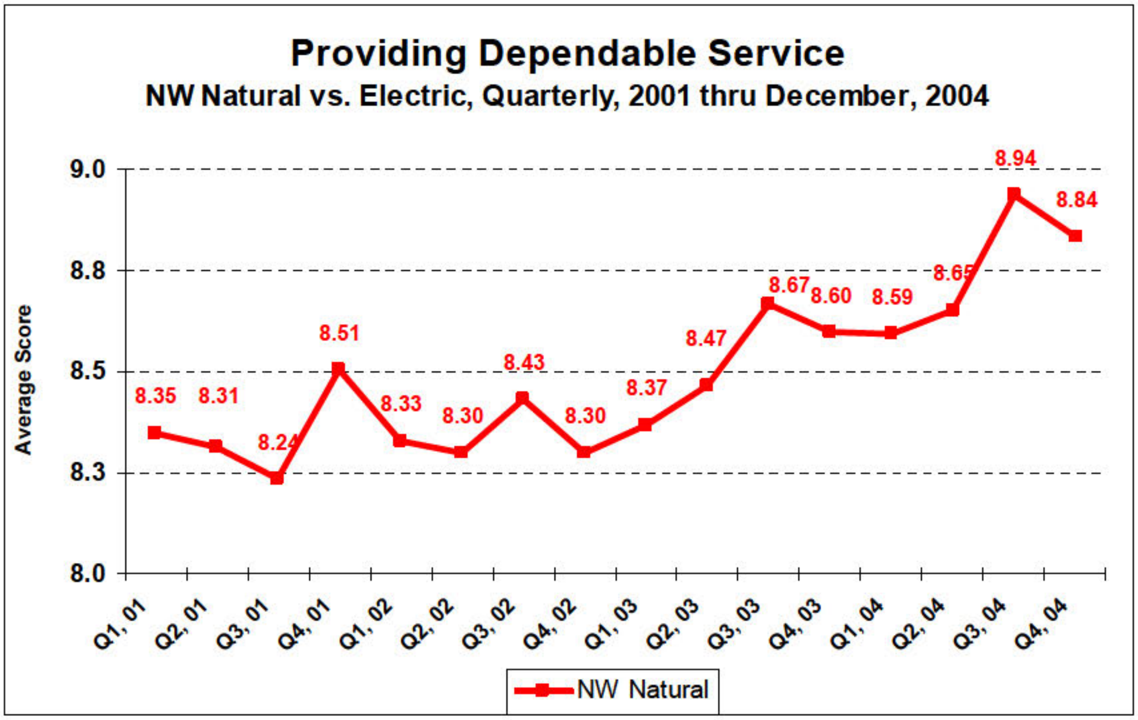
4.6.3 Customer Service Ratings

NW Natural conducts a monthly survey of customer satisfaction, with the sample consisting of customers that have contacted the company. Customers are asked to rate NW Natural in three areas on a scale from one (poor) through ten (excellent). The questions are as follows: *How well does your gas utility perform on…*

1. *Having skilled and knowledgeable employees.*
2. *Providing dependable service.*
3. *Providing timely customer service.*

The three figures below show NW Natural's ratings for each of these areas from 2001 through 2004.




Providing Dependable Service
NW Natural vs. Electric, Quarterly, 2001 thru December, 2004
Average Score
9.0
8.8
8.5
8.3
8.0
8.35
8.31
8.24
8.51
8.33
8.30
8.43
8.30
8.37
8.47
8.67
8.60
8.59
8.65
8.94
8.84
Q1, 01
Q2, 01
Q3, 01
Q4, 01
Q1, 02
Q2, 02
Q3, 02
Q4, 02
Q1, 03
Q2, 03
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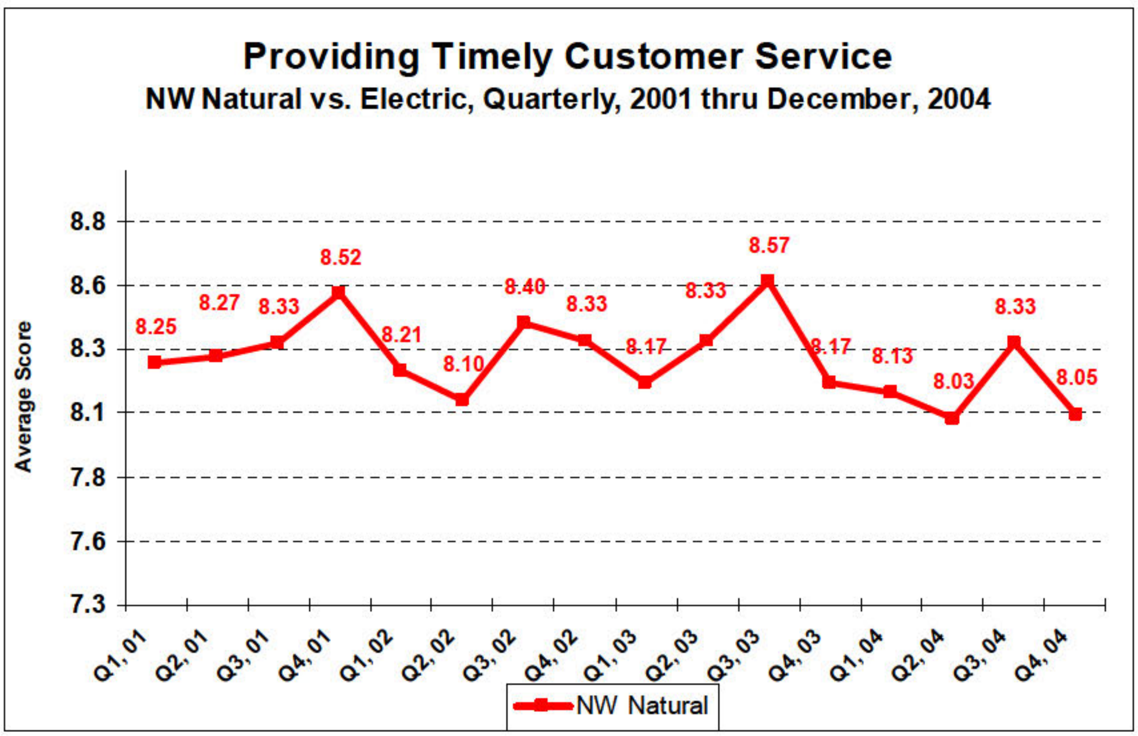
Q4, 03
Q1, 04
Q2, 04
Q3, 04
Q4, 04
NW Natural


Providing Timely Customer Service
NW Natural vs. Electric, Quarterly, 2001 thru December, 2004
Average Score
8.8
8.6
8.3
8.1
7.8
7.6
7.3
8.25
8.27
8.33
8.52
8.21
8.10
8.40
8.33
8.17
8.33
8.57
8.17
8.13
8.03
8.33
8.05
Q1, 01
Q2, 01
Q3, 01
Q4, 01
Q1, 02
Q2, 02
Q3, 02
Q4, 02
Q1, 03
Q2, 03
Q3, 03
Q4, 03
Q1, 04
Q2, 04
Q3, 04
Q4, 04
NW Natural

Since 2001, the “skilled employee” and “dependable service” ratings have increased, while the “timely service” rating has declined. However, note that the scale used in these figures is somewhat “tight,” so that only the increases in the “dependable service” rating seems to represent a significant change since DMN went into effect in the fourth quarter of 2002.

NW Natural has recently subscribed to the J.D. Power and Associates Customer Satisfaction Survey. This information is confidential, and therefore we will only describe the qualitative results for NW Natural with respect to responses to two questions and two indexes, which are compiled across a number of questions. The questions for which we describe the results are as follows.

1. *How would you rate the ability of your natural gas utility to help you reduce your monthly bill? Scale is from one (unacceptable) to ten (outstanding).*
2. *How familiar are you with education or rebate programs from your local natural gas utility to help you with ways to use less gas? Scale is from one (not at all familiar) to ten (very familiar).*

Regarding the first question, NW Natural was ranked 26th out of 55 companies in 2003. In 2004, this ranking improved to 14th out of 55 companies. For the second question, NW Natural ranked 6th out of 55 companies in both 2003 and 2004.

J.D. Power and Associates produces two indexes of interest: an Overall Customer Satisfaction Index and a Customer Service Index.

The Overall Customer Satisfaction Index includes the following factors:

- Price and value
- Company image
- Field service
- Customer service
- Billing and payment

Using this index, NW Natural was ranked 10th out of 55 in 2003 and 9th out of 55 in 2004.

The Customer Service Index includes the following factors:

- Courteous and friendly employees
- Answering questions first time final
- Length of time to answer questions/resolve problem
- Promptness in speaking to CSR
- Employees having sufficient knowledge

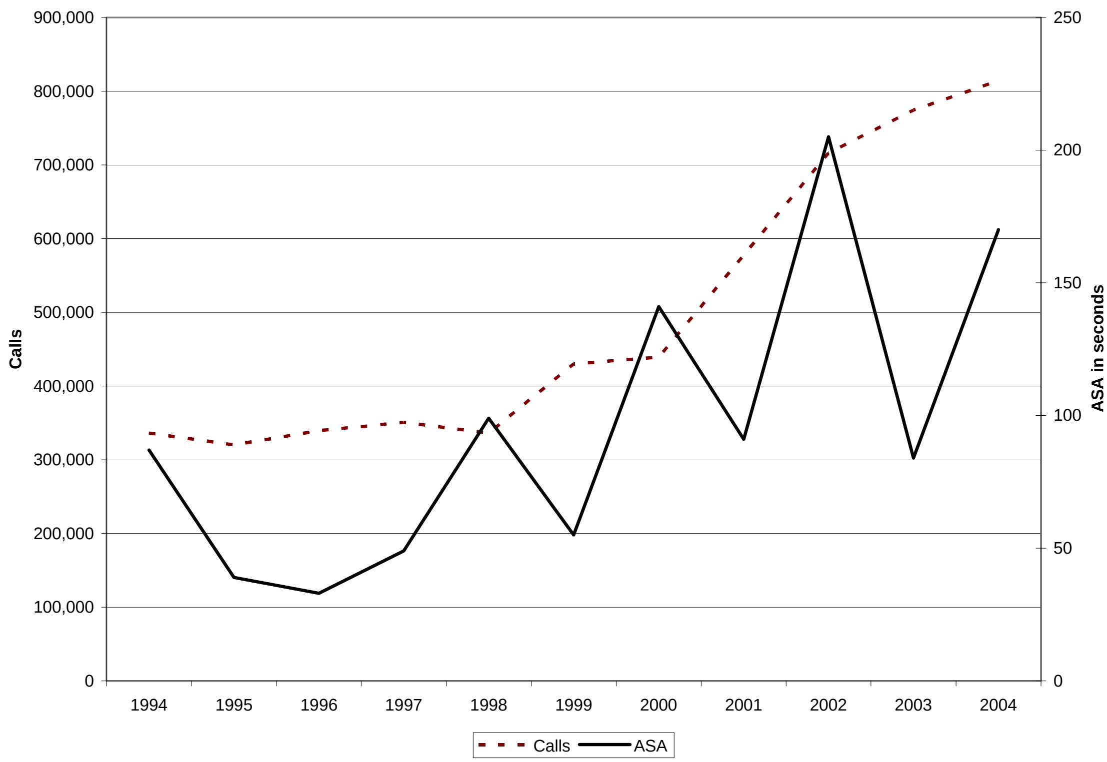
Using this index, NW Natural was ranked 4th out of 55 in 2003 and 5th out of 55 in 2004.

The information presented in this section indicates that NW Natural has not allowed its level of customer service to decline since DMN was implemented. According to both internal and national surveys, it appears that the level of customer service provided by NW Natural is very good overall.

4.6.4 Call Center Performance Data

In order to provide another measure of customer service quality, we obtained data on NW Natural call center volumes and average speed of answer (ASA, or the number of seconds that it takes for a caller to receive service) from 1994 through 2004. Figure 4-17 below displays this information.

Figure 4-17: Annual Call Center Volumes and Average Speed of Answer in Seconds: 1994 through 2004



This figure shows that ASA tends to follow call volumes. That is, as call volumes increase (in part because of price increases), it takes longer for a caller to speak to a customer service representative. The decrease that occurs in 2003 and 2004 is likely due to the fact that the Commission approved an increase in the number of NW Natural customer service personnel. We do not see a reason to directly attribute this change to DMN. Overall, we interpret this figure as showing that DMN did not negatively affect call center performance.

4.7 Uncollectible Accounts

As noted in Section 2 above, we do not believe that DMN affects NW Natural's incentives to pursue uncollectible accounts. That is, the DMN deferrals are calculated using (weather-adjusted) sendout volumes, the actual number of customers, and a pre-established margin per therm. Revenues that are not collected from customers do not flow back into the DMN deferrals.

Nevertheless, the Commission Staff expressed a desire to see data regarding uncollectible revenues before and after DMN was approved. Tables 4-11 and 4-12 contain NW Natural's annual uncollectible accruals and write-offs, respectively. Uncollectible revenues tend to increase as rates increase. The best example of this is seen in the change in residential uncollectible revenues between 2000 and 2001, in which a 20 percent increase in prices led to a 32 percent increase in uncollectible revenues. The effect of higher prices seems to stabilize, however, as uncollectible revenues decreased in 2002 and 2003 despite the presence of slightly higher prices than in 2001.

Table 4-11 provides evidence that DMN does not affect NW Natural's incentives to pursue uncollectible accounts, as uncollectible write-offs declined dramatically from 2002 to 2003, a period in which DMN was in effect.

Table 4-11: Annual Uncollectible Accrual by Rate Class

	Residential			Commercial		
Year	**Uncollectible Revenue**	**Percent Change**	**Avg. Rev.**	**Uncollectible Revenue**	**Percent Change**	**Avg. Rev.**
1999	$1,997,062		68.8	$278,718		55.2
2000	$1,873,153	-6.2%	78.7	$428,010	53.6%	63.8
2001	$2,477,666	32.3%	94.2	$377,925	-11.7%	78.5
2002	$2,098,109	-15.3%	99.3	$411,942	9.0%	83.9
2003	$1,381,340	-34.2%	95.6	$297,173	-27.9%	78.0
2004	$2,684,187	94.3%		$396,493	33.4%	

Table 4-12: Annual Uncollectible Net Write-offs by Rate Class

	Residential			Commercial		
Year	**Uncollectible Revenue**	**Percent Change**	**Avg. Rev.**	**Uncollectible Revenue**	**Percent Change**	**Avg. Rev.**
1999	$1,946,308		68.8	$280,529		55.2
2000	$1,509,603	-22.4%	78.7	$433,056	54.4%	63.8
2001	$2,268,892	50.3%	94.2	$389,204	-10.1%	78.5
2002	$2,369,467	4.4%	99.3	$428,877	10.2%	83.9
2003	$1,582,589	-33.2%	95.6	$296,442	-30.9%	78.0
2004	$2,139,123	35.2%		$376,229	26.9%	

4.8 OLGA and OLIEE

As part of Order 02-634 establishing DMN, the Commission approved Public Purposes Funding to support the Oregon Low-Income Energy Efficiency Program (OLIEE), the Oregon Low-Income Gas Assistance Program (OLGA), and enhanced energy efficiency programs. Section 4.4.2 discusses the performance of the most prominent enhanced energy efficiency program, the residential HEF program. This section discusses OLIEE and OLGA program performance. Note that NW Natural has retained Quantec to conduct an independent review of OLIEE. According to the 2003-2004 OLIEE Annual Report, Quantec's evaluation will address the following questions (among others):

- Do the current program structure, funding and practices provide optimal delivery?
- What are the bottlenecks in the program that impede complete implementation?
- Are there other channels for program delivery?
- Are there "best practices" from other states and programs that can be applied to this program?
- How are the funds expended? Is fund matching creating a bottleneck?

Because this evaluation is already in progress, we do not attempt to provide a complete evaluation of OLIEE. In addition, because the areas of inquiry established in the Commission's Order do not focus on OLIEE and OLGA program performance, we limit our examination of OLIEE and OLGA to the following:

1. To what extent do the CAP agencies value the OLIEE and OLGA funding provided by the Public Purposes charges?
2. What do the CAP agencies report with respect to NW Natural's efforts in administering the OLIEE and OLGA programs?

In order to address these issues, we contacted Jim Abrahamson, Oregon Energy Partnership Coordinator at Community Action Directors of Oregon, who then facilitated contact with the relevant staff members at the CAP agencies. We received feedback from four individuals regarding OLGA: Judy Schilling, Energy & Emergency Assistance Coordinator for Washington County; Karrie Durie of the Community Action Team; Terry Weygandt of the Community Services Consortium; and Margaret Davis of the Mid Columbia Community Action Council (MCCAC). We received feedback from two individuals regarding OLIEE: Jacque Meier, Weatherization Manager for Clackamas County and Joan Ellen Jones, Weatherization Manager for Washington County.

4.8.1 OLGA

The respondents were consistent in reporting the high value that their organizations place on the funding provided by OLGA. Judy Schilling's comments to us provide an example of this:

> As you probably know, the economy in Oregon is very depressed, energy costs are rising, and here in Washington County we have experienced a large growth in population in the past few years. I have been with the energy program for more than 20 years and I have never seen the demand for assistance as high as it is now. In the past, requests for help usually began declining after the coldest winter months. Now, the demand for assistance is high throughout the year. We find that many people end up turning off their gas altogether after the main heating season because they simply cannot afford to keep it on. They usually leave large arrearages

> which need to be paid in order to turn the gas back on in the fall. We often use OLGA for these situations, since our LIEAP funding is usually not available to us until December. We reply upon OLGA heavily in the months of September, October and November, just to get peoples' heat turned back on. If this program did not exist, many people would be completely without heat until December or January. Having OLGA as a year-round program helps in the summer, also, when all the LIEAP funding has been exhausted. Typically, we have no LIEAP dollars after April, so OLGA fills the gap between April/May and December. It is critical.

In addition, Margaret Davis and Karrie Durie reported that OLGA has allowed them to assist approximately 200 households each year.

Regarding their experiences in working with NW Natural, we received mostly positive feedback, along with some suggestions. Karrie Durie reported very positive experiences with NW Natural, noting that NW Natural has been prompt in responding to them, easy to work with (and easier to work with than other utilities), and that NW Natural's reporting requirements are not severe. She singled out Lois Douglass as being "great to work with". Her only recommendation was changing the OLGA calendar to a fiscal year that matches that of the state.

Judy Schilling was less positive regarding her interactions with NW Natural. She does not feel that NW Natural has been effective in communicating with the agencies in the planning and implementation of the program. In particular, she believes that using the state's existing energy assistance database instead of NW Natural's spreadsheets for tracking and reporting would eliminate extra work for the agency. In addition, she would like NW Natural to be more flexible with respect to changes in commitments (apparently no changes are allowed once the initial notification is posted to an account) and she would like to eliminate the $800 cap on the total benefits that a household can receive (including LIEAP funds).

Margaret Davis commented that the staff members that she has worked with at NW Natural have been "quick to respond, helpful, and always patient." She mentioned Lois Douglass, Gail Kamara and Angela Warren as being particularly helpful.

Terry Weygandt had the following comment in response to our question "In what ways has NW Natural been particularly helpful or unhelpful in assisting CAP agencies to maximize the performance of the OLIEE and OLGA programs? How could the relationship between NW Natural and CAP agencies be improved?"

> Since last September, many of the CAP agencies have been requesting a joint meeting with NW Natural to discuss this very topic. Our idea was to discuss what is working and what may not be working as well as we both would like. Unfortunately, we have not been successful in finding a date that would accommodate both NW Natural and the CAP providers. We understand NW Natural does not hold any admin funds from the OLGA

> program and their staff is limited to the amount of time they can spend on OLGA issues.
>
> At a minimum, I feel NW Natural and the OLGA providers should hold semi-annual meetings to discuss and facilitate change that would increase the effectiveness of OLGA and improve the relationship between NW Natural and the providing agencies. It is my understanding that the CAP providers are willing to travel to Portland if that would facilitate a meeting date.

Based on the feedback that we received, it appears that CAP agencies place a very high value on OLGA funding, that NW Natural has been helpful to them in many circumstances, but that there is room for improvement in the oversight of this program.

4.8.2 OLIEE

Both Jacque Meier and Joan Ellen Jones commented on the high value of the OLIEE program. Ms. Jones cited an example of the benefits that can come from this program:

> The homes we work with are generally older and often under maintained. The heating systems are often, especially in the case of gas heated homes, not working or running in an inefficient, and/or unsafe manner. The families often use space heaters or in some cases cooking appliances to heat their homes. Without this assistance these households would continue to use space heaters, or perhaps install electric baseboard heat. These situations may be complicated by closed accounts and/or arrearages. Weatherization works with the energy assistance program for service reconnection, then completes repairs and in some cases replaces heating systems.
>
> When there is no reported need for heating system service, weatherization requests are processed by a prioritization system based on points given for households with an elderly or disabled member, a child under six, or farm worker status. Though at a gas audit last week, the CO readings for the furnace were at such high levels that the test was immediately aborted and a service technician called. Without our intervention, the family would wonder why they were often sick, had headaches or perhaps worse. Their young pre-school children used the garage, where the furnace is located, as a play area.

Regarding her experience in working with NW Natural, Ms. Jones noted that she has a good working relationship with Ellen Prouty. She also had some suggestions for improving the program, including moving from reimbursement to up-front funding, that NW Natural acknowledge and assist with the safety and repair issues with gas heated homes, and help with the installation of 80% furnaces. Jacque Meier echoed the latter comment, based on the example that an 80% furnace is more efficient than the 70% furnace running at 50% efficiency (and producing carbon monoxide) it would likely replace. Therefore NW Natural should provide an incentive for the 80% furnace, which is more practical for these customers than a 90% high-efficiency furnace.

As with the OLGA program, the feedback that we received indicates that the CAP agencies place a high value on OLIEE funding and the agencies have had positive interactions with NW Natural staff, but that there are ways that they believe the program could be improved.

5. EVALUATION OF ALTERNATIVE RATE AND REGULATION OPTIONS

The DMN mechanism approved by the Commission is not the only way to address concerns about margin recovery and conservation. Indeed, NW Natural initially proposed a “full” decoupling mechanism that would allow for full fixed-cost recovery regardless of the source of usage changes (*i.e.*, that would not adjust actual usage for weather and would not include a 10% reduction in deferrals), while the Commission Staff has expressed a preference for a combination of price elasticity adjustments to adjust margin recovery for expected usage changes in response to price changes and lost revenue adjustments to compensate NW Natural for the adverse revenue effects associated with promoting energy efficiency. This section provides observations and analyses of some of the alternatives that have been proposed.

5.1 Fixed/Variable Rate Design

It is important to recognize that the original source of the problem of uncertain fixed-cost recovery due to usage variability, and thus the need for some form of decoupling, is the typical design of standard retail gas tariffs. That is, because a large percentage of fixed costs are recovered through volumetric (variable) rates, fixed cost recovery, and thus profits, depend on the level of sales. This design of recovering fixed costs primarily through variable energy prices has a number of implications, including the following:

1. The recovery of fixed costs through a volumetric rate creates weather-induced fixed-cost recovery risk for both the utility and its customers. For example, an unusually cold winter will cause customers to overpay for fixed costs, resulting in the utility over-recovering its fixed costs, while an unusually warm winter will cause the opposite result. This is a risk that can be “swapped” (*i.e.*, reduced or eliminated for both parties) by changing the method of fixed cost recovery.
2. The recovery of fixed costs through volumetric rates creates a disincentive for the utility to promote conservation that will reduce sales below the baseline level agreed upon in the most recent rate case for recovering allowed fixed costs.
3. The high variable price, which exceeds the market cost of natural gas, is appealing to environmentalists, as it provides a greater incentive for customers to engage in conservation efforts. The environmentalists justify this outcome based on the notion that a pure energy price that reflects private market costs does not account for the public externalities associated with energy consumption (*e.g.*, pollution). However, there is no direct link between the actual estimated externality cost associated with natural gas consumption and the fixed-cost margin by which the energy price exceeds the private marginal cost of natural gas. Furthermore, maintaining a retail energy price in excess of market costs invites

competition, such as from other fuel types, other states, or, where allowed, other suppliers.

4. The high variable price potentially offers customers a form of economic insurance. That is, if customers who fall on hard times reduce their usage, then the reduction in their bill will be larger than if the energy price covered only variable costs. That is, they would pay both reduced energy costs and a lower share of fixed costs. The cost of this insurance, however, is that for any increase in usage beyond their normal level, consumers pay for both additional energy and additional fixed costs.

A number of alternative rate structures have been considered that have the potential to alleviate one or more of the effects listed above. For example, a fixed/variable rate design, in which fixed costs are recovered primarily through fixed charges (*e.g.*, monthly customer charges and/or demand charges) and variable costs (*e.g.*, fuel costs) are recovered primarily through volumetric rates, eliminates all but the third concern listed above.[25] That is, with a fixed/variable rate design, fixed cost recovery is not sensitive to weather conditions. Secondly, because a fixed/variable rate design essentially ensures that fixed costs are recovered, the utility's disincentive to promote conservation is reduced or eliminated. Finally, it eliminates the possible economic insurance present in the variable pricing tariff, as customers who reduce their usage in response to declining incomes will receive bill reductions only for the reduction in fuel and other variable costs, but not a reduction in their contribution to fixed costs.

From an economic efficiency standpoint, fixed/variable pricing represents the most appropriate pricing method, as long as rates are set correctly to reflect fixed and variable costs, potentially including the addition of an explicit environmental externality component to the variable price. For this reason, we present this alternative to the current rate structure first, even though it has not been proposed recently by either NW Natural or the Commission. Two prominent objections have been raised that limit the use of fixed/variable pricing in Oregon's natural gas markets. These objections are the following:

1. *Equity concerns*. To the extent that natural gas use is correlated with income, increasing fixed charges relative to volumetric rates will adversely affect low income customers. We note that this concern can be largely alleviated by incorporating a demand charge in the fixed component of the rate, which would produce fixed charges that vary by customer size.
2. *Environmental concerns*. As noted above, reducing the volumetric price decreases customers' incentives to engage in conservation activities. This argument has some basis in theory to the extent that natural gas use imposes costs on the economy or environment that are not included in the price of energy.

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[25] There are a number of examples of this form of pricing in both regulated and non-regulated industries, including local telephone service, cable television, health clubs, and some retail merchants such as Sam's Club. It is beyond the scope of this study to assess the industry or firm characteristics that increase the feasibility and/or use of fixed/variable pricing. However, we have considered that non-regulated merchants would likely trade off the benefits of a less variable revenue stream with the costs of restricting walk-in business when considering whether to adopt fixed/variable pricing.

However, this problem can be addressed directly by estimating the magnitude of externality costs and adding that amount to the retail energy price rather than allowing the average fixed cost to serve as the default estimate.

Because of the above concerns, fixed/variable rates have not received widespread support as a means of stabilizing cost recovery or reducing disincentives to promote energy efficiency.

5.2 Full Decoupling

NW Natural's original proposal to the Commission was for a full decoupling mechanism. The total revenue effects of this proposal are quite close to those of DMN and WARM in combination, but the mechanism is mathematically less complex. Equation 4 shows how full decoupling revenue adjustments are calculated.
Equation 4: Margin Adjustment = $M * C * (QPC^B – QPC^A)$

In this equation, M is the dollar per therm margin from the standard tariff; C is the number of customers to which the program applies; QPC^B is baseline use per customer; and QPC^A is actual use per customer. The key differences between this mechanism and the combination of DMN and WARM are as follows:

1. Actual use per customer is not adjusted for weather conditions. This results in an incorporation of a WARM-style adjustment into the decoupling mechanism.
2. Baseline quantities are not adjusted for prices.
3. The 90% factor used to reduce the amount of revenue variation covered by the DMN program is not included.
4. Weather-induced changes in revenue recovery accumulate in a deferral account instead of flowing to bills in the same month (as it works in WARM).
5. Because the DMN and WARM adjustments are combined in full decoupling, there is no need to set the price elasticity or define normal weather. Once the utility and the Commission agree on the allowed margin rate per customer, both parties have the incentive to select the "correct" value of baseline use per customer in order to minimize deferrals.

Because full decoupling is most appropriately compared to the combination of DMN and WARM (and not DMN alone) and we have yet to perform a detailed analysis of WARM outcomes, we must provide a caveat regarding the discussion that follows. That is, some of what we express here is an expectation that may or may not be supported by subsequent WARM data analyses.

Our belief is that full decoupling is easier to comprehend and communicate than the combination of DMN and WARM. This could reduce customer service costs associated with confusion about bills.[26] In addition, full decoupling eliminates disputes over setting

[26] Simplifying the mechanism would not reduce disputes about *whether* the bills should be adjusted, which will be reduced only to the extent that decoupling deferrals may be more difficult to detect than WARM bill adjustments.

parameter values about which reasonable people can disagree: the price elasticity and normal weather (heating degree days).

Full decoupling has a potential disadvantage with respect to the combination of DMN and WARM: under full decoupling, weather-induced revenue adjustments are deferred until the following year, while WARM adjustments affect current bills. To the extent that customers want to reduce the "cash flow" risk associated with weather-induced fluctuations in monthly bills, WARM provides superior benefits (that may be improved through modifications to the program). In fact, full decoupling could increase customers' weather risk. For example, if a mild winter is followed by an unusually cold winter, the surcharges caused by the mild winter could increase customer bills at exactly the wrong time. In short, full decoupling is not as effective as WARM in reducing customer's weather-induced bill risk. However, note that the *total* effect over time on customer bills is largely the same with full decoupling as it would be under the DMN + WARM mechanism, so customer's weather-induced *wealth* risk is nearly identical under the two mechanisms.

We have not yet performed an in-depth analysis of WARM data. Doing so may alter some of the preliminary conclusions presented in this section.

5.3 Elasticity and Lost Revenue Adjustments

In our discussions with them, Commission Staff proposed an alternative to DMN, which is to maintain the price elasticity adjustment, but replace the deferral component with lost revenue adjustments. We consider this proposal in four parts: the effects of removing the deferral component of DMN, the efficacy of lost revenue adjustments, the implications of removing NW Natural from energy efficiency promotions, and the effects associated with the potential elimination of Public Purposes Funding.

5.3.1 Elasticity Adjustment without Deferral Component

As noted earlier, there are two components to DMN. The first component adjusts margins for price changes using an assumed price elasticity value (*e.g.,* -0.172 for residential customers). For example, if the residential price increases by 10%, DMN assumes that residential use per customer will decline by 1.72% (which is derived by multiplying 10% by -0.172). The margin rate is then adjusted (increased in this example) so that the product of baseline use per customer and the margin is left unchanged. We will refer to this as the "elasticity adjustment." The second component of DMN, which we refer to as the "deferral component," provides for surcharges or refunds to customers based on 90% of the total margins associated with the difference between weather-normalized actual usage and price-adjusted baseline usage.

Provided that the assumed elasticity value is correct, the elasticity adjustment compensates NW Natural for lost margins associated with conservation efforts undertaken by customers (or, in the case of declining prices, load growth) outside of formal programs. The deferral component compensates NW Natural for lost margins associated with other non-weather effects, including the effects of NW Natural's and the Energy Trust's energy efficiency programs on use per customer. This component can also provide for recovery of lost margins caused by the use of an incorrect elasticity value in the calculation of the elasticity adjustment. (Of course, all margin recovery or refunds that occur through the deferral component are subject to a 10% reduction.)

Currently the deferral component serves several purposes:

1. It removes NW Natural's disincentive to promote energy efficiency.
2. It corrects 90% of the errors associated with an inaccurate elasticity adjustment.
3. When combined with WARM, it corrects 90% of the errors associated with the use of an incorrect normal weather measure.

The mechanics associated with the second and third purposes can be found in our overviews of DMN and WARM in Sections 2 and 3, respectively. For purposes of this section, it is sufficient to point out that eliminating the deferral component of DMN could lead an increase in disputes between the Commission and NW Natural over the price elasticity values and measures of normal weather. In short, removing the deferral mechanism increases the parties' incentives to "game" the elasticity adjustment and WARM parameters.

5.3.2 Lost Revenue Adjustments

An alternative to decoupling in general (and DMN in particular) is to compensate the utility for conservation efforts through lost revenue adjustments. For example, lost revenue adjustments as applied to the high-efficiency appliance program would compensate NW Natural for lost margins based on estimated therm reductions for each HEF adoption. This compensation occurs on a case-by-case basis and is not reconciled to actual therm reductions at any point.

There are a number of disadvantages associated with this approach to promoting conservation.[27]

1. It is administratively burdensome, requiring that energy efficient appliance adoptions be verified, and the energy-saving effects of each adoption estimated through costly program evaluations.
2. It addresses only those programs that *can* be verified or are associated with relatively easily counted adoptions. That is, lost revenue adjustments can be applied to high-efficiency furnace programs, but it would be difficult to use this mechanism for a program such as the Energy Trust's Efficient Facility Operations Program, in which a diverse set of actions may be taken to improve energy efficiency.
3. Lost revenue adjustments encourage programs that look good on paper, but do not actually deliver therm reductions.
4. With only lost revenue adjustments, the utility is discouraged from backing more general conservation efforts, such as pleas from the Governor to reduce consumption during an energy crisis, or proposals to improve energy efficiency

[27] Some of the disadvantages listed below are taken from "Breaking the Consumption Habit: Ratemaking for Efficient Resource Decisions" by Sheryl Carter, which appeared in the Electricity Journal in December 2001.

standards embedded in building codes. In addition, to the extent that specific energy efficiency messages (*e.g.*, promoting the HEF program) can spur more general conservation efforts, the utility program is left uncompensated by lost revenue adjustments.

5. Lost revenue adjustments do not protect the utility from margin loss due to independent conservation efforts (*i.e.*, conservation efforts undertaken by customers outside of formal programs with the intent of lower their bill). In times of increasing prices, this can require the utility to file rate cases more frequently, which imposes costs on the regulator and customers (indirectly, to the extent that rate case expenses can be recovered through rates). Conversely, in times of declining prices, lost revenue adjustments do nothing to prevent over-recovery on the part of the utility. (In principle, the elasticity adjustment accounts for this effect. However, its effectiveness is affected by the accuracy of the elasticity parameter, which can be difficult to estimate.)

The principle advantage of lost revenue adjustments relative to decoupling mechanisms is that they limit revenue adjustments to conservation efforts, while decoupling may compensate the utility for consumption declines due to economic or other factors. Our findings in Section 4.3 above, which analyzed the factors that affect residential and commercial use per customer for NW Natural's Oregon customers, indicates that this potential advantage is not relevant in NW Natural's case. That is, we found that the Oregon unemployment rate is not related to use per customer, and that retail prices and heating degree days explain the vast majority of variations in use per customer. Given this, it is unlikely that a significant share of DMN revenue flows can be attributed to customer responses to changing economic conditions.

Taking all of the above into account, our belief is that lost revenue adjustments will not be as effective as decoupling is in changing utility attitudes and actions with respect to promoting energy efficiency and other conservation efforts.

5.3.3 Effects of Removing NW Natural from Energy Efficiency Promotions

Because of the change in NW Natural's incentives that are associated with removing the deferral component, our expectation (shared by Marc Hellman of the Commission Staff in our meeting on January 28, 2005) is that NW Natural would revert to promoting load growth and shift resources away from promoting energy efficiency. The task of promoting energy efficiency would then shift entirely to the Energy Trust of Oregon (assuming that the Public Purposes Funding that supports this activity is maintained, which would likely be a contentious issue).

Based on our interviews with Margie Harris, Executive Director of the Energy Trust, and two distributors of high-efficiency furnaces,[28] removing NW Natural from the promotion of energy efficient appliances would harm program performance. Each of these people indicated that NW Natural's connections with distributors and customers enhance HEF program performance. Ms. Harris commented on replacing DMN with a lost revenue adjustment. Her belief is that DMN allows NW Natural to market energy efficiency

[28] The individuals interviewed were Mike Dawson of Gensco and Glen Bellshaw of Airefco.

more freely and have a more open and comprehensive approach to promoting energy efficiency. If NW Natural were to cease its promotion of energy efficiency, Ms. Harris believes that the Energy Trust would have to work hard to build the connections to vendors and customers that NW Natural currently provides. Given that she sees no disadvantages associated with DMN and has had (overall) a positive experience in partnering with NW Natural in promoting energy efficiency, she supports the continuation of DMN.

The distributors with whom we spoke concurred with Ms. Harris' opinion. From their perspective, DMN has produced uniformly positive outcomes and they would support its renewal.

Some evidence of NW Natural's effectiveness in helping to promote Energy Trust initiatives is provided by Energy Trust call center tracking data. Two types of information are available on a monthly basis beginning in October 2004: the share of referrals for total call center intake by source, and the share of Home Energy Savings Program routings by source. These are presented in Tables 5-1 and 5-2 below.

Table 5-1: Share of Total Call Center Referrals by Source

Source	October 2004	November 2004	December 2004	January 2005
PGE	6	7	7	10
PacifiCorp	5	5	5	5
NW Natural	11	11	14	14
Other	78	77	74	71

Table 5-2: Share of Home Energy Savings Routings by Source

Source	October 2004	November 2004	December 2004	January 2005
PGE	8	10	9	13
PacifiCorp	6	6	7	7
NW Natural	16	16	21	19
Other	70	68	63	61

These tables show that NW Natural, which accounts for a small share of Energy Trust funding relative to PGE and PacifiCorp (about $6 million for NW Natural, versus about $45 million for PGE and PacifiCorp), accounts for a comparatively high percentage of referrals to the Energy Trust call center.

5.3.4 Effects of Eliminating Public Purposes Funding

As a part of its decoupling proposal, NW Natural included provisions for Public Purposes Funding for three purposes: low-income bill payment assistance, low-income weatherization assistance, and enhanced energy efficiency programs.

According to budgeted 2004 figures, the low-income bill payment assistance (OLGA) fund collected about $1.44 million in 2004, the low-income weatherization assistance

(OLIEE) fund collected about $1.35 million in 2004 and the energy efficiency fund collected about $6.75 million ins 2004. In an initial meeting regarding this study, Steve Weiss of the Northwest Energy Coalition asserted that the benefits associated with these funds should be included in the benefits of DMN to the extent that NW Natural will remove their support for Public Purposes Funding if decoupling is eliminated. In addition, Bob Jenks of the Citizens' Utility Board of Oregon supports DMN solely because of the presence of the Public Purposes Funding. Finally, the feedback we received from CAP agencies (presented in Section 4.8) indicates that they place a high value on the OLGA and OLIEE programs.

5.4 Conclusions Regarding Rate Structures

Both full decoupling and the combination of DMN and WARM, in conjunction with recovery of fixed costs through variable energy prices, have the following effects relative to standard rates and regulatory mechanisms:

1. They reduce or eliminate the utility's disincentive to promote energy efficiency.
2. They maintain an added incentive for individual consumers to undertake conservation efforts, through retail prices that exceed market costs of energy.
3. They reduce utilities' variability of fixed-cost recovery.

These two mechanisms are the only alternatives discussed here that have these three characteristics. A fixed/variable rate design would reduce variability in fixed-cost recovery, but does not maintain the high volumetric price. Replacing the deferral mechanism with lost revenue adjustments does not effectively reduce the utility's disincentive to promote energy efficiency (and, importantly, reinstates an incentive to promote load growth relative to decoupling mechanisms).

Given that our research on recent historical changes in prices, economic factors and energy consumption indicates that neither DMN nor full decoupling is likely to cause a shift of economic risk from NW Natural to its customers, we believe that full decoupling or DMN are the approaches that are likely to both:

- Meet the desired goals of allowing NW Natural to promote energy efficiency without harming its shareholders, while stabilizing fixed cost recovery; and
- Alleviate concerns about maintaining incentives to consumers to privately undertake conservation efforts and avoid potentially harmful distributional effects (that could be caused by higher fixed customer charges in a fixed/variable rate design).

A determination of whether full decoupling or a combination of DMN and WARM is a superior approach primarily depends on the effects that the two methods have on individual customer bills when weather deviates from normal conditions. An in-depth analysis of this topic is outside the scope of this report, but will be completed as part of a follow-up review that focuses on the effectiveness of WARM.

6. CONCLUSIONS AND RECOMMENDATIONS

6.1 Responses to Commission Questions

In Order 02-634 establishing DMN, the Commission required that this independent study address a number of questions. As part of the review process, Commission Staff added several issues to this list. As an initial step in providing conclusions and recommendations, we provide direct answers to those questions.[29] The questions appear in italics, and our responses appear as standard text.

1. *a. Did the mechanics of DMN accurately carry out the intentions of the Specified Parties and the Commission as expressed in this Agreement?* In August and September of 2004, an independent consultant named Gary Hill reviewed and audited the calculations performed for DMN. NW Natural commissioned this review as a precaution against the more strict accounting standards imposed by the Sarbanes-Oxley Act of 2002. Appendix 2 contains a letter from Mr. Hill to Alex Miller of NW Natural certifying the accuracy of the DMN calculations. In the interest of cost efficiency, we did not perform a separate audit of the DMN calculations. However, based on Mr. Hill's report, it appears that the DMN calculations as executed by NW Natural accurately reflect the intentions in the Agreement.

   b. To the extent lost margins have been recovered through DMN, what percentage of the margins recovered were due to conservation, economic activity, and price changes? We are unable to determine the exact percentages of recovered margins associated with these three factors. However, our analysis of factors that have affected recent historical changes in residential and commercial use per customer (in Section 4.3) indicates that the vast majority of DMN margin adjustments can be attributed to the effect of price changes. That is, economic activity (represented by the Oregon unemployment rate) and NW Natural-sponsored conservation efforts (the residential HEF program) have not had a statistically significant effect on use per customer. We provide one caveat to this conclusion, to the effect that to some extent, consumers' usage changes in response to price changes overlap with "conservation," in that the price elasticity effect occurs through a combination of short- and long-run changes in customer behavior. These can include actions such as turning the thermostat down, as well as adding insulation or purchasing higher efficiency equipment. To the extent that NW Natural's promotion of specific energy efficiency programs has general conservation effects (through increased awareness), price effects overlap with conservation effects.

2. *Did DMN effectively remove the relationship between the utility's sales and profits?* Our analysis of the DMN mechanism indicates that it is effective in reducing, but not completely removing, the link between utility sales and profits. Through simulations (described in Section 4.1), we estimate that DMN reduces the variability of residential margins per customer by 30 percent and reduces the variability of commercial margins per customer by 42 percent.

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[29] We have eliminated some WARM-specific issues that will be addressed in a separate report.

There are two reasons that DMN does not remove the relationship entirely. First, it excludes weather effects (which are subsequently accounted for through the WARM mechanism). Second, a 90% factor is applied to the deferral component. Still, according to CFO David Anderson, DMN has been effective in reducing the link between NW Natural's sales and its profits. Our simulation of DMN revenue effects (in Section 4.1) indicated the possibility that the assumed price elasticity values may be too low (in absolute value), which exposes a larger share of the revenue adjustments to the 90% factor in the deferral calculations. Updating the elasticities and/or removing the 90% factor could further reduce the link between sales and profits.

3. *Did DMN effectively mitigate the utility's disincentives to promote energy efficiency?* An examination of the theoretical effects of DMN leads us to conclude that it is an effective means of reducing NW Natural's disincentive to promote energy efficiency. This conclusion is reinforced by NW Natural's actions under DMN, which include effectively partnering with the Energy Trust of Oregon, improving HEF program performance, and shifting marketing resources towards energy efficiency promotions. (It is possible that the shift in marketing resources can be attributed in part to Order 99-697, in which the Commission disallowed recovery of image advertising expenses.)

4. *Did DMN improve the utility's ability to recover its fixed costs?* This question is closely related to Question #2 above, in that reducing the link between sales and profits will produce more stable recovery of fixed costs. Therefore, for the reasons stated above, we conclude that DMN has improved NW Natural's ability to recover fixed costs.

5. *a. Did DMN reduce business and other financial risks?* Yes, by reducing revenue fluctuations DMN has reduced NW Natural's risk.

   b. If yes, describe the risks and estimate the reduced costs to the Company associated with the business and financial risks that were impacted. As described in Section 4.5, CFO David Anderson believes that DMN and WARM were contributing factors to NW Natural obtaining the best rating in the Standard & Poor's (S&P) business risk profile (scoring a 1 on a scale of 1 to 10). Similarly, he believes that DMN and WARM contributed to the upgrade in NW Natural's S&P bond rating from A to A+. An improved risk profile has several beneficial effects. It allows NW Natural to maintain smaller lines of credit, reduce the share of equity in its capital structure, and maintain a lower coverage ratio. However, it is difficult to quantify these effects for two reasons. First, given that a number of events occurred that are unrelated to DMN and WARM (most prominently, the completion of general rate case UG-152), it is difficult to attribute changes in risk profiles or finances to any one cause. Second, given the changes in financial markets over time, we cannot simply attribute changes in interest rates to changes in NW Natural's risk profile. That is, interest rates fluctuate throughout the economy, so a reduction in interest rates may be due entirely to effects that are independent of NW Natural's circumstances.

   c. If yes, did the Company increase its efforts and activity on non-regulated activities? According the CFO David Anderson, non-regulated activities account for only about 3% of assets, and the risk reductions afforded by DMN and WARM did not affect non-regulated activities.

d. What was the level of impact and effects on operations? In addition to the potential effects on financial measures described above, DMN contributed to organization changes that are described in Section 4.4 and in response to question 7b below.

e. Were the reduced risks shifted away from the Company to customers or a third party or eliminated? In Section 2.2, we describe how DMN affects risk for NW Natural and its customers. Four sources of uncertainty were considered: weather, natural gas prices, economic conditions, and other random factors. We summarize the effect of DMN on the risk produced by each of these sources of uncertainty below.

Weather risk is not affected by DMN because of the weather normalization of usage that is incorporated in the deferral mechanism. Uncertainty in the price of natural gas affects the amount of natural gas that customers will use. The risk that NW Natural faces with respect to gas prices is that when prices rise, customer usage levels decrease, reducing fixed cost recovery. At the same time, the price increase causes customers' bills to increase (as long as any reductions in usage are not offset by the increase in the gas price). By reducing or eliminating the risk to NW Natural associated with uncertain gas prices, this risk to customers is increased. However, the element of DMN that shifts this risk is the elasticity adjustment, over which there appears to be no dispute with respect to its appropriateness. That is, various parties' views regarding the efficacy of DMN seem to hinge on their opinion of the decoupling mechanism, not the elasticity adjustment.

In theory, DMN could shift economic risk from the utility to customers. For example, if the regional unemployment rate increases, residential customers might lower their thermostat settings in an attempt to reduce their bills. DMN insures NW Natural against lost margins associated with reduced sales from this type of action. However, our findings from an analysis of recent historical data indicate that NW Natural's residential and commercial use per customer do not appear to be sensitive to such economic conditions. Therefore, we conclude that a shift of economic risk from NW Natural to its customers does not occur in NW Natural's service territory.

f. What impact did DMN and WARM have on the need for, or cost, of new security issuances or lines of credit? As described in Section 4.5, NW Natural CFO David Anderson believes that the presence of DMN and WARM have allowed NW Natural to retain smaller lines of credit and have a lower share of equity (*i.e.*, reduced the need for new security issuances).

h. What incremental impacts have DMN and WARM had on NW Natural's bond ratings? NW Natural CFO David Anderson believes that the risk mitigating effects of DMN and WARM contributed to an increase in NW Natural's Standard & Poor's bond rating from A to A+.

i. How does NW Natural's revenue variability compare to a representative sample of LDCs before and after DMN and WARM? This issue is addressed in Section 4.2, which shows that NW Natural's revenue variability is lower than the average utility in the representative sample used. Because relatively little time has passed since DMN was put in place, we did not compare the revenue variability both before and after DMN was implemented.

6. *Did DMN affect, positively or negatively, levels of service quality or the company's incentives to provide excellent service quality?* As shown in Section 4.6, DMN does not appear to have adversely affected NW Natural's level of service quality. This is consistent with our analysis of the incentive effects associated with DMN, which indicate that DMN does not alter NW Natural's incentives to provide high quality customer service.

7. *a. What changes in company culture or operating practices resulted from the implementation of DMN?* This issue is discussed in Section 4.4. The changes that may be attributed to DMN are a shift in marketing efforts (though this may also be due to a change in Commission policy with respect to allowed costs), taking a public stance that strongly supports energy efficiency, and shifting compensation policies (by adopting specific individual incentives and moving away from commission).

   b. What organizational changes and/or Company communications to NW Natural employees resulted from the changes to company culture or operating practices? As described in Section 4.4, a number of organizational changes occurred following the implementation of DMN. While it is difficult to quantify the extent to which these changes were brought about directly by DMN, Grant Yoshihara of NW Natural estimated that about 50% of the shift of personnel from sales and promotions (which decreased from 67 FTEs in 2002 to 20.5 FTEs in 2005) to customer service (which increased from 18 FTEs in 2002 to 44 FTEs in 2005) was due to a change in philosophy that is consistent with the incentives provided by DMN.

   c. What impact, if any, did DMN and WARM have on uncollectibles, new hookups, NW Natural's line extension policy and actions specific to natural gas customers? As discussed in Section 4.7, DMN had no effect on NW Natural's pursuit of uncollectible accounts. A discussion of new connections customers and NW Natural's line extension policy is contained in Section 4.4 and in response to question 8 below.

8. *How do usage and revenues associated with new connects compare to the base usage and revenues assumed in DMN?* Section 4.4 presents the limited information that we have to answer this question. We have seen mixed evidence, indicating that residential new connections and commercial conversion customers tend to have lower usage levels than existing customers, while commercial new construction customers have higher usage than existing customers. However, a number of other factors could be affecting this analysis (*e.g.*, small sample size for commercial new connections; and changes in building codes, building materials, and appliance efficiency levels in residential housing). In addition, our review of NW Natural's methods for evaluating new connections and conversion customers revealed that DMN revenue adjustments are not included. Based on this, we conclude that NW Natural has not "gamed" the DMN mechanism with respect to new connections customers.

9. *What impacts has DMN had on customers?* As shown in Section 4.1, the first year of DMN produced almost $15 million in surcharges to customers, or about 3 percent of

total residential and commercial revenues. This relatively high amount was due to the fact that baseline usage was set at a time when prices were substantially lower, thus requiring a large first-year DMN adjustment. In its second full year, DMN produced a much lower surcharge of about $578,000, or about 0.1% of total residential and commercial revenues. Customer complaint data show that negative views of DMN were limited to objections regarding the appropriateness and/or legality of imposing Public Purposes Funding charges on customer bills. The absence of complaints regarding the DMN mechanism could be due to a low awareness of the program, which (if true) could be caused by the fact that DMN adjustments are not separately listed on customer bills.

Public Purposes Funding approved in combination with DMN has provided about $1.4 million per year in low-income bill payment assistance, $1.3 million per year in low income weatherization funds, and $6.75 million per year for energy efficiency programs (*i.e.*, Energy Trust funding). (The values listed here are based on 2004 budgeted amounts.)

6.2 Recommendations

Based on the information and input that we have received and reviewed, we recommend that some form of revenue decoupling be retained. It has been effective in reducing the variability of distribution revenues and in altering NW Natural's incentives to promote energy efficiency. While DMN does not provide an *incentive* for NW Natural to promote energy efficiency, it does remove most of the *disincentive* that exists with the standard rates.

We have been impressed by the breadth of support that DMN has received. The Energy Trust of Oregon reports that NW Natural has been successful in creating a good working relationship with the Energy Trust, and that NW Natural's efforts to promote energy efficiency effectively complement their own efforts. HVAC distributors believe that NW Natural's marketing efforts, in conjunction with its relationships with consumers, distributors, and the Energy Trust have helped increase sales of high-efficiency furnaces to the point where Oregon has the highest share of high-efficiency furnaces in the nation (as a percentage of new furnace sales). The Citizens' Utility Board of Oregon, the Northwest Energy Coalition and a number of CAP agencies believe that the Public Purposes Funding established in conjunction with DMN is beneficial for consumers. The Natural Resources Defense Council and American Gas Association released a joint statement regarding the positive environmental effects of decoupling, specifically citing NW Natural's experience as an example of the positive outcomes that decoupling can yield. The negative feedback that we have received is limited to twenty-six customer complaints that questioned the appropriateness and/or legality of the Public Purposes Funding.

In our discussions with the Commission Staff, they expressed several concerns about DMN. We summarize the concerns and our evaluation of them below.

- *Concern that DMN might shift economic risk from NW Natural to customers.* In theory, DMN could shift economic risk from NW Natural to customers. That is, if use per customer declines during economic downturns, the DMN deferral mechanism would produce a surcharge that would offset some of the bill reductions that customers would otherwise experience. We found that this concern, while valid in theory, is not likely to be relevant in practice in NW Natural's Oregon service territory. We conducted a time series analysis of residential and commercial use per customer that indicated that use per customer is strongly affected by weather and changes in energy prices, but not significantly affected by economic conditions. Therefore, we do not believe that a significant portion of deferrals can be attributed to changes in economic conditions.

- *The deferral mechanism would be unnecessary if very little of it is caused by NW Natural sponsored conservation efforts.* It is true that a very small percentage of the deferral revenues can be attributed to NW Natural sponsored conservation efforts (specifically, the residential HEF program). However, NW Natural and the Energy Trust of Oregon agree that the DMN deferral mechanism gives NW Natural the freedom to be more aggressive in its promotion of energy efficiency.

  In addition, the deferral mechanism allows for the determination of the price elasticity values to be less contentious. In DMN's current form, when an error is made in setting the price elasticity, the deferral mechanism will correct 90% of the error. Given the range of short- and long-term responses that customers can make to price changes (*e.g.*, temporarily turn down the thermostat or permanently change appliances and/or fuel sources), price elasticity values are difficult to estimate and apply with precision.

  Finally, both the Commission Staff and NW Natural agree that NW Natural should be compensated for lost margins due to energy efficiency programs. The Commission Staff has proposed replacing the deferral mechanism with a lost revenue adjustment. Section 5.3.2 contains a discussion of the reasons that lost revenue adjustments are likely to be inferior to deferral mechanisms (*i.e.*, lost revenue adjustments are administratively burdensome, produce incentives to create programs that look good on paper but perform poorly in reality, and do not compensate the utility for general conservation efforts). The deferral mechanism expands the range of conservation programs and policies that NW Natural can support without harming its shareholders. Examples programs or policies that would be less tenable with lost revenue adjustments are conservation programs that are difficult to track (such as the Energy Trust's Efficient Facility Operations Program), supporting more energy efficient building standards, or supporting pleas for conservation during an energy crisis. In addition, to the extent that successful energy efficiency campaigns spur conservation efforts outside of the program, lost revenue adjustments do not adjust for the reduction in distribution revenues while DMN will.

- *It is appropriate for NW Natural to have an incentive to grow and to fully transfer the promotion of energy efficiency promotion to the Energy Trust of Oregon.* This view is contradicted by the views of the Energy Trust and HVAC distributors, who believe that NW Natural's involvement in the promotion of energy efficiency has improved program performance. By eliminating the deferral mechanism, NW Natural's incentives would oppose those of the Energy Trust, which would endanger the relationship that they have developed.

There is one negative incentive effect that DMN provides with respect to conservation: it reduces NW Natural's incentive to promote natural gas water heater conversions for current customers because each conversion would produce a short-term revenue loss through the deferral mechanism. In addition, DMN provides a short-term incentive to bias new customer connections policies toward smaller customers. On balance, however, it appears that the combination of Public Purposes Funding and NW Natural's improvements in HEF program performance outweigh these concerns.

We believe that the positive effects of DMN outweigh the negative effects. However, there are several ways in which DMN might be improved.

1. Eliminate the 90% factor applied to the deferral adjustments. This factor introduces incentives to manipulate parameter values, reduces the positive incentive effects of DMN, and can reduce refunds to customers as well as surcharges. There do not appear to be any positive incentive effects of this factor with respect to the performance of DMN, therefore it should be removed.
2. Re-evaluate the price elasticity values agreed to in the Order. Our research indicates that the values currently used may be too low (in absolute value). The use of price elasticity values that are too low will tend to increase the amount of revenues that flow through the deferral mechanism rather than the elasticity adjustment. This delays price-related revenue adjustments until the following year and, because of the 90% factor currently used, reduces the amount of revenue that is adjusted for price changes.
3. Re-evaluate the weather sensitivity parameter (β) used in WARM and DMN. In particular, it appears that the residential class value may be too high. Based on the information that we have seen, the methods used to initially estimate β values appear to be sound, so it may be that only the data used in the estimation needs to be updated. In addition, consideration should be given to estimating a weather sensitivity parameter expressed in units of *percentage* changes in use per HDD rather than *levels* of use, or customer-specific parameters.
4. Consider adopting full decoupling. Because of its simplicity, full decoupling would be easier for customers to understand than the combination of DMN and WARM. In addition, full decoupling does not have some of the gaming incentives present in DMN (which could also be eliminated by removing the 90% factor applied to deferral calculations). However, because full decoupling encompasses the effects of both DMN and WARM (because full decoupling does not weather normalize usage), a decision on this matter should be delayed until a more complete analysis of WARM has been conducted. In particular, customers may prefer the fact that WARM provides adjustments to current bills, whereas

weather-related revenue adjustments are deferred until the following year under full decoupling.

Appendix Table A1
Revenue Variability Data for the Comparison Sample of Utilities

		Residential			Commercial					
				Revenues			Revenues			
Utility	**Year**	**# Accounts**	**Sales**	**($000)**	**# Accounts**	**Sales**	**($000)**	**HDD**	**# Accounts**	**Sales Units**
AGL	1993	1,182,700	100,140	658,200	95,700	47,850	268,100	2,852	Avg	MDth
AGL	1994	1,215,200	100,310	700,700	98,000	47,890	285,800	2,565	Avg	MDth
AGL	1995	1,250,400	91,680	610,600	100,000	45,400	243,200	2,121	Avg	MDth
AGL	1996	1,289,400	116,540	708,800	102,500	53,820	288,800	3,191	Avg	MDth
AGL	1997	1,319,000	98,610	728,500	104,500	45,550	290,900	2,402	Avg	MDth
Atmos	1993	789,360	74,818	372,770	86,124	36,307	165,611	4,080	Yr end	MMcf
Atmos	1994	825,310	72,561	375,450	93,250	35,250	165,883	3,855	Yr end	MMcf
Atmos	1995	834,376	69,666	337,768	90,093	34,921	150,949	3,706	Yr end	MMcf
Atmos	1996	860,229	77,001	409,039	91,960	38,247	186,032	4,043	Yr end	MMcf
Atmos	1997	870,747	75,215	452,864	92,703	37,382	193,302	3,909	Yr end	MMcf
Atmos	1998	889,074	73,472	410,538	94,302	36,083	184,046	3,799	Yr end	MMcf
Atmos	1999	919,012	67,128	349,691	98,268	31,457	144,836	3,374	Yr end	MMcf
Atmos	2000	970,873	63,285	405,552	140,019	30,707	176,712	2,096	Yr end	MMcf
Atmos	2001	1,243,625	79,000	788,902	122,274	36,922	342,945	4,124	Yr end	MMcf
Atmos	2002	1,247,247	77,386	535,981	122,156	35,796	221,728	3,368	Yr end	MMcf
Atmos	2003	1,498,586	97,953	873,375	151,008	45,611	367,961	3,473	Yr end	MMcf
Atmos	2004	1,506,777	92,208	923,773	151,381	44,226	400,704	3,271	Yr end	MMcf
Cascade	1994	112,533	8,391	47,011	21,835	9,570	50,116	5,301	Yr end	MDth
Cascade	1995	120,096	9,352	56,816	22,797	10,115	58,145	5,607	Yr end	MDth
Cascade	1996	127,794	10,178	62,076	23,827	10,343	59,402	5,620	Yr end	MDth
Cascade	1997	135,126	11,014	65,324	24,591	10,731	55,132	5,525	Yr end	MDth
Cascade	1998	142,645	10,645	65,926	25,415	9,988	52,735	5,031	Yr end	MDth
Cascade	1999	150,296	11,991	77,925	26,305	10,696	59,548	5,535	Yr end	MDth
Cascade	2000	157,443	12,185	85,728	27,151	10,672	65,294	5,372	Yr end	MDth
Cascade	2001	162,568	12,678	115,974	27,491	11,182	92,099	5,793	Yr end	MDth
Cascade	2002	169,476	12,921	130,582	28,098	10,728	98,195	5,455	Yr end	MDth
Cascade	2003	176,986	12,262	121,026	28,615	10,019	89,136	5,042	Yr end	MDth
Cascade	2004	184,315	13,127	130,727	29,009	10,649	95,629	5,212	Yr end	MDth
Energen	1997	423,130	29,008	243,876	34,432	12,976	91,517		Avg	MMcf
Energen	1998	423,758	27,925	224,934	34,719	12,664	82,520		Avg	MMcf
Energen	1999	427,159	26,001	218,638	35,137	12,049	80,802		Avg	MMcf
Energen	2000	430,069	27,369	256,591	35,586	12,629	99,356		Avg	MMcf
Energen	2001	427,584	28,962	353,358	35,778	12,909	139,046		Avg	MMcf
Energen	2002	425,630	26,358	277,088	35,601	11,838	104,247		Avg	MMcf
Energen	2003	427,413	27,248	320,938	35,463	12,564	126,638		Avg	MMcf
Laclede	1993	555,467	61,906	348,494	36,514	29,321	136,462	4,838	Yr end	MDth
Laclede	1994	559,225	61,086	363,058	36,684	28,917	142,042	4,694	Yr end	MDth
Laclede	1995	566,421	54,178	302,770	37,409	25,691	109,270	4,005	Yr end	MDth
Laclede	1996	569,818	64,237	376,818	37,735	30,948	145,466	4,880	Yr end	MDth
Laclede	1997	572,794	60,633	395,250	37,985	29,622	152,222	4,953	Yr end	MDth
Laclede	1998	577,224	56,073	365,768	38,519	25,921	132,504	4,404	Yr end	MDth
Laclede	1999	582,719	53,092	324,115	39,041	24,514	112,890	4,140	Yr end	MDth
Laclede	2000	586,783	49,549	346,159	39,419	22,831	123,578	3,933	Yr end	MDth
Laclede	2001	584,269	60,784	619,090	39,264	28,044	250,741	5,102	Yr end	MDth
Laclede	2002	588,630	50,216	387,594	39,842	24,053	142,259	3,959	Yr end	MDth
Laclede	2003	590,785	57,719	502,071	40,166	25,653	188,688	4,803	Yr end	MDth
Laclede	2004	591,547	52,490	543,996	40,417	22,914	202,183	4,102	Yr end	MDth
Nicor	1997	1,710,000	233,200	1,126,000	161,700	65,200	314,800	6,254	Yr end	MMcf
Nicor	1998	1,737,600	192,400	813,600	163,800	44,300	189,400	4,834	Yr end	MMcf
Nicor	1999	1,769,200	209,000	899,800	166,100	39,800	172,300	5,272	Yr end	MMcf
Nicor	2000	1,799,100	219,000	1,353,900	167,600	38,400	236,000	5,717	Yr end	MMcf
Nicor	2001	1,824,600	201,500	1,486,400	168,700	37,200	274,600	5,422	Yr end	MMcf
Nicor	2002	1,860,400	212,900	1,057,400	171,300	41,600	209,400	5,779	Yr end	MMcf
Nicor	2003	1,890,300	214,900	1,611,900	172,800	46,700	351,700	6,068	Yr end	MMcf
NW Natural	1993	329,157	26,782	168,217	42,657	20,964	103,476	4,452	Yr end	MDth
NW Natural	1994	346,950	26,022	176,510	44,078	20,193	108,452	4,020	Yr end	MDth

Appendix Table A1
Revenue Variability Data for the Comparison Sample of Utilities

NW Natural	1995	363,903	25,646	165,662	45,402	19,672	99,079	3,779	Yr end	MDth
NW Natural	1996	385,213	30,631	183,802	47,309	22,512	104,582	4,427	Yr end	MDth
NW Natural	1997	407,061	30,636	177,835	50,315	22,525	100,677	4,092	Yr end	MDth
NW Natural	1998	425,606	31,569	205,388	51,159	22,912	117,889	4,011	Yr end	MDth
NW Natural	1999	447,659	35,297	242,952	52,870	25,238	139,425	4,256	Yr end	MDth
NW Natural	2000	468,087	35,638	280,642	54,684	25,038	159,660	4,418	Yr end	MDth
NW Natural	2001	485,207	35,007	329,905	55,096	24,229	190,236	4,325	Yr end	MDth
NW Natural	2002	503,402	35,709	354,735	56,087	24,016	201,475	4,232	Yr end	MDth
NW Natural	2003	519,427	34,353	328,464	57,969	22,626	176,385	3,952	Yr end	MDth
Peoples	1993	904,316	144,199	929,407	50,736	26,185	156,377	6,679	Avg	MDth
Peoples	1994	905,461	142,876	951,037	50,955	26,206	160,912	6,701	Avg	MDth
Peoples	1995	906,881	130,571	752,796	50,872	22,079	116,113	5,897	Avg	MDth
Peoples	1996	910,236	154,128	883,100	50,719	27,390	141,594	7,080	Avg	MDth
Peoples	1997	910,657	142,837	941,557	50,914	24,994	146,412	6,806	Avg	MDth
Peoples	1998	908,025	119,206	780,188	46,639	19,501	112,166	5,564	Avg	MDth
Peoples	1999	911,782	117,840	727,095	44,382	17,411	95,530	5,646	Avg	MDth
Peoples	2000	919,196	117,814	836,761	48,540	18,974	122,350	5,650	Avg	MDth
Peoples	2001	931,151	127,536	1,439,364	46,160	19,350	204,629	6,713	Avg	MDth
Peoples	2002		113,322	794,865		17,345	109,307	5,639		MDth
Peoples	2003		128,521	1,155,927		21,555	178,845	6,684		MDth
Peoples	2004		116,939	1,148,499		20,303	184,756	6,091		MDth
Piedmont	1993	396,394	34,277	221,632	54,451	28,179	154,894	3,659	Avg	MDth
Piedmont	1994	420,861	36,093	240,314	56,147	28,931	165,805	3,567	Avg	MDth
Piedmont	1995	446,118	33,513	229,546	57,803	22,867	135,933	3,144	Avg	MDth
Piedmont	1996	468,803	43,357	292,010	59,905	31,040	180,415	3,993	Avg	MDth
Piedmont	1997	495,739	38,339	319,722	62,258	28,476	195,862	3,471	Avg	MDth
Piedmont	1998	522,451	41,142	323,777	63,878	28,528	189,341	3,339	Avg	MDth
Piedmont	1999	549,610	38,111	295,108	66,409	26,668	168,731	3,124	Avg	MDth
Piedmont	2000	577,314	40,520	343,476	68,879	29,315	207,087	3,097	Avg	MDth
Piedmont	2001	601,682	47,869	525,650	71,069	31,002	299,672	3,821	Avg	MDth
Piedmont	2002	620,642	40,047	358,027	72,323	25,892	191,988	3,004	Avg	MDth
Piedmont	2003	657,965	52,603	524,933	75,924	33,648	299,281	3,643	Avg	MDth
Piedmont	2004	771,037	54,412	624,487	90,328	35,483	360,355	3,331	Avg	MDth
SEMCO	1993		23,302	122,216		12,608	61,379	7,053		MMcf
SEMCO	1994		23,437	121,066		12,469	59,413	6,861		MMcf
SEMCO	1995		24,676	115,242		12,738	54,763	7,158		MMcf
SEMCO	1996		26,703	138,644		13,670	65,509	7,099		MMcf
SEMCO	1997		25,968	139,538		13,483	66,577	6,838		MMcf
SEMCO	1998		21,946	118,220		8,840	42,041	5,566		MMcf
SEMCO	1999		28,583	137,407		8,882	38,451	6,650		MMcf
SEMCO	2000		41,397	190,221		14,591	62,354	7,293		MMcf
SEMCO	2001		41,529	201,754		16,032	73,831	7,038		MMcf
SEMCO	2002		42,671	227,086		16,970	84,480	7,394		MMcf
Southwestern	1999		55,451			26,603		1,928		MDth
Southwestern	2000		57,138			27,267		1,938		MDth
Southwestern	2001		58,994			27,997		1,963		MDth
Southwestern	2002		58,822			28,027		1,912		MDth
Southwestern	2003		59,305			27,915		1,772		MDth
WGL	1995		59,650			40,318		3,660		MDth
WGL	1996	711,837	73,960	551,943	59,603	47,365	303,011	4,570	Yr end	MDth
WGL	1997	736,513	66,545	574,590	61,400	42,683	307,769	3,876	Yr end	MDth
WGL	1998	756,682	61,579	514,713	62,210	34,581	245,572	3,662	Yr end	MDth
WGL	1999	782,648	60,416	487,869	62,919	28,535	195,592	3,652	Yr end	MDth
WGL	2000	810,855	55,783	477,185	64,169	24,024	181,674	3,637	Yr end	MDth
WGL	2001	837,993	63,495	756,709	65,031	25,855	272,849	4,314	Yr end	MDth
WGL	2002	872,362	50,924	517,798	66,168	19,392	163,235	3,304	Yr end	MDth
WGL	2003	892,382	64,881	737,264	66,804	23,963	239,907	4,550	Yr end	MDth
WGL	2004	921,767	62,973	792,999	67,564	22,641	245,242	4,024	Yr end	MDth

Appendix 2: Summary of the Review of the Decoupling Methodology by Gary C. Hill

September 14, 2004

Mr. Alex Miller
NW Natural
220 NW Second Avenue
Portland, Oregon 97209

Dear Alex

Subject: Review of NW Natural Decoupling Methodology

I have completed my review of the methodology for determining NW Natural's decoupling adjustment which provides for residential and commercial margins based on a baseline amount of volume. I have reviewed the overall methodology as well as the model, which is the basis for determining the baseline usage that is required for the monthly decoupling journal entry

To complete the review of the overall methodology, Company documents were reviewed that summarized the process employed for calculating the adjustment. These included the following summaries: NW Natural Decoupling Methodology, NW Natural Decoupling Mechanism – Development of Commercial Baseline Usage and Development of Residential Baseline Usage. Supporting documents were reviewed to provide background and validate that the actual model corresponded to the decoupling methodology as described. These documents included the Oregon PUC Order No. 02-634, Monthly JV 35, rate schedules 190 and 195 plus the derivation of margin change due to elasticity. The reclassification of customers from residential to commercial, and between commercial and industrial increased the complexity of the calculations of the baseline usage. Testing components of the baseline model provided a comprehensive understanding of the implications of customer reclassificat ion, adjustments for UG 152 volumes, weather normalization and elasticity. I believe that the overall approach employed to implement the decoupling mechanism is accomplishing what was intended.

The second portion of the review focused on testing the model, assuring the formulas were correct and that the appropriate documentation was included. The attached addendum provides a summary of the components of the model that were tested and some areas including source data that I did not validate. Overall, the model tested fine and tracked with the described methodology in the Company's documentation.

Sincerely,

Gary C. Hill
Consultant

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 370

370. Please discuss NW Natural's position on the purpose and performance of the Company's partial decoupling mechanism from its inception, to date. Provide any studies in Company's possession assessing or analyzing the performance and/or merits of the partial decoupling mechanism adopted in any state NW Natural provides retail service.

a. Please summarize the effects of the UG 435 initial filing on the Company's decoupling mechanism or collections, include, at minimum, baseline use-per-customer, by Schedule.

Response:

The Company believes the Decoupling mechanism has performed as intended since its inception. The mechanism has allowed the Company to endorse energy efficiency programs that have reduced customer demand over time, because that reduction has been mitigated by the mechanism. Please see UG 435 OPUC DR 370 Attachment 1 for a study that was conducted in 2005 as a provision in the Commission order authorizing decoupling.

a. The UG 435 filing, as described in NW Natural/1300, Walker/Page 10, proposes heating degree days, coefficients and use per customer amounts that get used in the Decoupling calculation. UG 435 – Exhibit 1304 includes the Decoupling usage baselines and coefficients.

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 372

372. Please provide the number of total customers, by Schedule, currently enrolled in WARM and the percentage of total eligible customers within the same Schedule, enrollments represent.

Response:

Rate Schedule	# of Accounts	# opt out	# enrolled (%)
02R	630107	46591	583516 (92.6%)
03R	1514	154	1360 (89.8%)
03C	57477	4545	52932 (92.1%)
Total	689098	51290	637808 (92.6%)

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 373

373. Please describe annual opt-in and opt-out activity in WARM for the years 2012-2021, inclusive.

Response:

The annual opt-in opt-out process automatically opts new customers into the program. If a customer elects to opt-out, their election is rolled over every year until such time that customer may choose to elect back into the WARM program. WARM election changes for active customers must happen before September 30th every year. New customers may opt out of WARM during the heating season within 30 days of receiving their Welcome Packet.

For the annual amount of opt-outs and opt-ins (excluding new customer opt-ins):

	Opted Out	Opted In
2012	5478	196
2013	2014	151
2014	1783	187
2015	7215	242
2016	6169	168
2017	1995	235
2018	2506	145
2019	2450	208
2020	2449	188
2021	2028	133

Total customers opted out of WARM by year and rate schedule:

Row Labels	02R	03C	03R
2012	56139	4262	127
2013	55443	4196	129
2014	53818	4115	128
2015	55931	5798	179
2016	57102	6840	195
2017	55279	6400	189
2018	54292	5953	187
2019	53184	5623	180
2020	52298	5297	174
2021	50841	5049	165

Total Customers opted in WARM by year and rate schedule:

Year	02R	03C	03R
2012	505930	52119	1442
2013	512102	52528	1413
2014	520241	52916	1341
2015	525591	51522	1295
2016	532359	50435	1282
2017	543315	51254	1290
2018	552715	52137	1303
2019	562566	52925	1300
2020	572569	53315	1302
2021	581732	53581	1362

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 375

375. Please:
a. Discuss NW Natural's position on the purpose of WARM and recent performance of the Company's WARM program since the Commission's review of the WARM program.
b. Provide any studies in Company's possession assessing or analyzing the performance and/or merits of the program adopted in any state NW Natural provides retail service.
c. Please summarize the effects of the UG 435 initial filing on the Company's WARM program, if any.

Response:

a. As described in item 3 of the stipulation approved in UM 1750, "WARM is designed "to recognize the need to separately identify and collect the revenues to cover the fixed costs from the revenues which cover truly usage-related costs, and to do so in a way that immediately benefits both customers and the Company." During the "WARM Period" (December 1 through May 15), WARM adjusts the rate per therm higher or lower depending on the winter weather, In colder than normal winters, WARM will lower a customer's bill to the extent the Company would have over-recovered fixed costs from the customer's increased gas usage as a result of the below-normal temperatures. In warmer than normal winters, WARM will increase a customer's bill to the extent the Company would have under-recovered its fixed costs from the customer's decreased gas usage as a result of the above-normal temperatures. WARM operates as a real-time bill adjustment during the WARM period."

   The Company considers the performance of the mechanism as fully appropriate given its intent.

b. Please see UG 435 OPUC DR 370 Attachment 1.

c. The UG 435 filing, as described in NW Natural/1300, Walker/Page 10, proposes heating degree days and coefficients that are used in the WARM calculation. UG 435 – Exhibit 1304 includes the WARM coefficients. Heating degree days from UG 435 – Exh. 1400 – WP1 – OR Normal Weather Model are proposed to be used for normal weather within the mechanism. These components used in the WARM mechanism ensure that WARM adjustments are calculated consistent with parameters approved in the rate case.

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Request No.: UG 435 OPUC DR 382

382. Please describe NW Natural's data collection efforts related to Oregon low-income customer metrics. At a minimum please provide the A) source and B) level of detail collected for:

a. Demographics;
b. Income level;
c. Dwelling type;
d. Household size;
e. Percentage of residential customers compared to total residential customers; and
f. Federal and state programs available to low-income customers and percentage of eligible customers participating in the programs.

Response:

NW Natural does not collect demographic information or any of the type of information indicated in this request for any of its customers. This data is not required for customer eligibility and is not required for utility service. NW Natural works with community action agencies that administer low-income programs such as LIHEAP, OLGA, OLIEE and GAP. These agencies work with customers to income-qualify for these programs.

NW Natural is in the process of developing a low-income needs assessment performed by a third-party to gain insight on the requested information in this data request.

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Request No.: UG 435 OPUC DR 383

383. Please describe current efforts to alleviate energy burden within the Company's service territory. Please include, where applicable:

a. Annual budgeted and actual amounts spent each year between 2012 and the test year 2023;
b. Funding source;
c. Actual and forecasted participation levels; and
d. Implications of the UG 435 proposal, as initially filed.

Response:

For decades, NW Natural has provided assistance to customers to ease energy burden through its low-income bill assistance program known as OLGA (Oregon Low-income Gas Assistance program), its low-income weatherization program known as OLIEE (Oregon Low-Income Energy Efficiency program), and its supplemental low-income assistance program known as GAP (Gas Assistance Program). These programs complement and are in addition to federal funding available through LIHEAP. NW Natural works with local CAP agencies to distribute these funds to income-qualified customers to alleviate their energy burden.

The Company is currently working on a bill discount program that will be previewed with stakeholders in March 2022 and filed in April 2022, with an effective date of November 1, 2022.

In addition, the Company is working with a third-party consultant to conduct a low-income needs assessment (LINA) study that will be completed in July 2022. NW Natural intends to use the learnings from the LINA along with the outcomes of the OPUC's investigation in docket UM 2211 to inform the development of future low-income programs to alleviate the energy burden of our customers.

a. The following tables illustrate the history of OLGA, OLIEE, GAP and LIHEAP funds:

OLGA – per reporting in docket RG 10: OLGA funds are Oregon-only.

	Number of Customers served	Average Payment per Household	Payments To Customers	Payments To Agencies
2002-2003	2,965	$265	$624,621	$114,919
2003-2004	4,996	$283	$1,323,802	$193,732
2004-2005	4,937	$309	$1,526,624	$262,478
2005-2006	3,996	$294	$1,176,224	$235,403
2006-2007	5,112	$325	$1,661,027	$332,205
2007-2008	5,345	$326	$1,743,530	$348,706
2008-2009	7,430	$365	$2,710,703	$542,141
2009-2010	6,007	$343	$2,059,555	$411,911
2010-2011	6,383	$342	$2,184,263	$436,853
2011-2012	5,087	$352	$1,788,657	$357,731
2012-2013	7,007	$342	$2,398,786	$479,757
2013-2014	7,379	$314	$2,315,379	$463,076
2014-2015	7,327	$300	$2,198,592	$439,718
2015-2016	7,558	$289	$2,182,788	$436,558
2016-2017	7,559	$327	$2,468,460	$493,692
2017-2018	7,436	$316	$2,353,326	$470,665
2018-2019	7,685	$297	$2,285,498	$457,100
2019-2020	5,942	$414	$2,459,130	$491,826
2020-2021	5,044	$445	$2,243,670	$448,734
Program Total	115,195	$327	$37,704,635	$7,417,205

OLIEE – per reporting in docket RG 13: OLIEE funds are Oregon-only.

	Homes weatherized (Target)	Homes weatherized (Actual)	Reimbursed Measure Costs	Reimbursed Health, Safety and Repairs	Estimated therms saved
2012-2013	213 to 328	151	$442,326	$63,257	36,995
2013-2014	253 to 358	201	$664,069	$80,537	46,756
2014-2015	208 to 334	198	$791,611	$85,928	45,876
2015-2016	238 to 351	231	$1,246,030	$193,184	52,817
2016-2017	300	260	$1,521,200	$237,019	59,232
2017-2018	320	299	$1,935,009	$289,364	103,708
2018-2019	300	260	$1,567,192	$242,617	73,441
2019-2020	306	248	$1,595,651	$185,938	68,320
2020-2021	545	341	$1,561,476	$156,805	60,394
Totals		2,189	$11,324,564	$1,534,649	547,539

GAP

Since 1982, more than $6.6 million in GAP funds have been donated and distributed to assist customers in need. History back to the 2002-2003 program year is included below. Amounts are total Company amounts.

GAP				
	Number of Customers served	Average Payment per Household	Payments To Customers	Payments To Agencies
2002-2003	1,231	$117.45	$144,583.00	$7,229.15
2003-2004	1,210	$120.24	$145,487.00	$7,274.35
2004-2005	1,368	$120.89	$165,375.00	$8,268.75
2005-2006	1,056	$123.11	$130,000.00	$6,500.00
2006-2007	1,359	$121.25	$164,775.00	$8,238.75
2007-2008	1,655	$120.85	$200,000.00	$10,000.00
2008-2009	1,658	$120.64	$200,014.00	$10,000.70
2009-2010	1,292	$116.11	$150,016.96	$7,500.85
2010-2011	1,251	$120.14	$150,300.00	$7,515.00
2011-2012	1,178	$115.82	$136,433.00	$6,821.65
2012-2013	1,137	$110.08	$125,164.00	$6,258.20
2013-2014	1,099	$122.84	$135,000.00	$6,750.00
2014-2015	1,343	$111.37	$149,574.00	$7,478.70
2015-2016	1,177	$116.21	$136,783.00	$6,839.15
2016-2017	1,411	$112.37	$158,554.00	$7,927.70
2017-2018	1,294	$112.80	$145,969.00	$7,298.45
2018-2019	1,366	$109.20	$149,174.00	$7,458.70
2019-2020	1,091	$116.03	$126,584.00	$6,329.20
2020-2021	1,135	$107.51	$122,029.00	$6,101.45
	24,311	$116.65	$2,835,814.96	$141,790.75

LIHEAP – Amounts are Oregon amounts.

LIIHEAP			
OREGON	Number of Customers served	Average Payment per Household	Payments To Customers
2002-2003	6,692	$191.16	$1,279,223.00
2003-2004	5,898	$179.65	$1,059,588.69
2004-2005	6,740	$188.03	$1,267,312.87
2005-2006	7,407	$202.55	$1,500,263.89
2006-2007	6,973	$200.90	$1,400,868.50
2007-2008	7,410	$198.13	$1,468,172.50
2008-2009	13,148	$222.41	$2,924,214.14
2009-2010	11,835	$234.72	$2,777,902.99
2010-2011	9,293	$233.18	$2,166,971.42
2011-2012	8,022	$235.24	$1,887,097.65
2012-2013	5,960	$211.44	$1,260,155.91
2013-2014	5,027	$202.74	$1,019,167.80
2014-2015	3,742	$203.30	$760,731.42
2015-2016	3,420	$235.10	$804,025.83
2016-2017	3,134	$260.07	$815,056.89
2017-2018	2,669	$254.06	$678,077.25
2018-2019	1,789	$229.67	$410,879.00
2019-2020	2,129	$323.43	$688,589.55
2020-2021	2,337	$404.85	$946,144.94
TOTALS:	113,625	$221.03	$25,114,444.24

b. Both OLGA and OLIEE are funded through public purpose charges as indicated in our tariff rate Schedule 301. LIHEAP is funded by federal funds, as allocated to the Oregon Housing and Community Services department, which uses local community action agencies to administer the program.

GAP is funded by NW Natural shareholders, employees, retirees and customers. The first $60,000 in donations are matched by NW Natural shareholders each program year. In addition, GAP occasionally receives grants/donations from organizations such as the Meyer Memorial Trust and The Community Foundation for Southwest Washington. Each year NW Natural includes GAP fundraising messages through a press release, bill insert and promo message, social media campaign, and Comfort Zone newsletter at the start of the heating season and through February for customers and NW Natural employees and retirees to voluntarily contribute to GAP. NW Natural has also staffed GAP information booths at community events to raise funds and awareness for GAP – this has included holiday events at Bridgeport Village, Pioneer Square and Oregon Garden's Rediscovery Forest. We hope to resume similar GAP information booths as post-pandemic conditions allow.

c. Please see the tables in section a above. NW Natural does not forecast expected OLGA participation. Any funds that remain after the collection of the OLGA public purpose charges are rolled forward for the next program year.

d. NW Natural has not proposed a program to address energy burden in UG 435. The Company's upcoming bill discount program, as well as any future programs addressing energy burden will be complementary to the programs listed above. As mentioned above, NW Natural intends to use the learnings from the LINA along with the outcomes of the OPUC's investigation in docket UM 2211 to inform the development of future low-income programs – which may include consideration of changes to NW Natural's existing programs.

Attachment B – RFP LINA

Statement of Work

Scope of Work

Goals: Compile relevant data and perform and summarize analyses to inform the low-income programs to serve NWN's low-income customers in both Oregon and Washington**.**

Deliverables: Draft a detailed project plan and report representing analysis, research background approach, findings, recommendations, and documentation of research approach that will be distributed to the Company and other stakeholders.

Target Study Completion Date: April 28, 2022

The study will need to include the following:

Eligibility/Participation:

- Determine eligibility threshold for NWN service territory:
  - # of eligible households for an energy assistance (EA) [1] by census block, zip code or another appropriate geographic identifier.
- Energy burden (percent of income spend on energy services) by NWN customers
  - Analysis on total household energy burden for fuel types (oil, wood, propane, electric, gas, etc.)
  - How many customers had late payments in the last 5 years (2015-2020)[2]? How many re-occurring late payments did these customers have?
  - Analysis by home type (house, apartment, multi-family, subsidized, etc.)
  - Analysis of volumetric usage (therms) by income level
- Historical program participation
  - How many customers have received energy assistance for home energy costs in the last 5 years (2015 – 2020)[3]? How much (in $) assistance did each customer receive?
  - Geographical location of program participants by census block, zip code or other appropriate geographic identifier
- Identify how many customers are eligible[4] for energy assistance in the last 5 years (2015-2020)[5]?
  - Determine how to reach customers who have not historically received EA

[1] Energy Assistance programs for NWN customers consist of the following: Oregon Customers - Low Income Home Energy Assistance Program (LIHEAP), Oregon Low-Income Gas Assistance (OLGA), Gas Assistance Plan (GAP) Washington Customers - Low Income Home Energy Assistance Program (LIHEAP), Gas Residential Energy Assistance Tariff (GREAT), Gas Assistance Plan (GAP).
[2] Include 2021 data if available
[3] Include 2021 data if available
[4] Eligibility is defined by each energy assistance program
[5] Include 2021 data if available

  - Identify barriers to program participation
  - Identify the characteristics of these communities (see list below)
- All findings must be presented on a state-by-state basis (i.e. Oregon and Washington) with further breakdown, if possible (counties, zip codes, communities, etc.) within NW Natural's service territory[6]

Penetration Rate:

- Identify the current energy assistant program penetration[7] rates in each region
- Identify any differences in program penetration by customer segment
  - Segment including, but not limited to: income, location, race, primary language, cultural group, percent children and elderly population, age, renter (vs. owner), housing type[8], etc.
- Identify the number of customers that were at risk of disconnection due to nonpayment in the last 5 years (2015-2020)[9].
- Analyze and present results that may predict which customers are likely to be experiencing hardship or need emergency energy assistance to prevent disconnection[10]
- All findings must be presented on a state-by-state basis (i.e. Oregon and Washington)

Characteristics of Communities:

- Characteristics of underserved communities[11]
- Geospatial mapping (heat map) of underserved communities, by state, with further breakdown, if possible (counties, zip codes, communities, etc.) including:
  - Income Strata
  - Ability to pay index – Federal Poverty Level[12] (FPL) segmented by (0-400%), (0-300%), (0-200%), (0-150%), (0-125%)
  - Area Median Income (AMI)[13] segmented by low income (80% AMI), very low income (50% AMI) and extremely low income (30% AMI)

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[6] NWN's service territory includes the following **counties: Oregon** – Benton, Clackamas, Clatsop, Columbia, Coos Bay, Hood River, Lane, Lincoln, Linn, Marion/Polk, Multnomah, Sherman/Wasco, Washington and Yamhill; **Washington** – Clark and Klickitat-Skamania

[7] The **penetration rate** is defined as the number of program participants (i.e., low-income energy assistance recipient households) to the eligible households

[8] **Housing Types** can be single family homes, multi-housing homes, apartment complexes, etc.

[9] Include 2021 data if available

[10] **Disconnection of Service** is defined as the cessation of gas service to a Customer where action is taken by Company to physically shut-off service at the meter, cut service at the curb, or other action that causes the Distribution Facilities that serve a Customer to become inactive

[11] **Underserved communities** consist of an area or community lacking an adequate level or quality of services.

[12] The **Federal Poverty Level** is a measure of income issued every year by the Department of Health and Human Services. The poverty levels are economic measures used to determine an individual's eligibility for certain federal benefits and programs.

[13] **Area Median Income** is the midpoint of a region's income distribution, AMI was created by the U.S. Department of Housing and Urban Development (HUD) to determine the eligibility of persons for federal housing programs

- Household demographics (number of individuals in home, age, household member, primary language, race, cultural group, percent children and elderly population, employment status, presence of disabilities, dwelling etc.)
- Fuel expenditures (oil, wood, propane, electric, gas, etc.)
- Energy burden (percent of income spend on energy services)
- Median income
- Housing structure type (house, apartment, multi-family, etc.) including rental versus owned
- Participation in other assistance programs such as Temporary Assistance to Needy Families (TANF), Supplemental Nutrition Assistance Program (SNAP), Women Infant and Children (WIC), etc.

Housing:

- Identify the numbers of homes rented, owned and subsidized
- Identify the number of customers who experience a housing/rent burden[14].
- What is the energy efficiency potential for income qualified homes
  - Identify the types of energy efficient appliances the home has (ex. Gas space heating, etc.)
  - What is the efficiency ratings of these appliances? Has the home been previously weatherized? If so, by whom?
- Identify the number of housing units by vintage, housing type and fuel type

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[14] **Housing/rent burden** is defined by the U.S. Department of Housing and Urban Development (HUB) as spending more than 30 percent of income on housing and 'severely rent burdened' as more than 50 percent.

NWN Response to OPUC DR 389
Attachment 1

is filed in electronic format

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Rates & Regulatory Affairs
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Data Request Response

Request No.: UG 435 OPUC DR 397

397. Please:

a. Describe and provide comparative tables and work papers for Rate Spread methodology if the proposed incremental revenue requirement (RR) of $73.5 million were to be reduced by 10 percent. :

b. Further, please address how a reduction in the RR would change the incremental margin caps and floors, and rate design overall.

Response:

a. Please refer to UG 435 OPUC DR 397 Attachment 1, which provides an updated version of the Company's filed workpaper, *UG 435 - Exh. 1402 - WP1 - Rate Spread Proposal Methodology*, assuming a scenario where the proposed incremental revenue requirement is reduced by 10 percent to roughly $66.1 million. The rate spread associated with this scenario is presented in the tab, "OPUC DR 397 Scenario," the Company's proposed rate spread is shown in tab, "UG 435 Proposed Filed," and a comparison between the two is presented in tab, "Delta."

b. For this exercise, the Company assumed that the revenue requirement reduction would be associated with a proportional decrease in total rate base across the functional categories: General, Services, Distribution, Transmission, and Storage. This resulted in little movement of each rate schedule's parity ratio at present rates, as shown in the "Delta" tab, because rate base was reduced for every schedule at roughly the same overall proportion that makes up the parity ratios under the filed revenue requirement. Therefore, the Company does not adjust the overall rate design or the caps and floors that apply to Steps 1 through 3 of the methodology.

   Note, however, that the small changes in the parity ratios do impact the relative ratio of parities between the Large Commercial Sales and Industrial / Transportation rate classes. This causes a change in the adjusted floor from 0.45 to 0.44 which impacts how rates are spread in Steps 4 and 5 of the methodology: about $60 thousand less is applied to Large Commercial Sales schedules while the same amount is applied to the Industrial / Transportation rate class compared to the Company's filed proposal, as shown on the "Delta" tab.

NWN Response to OPUC DR 397
Attachment 1

is filed in electronic format

NWN Response to OPUC DR 454
Attachment 1

is filed in electronic format

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Rates & Regulatory Affairs
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Request No.: UG 435 OPUC DR 457

457. Please describe how the Company's rate spread would differ from the proposed rate spread under the following circumstances: a) the Commission authorizes 50 percent of the requested rate increase; b) the Commission authorizes 25 percent of the requested rate increase.

Response:

For responses to parts (a) and (b) below, the Company used the same methodology as explained in its response to UG 435 OPUC DR 397. For the same reasons explained in that DR 397 response, for the scenarios below the Company does not adjust the overall rate design or the caps and floors that apply to Steps 1 through 3 of the methodology.

a. Please refer to UG 435 OPUC DR 457 Attachment 1. This scenario ("Scenario A") causes a change in the filed adjusted floor of 0.44 to 0.47 which impacts how rates are spread in Steps 4 and 5 of the methodology. Using the filed adjusted floor of 0.44, about $134 thousand less would be applied to the Industrial / Transportation rate class and instead apportioned to the Large Commercial Sales schedules; however, applying a consistent methodology as filed to produce the new adjusted floor of 0.47, Scenario A produces a higher adjusted floor where roughly $57 thousand less would be applied to the Industrial / Transportation rate class.

b. Please refer to UG 435 OPUC DR 457 Attachment 2. This scenario ("Scenario B") causes a change in the filed adjusted floor of 0.44 to 0.49 which impacts how rates are spread in Steps 4 and 5 of the methodology. Using the filed adjusted floor of 0.44, about $67 thousand less would be applied to the Industrial / Transportation rate class and instead apportioned to the Large Commercial Sales schedules; however, applying a consistent methodology as filed to produce the new adjusted floor of 0.49, Scenario B produces a higher adjusted floor where roughly $14 thousand less would be applied to the Industrial / Transportation rate class.

NWN Response to OPUC DR 457
Attachments 1 and 2

are filed in electronic format

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Request No.: UG 435 OPUC DR 458

458. Please provide a table showing both the number of customers enrolled in interruptible service and the, date and number of interruptions per annum by (interruptible) schedule between 2016 and 2021, inclusive. Are the interruptions controlled by the Company or the customer? If it is the latter, by customer, provide the number of requested interruptions and the number of instances service was actually curtailed.

Response:

Interruptions are generally controlled by the Company.

Oregon Annual Interruptible Customer Curtailment Data (2016-2021)											
YEAR	Total Interruptible Customers	Interruptible Sales Customers	Interruptible Transportation Customers	Number of Interruptible Sales Customers Curtailed	Interruptible Transportation Customers Curtailed	Curtailment Event 1 Dates	Curtailment Event 2 Dates	Curtailment Event 3 Dates	Curtailment Event 4 Dates	Curtailment Event 5 Dates	Curtailment Event 6 Dates
2016	192	120	72	1	1	6/23 (2 accts)					
2017	196	119	77	6	6	1/6 -1/8 (3)	1/11-1/13 (1)	4/20 (1)	6/26-7/1 (4)	7/12 (1)	10/17-10/18 (2)
2018	199	115	84	98	68	10/10-10/11 (166)					
2019	203	122	81	122	0	2/25-3/6 (122)					
2020	193	110	83	0	2	12/21-12/24 (1)	9/9-9/16 (1)				
2021	204	115	89	2	1	2/11-2/15 (1)	2/12-2/14 (2)				

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Request No.: UG 435 OPUC DR 459

459. Please describe NW Natural's rationale and methodology in the allocation of: (1) Mains and (2) Storage costs. Please address, at a minimum:
a. Metrics and cost-causation considerations that were employed in allocating these costs at the proposed levels to specific customer schedules; and
b. Differences (if any) between NW Natural's proposal in UG 435 and what was authorized in UG 388 and UG 344.

Response:

a. **Mains.** NW Natural's methodology for the allocation of distribution mains and system core mains in the Long Run Incremental Cost ("LRIC") Study is described at Docket No. UG 435 NW Natural/1400 Wyman/Page 26 at line 6 through Page 30 line 19.

The testimony cited above describes the mains allocation rationale, methodology, and metrics in detail. In summary, distribution mains are analyzed based on the characteristics: Total cost (excluding construction overhead) and footage installed per job, pipe size and material, and delineated by service type (conversion vs new construction) and market segment. Using Geographic Information Systems data, the Company ran a query to estimate the pipe size of the mains that customers in each rate class have been connected to historically. The rationale being that there are certain characteristics associated with the types of mains that each customer class are connected to, one such characteristic being pipe size where generally lower use rate classes such as residential are connected to mains of less than four inches diameter and higher use rate classes such as industrial are connected to mains of equal to or greater than four inches in diameter. These metrics were the driver of the mains direct allocator developed in the filed workpaper, U*G 435 - Exh. 1401 - WP2 - Development of Mains and Services Lengths and Costs,* and shown on *UG 435 - Exh. 1401 - WP6 - Long-Run Incremental Cost Study (LRIC) Model* Tab "LRIC Allocators" Lines 8d and 8e.

Mains costs that are not directly assigned through the methodology described above are allocated based on the Design Day Peak and Average Allocator. This allocator – the rationale and methodology behind its use in the LRIC Study – is described in detail at Docket No. UG 435 NW Natural/1400 Wyman/Page 21 at line 19 through Page 24 line 16. This allocator is developed in the filed workpaper, *UG 435 - Exh. 1401 - WP1 - Design Day Load Factor Development* and is shown on *UG 435 - Exh. 1401 - WP6 - Long-Run Incremental Cost Study (LRIC) Model* Tab "LRIC Allocators" Line 8c.

Storage. The Company's methodology for the allocation of storage costs in the LRIC Study is described at Docket No. UG 435 NW Natural/1400 Wyman/Page 32: 7-21. Also, please refer to the Company's response to UG 435 OPUC DR 460 for a discussion of how the storage costs were treated in the LRIC Study.

NW Natural used a ratio based on Test Year average winter sales that exceed Test Year average summer sales to allocate the storage costs to sales customers. This is because underground storage is a primarily winter peaking resource; this methodology avoids assigning costs to non-heating resource processing customers that peak during non-winter months. The storage allocator is shown on *UG 435 - Exh. 1401 - WP6 - Long-Run Incremental Cost Study (LRIC) Model* Tab "LRIC Allocators" Line 11b.

b. The data request asks NW Natural to identify differences (if any) between its proposal in UG 435 and "what was authorized in UG 388 and UG 344." Please note that the LRIC Studies presented in UG 344 and UG 388 were not explicitly authorized by the Commission or otherwise. These studies were used in settlement discussions in both proceedings as a starting point for rate spread and rate design.

Mains. The mains cost allocation methodology employed in UG 435 is similar to that used in UG 388. In this current proceeding, UG 435, the Company made a distinction between mains of less than four inches in diameter versus mains of equal to or greater than four inches in diameter for its direct allocation of both distribution mains and system core mains costs. Both studies, however, used a Design Day Peak and Average Allocator to assign indirect mains costs.

In UG 344, the Company employed only the peak capacity component in designing the mains cost allocator. Staff recommended that the Company use an allocator that takes the rate schedule load factor and "allocates the load factor percentage of the total of system mains costs on the basis of throughput and allocates the balance of the system mains costs on the basis of the demand measure shares."[1] The Company's mains allocator has been consistent with this recommendation beginning with UG 388.

Storage. The Company used a similar storage allocation methodology in UG 344 and UG 388 which estimated incremental storage costs per therm based on the investment costs associated with a Mist capacity recall in 2015 as a proxy for the market cost of procuring the Company's underground storage capacity.[2] Costs were only allocated to sales customers.

In testimony, Staff recommended and the Company adopted an alternative approach, as discussed in the Company's response to UG 435 OPUC DR 460.

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[1] Docket No. UG 344 Staff/1200 Compton/Page 9 line 19 through Page 10 line 2.
[2] Docket No. UG 388 NW Natural/1100 Wyman/Page 26 line 20 through Page 27 line 10.

AWEC, in UG 388, similarly recommended that the Company adopt a different approach.[3]

[3] Docket No. UG 388 AWEC/100 Mullins/Page 8 line 12 through Page 9 line 12.

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Request No.: UG 435 OPUC DR 460

460. Referring to Docket No. UG 388, Staff/1100, Compton/10-11 beginning on line 11; Staff proposed the LRIC model distinguishing between two kinds of Peak Firm Day Deliveries for transportation only and interruptible customers. Staff testimony further states that Staff and Company are in agreement regarding this treatment of storage costs. Please discuss whether the Company employed this distinction in the present proceeding, UG 435 and why or why not.

Response:

Yes, in the present proceeding, UG 435, the Company employed a distinction between transportation only and interruptible customers regarding the allocation of storage costs. The Company's discussion of its storage cost allocation methodology in this proceeding can be found at Docket No. UG 435, NW Natural/1400, Wyman/32: 7-21.

NW Natural's Long Run Incremental Cost ("LRIC") Study did not allocate any storage costs to transportation customers, which is standard treatment for a cost allocation study and aligns to Staff's discussion at Docket No. UG 388, Staff/1100, Compton/10: 14-17.

The LRIC Study allocates costs to all sales customers, including interruptible customers, using a ratio based on Test Year average winter sales that exceed Test Year average summer sales. This is a measure of each schedule's contribution to winter peaking load. The Company then made an adjustment for interruptible sales customers to acknowledge the possibility of service interruptions that could occur during the winter months when storage is being utilized.[1] This adjustment is based on a similar principle as Staff's proposal for core mains costs treatment from an Avista rate case.[2] The Company believes that such an adjustment for interruptible sales customers is appropriate in the LRIC Study given the fact that these customers can and do get interrupted during winter months.[3]

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[1] NW Natural/1400, Wyman/32: 10-12.
[2] Docket No. UG 388, Staff/1100, Compton/9: 15-19; 10: 1-10.
[3] Refer to the Company's response to UG 435 OPUC DR 458.

Rates & Regulatory Affairs
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Data Request Response

Request No.: UG 435 OPUC DR 461

461. Please discuss NW Natural's position and history regarding the use of seasonal retail rates for each of your retail schedules.

Response:

The Company is not aware of a market driven need for seasonal rates different from the rate structure that has been in place since 2003, when the rate structure for larger commercial and industrial customers was changed. In UG 152, the Company moved from a structure that included individual rate schedules developed to address seasonal characteristics, sales/transportation options, and firm/interruptible options to a structure that simplified the options available to customers while still addressing the same variables. What had been an assortment of schedules was reduced to two schedules (RS 31 and RS 32), with optionality included within each schedule to allow for sales vs transportation, firm vs interruptible, and MDDV vs per therm rates to address load factor and period of use for customers.

NW Natural

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 463

463. Please discuss the Company's position on distinguishing between single and multi-family residential customer charge rates. Please address at a minimum:

a. Pros and Cons;

b. Any previous internal and/or external discussions with supporting documentation;

c. Included estimated costs in current ($8.00) charge; and

d. How the Company would propose to adjust the current rate to reflect single versus multi-family households if required.

Response:

The Company interprets the definition of "multi-family residential" in this request to mean a building or multiple buildings within a single complex that contain multiple residential household units. Units within multi-family residential buildings can be either renter-occupied or owner-occupied.

Multi-family residential customers on the Company's system can fall under different charge rates depending upon the circumstances of their dwelling, for example: Individually metered customers on the Schedule 2 Residential Sales Service ("Schedule 2"); customers that reside in Participant Multi-Family Buildings on the Schedule 4 Residential Multi-Family Service ("Schedule 4"); and residents of multi-family buildings with natural gas service that is master metered under a commercial rate schedule who are not directly charged by the utility and are not utility customers.

As mentioned above, the Company offers a separate multi-family residential customer charge rate for eligible new construction multi-family developments through its Multi-Family Program filing to establish Schedule 4. The charge rate for this schedule is based on a cost of service analysis for a specific type of eligible new construction multi-family development.[1]

a. NW Natural discusses its reasons for support of its Multi-Family Program and Schedule 4 in its Initial Filing to Docket No. ADV 576. Refer to UG 435 OPUC DR

[1] *NW Natural Multi-Family Program Schedules 405 & 4*. Docket No. ADV 576, Advice No. 17-03, filed June 2, 2017.

463 Attachment 1 for the Company's Initial Filing in this docket, filed on June 2, 2017. UG 435 OPUC DR 436 Attachment 2 contains the Staff Report and recommendation to approve the Company's proposal with an effective date of July 12, 2017 (as acknowledged in UG 435 OPUC DR 436 Attachment 3). The Company also provides its existing Schedule 4 and Schedule 405 tariffs as UG 435 OPUC DR 436 Attachment 4 and Attachment 5, respectively.

b. Please see the response to part (a).

c. The current $8.00 fixed base monthly charge is one piece of the Schedule 2 rate mechanism the Company uses to collect a portion of the fixed cost component of its overall authorized revenue requirement. The other piece is the volumetric rate, which is used to collect the remainder of the fixed cost component as well as the variable component of the overall authorized revenue requirement. As such, there are no specific costs that make up this charge.

d. For existing customers living in multi-family dwellings, the Company does not see any benefits of adjusting Schedule 2 at this time. These customers tend to use less natural gas, and therefore pay less compared to single-family residences during the heating season when the volumetric portion is the largest component of most bills. For residents of multi-family buildings with natural gas service that are billed under a master meter on a commercial rate schedule there would be no impacts if Schedule 2 were adjusted; for that to happen, the Company would have to install individual meters and add each residence as a separate Schedule 2 customer, which may or may not be feasible depending on the specific characteristics of each building.

   Currently, there is not enough information in this request to make an informed assessment of how the Company would propose to adjust its current Schedule 2 rate structure if required. For instance, the Company would need to better understand how multi-family residences are being defined for the purposes of this hypothetical exercise, which multi-family dwelling types would be included in the rate, examine how (or whether) the cost to serve varies between these types of residences, and determine what goal is desired or what deficiency is being addressed by such an adjustment.

CASE: UG 435
WITNESS: MICHELLE SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1303

Work Papers in Support of Opening Testimony

April 22, 2022

"NW Natural/1401 WP6
Long-Run Incremental Cost Study (LRIC) Model"

is filed in electronic format

**“NW Natural/1402 WP1
Rate Spread Proposal Methodology”**

is filed in electronic format

“Staff OT UG 435 Proposed Rate Spread WP”

is filed in electronic format

CASE: UG 435
WITNESS: STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1400

Opening Testimony

April 22, 2022

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

A. My name is Steve Storm. I am a Senior Economist employed in the Rates, Finance & Audit (RFA) Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1401.

Q. What is the purpose of your testimony?

A. My testimony examines requirements imposed by the Commission associated with NW Natural's Integrated Resource Plan (IRP) process and reports, including updates, to assess whether such requirements had an impact on NW Natural's general rate case filing. I also examine NW Natural's responses to data requests concerning the Company's current deferrals.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/1401, my witness qualifications statement, Exhibit Staff/1402, consisting of NW Natural's non-confidential responses to Staff Data Requests (DRs); and confidential Exhibit Staff/1403, consisting of NW Natural's confidential response to a Staff DR.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. IRP AND THE GENERAL RATE CASE

Q. What was NW Natural's most recently filed IRP?

A. The Company filed its 2018 IRP on August 24, 2018, in Docket No. LC 71.

Q. Why has NW Natural not filed an IRP more recently than 2018?

A. The Company filed a request on December 1, 2020, in LC 71 for a partial exemption from the requirement in OAR 860-027-0400(3) to file an IRP within two years of acknowledgement of its previous plan and allowing it to file its subsequent IRP on or before July 30, 2022. NW Natural was concerned with the lack of clarity at that time into the DEQ's Climate Protection Program and other activities associated with Governor Brown's Executive Order 20-04.[1] The Company's request included its proposal to file an Update to the 2018 IRP that would "seek acknowledgement of projects with limited scope" and "include items that are not typically included [in] an update filing."[2]

Q. What Action Items in the 2018 IRP did the Commission acknowledge?

A. The Action Items, after revision within the IRP process, included:

1. Recall 10,000 Dth/day of Mist storage capacity for the 2020-21 gas year and 35,000 Dth/day of Mist storage capacity for the 2021-22 gas year.
2. Participate in an investigation into the use of the Company's proposed methodology for evaluating renewable natural gas resources (RN) against sources of conventional gas.

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1 *See In the Matter of Northwest Natural Gas Company, dba, NW Natural, 2018 Integrated Resource Plan*, Docket No. LC 71, Order No. 21-013, Appendix A, p. 3 (January 13, 2021).

2 NW Natural Petition for Temporary Exemption from OAR 860-027-0400(3), p. 7, Docket No. LC 71 (December 1, 2020).

3. Proceed with six distribution system planning projects. These included:
   a. The Hood River Reinforcement project;
   b. The Happy Valley Reinforcement project;
   c. The Sandy Feeder Reinforcement project;
   d. The North Eugene Reinforcement project;
   e. The South Oregon City Reinforcement project; and
   f. The Kuebler Road Reinforcement project.
4. Work through Energy Trust to acquire therm savings of 5.2 million therms in 2019 and 5.4 million therms in 2020, or the amount identified and approved by the Energy Trust board.

Q. Did Staff have any recommendations for NW Natural related to its 2018 IRP?

A. Yes. Staff's Report for the February 26, 2019 Public Meeting included 15 discrete recommendations, most of which related to actions to evaluate and processes or content to include in its subsequent IRP. Staff recommended Commission acknowledgement of Action Items associated with the demand-side energy savings targets and with five of the six distribution system planning projects.

Q. Which distribution system planning project Action Item did Staff not recommend?

A. Staff's recommendations did not include one for the North Eugene Reinforcement project.

Q. Which Action Items did the Commission acknowledge?

A. The Commission adopted Staff's recommendations, including those related to NW Natural's Action Items listed above, except for the North Eugene Reinforcement project.[3]

Q. Did NW Natural file an Update to its 2018 IRP that included Action Items?

A. Yes. The Company filed updates on April 17, 2019, and November 7, 2019, with neither update including a request for Commission action. NW Natural filed its third 2018 IRP update on March 1, 2021. Action Items included in this Update were:

1. Replacement of the Newport LNG plant's cold box;
2. Reinforcement of the North Coast Feeder; and
3. Use of avoided cost values and methodologies for distribution capacity and risk reduction for NW Natural's next avoided cost filing.

Q. Did Staff recommend Commission acknowledgement of these Action Items?

A. Not entirely. Staff recommended acknowledgement of the Newport LNG cold box replacement and reinforcement of the North Coast Feeder action items. Staff recommended non-acknowledgement of the Avoided Cost values and methodologies in the 2018 IRP proceeding.[4]

Q. What Action Items in the Third Update to the 2018 IRP did the Commission acknowledge?

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3 *In the Matter of Northwest Natural Gas Company, dba, NW Natural, 2018 Integrated Resource Plan*, Docket No. LC 71, Order No. 19-073 (March 19, 2019).

4 Staff Final Report on Northwest Natural's update to its 2018 Integrated Resource Plan, Docket No. LC 71 (July 12, 2021).

A. The Commission adopted Staff's recommendation, meaning that it acknowledged both the replacement of the Newport LNG cold box and the reinforcement of the North Coast Feeder Action Items.[5]

Q. For which of the above Action Item projects included in either the 2018 IRP or an Update does NW Natural seek cost recovery in this proceeding?

A. The Kuebler Road [Boulevard] Reinforcement project.[6]

Q. Is this project currently in service?

A. Staff presumes it is not, as NW Natural has indicated completion is not expected until October 2022. Please see Staff's discussion of this project in Exhibit Staff/300.

Q. Are there other projects for which cost recovery is sought in this proceeding that perhaps should have been included as an Action Item in NW Natural's 2018 IRP or an update thereto?

A. There are multiple projects other than the Kuebler Road Reinforcement project included for cost recovery in this proceeding. Staff lists those having an estimated capital cost of greater than $1.3 million below in Table 1400-1.

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5 LC 71, Order No. 21-274 (September 8, 2021).
6 NWN/400, Kizer/3.

Table 1400-1: Projects Included for Cost Recovery with Capital Cost Estimate

Name	Type	Estimated UG 435 Capital Cost ($Millions)
Kuebler Boulevard	Trans/Dist. Sys	24.2
Toledo Regional Station	Trans/Dist. Sys	2.5
Mist Electrical Upgrades	Storage	1.7
Mist Corrosion Abatement	Storage	2.7
Mist 300/400 Compressor Controls	Storage	3.5
Mist Well Rework 2021 & 2022	Storage	3.3
Mist Well Integrity	Storage	2.7
Newport LNG Pretreatment Regeneration	Storage	5.1
Portland LNG PLC Upgrade	Storage	2.5
Portland LNG Boil-off Compressor	Storage	1.3
McMinnville/Lafayette ILI	Trans/Dist. Sys	3.8
North Eugene ILI	Trans/Dist. Sys	3.0
Springfield ILI	Trans/Dist. Sys	1.5
Total		57.8

Q. There are a dozen projects in this list other than the Kuebler Boulevard Reinforcement project that appear to be the subject of IRP analysis, such as transmission/distribution system-related or storage-related projects. Should all of these have been included in an IRP?

A. Not necessarily. There are times when the required lead time in which to include a project in an IRP, including time prior to the issuance of an acknowledging order, could prevent utilities from “meeting the needs of the business," e.g., a resource may need near-term attention to meet and continue to meet service quality standards.

Q. Is it likely that all projects in Table 1400-1 fit the "meeting the needs of the business" urgency that insufficient time was available to include in the IRP process?

A. Staff thinks not. Storage projects listed in Table 1400-1 are for all three of NW Natural's on-system storage facilities and some – such as the Mist Corrosion Abatement project – are beyond the initial phase.

Q. What does Staff recommend?

A. Staff Witness John Fox is analyzing these projects for prudence in Exhibit Staff/300. However, with respect to NW Natural's planning process Staff:

1. Requests that NW Natural explain, in its next round of testimony, its thinking regarding the criteria it uses in determining whether a proposed project (or phases of a larger project) is included in an IRP or IRP Update; and
2. Noting that the Mist projects included in Table 1400-1 in aggregate exceeds $10 million capital cost, requests the Company include in its next round of testimony a discussion regarding whether and how a project that is composed of multiple phases plays a role in determining whether the Company includes the project (or one or more phases of the project) in an IRP or IRP Update.

ISSUE 2. DEFERRALS

Q. Has Staff investigated NW Natural's existing deferrals?

A. Staff has reviewed the status of deferrals, other than those pertaining to AFUDC, ADIT, or EDIT, finding that there is currently only one deferral that both the Commission has approved, and NW Natural intends to incorporate into rates through the proceeding at hand. This involves the start-up costs associated with Horizon 1.[7] Please see Staff's discussion of this investment in Exhibit Staff/200.

Q. Are there deferrals the Commission has not approved that NW Natural proposes to incorporate into UG 435 rates?

A. Yes, there are three.[8] First is the TSA Security Directive 2 Compliance Expenses deferral, which project is a topic in Exhibit Staff/200. The second deferral is associated with the Lexington/Tyson RNG project, which is discussed in Exhibit Staff/1700. The third deferral is associated with the Williams Pipeline outage, which is discussed in Exhibit Staff/800.

Q. Please discuss existing deferrals that are not part of UG 435 rate changes, other than those related to AFUDC, ADIT, or EDIT.

A. There are 66 deferrals not related to AFUDC, ADIT, or EDIT having positive balances (amounts presumed to be owed to the Company), which collectively had a total balance as of December 31, 2021, of $341.1 million. There are 24 deferrals not related to AFUDC, ADIT, or EDIT representing negative balances

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7 *See* Staff/1403, NW Natural's confidential response to Staff DR 298.
8 *See* Staff/1402, NW Natural's response to Staff DR 299.

(amounts presumed to be owed to customers), which collectively had a total balance as of December 31, 2021, of $555.9 million.[9]

Q. Please list the five deferrals having the largest <u>positive</u> balance and indicate their December 31, 2021, balance.

A. These include an environmental site deferral for the Portland LNG ("Gasco") plant ($117.4 million); the DBP pension cost deferral ($110.9 million); the Oregon Pension Balancing Account ($38.3 million) deferral; the Environmental SRRM post-Prudence for Oregon ($25.1 million) deferral; and the Commodity Cost Amortization – Oregon ($24.4 million) deferral. These five deferrals collectively account for a positive $316.2 million balance as of December 31, 2021. These deferrals are, with the exception of the GasCo deferral and the DBP pension cost deferral, amortized through automatic adjustment clauses.[10] The GasCo deferral has not yet been authorized for amortization and the Oregon DB pension deferral is amortized in base rates as part of pension expense.

Q. Please list the five deferrals having the largest <u>negative</u> balance, and indicate their December 31, 2021, balance.

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[9] Note that not all deferrals having a positive balance are identified by NW Natural as regulatory assets. Similarly, not all deferrals having a negative balance are identified by NW Natural as regulatory liabilities.

[10] *In the Matter of Northwest Natural Gas Company Request for General Rate Revision (Phase II)*, Docket No. UG 344, Order No. 19-105 (March 25, 2019) (Adopting Stipulation authorizing NW Natural to amortize Pension Balancing Account); *In the Matter of Northwest Natural Gas Company Mechanism for Environmental Remediation Costs*, Docket No. UM 1635, Order No. 15-049 (February 20, 2015); Docket No. UG 263, Order No. 13-393 (Oct 29, 2013) (reinstating Schedule 184 as "Special Rate Adjustment Gasco Upland Pumping Station*"); In the Matter of Northwest Natural Gas Company Investigation into Prudence of Gasco Site Capital Costs*, Docket No. UG 263, Order No. 13-393 (October 29, 2013); *In the Matter of the Investigation into Purchased Gas Adjustment Mechanism*, Docket No. UM 1286, Order No. 08-504 (October 21, 2008).

A. These include an Asset Retirement Obligation (-$442.5 million); a deferral for Insurance and Third-Party Recoveries – Oregon (-$58.0 million); a deferral associated with FAS 133 Long-term Regulatory Gains – Financial (-$46.9 million); a deferral for ISS/Optimization Revenue Sharing (Current Portion) – Oregon (-$41.5 million); and a deferral associated with FAS 133 Short-term Regulatory Gains – Financial (-$10.7 million). These five deferrals account for a negative $599.6 million balance as of December 31, 2021.

The Asset Retirement Obligation is not being specifically amortized, but instead is part of Net Plant in rate base.[11] The Insurance and Third-Party Recoveries – Oregon deferral is currently being amortized over a 20-year period ending 2033.[12] The deferral period for the FAS 133 Long-term Regulatory Gains – Financial deferral is that coinciding with the current PGA year (November 2021 – October 2022).[13] The ISS/Optimization Revenue Sharing (Current Portion) – Oregon deferral amortization was approved for bill credits in January – March, 2022.[14] The FAS 133 Short-term Regulatory Gains – Financial deferral, similar to that for long-term, coincides with the current PGA year (November 2021 – October 2022).[15]

Q. Do you have any recommendations for the Commission regarding NW Natural's deferrals?

11 NW Natural's response to Staff data request 300, included in Exhibit Staff/1402.
12 *Id.*
13 *Id.*
14 *Id.*
15 *Id.*

A. Not at this time, however Staff recommends amortization of certain COVID-19-related deferral balances in Exhibit Staff/1500.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 435
WITNESS: STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1401

Witness Qualification Statement

April 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME	Steve Storm
EMPLOYER	Public Utility Commission of Oregon
TITLE	Senior Economist
ADDRESS	201 High Street SE, Suite 100 Salem, OR 97301
EDUCATION	MBA; University of Oregon; Eugene, Oregon AB (Economics); Harvard University; Cambridge, Massachusetts

EXPERIENCE

I have been employed by the Public Utility Commission of Oregon since October 2018 as a Senior Economist. I was previously employed by the Commission as a Senior Economist 2007–2008, as the Program Manager of the Economic and Policy Analysis section 2008–2012, and as an Economist 4 2012–2013. My responsibilities have included performing as well as leading a team of analysts performing economic and financial research and providing technical support on a wide range of policy issues involving electric, natural gas, and telecommunications utilities. I have testified before the Commission on policy and technical issues in multiple dockets.

I have over 35 years of professional experience performing and directing the performing of economic, financial, and other quantitative analysis.

I was employed by NW Natural as a Senior Economist in its IRP team 2013–2018, where my responsibilities included customer and industrial load forecasting; performing cost of service and related financial analysis on a variety of infrastructure projects and alternatives; and preparing economic information for executive communications.

I was a self-employed financial planner for eight years following an 18-year career in a variety of management positions in which I was responsible for pricing and cost analysis; financial analysis, planning and management; and strategic planning in the publishing and telecommunications industries. I managed the pricing and cost accounting functions for Pacific Northwest Bell's Directory department and its successor company, US WEST Direct, for five years. I managed the departmental budgeting and management reporting functions at US WEST Direct for three years and had seven years management experience in capital budgeting, financial analysis, and strategic planning functions at US WEST Communications. I managed the corporate financial planning, analysis, and management reporting functions for one year at Electric Lightwave.

CASE: UG 435
WITNESS: STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1402

Exhibits in Support
Of Opening Testimony

April 22, 2022

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 299

299. Please prepare a table for each use of deferred accounting NW Natural has proposed but not received an Order approving that the Company intends to have impact rates resulting from this proceeding or is otherwise included in this proceeding, other than those related to AFUDC, ADIT, or EDIT. Please submit this as an Excel spreadsheet, with all formulae and cell references intact and operational. "Horizontal" elements (columns) for each usage (row) are to include:

a. The identifying "name" or other descriptor of the deferral application.
b. The date NW Natural filed the application for use of deferred accounting.
c. The docket(s) pertaining to the application.
d. The date of any Public Meeting in which the application appeared as an agenda item.
e. Order(s) relating to the application, where relevant.
f. The date NW Natural proposed the deferral should begin.
g. The date NW Natural proposed or intends to propose amortization to begin.
h. The date amortization began, where relevant.
i. The balance as of year-end 2021.
j. The balance as of the date NW Natural proposed amortization begin.
k. The balance as of the most recently requested rate effective date for this proceeding.
l. The rate base impact as of both the beginning and end of the Test Year.
m. The requested duration of the amortization period.
n. Whether the expected balance as of the date of amortization did or will represent a regulatory asset or a regulatory liability.
o. The NW Natural provided workpaper(s) for this proceeding that incorporates the deferral balance.
p. The location in NW Natural's testimony discussing the inclusion of the deferral in this proceeding.

Response:

Please see "UG 435 OPUC DR 299 Attachment 1.xlsx" for each use of deferred accounting NW Natural has proposed but not received an Order approving that the Company intends to have impact rates resulting from this proceeding or is otherwise included in this proceeding, other than those related to AFUDC, ADIT, or EDIT.

NW Natural
UG 435 OPUC DR 299

Item	Data Request	Deferral # 1	Deferral # 2	Deferral # 3
a	The identifying "name" or other descriptor of the deferral application.	TSA Security Directive 2 Compliance Expenses	Lexington/Tyson RNG Project	Williams Pipeline Outage
b	The date NW Natural files the application for use of deferred accounting.	September 2, 2021	December 31, 2020	December 21, 2020
c	The docket(s) pertaining to the application.	UM 2192	UM 2145	UM 2139
d	The date of any Public Meeting in which the application appeared as an agenda item.	N/A - Still Pending	N/A - Still Pending	N/A - Still Pending
e	Order(s) relating to the application	Pending authorization	Pending authorization	Pending authorization
f	The date NW Natural proposed the deferral should begin.	September 2, 2021	December 31, 2020	December 21, 2020
g	The date NW Natural proposed or intends to propose amortization to begin.	November 1, 2022	November 1, 2022	November 1, 2022
h	The date amortization began, where relevant.	November 1, 2022	November 1, 2022	November 1, 2022
i	The balance as of year-end 2021.	Oregon allocated is $940,409	$82,213 (all Oregon)	Oregon allocated $569,348
j	The balance as of the date NW Natural proposed amortization begin.	The forecasted balance is $6,573,656, plus interest	The forecasted balance is $1,380,790, plus interest	$569,348, plus interest
k	The balance as of the most recently requested rate effective date for this proceeding.	The forecasted balance is $6,573,656, plus interest	The forecasted balance is $1,380,790, plus interest	$569,348, plus interest
l	The rate base impact as of the both the beginning and end of the Test Year.	Rate Base at 11/2022 is $24,512,874 and Rate Base at 10/2023 is $20,836,800	Rate Base at 11/2022 is $8,164,048 and Rate Base at 10/2023 is $7,679,455	There is no rate base impact since this is O&M costs
m	The requested duration of the amortization period.	2 Years	1 Year	1 Year
n	Whether the expected balance as of the date of amortization did or will represent a regulatory asset or a regulatory liability.	Regulatory Asset	Regulatory Asset	Regulatory Asset
o	The NW Natural provided work paper(s) for this proceeding that incorporates the deferral balance.	"UG 435 - Exh. 1317 - WP1 -TSA Directive 2 COS.xlsx" and "UG 435 - Exh. 1403 and 1404 - WP1 - Rate Spread and Rate Allocation Model.xlsx"	"UG435 - Exh. 1314 - WP1 - Lexington RNG COS -CONFIDENTIAL.xlsx" and "UG 435 - Exh. 1403 and 1404 - WP1 - Rate Spread and Rate Allocation Model.xlsx"	"UG 435 - Exh. 1403 and 1404 - WP1 - Rate Spread and Rate Allocation Model.xlsx"
p	The location in NW Natural's testimony discussing the inclusion of the deferral in this proceeding.	NW Natural/700, Downing/Page 29-33 and NW Natural/1300, Walker/Page 33-34	NW Natural/1300, Walker/Page 27-29 and NW Natural/Exhibit 1314, Walker/Page 1-2	NW Natural/1000, Shampine/Page 8, NW Natural/1300, Walker/Page 30-31; NW Natural/1403, Wyman/Page 2; NW Natural/1404, Wyman/Page 1

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 300

300. Please prepare a table for each regulatory asset or liability that is not associated with AFUDC, ADIT, or EDIT and that does not appear in NW Natural's response to one of the two immediately preceding data requests. Please submit this as an Excel spreadsheet, with all formulae and cell references intact and operational. "Horizontal" elements (columns) for each entry (row) are to include:

a. The identifying "name" or other descriptor of the deferral application.
b. The date NW Natural filed the application for use of deferred accounting.
c. The docket(s) pertaining to the application.
d. The date of any Public Meeting in which the application appeared as an agenda item.
e. Order(s) relating to the application, where relevant.
f. The date NW Natural proposed the deferral should begin.
g. The date NW Natural proposed or intends to propose amortization to begin.
h. The date amortization began, where relevant.
i. The balance as of year-end 2021.
j. The balance as of the date NW Natural proposed amortization begin.
k. The balance as of the most recently requested rate effective date for this proceeding.
l. The rate base impact as of both the beginning and end of the Test Year, if any.
m. The requested duration of the amortization period.
n. Whether the expected balance as of the date of amortization did or will represent a regulatory asset or a regulatory liability.
o. The NW Natural provided work paper(s) for this proceeding that incorporates the deferral balance.

Response:

a. – o. Please see UG 435 OPUC DR 300 Attachment 1. The name of the deferral application, and the initial and subsequent filing dates, can be found at the OPUC's website under the docket numbers provided in UG 435 OPUC DR 300 Attachment 1. We do not have records of the Public Meetings in which these dockets were discussed; orders issued as a result of any approvals pronounced in Public Meetings are provided in UG 435 OPUC DR 300 Attachment 1. The most recent Order Numbers in the docket are provided in UG 435 OPUC DR 300 Attachment 1; previous orders can be found at the OPUC's website under the docket numbers provided in UG 435 OPUC DR 300 Attachment 1. For each of the amortization accounts, the most recent balance approved for amortization is provided in UG 435 OPUC DR 300 Attachment 1; the Company does not have a forecast of the deferral balances that it intends to request amortization of at this time unless noted specifically in UG 435 OPUC DR 300 Attachment 1. NW Natural is not requesting to amortize the deferral balances listed in UG 435 OPUC DR 300 Attachment 1 in this proceeding, unless otherwise noted in the attachment.

Exhibit Staff/1402
Storm/5

NW Natural
UG 435 OPUC DR 300 - Attachment 1
Schedule of Regulatory Assets and Liabilities
Balances as of December 31, 2021

Account	Account Name (DR 300 part a)	Description (DR 300 part a)	Docket (DR 300 part b, c, d, e)	Deferral/Amortization Periods (DR 300 part f, g, h, m)	Most Recent Balance Approved for Amortization	Balance at 12/31/2021 (DR 300 part i)	Regulatory Asset or Liability for Amortization? (DR 300 part n)	Included in OR Rate Base?	Nov. 1 2022 and Oct. 31 2023 forecasted Rate Base Balances (DR 300 part l)	UG 435 Workpaper Reference (DR 300 part o)
REGULATORY ASSETS										
192640	FAS 133 Short-term Regulatory Losses - Financial	This account is used for recording the mark-to-market adjustment for the difference between the fixed price and the fair value of a financial derivative (losses in this case) at a point in time. As required by GAAP, this account captures the adjustment for financial derivatives that will settle within 12 months. Since this relates to hedges on gas costs for sales customers, it is included in the regulatory deferrals classification. The offsetting account is 262640. (Note: since it is a valuation at a point in time, the mark-to-market adjustments are not included in	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	6,027,903	N/A - see description	No	N/A - see description	N/A
192645	FAS 133 Short-term Regulatory Losses - Physical	This account is used to record the fair value of the index adjuster (to be paid out) on existing commodity deals within the next 12 months. Since this relates to physical gas purchases for sales customers, it is included in the regulatory deferrals classification. The offsetting account is 262645. (Note: since it is a valuation at a point in time, the mark-to-market adjustments are not included in customer rates.)	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	3,259,350	N/A - see description	No	N/A - see description	N/A
192647	FAS 133 Short-term Regulatory Losses - Physical Options	This account captures the fair value of existing physical commodity options (losses in this case) for potential gas flows within the next 12 months using a Black 76 model calculation. Since this relates to gas costs for sales customers, it is included in the regulatory deferrals classification. The offsetting account is 262648. (Note: since it is a valuation at a point in time, the mark-to-market adjustments are not included in customer rates.)	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	1,114,419	N/A - see description	No	N/A - see description	N/A
192630	FAS 133 Long-term Regulatory Losses - Financial	This account is used for recording the mark-to-market adjustment for the difference between the fixed price and the fair value of a financial derivative (losses in this case) at a point in time. As required by GAAP, this account captures the adjustment for financial derivatives that will settle beyond 12 months. Since this relates to hedges on gas costs for sales customers, it is included in the regulatory deferrals classification. The offsetting liability account is 262630. (Note: since it is a valuation at a point in time, the mark-to-market adjustments are not included in customer rates.)	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	411,607	N/A - see description	No	N/A - see description	N/A
192635	FAS 133 Long-term Regulatory Losses - Physical	This account is used to record the fair value of the index adjuster (to be paid out) on existing commodity purchase deals beyond 12 months. Since this relates to physical gas purchases for sales customers, it is included in the regulatory deferrals classification. The offsetting liability account is 262635. (Note: since it is a valuation at a point in time, the mark-to-market adjustments are not included in customer rates.)	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	-	N/A - see description	No	N/A - see description	N/A
192637	FAS 133 Long-term Regulatory Losses - Physical Options	This account captures the fair value of existing physical commodity options (losses in this case) for potential gas flows beyond the next 12 months using a Black 76 model calculation. Since this relates to gas costs for sales customers, it is included in the regulatory deferrals classification. The offsetting liability account is 262638. (Note: since it is a valuation at a point in time, the mark-to-market adjustments are not included in customer rates.)	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	-	N/A - see description	No	N/A - see description	N/A
189008	Unamortized Loss 9.75% Bonds	Represents the unamortized balance of the discount at which the bond was issued. The balance is being amortized over the life of the bonds.	This is included in the embedded cost of debt which is considered in a rate case. Most recently: Oregon - UG 388, Order 20-364	N/A. This is included in the embedded cost of debt in the rate case.	N/A	748,912	Regulatory Asset is included in the Embedded Cost of Debt calculation of the requested rate of return.	No	N/A	NW Natural/200, Wilson/Page 2 thru Page 9, NW Natural/1309, Walker/Page 1
189013	Unamortized Loss 5.62% Bonds	Represents the unamortized balance of the discount at which the bond was issued. The balance is being amortized over the life of the bonds.	This is included in the embedded cost of debt which is considered in a rate case. Most recently: Oregon - UG 388, Order 20-364	N/A. This is included in the embedded cost of debt in the rate case.	N/A	270,688	Regulatory Asset is included in the Embedded Cost of Debt calculation of the requested rate of return.	No	N/A	NW Natural/200, Wilson/Page 2 thru Page 9, NW Natural/1309, Walker/Page 1
182300	Current Regulatory Asset - Pension Balancing	Represents the recovery of the PBA balance over the next 12 months via a tariff rate. The PBA balance is to be amortized over 10 years beginning April 2019.	Oregon - UG 344, Order 19-105	This represents the amount of the Pension Balancing Account to be amortized over the next 12 months as approved in Order 19-105.	7,131,059	7,131,059	Regulatory Asset	No	N/A	NW Natural/1200, Davilla/Page 16
186145	Environmental site deferral - Gasco - Oregon	Includes 96.68% of pre-prudence reviewed costs incurred pertaining to remediation of Gasco Upland, Source Control, Sediments, and Siltronic beginning in 2017 forward. Also includes 100% of estimated future costs to complete remediation of which a portion will be allocated to Washington once the costs are incurred. Interest is charged only on the actual spend amounts.	Oregon - UM 1078; last approval given in Order 22-032	Deferred balances include expenditures and interest from Jan. 2021 through Dec. 2021 (approx. $15.7m) plus forecasted expenditures over the foreseeable future. NWN only seeks to amortize actual expenditures. Last authorized deferral period is 1/26/21 - 1/25/22. Pending deferral authorization is for 1/26/22 - 1/25/22.	None of this balance has been approved for amortization. A prudence review will be requested for the 2021 expenditures by 3/15/22.	117,392,686	Regulatory Asset - actual expenditures to be included in SRRM mechanism	No	N/A	N/A
186147	Environmental site deferral - Siltronic - Oregon	This account captured pre-prudence reviewed costs; however, all costs have since been approved as prudent. From 2017 forward remediation activities are included in the Gasco site.	Oregon - UM 1078; last approval given in Order 22-032	Last authorized deferral period is Jan. 2021 through Dec. 2021. Pending deferral authorization is for Jan. 2022 through Dec. 2022.	No expenditures incurred since 2017.	-	No expenditures incurred since 2017.	No	N/A	N/A
186148	Environmental site deferral - Harbor - Oregon	Includes 96.68% of pre-prudence reviewed costs incurred pertaining to the Portland Harbor. Also includes 100% of estimated future costs to complete remediation of which a portion will be allocated to Washington once the costs are incurred. Interest is charged only on the actual spend amounts.	Oregon - UM 1078; last approval given in Order 22-032	Deferred balances include expenditures and interest from Jan. 2021 through Dec. 2021 (approx. $1.7m) plus forecasted expenditures over the foreseeable future. NWN only seeks to amortize actual expenditures. Last authorized deferral period is 1/26/21 - 1/25/22. Pending deferral authorization is for 1/26/22 - 1/25/22.	None of this balance has been approved for amortization. A prudence review will be requested for the 2021 expenditures by 3/15/22.	13,721,670	Regulatory Asset - actual expenditures to be included in SRRM mechanism	No	N/A	N/A
186149	Environmental site deferral - PGM Oregon	Includes 96.68% of pre-prudence reviewed costs incurred pertaining to the Portland Harbor. Also includes 96.68% of estimated future costs to complete remediation. Interest is charged only on the actual spend amounts.	Oregon - UM 1078; last approval given in Order 22-032	Deferred balances include expenditures and interest from Jan. 2021 through Dec. 2021 (approx. $1.4m) plus forecasted expenditures over the foreseeable future. NWN only seeks to amortize actual expenditures. Last authorized deferral period is 1/26/21 - 1/25/22. Pending deferral authorization is for 1/26/22 - 1/25/22.	None of this balance has been approved for amortization. The 2021 expenditures are currently pending a prudence review.	3,234,711	Regulatory Asset - actual expenditures to be included in SRRM mechanism	No	N/A	N/A
186151	Environmental site deferral - Tar - Oregon	This account captured pre-prudence reviewed pertaining to an early action to clean up a tar body at the Gasco site as required by the EPA. All costs have since been approved as prudent.	Oregon - UM 1078; last approval given in Order 22-032	Last authorized deferral period is Jan. 2021 through Dec. 2021. Pending deferral authorization is for Jan. 2022 through Dec. 2022.	No expenditures incurred since 2014.	-	No expenditures incurred since 2017.	No	N/A	N/A
186152	Environmental site deferral - Oregon Steel - Oregon	This account captured 96.68% of pre-prudence reviewed costs incurred pertaining to the Oregon Steel site. These costs have since been deemed prudent. It also includes 96.68% of estimated future costs. Interest is charged only on the actual spend amounts.	Oregon - UM 1078; last approval given in Order 22-032	Deferred balances represent forecasted expenditures over the foreseeable future. NWN only seeks to amortize actual expenditures. Last authorized deferral period is 1/26/21 - 1/25/22. Pending deferral authorization is for 1/26/22 - 1/25/22.	No expenditures incurred prior to 2014.	179,077	No expenditures incurred prior to 2014.	No	N/A	N/A
186153	Environmental site deferral - Central - Oregon	Includes 96.68% of pre-prudence reviewed costs incurred pertaining to the Central Service Center site. Also includes 100% of estimated future costs to complete remediation of which a portion will be allocated to Washington once the costs are incurred. Interest is charged only on the actual spend amounts.	Oregon - UM 1078; last approval given in Order 22-032	Last authorized deferral period is Jan. 2021 through Dec. 2021. Pending deferral authorization is for Jan. 2022 through Dec. 2022.	No expenditures incurred since 2019.	-	No expenditures incurred since 2019.	No	N/A	N/A
186160	Insurance and Third Party Recoveries - Oregon	Includes 96.68% of insurance proceeds and third party recoveries received that have yet to be applied towards pre-prudence spend and future costs.	Oregon: UM 1078 - Last approval given in Order 22-032 UM 1635, Orders 16-029 and 15-049	Deferred balances are to be amortized over a 20 year period ending 2033.	$5m of offsets plus annual interest accrued are applied against expenditures deemed prudent each year.	(58,014,083)	Regulatory Liability	No	N/A	N/A
186161	Environmental Base Rate Deferral - Oregon	Represents the accumulation of $5M collected annually in Oregon customers' base rates. This is applied to costs once deemed prudent.	Oregon - UM 1635, Orders 16-029 and 15-049	See the account description.	$5m was applied to 2020 expenses deemed prudent in 2021.	(5,000,000)	Regulatory Liability	No	N/A	N/A
186182	Environmental SRRM Post Prudence - Oregon	Balance represents costs deemed prudent that will be recovered on a rolling 5 year basis.	Oregon: UG 221, Orders 12-408 and 12-437 UM 1635, Orders 16-029 and 15-049	See the account description.	Refer to account 186183 note below.	25,143,659	Regulatory Asset	No	N/A	N/A
186183	Environmental SRRM Amortization - Oregon	Represents costs currently being amortized through customer rates.	Oregon - UG 424, Order 21-368	Amortization period is 11/1/21 - 10/31/22	$6 3m authorized for amortization in during the 2021-22 PGA year.	5,261,664	Regulatory Asset	No	N/A	N/A

186404	DBP Pension Costs	Represents the accumulated gains/losses on the pension plan due to changes in actuarial assumptions (mortality rates, discount rate, expected returns, etc.) as well as prior service cost adjustments. These amounts are generally amortized over the remaining service period of active employees.	Oregon: Deferral - UM 1293, Order 07-030 Amortization - is included in pension expense in NW Natural's general rate cases. Most recently Oregon - UG 388, Order 20-364.	This is an ongoing deferral first authorized and is amortized as part of pension expense included in base rates.	Amortization of the balance is included in pension expense in the most recent rate case.	110,938,311	Regulatory Asset	No		N/A	NW Natural/1201, Davilla/Page 1, NW Natural/1202, Davilla/Page 1
186406	FAS 106 Costs	Represents the accumulated gains/losses on post retirement medical plan due to changes in actuarial assumptions (mortality rates, discount rate, expected returns, etc.) as well as prior service cost adjustments. These amounts are generally amortized over the remaining service period of active employees.	Oregon: Deferral - UM 1293, Order 07-030 Amortization - is included in pension expense in NW Natural's general rate cases. Most recently Oregon - UG 388, Order 20-364.	This is an ongoing deferral first authorized and is amortized as part of pension expense included in base rates.	Amortization of the balance is included in pension expense in the most recent rate case.	5,501,569	Regulatory Asset	No		N/A	NW Natural/1201, Davilla/Page 1, NW Natural/1202, Davilla/Page 1
191400	Commodity Cost Deferral - Oregon	Represents 90% of the difference between estimated commodity costs embedded in current Oregon customer rates and actual commodity costs.	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Current deferral period is 11/1/21 - 10/31/22	See account 191401.	15,939,577	Regulatory Asset at this time. The balance fluctuates depending on whether actual costs are greater or less than collections.	No		N/A	N/A
191401	Commodity Cost Amortization - Oregon	Represents the prior PGA year's commodity deferrals currently being amortized in customer's rates.	Oregon - UG 432, Order 21-376	Current deferral period is 11/1/21 - 10/31/22	$29.5m regulatory asset	24,443,601	Regulatory Asset at this time. The balance fluctuates depending on whether actual costs are greater or less	No		N/A	N/A
191410	Demand Cost Deferral - Oregon	Represents the difference between estimated pipeline capacity costs embedded in current Oregon customer rates and actual pipeline capacity costs.	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Current deferral period is 11/1/21 - 10/31/22	$0 02m regulatory asset	732,177	Regulatory Asset at this time. The balance fluctuates depending on whether actual costs are greater or less than collections.	No		N/A	N/A
191411	Demand Cost Amortization - Oregon	Represents the prior PGA year's demand deferrals currently being amortized in customer's rates.	Oregon - UG 432, Order 21-376	Amortization period is 11/1/21 - 10/31/22	This account includes authorized amounts from accounts 191410, 191417 and 191450	2,435,042	Regulatory Asset at this time. The balance fluctuates depending on whether actual costs are greater or less than collections.	No		N/A	N/A
191417	Coos County Demand Cost Deferral - Oregon	Represents the Coos County pipeline demand charge in excess of the surcharge collected from Coos Bay customers.	Oregon - UG 152, Order 03-236	The settlement approved in Order 03-236 is for a 20 year period.	$0 07m regulatory asset	232,678	Regulatory Asset at this time. The balance could fluctuate depending on whether actual costs are greater or less than collections from Coos Bay customers..	No		N/A	N/A
191450	Seasonalized Demand Cost Deferral - Oregon	Represents the difference between the pipeline capacity costs collected from Oregon customers and estimated pipeline capacity costs on a seasonalized basis.	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Current deferral period is 11/1/21 - 10/31/22	$2 8m regulatory asset	247,571	Regulatory Asset at this time. The balance fluctuates depending on whether actual costs are greater or less than collections.	No		N/A	N/A
191451	WACOG Equalization - Oregon	Tracks the monthly difference between the annual PGA Rate in Oregon and the monthly estimated commodity costs used to develop that rate. For the PGA year, the activity nets to $0.	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Current deferral period is 11/1/21 - 10/31/22	N/A - see description	313,765	N/A - see description	No		N/A	N/A
186203	Estimated Unbilled Revenues - estimated amortizations	Whereas the other amortization accounts calculate the amortization of deferrals based on customer billings, this account tracks the amortization of other deferrals based on estimated unbilled volumes for a month. This estimate is reversed the following month and the amortizations are recorded in their respective accounts based on billed volumes.	n/a - for GAAP reporting purposes only as we report on an accrual basis	N/A - see description.	N/A. This account is used to estimate the volumetric amortizations that have not yet been billed at the end of each month. NWN does not request amortiztion of this specific account.	(4,163,618)	N/A - see description	No		N/A	N/A
186225	250 Taylor Lease Deferral	Represents the difference between lease expense calculated in accordance with GAAP and the lease payments used for cost recovery purposes. This account will build and then reduce such that at the end of the lease the balance will equal $0. Please note that this account does not accrue interest.	Oregon - UM 2034, Order 19-407	Deferral period is the 20-year lease of the 250 Taylor building commencing May 2020.	N/A - see description	5,660,562	N/A - see description	No		N/A	N/A
186228	Oregon CAT Amortization	Represents the CAT deferral from docket UM 2044 (Order 20-373) currently being amortized through customer rates.	Oregon - UG 428, Order 20-373	Amortization period is 11/1/21 - 10/31/22	$0 5m regulatory asset	359,488	Regulatory asset	No		N/A	N/A
186232	Oregon Industrial DSM Deferral	Represents the payments made to Energy Trust of Oregon for administering a DSM program on NWN's behalf. The cost is then passed on to Oregon industrial customers.	Oregon - UM 1420; last approval given in Order 21-116; current period deferral request is pending approval	Current authorized deferral period is 3/1/2021-2/28/22. Application to reauthorize deferral for 3/1/22-2/28/23 is pending OPUC approval.	See account 186233.	5,521,260	Regulatory asset	No		N/A	N/A
186233	Oregon Industrial DSM Amortization	Represents the prior Program Year's Industrial DSM deferrals currently being amortized in customer's rates.	Oregon - UG 425, Order 21-369	Amortization period is 11/1/21 - 10/31/22	$2 9m	2,482,581	Regulatory asset	No		N/A	N/A
186236	Oregon Regulatory Fee Deferral	Deferral of the difference between the PUC fee rate embedded in rates and the actual PUC fee rate.	Oregon - UM 1766; last approval given in Order 21-117	Current authorized deferral period is 3/23/2021-3/22/22.	See account 186237	-	Dependant upon whether the OPUC fee increases or decreases in comparison to the amounts authorized in the rate case.	No		N/A	N/A
186237	Oregon Regulatory Fee Amortization	Represents the prior PGA year's PUC deferral currently being amortized in customer's rates.	Oregon - UG 423, Order 21-367	Amortization period is 11/1/21 - 10/31/22	$0.4m regulatory asset	358,368	Regulatory asset	No		N/A	N/A
186238	Oregon Residential WARM Deferral	Represents the portion of WARM adjustments to Oregon Residential customer bills that exceed or fall below thresholds on a bill-by-bill basis. This deferral is then amortized in all Oregon Residential rates the following PGA year.	Oregon - UM 1798; last approval given in Order 21-345	Current deferral period is 11/1/21 - 10/31/22	See account 186239 below	450,420	Regulatory Asset at this time. The balance fluctuates depending on if weather is warmer or colder than	No		N/A	N/A
186239	Oregon Residential WARM Amortization	Represents the prior PGA year's Residential WARM deferral currently being amortized in customer's rates.	Oregon - UG 427, Order 21-371	Amortization period is 11/1/21 - 10/31/22	$1.7m regulatory asset	1,408,794	Regulatory Asset	No		N/A	N/A
186244	Oregon Commercial WARM Deferral	Represents the portion of WARM adjustments to Oregon Commercial 3 customer bills that exceed or fall below thresholds on a bill-by-bill basis. This deferral is then amortized in all Oregon Commercial 3 rates the following PGA year.	Oregon - UM 1798; last approval given in Order 21-345	Current deferral period is 11/1/21 - 10/31/22	See account 186245 below	502,941	Regulatory Asset at this time. The balance fluctuates depending on if weather is warmer or colder than normal.	No		N/A	N/A
186245	Oregon Commercial WARM Amortization	Represents the prior PGA year's Commercial WARM deferral currently being amortized in customer's rates.	Oregon - UG 427, Order 21-371	Amortization period is 11/1/21 - 10/31/22	$1.1m regulatory asset	972,071	Regulatory Asset	No		N/A	N/A
186250	Western States Pension Regulatory Asset - Oregon	In 2013, NWN withdrew from a multi-employer retirement plan which resulted in a one-time charge to exit the plan. This account, approved by an OPUC accounting order, captures the deferral of the one-time charge (representing the PV of 20 years of payments) allocated to Oregon and is being amortized over the 20 years of payments to the plan for withdrawing. The offset is included in liability account 253201. In particular, this account includes the payments to be made beyond 12 months whereas account 186251 represents the payments to be made within 12 months.	Oregon - UM 1680, Order 14-041	See the account description	See the account description	4,813,381	Regulatory Asset	No	N/A		NW Natural/1201, Davilla/Page 1, NW Natural/1202, Davilla/Page 1
186251	Curr. Portion of West States Pension Asset - Oregon	See explanation in account 186250. This account represents the payments to be made in the next 12 months.	Oregon - UM 1680, Order 14-041	See the account description	See the account description	341,232	Regulatory Asset	No	N/A		NW Natural/1201, Davilla/Page 1, NW Natural/1202, Davilla/Page 1
186265	Oregon Commercial 31 Decoupling Deferral	Represents deferral of the margin difference caused by the differences between actual Oregon Commercial 31 customer volumes (normalized for weather) and baseline volumes set in the most recent rate case.	Oregon - UM 1027; last approval given in Order 20-442; current period deferral reauthorization request is pending approval	Current deferral period is 11/1/21 - 10/31/22	See account 186266 below	(79,656)	Regulatory liability at this time. The balance to be placed into amortization in the next year depends on whether customers use more or less than	No		N/A	N/A
186266	Oregon Commercial 31 Decoupling Amortization	Represents the prior PGA year's Commercial 31 decoupling deferral currently being amortized in customer's rates.	Oregon - UG 427, Order 21-371	Amortization period is 11/1/21 - 10/31/22	$0.1m regulatory asset	116,877	Regulatory Asset	No		N/A	N/A
186269	Oregon Commercial 3 Decoupling Amortization	Represents the prior PGA year's Commercial 3 decoupling deferral currently being amortized in customer's rates.	Oregon - UG 427, Order 21-371	Amortization period is 11/1/21 - 10/31/22	$1.1m regulatory asset	852,473	Regulatory Asset	No		N/A	N/A

186270	Oregon Commercial 3 Decoupling Deferral	Represents deferral of the margin difference caused by the differences between actual Oregon Commercial 3 customer volumes (normalized for weather) and baseline volumes set in the most recent rate case.	Oregon - UM 1027; last approval given in Order 20-442; current period deferral reauthorization request is pending approval	Current deferral period is 11/1/21 - 10/31/22	See account 186269 above	(1,114,281)	Regulatory liability at this time. The balance to be placed into amortization in the next year depends on whether customers use more or less than baseline.	No	N/A	N/A
186275	Oregon Residential Decoupling Deferral	Represents deferral of the margin difference caused by the differences between actual Oregon Residential customer volumes (normalized for weather) and baseline volumes set in the most recent rate case.	Oregon - UM 1027; last approval given in Order 20-442; current period deferral reauthorization request is pending approval	Current deferral period is 11/1/21 - 10/31/22	See account 186277 below	(3,177,282)	Regulatory liability at this time. The balance to be placed into amortization in the next year depends on whether customers use more or less than	No	N/A	N/A
186276	Oregon CUB Intervenor Funding Deferra	Represents the payments made to the Citizens Utility Board as ordered by the OPUC. The cost is then passed on to Oregon residential customers via rates each	Oregon - UM 1101; last approval given in Order 21-256	Current deferral period is 7/1/21 - 6/30/22	$0.1m regulatory asset	-	Regulatory Asset	No	N/A	N/A
186277	Oregon Residential Decoupling Amortization	Represents the prior PGA year's Residential decoupling deferral currently being amortized in customer's rates.	Oregon - UG 427, Order 21-371	Amortization period is 11/1/21 - 10/31/22	$4.1m regulatory liability	(3,515,326)	Regulatory Asset	No	N/A	N/A
186278	Oregon AWEC Intervenor Funding Deferral	Represents the payments made to the industrial user intervenor group as ordered by the OPUC. The cost is then passed on to Oregon industrial customers via rates each PGA year.	Oregon - UM 1101; last approval given in Order 21-256	Current deferral period is 7/1/21 - 6/30/22	$0 01m regulatory asset	40,349	Regulatory Asset	No	N/A	N/A
186284	Oregon Intervenor Funding Deferral - Issue Specific	Includes payments made to intervenor groups for the work performed in specific dockets. The cost is then passed on to the appropriate customer classes through rates each PGA year.	Oregon - UM 1101; last approval given in Order 21-256	Current deferral period is 7/1/21 - 6/30/22	$.07m regulatory asset to account 18286 and $0 07m regulatory asset to account 186288	5,000	Regulatory Asset	No	N/A	N/A
186285	Oregon SB 844 Deferral	Balance captures the deferral of costs incurred related to projects submitted (or to be submitted) under Oregon Senate Bill 844.	Oregon - UM 1714 (last Order was 21-105)	Last authorized deferral period is 1/20/21 through 1/19/2022. Pending deferral authorization is for 1/20/22 through 1/19/2023.	None	-	Dependant on incurring expenses for SB844 projects.	No	N/A	N/A
186286	Oregon CUB Intervenor Funding Amortization	Represents the prior PGA year's deferral of payments to CUB currently being amortized in customer's rates.	Oregon - UG 422, Order 21-366	Amortization period is 11/1/21 - 10/31/22	This account includes authorized amounts from accounts 186276 and 186284.	139,676	Regulatory Asset	No	N/A	N/A
186288	Oregon AWEC Intervenor Funding Amortization	Represents the prior PGA year's deferral of payments to industrial intervenors being amortized in customer's rates.	Oregon - UG 422, Order 21-366	Amortization period is 11/1/21 - 10/31/22	This account includes authorized amounts from accounts 186278 and 186284.	68,222	Regulatory Asset	No	N/A	N/A
186370	Oregon Pension Balancing Account	Represents the recovery balance of the PBA balance minus the amounts included in account 182300. The PBA balance is to be amortized over 10 years beginning April 2019 through a tariff rate.	Oregon - UM 1475, Order 11-051 Additionally amortization of this account is included in pension expense in NW Natural's general rate cases. Oregon - UG 388, Order 20-364	See account description.	See account 182300	38,301,663	Regulatory Asset	No	N/A	NW Natural/1200, Davilla/Page 16
186380	Oregon Multi-family Tariffs	Deferral of expenditures associated with Schedule 405 and Schedule 4 multi-family tariffs (e g. incentive payments to developers and cost of shut-off valves).	Oregon - UM 1850, Order 17-285	Balance will build as developer payments are made. The offset to this account is 186381.	Balance will build as developer payments are made. The offset to this account is 186381.	333,533	Regulatory Asset	Yes (for multi-family customers only)	N/A - Multi-family rate base is not included in the current proceeding.	N/A - Multi-family rate base is not included in the current proceeding.
186381	Oregon Multi-family Tariffs Amortization	Represents the portion of account 186380 recovered from multi-family customers. For GAAP purposes, the recovery is treated as a contra-asset account much like accumulated depreciation is a contra-asset account for plant.	Oregon - UM 1850, Order 17-285	Amortization will continue to occur until this account equals account 186380.	$3 29/customer/month embedded in Sch. 4 rates.	(14,663)	Regulatory Asset - contra account	Yes (for multi-family customers only)	N/A - Multi-family rate base is not included in the current proceeding.	N/A - Multi-family rate base is not included in the current proceeding.
186311	Oregon Residual Amortization	Represents residual amortization balances of various one-time deferrals. For the 2020-21 PGA year, this was not included in customer rates as the balance was too small (would not create a rate increment within 5 decimal places).	Oregon - UG 431, Order 21-375	Amortization period is 11/1/21 - 10/31/22	$0 2m regulatory liability	(66,147)	Regulatory Liability	No	N/A	N/A
186430	Oregon COVID Uncollectibles Deferral	Represents the difference between actual uncollectible expense and the amount embedded in the last general rate case. The deferral was filed in response to the COVID19 pandemic.	Oregon - UM 2068, last approval given in Order 20-380; current period pending approval	Current deferral period is 3/24/21 - 3/23/22	None approved	1,959,677	Regulatory Asset	No	N/A	N/A
186431	Oregon COVID Late Fees Deferral	Represents the difference between actual late fee revenue and the amount embedded in the last general rate case. In response to the COVID19 pandemic, beginning in April 2020 Oregon utilities were prohibited from charging late fees on delinquent accounts until a date as determined by the OPUC.	Oregon - UM 2068, last approval given in Order 20-380; current period pending approval	Current deferral period is 3/24/21 - 3/23/22	None approved	2,517,765	Regulatory Asset	No	N/A	N/A
186432	Oregon COVID Other Expenses Deferra	Represents Oregon's allocation of direct expenses incurred as a result of the COVID19 pandemic.	Oregon - UM 2068, last approval given in Order 20-380; current period pending approval	Current deferral period is 3/24/21 - 3/23/22	None approved	3,281,179	Regulatory Asset	No	N/A	N/A
186442	Oregon COVID Cost Savings Deferra	Represents Oregon's allocation of cost savings as as result of the COVID19 pandemic.	Oregon - UM 2068, last approval given in Order 20-380; current period pending approval	Current deferral period is 3/24/21 - 3/23/22	None approved	(814,028)	Regulatory Liability	No	N/A	N/A
186444	Oregon COVID Late Fees Deferral Reserve	This is a contra asset account to account 186431 as GAAP rules do not allow the recognition of forgone revenues until the Commission approves amortization of the amounts. This is a timing issue for accounting purposes as NWN's deferral request was approved.	Oregon - UM 2068, last approval given in Order 20-380; current period pending approval	Current deferral period is 3/24/21 - 3/23/22	None approved	(2,517,765)	Regulatory Asset - contra account	No	N/A	N/A
186320	Oregon GeoTEE Commercial Deferral	Represents costs for increased energy efficiency incentives for commercial customers in the Creswell/Cottage Grove area as part of Phase 3 of the Geographically Targeted Energy Efficiency pilot program.	Oregon - Docket UM 2155; last approval given in Order 21-121; current period pending approval	Current deferral period is 2/28/22 - 2/27/23	None approved	108,593	Regulatory Asset	No	N/A	N/A
186321	Oregon GeoTEE Residential Deferral	Represents costs for increased energy efficiency incentives for residential customers in the Creswell/Cottage Grove area as part of Phase 3 of the Geographically Targeted Energy Efficiency pilot program.	Oregon - Docket UM 2155; last approval given in Order 21-121; current period pending approval	Current deferral period is 2/28/22 - 2/27/23	None approved	548,854	Regulatory Asset	No	N/A	N/A
186448	OR COVID AMP Deferral	Represents costs of Arrearage Management Program for Oregon customers, which helps customers to pay past due balances to avoid losing service.	NW Natural filed an OPUC Advice No. 21-02 to add Schedule R (Residential Arrearage Management Program (AMP) under Docket UM 2114 and Order No. 20-41	Current deferral period is 3/24/21 - 3/23/22	None approved	3,730,918	Regulatory Liability	No	N/A	N/A
REGULATORY LIABILITIES										
254630	FAS 133 Short-term Regulatory Gains - Financial	This account is used for recording the mark-to-market adjustment for the difference between the fixed price and the fair value of a financial derivative (gains in this case) at a point in time. As required by GAAP, this account captures the adjustment for financial derivatives that will settle within 12 months. Since this relates to hedges on gas costs for sales customers, it is included in the regulatory deferrals classification. (Note: since it is a valuation at a point in time, the mark-to-market adjustments are not included in customer rates.)	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	(10,660,023)	N/A - see description	No	N/A	N/A
254635	FAS 133 Short-term Regulatory Gains - Physical	This account is used to record the fair value of the index adjuster (to be received) on existing commodity deals within the next 12 months. Since this relates to physical gas purchases for sales customers, it is included in the regulatory deferrals classification. (Note: since it is a valuation at a point in time, the mark-to-market adjustments are not included in customer rates.)	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	-	N/A - see description	No	N/A	N/A
254637	FAS 133 Short-term Regulatory Gains - Physical Options	This account captures the fair value of existing physical commodity options (gains in this case) for potential gas flows within the next 12 months using a Black 76 model calculation. Since this relates to gas costs for sales customers, it is included in the regulatory deferrals classification. (Note: since it is a valuation at a point in time, the mark-to-market adjustments are not included in customer rates.)	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	(70,128)	N/A - see description	No	N/A	N/A
254640	FAS 133 Long-term Regulatory Gains - Financial	This account is used for recording the mark-to-market adjustment for the difference between the fixed price and the fair value of a financial derivative (gains in this case) at a point in time. As required by GAAP, this account captures the adjustment for financial derivatives that will settle beyond 12 months. Since this relates to hedges on gas costs for sales customers, it is included in the regulatory deferrals classification. (Note: since it is a valuation at a point in time, the mark-to-market adjustments are not included in customer rates.)	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	(46,937,392)	N/A - see description	No	N/A	N/A
254645	FAS 133 Long-term Regulatory Gains - Physical	This account is used to record the fair value of the index adjuster (to be received) on existing commodity purchase deals beyond 12 months. Since this relates to physical gas purchases for sales customers, it is included in the regulatory deferrals classification. (Note: since it is a valuation at a point in time, the mark-to-market adjustments are not included in customer rates.)	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	(1,005,400)	N/A - see description	No	N/A	N/A

254647	FAS 133 Long-term Regulatory Gains - Physical Options	This account captures the fair value of existing physical commodity options (gains in this case) for potential gas flows beyond the next 12 months using a Black 76 model calculation. Since this relates to gas costs for sales customers, it is included in the regulatory deferrals classification. (Note: since it is a valuation at a point in time, the mark-to-market adjustments are not included in customer rates.)	Oregon - UM 1496; last approval given in Order 20-350; current period deferral requested is pending in approval	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	(187,051)	N/A - see description	No	N/A	N/A
108102	Asset Retirement Obligation - Utility	Includes the estimated future cost to remove utility plant when it is retired, offset by the estimated salvage value of those assets.	Oregon - UG 388, Order 20-364	This regulatory account is not being specifically amortized, but instead is part of Net Plant in rate base.	This balance is part of Accum. Depreciation in rate base (on an allocated basis. In the previous rate case, the test year Accum Depreciation at 10/31/2020 = $1.3b and Accum Depreciation at 10/31/2021 = $1.4b	(442,478,265)	This regulatory account is not being specifically amortized, but instead is part of Net Plant in rate base.	Yes	Accum Depreciation at 10/31/2022 = $1.5b and Accum Depreciation at 10/31/2023 = $1.6b	NW Natural/1300, Walker, Page 21-22;NW Natural/1302, Walker, Page 1; NW Natural/1312, Walker, Page 1;UG 435 - Exh. 1312 - WP1 - Gross Plant and Accum Deprec - CONFIDENTIAL Errata.xlsx
252011	CIAC - Residential New Construction - Oregon	Includes customer advances received in aid of construction.	Accounts included in rate base of most recent rate case: Oregon - UG 388, Order 20-364	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	CIAC is a reduction to rate base. The test-year balance in UG 388 was $1.0m.	(1,542,860)	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	Yes	(2,936,063)	NW Natural/1312, Walker, Page 1, UG 435 - Exh. 1312 - WP2 - Other Rate Base Items.xlsx
252013	CIAC - Residential Conversion - Oregon	Includes customer advances received in aid of construction.	Accounts included in rate base of most recent rate case: Oregon - UG 388, Order 20-364	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	CIAC is a reduction to rate base. The test-year balance in UG 388 was $2.2m.	(2,260,691)	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	Yes	(2,403,435)	NW Natural/1312, Walker, Page 1, UG 435 - Exh. 1312 - WP2 - Other Rate Base Items.xlsx
252021	CIAC - Multi-Family New Construction - Oregon	Includes customer advances received in aid of construction.	Accounts included in rate base of most recent rate case: Oregon - UG 388, Order 20-364	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	CIAC is a reduction to rate base. The test-year balance in UG 388 was $0.1m.	(110,168)	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	Yes	(187,468)	NW Natural/1312, Walker, Page 1, UG 435 - Exh. 1312 - WP2 - Other Rate Base Items.xlsx
252023	CIAC - Multi-Family Conversion - Oregon	Includes customer advances received in aid of construction.	Accounts included in rate base of most recent rate case: Oregon - UG 388, Order 20-364	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	CIAC is a reduction to rate base. The test-year balance in UG 388 was $0 02m.	(31,342)	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	Yes	(29,002)	NW Natural/1312, Walker, Page 1, UG 435 - Exh. 1312 - WP2 - Other Rate Base Items.xlsx
252031	CIAC - Commercial New Construction - Oregon	Includes customer advances received in aid of construction.	Accounts included in rate base of most recent rate case: Oregon - UG 388, Order 20-364	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	CIAC is a reduction to rate base. The test-year balance in UG 388 was $0.7m.	(1,071,809)	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	Yes	(1,165,706)	NW Natural/1312, Walker, Page 1, UG 435 - Exh. 1312 - WP2 - Other Rate Base Items.xlsx
252033	CIAC - Commercial Conversion - Oregon	Includes customer advances received in aid of construction.	Accounts included in rate base of most recent rate case: Oregon - UG 388, Order 20-364	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	CIAC is a reduction to rate base. The test-year balance in UG 388 was $0.4m.	(385,182)	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	Yes	(485,335)	NW Natural/1312, Walker, Page 1, UG 435 - Exh. 1312 - WP2 - Other Rate Base Items.xlsx
252041	CIAC - Industrial New Construction - Oregon	Includes customer advances received in aid of construction.	Accounts included in rate base of most recent rate case: Oregon - UG 388, Order 20-364	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	CIAC is a reduction to rate base. The test-year balance in UG 388 was <$0.01m	(13,989)	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	Yes	(4,353)	NW Natural/1312, Walker, Page 1, UG 435 - Exh. 1312 - WP2 - Other Rate Base Items.xlsx
252043	CIAC - Industrial Conversion - Oregon	Includes customer advances received in aid of construction.	Accounts included in rate base of most recent rate case: Oregon - UG 388, Order 20-364	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	CIAC is a reduction to rate base. The test-year balance in UG 388 was $0.1m.	(5,450)	This regulatory account is not being specifically amortized, but instead is a reduction to rate base.	Yes	(56,761)	NW Natural/1312, Walker, Page 1, UG 435 - Exh. 1312 - WP2 - Other Rate Base Items.xlsx
254301	Oregon - ISS/Optimization Revenue Sharing (Current Portion)	Includes interstate storage and optimization net revenues shared with Oregon utility customers. This account represents the portion that will be credited to customers within the next 12 months. The amount to be credited to customers beyond 12 months is included in account 254311.	Oregon: UG 344, Order 18-419 Last amortization allowed in Advice Filing 1353	Last amortization approved for bill credits in Jan., Feb., and Mar. 2022.	$41.5m regulatory liability	(41,477,059)	Regulatory Liability	No	N/A	N/A
254304	FAS 133 Gains/Losses on Optimization Contracts	This account is used to record the fair value of the optimization contracts using the same sharing inputs from the Oregon and Washington utility customer revenue sharing. As with the other FAS 133 regulatory assets and liabilities the amount represents a valuation at a point in time and is not added to or deducted from the revenues credited to utility customers.	Oregon - UG 344, Order 18-419	Deferral period coincides with the current PGA year (Nov. 2021 - Oct. 2022)	N/A - see description	-	N/A - see description	No	N/A	N/A
254311	Oregon - ISS/Optimization Revenue Sharing (Long-term Portion)	Represent's Oregon utility customers' share of revenues that will be credited beyond 12 months.	Oregon - UG 344, Order 19-105	Last amortization approved for bill credits in Jan., Feb., and Mar. 2022.	Balance plus additional accumulations will be included in the Feb. 2023 bill credits.	(1,810,486)	Regulatory Liability	No	N/A	N/A
254400	Oregon - North Mist Deferral for Gain on Sales Type lease - ST	Represents the portion of the gain calculated in accordance with GAAP for the N. Mist sales-type lease that will be amortized in the next 12 months. Since the N. Mist assets are being recovered through tariffs, the gain calculated on a GAAP basis is deferred and will reduce over the life of the lease.	n/a - for GAAP reporting purposes only	n/a - for GAAP reporting purposes only	n/a - for GAAP reporting purposes only	(729,659)	Regulatory Liability	No	N/A	N/A
254401	Oregon - North Mist Deferral for Gain on Sales Type lease - LT	Represents the portion of the regulatory liability for the N. Mist gain on sales-type lease that will be amortized beyond one year.	n/a - for GAAP reporting purposes only	n/a - for GAAP reporting purposes only	n/a - for GAAP reporting purposes only	(3,999,775)	Regulatory Liability	No	N/A	N/A
254305	Oregon Deferral of Gain on Sale of Property	Includes Oregon's portion of the net gain on sale of utility property that is to be credited to customers.	Oregon - UP 410, Order 20-495	Deferral of gain on sale of Astoria property that closed in Dec. 2021.	$0 8m regulatory liability	(776,974)	Regulatory Liability	No	N/A	N/A
254318	Deferral of Sales of OPS Leasehold Improvements	Represents the deferral of proceeds from sales of OPS Leasehold Improvements such as artwork. These amounts will be credited to customers as decided in a future proceeding.	No docket; however as customers paid for the OPS leasehold improvements, we will include the proceeds as a credit to customers in the next PGA.	N/A - see account description	None approved	(30,476)	Regulatory Liability	No	N/A	N/A
254312	Oregon Curtailment/Entitlement Revenue Deferral	Represents curtailment revenue received when an interruptible customer does not follow the order to cutail service; and entitlement revenue received when a transportation service customer does not follow the order to control gas usage to be within a specified threshold percentage per its Tariff.	Oregon - UM 2123, Order 21-454	Current deferral period is 11/1/21 - 10/31/22	See account 254313 below	(61,240)	Regulatory Liability	No	N/A	N/A
254313	Oregon Amortization of Curtailment/Entitlement Revenue Amortization	Represents the prior PGA year's deferral of curtailment and entitlement revenue currently being amortized in rates.	Oregon - UG 429, Order 21-373	Current amortization period is 11/1/21 - 10/31/22	$0 3m regulatory liability	(268,983)	Regulatory Liability	No	N/A	N/A
Number Representing Regulatory Assets		66				341,080,724	92.7%			
Number Representing Regulatory Liabilities		24				(555,914,402)	107.9%			
						(214,833,678)				

CASE: UG 435
WITNESS:STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1403
IS
CONFIDENTIAL

Exhibits in Support
Of Opening Testimony

April 22, 2022

CASE: UG 435
WITNESSES: CURTIS DLOUHY, JOHN FOX, STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1500
Deferrals Related to Covid-19

Opening Testimony

April 22, 2022

Q. Please state your business address, names, and occupations.

A. Our common business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

My name is Dr. Curtis Dlouhy, Ph.D. I am a Senior Economist within the Rates, Finance and Audit (RFA) Division of the Public Utility Commission of Oregon (Commission or OPUC).

My name is John L. Fox. I am a Senior Financial Analyst employed in the RFA Division of the OPUC.

My name is Steve Storm. I am a Senior Economist employed in the RFA Division of the OPUC.

Q. Please describe your educational background and work experience.

A. Our witness qualifications statements are found in Exhibits Staff/701, Staff/301, and Staff/1401, respectively.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to discuss NW Natural's deferral of costs associated with the COVID-19 Public Health Emergency and Staff's proposal to amortize those costs concurrently with the general rate revision in this case.

Q. How is your testimony organized?

A. Our testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Staff recommends the Commission order the Company to begin amortizing the COVID-19 deferral over a two-years period in the amount of approximately $5.8 million per year as a temporary increment in the Purchased Gas Adjustment (PGA) effective November 1, 2022. This amount represents the total amount in the deferral through 2021 as well as any accrued interest at the stipulated interest rate in Order No. 20-401. Regarding rate spread, Staff recommends several methodologies for the various components of the overall deferral.

Please note that Staff may revise its recommendations based on testimony filed by other participants in this rate case and the discovery of new information.

BACKGROUND

Q. Please a brief history of the Commission's response to the Covid-19 pandemic with respect to energy utilities.

A. In March 2020, Oregon Governor Kate Brown declared a state of emergency as a result of the COVID-19 pandemic. Later that month, all six jurisdictional energy utilities filed applications to defer costs associated with the pandemic. NW Natural's application was docketed as UM 2068.

In June 2020, the Commission initiated a public process to evaluate the impacts of the COVID-19 pandemic, including actions taken by utilities and additional actions needed to protect customers during this pandemic. A series of workshops occurred over the summer months and a formal investigation was docketed as UM 2114. In September 2020, the Commission authorized Staff and the affected utilities and stakeholders to enter into a Stipulated Agreement reflecting terms that were developed during the Commission's investigation.[1]

Q. What is the status of NW Natural's deferral application for COVID-19 related costs?

[1] See *In the* Matter *of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into the Effects of the COVID-19 Pandemic on Utility Customers*, Docket No. UM 2114, Order No. 20-324 (October 2, 2020).

A. In Order No. 20-380, the Commission approved NW Natural's application for deferred accounting of COVID-19 related costs for the 12-month period beginning March 24, 2020.[2]

NW Natural filed a supplemental application on March 23, 2021, requesting a reauthorization of the deferral for the 12-month period beginning March 24, 2021, through March 23, 2022. The supplemental application was approved at the March 22, 2022, Public Meeting under Order No. 22-093.

Q. Are there ongoing reports associated with NW Natural's deferral?

A. Yes. There are three ongoing reports.

- Docket No. RG 90 - Quarterly Report itemizing utility costs, savings, and benefits resulting from COVID-19.[3]
- Docket No. RG 94 –Monthly Report of number of customers, number of customers with arrearage balances, etc., by zip code.[4]
- Docket No. RG 98 – Monthly report for Arrearage Management Program (AMP) of total funds available, total funds available per Program option, average customer payments per option, etc.[5]

Q. Please briefly describe the intent of the Stipulated Agreement underlying the deferral.

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[2] *See In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Application to Defer Costs Associated with the COVID-19 Public Health Emergency*, Docket No. UM 2068, Order No. 20-380, Oct 27, 2020.

[3] *NW Natural Covid-19 Deferred Accounting Quarterly Report,* Docket No. RG 90.

[4] *In the Matter of Northwest Natural Gas, dba, NW Natural, Covid-19 Monthly Report*, Docket No. RG 94.

[5] *NW Natural's Arrearage Management Plan (AMP) Compliance Report, Docket No. RG 98.*

A. In November 2020, the Commission approved the Stipulated Agreement on the Effects of COVID-19 Pandemic on Energy Utility Customers.[6] The specific provisions of the Agreement are voluminous and need not be repeated here but will be briefly summarized.

As stated in the Agreement, the intent of the Stipulated Agreement is to:[7]

- Memorialize the customer protections that electric and natural gas utilities subject to the jurisdiction of the Commission have voluntarily put in place during the COVID-19 pandemic.
- Establish additional customer protections for residential and small commercial customers to mitigate the impacts from resumption of utility service disconnections and late fees.
- Establish regulatory certainty for incremental net costs that utilities have incurred and will incur as a result of the COVID-19 pandemic, including but not limited to all costs associated with the topics of the Stipulated Agreement.

Q. Does the Stipulated Agreement include a prudence review?

A. Yes. The stipulating parties agreed that the utilities' applications for deferred accounting of COVID-19 related costs and benefits should be submitted with an approval recommendation to the Commission and recovery of those amounts deferred will be subject to a future Commission prudence review as specified in paragraph 25(g). The prudence review proceeding will assure

6 In the Matter of the Oregon Public Utility Commission Investigation into the Effects of the Covid-19 Pandemic on Utility Customers, Docket UM 2114, Order No. 20-401, (November 5, 2020).
7 *Id., at* 11.

deferrals are either directly related to the Stipulated Agreement or are related to other increased costs due to COVID-19.[8]

The agreement lists a number of anticipated direct costs but also notes that "Due to the unprecedented nature of the COVID-19 pandemic, not all costs may be known at this time. Utilities are not limited to deferring costs that are expressly enumerated above; provided, however, that all such costs are subject to a future Commission prudence review proceeding."[9]

Specifically, the agreement establishes the following framework:[10]

> The Parties agree that the deferral balance will be reviewed for prudence on an annual basis. The specific timing of the annual prudency review will be established in each Utility's docket requesting deferred accounting. The timing of the amortization and the amortization period will be determined as part of the prudency review process.
>
> The deferral balance, whether being accrued (pre-prudence), found to be prudent in an annual prudence review (pre-amortization), or being amortized, shall accrue the same interest rate, equal to the blended Treasury rate plus 100 basis points. To the extent the amortization of the deferral is more than two years for a Utility that Utility may request that the Commission authorize a larger basis point spread. For regulatory and ratemaking purposes, the financing of the deferral will not be included in the capital structure of the utility.

Q. Please briefly describe the Company's current arrearage management program.

[8] *Id.,* at 19.
[9] *Id.*
[10] *Id.,* at 20.

A. In February 2021, the Commission adopted Staff's recommendations regarding arrearage management.[11] The provisions of NW Natural's program were summarized therein as follows:[12]

> This set of options provides flexibility to meet residential customer needs and also considers individual account conditions without income eligibility verification up to a program limit of $1,200.
>
> • Instant Grant Option – An option that offers a one-time grant up to $100 for the residential customer with a smaller past due or full account balance who expresses economic hardship.
>
> • 50/50 Matching Grant Option – A one-time payment match option that offers up to a $300 matching grant in the form of a credit applied to the account and eliminates a past due or full account balance.
>
> • Time Payment Arrangement (TPA) with Matching Grant Option – An option that offers a TPA in which the residential customer makes a payment each month and receives a matching grant payment to reduce the balance at the time the customer's TPA payment posts. The customer's grant is equal to 50 percent of the total account balance with matching grant payments divided up in a number equal to the number of TPA payments required by the TPA term. Grant not to exceed the $1,200 Program limit.

Q. Has the Company proposed to begin amortization of its COVID-19 deferral?

A. No.

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[11] *Covid-19 Investigation*, *Docket* No. UM 2114, Order No. 21-057.
[12] *Id., at* 13.

ISSUE 1 – STAFF'S REVIEW OF AMOUNTS DEFERRED

Q. What is the balance of the COVID-19 deferral and what does it include?

A. The Company's aggregate deferral is $10.7 million as of December 31, 2021.[13] Table 15-1 includes a breakdown of the balances by calendar year according to the Company's most recent filing in RG 90.

Table 15-1: NWN's Current UM 2068 Balances

Term Sheet Category	COVID Itemization:	2020 Total	2021 Total*	Aggregated Total*
Item a	**Direct Costs**	$ 2,517,468.93	$ 763,710.50	$ 3,281,179.43
Item a	**Direct Savings and Benefits**	$ (237,839.11)	$ (576,188.38)	$ (814,027.85)
	Travel, meals and entertainment related	$ (236,843.18)	$ (362,052.85)	$ (598,896.03)
	Employee expenses: education and refreshments		$ (201,228.65)	$ (201,228.65)
	Interest	$ (995.93)	$ (12,906.88)	$ (13,902.81)
Item b	**Late Payment Fees Not Assessed**	$ 1,254,486.50	$ 1,263,278.35	$ 2,517,764.85
Item c	**Bad Debt Expense Above Baseline**	$ 2,093,760.75	$ (134,083.65)	$ 1,959,677.10
	Residential	$ 1,188,554.27	$ 212,534.76	$ 1,401,089.03
	Commercial	$ 853,113.58	$ (299,948.26)	$ 553,165.32
	Industrial	$ 29,303.25	$ (100,268.41)	$ (70,965.16)
	Interest	$ 22,789.40	$ 53,598.26	$ 76,387.66
Item d	**Reconnections and Field Visits Apr. 1, 2021-Oct. 1, 2022**	$ -	$ -	$ -
Item e	**Foregone Reconnection Charges through Nov. 15, 2020**	$ -	$ -	$ -
Item f	**COVID-19 Bill Payment Assistance Program**	$ -	$ 3,730,917.93	$ 3,730,917.93
	Total**	**$ 5,627,877.06**	**$ 5,047,634.75**	**$ 10,675,511.46**

As agreed to by all parties as part of the Stipulated Agreement in November 2020, this amount includes the following elements:

- Direct Costs of reasonable measures taken by the Utility in response to the COVID-19 pandemic.
- Direct Savings and Benefits received from government agencies or forgone due to changes in business.
- Late Payment Fees Not Assessed.

[13] See *NW Natural's REVISED COVID-19 Deferred Accounting Quarterly Report*, Docket No. RG 90, Supplemental Application filed January 28, 2022.

- Bad Debt Expense Above Baseline, as determined by the Company's last general rate proceeding.
- COVID-19 Arrearage Management Program (AMP). This may also be referred to as a Bill Payment Assistance Program.

As $10.7 million is a significant amount due to the Company, Staff recommends the Company begin amortization concurrent with the effective date of the base rate increase in this case, November 1, 2022.

Q. The Company incurred zero expenses in categories (d) and (e) in Table 15-1 above. Why is this the case?

A. It is unclear why there were no charges in 2021 for item (d) or 2020 for item (e). However, item (e) was meant to expire before 2021 and item (d) did not begin until 2021, so it makes sense that those terms should have zero expenses. Staff continues to investigate this issue.

Q. Does Staff have the information necessary to determine the prudence of deferred amounts at this time?

A. Yes. To supplement the information included in the Company's January 28, 2022, filing in Docket No. RG 90, Staff issued data requests in Docket No. UM 2068 to further investigate the values included in the Company's COVID-19 deferral.

Q. What issues does Staff anticipate will need additional analysis during the prudence review?

A. Staff notes that there is a discrepancy in reporting between the six Oregon-regulated utilities, particularly in the area of Direct Savings and Benefits. As per the terms of the Stipulated Agreement, the Company is required to track:

> Direct costs are net of credits, payments, direct cost savings, or other benefits received by the Utility from a federal, state, or local government that are directly related to a COVID-19 direct cost, including federal, state, or local tax credits or benefits.[14]

This language contains two parts, one that is easy to verify and another that is not easily verified. The easier part is the external benefits, including tax credits, received by the Company from a government agency because they can be identified by a clear policy change that is external to the Company or an inflow of cash to the Company. The harder item to track is the direct cost savings due to operational changes.

Q. Why does Staff believe that the direct cost savings are more difficult to track?

A. Unlike benefits received directly from a government agency, direct cost savings have elements of endogeneity and opaqueness that can be harder to disentangle. That is, how the Company adapted *internally* is harder to measure than the benefits it is receiving *externally*. Further, the Company may not have included some items in its cost savings category that Staff would include. While Staff does not claim that there was any intentional obfuscation, Staff notes that the quarterly updates in Docket No. RG 90 contain only a

[14] *Covid-19 Investigation*, Docket No. UM 2114, Order No. 20-401, Appendix A, page 19.

single line item that aggregates all benefits with a short description of what is contained in that category.

Q. What has Staff done to facilitate its investigation of direct cost savings?

A. Staff issued Staff DR No. 414.[15] In this data request, Staff highlights eight areas where it anticipates that there were significant cost savings due to the COVID-19 pandemic and asked the Company to compare the amounts included in rates to the actual expenses incurred in 2020 and 2021.

Q. What are the results of your analysis of the Company's response to Staff DR No. 414 and other discovery requests?

A. Based on Staff's analysis of the Company's most recent filing in Docket No. RG 90 and the Company's responses to Staff Data Requests, Staff has made changes to the following items relative to the Company's January 28, 2022, filing in RG 90:

- Adjust the 2020 and 2021 Bad Debt expense to conform to the Company's response to Staff DR No. 416 Attachments 1 and 2.[16]
- Adjust Late Payment Fees Not Assessed for 2020 and 2021 to conform to the Company's response to Staff DR No. 417 Attachment 1 and to eliminate values that occurred before the Company's initial filing of UM 2068.[17]

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15 Staff/1501, Dlouhy-Fox-Storm/3.
16 Staff/1501, Dlouhy-Fox-Storm/6.
17 Staff/1501, Dlouhy-Fox-Storm/29.

- Adjust the timing of some of the entries into the Employee Expenses line item to conform to the Company's response to Staff DR No. 414.[18]

Q. Please describe how the Company's responses to data requests lead you to conclude that the total amount included in the Company's COVID-19 deferral is does not accurately account for the Company's net Covid-19 costs?

A. It should be stated that Staff is still continuing to investigate some costs in this docket. However, Staff issued data requests asking the Company to disaggregate the Company's COVID-19 cost savings into various categories that were reported by other utilities but did not seem explicitly included in the Company's reports in the RG 90 docket. The Company included the disaggregation of these cost savings in response to Staff DR No. 414.[19] Staff compared these benefits to the benefits included in the most recent RG 90 filing.

In Staff DR No. 416 Staff asked the Company to demonstrate its Bad Debt expense calculation,[20] and in Staff DR No. 417 Staff asked the Company to demonstrate its Late Payment Fee expense calculations.[21] Staff compared these values to those included in the Company's most recent filing in Docket No. RG 90 and to the Company's initial filing of its COVID-19 deferral in Docket No. UM 2068.

18 Staff/1501, Dlouhy-Fox-Storm/3.
19 Staff/1501, Dlouhy-Fox-Storm/3.
20 Staff/1501, Dlouhy-Fox-Storm/5.
21 Staff/1501, Dlouhy-Fox-Storm/29.

Q. Please describe your adjustments to the Company's Bad Debt Expense included in this deferral based on the Company's most recent RG 90 filing and the Company's response to Staff DR No. 416.

A. In its most recent filing in the RG 90 docket, the Company includes an Oregon-allocated Bad Debt Expense of $2,093,761 for 2020 and -$134,084 for 2021, reflecting that customer debt repayment to the Company was actually better than its pre-pandemic baseline.

In the Company's attachments included in its response to Staff DR No. 416, the Company calculates that it should include $2,074,679, for 2020, and -$187,682, for 2021, on an Oregon-allocated basis. The Company's workbook seems to indicate that the Company properly excluded the months prior to its initial filing of UM 2068 when calculating its Bad Debt Expense.

For the time being, we recommend adjusting both the 2020 and the 2021 values to reflect the Company's recent data responses. This lowers the 2020 bad debt expense by $19,082 and the 2021 bad debt expense by $53,598. Staff has issued follow-up data requests to dig deeper into the allocation of the bad debt expense between customer classes.

Q. Please describe your adjustments to the Company's Late Fee Expense based on the Company's most recent RG 90 filing and the Company's response to Staff DR No. 417.

A. In its most recent filing in the RG 90 docket, the Company includes $1,254,487 in 2020 and $1,263,278 in 2021 for its Late Fee Expense.

In the workbook provided by the Company in response to Staff DR No. 417, the Company calculates its 2021 Late Fees deferred as $1,173,020.

For 2020, it appears that the Company uses all of January, February, and March to calculate the amount of Late Fees to put into its deferral even though the Company didn't file its deferral until March 24, 2020.[22] Using the workbook provided by the Company in response to Staff DR No. 417, Staff eliminated late fees accrued in January and February of 2020. Staff further scaled down the March 2020 expense by 8/31 to account for the deferral only being active for eight days in March. This brings the Company's total Late Fee Expense included in this deferral to $1,112,539 in 2020.

Staff recommends adjusting the Company's Late Fee Expense to the two values found in the Company's response to Staff DR No. 417 after excluding the dates before the beginning of the deferral. This lowers the deferral balance's Late Fee Expense by $141,948 in 2020 and $90,258 in 2021.

Q. Please describe Staff's adjustments to the Company's Cost Savings based on the Company's most recent RG 90 filing and the Company's response to Staff DR No. 414.

A. Staff finds no issue with the total amount included in the Cost Savings category in the Company's COVID-19 deferral but believes that the timing of the amounts entered into the deferral is not correct. In its most recent filing of RG 90, the Company does not list any cost savings under the Employee Expenses: education and refreshments category until the first quarter of 2021.

[22] Staff/1501, Dlouhy-Fox-Storm/29.

This is inconsistent with the Company's response to Staff DR No. 414 where it indicates that $157,955 of these savings occurred in 2020.

Staff recommends moving this amount to 2020 to properly align the timing of costs.

Q. Please summarize all of your adjustments based on your review of the costs included in the Company's COVID deferral.

A. Table 15-2 contains the costs and timing of costs that Staff believes to be appropriately accrued in the Company's COVID-19 Deferral at this time. Staff also finds no costs in the table below that Staff believes were imprudent.

Table 15-2: Prudent Costs in UM 2068

Term Sheet Category	COVID Itemization:	2020 Total	2021 Total*	Aggregated Total*
Item a	**Direct Costs**	$ 2,517,468.93	$ 763,710.50	$ 3,281,179.43
Item a	**Direct Savings and Benefits**	$ (395,794.11)	$ (418,233.38)	$ (814,027.49)
	Travel, meals and entertainment related	$ (236,843.18)	$ (362,052.85)	$ (598,896.03)
	Employee expenses: education and refreshments	$ (157,955.00)	$ (43,273.65)	$ (201,228.65)
	Interest	$ (995.93)	$ (12,906.88)	$ (13,902.81)
Item b	**Late Payment Fees Not Assessed**	$ 1,112,539.00	$ 1,173,020.00	$ 2,285,559.00
Item c	**Bad Debt Expense Above Baseline**	$ 2,074,679.00	$ (187,682.00)	$ 1,886,997.00
	Residential	$ 1,188,554.27	$ 212,534.76	$ 1,401,089.03
	Commercial	$ 853,113.58	$ (299,948.26)	$ 553,165.32
	Industrial	$ 29,303.25	$ (100,268.41)	$ (70,965.16)
	Interest	$ 22,789.40	$ 53,598.26	$ 76,387.66
Item d	**Reconnections and Field Visits Apr. 1, 2021-Oct. 1, 2022**	$ -	$ -	$ -
Item e	**Foregone Reconnection Charges through Nov. 15, 2020**	$ -	$ -	$ -
Item f	**COVID-19 Bill Payment Assistance Program**	$ -	$ 3,730,917.93	$ 3,730,917.93
	Total**	**$ 5,308,892.81**	**$ 5,061,733.05**	**$ 10,370,625.87**

ISSUE 2 – EARNINGS REVIEW AND AMORTIZATION

Q. Please discuss the requirement for an earnings review prior to amortization.

A. ORS 757.259(5) states that unless subject to an automatic adjustment clause, amounts deferred under ORS 757.259 shall be allowed in rates only to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates, and upon review of the utility's earnings at the time of application, to amortize the deferral. The Commission may require that amortization of deferred amounts be subject to refund. The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility.

Q. Does Staff need any more information to conduct an earnings review pursuant to ORS 757.259(5)?

A. Yes. As the $10.7 million deferred amount spans both 2020 and 2021, Staff believes it is appropriate to wait until after May 1 to complete the earnings review so we can incorporate additional information.

Q. What is the method of amortization proposed by Staff?

A. Staff proposes that amounts deferred through December 2021 be amortized as a temporary increment in the Company's Purchased Gas Adjustment (PGA) over two years beginning November 1, 2022. The total outstanding deferrals for 2020 and 2021 are $5.309 million and $5.062 million, respectively.

Accordingly review of 2020 earnings at this time will account for the entire amount proposed for return to customers in the 2022-23 PGA year.

Q. Please discuss Staff's proposed earnings thresholds for amounts deferred in 2020.

A. Staff proposes the following earnings thresholds:

- Item (a): Authorized ROE (9.40 percent) less 50 basis points or 8.90 percent.
- Items (b) through (f): Staff proposes full recovery of these amounts.

Q. Why does Staff propose ROE less 50 basis points for item a?

A. The Commission has clarified that "the earnings test, coupled with deferral and amortization, is designed to ensure that utilities do not receive the extraordinary relief of retroactive rate making for added costs when earnings exceed a reasonable rate of return."[23] What is a reasonable rate of return for purposes of the earnings review depends on the nature of the deferral.[24] Unlike the amounts at issue for items (b) through (f), the amounts deferred for category (a) are simply changes in revenues and costs NWN experienced during the pandemic. NWN's experience in this regard was not unique and many business owners suffered the same impacts.

The shift to remote work arrangements and other measures to adjust business processes due to the COVID-19 pandemic were borne by all organizations in the economy. Although Staff concludes the amounts deferred

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[23] *In re Portland General Electric Co*., Docket No. UE 82, Order No. 93-257 (February 22, 1993).
[24] *Id.*

for Item (a) are recoverable, Staff sees no reason NWN should be allowed to completely avoid the negative impacts of Covid-19 with an earnings test benchmark that would allow it to pass these negative impacts on to ratepayers, up to the point NWN earns its authorized rate of return.

In Staff's view, an earnings test threshold set at AROE minus 50 basis points is a reasonable benchmark that would allow NWN to amortize deferred net costs associated categorized as Item (a) up to a rate of return that is reasonable for a period during which many people and business suffered negative economic consequences of a pandemic.

Q. Why does Staff propose full recovery for items (b) through (f) in Table 15-2?

A. At the outset of the pandemic the Commission and stakeholders initiated an extensive public process to mitigate the effect of the COVID-19 pandemic on utility customers. In Staff's view, items (b) though (f) ought to be recovered in full as they are specific measures agreed upon by the utilities and stakeholders and approved by the Commission to mitigate the pandemic impact.

Q. Please discuss Staff's review of 2020 earnings.

A. As discussed above, $5.309 million has been deferred for 2020.

- Item (a) - $2.122 million
- Items (b) through f - $3.187 million

NW Natural reports that deferred costs have been recorded in a regulatory asset and would have been recorded in various expense accounts if deferred accounting had not been approved.[25] NW Natural reported a 2020 actual return on equity (ROE), without the deferred expenses, of 8.56 percent.[26]

Accordingly, as actual earnings are below the proposed threshold of 8.90 percent, Staff concludes that the entire $2.122 million deferred amount for item (a) can be recovered in rates.

Q. Does Staff's review of 2020 earnings supplant the Company's annual spring earnings review?

A. No, it does not. Staff's review above ensures the Company's has not over earned in 2020 as a result of removing the deferred expenses from operating results. The Purchased Gas Adjustment (PGA) process ensures that the Company does not over earn in any particular year after considering all deferrals being amortized and also that the aggregate deferrals do not exceed the statutory limits.

Q. Please briefly discuss the earnings review mechanism for the PGA.

A. Pursuant to OAR 860-022-0070, Order No. 08-504 in Docket No. UM 1286, and Order No. 04-203 in Docket No. UM 903, each natural gas Local Distribution Company (LDC) with a Purchase Gas Adjustment (PGA) is subject to a spring earnings review.

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25 See *In the Matter of Northwest Natural Gas Company, dba, NW Natural, Application to Defer Costs Associated with the COVID-19 Public Health Emergency*, Docket No. UM 2068, initial application, Mar 24, 2020 at 3 and Order No. 20-380, Oct 27, 2020 at 6.

26 See *In the Matter of Northwest Natural Gas Company, dba, NW Natural, Annual Earnings Review Report, Docket No. RG 40*, Supplemental Application: NW NATURAL's Annual Earnings Review Report for year ending December 31, 2020, filed Apr 30, 2021.

Each year the Commission establishes Gas Earnings Threshold (GET) limits based on the prior year results of operations. This information is published on the PUC website in January of each year.[27] For 2022, NW Natural's GET is 10.50 percent compared to the Company's currently approved return on equity (ROE) of 9.40 percent.

Q. Please briefly discuss the spring earnings review.

A. To ensure that earnings of a natural gas utility are not excessive prior to passing through prudently incurred base gas costs, the Commission, by rule (OAR 860-022-0070), requires that an earnings review be conducted on an annual basis. The most recent review occurred subsequent to filing of the Company's 2020 results of operations.[28] Staff reviewed the Company's ROO report and the supporting work papers and concluded that NW Natural's reported ROE had been calculated correctly. Because NW Natural's 2020 adjusted ROE of 8.56 percentwas below the 2021 GET of 10.40 percent, no Earnings Sharing was required.

Q. Please discuss the requirement that deferrals not exceed three percent of revenue.

A. ORS 757 .259(6) states that the overall average rate impact of the amortizations authorized under this section in any one year may not exceed three percent of the utility's gross revenues for the preceding calendar year. ORS 757.259(7) allows the Commission to consider an overall average rate

[27] https://www.oregon.gov/puc/forms/Forms%20and%20Reports/Gas-Earnings-Threshold-GET.pdf

[28] See *Purchase Gas Adjustments*, Docket No. UM 903, Order No. 21-230 (Jul 15, 2021).

impact greater than that specified in subsection (6) for natural gas commodity and pipeline transportation costs incurred by a natural gas utility, if the Commission finds that allowing a higher amortization rate is reasonable under the circumstances.

Q. Please discuss how the three percent test is applied with respect the PGA.

A. The annual average rate impact of the amortizations authorized under the statutes may not exceed three percent of the natural gas utility's gross revenues for the preceding calendar year unless the Commission finds that allowing a higher amortization rate is reasonable under the circumstances. Staff evaluates this on an annual basis and makes an appropriate recommendation to the Commission. In the most recent PGA, NW Natural's authorized amortizations were 6.16 percent of gross revenues.[29]

Q. Please discuss why amortization of the outstanding COVID-19 deferral amounts in the PGA is in customers' best interests.

A. Amortizing the COVID-19 deferral through the PGA promotes administrative efficiency by utilizing an existing annual rate update mechanism and thereby minimizes the frequency of rate changes by considering the effects of the COVID-19 deferral along with the Company's other annual rate changes. This approach also promotes efficiency by allowing the Commission to consider

[29] See *In the Matter of Northwest Natural Gas Company, dba, NW Natural, Request for Amortization of Certain Deferred Accounts Related to Gas Costs*, *Schedules P, 162, 164,* Docket No. UG 432, Order No. 21-376, Attachment C (Oct 28, 2021).

amortization of the COVID-19 deferral and its effects on earnings on a holistic basis.

ISSUE 3 – RATE SPREAD

Q. What costs are pertinent to this issue regarding rate spread?

A. The costs pertinent to the rate spread issue are those in Table 15-2 above and reflect COVID deferrals for 2020 and 2021. Amounts included in Table 15-2 are those reported by NW Natural that Staff finds are appropriately included in the deferral. Staff's rate spread analysis uses amounts resulting from Staff adjustments, as discussed above.

Q. How did Staff approach this issue?

A. Staff recommends a different approach to rate spread for each of three different COVID costs, or groups of costs, considered in this proceeding and shown in Table 15-2. These are:

- Items (b) plus (d) through (f);
- Item (c) Bad Debt; and
- Item (a) Direct Costs and Direct Savings and Benefits.

Staff's recommended rate spread approaches use deferral dollar amounts after Staff adjustments; i.e., as shown in Table 15-2.

Staff first discusses the rate spread and amortization of COVID Items (b) plus (d) – (f). These involve amounts associated with:

- Item (b), Late Payment Fees Not Assessed;
- Item (d), Reconnections and Field Visits;
- Item (e), Foregone Reconnection Charges Incurred; and

- Item (f), COVID-19 Bill Payment Assistance Program.[30]

NW Natural reported these costs by quarter for the period Q1 2020 through Q4 2021 in the confidential version of its Oregon Quarterly COVID report filed January 28, 2022.[31]

NW Natural's reporting itemizes Item (c) by customer class and the rate spread for these amounts will be addressed within this Issue after Items (b) plus (d) – (f). Staff notes that Items (d) and (e) had no charges per NW Natural's January 28, 2022, report covering the Q1 2020 through Q4 2021 period.

Q. Please provide Staff's perspective on the credits NW Natural has provided customers during the COVID pandemic.

A. Staff views the credits as conceptually similar to short-term transfer payments from a government agency to consumers (and for Item (c) – Bad Debt Expense above Baseline – transfer payments to each customer class) because these costs are being incurred by NW Natural in concert with and at the behest of the Commission.[32] When discussing these transfer payments, Staff views any discrepancy between all consumers living within NW Natural's Oregon service area and those consumers living within the Company's Oregon service area

30 The Bill Payment Assistance Program is also referred to as the Arrearage Management Program (AMP), as noted above. *See* Section f on page 20 of Attachment A to Order No. 20-401 in UM 2114.

31 NW Natural's January 28, 2022, filing included in the cover letter that information in the filing was confidential, but would not require the *confidential* designation after February 25, 2022.

32 *See* Order No. 20-401, which authorized multiple changes in prior Oregon investor-owned energy utility operating policies resulting from a Stipulated Agreement between numerous parties to the proceeding. One authorized change was the utilities' use of deferred accounting of costs and benefits related to COVID-19, with recovery of those amounts to be subject to a future Commission prudence review proceeding.

who do not receive residential gas service as not material for Staff's purposes here.

Q. What NW Natural costs are included in the Items (b) plus (d) – (f)?

A. These are reproduced in Table 15-3 below and reflect Staff's adjustments shown in Table 15-2.

Table 15-3: Certain Covid-19 Related Costs for 2020 and 2021 ($Thousands[33])

Item	Description	Total 2020	Total 2021
b	Late Payment Fees Not Assessed	$1,112.5	$1,173
d	Reconnections & Field Visits	$0.0	$0.0
e	Foregone Reconnection Charges	$0.0	$0.0
f	COVID-19 Bill Payment Assistance Program	$0.0	$3,730.9
Total		$1,112.5	$4,903.9

Q. How does Staff propose to spread the 2020 and 2021 amounts in Table 15-3 between customer classes?

A. Staff relies upon the proposal that certain subsets of consumers were provided a short-term credit against their energy bills, which allows them to spend more than they otherwise would on other categories in their budget, such as food, shelter, and transportation.[34] This leads to a fiscal multiplier effect on the total output of Oregon's economy, with benefits received well beyond the actual recipients of the credits.

[33] Table totals may differ from addition of line values due to rounding.

[34] Staff notes that, for residential customers of energy utilities, such credits may not have allowed customers to <u>increase</u> their spending on other categories, but only to <u>maintain at some level</u> such spending.

Q. How is the total output of an economy measured?

A. There are three common ways economists measure the total output, or Gross Domestic Product (GDP), of an economy.[35] The first is by adding the amount of goods and services sold to final users, which are persons, businesses, governments, and foreigners. This is also described as the expenditures approach.

Q. What are the components of "goods and services sold to final users" in the expenditure approach?

A. Staff follows the Bureau of Economic Analysis' (BEA) national income taxonomy on this point, where BEA categorizes such amounts as either personal consumption expenditures, gross private fixed investments, the change in private inventories, government consumption expenditures and gross investment, or the net exports of goods and services.

Q. What are the other two approaches to measuring GDP?

A. The second approach is the sum of income payments and other costs incurred in the production of goods and services, known as the income approach. The components of this approach are compensation of employees, taxes on production and imports, subsidies paid by government (a subtraction), net operating surplus (related to some concepts of "profit"), and the consumption of fixed capital (similar to depreciation).

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[35] *See* pages 2-7 – 2-11 of Chapter 2: Fundamental Concepts of BEA's National Income and Product Accounts (NIPA) Handbook (BEA, updated December 2020), retrieved by Staff on March 28, 2022 from https://www.bea.gov/resources/methodologies/nipa-handbook .

The third approach is to use the sum of "value added" by all industries in the economy.

Q. Is GDP compiled and reported for Oregon?

A. Yes, and actual values as well as forecasts of GDP and certain components are provided by Oregon's Office of Economic Analysis, an organization within the State's Department of Administrative Services (DAS).[36] Actuals for both GDP and certain components of GDP are reported not only by OEA, but also by agencies of the Federal government, such as BEA. BEA is part of the U.S. Department of Commerce.

Q. What component has the largest share of Oregon's GDP?

A. The largest component is personal consumption expenditures, which is the largest by far. During a three-year pre-COVID baseline of 2017 – 2019, Oregon's personal consumption expenditures averaged 73.2 percent of Oregon's GDP.[37]

Q. You mentioned a fiscal multiplier effect due to the credits NW Natural's residential customers received. How large is this multiplier effect?

A. The Congressional Budget Office (CBO) prepared estimates of the fiscal multiplier for the U.S. economy associated with the effects of Federal COVID-19 pandemic-related legislation.[38] These were estimated as the cumulative

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[36] *See* at https://www.oregon.gov/das/OEA/Pages/Index.aspx (accessed by Staff on March 28, 2022).

[37] Calculated using values Staff retrieved from BEA on March 23, 2022.

[38] See "Key Methods That CBO Used to Estimate the Effects of Pandemic-Related Legislation on Output, "Working Paper 2020-07" by Seliski, et al (CBO, October 2020). Retrieved by Staff on March 28, 2022, from https://www.cbo.gov/publication/56612

effect of such incremental fiscal policies over a four-quarter period corresponding to Q2 2020 through Q1 2021. Staff includes in Table 15-4 below key estimates included in CBO's Table 2.[39] Note that CBO's estimated central values are averages of the "Low" and "High" values.[40]

Table 15-4: Changes in Output from One Dollar of Direct Effects on Overall Demand When Output Is Well Below Potential and the Federal Reserve's Responses Are Limited

			Under Social Distancing	
	Low Estimate	High Estimate	Low Estimate	High Estimate
Cumulative Effect Over 4 Quarters	0.50	2.50	0.31	1.78

Q. What key assumptions did CBO make in developing these estimated multiplier values?

A. CBO assumed, as stated above, that there would not be any effects beyond the fourth quarter following the initial impact of a measure.

Q. Is this a reasonable assumption given the credits to NW Natural Residential customers in this context?

A. Probably, and especially as pertaining to expenditures made by Residential customers receiving credits, i.e., the direct effects. Staff believes it likely that recipients collectively spent most of the value of the credits in short order. Again, the credits may have only allowed recipients to continue their usual expenditure patterns on things like food, shelter, and transportation. Some indirect effects will likely take somewhat longer to be realized.

39 *Id.*, page 24.
40 *Id.*, page 5.

Q. What are other key assumptions?

A. Two other key assumptions are indicated by language in the label for Table 15-4:[41] 1) output (GDP) is well below potential and 2) the Federal Reserve's policy responses to COVID-related fiscal stimulus are limited.

Q. Does Staff believe each of these assumptions applied in the 2020 through Q3 2021 period?

A. Yes. Figure 15-1[42] shows that Oregon's nominal GDP was below the Q1 2017 – Q4 2019 trend from the pandemic's onset in Q1 2020 until very recently. Data not yet available as of the date of this testimony will presumably indicate whether Oregon's GDP is fully "on trend" in the near-term.

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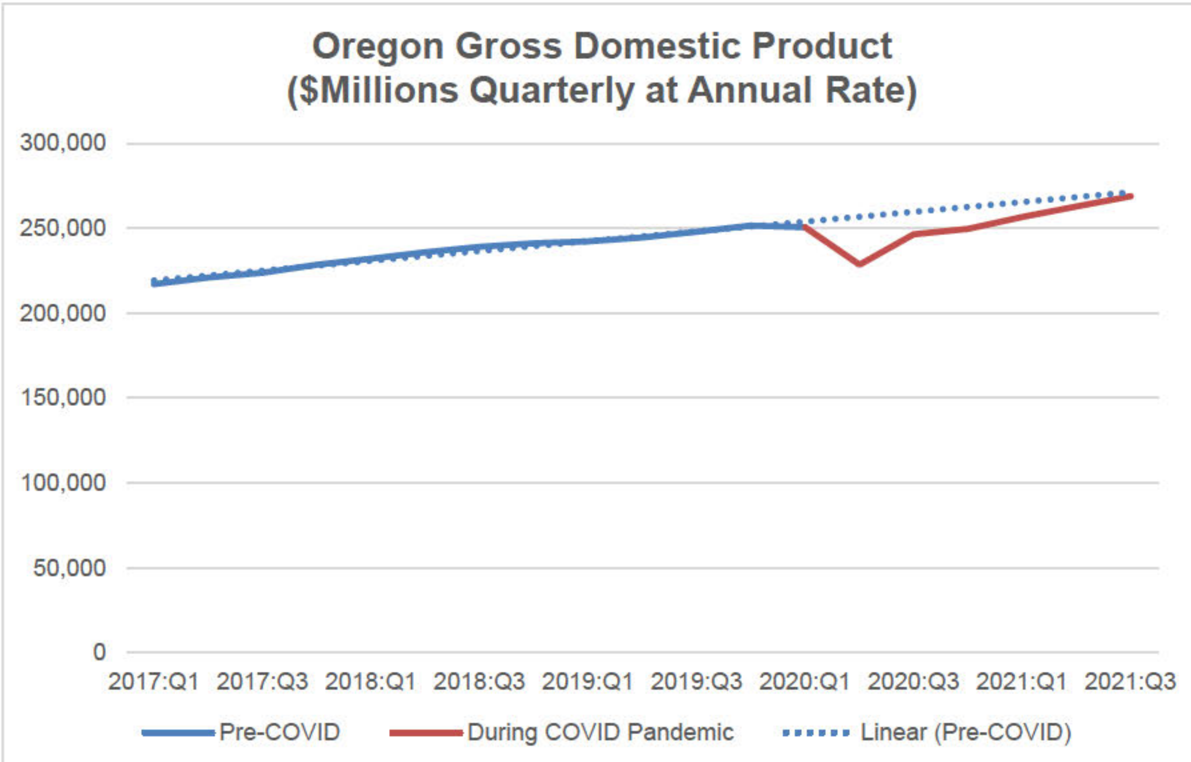
41 *Id*., page 24. See CBO's *label* for their Table 2, which Staff has replicated for Table Z.
42 Underlying data retrieved by Staff March 23, 2022, from BEA.

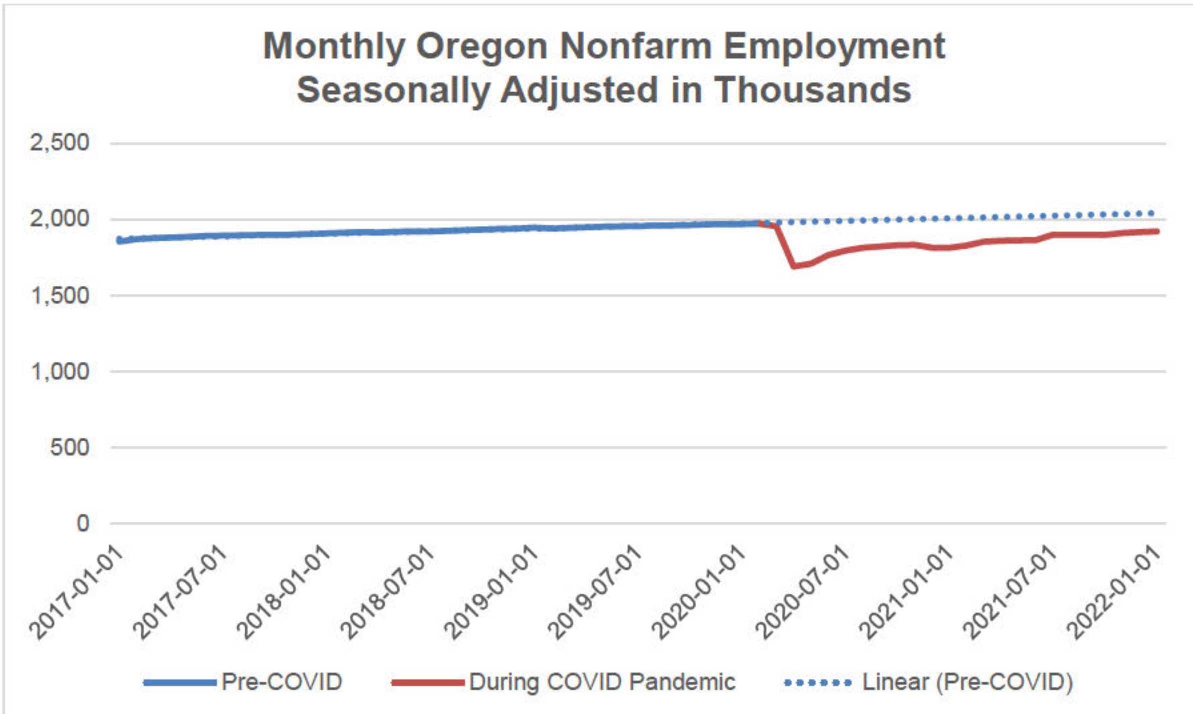
Figure 15-1: Oregon Nominal Gross Domestic Product: Q1 2017 – Q3 2021



Reviewing labor market data indicates Oregon may not have reached potential levels of demand, as the nonfarm employment level remains not only under the 2017 – 2019 trend, as shown in Figure 15-2,[43] but also below the pre-COVID peak.

[43] Underlying data retrieved by Staff on March 23, 2022, from FRED.

Figure 15-2: Oregon's Nonfarm Employment 2017 – 2021



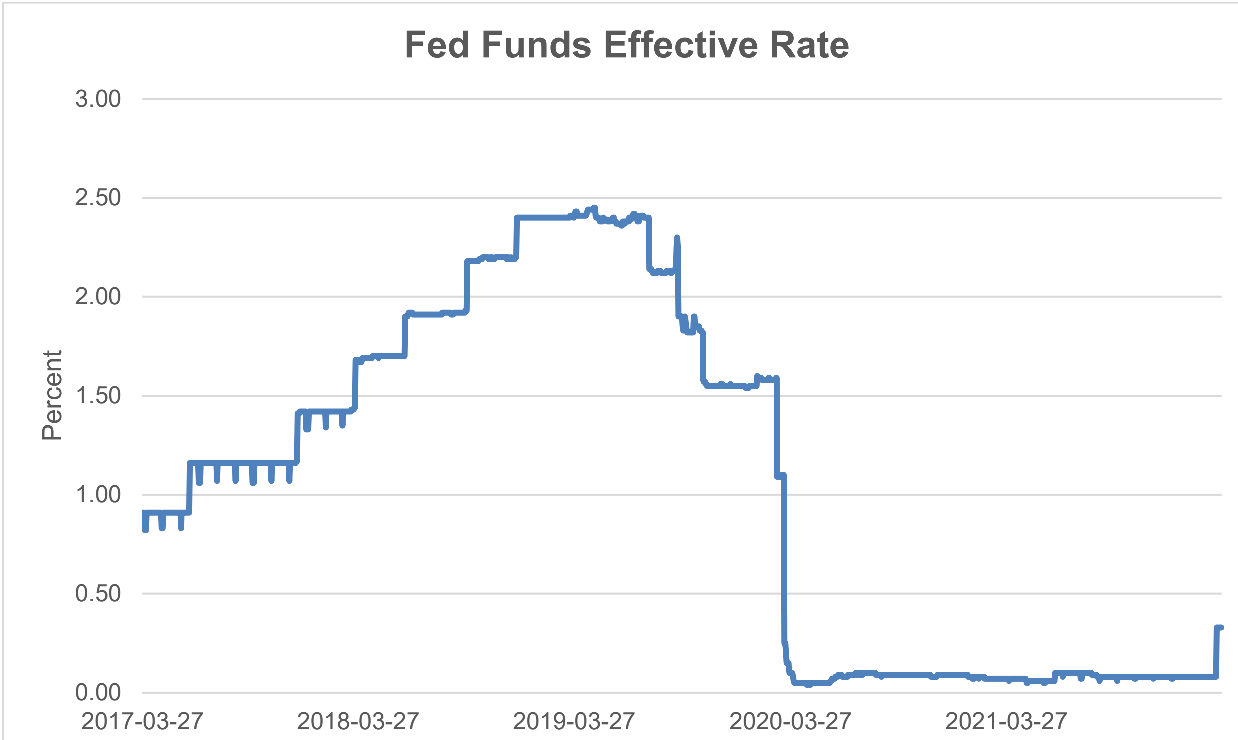
Q. What about the assumption that the Federal Reserve's policy responses to the COVID pandemic were limited?

A. Oregon has neither its own currency nor associated money supply, and U.S. monetary policy is largely implemented by the Federal Reserve Bank (Federal Reserve or Fed). Given that, this assumption is also largely validated. The Federal Reserve, early in the pandemic, reduced the Fed Funds rate to near zero; i.e., the Fed's incremental policy moves were constrained by a zero lower bound (ZLB) on the Fed Funds rate, as shown in Figure 15-3.[44] After the initial reduction at the pandemic's onset, the Federal Reserve's primary policy tool

[44] Underlying data retrieved by Staff on March 23, 2022, from FRED.

could not be effectively lowered, indicating it had limited policy options at the time NW Natural's customers began receiving the Company's credits.

Figure 15-3: Federal Funds Effective Rate



Q. Returning to potential values of a multiplier to use for analyzing the impact of NW Natural's credits to ratepayers, which CBO value does Staff advocate using?

A. None of them. Staff believes a more realistic value for the multiplier results from assuming the amount of the provided credit Residential customers spent — as opposed to saved – was larger than that implied by any of CBO's multiplier values. Staff uses a 0.90 marginal propensity to consume (MPC) value, which implies a fiscal multiplier value of 10. The intuition here is that a large share of customers receiving credits during the pandemic were probably not doing much – if any – incremental savings, and a 0.10 value for the marginal propensity to save (MPS) – meaning the average customer receiving one or more credits spent 90 percent of the credits' aggregate value – seems eminently reasonable to Staff.

Q. What is the marginal propensity to consume?

A. It is the proportion of fiscal stimulus that will be spent, and not saved, by Residential customers.

Q. If Personal Consumption Expenditures represented 73.2 percent of Oregon's GDP during the 2017 – 2019 baseline period, and recipients of NW Natural's credits spend 90 percent of those credits, should Residential customers pay for the entire cost of NW Natural's having provided those credits?

A. Staff has concluded they should not and considers two additional facets to this question. Who else benefits when a Residential customer spends $0.90 of each dollar's worth of credit received? Indirect benefits accrue to Residential customers as a class, and one example of this is that spending assists in keeping employment levels higher than would otherwise be the case. Additionally, the owners of commercial and industrial enterprises benefit, in the form of increased earnings paid to proprietors (for non-corporate ownership structures), increased dividends paid to corporate owners, as well as corporate owners benefiting from increased retained earnings in the future. As stated above, benefits may take the form of a lower reduction that might otherwise be the case.

Q. Are these "corporate owners" shareholders?

A. Yes; if the enterprise is a share-issuing corporation, shareholders are the owners and beneficiaries of share-issuing corporations. Terms used for owners of other organizational structures may differ; e.g., a limited liability company (LLC)[45] may have "members" and not "shareholders," while owners of partnerships have "partners."

Q. Shareholders of some corporations are other corporations, foundations, or government entities, such as Oregon's PERS through its investment portfolio. Who benefits in these situations?

A. The corporate owner and its shareholders are the beneficiaries in corporate ownership structures. The beneficiaries of a foundation having shares of corporations in its investment portfolio are presumably individuals and beneficiaries of PERS are individual retirees from the State of Oregon.

Q. If individuals are the beneficiaries of incremental amounts received from such organizations, what happens to the amounts they receive as dividends, charitable benefits, pension payments, etc.?

A. Individuals both spend a portion and save a portion of such amounts.

Q. Why does Staff include the owners of Industrial companies as indirect beneficiaries of credits received by Residential customers of NW Natural?

[45] LLCs may have features of both partnerships and corporations. See; e.g., Investopedia at https://www.investopedia.com/terms/l/llc.asp#:~:text=A%20limited%20liability%20company%20(LLC)%20is%20a%20business%20structure%20in,a%20partnership%20or%20sole%20proprietorship. (accessed by Staff April 11, 2022).

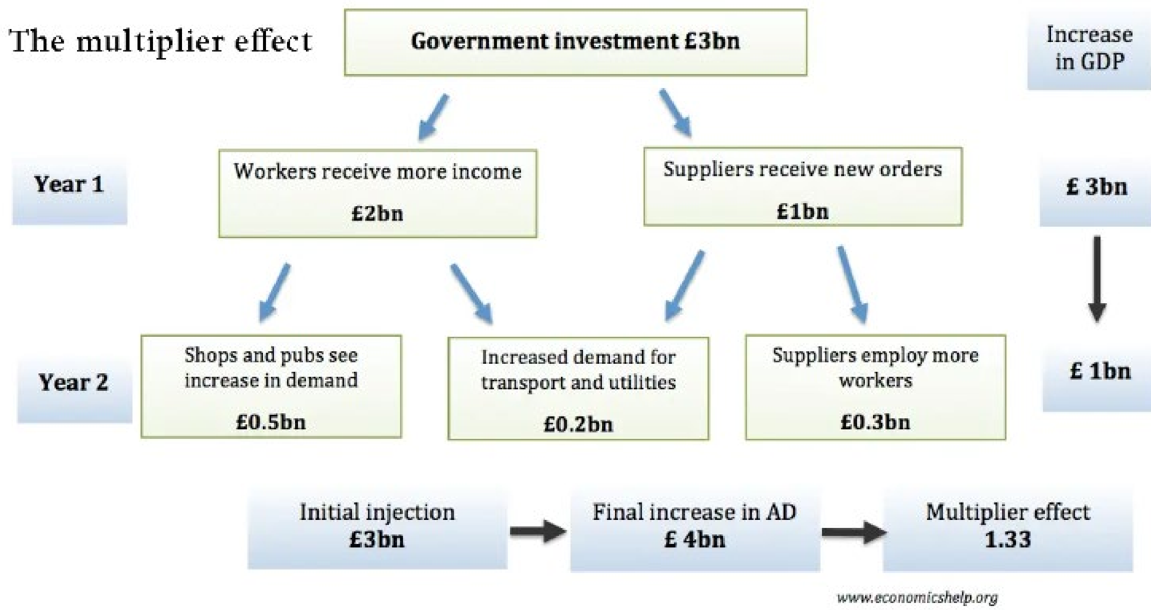
A. Benefits to owners of industrial companies are illustrated by the increase in sales, prices, or both due to the toilet paper shortage, early in the pandemic, as an example. Consumers depleted existing stocks from retail stores (Commercial customers), and production had to ramp-up to rebuild inventories to a sustainable level (perhaps at higher prices). This product is produced by industrial firms, such as Georgia Pacific (GP), and GP has multiple production facilities within Oregon, potentially including within NW Natural's Oregon service area. This production may have occurred within Oregon's borders or in different states (or countries).

Q. Is it accurate to say that, if consumers receive an extra dollar, a portion of that dollar ends up being spent not only by the recipient consumer, but also by multiple organizations, as inputs to some organizations are the outputs of others?

A. Yes. Additionally, as most organizations have employees and some of the downstream incremental spending by such organizations may be on incremental payroll, incremental employment creates an indirect benefit to consumers as a result of the incremental employment. Such spending results in additional "rounds" (or "cycles") of spending, e.g., employees spending incremental amounts of the incremental payroll paid by organizations. Staff includes a simple multi-year illustration of the multiplier effect from government investment in Figure 15-4.[46]

[46] *See* "Economics Help" at https://www.economicshelp.org/blog/1948/economics/the-multiplier-effect/ (accessed by Staff on April 11, 2022).

Figure 15-4: Example of Multiplier Effect from Government Investment



Q. Does Staff believe the owners of NW Natural's Oregon Commercial and Industrial customers have benefited from the credits to Residential customers?

A. Yes, although there is a representation issue here.

Q. What do you mean by a "representation issue?"

A. Oregon is not known as a state with a large concentration of corporate headquarters. As an example, while Intel may be Oregon's largest private sector employer, it is not headquartered in Oregon, and it is highly unlikely that most of its shareholders reside in Oregon.[47]

Q. Why is this important?

[47] Staff notes that this is probably the case for Georgia Pacific and many other firms having Oregon operations as well.

A. While employees at the local, Oregon-located, operations of national or international firms may receive indirect benefits resulting from NW Natural's credits to its Residential customers, the owners of such firms—also receiving indirect benefits – may not reside in NW Natural's Oregon service area.[48] For that reason, Staff allocates some of the indirect benefits, and thereby some of the direct costs of NW Natural's credits provided to its Residential customers, to both the Company's Commercial and Industrial customers as proxies – or "flow-through'' entities—for the owners of such firms. Additionally, employees at locations outside Oregon may benefit; related to the example above, consider employees working in a plant producing toilet paper that is located outside Oregon.

Q. How did Staff implement this assignment of customer credits and NW Natural costs for Items (b) plus (d) - (f)?

A. Staff developed and evaluated three alternative scenarios, which varied on the values of the Multiplier and the MPC used. These values for each scenario are shown in Table 15-5.

Table 15-5: Multiplier and Marginal Propensity to Consume Values in Three Scenarios

	Multiplier	MPC
Scenario 1	2.50	0.60
Scenario 2	1.78	0.44
Scenario 3	10.00	0.90

48 This is related to what is termed the "border effect" in regional economics.

Staff provides CBO's multiplier values for Scenarios 1 and 2 in Table 15-4. These are CBO's High Estimate in each of these two scenarios.[49] The difference between the two scenarios is that Scenario 2 uses the 1.78 Multiplier value associated with CBO's Social Distancing alternative. For both Scenarios 1 and 2, the MPC values are as calculated by Staff. Staff selected the MPC value for Scenario 3 and calculated the Multiplier value based on the selected MPC value.

Q. What is the significance of the MPC value?

A. The MPC directly impacts the assumed multiplier. Staff's analysis incorporates the standard assumption that recipients of the credits spend (consume) a portion of the credited amount and save a portion.[50] Staff additionally assumes consumption occurs in same approximate timeframe in which credits are received and that savings remain savings throughout this timeframe. Recall that consumption might mean *less reduction* in consumption than would be the case absent the credits, and not necessarily more consumption *per se*.

A significant feature, given these assumptions, is that Residential customers receiving credits save (or use to mitigate a reduction in savings) 40 percent of the dollar amount of credits received in Scenario 1, 56 percent of the dollar amount of credits received in Scenario 2, and 10 percent of the dollar amount of credits received in Scenario 3. Staff contends that Scenario 3 is the

[49] Staff did not find the Low Estimates, in which a credit recipient would spend 50 percent or less of his/her credits' value and save the remainder, to be plausible in the current context.

[50] The Marginal Propensity to Save (MPS) is calculated as 1 – MPC.

most likely of the three to represent the behavior of NW Natural's Residential customers who have received credits during the COVID pandemic.

Q. How is the multiplier involved in allocating the recovery of NW Natural's credits between the Company's Residential, Commercial, and Industrial customers?

A. Staff's model assigns, for Residential customers, the implied Marginal Propensity to Save (MPS) as the Savings portion of the credits received and the MPC as the direct effect. There are no direct effects assigned to Commercial or Industrial customers.

Staff's model calculates the indirect effect for Residential customers as Oregon's pre-COVID baseline 2017 – 2019 Personal Consumption Expenditures (73.2 percent) multiplied by the quantity Multiplier less Residential direct effect. The indirect effect for Commercial and Industrial customers is the quantity Multiplier less Total Residential effect multiplied by the respective share of COM+IND Margin Revenue.

Q. What do the indirect effects allocated to Commercial and Industrial customers represent?

A. These indirect effects represent benefits accruing to employees and owners of these organizations who reside outside Oregon[51] as well as other components of the expenditures approach, both within and outside of Oregon, such as gross private fixed investments, the change in private inventories, government

[51] With the result that their Personal Consumption Expenditures are captured in another state's GDP.

consumption expenditures and gross investment, and the net exports of goods and services.

Q. How do allocation shares differ between the three scenarios used by Staff?

A. Table 15-6 includes the allocation for each customer class for Items (b) plus (d) – (f). Staff notes that, despite using a wide range of multiplier values, the impacts by customer class are similar for the three scenarios.

Table 15-6: Allocation Results by Customer Class for Each Scenario

	Multiplier	RES	COM	IND	Total
Scenario 1	2.50	79.64%	16.93%	3.43%	100.0%
Scenario 2	1.78	79.80%	16.80%	3.40%	100.0%
Scenario 3	10.00	75.62%	20.27%	4.11%	100.0%

Q. The above discussion pertained to Items (b) and (d) – (f). How does Staff propose to allocate Item (c): Bad Debt Expense above Baseline?

A. NW Natural's reporting includes values for Item "c" by customer class. However, Staff does not recommend use of these values as the allocation. As values reported by NW Natural are deviations against a baseline, how the baseline was established is relevant. NW Natural's values, after Staff's adjustments previously discussed, are shown in Table 15-2. For purposes of Staff's Opening Testimony, Staff uses shares of Base Year Total Revenue[52] to allocate this cost, after Staff adjustments, to customer classes. Staff is

[52] Staff uses values in Exhibit NW Natural/1403 as the basis for this allocation.

conducting discovery to ascertain the methods by which NW Natural established the baseline.

Q. How does Staff propose to allocate Item (a) Direct Costs and Direct Savings and Benefits?

A. NW Natural's reporting provides no detail regarding direct costs in its RG 90 docketed filings. However, Northwest Natural supplemented these direct costs with its response to Staff Data Request No. 413. These costs appear to largely involve setting up work-from-home arrangements and increased sanitation protocols. The Company does report Direct Savings and Benefits by four categories: travel, meals and entertainment-related; employee expenses – education and refreshments; and interest. Staff proposes to allocate the sum of these based on Test Year Margin Revenue.[53]

Q. Please provide summary tables showing the results by customer class of each of the three allocations.

A. First, Table 15-7 summarizes the allocation values by customer class.

Table 15-7: Allocation Percent by Category by Customer Class for 2020 and 2021

	RES	COM	IND	Total
Item (a) Direct Cost/Savings & Benefits	68.5%	26.5%	5.0%	100.0%
Item (c) Bad Debt	63.3%	30.2%	6.5%	100.0%
Items (b) + (d) – (f) All Other	75.6%	20.3%	4.1%	100.0%

[53] Staff uses values in Exhibit NW Natural/1403 as the basis for this allocation.

Tables 15-8 summarizes the amortization amounts and rate impacts by deferral year and customer class.

Table 15-8: Summary of Amortization Impacts on Test Year ($Thousands)

	Test Year Incremental Revenue Requirement			Test Year Rate Impact		
	Deferral Year			Deferral Year		
	2020	2021	Total	2020	2021	Total
RES	$2,045.5	$2,107.1	$4,152.5	0.44%	0.45%	0.89%
COM	$804.0	$567.8	$1,371.8	0.36%	0.25%	0.61%
IND	$167.6	$114.6	$282.2	0.35%	0.24%	0.58%
Total	$3,017.1	$2,789.5	$5,806.6	0.41%	0.38%	0.78%

Table 15-9 shows the dollar impact of amortization on the Test Year revenue requirement by customer class for each deferral year and Table 15-10 shows the incremental rate increase percent over Base Year Total Revenue by customer class for each deferral year. Values in Tables 15.9 and 15-10 are based on a two-year amortization period beginning November 1, 2022, which is the rate effective date for this proceeding as well as for the Purchased Gas Adjustment proceeding.

Table 15-9: Amortization Impact on Test Year Revenue Requirement ($Thousands)

	Item (a) Direct Cost/ Savings & Benefits		Item (c) Bad Debt		Items (b) + (d) – (f) All Other	
	2020	**2021**	**2020**	**2021**	**2020**	**2021**
RES	$823.3	$129.9	$743.3	($62.7)	$478.9	$2,039.8
IND	$321.4	$50.7	$354.2	($29.9)	$128.4	$546.9
COM	$65.1	$10.3	$76.5	($6.4)	$26.0	$110.8
Total	$1,209.8	$190.9	$1,174.0	($99.0)	$633.3	$2,697.5

Table 15-10: Amortization Impact on Test Year Rates

	Item (a) Direct Cost/ Savings & Benefits		Item (c) Bad Debt		Items (b) + (d) – (f) All Other	
	2020	**2021**	**2020**	**2021**	**2020**	**2021**
RES	0.18%	0.03%	0.16%	-0.01%	0.10%	0.44%
IND	0.14%	0.02%	0.16%	-0.01%	0.06%	0.24%
COM	0.13%	0.02%	0.16%	-0.01%	0.05%	0.23%
Total	0.16%	0.03%	0.16%	-0.01%	0.09%	0.36%

Q. What recommendation does Staff have for the Commission regarding the rate spread and amortization period?

A. Staff has a three-part recommendation:

Authorize NW Natural to include in its compliance filing for this proceeding a new rate schedule, effective on the same November 1, 2022 date on which rates are generally to be effective as a result of this proceeding, that includes rates for each base rate schedule reflecting the total of:

1. The revenue requirement for amortizing the deferral balance associated with Item (a) Direct Costs and Direct Savings and Benefits, inclusive of the adjustments recommended by Staff and for the total of both the 2020 and 2021 deferrals, over a two-year period using the Test Year Margin Revenue shares by customer class.
2. The revenue requirement for amortizing the deferral balance associated with Item (c) Bad Debt Above Baseline, inclusive of the adjustments recommended by Staff and for the total of both the

2020 and 2021 deferrals, over a two-year period using the Base Year Total Revenue shares by customer class.

3. The revenue requirement for amortizing the deferral balance associated with total of Items (b) and (d) – (f), inclusive of the adjustments recommended by Staff and for both the 2020 and 2021 deferrals, over a two-year period using the Scenario 3 share by customer class derived using the methodology described in Staff's testimony.

Rates for each base rate schedule within a given customer class are to be the same rate per kWh. Use of the new rate schedule is to be discontinued two years from the date rates are effective in this proceeding.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 435
WITNESSES: CURTIS DLOUHY, JOHN FOX, STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1501

Non-Confidential Data Responses in Support Of Opening Testimony

April 22, 2022

Staff/1501
Dlouhy-Fox-Storm/1

2021 Total COVID Costs
December 2021

Summary of NWN COVID19 costs	January 2021	February 2021	March 2021	Q1 - QTD	April 2021	May 2021	June 2021
	Total COVID Costs	Total COVID Costs	Total COVID Costs	Total COVID Costs	Total COVID Costs	Total COVID Costs	Total COVID Costs
Overtime Pay	422	515	281	1,218	820	234	-
AMP Program Incremental Costs	-	-	73,046	73,046	24,103	13,035	(9,858)
Incremental janitorial	19,297	15,394	10,351	45,043	14,966	11,223	10,537
Incremental materials and supplies and safety gear	-	1,229	(2,990)	(1,761)	(6,494)	4,321	41,444
Incremental rental	21,041	15,541	25,254	61,837	49,572	17,131	22,649
Incremental printing	587			587		1,896	22,666
Workcare	8,700	19,600	7,950	36,250	9,350	7,100	4,200
Other misc	-	26	-	26	-	-	-
Interest on OR - Other COVID/Direct costs - 186432	4,741	4,837	4,992	14,570	5,184	5,307	5,449
Total COVID Operational Spend	**54,788**	**57,142**	**118,884**	**230,815**	**97,501**	**60,247**	**97,088**
COVID Direct Cost Savings	**(31,211)**	**(43,915)**	**(246,775)**	**(321,901)**	**(69,502)**	**(37,630)**	**(56,004)**
Interest on OR - Cost Savings - 186442	**(467)**	**(518)**	**(743)**	**(1,728)**	**(996)**	**(1,073)**	**(1,135)**
Total Direct Costs net of Cost Savings					27,003	21,544	39,949
Uncollectible reserve	-	-	279,133	279,133	-	-	274,248
Interest on OR - Uncollectibles - 186430	-	-	11,980	11,980	-	-	13,445
Total COVID Bad Debt Expense	**-**	**-**	**291,113**	**291,113** 0	**-**	**-**	**287,694**
Interest Expense	-	-	-	-	-	-	-
Interest (Income)	-	-	-	-	-	-	-
Financing costs	-	-	-	-	-	-	-
Total COVID Financing Costs	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total net expense charged to cost center 85701	**54,788**	**57,142**	**409,998**	**521,928**	**97,501**	**60,247**	**384,782**
Healthy Accounts	100	295	6,921	7,315	6,777	149	708
AMP Deferrals + interest	**-**	**-**	**-**	**-**	**-**	**182,562**	**243,125**
Missed (revenues):							
Late fees not assessed (missed revenue)	144,412	139,995	215,011	499,419	180,259	153,446	104,944
Interest on OR - Late Fees - 186431	2,425	2,632	3,317	8,374	3,386	3,687	3,924
Total missed (revenue)	**146,837**	**142,627**	**218,329**	**507,793**	**183,645**	**157,133**	**108,868**
Total Deferral							

Summary of NWN COVID19 costs	Q2 - QTD	July 2021	August 2021	September 2021	Q3 - QTD	October 2021	November 2021	December 2021	Q4 - QTD	2021 YTD		
	Total COVID Costs	Total COVID Costs	Total COVID Costs	Total COVID Costs	Total COVID Costs	Total COVID Costs	Total COVID Costs	Total COVID Costs	Total COVID Costs	Total COVID Costs		
Overtime Pay	1,054	-	764	(764)	-	-			-	2,272		
AMP Program Incremental Costs	27,280	88	-		88				-	100,414		
Incremental janitorial	36,726	9,216	12,701	12,295	34,211	12,548	11,013	12,598	36,159	152,139		
Incremental materials and supplies and safety gear	39,271	3,800	275	29,744	33,819	16,014	9,141	5,610	30,765	102,093		
Incremental rental	89,352	21,290	29,735	19,586	70,611	26,271	27,812	19,425	73,509	295,309		
Incremental printing	24,562	-	-		-				-	25,149		
Workcare	20,650	5,300	3,650	8,700	17,650	10,500	7,700	-	18,200	92,750		
Other misc	-	-	-		-				-	26		
Interest on OR - Other COVID/Direct costs - 186432	15,941	5,570	5,654	5,761	16,984	5,883	5,994	6,082	17,959	65,454		
Total COVID Operational Spend	**254,836**	**45,263**	**52,778**	**75,322**	**173,363**	**71,216**	**61,660**	**43,716**	**176,592**	**835,605**		
COVID Direct Cost Savings	(163,136)	(8,074)	(35,824)	**(67,409)**	(111,307)	**(65,220)**	**(38,320)**	**(30,806)**	(134,346)	(730,690)		
Interest on OR - Cost Savings - 186442	(3,204)	(1,176)	(1,203)	**(1,279)**	(3,658)	**(1,375)**	**(1,447)**	**(1,495)**	(4,316)	(12,907)		
Total Direct Costs net of Cost Savings	88,496	36,013	**15,750**	**6,634**	**58,398**	**4,622**	**21,893**	**11,415**	**37,930**	**92,008**		
Uncollectible reserve	274,248	-	-	(122,332)	(122,332)	-	-	(649,769)	(649,769)	(218,720)		
Interest on OR - Uncollectibles - 186430	13,445	-	-	14,566	14,566	-	-	13,607	13,607	53,598		
Total COVID Bad Debt Expense	**287,694**	**-**	**-**	**(107,766)**	**(107,766)**	**-**	**-**	**(636,162)**	**(636,162)**	**(165,122)**		
Interest Expense	-	-	-	-	-	-	-	-	-	-		
Interest (Income)	-	-	-	-	-	-	-	-	-	-		
Financing costs	-	-	-	-	-	-	-	-	-			
Total COVID Financing Costs	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**		
Total net expense charged to cost center 85701	**542,529**	**45,263**	**52,778**	**(32,445)**	**65,596**	**71,216**	**61,660**	**(592,446)**	**(459,571)**	**670,483**		
										-		
Healthy Accounts	7,634	1,414	87	13	1,514	-	-	-	-	16,463		
										-		
AMP Deferrals + interest	**425,686**	**543,778**	614,199	486,299	1,644,276	738,892	605,497	383,905	1,728,295	3,798,257		
										-		
Missed (revenues):										-		
Late fees not assessed (missed revenue)	438,650	47,353	48,660	45,416	141,429	42,773	54,740	116,343	213,855	1,293,354		
Interest on OR - Late Fees - 186431	10,997	4,066	4,158	4,249	12,473	4,335	4,429	4,589	13,352	45,195		
										-		
Total missed (revenue)	**449,647**	**51,419**	**52,818**	**49,664**	**153,902**	**47,108**	**59,169**	**120,931**	**227,208**	**1,338,549**		
Total Deferral		**632,625**	**682,854**	**434,844**	**1,750,323**	**790,622**	**686,559**	**(119,911)**	**1,357,270**	**5,080,156**	5,080,156	-

Staff/1501
Dlouhy-Fox-Storm/2

Source: General Accounting COVID details / JE 136 series

OR 0.886206686
WA 0.113793314

Summary of NWN COVID costs incurred March - September 2020	System March	OR March	WA March	System April	OR April	WA April	System May	OR May	WA May	System June	OR June	WA June
Incremental Costs Already Incurred												
Overtime Pay		-		239	212	27 24	2 181	1 932	248 16	1 216	1 078	1 8 39
Incremental janitorial cleaning	6 08	5 412	695 03	8 187	7 256	931 73	5 279	4 678	600 78	6 814	6 038	775 41
Materials, supplies, safety gear	29 118	25 804	3 313 63	52 581	46 597	5 983 70	145 634	129 061	16 573 18	157 409	139 496	17 913 19
Mileage and parking	-	-		50	44	5 67	20	8	2 28	19	17	2 16
Truck rental	-	-		1 355	1 200	154 14	12 626	11 189	1 436 78	15 203	13 473	1 7 0 08
Printing and signage	-	-		180	60	20 48	21 662	19 197	2 465 14	-	-	
Clinic Covid- 9 testing fees	-	-		-	-		20 000	17 724	2 276 00	-	-	
Software support for WFH Call Center	-	-		-	-		-	-		-	-	
Workcare daily health screening and nurse line	-	-		-	-		-	-		-	-	
Other misc	-	-		-	-		-	-		143	126	6 22
Healthy Accounts Write-Offs		-			-			-			-	
Total COVID Operational Spend	35.226	31.217	4.009	62.592	55.469	7.123	207.402	183.799	23.602	180.804	160.228	20.575
Interest Expense	31 768	28 152	3 6 5 14	171 549	152 027	9 522 28	188 761	167 280	21 481 01	1 243 906	1 102 350	141 556 56
Interest (Income)	(8 620)	(7 639)	(980 96)	-	-	-	(48 104)	(42 6 0)	(5 474 28)	(116 06)	(102 855)	(13 207 99)
Financing costs	22 350	19 807	2 543 43	-		-	2 000	1 772	227 60		-	-
Total COVID Financing Costs	45.498	40.320	5.178	171.549	52.027	19.522	142.657	126.422	16.234	1.127.843	999.495	128.349
Total Direct Costs	80.723	71.537	9.186									
COVID Direct Cost Savings	-	-	-	-	-	-	-	-	-	-	-	-
Uncollectible reserve	359 358	326 811	32 546 85	-	-		-	-		373 626	321 706	51 920 28
Total COVID Bad Debt Expense	359.358	326.811	32.547	-	-	-	-	-	-	373.626	321.706	51.920
Total Incremental Costs Already Incurred	440.081	398.348	41.733	234.141	207.496	26.645	350.058	3 0.222	39.837	1.682.273	1.481.429	200.844
Foregone Revenues:												
Late fees not assessed (missed revenue)	249 529	221 133	28 396 40	170 60.60	81 775	(11 614 14)	218 749	209 135	9614.46	167 272	161 840	5432.1
Total Foregone Revenues	249 529.00	221.133	28 396.40	170 60.60	81.775	(11 614.14)	2 8 749.15	209.135	9 614.46	167 272.40	161 840.30	5 432.10
Interest on Deferrals:												
Interest on OR - Other COVID/Direct costs - 186432												
Interest on OR - Late Fees - 86431												
Interest on OR - Cost Savings - 186442												
Interest on OR - Uncollectibles - 1864 0												
Total Interest	-	-	-	-	-	-	-	-	-	-	-	-
Total Deferral	689 610.00	619 480.47	70 1 9.53	404 01.53	389 270.43	5 031.10	568 807.52	519 56.42	49 451.10	1 849 545.43	1 643 269.04	206 276.39

Summary of NWN COVID costs incurred March - September 2020	Q2 2020 System Q2	OR Q2	WA Q2	System July	OR July	WA July	System August	OR August	WA August	System September	OR September	WA September
Incremental Costs Already Incurred												
Overtime Pay	3 636 04	3 222 26	413 78	94	83	10 64	234	207	26 60	327 26	290 02	37 24
Incremental janitorial cleaning	20 280 56	17 972 63	2 307 93	14 715	13 040	1 674 57	6 710	5 947	763 63	17 804 21	15 778 21	2 026 00
Materials, supplies, safety gear	355 624 43	315 154 37	40 470 06	2 380	2 09	270 83	1 983	1 757	225 63			
Mileage and parking	88 80	78 69	0 11	-	-		-	-				
Truck rental	29 182 79	25 861 79	3 321 00	12 7 9	11 272	1 447 43	21 052	8 656	2 395 67	6 047 37	4 221 29	1 826 08
Printing and signage	21 842 00	19 356 8	2 485 62	1 075	953	122 34	12 343	0 9 8	1 404 62			
Clinic Covid- 9 testing fees	20 000 00	17 724 00	2 276 00	-	-		-	-				
Software support for WFH Call Center	-	-	-	50 649	44 885	5 763 86	-	-				
Workcare daily health screening and nurse line	-	-	-	-	-		-	-		5 369 00	4 758 01	610 99
Other misc	142 57	126 35	6 22	-	-		-	-				
Healthy Accounts Write-Offs	-	-	-		-		424	4 5	8 48	4 805 14	3 874 88	930 26
Total COVID Operational Spend	450.797	399.496	51.301	81.632	72.342	9.290	42.745	37.920	4.825	44.353	38.922	5.431
Interest Expense	1 604 216 56	1 421 656 72	182 559 84	101 2 9	89 700	11 518 71	88 799	78 693	10 105 27	104 002 25	92 166 79	11 835 46
Interest (Income)	(164 167 63)	(145 485 35)	(8 682 28)		-	-	(13 835)	(12 260)	(1 574 40)	(1 646 66)	(1 459 27)	(87 39)
Financing costs	2 000 00	1 772 40	227 60	-	-	-		-	-			
Total COVID Financing Costs	1.442.049	1.277.944	164.105	101.219	89.700	11.519	74.964	66.433	8.531	102.356	90.708	11.648
Total Direct Costs	1.892.846	1.677.440	215.406	182.850	62.042	20.808	117.709	104.353	13.355	146.709	129.630	17.079
COVID Direct Cost Savings	-	-	-	-	-	-	-	-	-	(212.16)	(121.254)	(90.907)
Uncollectible reserve	373 626 21	321 705 93	51 920 28	-	-		-	-		408 149 62	365 359.86	42 789.76
Total COVID Bad Debt Expense	373.626	321.706	51.920	-	-	-	-	-	-	408.150	365.360	42.790
Total Incremental Costs Already Incurred	2.266.472	1.999.146	267.326	182.850	62.042	20.808	117.709	104.353	13.355	554.858	494.990	59.868
Foregone Revenues:												
Late fees not assessed (missed revenue)	556 182 15	552 749.73	3 432 42	94 411	90 437	3973.49	82 439	78 754	3685.29	79 125 71	75 835 07	3 290.64
Total Foregone Revenues	556 182.15	552 749.73	3 432.42	94 410.82	90 437.33	3 973.49	82 439.06	78 753.77	3 685.29 #	79 125.71	75 835.07	3 290.64
Interest on Deferrals:												
Interest on OR - Other COVID/Direct costs - 186432												
Interest on OR - Late Fees - 86431												
Interest on OR - Cost Savings - 186442												
Interest on OR - Uncollectibles - 1864 0												
Total Interest	-	-	-	-	-	-	-	-	- #	-	-	-
Total Deferral	2 822 654.48	2 551 895.89	270 758.59	277 61.21	252 479.35	24 781.86	200 147.59	83 06.80	17 040.79 #	421 823.16	449 571.08	(27 747.92)

Summary of NWN COVID costs incurred March - September 2020	Q3 System Q3	OR Q3	WA Q3	Total Costs Evaluated October	System Deferral October	OR Deferral October	WA Deferral October	Total Costs Evaluated November	System Deferral November	OR Deferral November	WA Deferral November
Incremental Costs Already Incurred											
Overtime Pay	654 51	580 03	74 48	280 50	280 50	248 58	31 92	-	-		
Incremental janitorial cleaning	39 229 53	34 765 33	4 464 20	7 931 68	7 931 68	7 029 05	902 63	14 069 18	14 069 18	12 468 11	1 601 07
Materials, supplies, safety gear	4 362 57	3 866 11	496 46	71 152 06	71 152 06	63 054 96	8 097 0	49 465 10	49 465 10	43 835 97	5 629 13
Mileage and parking	-	-	-	-	-	-	-	-	-	-	-
Truck rental	49 818 05	44 148 86	5 669 9	17 130 8	17 130 8	15 180 77	1 949 41	26 681 92	26 681 92	23 645 52	3 036 40
Printing and signage	13 417 85	11 890 90	1 526 95	-	-	-	-	-	-	-	-
Clinic Covid- 9 testing fees	-	-	-	-	-	-	-	-	-	-	-
Software support for WFH Call Center	50 649 00	44 885 14	5 763 86	-	-	-	-	-	-	-	-
Workcare daily health screening and nurse line	5 369 00	4 758 01	610 99	-	-	-	-	3 150 00	3 150 00	2 791 53	358 47
Other misc	-	-	-	45 89	-	-	-	-	-	-	-
Healthy Accounts Write-Offs	5 228 81	4 290 07	938 74	174 62	174 62	174 62	-	20 68	20 68	20 68	-
Total COVID Operational Spend	68.729	149.184	4.825	96.7 5	96.669	85.688	0.981	93.387	93.387	82.762	10.625
Interest Expense	294 019 62	260 560 18	33 459 44	93 328 75	93 328 75	82 707 94	10 620 81	-	-	-	-
Interest (Income)	(15 481 45)	(13 719 66)	(1 761 79)	(422 61)	(422 61)	(374 52)	(48 09)	(532 81)	(532 81)	(472 18)	(60 63)
Financing costs	-	-	-	-	-	-	-	-	-	-	-
Total COVID Financing Costs	278.538	246.841	31.698	92.906	92.906	82.333	0.573	(533)	(533)	(472)	(61)
Total Direct Costs	447.267	396.025	36.522	189.621	189.575	68.021	21.554	92.854	92.854	82.290	10.564
COVID Direct Cost Savings	(212 160 74)	(121 253 78)	(90 906 96)	(55 525)	(55 525)	(36 912)	(8 614)	(47 513)	(47 513)	(34 574)	(12 938)
Uncollectible reserve	408 149 62	365 359 86	42 789 76	261 683 85	261 683 85	233 126 33	28 557 52	-	-	-	-
Total COVID Bad Debt Expense	408. 50	365.360	42.790	261.684	261.684	233.126	28.558	-	-	-	-
Total Incremental Costs Already Incurred	855.417	761.385	79.312	451.305	451.259	401.148	50.111	92.854	92.854	82.290	10.564
Foregone Revenues:											
Late fees not assessed (missed revenue)	255 975.59	245 026 17	10 949 42	79 714.50	79 714.50	76 536.99	3 177.51	92 786.27	92 786.27	88 411.92	4 374.35
Total Foregone Revenues	255 975.59	245 026.17	10 949.42	79 714.50	79 714.50	76 536.99	3 177.51	92 786.27	92 786.27	88 411.92	4 374.35
Interest on Deferrals:											
Interest on OR - Other COVID/Direct costs - 186432											
Interest on OR - Late Fees - 86431											
Interest on OR - Cost Savings - 186442											
Interest on OR - Uncollectibles - 1864 0											
Total Interest	-	-	-	-	-	-	-	-	-	-	-
Total Deferral	899 231.96	885 157.23	(645.51)	475 494.05	475 448. 6	440 773.06	34 675. 0	138 127.83	138 127.83	1 6 127.39	2 000.44

Summary of NWN COVID costs incurred March - September 2020	*enter from JE 136 Summary Tab* Total Costs Evaluated December	System Deferral December	OR Deferral December	WA Deferral December	Q4 Activity System Q4 Activity	OR Q4 Activity	WA Q4 Activity	2020 YTD System YTD	OR YTD	WA YTD
Incremental Costs Already Incurred										
Overtime Pay	187 00	187 00	65 72	21 28	468	414 30	53	4 758	4 217	541
Incremental janitorial cleaning	8 251 76	8 251 76	7 312 70	939 06	30 253	26 809 86	3 443	95 870	84 960	0 9 0
Materials, supplies, safety gear	52 914 74	52 914 74	46 893 04	6 021 70	173 532	153 783 97	19 748	562 637	498 609	64 028
Mileage and parking	-	-	-	-	-	-	-	89	79	0
Truck rental	6 979 88	6 979 88	23 909 57	3 070 31	70 792	62 735 86	8 056	149 793	132 747	17 046
Printing and signage	2 205 00	2 205 00	1 954 07	250 93	2 205	1 954 07	251	37 465	33 201	4 264
Clinic Covid- 9 testing fees	-	-	-	-	-	-	-	20 000	17 7 4	2 276
Software support for WFH Call Center	-	-	-	-	-	-	-	50 649	44 885	5 764
Workcare daily health screening and nurse line	-	-	-	-	3 150	2 791 53	358	8 519	7 550	969
Other misc	-	-	-	-	-	-	-	143	126	6
Healthy Accounts Write-Offs	0 09	0 09	30 09	-	225	225 39	-	5 454	4 515	939
Total COVID Operational Spend	90.568	90.568	80.265	10.303	280.624	248.715	4.825	935.376	828.613	106.764
Interest Expense	-	-	-	-	93 329	82 707 94	0 621	2 023 332	1 793 077	2 0 255
Interest (Income)	(164 72)	(164 72)	(145 97)	(8 75)	(1 120)	(992 67)	(127)	(189 389)	(167 837)	(21 552)
Financing costs	-	-	-	-	-	-	-	24 350	21 579	2 771
Total COVID Financing Costs	(165)	(165)	(146)	(19)	92.209	81.715	0.493	1.858.293	1.646.819	211.474
Total Direct Costs	90.404	90.404	80.119	10.285	372.833	330.430	5.3 8	2.793.670	2.475.432	3 8.237
COVID Direct Cost Savings	(54 415 8)	(54 415 8)	(44 03 58)	(0 312 25)	(157 454)	(115 589 40)	(41 864)	(369 614)	(2 6 843)	(132 771)
Uncollectible reserve	930 088	930 088	823 968	106 120	1 191 772	1 057 094 41	134 678	2 332 906	2 070 971	261 934
Total COVID Bad Debt Expense	930.088	930.088	823.968	106.120	1.191.772	1 057 094	134.678	2.332.906	2.070.971	261.934
Total Incremental Costs Already Incurred	1.020.492	1.020.492	904.087	116.405	1.564.605	1.387.525	149.996	5.126.575	4.546.404	580.172
Foregone Revenues:										
Late fees not assessed (missed revenue)	54 612.47	54 612 47	47 214 0	7 398 37	227 113	212 163 01	14 950	1 288 800	1 231 072	57 728
Total Foregone Revenues	54 612.47	54 612.47	47 214. 0	7 398.37	227 113	212 163.01	14 950	1 288 799.98	1 231 071.51	57 728.47
Interest on Deferrals:										
Interest on OR - Other COVID/Direct costs - 186432	42 0 6.75	42 0 6.75	42 036.75	-	42 037	42 036.75	-	42 037	42 037	-
Interest on OR - Late Fees - 86431	23 415	23 415	23 415	-	23 415	23414.99	-	23 415	23 415	-
Interest on OR - Cost Savings - 186442	(996)	(996)	(996)	-	(996)	-995.93	-	(996)	(996)	-
Interest on OR - Uncollectibles - 1864 0	22 789	22 789	22 789	-	22 789	22789.4	-	22 789	22 789	-
Total Interest	87 245.21	87 245.21	87 45.21	-	87 45	64 455.81	-	87 245.21	87 45.21	-
Total Deferral	1 107 933.70	1 107 933.70	994 443.03	113 490.67	1 721 509.69	1 548 554.08	123 081.42	6 133 006.13	5 627 877.06	505 129.06

	March OR	March WA	Q2 OR	Q2 WA	Q3 OR	Q3 WA	Q4 OR	Q4 WA	YTD System	YTD OR	YTD WA	
Deferral total - Direct Costs	292 669	37 583	2 2 0 190	218 838	641 051	47 472	372 467	15 318	2 835 706	2 517 469	3 8 237	Total above
GL 186432/36	292 669	37 583	2 435 581	231 888	435 661	49 142				2 517 469	3 8 2 8	SAP
Difference	0.15	0.02	205 390.75	13 049.67	(205 390.55)	1 670.46	(372 467)	(15 318)		0	0	
Deferral total - Late Fees	285 030	36 602	2 084 705	200 156	(13 720)	(1 762)	235 578	14 950	1 312 215	1 254 487	57 728	Total above
GL 18643 /35	(326 811)	37 583	(321 706)	(51 920)	648 517	(42 790)				1 254 487	57 7 8	SAP
Difference	###########	980 98	(2 406 410.54)	(252 076.31)	662 236.47	(41 027.97)	(235 578)	(14 950)		0	(0)	
Q2 Disconnect fees unwound					-	-	-	-				
Bad Debt Expense Deferral total	326 811	32 547	321 706	51 920	365 360	42 790	1 079 884	134 678	2 355 695	2 093 761	261 934	Total above
GL 186430/34	326 811	32 547	321 706	51 920	365 360	42 790				2 093 761	261 934	SAP
Difference	0	-	-	-	-	-	1 079 884	134 678		0	-	
Total Cost Savings Deferral							(116 585)	(41 864)	(370 610)	(237 839)	(132 771)	Total above
GL 186442/3										(237 839)	(132 771)	SAP
							116 585	41 864		0	0	
Total	619 480		2 551 896		1 006 411		-	-		5 627 877	505 129	
	-		-	Q3 to unwind	-					-	-	
			Difference is reconnect and field collection above		Difference is zero							

		GL Account
a.	Employee Business Meals;	512100 - Meals and Entertainment
b.	Employee Car Rentals;	
c.	Employee Auto Mileage;	513100 - Conference Travel
d.	Airfare;	513200 - Business Travel
e.	Employee Lodging;	
f.	Conference Fees;	501100 - Education
h.	Trainings;	
g.	Employee Miscellaneous Expenses;	503300 - Refreshments
i.	Any other area where savings occurred.	*None*
		Cost Savings

**No savings so not included in the 2021 cost savings, but was reviewed each q*

OR Actuals 2020	OR Baseline	OR Cost Savings	OR Actuals 2021	OR Baseline	OR Cost Savings		Total Cost Savings
289,346	526,189	236,843	221,845	583,899	362,054		**598,897**
392,133.94	495,000	102,866	553,474.48	495,000	(58,474)	*	**102,866**
36,510.70	91,600	55,089	48,327.54	91,600	43,272		**98,362**
		394,799			**405,326**		**800,125**

ɥuarter to confirm

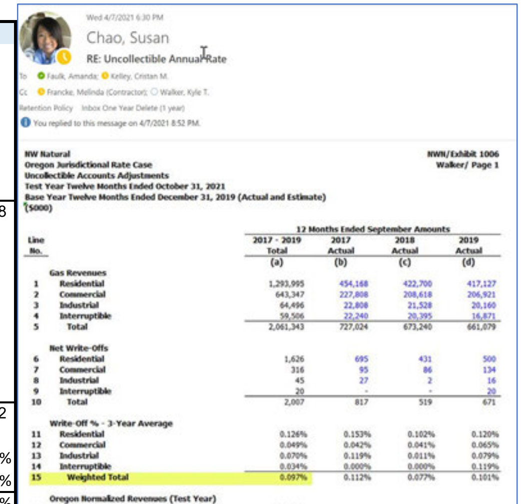
2021 Uncollectible Deferral Calculation

REQUIRED QUARTERLY

Instructions

1. Update the "PQ YTD Dept. Adj." in rows 37-40 with prior quarters "Total YTD Credit Dept. Adj."
2. Run current month Sales and Transportation BI report. Paste values in the "Srev by Dist" tab.
3. Run the current Uncollectible Report and paste values in the "Uncoll Report" tab.
4. If Credit Dept. adds and adjustment, populate the "Credit Dept. Adj" section below (expected during quarter-end).

			from Uncollect. Tab	88.84%	11.16%
			System	Oregon Allocated	Washington Allocated
YTD Sales Revenues			*(check links each month)*		
Residential			483,215,315		
Commercial			214,237,235		
Industrial - Firm			21,739,598		
Industrial - Interruptible			23,814,955		
Total			743,007,102	660,089,589.21	82,917,513.08
	from Uncollect. Tab				
	(check links each month)	*enter from Memo tab*			
Uncollectible Accrual	Before Treasury Adjust.	CQ Credit Dept. Adj.	After Credit Dept. Adj	Oregon Allocated	Washington Allocated
Residential	1,562,436.89	(724,000.00)	838,436.89		
Commercial	(308,144.74)	58,000.00	(250,144.74)		
Industrial - Firm	(112,993.57)	16,000.00	(96,993.57)		
Industrial - Interruptible	18,160.64	-	18,160.64		
	1,159,459.22	(650,000.00)	509,459.22	452,605.00	56,854.22
			% of revenues	0.069%	0.069%
			Rate case uncollectible	0.097%	0.106%
			Variance	-0.028%	-0.037%
			YTD Uncollectibles to defer	(187,681.90)	(31,038.34)


Wed 4/7/2021 6:30 PM
Chao, Susan
RE: Uncollectible Annual Rate
To Faulk, Amanda; Kelley, Cristan M.
Cc Francke, Melinda (Contractor); Walker, Kyle T.
Retention Policy Inbox One Year Delete (1 year)
You replied to this message on 4/7/2021 8:52 PM.

NW Natural
Oregon Jurisdictional Rate Case
Uncollectible Accounts Adjustments
Test Year Twelve Months Ended October 31, 2021
Base Year Twelve Months Ended December 31, 2019 (Actual and Estimate)
($000)

NWN/Exhibit 1006
Walker/ Page 1

Line No.		12 Months Ended September Amounts 2017 - 2019 Total (a)	2017 Actual (b)	2018 Actual (c)	2019 Actual (d)
	Gas Revenues				
1	Residential	1,293,995	454,168	422,700	417,127
2	Commercial	643,347	227,808	208,618	206,921
3	Industrial	64,496	22,808	21,528	20,160
4	Interruptible	59,506	22,240	20,395	16,871
5	Total	2,061,343	727,024	673,240	661,079
	Net Write-Offs				
6	Residential	1,626	695	431	500
7	Commercial	316	95	86	134
8	Industrial	45	27	2	16
9	Interruptible	20	-	-	20
10	Total	2,007	817	519	671
	Write-Off % - 3-Year Average				
11	Residential	0.126%	0.153%	0.102%	0.120%
12	Commercial	0.049%	0.042%	0.041%	0.065%
13	Industrial	0.070%	0.119%	0.011%	0.079%
14	Interruptible	0.034%	0.000%	0.000%	0.119%
15	Weighted Total	0.097%	0.112%	0.077%	0.101%

Oregon Normalized Revenues (Test Year)

Review proof:

Baseline bad debt expense	Actual bad debt expense	Difference - defer
728,179.47	509,459.22	(218,720.25)
	Per calc	(218,720.25)
	proof	-

Qtr proof

Manual provision - Q3 only	(650,000.00)
Deferred provision - Q3 only	(649,769.13)
	100%

Makes sense that almost all of the manual provision is 'above baseline' as the automatic provision is supposed to be the rate case rate

copy from PQ workbook	*formula*	*formula*
PQ YTD Credit Dept. Adj.	CQ Credit Dept. Adj.	Total YTD Credit Dept. Adj.
972,000.00	(724,000.00)	248,000.00
(408,000.00)	58,000.00	(350,000.00)
(133,000.00)	16,000.00	(117,000.00)
-	-	-
431,000.00	(650,000.00)	(219,000.00)

YTD Uncollectible deferral allocated		
Residential	212,534.76	35,148.44
Commercial	(299,948.25)	(49,604.65)
Industrial - Firm	(100,268.41)	(16,582.13)
Industrial - Interruptible	-	-
	(187,681.90)	(31,038.34)
check	-	-

(187,681.90)	Total OR 2021 bad debt exp to def
(187,681.90)	Total OR 2021 bad debt exp def

YTD Already deferred	Q1+Q2+Q3 OR	Q1+Q2+Q3 WA
Residential	873,051.88	99,058.36
Commercial	(366,466.22)	(41,580.05)
Industrial - Firm	(119,460.80)	(13,554.28)
Industrial - Interruptible	-	-
	387,124.86	43,924.03

YTD Uncollectible to record	OR	WA	Total	Internal Orders	
Residential	(660,517.12)	(63,909.92)	(724,427.04)	904-02595	Dr
Commercial	66,517.97	(8,024.60)	58,493.37	904-02596	Cr
Industrial - Firm	19,192.39	(3,027.85)	16,164.54	904-02597	Cr
Industrial - Interruptible	-	-	-	904-02598	Dr
	(574,806.76)	(74,962.37)	(649,769.13)	**TO JE**	
Deferral account #'s	186430	186434			
	Cr	Cr			

MEMORANDUM

NW Natural

220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

Date: January 7, 2022

To: Brody Wilson, Amanda Faulk

From: Ashlee Minty

Subject: **Fourth Quarter 2021 Uncollectible Additional Reserve Adjustment**

This memo will authorize you to record an additional adjustment to the provision for uncollectible accounts. See additional analysis for detail.

Account Number	Transaction Description	Debit Amt	Credit Amt		
144011	Resid Prov. Adj.	$724,000		Residential	(724,000) dr
504500-85410-904-02595	Resid BD Expense		$724,000		
144012	Com. Prov. Adj.		$58,000	Commercial	58,000 cr
504500-85410-904-02596	Com BD Expense	$58,000			
144013	Ind Firm Prov. Adj.		$16,000	Industrial	16,000 cr
504500-85410-904-02597	Ind Firm BD Expense	$16,000			
					(650,000)
144014	Ind Intr Prov. Adj.				
504500-85410-904-02598	Ind Intr BD Expense				
144025	SAP A/R Prov. Adj.		$114,000	Not used in this JE	
504500-85410-904-02599	SAP BD Expense	$114,000			

Provision

Minty, Ashlee
To Francke, Melinda (Contractor)
2:30 PM
Retention Policy Inbox One Year Delete (1 year) Expires 1/7/2023

2021 Fourth Quarter Provision Memo.docx
43 KB

Melinda,

I have Brody's verbal approval on these numbers, but I am awaiting his email approval. I wanted to get this over to you ASAP but I will also forward along his written approval when I get it. Hope this helps. Thank you.

Ashlee Minty, CCRA, CBA
NW Natural | Director of Credit
250 SW Taylor Street
Portland, OR 97204
w: (503) 610-7239

INTERNAL USE

NORTHWEST NATURAL
UNCOLLECTIBLE ACCOUNTS ANALYSIS
December 2021

	CURRENT MONTH			YEAR-TO-DATE			TWELVE MONTHS		
	CURRENT YEAR	PREVIOUS YEAR	INCREASE OVER LAST YEAR	CURRENT YEAR	PREVIOUS YEAR	INCREASE OVER LAST YEAR	CURRENT YEAR	PREVIOUS YEAR	INCREASE OVER LAST YEAR
GAS REVENUES									
Residential	73,717,992	69,205,803	4,512,190	483,215,315	450,901,518	32,313,797	483,215,315	450,901,518	32,313,797
Commercial	31,562,650	28,256,866	3,305,784	214,237,235	193,255,018	20,982,217	214,237,235	193,255,018	20,982,217
Industrial - Firm	2,446,100	2,157,235	288,865	21,739,598	20,151,209	1,588,389	21,739,598	20,151,209	1,588,389
Industrial - Interruptible	3,086,442	2,157,608	928,835	23,814,955	18,578,161	5,236,793	23,814,955	18,578,161	5,236,793
Transportation	3,449,122	3,417,701	31,421	39,253,273	39,754,318	(501,045)	39,253,272	39,754,318	(501,046)
Sub-total	114,262,286	105,195,112	9,067,174	782,260,375	722,840,223	59,420,151	782,260,375	722,840,223	59,420,151
Unbilled	0	4,080,180	(4,080,180)	(2,125,099)	4,654,786	(6,779,885)	(2,125,099)	4,654,786	(6,779,885)
Interstate Storage (3)	1,097,908	1,711,312	(613,404)	64,193,510	23,425,409	40,768,100	64,193,510	23,425,409	40,768,100
TOTAL	115,360,194	110,986,614	4,373,580	844,328,786	750,720,419	93,608,367	844,328,786	750,720,419	93,608,366
ACCOUNTS RECEIVABLE BALANCE									
Residential	54,279,484	44,379,606	9,899,879						
Commercial	25,711,218	21,381,858	4,329,360						
Industrial - Firm & Trans	3,215,404	2,687,821	527,584						
Industrial - Inter & Trans	1,954,231	1,456,280	498,951						
Interstate Storage	1,133,668	1,697,804	(564,136)						
Miscellaneous (SAP)	841,690	504,141	337,549						
TOTAL	87,135,696	72,106,509	15,029,187						
DELINQUENT ACCOUNTS									
Residential	4,961,638	5,793,644	(832,007)						
Commercial	362,502	1,016,407	(653,904)						
Industrial - Firm	16,073	38,966	(22,893)						
Industrial - Interruptible	N/A	N/A	N/A						
Interstate Storage	N/A	N/A	N/A						
Miscellaneous (SAP)	336,290	197,274	139,016						
TOTAL	5,676,503	7,046,291	(1,369,788)						
% of Accounts Receivable	6.51%	9.77%	-19.44%						
UNCOLLECTIBLE ACCRUAL									
Residential	91,888	715,885	(623,997)	1,562,437	2,049,262	(486,825)	1,562,437	2,049,262	(486,825)
Commercial	15,054	143,162	(128,108)	(308,145)	821,107	(1,129,252)	(308,145)	821,107	(1,129,252)
Industrial - Firm	2,130	28,816	(26,686)	(112,994)	61,880	(174,874)	(112,994)	61,880	(174,874)
Industrial - Interruptible	2,164	1,578	586	18,161	15,275	2,886	18,161	15,275	2,886
Unbilled revenues	0	4,841	(4,841)	398,001	10,337	387,664	398,001	10,337	387,664
Interstate Storage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Miscellaneous (SAP)	0	55,000	(55,000)	145,000	154,200	(9,200)	145,000	154,200	(9,200)
TOTAL	111,226	949,290	(838,064)	1,702,480	3,112,081	(1,409,601)	1,702,480	3,112,081	(1,409,601)
% of Gas Revenues (4)	0.10%	0.81%	-88.28%	0.18%	0.39%	-45.29%	0.18%	0.39%	-45.29%
NET WRITE OFF									
Residential	10,957	15,707	(4,750)	1,476,430	438,286	1,038,144	1,476,430	438,286	1,038,144
Commercial	(6,919)	1,398	(8,317)	276,053	173,869	102,184	276,053	173,869	102,184
Industrial - Firm	(0)	1,429	(1,429)	(4,389)	7,440	(11,829)	(4,389)	7,440	(11,829)
Industrial - Interruptible	0	0	0	0	0	0	0	0	0
Unbilled revenues	0	0	0	0	0	0	0	0	0
Interstate Storage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Miscellaneous (SAP)	2,414	35,119	(32,705)	176,908	57,216	119,692	176,908	57,216	119,692
TOTAL	6,451	53,653	(47,202)	1,925,003	676,802	1,248,201	1,925,003	676,802	1,248,201
% of Gas Revenues (2) (4) (5)	0.00%	0.02%	-0.17%	0.21%	0.08%	184.43%	0.21%	0.08%	184.43%
ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS BALANCE									
Residential	2,129,029	2,043,022	86,007						
Commercial	119,585	703,783	(584,198)						
Industrial - Firm	(13,482)	95,122	(108,605)						
Industrial - Interruptible	64,621	46,460	18,161						
Unbilled	486,187	98,186	388,001						
Interstate Storage	N/A	N/A	N/A						
Miscellaneous (SAP)	118,411	150,319	(31,908)						
TOTAL	2,884,310.51	3,106,853	(222,542)						
% of Accounts Receivable (1) (4)	2.84%	4.01%	-7.16%						

Footnotes to "Uncollectible Accounts Analysis" report:
1) Calculation excludes Unbilled Allowance for Uncollectible Accounts Balance.
2) Calculation excludes Unbilled Gas Revenues.
3) Interstate Storage revenues include optimization and interstate gas storage services.
4) Excludes Miscellaneous
5) Net write off amount is net of Allowance for Uncollectible Accounts for public purpose programs.

NW Natural

INTERNAL USE ONLY

PRELIM_Sales and Transportation Revenue by District

Period/Fiscal Year DEC 2021

Last Data Update:

09/20/2021 10:54:31

Display As

	DEC 2021 CUSTOMER COUNT	DEC 2021 THERMS	DEC 2021 AMOUNT	2021 YTD THERMS	2021 YTD AMOUNT	
TOTAL REVENUE	783,907 EA	140,797,383 THM	$114,214,916	1,166,171,009 THM	$770,009,139	
OREGON	690,224 EA	128,130,295 THM	$102,109,115	1,065,995,993 THM	$686,142,914	
BY DISTRICT						
BY RATE SCHEDULE						
RESIDENTIAL	627,914 EA	53,314,295 THM	$65,324,802	380,796,300 THM	$418,945,274	A
COMMERCIAL	61,314 EA	29,701,476 THM	$28,419,768	227,595,054 THM	$188,675,028	A
INDUSTRIAL	600 EA	3,016,144 THM	$2,176,096	31,811,072 THM	$19,543,952	A
INTERRUPTIBLE	111 EA	6,293,804 THM	$2,999,219	54,332,773 THM	$22,404,974	A
TRANSPORTATION - COMMERCIAL FIRM	87 EA	1,234,565 THM	$230,899	9,037,821 THM	$1,986,029	
TRANSPORTATION - INDUSTRIAL FIRM	118 EA	14,839,745 THM	$2,362,807	147,340,018 THM	$27,402,570	
TRANSPORTATION - INTERRUPTIBLE	80 EA	19,730,266 THM	$595,524	215,082,956 THM	$7,185,243	
TRANSPORTATION - INCENTIVE						
WASHINGTON	93,683 EA	12,667,088 THM	$12,105,801	100,175,016 THM	$83,866,225	
BY DISTRICT						
BY RATE SCHEDULE						
RESIDENTIAL	86,252 EA	7,325,991 THM	$8,393,190	52,824,726 THM	$56,618,874	
COMMERCIAL	7,350 EA	3,039,344 THM	$3,142,861	23,568,264 THM	$22,125,844	
INDUSTRIAL	48 EA	355,322 THM	$270,004	3,219,343 THM	$2,195,646	
INTERRUPTIBLE	4 EA	135,035 THM	$87,224	1,152,382 THM	$655,628	
TRANSPORTATION - COMMERCIAL FIRM	10 EA	233,944 THM	$50,337	2,162,368 THM	$421,326	
TRANSPORTATION - INDUSTRIAL FIRM	9 EA	971,428 THM	$98,751	9,696,583 THM	$1,053,470	
TRANSPORTATION - INTERRUPTIBLE	10 EA	606,024 THM	$63,434	7,551,350 THM	$795,437	
TRANSPORTATION - INCENTIVE						
TOTAL RESIDENTIAL	714,166 EA	60,640,286 THM	$73,717,992	433,621,025 THM	$475,564,148	B
TOTAL COMMERCIAL	68,664 EA	32,740,820 THM	$31,562,630	251,163,318 THM	$210,800,871	B
TOTAL INDUSTRIAL	648 EA	3,371,466 THM	$2,446,100	35,030,415 THM	$21,739,598	B
TOTAL INTERRUPTIBLE	115 EA	6,428,839 THM	$3,086,442	55,485,155 THM	$23,060,602	B
TOTAL TRANSPORTATION - COMMERCIAL FIRM	97 EA	1,468,509 THM	$281,236	11,200,189 THM	$2,407,355	
TOTAL TRANSPORTATION - INDUSTRIAL FIRM	127 EA	15,811,173 THM	$2,461,558	157,036,601 THM	$28,456,040	
TOTAL TRANSPORTATION - INTERRUPTIBLE	90 EA	20,336,290 THM	$658,958	222,634,306 THM	$7,980,680	
TOTAL TRANSPORTATION - INCENTIVE						
UNBILLED REVENUE		27,738,780 THM	$21,405,806	18,602,608 THM	$19,280,708	
AGENCY FEES						
NET BALANCING/OVERRUN			$47,370		$60,325	
TOTAL ADJUSTMENTS		27,738,780 THM	$21,453,176	18,602,608 THM	$19,341,033	
ADJUSTED REVENUE		168,536,163 THM	$135,668,092	1,184,773,617 THM	$789,350,171	
REVENUE - GAS OP REPORT		168,536,163 THM	$135,103,175	1,184,773,617 THM	$789,790,871	
DIFFERENCE		0 THM	$564,917	0 THM	$(440,700)	

Oregon Sales Rev	$649,569,227	sum of A
WA Sales Rec	$731,165,219	sum of B
% of Total Rev	88.84%	sum of A/sum of B

During 2020, NW Natural increased the allowance for uncollectible accounts by $2.4 million to $3.1 million. Our residential and commercial uncollectible accounts estimate increased from 0.1% of gas sales to approximately
for the year ended December 31. 2020.

Account Number	144011	PROV-UNCOLL RESIDEN
to	144014	PROV-UNCOLL IND INT
Company Code	5000	Northwest Natural Gas Com
Fiscal Year	2020	

Display More Chars

All Documents in Currency * Display Currency USD Co

Period	Debit	Credit	Balance	Cumulativ
Bal.Carryfor...				56
1	267,621.23	405,380.17	137,758.94-	69
2	271,277.35	360,941.43	89,664.08-	78
3	302,305.92	738,103.50	435,797.58-	1,22
4	410,176.81	376,011.23	34,165.58	1,18
5	561,372.97	511,069.17	50,303.80	1,13
6	695,770.57	1,006,599.00	310,828.43-	1,45
7	815,691.07	735,433.28	80,257.79	1,36
8	1,007,074.90	924,059.11	83,015.79	1,28
9	1,052,190.59	1,401,944.22	349,753.63-	1,63
10	1,046,054.10	1,387,470.99	341,416.89-	1,97
11	1,103,998.12	1,143,545.08	39,546.96-	2,01
12	1,184,871.95	2,055,786.92	870,914.97-	2,88
Total	8,718,405.58	11,046,344.10	2,327,938.52-	2,88

	12/31/2020	
Revenues	600,000,000	
Bad Debt Expense Recorded	2,400,000.00	0.40%
Bad Debt Expense Baseline	600,000.00	0.10%
COVID (above baseline)	1,800,000.00	

Record bad debt expense

DR Bad Debt Exp -904	2,400,000.00		
CR Allowance BS GL		2,400,000	
DR Covid Deferral	1,800,000.00		
CR Bad Debt Exp -904		1,800,000	0.75
Net P&L	600,000.00		

	12/31/2020	9/30/2021	Total	
Total provision exp	2,947,524.29	946,739	3,894,263.16	
ending Allowance	2,888,367.00	2,426,524		
Provision deferral	2,332,914.26	431,048.88	2,763,963.14	
Closed + Aged 121 days - reducing allowar	1,063,000.00	2,245,213	1,182,213.00	*Change: h*
AMP		2,069,961		How is AM
			Look at Residential separa	
				Open grea
				We are au

Account Number	186448	OR COVID AMP		
to	186449	WA COVID AMP		
Company Code	5000	Northwest Natural Gas Com		
Fiscal Year	2021			
Display More Chars				
All Documents in Currency	*	Display Currency	USD	Cor

Period	Debit	Credit	Balance	Cumulative
Bal.Carryfor...				
1				
2				
3				
4				
5	182,561.71		182,561.71	182,
6	243,124.59		243,124.59	425,
7	544,815.20	1,037.09	543,778.11	969,
8	[illegible]	[illegible]	[illegible]	[illegible]

8	627,950.13	13,751.41	614,198.72	1,583,
9	486,598.77	300.00	486,298.77	2,069,
10	93,089.38		93,089.38	2,163,
11				2,163,
12				2,163,
Total	2,178,139.78	15,088.50	2,163,051.28	2,163,

· allowance for
0.4% of gas sales

ompany code currenc

e balance	
0,428.87-	
8,187.81-	
7,851.89-	
3,649.47-	
9,483.89-	
9,180.09-	
0,008.52-	
9,750.73-	
6,734.94-	
6,488.57-	
7,905.46-	
7,452.42-	
8,367.39-	
8,367.39-	

Account Number
to
Company Code
Fiscal Year
Display More Chars
All Documents in Currency

Period	
Bal.Carryfor...	
1	1,1
2	1,2
3	1,7
4	1,7
5	1,8
6	2,1
7	2,2
8	2,3
9	2,7
10	
11	
12	
Total	17,2

$2.8M The NWN 12/31/20 al
$560k PYE allowance

Aged 121 days
DR allowance
CR A/R

But does this make sense, unless it is appropriatelly fully reserved for in the allowance

write-off
DR Allowance
CR A/R

normal payment
DR cash
CR A/R So allowance is only releived organically through the quarterly uncollectible review

AMP fund applied
DR AMP Deferral
CR A/R So allowance is only relieved organically through the quarterly uncollectible review

2020 provision exp per 10K rollforward 3,057,000.00
109,475.71 imm

ow does this work in provision? how does this work in t
P considered, should it be included in Rollfwd?
ıtely
ter than 120 days is the $5M
tomatically accruing

Accounts Receivable and Allowance for Uncollectible Acco
Accounts receivable consist primarily of amounts due for natu
amounts due for gas storage services. NW Holdings and NW
for trade receivables, including accrued unbilled revenue, bas
account balances including payment plans, and historical tren
established and recorded for large individual customer receiva

Table of Contents

recovered. Inactive accounts are written-off against the allowa
uncollectible. Differences between the estimated allowance ar
including changes in economic conditions, customer creditwor
accounts is adjusted quarterly, as necessary, based on inform

ALLOWANCE FOR TRADE RECEIVABLES. Accounts receivable
transportation services to NGD customers and amounts due f
generally 15 days. For these short-term receivables, it is not e
affect the loss estimates under stable economic conditions. Fo
economic slowdown caused by pandemics like COVID-19, we

After considering the significant exposure to quarantine-relate
NW Natural expanded our standard review procedures for our
analyzing the significant indications of unemployment rate and
period when the country experienced an economic recession.
customer interactions related to payment plans and credit issu
economic stimulus provided by the federal government which
customers' abilities to ultimately make payment on their accou
accounts was estimated as a percentage of accounts that no
accounts, we continue to analyze those accounts on an accou

The following table presents the activity related to the NW Hol
of which is related to NW Natural's accounts receivable:

npany code cu

balance
,561.71
,686.30
,464.41

,663.13
,961.90
,051.28
,051.28
,051.28
,051.28

144011 PROV-UNCOLL RESIDEN

144014 PROV-UNCOLL IND INT

5000 Northwest Natural Gas Com

2021

* Display Currency USD Company code cur

Debit	Credit	Balance	Cumulative balance
			2,888,367.39-
99,588.82	1,283,821.31	84,232.49-	2,972,599.88-
70,036.43	1,328,416.91	58,380.48-	3,030,980.36-
57,924.79	1,956,281.58	198,356.79-	3,229,337.15-
12,415.44	1,613,858.71	98,556.73	3,130,780.42-
72,063.57	1,712,867.17	159,196.40	2,971,584.02-
21,017.75	2,201,287.21	80,269.46-	3,051,853.48-
30,580.04	2,007,609.51	222,970.53	2,828,882.95-
89,037.06	2,209,389.77	179,647.29	2,649,235.66-
40,142.30	2,517,430.93	222,711.37	2,426,524.29-
1,176.28	2,254,205.54	2,253,029.26-	4,679,553.55-
			4,679,553.55-
			4,679,553.55-
93,982.48	19,085,168.64	1,791,186.16-	4,679,553.55-

ounts

ıral gas sales and transportation services to NGD customers, plus
Natural establish allowances for uncollectible accounts (allowance)
ed on the aging of receivables, collection experience of past due
ıds of write-offs as a percent of revenues. A specific allowance is
ables when amounts are identified as unlikely to be partially or fully

ance after they are 120 days past due or when deemed
nd actual write-offs will occur based on a number of factors,
rthiness, and natural gas prices. The allowance for uncollectible
ation currently available.

consist primarily of amounts due for natural gas sales and
or gas storage services. The payment term of these receivables is
expected that forecasted economic conditions would significantly
or extreme situations like a financial crisis, natural disaster, and the
e enhance our review and analysis.

d job losses in Oregon and Washington state, NW Holdings and
r allowance for uncollectible accounts calculation, including
d comparing to historic economic data during the 2007-2009 time
We then considered other qualitative information including recent
ues, statistics from our website related to credit inquiries, and
could have a beneficial impact on residential and commercial
unts. Our provision calculation for residential and commercial
customer payment was received for 90 or more days. For industrial
unt-by-account basis with specific reserves taken as necessary.

ldings provision for uncollectible accounts by pool, substantially all

2020 Uncollectible Deferral Calculation

Instructions

1 Update the "PQ YTD Dept. Adj." in rows 37-40 with prior qua
2 Run current month Sales and Transportation BI report. Past
3 Run the current Uncollectible Report and paste values in the
4 If Credit Dept. adds and adjustment, populate the "Credit De

YTD Sales Revenues
Residential
Commercial
Industrial - Firm
Industrial - Interruptible
Total

Uncollectible Accrual	*Bad Debt Expense* Before Dec Manual Provision	*from Memo tab* CQ Credit Dept. Adj.
Residential	1,519,703.27	626,000.00
Commercial	745,459.76	128,000.00
Industrial - Firm	41,909.06	27,000.00
Industrial - Interruptible	15,274.81	
	2,322,346.90	781,000.00

Review proof:

Baseline bad debt expense	Actual bad debt expense	Difference - defer
770,433.19	3,103,347	2,332,913.71
	Per calc	2,332,914.26
	proof	(0.55)

Qtr proof	Q4	YTD
Manual provision - YTD	781,000.00	2,230,000.00
Deferred provision - YTD		2,332,914
		105%

Makes sense that almost all of the manual provision is 'above baseline' as the automatic provision is supposed to be the rate case rate

Also the reason they are slightly higher than 100% is because in Nov the rate changed to 0.097% for OR for the auto provision but we still used the prior rate here, this would have left a tiny bit "on the table" and not deferred as could have deferred 0.153% of the total instead of the 0.136% that we did

REQUIRED QUARTERLY

arters "Total YTD Credit Dept. Adj."
e values in the "Srev by Dist" tab.
e "Uncoll Report" tab.
ept. Adj" section below (expected during quarter-end).

	from Uncollect. Tab	89.16%	10.84%
	System	Oregon Allocated	Washington Allocated
	449,622,142		
	192,729,570		
	20,151,209		
	18,497,670		
	681,000,591	607,157,020.71	73,843,570.77
	After Credit Dept. Adj	Oregon Allocated	Washington Allocated
	2,145,703.27		
	873,459.76		
	68,909.06		
	15,274.81		
	3,103,346.90	2,766,838.80	336,508.10
% of revenues		0.456%	0.456%
Rate case uncollectible		0.114%	0.106%
Variance		0.342%	0.350%
YTD Uncollectibles to defer		2,074,679.79	258,233.92
	from PQ workbook	*formula*	*formula*
	PQ YTD Credit Dept. Adj.	CQ Credit Dept. Adj.	Total YTD Credit Dept. Adj.
	842,000.00	626,000.00	1,468,000.00
	590,000.00	128,000.00	718,000.00
	17,000.00	27,000.00	44,000.00
	-	-	-
	1,449,000.00	781,000.00	2,230,000.00
YTD Uncollectible deferral allocated			
Residential		1,365,753.34	169,994.35
Commercial		667,991.07	83,144.37
Industrial - Firm		40,935.39	5,095.20
Industrial - Interruptible		-	-
		2,074,679.79	258,233.92

Total OR calculated		2,074,679.79	
Total OR deferral		2,070,971.35	
	diff	3,708.44	imm

y All Forward IM

er, Kyle T. Kelley, Cristan M.; Faulk, Amanda

llectible Annual Rate in Rate Case - For COVID-19 Deferral

e had in the OR rate case (UG 344):

)ff % - 3-Year Average	
dential	0.153%
nercial	0.039%
strial	0.217%
rruptible	0.000%
eighted Total	0.114%
Normalized Revenues (Test Year)	
dential	387,770
nercial	182,100
strial	20,162
rruptible	19,983
tal	610,016
ized Uncollectible	
dential	$594
nercial	72
strial	44
rruptible	0
tal Normalized Uncollectible	$710
e O&M	$0
nent (Test Year)	$710
ctible rate for normalizaing adjustments	0.114%

e had in the WA rate case (UG-181053)

ff % - 3-Year Average	
ential	0.135%
ercial	0.043%
rial	0.231%
ptible	0.000%
ghted Total [1]	0.106%

MEMORANDUM

NW Natural

220 NW 2ND AVENU
PORTLAND, OR 972
TEL 503.226.4211
www.nwnatural.co

Date: January 8, 2021

To: Brody Wilson, Amanda Faulk, David Aimone

From: Ashlee Minty

Subject: **Fourth Quarter 2020 Uncollectible Additional Reserve Adjustment**

Account Number	Transaction Description	Debit Amt	Cre
144011	Resid Prov. Adj.		
504500-85410-904-02595	Resid BD Expense	$626,000	
144012	Com. Prov. Adj.		
504500-85410-904-02596	Com BD Expense	$128,000	
144013	Ind Firm Prov. Adj.		
504500-85410-904-02597	Ind Firm BD Expense	$27,000	
144014	Ind Intr Prov. Adj.		
504500-85410-904-02598	Ind Intr BD Expense		
144025	SAP A/R Prov. Adj.		
504500-85410-904-02599	SAP BD Expense	$55,000	

Thanks

Ashlee Minty, CCRA,CBA

Director of Credit

edit Amt	
$626,000	Residential
$128,000	Commercial
$27,000	Industrial
$55,000	Not used in this JE

PRELIM_Sales and Transportation Revenue by District

Run date 1.8.2021
(run by Harvest)

Period/Fiscal Year DEC 2020

Last Data Update:

09/29/2020 09:41:10

Display As

	DEC 2020 CUSTOMER COUNT	DEC 2020 THERMS	DEC 2020 AMOUNT
TOTAL REVENUE	**774,954 EA**	**147,894,236 THM**	**$103,276,302**
OREGON	**684,401 EA**	**134,103,672 THM**	**$91,875,220**
BY DISTRICT			
BY RATE SCHEDULE			
RESIDENTIAL	**622,161 EA**	**59,909,960 THM**	**$59,906,193**
COMMERCIAL	**61,230 EA**	**31,720,357 THM**	**$24,855,608**
INDUSTRIAL	**612 EA**	**3,169,711 THM**	**$1,918,058**
INTERRUPTIBLE	**110 EA**	**5,287,637 THM**	**$2,014,499**
TRANSPORTATION - COMMERCIAL FIRM	**88 EA**	**1,052,998 THM**	**$209,117**
TRANSPORTATION - INDUSTRIAL FIRM	**116 EA**	**12,833,056 THM**	**$2,344,534**
TRANSPORTATION - INTERRUPTIBLE	**84 EA**	**20,129,953 THM**	**$627,211**
TRANSPORTATION - INCENTIVE			
WASHINGTON	**90,553 EA**	**13,790,564 THM**	**$11,401,081**
BY DISTRICT			
BY RATE SCHEDULE			
RESIDENTIAL	**83,239 EA**	**8,269,806 THM**	**$8,020,234**
COMMERCIAL	**7,230 EA**	**3,273,845 THM**	**$2,875,810**
INDUSTRIAL	**48 EA**	**369,346 THM**	**$239,177**
INTERRUPTIBLE	**5 EA**	**127,248 THM**	**$62,517**
TRANSPORTATION - COMMERCIAL FIRM	**11 EA**	**223,458 THM**	**$44,835**
TRANSPORTATION - INDUSTRIAL FIRM	**10 EA**	**912,553 THM**	**$95,290**
TRANSPORTATION - INTERRUPTIBLE	**10 EA**	**614,309 THM**	**$63,217**
TRANSPORTATION - INCENTIVE			
TOTAL RESIDENTIAL	**705,400 EA**	**68,179,766 THM**	**$67,926,428**
TOTAL COMMERCIAL	**68,460 EA**	**34,994,202 THM**	**$27,731,419**
TOTAL INDUSTRIAL	**660 EA**	**3,539,057 THM**	**$2,157,235**
TOTAL INTERRUPTIBLE	**115 EA**	**5,414,885 THM**	**$2,077,016**
TOTAL TRANSPORTATION - COMMERCIAL FIRM	**99 EA**	**1,276,456 THM**	**$253,952**
TOTAL TRANSPORTATION - INDUSTRIAL FIRM	**126 EA**	**13,745,609 THM**	**$2,439,824**
TOTAL TRANSPORTATION - INTERRUPTIBLE	**94 EA**	**20,744,262 THM**	**$690,428**
TOTAL TRANSPORTATION - INCENTIVE			
UNBILLED REVENUE		631,554 THM	$4,080,190
AGENCY FEES			
NET BALANCING/OVERRUN			
TOTAL ADJUSTMENTS		**631,554 THM**	**$4,080,190**

ADJUSTED REVENUE		**148,525,790 THM**	**$107,356,492**
REVENUE - GAS OP REPORT		148,525,790 THM	**$107,329,314**
DIFFERENCE		**0 THM**	**$27,178**

2020 YTD THERMS	2020 YTD AMOUNT	
1,144,709,988 THM	$709,949,805	
1,046,414,391 THM	$634,943,504	
383,094,801 THM	$391,653,175	A
221,180,841 THM	$170,832,863	A
31,250,771 THM	$18,241,586	A
47,659,087 THM	$17,316,382	A
9,739,678 THM	$2,085,942	
139,927,085 THM	$27,665,625	
213,562,128 THM	$7,147,930	
98,295,597 THM	$75,006,301	
52,610,361 THM	$51,280,792	
22,004,646 THM	$18,981,614	
3,018,728 THM	$1,909,623	
1,198,317 THM	$563,199	
2,588,581 THM	$490,817	
9,441,722 THM	$1,035,096	
7,433,242 THM	$745,159	
435,705,162 THM	$442,933,967	B
243,185,487 THM	$189,814,477	B
34,269,500 THM	$20,151,209	B
48,857,404 THM	$17,879,581	B
12,328,259 THM	$2,576,759	
149,368,807 THM	$28,700,722	
220,995,370 THM	$7,893,089	
(1,813,202) THM	$4,654,786	
	$216,908	
(1,813,202) THM	$4,871,694	

1,142,896,786 THM	**$714,821,499**
1,142,896,786 THM	**$713,869,506**
0 THM	**$951,994**

Oregon Sales Rev	$598,044,006	sum of A
WA Sales Rec	$670,779,235	sum of B
% of Total Rev	89.16%	sum of A/sum of B

2021 Late Fee Charge Deferral Calculation **Dec 2021**

Instructions:

OREGON	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total		
OR Actual Billed	152,874	169,880	58,632	88,574	67,762	44,071	36,725	30,053	29,263	33,532	52,906	68,005	832,277.50	-	*YTD ties to GL*
OR UG 388	241,961	297,474	262,799	252,580	213,854	150,477	80,815	76,018	72,217	74,222	104,822	178,059	2,005,297.89		
Difference	**(89,087)**	**(127,594)**	**(204,167)**	**(164,007)**	**(146,092)**	**(106,407)**	**(44,090)**	**(45,966)**	**(42,953)**	**(40,690)**	**(51,916)**	**(110,054)**	(1,173,020.39)		

YTD	(1,173,020.39)
Recorded	(1,062,966.75)
Amount to record	(110,053.64)

2020 Late Fee Charge Deferral Calculation **December 2020**

OREGON	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
OR Actual Billed	266,454	287,781	116,876	(1,366)	(1,147)	(269)	(67)	(46)	(81)	(14)	11	102,182	770,312.45
OR UG 344	259,514	306,130	261,259	245,748	207,988	161,572	90,370	78,708	75,754	76,523	88,422	149,396	2,001,384.30
Difference	6,940	(18,349)	(144,383)	(247,115)	(209,135)	(161,840)	(90,437)	(78,754)	(75,835)	(76,537)	(88,412)	(47,214)	(1,219,662.15)

YTD	(1,219,662.15)
Recorded	(1,183,857.75)
Amount to record	(35,804.40)

CASE: UG 435
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1600

Opening Testimony

April 22, 2022

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

A. My name is Scott Gibbens. I am a manager 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/1601.

Q. What is the purpose of your testimony?

A. I will addresses the long-run incremental cost (LRIC) analysis for Northwest Natural Gas Company (NW Natural, NWN, or Company).

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Staff is generally satisfied with NWN's LRIC study. Staff does have a few adjustments to the Company's methodology, however the adjustments are too small to impact the overriding results of the study. More specifically, the conclusion of the study that residential and small commercial customers are generally being subsidized by larger industrial and commercial customers remains valid following Staff's proposed adjustments.

However, Staff's adjustments reduce the overall discrepancy between schedules, bringing most schedules closer to parity, perhaps reducing the amount to which the Commission should rely on the study as the impetus for rate design and rate spread decisions. A comparison of Staff's and the Company's parity ratios at present rates for each rate class is shown in the figure below.

TABLE 1

Schd	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI
NWN	0.95	0.95	1.19	0.85	1.46	1.63	1.53	2.2	1.57	2.2	2.46	2.11	1.16	2.16	2.49	1.89
Staff	0.96	0.96	1.15	0.86	1.49	1.61	1.51	2.1	1.61	2	2.33	1.97	1.04	1.73	4.88	1.1
	1%	1%	4%	1%	3%	-2%	2%	10%	4%	20%	13%	14%	12%	43%	239%	79%

Please note that I may revise my recommendations based on testimony filed by other participants in this rate case.

ISSUE 1. LONG-RUN INCREMENTAL COST STUDY

Q. What is the LRIC and what is its goal?

A. The LRIC is a study that identifies the difference in costs to serve each customer schedule. The results of the LRIC are then used to inform appropriate rate spread and design considerations so that different customer classes pay rates that reflect the costs of service. LRIC uses as its basis the costs of replacing all facilities needed to serve customers. The costs are functionalized by dividing them into several cost categories.

Q. How are costs allocated in the LRIC?

A. The cost categories associated with service are assigned to each customer type where possible, such as for meters and service lines. These costs that can be easily divided are calculated by taking the per-customer average and multiplying by the number of customers in that schedule. The remaining costs are allocated by identifying cost types within each cost category and customer class.

For example, distribution mains are large pipes utilized by all customer classes to deliver gas for use. These can be broken down into “system mains” and “main extensions” based on their size and position in the distribution system. Since a major cost driver of these large-diameter mains is meeting peak demand, a customer class’s burden to pay for these system mains should arguably correlate to each customer schedule’s use when the system peak load occurs. The higher the peak day load for a schedule, the more they are requiring the Company to invest in larger system mains to meet peak demand.

Once each cost category is broken down and each customer class's cost causation has been identified, ratios are used to allocate the embedded costs for each designated functional category. If residential customers are responsible for 20 percent of new system main costs, they are allocated 20 percent of the embedded costs for system mains. Ultimately, the study compares what portion of costs each customer class is currently paying, to what they should be paying based on the above noted allocation method. This can be used as the basis for cost-based rates, the theory being you should pay for the costs you are causing to the system

Q. Are LRIC results directly applied for rate spread determinations?

A. Not exactly. There are many other considerations that often can and do go into rate spread and rate design, but usually the LRIC is a large driving force behind the allocation of costs to a customer class.

Q. Does Staff believe that the Company has utilized the proper methodology for their LRIC?

A. Generally yes. Staff does have a few proposed adjustments to the Company's LRIC. However, Staff's adjustments are too small to impact the main results of the Company's LRIC study. Even with Staff adjustments, the Company's LRIC study shows that residential and small commercial customers are being subsidized by larger industrial and commercial customers.

TABLE 2

Schd	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI
NWN	0.95	0.95	1.19	0.85	1.46	1.63	1.53	2.2	1.57	2.2	2.46	2.11	1.16	2.16	2.49	1.89
Staff	0.96	0.96	1.15	0.86	1.49	1.61	1.51	2.1	1.61	2	2.33	1.97	1.04	1.73	4.88	1.1

Q. Please describe Staff's adjustments.

A. Staff has two adjustments. The first is in regard to the Company's calculation of the "Maximum Daily Demand Value" (MDDV). The second relates to the Company's allocation of system core mains.

Q. What is the MDDV?

A. The MDDV is a metric that the Company uses to calculate the load factor of large commercial and industrial customers. Because the Company does not forecast the peak design day usage for these schedules, an approximation has to be made in order to calculate the load factor for customers in the test year. The load factor is a measure of the "peakiness" of a customer's load, i.e., the extent to which a customer's peak use relates to their annual use.

Industrial customers generally have a higher load factor because they use a relatively even amount of energy every day of the year. The peak load factor is used to capture the capacity related burden each customer is placing on different system capacity costs. To calculate the load factor for these schedules, the Company takes the expected energy used for each schedule or the Test Year energy forecast and divides it by what energy demand would have been if customers had used their peak day demand every day of the year. To estimate the Test Year peak demand for each customer, the Company identifies each individual customer's historical maximum daily load for each rate schedule by year.

The daily loads for every customer are summed up across each applicable rate schedule for each year, 2016-2020. Then the Company takes the average of these summed up daily loads over the five years. This results in the five-year average total peak daily load for each customer schedule. Then each number is multiplied by 365, to identify what demand would have been if each customer had used their maximum daily demand, every day. This is the MDDV. The normalized test year therms by schedule is then divided by the MDDV. This produces the load factor.

Q. What is Staff's adjustment to the MDDV?

A. As described above the Company takes the average of five years of data to calculate the MDDV. When the Company does this, it only includes customers who are also included in the test year of the GRC load forecast. The idea presumably being, that if a customer is no longer on the system, they cannot be utilized to allocate costs, as they wouldn't be in the test year therm forecast.

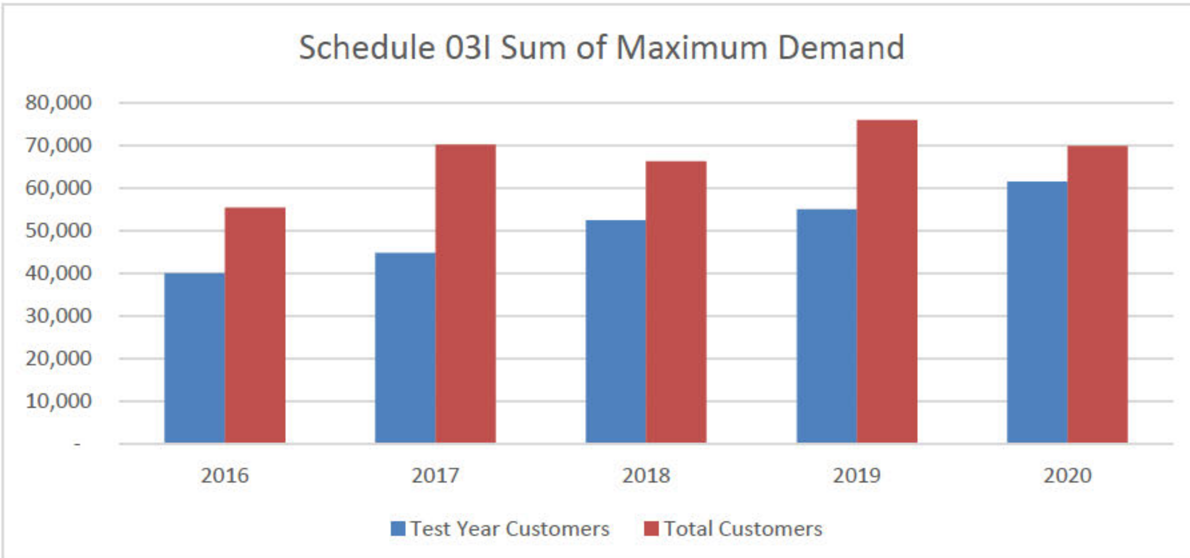
The issue is that the goal of the MDDV is to identify what the actual peak day demand would be for each schedule so that it can be compared to the actual Test Year forecast, but instead the MDDV currently estimates only a portion of the true Test Year max demand. The higher daily demand of a single customer holding all else equal (including total yearly demand), the lower the load factor and the more "peaky" the load is. The peakier the load is, the more responsible the customer should be for capacity costs.

By only utilizing customers who are in the Test Year, they are treating any customer who became a new customer in the last five years as having zero peak demand for any of the previous years in the study. Consider a large business who shut down in 2019 but then reopens under a new name and new owner the same year. This business may be considered two different customers in the Company's system, with two different accounts. The demand of the original owner would not be included in the MDDV calculation as they aren't in the Test Year, instead the new owner's demand would be effectively zero for the first three years based on the Company's current methodology. This zero demand would then lower the total daily demand for that customer class.

Of course, not only a factory shutting down and starting back up would cause this issue. Any customer who opened for business during the five-year time frame would contribute to this issue. Consider a customer who opened in 2019 and had a peak daily demand of 500 therms in 2019 and 500 therms in 2020. Now although they were not operating every year in the last five years, what peak usage should be expected from the customer in the Test Year? The Company's methodology utilizes the average over five-years, or roughly 200 therms, Staff believes that a more reasonable estimate would be roughly 500 therms.

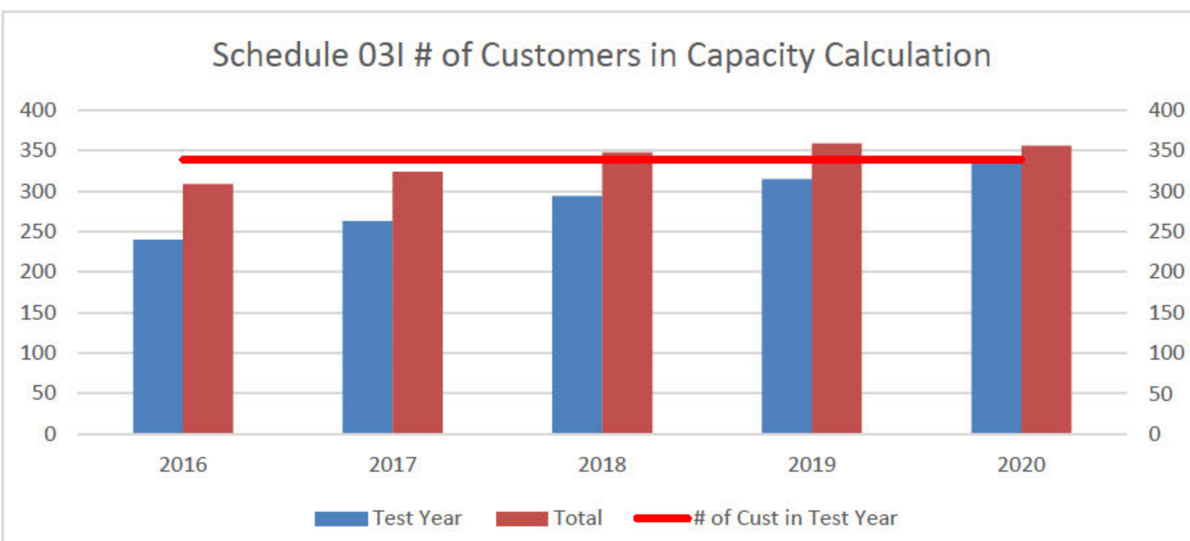
As evidenced by looking at the MDDV by year of a sample schedule in the figure below, it is clear that this problem persists. The MDDV monotonically increases during the five-year study time period. However, that is not the case when looking at all customers, even those who aren't included in the Test Year.

FIGURE 1



This can be further seen by looking at the number of customers that are being included in the data each year.

FIGURE 2



Because the Company fails to weight the years by the number of customers present in the data, the average MDDV numbers fall well below what the actual expected value is for those 339 customers in the Test Year (shown on the red line of the figure above). So, when the Company takes the normalized Test Year therms by schedule, and divides by the calculated MDDV to get a capacity factor estimate, they are overestimating the capacity factors for all large Commercial and Industrial customers.[1]

Q. What is the impact of overestimating capacity factors?

A. Capacity factors are used by the Company to estimate the burden a particular customer class puts on the need for capacity on the system. The largest cost category this relates to is the system mains, but it also plays into other cost categories. In general, the more costly something is to install simply to serve a large amount of load in a single day, the more a customer with a lower capacity factor will pay. This is often related to responsiveness to weather, as Staff will discuss later in testimony, but even if peak demand is not related to weather, the customers may be causing added strain on the system during peak times, warranting further investment. Correctly estimating the capacity factor ensures that each customer class is paying its fair share of fixed costs. Staff shows the impact of correcting the Company's MDDV calculation in Table 3 below.

Q. How does Staff propose to fix this issue?

[1] The Company does not simply use test year therms by schedule, instead they adjust the load so that it includes a 50/50 weighting by schedule and by class of customer. Presumably under the assumption that similar class types will have similar load factors or capacity needs.

A. There are potentially two simple fixes that could be made by the Company to correctly weight the number of customers included in the load factor calculation. The first is to adjust the other side of the load capacity calculation so that it is the average annual throughput for Test Year customers over the last five years. This would not result in a close estimate of the Test Year therms, due to the same problems noted by Staff above. Instead it would provide the average throughput for those customers present in the Test Year over the last five years. This would match the MDDV in terms of metric, thus the capacity factors would be accurate, even though neither the expected MDDV nor test year therms were used in the calculation.

Another potential solution is Staff's preferred approach as it maintains the use of the normalized test year therms. Although only the load factor numbers are utilized for cost allocation in this calculation, Staff believes that it is better practice to calculate the actual expected usage and maximum demand when estimating the capacity factor. Staff simply weighted each year's MDDV calculation by the number of Test Year customers included in the data for each year. Staff did this by dividing each year's number of customers by the Test Year customer count for each year, then using that as a factor to gross up (or down) the total MDDV for each year. This provides an estimate for what the Test Year count of customers would have had for maximum demand in each year, assuming that the customers not included in each historical year would have had similar demand as the average customers for each schedule.

Q. Did Staff test the assumption that existing customers were like new customers?

A. Yes. To test the validity of this assumption in an expedient manner, Staff calculated the correlation coefficient between the five-year average percentage of customers not included in a particular year per schedule to the average peak demand per customer in that schedule.[2] The concern being that if smaller customers were more likely to begin/cease operations then their usage may not be average. However the relative size of each customer's peak demand had no significant relationship with the likelihood that customers would not be present in the data.

Q. How did Staff then complete the capacity factor calculation?

A. Staff took the weighted numbers and calculated the five-year average peak demand and fed this into the Company's LRIC model. A comparison of Staff's and the Company's parity ratio at present rates for each rate class is shown in the table below. This displays how close each schedule is to rates which recover the costs they impose on the system, with numbers below one meaning they only pay that percentage of their fair costs.

TABLE 3

Schd	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI
NWN	0.95	0.95	1.19	0.85	1.46	1.63	1.53	2.20	1.57	2.20	2.46	2.11	1.16	2.16	2.49	1.89
Staff	0.95	0.95	1.17	0.85	1.46	1.59	1.48	2.06	1.58	1.99	2.27	1.91	1.18	2.09	2.67	1.77

---

2 Staff notes that a more appropriate test may be to compare the average usage (during years of operation) for customers who were not present in a particular year with the annual average usage for that schedule to identify if the customers who joined later were in fact close to average usage for that schedule. Staff did not go through the process of calculating each of these numbers due to time constraints.

The results of the correction generally lowered the apparent subsidization by industrial customers and worsened the apparent subsidization by large commercial customers.

Q. Please describe Staff's adjustment to system core main allocation.

A. To allocate system core mains, the Company calculates a weighted allocation that is based on the throughput allocation and firm demand allocation. When allocating costs to interruptible customers, the Company does not include any firm (peak day) demands as the customer would presumably be interrupted during peak day events and thus their loads aren't taken into consideration when investing to meet the system's peak demand.

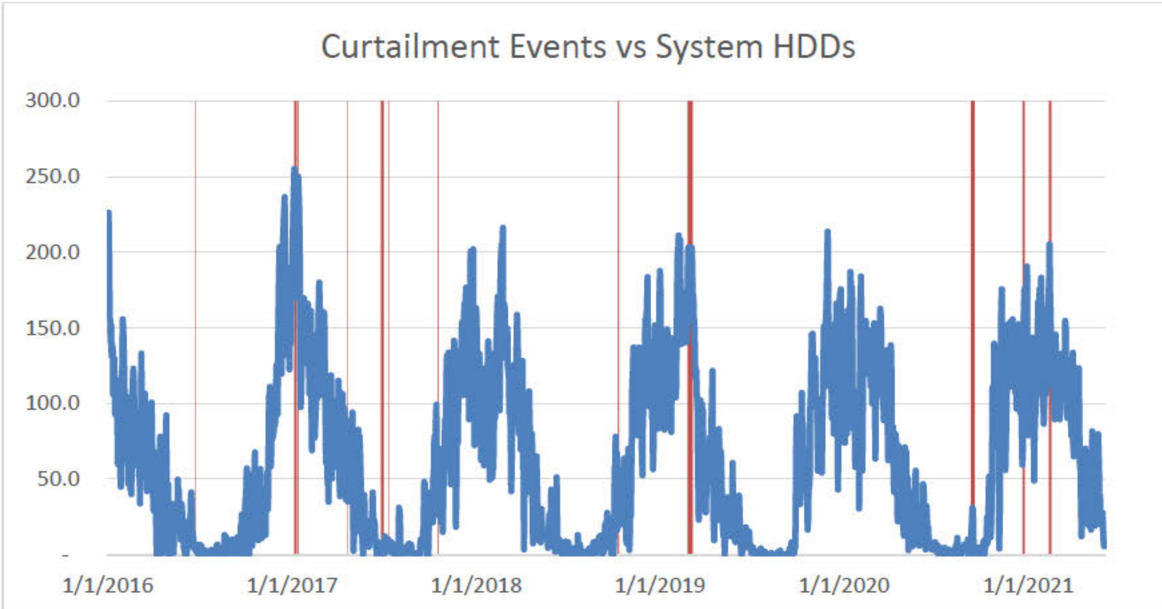
However, interruptible customers are seldom, if ever interrupted, and so they receive tangible benefits from the peak day planning investments. The table below shows the number of curtailment events for interruptible customers over the last six years.

TABLE 4

Curtailment Start Date	Number of Customers	Number of Days
6/23/16	2	1
1/6/17	3	3
1/11/17	1	3
4/20/17	1	1
6/26/17	4	6
7/12/17	1	1
10/17/17	2	2
10/10/18	166	2
2/25/19	122	10
12/21/20	1	4
9/9/20	1	8
2/11/21	1	5
2/12/21	2	3
Percent of Total	25.9%	2.5%
Only Heating Season	11.0%	1.5%

There were roughly 200 interruptible customers each year on average from 2016-2021, of those customers only two curtailment events impacted more than a small handful. Further, the October 2018 event is presumably due to the October 9, 2018 Enbridge pipeline rupture. Meaning that curtailment had more to do with gas supply that it did with gas demand and capacity on the system. Only a single event, occurring in February 2019, where the region experienced unseasonable cold temperatures and snowy conditions could be categorized as a large demand related event that limited the available capacity on the system and resulted in impacts to more than three percent of the interruptible customers. When looking at curtailment events compared to the weather, this is further evidenced.

TABLE 5



The Company argues that "load peaks for NW Natural are a matter of space heating requirements, and are therefore directly related to weather."[3] However, the majority of curtailment events have little correlation with weather and usually only tend to impact a very small percentage of interruptible customers. Thus allocating no capacity costs to interruptible customers based on the fact that their load may be curtailed during peak events is supported by little historic evidence. Staff recommends that these customers be allocated fifty percent of the standard demand allocation as if they were firm customers. This is done by utilizing the average and peak day deliveries (firm and non-firm) as opposed to the average firm and peak firm daily deliveries when allocating the demand related costs, dividing the interruptible schedules by two

[3] NW Natural/1400, Wyman/22, lines 1-3.

and re-indexing the amounts so they sum to 100 percent of the total costs but maintain their relative relationship between schedules.

This change allocated a higher burden of costs to most interruptible schedules, however it reduces the allocated costs on Schedule 32 commercial transportation interruptible customers and shows that they are highly subsidizing other schedules. This is because the Company's adjusted allocation factors for this schedule were higher than their fifty percent share of peak day deliveries. Staff's adjusted LRIC parity ratios are found below, inclusive of both Staff adjustments.

TABLE 6

Schd	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI
NWN	0.95	0.95	1.19	0.85	1.46	1.63	1.53	2.2	1.57	2.2	2.46	2.11	1.16	2.16	2.49	1.89
Staff	0.96	0.96	1.15	0.86	1.49	1.61	1.51	2.1	1.61	2	2.33	1.97	1.04	1.73	4.88	1.1
	1%	1%	4%	1%	3%	-2%	2%	10%	4%	20%	13%	14%	12%	43%	239%	79%

As can be seen in the table above, Staff's adjustments to the LRIC do reduce the subsidization of the smaller sized customer classes and largely brings larger customers closer to parity.

Q. Has Staff reviewed other aspects of the LRIC?

A. Yes. Staff reviewed the Company's assumptions and methodology of the LRIC study. Staff paid special attention to those issues noted by Staff in NWN's previous GRC (UG 388) as concerns regarding the Company's LRIC methodology.

One such issue was the allocation of storage costs to interruptible customers as these customers benefit from storage due to the decreased likelihood that interruption of service will be necessary. The Company no longer utilizes the peak firm day deliveries as the sole allocation metric, and instead utilizes the relative demand by schedule between winter and summer months. The more a customer uses in the winter compared to the summer, the more it is assumed their load is responsible for the system storage needs. Interruptible customers are allocated in the same manner with a 50 percent reduction in their demand related costs for storage. Staff finds that this is a reasonable compromise between the benefits interruptible customers receive from storage and reduced need for additional storage provided by their interruptible load.

Q. What are Staff's conclusions and recommendations for the Commission regarding the Company's LRIC study?

A. Staff recommends that the Company utilize Staff's adjusted methodologies for this and future LRIC studies. The capacity factor calculation plays a part in the majority of the allocations made in the LRIC where demand or capacity is involved. Staff further believes that interruptible customers should bear some of the burden for demand related costs of system core mains as their load has been shown to be almost indistinguishable from firm. Staff's adjustments bring most schedules closer to parity, perhaps allowing all customers to more evenly share the additional revenue requirement requested by the Company in this case while still maintain fair and equitable rates. For further discussion on Staff's recommended rate spread please see Exhibit Staff/1300.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 435
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1601

Witness Qualification Statement

April 22, 2022

WITNESS QUALIFICATION STATEMENT

NAME:	Scott Gibbens
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Policy and Economics Manager Strategy and Integration
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Bachelor of Science, Economics, University of Oregon Masters of Science, Economics, University of Oregon
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include management of the Policy and Economics Group. Our focus is technical analysis supporting the Commission Utility Program functions, including load forecasting, rate spread/rate design, capacity valuation, consumer choice programs, and general modeling analysis. I was the power cost team manager from January 2017 to February 2021. I have worked on the following power cost dockets: PAC UE 307, UE 309, UE 323, UE 327, UE 339, UE 344, UE 356, UE 361, and current UE 375 and UE 379. PGE UE 308, UE 310, UE 319, UE 329, UE 335, UE 346, UE 359, UE 362, and UE 377. IPC UE 301, 305, UE 314, UE 320, UE 333, UE 336, UE 350, UE 354, UE 366, and UE 376. I've also performed analysis and review on a variety of other issues at the Commission. I have reviewed issues and made recommendations to the Commission in the following general rate cases: AVA UG 325, UG 366 and current UG 389; NWN UG 344, UG 388, and current UG 435; PAC UE 374; PGE UE 319, UE 335, UE 394; and CNG UG 305, UG 347 and UG 390. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

CASE: UG 435
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1602

Exhibits in Support of Opening Testimony

April 22, 2022

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 458

458. Please provide a table showing both the number of customers enrolled in interruptible service and the, date and number of interruptions per annum by (interruptible) schedule between 2016 and 2021, inclusive. Are the interruptions controlled by the Company or the customer? If it is the latter, by customer, provide the number of requested interruptions and the number of instances service was actually curtailed.

Response:

Interruptions are generally controlled by the Company.

Oregon Annual Interruptible Customer Curtailment Data (2016-2021)

YEAR	Total Interruptible Customers	Interruptible Sales Customers	Interruptible Transportation Customers	Number of Interruptible Sales Customers Curtailed	Interruptible Transportation Customers Curtailed	Curtailment Event 1 Dates	Curtailment Event 2 Dates	Curtailment Event 3 Dates	Curtailment Event 4 Dates	Curtailment Event 5 Dates	Curtailment Event 6 Dates
2016	192	120	72	1	1	6/23 (2 accts)					
2017	196	119	77	6	6	1/6 -1/8 (3)	1/11-1/13 (1)	4/20 (1)	6/26-7/1 (4)	7/12 (1)	10/17-10/18 (2)
2018	199	115	84	98	68	10/10-10/11 (166)					
2019	203	122	81	122	0	2/25-3/6 (122)					
2020	193	110	83	0	2	12/21-12/24 (1)	9/9-9/16 (1)				
2021	204	115	89	2	1	2/11-2/15 (1)	2/12-2/14 (2)				

CASE: UG 435
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1700
Highly Confidential
Subject to Modified Protective Order No. 21-465

Opening Testimony:
Lexington Renewable Natural Gas Project

April 22, 2022

CERTIFICATE OF SERVICE

UG 435

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

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

/s/ Kay Barnes

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Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (971) 375-5079

UG 435 – SERVICE LIST (4/22/2022)

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