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December 29, 2017 NWN Advice No. OPUC 17-22 / ADV __

VIA ELECTRONIC FILING AND PERSONAL DELIVERY

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: UG 344
Application of NW Natural for a General Rate Revision

In accordance with OAR 860-022-0019, Northwest Natural Gas Company, dba NW Natural ("NW Natural" or "Company"), files herewith its Application for a General Rate Revision. Twenty (20) copies of the Executive Summary, Direct Testimony, and Exhibits are included with this filing. An electronic version of the Application, all supporting work papers, and responses to the Standard Data Requests are also being provided on the Commission's Huddle site. Notices will be published in accordance with the requirements of OAR 860-022-0017.

Please note the filing contains some limited confidential information that represents business-sensitive, non-public information.

Included with this filing are the following revisions to Tariff, P.U.C. Or. 25[1], stated to become effective with service on and after **November 1, 2018**:

First Revision of Sheet 167-1,
Schedule 167,
"General Adjustments to Rates."

The Company waives paper service in this proceeding.

Please address correspondence on this matter to me with copies to the following:

[1] Tariff P.U.C. Or. 25 originated November 1, 2012 with Docket UG 221; OPUC Order No. 12-408 as supplemented by Order No. 12-437, and was filed pursuant to ORS 767.205 and OAR 860-022-0005.

Zachary Kravitz
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Telephone: 503-595-3925
Facsimile: 503-595-3928
lisa@mcd-law.com

Please call me if you have questions.

Sincerely,

NW NATURAL

/s/ Mark R. Thompson

Mark R. Thompson
Manager, Rates & Regulatory Affairs

enclosures

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UG 344

In the Matter of NORTHWEST NATURAL GAS COMPANY Application for a General Rate Revision.	**NW NATURAL'S EXECUTIVE SUMMARY**

I. INTRODUCTION

Northwest Natural Gas Company ("NW Natural" or "Company") is filing a general rate increase with the Public Utility Commission of Oregon ("Commission"), pursuant to ORS 757.205, 757.215 and 757.220, to revise its schedules of rates and charges for natural gas service in Oregon to become effective with service provided on and after November 1, 2018. With this filing, the Company requests a revision to customer rates that will increase the Company's annual Oregon jurisdictional revenues by $52.4 million, or an approximately 8.3 percent increase over current customer rates. Because the rate case includes $12.07 million otherwise collected through NW Natural's decoupling deferral, the net increase of $40.38 million, about 6.3 percent, represents the incremental impact to customers' future billing rates.

The revised rates produce revenues necessary to sustain the provision of safe, reliable, and low-cost natural gas service to customers in Oregon, while preserving the Company's ability to attract capital for future investments. The Company files this Executive Summary in accordance with OAR 860-022-0019(1). Exhibit A to the Executive

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Summary provides the required information in accordance with OAR 860-022-0019(1)(a)-(h).

II. BACKGROUND

NW Natural is an Oregon corporation whose principal place of business is 220 NW Second Avenue, Portland, Oregon, 97209. NW Natural is a public utility providing natural gas service in Oregon within the meaning of ORS 757.005, and is subject to the jurisdiction of this Commission. NW Natural has approximately 735,000 customers, consisting of approximately 666,000 residential, 68,000 commercial, and 1,000 industrial customers. Approximately 90 percent of NW Natural's customers are located in Oregon and 10 percent are located in Washington.

Communications regarding this filing, including data requests issued to the Company, should be addressed to:

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Email: Zachary.Kravitz@nwnatural.com

III. CASE SUMMARY

A. The Test Year

The Company's test year in this case is the twelve months ending October 31, 2019 ("Test Year"). NW Natural provides information for a historical base year of the twelve months ending December 31, 2017 ("Base Year"), and makes adjustments to that information to reflect the forecast Test Year. In order to meet the legal requirement that rates be fair, just, reasonable, and sufficient, the Company has selected the Test Year to closely reflect the investment and expense levels that will exist during the time that the rates adopted in this case are expected to be in effect. The new rates are filed with a requested effective date of November 1, 2018. This assumes the addition of the full nine-month statutory suspension period to the 30-day effective date normally applicable to tariff revisions.

B. Return on Equity

The Company's current authorized return on equity ("ROE") is 9.5 percent, as established in the Company's most recent rate case, Docket UG 221, Order No. 12-437. In this case, the Company seeks an authorized ROE of 10.0 percent. As described in the testimony of Dr. Bente Villadsen, the Company believes that an ROE of 10.0 percent represents a fair return for both shareholders and customers.

C. Factors Driving Rate Adjustment

As described in the testimony of David Anderson, NW Natural strives to keep rates low for its customers, and it has been managing the Company's operations to avoid having to request a rate increase for six years. However, since the Company's last rate

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case, a variety of factors have put building pressure on the need to adjust rates. These factors include continued investments in the gas distribution system for safety and reliability needs, and increased operations and maintenance ("O&M") expense, coupled with low customer growth rates compared to historical growth rates.

1. System Investments

Since its last rate case six years ago, the Company has made substantial capital investments in its gas distribution system. These investments are necessary to continue to deliver gas to NW Natural's customers in a manner that is reliable and safe as the system grows, and as components age.

2. Increased O&M Expenses

Since the Company's last rate case, the Company's O&M expenses have increased. The increase in O&M expenses is attributable to inflation, work force-related costs, and increases in other costs of providing utility service. Overall, however, the Company's O&M levels have grown at a reasonable rate that is consistent with O&M expenses for the Company's peer utilities. The Company's overall O&M expenses reflect good cost management practices at the Company, and that the utility is managing its O&M levels to stabilize rates as much as possible for customers.

D. Cost Control Efforts

NW Natural has worked hard to control costs and avoid the need for a rate case, which is demonstrated by the fact that the Company has not requested a rate increase in six years. NW Natural has been able to avoid the need for a rate case by careful planning and budgeting, with an ongoing focus on controlling costs.

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E. Tax Reform

At the time the rate case was finalized for printing, the Tax Cuts and Jobs Act had not been finalized, and the proposed rate changes do not reflect the implications of the new law on ratemaking. NW Natural will work with the OPUC Staff and parties to ensure an appropriate transition to the new tax law, and will make appropriate supplemental filings to reflect the implications of the tax reform on NW Natural's rates.

IV. TESTIMONY SUMMARY

The Company's direct case consists of the testimony and exhibits of 11 witnesses:

- In NW Natural/100, **David Anderson**, NW Natural's President and Chief Executive Officer, describes NW Natural's overall operating environment, as well as the Company's current goals and provides a high-level overview of the Company's application for a general rate revision.
- In NW Natural/200, **Kevin McVay**, Revenue Requirement Analytics Consultant, provides the calculation of the Company's "revenue requirement," which represents the annual dollars needed to recover prudently incurred costs of operating the utility business.
- In NW Natural/300, **Frank Burkhartsmeyer**, NW Natural's Senior Vice President and Chief Financial Officer, provides testimony about the Company's cost of capital. His testimony provides information about the costs of the Company's outstanding debt, and debt NW Natural will issue during the Test Year. Mr. Burkhartsmeyer's testimony also describes the Company's balance of financing the Company with debt versus equity from shareholder investments in the

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Company. He demonstrates that the Company continues to adhere to its policy of balancing debt and equity financing with a 50/50 capital structure, and thus requests that the Commission recognize this capital structure when approving rates in this case.

- In NW Natural/400, **Dr. Bente Villadsen**, an outside expert on utility finance and required rates of return for regulated companies, provides testimony about the Company's cost of equity, or in other words, the return that investors in NW Natural should reasonably expect to have the opportunity to earn. Her testimony provides a range of return on equity that NW Natural should be given the opportunity to earn in order to attract capital. Her testimony supports the Company's request for approval to include a 10.0 percent return on equity in the revenue requirement authorized in this proceeding (the mid-point of the range that Dr. Villadsen has determined is reasonable for NW Natural's investors).
- In NW Natural/500, **Wayne Pipes**, Senior Manager of Security and Facilities, provides testimony about the Company's facilities plan, and the actions the Company has taken pursuant to the plan to ensure that our facilities remain operable, safe, and that they provide the efficiencies needed to continue to provide service to our customers in accordance with the Company's and customers' standards.
- In NW Natural/600, **Jorge Moncayo**, Director of Finance and Budget, provides testimony about the operations and maintenance expense levels that the Company

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has been incurring and expects to incur, as well as overall capital spending, for which it requests recovery in this application.

- In NW Natural/700, **Lea Anne Doolittle**, Senior Vice President and Chief Administrative Officer, provides testimony on NW Natural's labor costs, and describes the Company's practices related to compensation, which ensure that all employees receive compensation at market median rates. She sets forth the Company's request to include these costs in the Company's revenue requirement.
- In NW Natural/800, **Joe Karney**, Director of Engineering, provides testimony about some of the major capital projects the Company has undertaken in order to keep our system safe, reliable, and economical.
- In NW Natural/900, **Kyle Walker**, Rates and Regulatory Analyst, provides testimony about the Company's Decoupling mechanism and the Company's Weather Adjustment Rate Mechanism. He also sets forth the Company's request to improve the Decoupling mechanism by synching up the weather-normalized values used by the mechanism with those that reflect customer participation in the WARM program, and to extend the Decoupling mechanism to large commercial customers.
- In NW Natural/1000, **Kim Heiting**, Chief Marketing Officer and Vice President, Communications, provides testimony about the Company's communications to customers, on matters of safety, as well as communicating information to customers about the nature of the services offered to them by the Company, and

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opportunities to conserve and be educated about the products that they purchase from NW Natural.

- In NW Natural/1100, **Andrew Speer**, Rates and Regulatory Analyst, provides the Company's long-run incremental cost study, and provides the proposed spread across rates of the revenue requirement increase requested.

V. CONCLUSION

For the reasons described in this application, and further by the testimony of the witnesses offered in this proceeding, the Company requests that the Commission issue an order approving the proposed rate changes and proposed tariffs.

DATED: December 29th, 2017

MCDOWELL RACKNER & GIBSON PC

/s/Lisa F. Rackner

Lisa F. Rackner
Jocelyn C. Pease

NORTHWEST NATURAL GAS COMPANY

Zach Kravitz

Of Attorneys for Northwest Natural Gas Company

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Exhibit A to NW Natural's Executive Summary
Summary of Requested General Rate Increase
Filed December 29, 2017

Total Revenues Collected Under Proposed Rates:	$ 682,535,000
Revenue Change Requested:	$ 52,446,000
Revenues Net of any Credits from Federal Agencies:	$ 682,535,000
Percentage Change in Revenues Requested:	8.32%
Percentage Change in Revenues Net of any Credits from Federal Agencies:	8.32%

Test Period: November 1, 2018 to October 31, 2019

Requested Overall Rate of Return	7.617%
Requested Rate of Return on Equity:	10.0%
Proposed Rate Base:	1,189,882,000

Results of Operation

Before Proposed Rate Change[1]

Utility Operating Income:	60,005,000
Average Rate Base:	1,189,882,000
Rate of Return on Capital:	5.04
Rate of Return on Equity:	4.85

After Proposed Rate Change[2]

Utility Operating Income:	90,627,000
Average Rate Base:	1,189,882,000
Rate of Return on Capital:	7.62%
Rate of Return on Equity:	10.0%

Effect of Rate Change on Each Customer Class

Customer class	% Change
Schedule 2 - Residential Sales Service	9.16%
Schedule 3 - Basic Firm Non-Residential Sales Service: Commercial	7.87%
Schedule 3 - Basic Firm Non-Residential Sales Service: Industrial	7.29%
Schedule 31 - Non-Residential Firm Sales Service: Commercial	6.98%
Schedule 31 - Non-Residential Firm Transportation Service: Commercial	14.93%
Schedule 31 - Non-Residential Firm Sales Service: Industrial	5.56%

[1] Based upon the Company's Projected Test Year Results of Operations.

[2] Based upon the Company's December 29, 2017 general rate case filing.

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Schedule 31: Non-Residential Firm Transportation Service: Industrial	14.91%
Schedule 32: Large Volume Non-Residential Firm Sales Service: Commercial	6.16%
Schedule 32: Large Volume Non-Residential Firm Sales Service: Industrial	4.69%
Schedule 32: Large Volume Non-Residential Transportation Service: Firm Service	19.14%
Schedule 32: Large Volume Non-Residential Interruptible Sales Service: Commercial	4.68%
Schedule 32: Large Volume Non-Residential Interruptible Sales Service: Industrial	4.61%
Schedule 32: Large Volume Non-Residential Transportation Service: Interruptible Service	15.86%
Schedule 33: High Volume Non-Residential Firm and Interruptible Transportation Service	0%

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SCHEDULE 167
GENERAL ADJUSTMENTS TO RATES

(c)

PURPOSE:
To identify adjustments made to the billing rates stated in the Rate Schedules listed below to reflect the effects of general rate changes approved by the Commission under the authority of ORS 757.210

DESCRIPTION:
The general rate changes shown in this Schedule 167 reflect the outcome of a general rate case review by the Commission in Docket UG-344 initiated following a Company request to change rates due to increases or decreases in the cost of general utility operations.

APPLICABLE:
To Customers taking service under the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 27	Rate Schedule 32
Rate Schedule 3	Rate Schedule 31	Rate Schedule 33

RATE ADJUSTMENTS: Effective:
The Base Rates stated in the listed Rate Schedules are adjusted as follows:

	Adjustment Amount				Adjustment Amount	
Schedule/Class	**Customer Charge**	**Volumetric Charge**		**Schedule/Class**	**Customer Charge**	**Volumetric Charge**
02R	$0.00	$0.09104		03 CSF	$0.00	$0.06433
27	$0.00	$0.07011		03 ISF	$0.00	$0.05511

Schedule/ Class	Block	Amount		Schedule/ Class	Block	Amount		Schedule/ Class	Block	Amount
31 CSF	Cust. Charge	$0.00		32 CSF	Cust. Charge	$0.00		32 CSI	Cust. Charge	$0.00
	Block 1	$0.05164			Block 1	$0.03621			Block 1	$0.02185
	Block 2	$0.04720			Block 2	$0.03077			Block 2	$0.01858
31CTF	Cust. Charge	$0.00			Block 3	$0.02173			Block 3	$0.01311
	Block 1	$0.05015			Block 4	$0.01268			Block 4	$0.00765
	Block 2	$0.04586			Block 5	$0.00000			Block 5	$0.00437
31ISF	Cust. Charge	$0.00			Block 6	$0.00000			Block 6	$0.00000
	Block 1	$0.03685		32 ISF	Cust. Charge	$0.00		32 ISI	Cust. Charge	$0.00
	Block 2	$0.03330			Block 1	$0.02655			Block 1	$0.02150
31 ITF	Cust. Charge	$0.00			Block 2	$0.02257			Block 2	$0.01828
	Block 1	$0.03991			Block 3	$0.01593			Block 3	$0.01290
	Block 2	$0.03607			Block 4	$0.00930			Block 4	$0.00753
					Block 5	$0.00000			Block 5	$0.00430
					Block 6	$0.00000			Block 6	$0.00000
				32 ITF/CTF	Cust. Charge	$0.00		32 CTI/ITI	Cust. Charge	$0.00
					Block 1	$0.02361			Block 1	$0.01735
					Block 2	$0.02006			Block 2	$0.01475
					Block 3	$0.01417			Block 3	$0.01041
					Block 4	$0.00826			Block 4	$0.00607
					Block 5	$0.00472			Block 5	$0.00347
					Block 6	$0.00237			Block 6	$0.00174
								33	All	$0.00000

(c)

GENERAL TERMS:
Service under this Rate Schedule is governed by the terms of this Rate Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

UG 344
NOTICE OF APPLICATION FOR
GENERAL RATE REVISION

December 29, 2017

<u>To All Parties Who Participated in UG 221:</u>
Please be advised that on December 29, 2017 Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), has filed for a GENERAL RATE REVISION. A copy of the Company's ADVICE 17-22, EXECUTIVE SUMMARY, DIRECT TESTIMONY, and EXHIBITS are available for inspection at its main office or at the Public Utility of Oregon's ("Commission") eDocket website. An electronic copy is also attached.

The purpose of this Notice is to inform parties that participated in the Company's most recent general rate case, UG 221, that a General Rate Revision has been filed.

Parties who desire more information or who wish to obtain a copy of the filing, or notice of the time and place of any hearing, if scheduled, should contact the Company or the Commission as follows:

NW Natural
Attn: Zach Kravitz
220 NW Second Ave
Portland, Oregon 97209-3991
Telephone: (503) 220-2379

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
PO Box 1088
Salem, Oregon 97301-1088
Telephone: (503) 373-0886

Any person may submit to the Commission written comments on this General Rate Revision Application by January 29, 2017 or seek to intervene in the proceeding. The granting of this General Rate Revision Application will authorize a change in rates.

* * * * *

CERTIFICATE OF SERVICE
UG 344

I hereby certify that on December 29, 2017 I have served by electronic mail and/or physical copies ADVICE 17-22, EXECUTIVE SUMMARY, DIRECT TESTIMONY, and EXHIBITS of NW Natural's Oregon General Rate Revision upon all parties of record in docket UG 221, which is the Company's most recent general rate case.

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DATED December 29, 2017 Portland, OR.

/s/ Erica Lee
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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Direct Testimony of David H. Anderson

FILING OVERVIEW
EXHIBIT 100

December 2017

EXHIBIT 100 – DIRECT TESTIMONY – FILING OVERVIEW

Table of Contents

Rates & Regulatory Affairs
NW NATURAL
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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is David H. Anderson. I am the President and Chief Executive Officer of NW Natural.

Q. Please summarize your educational background and business experience.

A. I received my Bachelor's degree in Accounting from Texas Tech University. I am a Certified Public Accountant (retired) in Oregon, Washington, and Texas. I have spent over 30 years in the energy and utility industries. I joined NW Natural in 2004, and became Chief Executive Officer in 2016. Prior to being CEO, I held positions including President and Chief Operating Officer, Executive Vice President and Chief Operating Officer, Executive Vice President of Operations and Regulation, and Senior Vice President and Chief Financial Officer. Prior to joining NW Natural, I worked for TXU Corporation (formerly Texas Utilities Corporation) for 16 years, where I held various management and executive positions including Vice President of Investor Relations and Shareholder Services, Senior Vice President and Chief Accounting Officer, and Senior Vice President and CFO of TXU Gas.

Q. Please summarize your testimony.

A. In my testimony I:

- Describe NW Natural's overall operating environment, as well as the Company's current efforts and goals; and

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NW NATURAL
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- Provide a high-level overview of the Company's application for a general rate revision.

II. NW NATURAL'S OVERALL OPERATING ENVIROMENT, CURRENT EFFORTS, AND GOALS

Q. As Chief Executive Officer, can you please describe NW Natural's goals as a company?

A. NW Natural strives to operate a safe and reliable gas distribution business, while maintaining strong customer satisfaction, low rates for customers, financial strength, and being true to our core values.

Q. Can you please describe NW Natural's core values and describe how the Company demonstrates those values?

A. NW Natural's core values include: Safety, Integrity, Service Ethic, Caring, and Environmental Stewardship. Each of these values have current initiatives and efforts associated with them. I describe a few of those initiatives and efforts to provide background on the Company's current operating environment.

Safety—NW Natural's highest priority is to deliver our product safely to our customers. We have one of the most modern systems in the country, in large part due to constructive regulatory support to proactively maintain the integrity of our system. As discussed in the testimony of Joe Karney, Director of Engineering - Field Operations, we are focused on what we can do to keep our system safe for customers and employees, and are continually engaged in efforts to make our system even safer. For example, we are looking at how we can

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establish a broader utilization of Excess Flow Valves throughout our system. These valves automatically shut off a gas service when pressures indicate that a line breakage or other gas leak may have occurred. We currently install these devices on all new services, and offer them at cost to customers that have existing services. However, we are developing a plan to further facilitate installations on existing services, on an accelerated basis. We do not have a regulatory request at this time, but are looking forward to collaboratively engaging with the OPUC and other interested parties on this important topic.

Service Ethic and Caring—NW Natural strives to thoughtfully serve our customers and community. We want to be connected with our customers and responsive to their needs and their expectations of a modern utility. We seek to ensure that our facilities are functional and sound, so that we can provide quality service to our customers and efficient working spaces for our employees. We are immeasurably proud of our emergency response crews that keep the public safe, and much of their life-saving response efforts have been credited to the training they receive at our training facilities. NW Natural's Senior Manager of Security and Facilities, Wayne Pipes, in his testimony describes in more detail the continued investments in our facilities, including our Sherwood Facility's training and emergency response center.

We additionally try to stay connected with our customers through effective communication channels that reach our broad customer base throughout the state. First and foremost, we want customers to use natural gas safely. We also

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want them to take advantage of ways to conserve gas, and encourage them to use natural gas responsibly with an understanding of the environmental impacts associated with their utility use. Kim Heiting, Vice President of Communications and Chief Marketing Officer, explains our communication efforts to our customer base in more detail.

I am proud of the devotion to our customers that the Company exhibits on a daily basis. This ethic is instilled in all of our employees, and we are always appreciative of our customers when our efforts to provide excellent service are recognized. As an example, for the fifth year in a row, NW Natural has received the highest score for large utilities in the West in the 2017 J.D. Power Gas Utility Residential Customer Satisfaction Study. Now in its 16th year, the study measures residential customer satisfaction with natural gas utilities across six factors: safety and reliability, billing and payment, price, corporate citizenship, communications and customer service. 2017 was the eighth time in 11 years that the company has ranked first in the West, and the 10th time it has scored second or higher in the nation.

Environmental Stewardship—NW Natural has long held environmental stewardship as one of its core values. This has taken many forms, including a strong commitment to energy efficiency (being one of the first local distribution companies ("LDC") to adopt a decoupling mechanism, and our continued engagement with the Energy Trust), establishing a voluntary carbon offset program that our customers can participate in (Smart Energy), and our

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commitment to responsible cleanup of the Portland Harbor (where we have sought to limit costs to protect our customers, and to provide leadership where doing so furthers an overall efficient process).

Q. Has NW Natural undertaken any recent efforts to revisit its core values, direction, or goals?

A. Yes. In 2016, we undertook a "Strategic Plan." In this exercise, we looked at several aspects of the Company, in both the near-term as well as the long-term. We specifically focused on five areas:

1. A Low-Carbon Pathway;
2. Constructive Regulation;
3. Enabling Growth;
4. Superior Customer Service; and
5. Workforce of the Future.

In this exercise, we confirmed our core values described above, and also our commitment to providing safe, reliable, and affordable energy in an environmentally responsible way to better the lives of the public we serve.

Q. Can you elaborate more on how environmental policies are affecting, and will affect NW Natural?

A. NW Natural expects that climate change policy will continue to shape the environment within which we operate. NW Natural believes that there is a climate imperative, and we plan to be an industry leader on this topic. To advance this cause, we have established a voluntary goal for our Company to

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create carbon savings equivalent to 30 percent of the Company's 2015 emissions by the year 2035. I will not go into the details of that goal or our related efforts here, but point this out because it represents a major focus for the Company. We are calling this our "Less We Can" initiative and more information about our low carbon pathway can be found at http://www.lesswecan.com.

While NW Natural is committed to playing a productive role in mitigating climate change, I also note that climate change policy can represent a threat to NW Natural's traditional business model. At this time, we face uncertainty regarding the structure and form that climate policies will take, and some proposals present risks to our industry. For example, in the Oregon legislature, there are discussions about cap and trade legislation that could be implemented in the near-term. While we have not taken a stance on this policy, we will carefully review any new proposal that could lead to increased costs for our customers, and if not designed correctly, could have unintended or harmful consequences. For these reasons, we are actively engaged in these discussions.

Another example of how carbon emissions policy could affect the Company is the City of Portland's resolution to serve all local electricity with renewables by 2035, and to replace all local energy with renewables, including transportation, industry and natural gas use, by 2050. Although the resolution is not binding, it creates uncertainty about the long-term viability for delivery of natural gas within Portland, which is a major portion of our service territory. NW

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Natural believes that this policy overlooks the value of our current distribution system's ability to deliver a major portion of our customers' energy, for a small carbon footprint, with a clean-burning fuel, and the ability to use the system to deliver renewable energy products as well. We believe that the system our customers have invested in represents a tremendous value to the region and the energy system as a whole, and that it will remain a key component of a low-carbon future.

Again, we continue to be engaged, and are convinced that we have a vital role to play in climate policy and mitigation actions, due to the fact that natural gas is an affordable clean-burning fuel, and that we are taking a proactive and creative role in determining how our Company can have a positive influence and provide leadership on this topic.

I note that Bente Villadsen, the Company's outside expert witness providing testimony about our authorized return on equity provides additional testimony on the topic of the risk presented to the LDC industry, and NW Natural specifically, by climate change policies. I raise these risks here because I think it is important for the Commission and parties to understand the changing business environment within which NW Natural operates, as well as the very real investment that customers have made in NW Natural's system and the significant benefits from that investment that our customers and Oregonians receive.

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III. NW NATURAL'S APPLICATION FOR GENERAL RATE REVISION

Q. Can you please comment on the considerations NW Natural undertook before filing this general rate revision?

A. As described above, NW Natural is committed to customer satisfaction, and providing natural gas service at reasonable rates for customers. We understand that natural gas plays a vital role in our customers' lives, and we do not take lightly the prospect of a general rate case. These cases can cause customers concern, and any significant increase in overall rates can present a financial hardship for some of our customers. Rate cases also cause strain on the utility's resources and personnel. Finally, we recognize that not all households and businesses have natural gas service, and they have other options for serving their energy needs. This means that, even as a regulated utility, we compete for business with other energy providers, and therefore are always motivated to keep natural gas rates as low as possible while still being able to provide excellent customer service, exceed safety standards, and maintain financial integrity as a Company.

We determined, however, that after six years of managing the Company without any request to increase general rates, NW Natural would file this application with the Commission seeking to revise its rates to recognize an increased revenue requirement related to its provision of utility service.

Q. What factors have caused the utility a need to raise its rates?

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A. It is a combination of factors that has caused NW Natural to need to request a rate increase at this time. During the six years since the Company's last rate case every factor that affects NW Natural's revenue requirement has changed to put building pressure on the need for a rate adjustment. The Company's witness Kevin McVay, Revenue Requirement Analytics Consultant, quantifies these changes and explains the calculation of the Company's revenue requirement.

In short, continued investments in system reliability and safety have led to a significant increase in rate base since we last changed our rates. The Company has also, similar to most companies, borne increasing operations and maintenance costs as we experience the impacts of inflation, retain and build our labor force needed to provide utility service, and obtain the other resources necessary to address the myriad of issues the utility is required to navigate in today's energy environment. In addition to Mr. McVay's testimony, Jorge Moncayo, our Director of Finance and Budget, provides more information on these costs.

Finally, NW Natural finds itself in a different growth environment than it did historically. Prior to the "great recession," NW Natural's customer growth rates were as high as over three percent per year. This level of growth helped the Company avoid rate increases in light of the margins realized from the addition of large numbers of new customers. In more recent years, however, we have experienced slower growth rates, rising from just above one percent, but still well

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below two percent. This puts more pressure on the need for a rate case in order to allow the utility to true-up its rates to reflect increased costs.

Q. Can you comment on customers' bills over the past several years, and how this rate case may affect them?

A. As stated above, NW Natural strives to provide quality service, and make the necessary investments in our system, all while raising rates as infrequently as practical. I wish we could do this without ever needing to raise rates because I know that rate increases can be difficult for customers.

I am pleased, however, that NW Natural has managed to keep from raising general rates for six years. I am also pleased that we have been able to provide customers with not only stable, but decreasing overall rates for many years. Much of this has come about because of decreasing natural gas commodity costs. And, NW Natural has sought to manage its business in a way that allows us to avoid rate increases when unnecessary. The chart below shows overall billing rates for the average residential customer since 2007, and demonstrates that customers have been able to take gas service at rates that have dramatically fallen.

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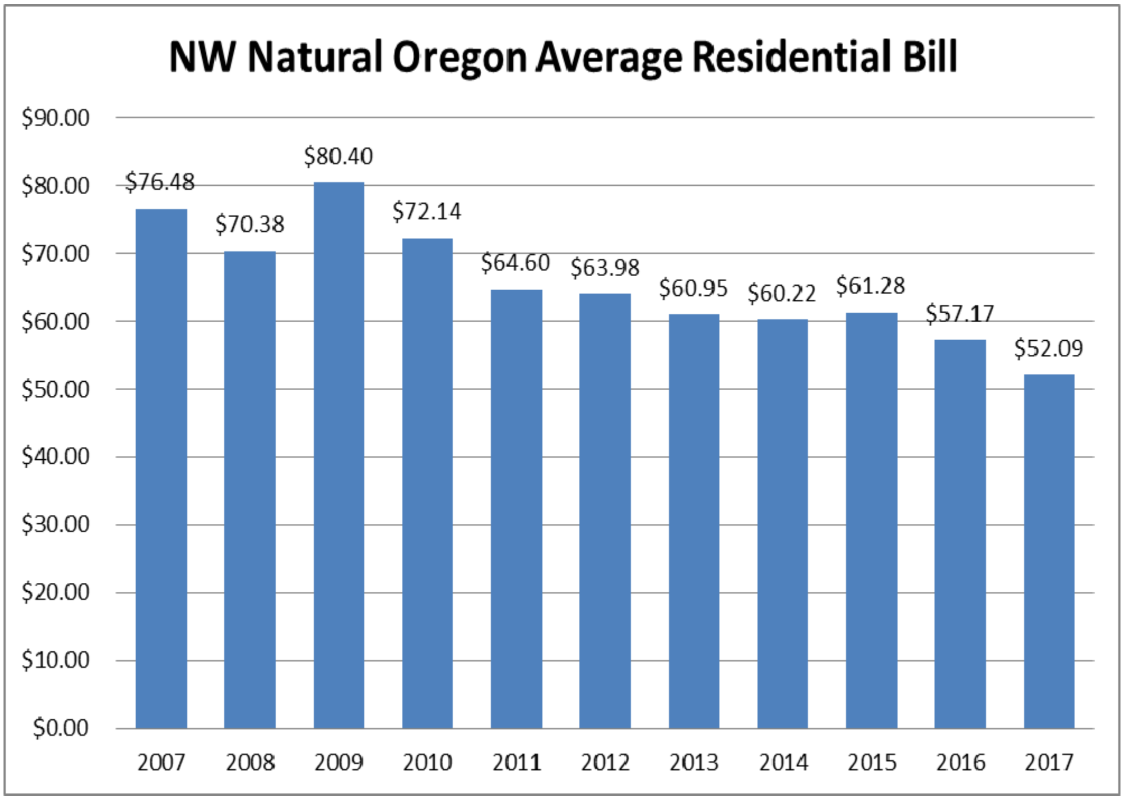

As shown above, the average residential customer's bill has decreased by around 32 percent since 2007, or by 35 percent since 2009. This fact is not the rationale for raising rates in this application, but I point this out because it is relevant when evaluating the impact on customers of the rates that they pay for natural gas.

Q. Can you please summarize the company's requested rate increase?

A. NW Natural is seeking to increase revenues from base rates by $52.4 million. As described in the testimony of Kevin McVay, over $12 million of that amount is not related to increasing costs at the Company, and is instead due to the fact that when base rates are updated, our decoupling baseline is also updated to reflect

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new use-per-customer amounts. This update thus moves into base rates what had previously already been included in customers' bills through the decoupling deferral. Taking this into account, the better reflection of the increased costs to customers is $40.4 million.

Kevin McVay's testimony also demonstrates that without the requested increase in base rates, NW Natural's gas distribution utility would expect to earn a return of only 4.85 percent in the test year. The Company, therefore, needs to increase its rates in order to maintain an ability to earn a reasonable return that will allow it to attract the capital that is required to run its utility system for the benefit of its customers.

The rate increase requested in our application would result in approximately a 6.3 percent increase to revenues collected from customers' base rates (recognizing that customers currently pay for the Company's decoupling deferral), or about an 8.3 percent increase to total base rates (ignoring the effects of the decoupling deferral moving to base rates). In light of the fact that the Company has not raised rates for six years, this equates to a just over one percent increase in customers' bills per year over those six years.

Q. Can you please explain how this rate case may be different from NW Natural's last general rate case filed in 2011?

A. NW Natural was required to file its last general rate case pursuant to a stipulation that was approved by the Commission in Docket No. UG 152. The rate case that NW Natural filed at that time involved numerous difficult issues and major policy

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1-503-226-4211

questions. That case included, for example, the establishment of a Site Remediation and Recovery Mechanism providing the opportunity for cost recovery related to our involvement in environmental remediation of the Portland Harbor and the Company's Gasco site; a request to extend the safety cost tracker for the Company's System Integrity Program; a request that the Commission authorize NW Natural to include in rates the costs that it incurs in financing required contributions that NW Natural makes to its pension fund; a major redesign of NW Natural's rate structure; and an issue raised by OPUC Staff about whether the Commission should modify NW Natural's revenue sharing arrangement related to its FERC-regulated interstate storage operations and optimization activities.[1]

In contrast, the application that the Company filed in this case does not involve numerous policy issues, and instead involves more traditional cost of service items. The Company's request, for example, does not seek any redesign of its current rate structure, and instead proposes to leave that structure unchanged. The Company also does not seek any new cost recovery mechanisms. The Company instead discusses the status of its safety-related investments in its system, and preserves for a future application the Company's plans for seeking a tailored cost recovery mechanism related to new rules and

[1] This last issue was reviewed in UM 1654, subsequent to UG 221, and the Commission ultimately determined that a third-party cost study should be conducted as part of that docket, which is currently under finalization and would be subject to review in that docket.

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1-503-226-4211

safety initiatives, once those are further developed by outside regulators and the Company.

The Company does not, through this application, generally seek to modify the Commission's historical approach to ratemaking. One exception, set forth in the testimony of Lea Anne Doolittle, Senior Vice President and Chief Administrative Officer, is that the Company does request that the Commission revisit its historical practice of requiring a split between customers' rates and shareholders' returns of the costs of "at-risk" pay for utility employees. The Company believes that this policy is not tailored to best practices for compensating employees, and overlooks the fact that at-risk pay is provided by NW Natural as a means of delivering market median pay to its employees; accordingly, we believe that these costs should be counted as a prudent cost in the Company's revenue requirement.

Q. Can you briefly describe the testimony provided by other witnesses in this case?

A. Ten other witnesses describe the various components of cost that demonstrate the need for the requested rate increase.

Frank Burkhartsmeyer, NW Natural's Senior Vice President and Chief Financial Officer, provides testimony about the Company's cost of capital. His testimony provides information about the costs of the Company's outstanding debt, and debt we will issue during the "test year." Mr. Burkhartsmeyer's testimony also describes the Company's balance of financing the Company with debt versus equity from shareholder investments in the Company. He demonstrates that the Company continues to adhere to its policy of balancing debt and equity financing with a 50/50 capital structure, and thus requests that the Commission recognize this capital structure when approving rates in this case.

Bente Villadsen, an outside expert on utility finance and required rates of return for regulated companies, provides testimony about the Company's cost of equity, or in other words, the return that investors in NW Natural should reasonably expect to have the opportunity to earn. Her testimony provides an analysis of NW Natural's cost of equity, and a range of return on equity that NW Natural should be given the opportunity to earn in order to attract capital. Her testimony supports the Company's request for approval to include a 10.0 percent return on equity in the revenue requirement authorized in this proceeding (the mid-point of the range that Ms. Villadsen has determined is reasonable for NW Natural's investors).

Joe Karney, Director of Engineering, provides testimony about some of the major capital projects the Company has undertaken in order to keep our system safe, reliable, and economical.

Jorge Moncayo, Director of Finance and Budget, provides testimony about the operations and maintenance expense levels that the Company has been incurring and expects to incur, as well as overall capital spending, for which it requests recovery in this application.

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Lea Anne Doolittle, Senior Vice President and Chief Administrative Officer, provides testimony on our labor costs, and describes the Company's practices related to compensation, which ensure that all employees receive compensation at market median rates. She sets forth the Company's request to include these costs in the Company's revenue requirement.

Wayne Pipes, Senior Manager of Security and Facilities, provides testimony about the Company's facilities plan, and the actions the Company has taken pursuant to the plan to ensure that our facilities remain operable, safe, and that they provide the efficiencies needed to continue to provide service to our customers in accordance with the Company's and customers' standards.

Kim Heiting, Chief Marketing Officer and Vice President, Communications, provides testimony about the Company's communications to customers, on matters of safety, as well as communicating information to customers about the nature of the services offered to them by the Company, and opportunities to conserve and be educated about the products that they purchase from us.

Kyle Walker, Rates and Regulatory Analyst, provides testimony about the Company's decoupling mechanism and the Company's Weather Adjustment Rate Mechanism. He also sets forth the Company's request to improve the decoupling mechanism by synching up the weather-normalized values used by the decoupling mechanism with those that reflect customer participation in the

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220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

WARM program, and to extend the decoupling mechanism to large commercial customers.

Kevin McVay, Revenue Requirement Analytics Consultant, provides the calculation of the Company's revenue requirement, which represents the annual dollars needed to recover prudently incurred costs of operating the utility business.

Andrew Speer, Rates and Regulatory Analyst, provides the Company's long-run incremental cost study, and provides the proposed spread across rates of the revenue requirement increase requested.

NW Natural seeks to continue to provide safe and reliable service, at affordable rates for its customers. As described by these witnesses in greater detail, the Company at this time seeks to revise its rates to reflect increasing costs, and continued investment in its system. This application for a general rate increase is important to the Company to maintain our financial strength, which is necessary to continue to attract the capital, at favorable rates, to finance our utility operations. Although rate increases can be difficult for customers, this rate increase is necessary to ultimately benefit NW Natural's customers through maintaining the ability for the Company to continue to operate a financially sound natural gas utility that will continue to provide safe and reliable service.

Q. Does this conclude your testimony?

A. Yes it does.

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1-503-226-4211

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Direct Testimony of Kevin McVay

TEST YEAR / REVENUE REQUIREMENTS
EXHIBIT 200

December 2017

EXHIBIT 200 – DIRECT TESTIMONY - TEST YEAR / REVENUE REQUIREMENTS

Table of Contents

Rates & Regulatory Affairs
NW NATURAL
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Portland, Oregon 97209-3991
1-503-226-4211

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company ("NW Natural" or the "Company").

A. My name is Kevin S. McVay. My current position is Revenue Requirements Analytics Consultant. My responsibilities for preparation of the revenue requirement for this rate case included direction of the load forecasting work and rate base development, coordination of tax issues, and forecasting of miscellaneous revenues and other taxes.

Q. Please describe your education and employment background.

A. I received a Bachelor of Science Degree in Accounting from George Mason University, Fairfax, Virginia, and a Master of Business Administration degree from George Washington University, Washington, D.C. Before my employment with NW Natural, I held positions in accounting, auditing, and forecasting for Washington Gas Light Company in Washington, D.C. In 1987, I joined NW Natural, where I have held positions primarily in finance and regulatory affairs, as well as business development.

Q. Please summarize your testimony.

A. In my testimony, I:

- Provide an overview of how revenue requirement is calculated;
- Explain the historical base year of calendar year 2017 ("Base Year") and the test year of November 1, 2018 to October 31, 2019 ("Test Year");

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- Present the revenue requirement needed to yield NW Natural's proposed overall rate of return (ROR) of 7.617 percent and return on equity (ROE) of 10.0 percent, and detail the increase required;
- Present the adjusted results of operations for the Test Year and explain the Company's projected revenues at current rates, projected operations and maintenance expense (O&M), and other expenses for the Test Year;
- Describe the methodology used to produce weather normalized use-per-customer for the Residential and Commercial classes;
- Describe the development of the industrial load forecast;
- Explain how rate base was calculated for the Test Year; and
- Explain the allocation or assignment of revenues, costs, and rate base elements to the Oregon jurisdiction.

Q. Before explaining the specifics of revenue requirement in this rate case, can you please provide a brief overview of the elements of revenue requirement, and why the determination of revenue requirement is central to a general rate case?

A. A utility's revenue requirement, or cost of service, represents the total annual cost to serve its customers. Costs can be considered to primarily consist of operating and maintenance costs, revenue-related costs, and investment related costs. Operating and maintenance costs include commodity and upstream

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Portland, Oregon 97209-3991
1-503-226-4211

pipeline gas costs, as well as payroll and other non-capital costs of serving customers.[1] Revenue-related costs primarily include franchise taxes.

Investment-related costs include the **return of** investment, or depreciation, and the **return on** investment, which includes the return on the costs of long-term debt and equity to finance our investments.[2] The return on equity ("ROE") is the amount of return that shareholders of the company are expected to require, given the company's risk and how it compares to alternative investments available to the shareholder.

These investments make up our rate base, which includes a number of components, but is primarily net plant. Net plant represents the assets that have been acquired by the company for purposes of serving its customers, and which are being financed by the Company. Rate base also includes certain other items that are financed, such as gas in storage, and inventories. There are also amounts that are received by the company that reduce the amount of financing required. The largest of those is for deferred income taxes, where our ability to deduct depreciation quickly reduces our tax bill, and we factor that benefit in as a reduction to the total amount that we are financing. The overall rate base,

[1] Although gas and upstream gas supply costs are a major operations and maintenance cost for the utility, and form a part of NW Natural's revenue requirement, these costs are recovered through the utility's Purchased Gas Adjustment, and not as part of the utility's base rates, which we seek to modify through this general rate case proceeding.

[2] Investment related costs also include income and property taxes associated with earnings and plant balances, respectively

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

including all of these components, represents the amount that requires financing from shareholders and bondholders.

The aggregation of operating and maintenance costs, revenue-related costs, and investment related costs represents the amount that is needed to be recovered from the utility's customers in a year. Our incremental revenue requirement is the amount of additional revenue needed over the amount already generated by existing rates, so that the Company can recover its costs and have the opportunity to earn its authorized return on equity.

Q. Can you please describe how the testimony offered in this case establishes NW Natural's revenue requirement?

A. Yes. The testimony of Frank Burkhartsmeyer provides evidence of NW Natural's cost of debt, and the amount of debt and equity the Company uses to finance its investments and operations. Bente Villadsen's testimony provides evidence of the returns that NW Natural must pay shareholders in order to continue to attract their investments in the Company through purchasing stock. Together, these pieces of testimony establish NW Natural's required return on rate base.

Lea Anne Doolittle's testimony demonstrates NW Natural's costs of labor, and Kim Heiting's testimony describes the costs of customer communications. Jorge Moncayo's testimony describes all other operations and maintenance expense, and the levels of expense the Company incurs. These pieces of testimony, along with my description of taxes, establish the utility's operating expenses.

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1-503-226-4211

Finally, the testimony of Wayne Pipes and Joe Karney provides descriptions of the Company's recent activities related to developing capital assets. These pieces of testimony, in conjunction with my calculations, demonstrate NW Natural's rate base that is used in serving customers with natural gas.

My testimony provides the summation of all of these costs, and the calculations of revenue requirement in accordance with established methodologies for calculating the Company's revenue requirement during the Test Year.

II. BASE YEAR AND TEST YEAR

Q. Why did NW Natural use calendar year 2017 as the Base Year?

A. The Company chose calendar year 2017 as the Base Year because it is the most recent calendar year ahead of the Company's filing. While the last three months of 2017 shown in this filing are forecast data, the actual information will be available within a few months of our filing.

Q. Why did NW Natural choose the period of November 1, 2018 to October 31, 2019 as the Test Year in this case?

A. The Company chose the 12-month period from November 1, 2018 to October 31, 2019 because it best reflects the conditions expected when new rates from this rate case will be in effect. Given a filing date of late December 2017 for the rate case, the normal timeline for the rate case process would mean that rates would be expected to be effective by November 1, 2018. This matches the Test Year

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Portland, Oregon 97209-3991
1-503-226-4211

used to calculate the revenue requirement in this case, and also coincides with the effective date of the annual Purchased Gas Adjustment rate change, which minimizes the frequency of rate changes.

III. TEST YEAR REVENUE REQUIREMENT

Q. What is the Test Year revenue requirement needed to achieve the ROR proposed in this case?

A. To achieve the proposed ROR of 7.62 percent in the Test Year, a revenue requirement increase of $52.45 million over the revenues expected for the Test Year at present rates is necessary, or an approximately 8.3 percent increase over current customer rates. Because the rate case includes $12.07 million otherwise being collected through our decoupling deferral, the net increase of $40.38 million represents the relevant increase to future billing rates. The overall increase to rates is about 6.3 percent after taking into account that the decoupling deferral recovery is already in customers' current rates.

Q. What would NW Natural's ROE be in the Test Year absent the requested rate increase?

A. At current rate levels, the Company's ROE would be 4.85 percent. This is significantly below the 10.0 percent ROE proposed in this case.

Q. Please describe the changes to revenue requirement elements since the last rate case that combine to cause NW Natural to under-earn at current rate levels in the Test Year.

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. *NW Natural/201, McVay/1* shows a side-by-side comparison of the results of operations from UG 221, the Company's last case in 2012, and the Test Year results from this rate case. Of particular note in this detailed comparison, are three specific areas: 1) line 5 shows a growth in margins (revenues net of cost of gas) of $48.7 million during the period; 2) line 7 shows operating and maintenance expenses increasing by $39 million; and 3) line 18 shows an increase in net plant of $394.6 million, offset by the increase in deferred taxes of $116.1 million on line 24. In summary, NW Natural has generated strong revenue growth over the period, but that growth has been insufficient to offset costs for O&M and rate base increases.

IV. RESULTS OF OPERATIONS

Q. Please explain how NW Natural calculated the Test Year revenue requirement.

A. The Company began with actual and forecasted results from the Base Year. We made normalizing and known and measurable changes to Base Year revenues, expenses, and capital (rate base) to reflect conditions anticipated to be in effect in the Test Year. This testimony and the related exhibits explain how these adjustments are reflected in the Test Year revenue requirement.

Q. Have you prepared NW Natural's Oregon-allocated results of operations for the Test Year?

A. Yes. See *NW Natural/202, McVay/1* for a summary of NW Natural's Oregon-allocated Results of Operations for the Test Year.

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1-503-226-4211

Q. Please describe Exhibit *NW Natural/202, McVay/1.*

A. Column "a" of *NW Natural/202, McVay/1* shows the Oregon-allocated results for the Base Year, including operating revenues, operating revenue deductions, taxes, and rate base. Column "b" shows the adjustments to Base Year results for each of these categories. Column "c" shows Test Year results at present rates based on the adjustments to Base Year results. Column "d" shows the removal of the forecasted Test Year decoupling deferred amount, since the deferral will be replaced by a component of the rate change resulting from this case, with a commensurate resetting of the decoupling baseline amount. Column "e" shows the test period results excluding the decoupling. Column "f" indicates the proposed revenue increase necessary to reach the requested ROE. Finally, column "g" shows Test Year results that reflect the requested ROE.

Q. Please explain the adjustments set forth in Column "b."

A. The amounts in Column "b" show the adjustments from the Base Year to the Test Year. These adjustments reflect adjustments to operating revenues, operating revenue deductions, including taxes, and changes in rate base.

<u>A. Sales of Gas Revenues and Transportation Revenues</u>

Q. Please explain the adjustments to Base Year operating revenues.

A. The first two adjustments to operating revenues are for Sale of Gas and Transportation revenues, shown on lines 1 and 2 of *NW Natural/202, McVay/1*. These adjustments are calculated as the difference between Base Year and Test Year volumes and customers multiplied by current rates.

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Portland, Oregon 97209-3991
1-503-226-4211

Q. How did you calculate Base Year Sale of Gas and Transportation revenues?

A. Base Year revenues were projected using the latest available actual volumes and customers for the year to date at September 30, 2017, as well as a forecast for the remaining three months of the year, multiplied by current rates that became effective November 1, 2017. This calculation is shown in *NW Natural/203, McVay/1*.

Q. How did you forecast Test Year Sale of Gas and Transportation revenues?

A. Test Year revenues reflect Test Year forecast volumes and customers multiplied by current rates, which are the rates that became effective November 1, 2017.

Q. How did you forecast Test Year customers and volumes?

A. NW Natural used different methodologies for forecasting customers and volumes for the residential and commercial classes and for the industrial customer classes. For residential and commercial customers, Test Year forecasted customer counts were developed by adding new customers to the existing customer base. Customer attrition, or loss of customers, was deducted from the existing customer base. New customers are based on historical regional growth trends, housing starts forecasts and economic and other factors. The customer growth forecast used for purposes of developing additional volumes and revenues is the same forecast used for producing capital expenditures that go into gross plant in rate base.

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Portland, Oregon 97209-3991
1-503-226-4211

A forecast of use-per-customer (UPC) was then developed by accumulating actual historical UPC per day and heating degree days (HDDs) for the period of September 2012 through May 2017. A simple linear regression relating UPC per day as a function of HDD per day was performed, using a 59 degree day set point for the residential class and a 58 degree day set point for the commercial class. The intercept value from the regression represents customer base load use, and was further specified for differences in summer and winter base use. The slope is multiplied by the daily normal HDD value to calculate the heating load for each day. The sum of the base load and heat load provides a daily UPC value, and the aggregation of the 365 daily results produces an annual UPC level.

The normal daily HDD amounts were developed using daily HDD values from a data set spanning 25 years (1992-2017). The calculated UPC was then reduced by the estimated demand side management savings forecast from the Company's current Integrated Resource Plan (IRP) to project UPC for the Test Year. The resulting UPC for the Test Year is 635.7 therms for residential customers and 3,773 for commercial customers. The UPC for Commercial customers were further defined for each of the rate schedules within the commercial classes, to allow for the calculation of revenues using rates from each class. A scalar was used to equate the aggregation of the rate schedule UPCs to the overall commercial UPC.

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220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Residential and commercial Test Year monthly volumes were calculated by multiplying normalized UPC by forecasted customer counts for each month. The resulting class level customers and monthly volumes were used with existing revenue rates (customer and volumetric charges) to produce monthly revenues, which were then aggregated to provide the overall test period annual revenue.

For the industrial class, the Test Year forecast of volumes and customers was developed using a customer-specific methodology. The customer-specific forecast begins with a recent 12-month period of actual usage and customer counts and is then adjusted for changes in projected load usage, additions, losses, and rate schedule changes.

The summary of sales of gas and transportation revenues, as well as the related cost of gas, is presented in detail by class as *NWN/203, McVay/1* and is shown in summary at *NW Natural/202, McVay/1*, on lines 1 and 2. These revenues represent the amounts the company can expect to receive from customers during the Test Period assuming normal weather.

Q. What is the third adjustment to operating revenues?

A. The third adjustment is to the decoupling amount. Decoupling was adjusted to reflect the amounts that would be produced in the Test Year given test period volumes and existing decoupling baseline amounts. This adjustment has been included to demonstrate the ongoing level of billed revenue (the decoupling deferred amount is amortized in billing rates each year), so that the overall revenue requirement can be explained as partly a replacement of the deferred

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220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

amount and partly as additional revenue needed to attain an appropriate return on equity.

Q. What is the fourth adjustment to operating revenues?

A. The fourth adjustment is to remove the WARM revenue (a credit due to colder than normal weather) that was related to the Base Year. Because the Test Year is based on normal weather, no WARM amount is applicable to that period.

B. Miscellaneous Revenues

Q. What is the fifth and last adjustment to operating revenues?

A. The last adjustment is to Miscellaneous Revenues, identified on line 5 of *NW Natural/202, McVay/1*. This adjustment reflects the difference between Base Year Miscellaneous Revenue, which was based on actual totals for the 12-months ended September 30, 2017 as a proxy for the Base Year, and the forecast for the Test Year. The adjustment was calculated by adjusting specific categories of Miscellaneous Revenues to reflect levels of operating activity, based on a three-year history of amounts. 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 historic amounts, a simple three-year average was used. The adjustments to specific categories of Miscellaneous Revenues are set forth in *NW Natural/204, McVay/1*.

C. Cost of Gas

Q. Please explain the adjustments to Operating Revenue Deductions.

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A. The first adjustment to Operating Revenue Deductions is for Gas Purchased, shown on line 7 of *NW Natural/202, McVay/1*. This adjustment reflects the difference between Base Year and Test Year sales volumes multiplied by current commodity and demand rates.

Q. Is the cost of gas included in base rates?

A. No. The annual Purchased Gas Adjustment (PGA) filing revises billing rates to include the cost of gas for the upcoming year through a mechanism outside of base rates. As a result, the gas cost pricing issue is addressed in the PGA rather than in a general rate case. Although gas costs are not included in base rates, gas costs are included in total revenue calculation to provide an appropriate expense level relative to the revenues that are forecast for the rate case. This ensures that base rates in the rate case are calculated based on an accurate matching of costs and revenues.

Q. Please explain the Uncollectable Accrual for Gas Sales adjustment.

A. The expense amount for uncollectible accounts is shown on line 8 of *NW Natural/202, McVay/1* in summary, and in detail in *NW Natural/205, McVay/1*. 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 of write-offs as a percent of total revenues times Test Year sales revenue.

D. Operations and Maintenance Expense

Q. Please explain the Other O&M Expenses adjustment.

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A. The Oregon and System O&M expense excluding Uncollectible Accrual for Gas Sales is set forth in detail for the Base Year in *NW Natural/206, McVay/1-2,* for the Test Year in *NW Natural/206, McVay/3-4,* and in summary at line 9 of *NW Natural/202, McVay/1*. The direct testimony of Jorge Moncayo explains in more detail how NW Natural calculated its Test Year O&M.

Q. Please describe any other adjustments to O&M to determine the overall Test Year expense level.

A. The only change to O&M as presented in Mr. Moncayo's testimony was for the addition of an equity issuance flotation cost. When a company issues common equity, there are costs of issuance including expenses such as underwriting fees, legal fees, and registration fees. The Company has included costs in the Test Year O&M based on a three-year average of costs realized during the years 2016, 2017, and the forecast year 2018. The Oregon-allocated amount of the three-year average was $1.2 million.

<u>E. Income Taxes</u>

Q. Please explain the adjustments to taxes.

A. The first two adjustments to taxes, shown on lines 11 and 12 of *NW Natural/202, McVay/1,* reflect adjustments to Federal and State Income Taxes. Tax differences are a function of marginal tax rates and changes to revenues and expenses from period to period. The calculations are shown in *NW Natural/207, McVay/1*. The marginal tax rate for federal income taxes is 35 percent, and is 7.6 percent for Oregon. The composite rate for both federal and state income

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taxes is 39.94 percent, derived by adding the federal rate to the state rate net of the federal deduction for state taxes. A summary of the tax rates used in the case, as well as the calculation of the weighted average cost of capital, are shown in *NW Natural/208, McVay/1.*

Q. Please describe the treatment of permanent differences for tax, tax credits, and the amortization of investment tax credits (ITC).

A. NW Natural has included levels of permanent tax differences related to depreciation and removal costs associated with pre-1981 assets in a manner that will result in the amortization of the bases of those elements over approximately 20 years. No change is proposed to the amounts for those categories in this rate case. In 2017, the amortization schedule for ITCs was completed, so that is now set to zero for this case. There is a tax credit associated with research and development, and given our proposed level of R&D in O&M for the Test Year, the credit yields $75,000 for the impact on income tax in the Test Year. The use of the statutory tax rates as well as the flow-through and tax credit amounts combine to produce the federal and state taxes for the Test Year. Income taxes are shown on a total provision basis, without a breakout of current and deferred components.

Q. Have you included any adjustments related to potential federal tax reform?

A. At the time the rate case was finalized for printing, federal tax reform appeared imminent but had not been finalized. If a tax reform bill is passed, NW Natural will work with the OPUC Staff and parties to ensure an appropriate transition to

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1-503-226-4211

the new tax rules, and will make appropriate supplemental filings to reflect the implications of the tax reform on NW Natural's rates.

<u>F. Taxes Other Than Income Taxes</u>

Q. Please explain the adjustment to Property Taxes.

A. The adjustment to Property Taxes is shown on line 13 of *NW Natural/202, McVay/1*. The calculations are shown in detail in *NW Natural/209, McVay/1.* The Base Year Property Tax reflects the tax bills received during October and November of 2017. Test Year Property Taxes were calculated using the rate resulting from a one-third two-third average of the 2016 and 2017 rates, respectively, derived by taking the assessed taxes divided by net utility plant at December 31 of the year prior to each assessment. The rate was then applied to net plant at year end 2017 for the 2018 tax assessment and to year end 2018 for the 2019 tax assessment. The forecast assessments for the two years were then combined at a ratio of eight months of 2018 and four months of 2019 to arrive at an appropriate tax expense to include for the Test Year. This is because the ratio is based on property tax assessments occurring on a July to June cycle.

Q. Please explain the adjustment to Other Taxes.

A. The adjustment to Other Taxes is shown on line 14 of *NW Natural/202, McVay/1*. This adjustment was calculated as follows for the different categories within Other Taxes, the detail of which is shown in *NW Natural/209, McVay/1*:

- Franchise fees were derived by applying the effective rate of 2.37 percent to gross sales and transportation revenue and miscellaneous

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1-503-226-4211

revenues to provide a forecast for total franchise fees for both the Base Year and Test Year.

- Payroll taxes were tied to the payroll tax credit that is calculated within the O&M methodology. The credit within O&M is made to extract the payroll taxes associated with payroll for O&M, with the commensurate charge to the payroll tax expense line item under the Other Tax category.
- The regulatory fee was calculated using the current rate of three tenths of 1 percent multiplied by total revenues for both the Base Year and Test Year.
- The Oregon Department of Energy fee is a function of gross revenues. For both the Base Year and Test Year, the fee was calculated by first calculating an average effective rate for the two-year period of 2015 and 2016, and then applying the average effective rate to total operating revenues.
- Other taxes, such as permit and licensing fees, were forecast for the Test Year based on an average of 12 months ended September 2015, 2016, and 2017 amounts. The amounts for the 12 months ended September 30, 2017 were used as a proxy for the Base Year. The system-related other taxes were allocated to Oregon based on a three-factor allocation of 89.1 percent.

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Portland, Oregon 97209-3991
1-503-226-4211

- The storage property tax offset is included to reflect an allocation of property taxes to the interstate storage non-utility segment. The Base Year and Test Year amounts were taken from the forecasted results for the segment, which is based on storage assets in place during each period.

G. Depreciation and Amortization

Q. Please explain the adjustment to Depreciation and Amortization.

A. The Depreciation and Amortization adjustment is shown on line 15 of *NW Natural/202, McVay/1* and in detail in *NW Natural/210, McVay/1*. This adjustment reflects the difference in depreciation expense for the Base Year and Test Year. Depreciation expense was developed by using utility plant as of August 31, 2017 as a base and increasing plant accounts for capital expenditures from September 2017 through the end of the Test Year. Applicable account balances were then decreased for expected retirements, and depreciation rates were applied to generate expense.

Q. Please describe how depreciation rates for each asset category were determined?

A. The use of plant-specific depreciation rates by Federal Energy Regulatory Commission (FERC) account ensures that a reasonable forecast of expense is obtained. Depreciation rates used by NW Natural have been at the current level since January 1, 2009, the last time a depreciation study for a revision of rates

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220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

was approved by the Commission (UM 1335[3]). A new depreciation study for NW Natural was processed prior to its last rate case (UG 221), and the results were included in the filing of the case, with a recommendation to not implement new rates due to the immateriality of the difference. Depreciation rates were subsequently not changed with that rate case. The Company processed a new depreciation study based on December 31, 2015 depreciable plant balances, which was filed with the Commission in 2016 under Docket UM 1808. Parties to the docket reached a settlement on new depreciation rates to implement, with an assumption that rates would go into effect at the same time as the effective rates from a future general rate case. The existing depreciation rates have been used to generate depreciation expense and accumulated depreciation through October 2018, the month preceding the projected effective date of rates produced by this rate case, and the new rates from the settlement in UM 1808 have been applied for all months afterward, or the Test Year months of this case.

<u>H. Recovery of FAS 87 Pension Expense</u>

Q: Please describe the treatment of FAS 87 pension expense in the revenue requirement.

A: NW Natural includes $3.8 million of FAS 87 pension expense in rates each year, which is subject to a pension balancing account that tracks the difference

[3] *Re. NW Natural Gas Co. Application for an Accounting Order Regarding Depreciation Rates and Flow-Through Amounts*, Docket UM 1335, Order No. 08-578 at 4 (Dec. 8, 2008).

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1-503-226-4211

between the $3.8 million in rates and the Company's actual pension expense.[4] When the Company's actual FAS 87 pension expense becomes less than the $3.8 million, and eventually negative (*i.e*. pension income), which is expected in future years, those amounts will reduce the balancing account.

Eventually, the pension balancing account itself will become negative, and it will terminate upon the effective date of the Company's first rate case after the account becomes negative. This approach allows the Company to stabilize the FAS 87 pension expense recovered in rates without having to increase customers' rates as the Company experiences volatility in the actual amount of FAS 87 pension expense each year.

Q. Has any discussion occurred between the parties on the subject of the balancing account status and recovery level?

A. Yes, NW Natural approached the parties to docket UM 1475 recently to discuss the pension balancing account. We explained that our projection for when the balancing account will become negative has been extended, and that we would be open to considering whether an increase to FAS 87 pension expense recovered in rates would be appropriate if all parties supported the change to the stipulation. We also explained that the mechanism is continuing to function well in stabilizing customer rates and allowing NW Natural to collect its pension

[4] The pension balancing account was developed as a part of a stipulation and approved by the Commission in Docket UM 1475, Order No. 11-051 (February 10, 2010). Pursuant to the Stipulation, no party may request an increase to FAS 87 pension expense included in rates prior to the termination of the balancing account.

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NW NATURAL
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Portland, Oregon 97209-3991
1-503-226-4211

expense, and that if we made no changes to the amount we collect in rates, the pension balancing account will eventually terminate as intended.

The discussions were informational in nature, and the parties discussed the potential for NW Natural to increase the amount of FAS 87 pension expense included in rates as part of this rate case. No agreement was made, and in light of the stipulation that sets this amount at $3.8 million, NW Natural is not requesting any change to the current FAS 87 pension expense recovered in rates. In the event that the parties reach an agreement to modify the amount of FAS 87 pension expense recovered in rates, we could bring forward such a settlement in this case.

V. <u>RATE BASE</u>

Q. Describe the calculation of rate base.

A. The components of rate base are shown in *NW Natural/202, McVay/1* at lines 18-26 and at *NW Natural/210, McVay/1.* Rate base is made up of Utility Plant in Service, net of Accumulated Depreciation, with additions and subtractions for Aid in Advance of Construction, Customer Deposits, Gas Inventory, Materials and Supplies, Leasehold Improvements, and Accumulated Deferred Income Taxes. These components are described in detail below.

Q. How were amounts for Utility Plant in Service calculated?

A. Since the last rate case in 2012, NW Natural has implemented a forecasting tool, or model, called UI Planner. The model allows the Company to accurately generate financial forecasts, but it also provides a platform to develop a very

Rates & Regulatory Affairs
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Portland, Oregon 97209-3991
1-503-226-4211

detailed forecast of utility plant balances and associated depreciation and accumulated depreciation. The model is updated several times each year, which provides for a starting point of actual book balances as of the update month. Additions to plant are then included, to reflect customer additions (mains, services, and meters) as well as recurring replacement of capital assets, and also larger planned projects. As future plant balances are then developed, depreciation expense associated with each asset class is able to be calculated, which also provides for a projection of the accumulated depreciation reserve. Consistent with Company and industry accounting policy, both the gross plant and Accumulated Depreciation amounts are lowered to reflect projected retirement activity. Detail on the various capital projects that are included in the plant projection are described in other testimony.

The new depreciation rates have been incorporated that resulted from our recent depreciation study and subsequent filing and stipulation. Those rates appear as of November 2018, following what is expected to be the effective date of rates from this proceeding.

Q. Please describe the remaining components of rate base.

A. The following components complete the calculation of total rate base:

- **Aid in Advance of Construction –** This reduction to rate base represents the amounts of customer-provided contributions toward construction costs. The Test Year balance is calculated using the

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220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

September 30, 2017 actual balance plus trended amounts based on historic balances for the remaining months.

- **Customer Deposits –** This reduction to rate base represents amounts that customers are required to provide to comply with credit requirements under our tariff.
- **Gas Inventory –** This component of rate base includes a 13-month average of stored gas supplies and is composed of two categories. The first, cushion gas, assumes a continuation of the September 30, 2017 balance. Second, working gas inventory was derived by starting with October 1, 2017 storage volume and price balances and by then modeling injections and withdrawals on a monthly basis through the end of the Test Year. Withdrawals reflected the PGA pattern of cycling the gas facilities. Injections of gas volumes were priced at forward prices per the NYMEX closing information at October 16, 2017. In addition, recall amounts per the IRP were included via increased injections. Monthly balances of the two categories were projected for the Test Year to calculate the 13-month average included in rate base.
- **Materials and Supplies –** The Test Year amount of $10.4 million is derived using a 45-month trend from the period January 2014 through September 2017 of actual Material and Supplies inventory.
- **Leasehold Improvements –** The Test Year forecast for this element was obtained by taking the existing principal balances net of

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

amortization through September 2017 and continuing the consistent monthly amortizations, with an assumption of no new improvements through 2019. The result of the forecast was an amount for this category of zero.

- **Deferred Income Taxes –** This final component of rate base is produced by taking the balances for depreciation and other utility deferred taxes at December 31, 2016, and forecasting forward for incremental amounts. For depreciation, new capital expenditures were considered as well as previous basis amounts in generating book-tax differences and consequent tax effects. For the other utility federal and state accounts, projections were made for various sub-categories of utility operations.

Q. How did you calculate average rate base balances?

A. Average rate base balances utilized monthly forecast amounts to construct a 13-month average of monthly amounts for all rate base components other than deferred taxes. For deferred taxes, the rate base has traditionally included a simple average of beginning and ending values. However, NW Natural has become aware of a proration methodology that has been proscribed to ensure compliance with normalization requirements of the IRS, and proposes to utilize the method for the determination of deferred taxes in rate base in this rate case. The method develops a monthly amount of deferred taxes for the Test Year

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

based on the number of days within each month of the period. The simple average is then applied to the calculated beginning and ending balances.

Q. Please describe the treatment in this rate case for the North Mist project for Portland General Electric and the company's investment in gas reserves.

A. The North Mist project is expected to be in service during the Test Year for the case, but the ratemaking for that project is accomplished on a standalone basis, through Rate Schedule 90, and will not affect the ratemaking for our other utility customers. Likewise, the ratemaking related to gas reserves is self-contained and administered through the Purchased Gas Adjustment filing on an annual basis, and is not a component of this case other than its inclusion in the WACOG, or weighted average cost of gas.

VI. STATE ALLOCATION

Q. Please describe NW Natural's state allocation methodology.

A. NW Natural has used the same approved methodology since 2000. The methodology was originally approved in the Company's filing under Tariff Advice 00-18. Revenues, costs, and rate base are directly assigned, if applicable, and if elements are allocated, several different factors are available to apply as needed. The factors are typically based on customers, volumes, plant, or labor. The allocation factors used in this case are presented in *NW Natural/211, McVay/1.*

Q. How did you allocate revenues to Oregon?

A. Gas Sales and Transportation Revenues and Miscellaneous Revenues attributed to Oregon customers are directly assigned to Oregon. Utility property rental

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

income within the Miscellaneous Revenue category is allocated based on a 3-factor formula.

Q. How did you allocate the various categories of expense to Oregon?

A. Gas costs correspond precisely with gas costs collected in billing rates over the period, based on therms sold. The gas costs are the same as the rates currently in effect at the time of the filing of this rate case. Gas costs, including demand and commodity components, are changed every year in the Purchased Gas Adjustment (PGA) filing. Because those costs are fully considered in the PGA filing process, gas costs have not been an issue in general rate cases, and costs at the time of the rate case filing have been accepted as appropriate for inclusion in the general rate case revenue requirement.

The allocation of O&M expense is accomplished by allocating common costs, along with a direct assignment of non-common costs to the appropriate jurisdiction. The common costs are considered with respect to specific drivers, such as volumes or customers that have a causative effect on costs. The O&M costs in this rate case were allocated to the appropriate jurisdictions by applying this methodology to the calendar year 2016 O&M expense. The resulting average jurisdictional allocation by FERC account was then applied to the forecasted O&M expenses developed for this case.

Q. Please describe the jurisdictional allocation of Utility Plant in Service, Depreciation Expense, and Accumulated Depreciation.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. Intangible software is allocated between Oregon and Washington on the basis of the "all customers" allocation factor; other intangible, production, non-storage related transmission, and distribution plant is directly assigned; storage plant including related transmission has been allocated to both Oregon and Washington on the basis of firm volume deliveries; compressed natural gas and liquefied natural gas refueling facilities and most general plant is allocated using the three-factor allocation factor; and land and structures are allocated on a mix of direct and other allocation factors.

Q. Please explain the method for allocating other rate base items.

A. The allocation of rate base items differs by category. For aid in advance of construction, the rate base amount was derived specifically for Oregon. Gas inventory, including both cushion and working gas, was forecast on a system basis and allocated using the firm volume allocation factor. The Materials and Supplies amount was allocated using the gross distribution plant factor. Finally, federal deferred taxes were developed using a gross plant allocation factor since most of the deferred balance is related to depreciation book-tax timing differences. All deferred taxes for Oregon were directly assigned to Oregon.

Q. Does this conclude your direct testimony?

A. Yes.

Rates & Regulatory Affairs
NW NATURAL
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1-503-226-4211

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Exhibits of Kevin McVay

TEST YEAR / REVENUE REQUIREMENTS
EXHIBITS 201 - 211

December 2017

EXHIBITS 201 - 211 – TEST YEAR / REVENUE REQUIREMENTS

Table of Contents

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019
Base Year Twelve Months Ended December 31, 2017
Comparison of Test Year to Prior Rate Case
($000)

Line No.		UG 221 Order 12-437 (a)	Current Test Year at Present Rates (b)	Change from Last GRC (c)
	Operating Revenues (net of Cost of Gas)			
1	Sale of Gas (net of Cost of Gas)	$298,923	$333,162	$34,239
2	Transportation	12,871	16,647	3,776
3	Decoupling	0	12,068	12,068
4	Miscellaneous Revenues	4,819	3,426	(1,393)
5	Total Operating Revenues	316,613	365,303	48,690
	Operating Revenue Deductions			
6	Uncollectible Accrual for Gas Sales	2,148	710	(1,438)
7	Other Operating & Maintenance Expenses	110,525	149,648	39,123
8	Total Operating & Maintenance Expense	112,673	150,358	37,685
9	Federal Income Tax	25,644	23,085	(2,559)
10	State Excise	6,068	5,500	(568)
11	Property Taxes	19,604	22,382	2,778
12	Other Taxes	23,639	23,315	(324)
13	Depreciation & Amortization	60,059	73,605	13,546
14	Total Operating Revenue Deductions	247,687	298,244	50,557
15	Net Operating Revenues	$68,926	$67,060	($1,866)
	Average Rate Base			
16	Utility Plant in Service	2,183,588	2,844,623	661,035
17	Accumulated Depreciation	(990,862)	(1,257,248)	(266,386)
18	Net Utility Plant	1,192,726	1,587,375	394,649
19	Aid in Advance of Construction	(2,274)	(3,476)	(1,202)
20	Customer Deposits	(5,101)	(3,849)	1,252
21	Gas Inventory	12,682	35,373	22,691
22	Leasehold Improvements	1,155	0	(1,155)
23	Materials & Supplies	6,789	10,399	3,610
24	Accumulated Deferred Income Taxes	(319,816)	(435,940)	(116,124)
25	Total Rate Base	$886,161	$1,189,882	$303,721

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019
Base Year Twelve Months Ended December 31, 2017
Increase in Revenue Requirement
($000)

Line No.		Base Year at Present Rates (a)	Adjustments to Base Year (b)	Test Year at Present Rates (c)	Removal of Test Year Decoupling (d)	Adjusted Test Year at Present Rates (e)	Required Increase (f)	Proposed Total (g)
	Operating Revenues							
1	Sale of Gas	$637,346	($27,330)	$610,016	$0	$610,016	$52,446	$662,462
2	Transportation	17,390	(743)	16,647	0	16,647	0	16,647
3	Decoupling	11,599	469	12,068	(12,068)	0	0	0
4	WARM	(16,622)	16,622	0	0	0	0	0
5	Miscellaneous Revenues	3,564	(138)	3,426	0	3,426	0	3,426
6	Total Operating Revenues	653,277	(11,120)	642,157	(12,068)	630,089	52,446	682,535
	Operating Revenue Deductions							
7	Gas Purchased	291,761	(14,907)	276,854	0	276,854	0	276,854
8	Uncollectible Accrual for Gas Sales	716	(7)	710	0	710	60	769
9	Other Operating & Maintenance Expenses	136,344	13,305	149,648	0	149,648	0	149,648
10	Total Operating & Maintenance Expense	428,821	(1,610)	427,211	0	427,211	60	427,271
11	Federal Income Tax	28,115	(5,030)	23,085	(3,799)	19,287	16,489	35,776
12	State Excise	6,696	(1,196)	5,500	(893)	4,607	3,875	8,482
13	Property Taxes	20,448	1,934	22,382	0	22,382	0	22,382
14	Other Taxes	23,208	106	23,315	(322)	22,992	1,400	24,393
15	Depreciation & Amortization	71,412	2,193	73,605	0	73,605	0	73,605
16	Total Operating Revenue Deductions	578,700	(3,603)	575,097	(5,014)	570,084	21,824	591,908
17	Net Operating Revenues	$74,577	($7,517)	$67,060	($7,055)	$60,005	$30,622	$90,627
	Average Rate Base							
18	Utility Plant in Service	2,576,151	268,472	2,844,623	0	2,844,623	0	2,844,623
19	Accumulated Depreciation	(1,143,056)	(114,192)	(1,257,248)	0	(1,257,248)	0	(1,257,248)
20	Net Utility Plant	1,433,095	154,280	1,587,375	0	1,587,375	0	1,587,375
21	Aid in Advance of Construction	(3,298)	(179)	(3,476)	0	(3,476)	0	(3,476)
22	Customer Deposits	(4,189)	340	(3,849)	0	(3,849)	0	(3,849)
23	Gas Inventory	54,775	(19,402)	35,373	0	35,373	0	35,373
24	Materials & Supplies	9,087	1,312	10,399	0	10,399	0	10,399
25	Accumulated Deferred Income Taxes	(400,914)	(35,026)	(435,940)	0	(435,940)	0	(435,940)
26	Total Rate Base	$1,088,556	$101,326	$1,189,882	$0	$1,189,882	$0	$1,189,882
27	Rate of Return	6.85%		5.64%		5.04%		7.62%
28	Return on Common Equity	8.47%		6.04%		4.85%		10.00%

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019
Base Year Twelve Months Ended December 31, 2017 (Actual and Estimate)
Derivation of Forecasted Test Period Revenue

		BASE YEAR			TEST YEAR		
		Actual Therms Sales	Average Class Price Per Therm	Revenues and Margin at present rates	Normalized Therms Sales	Average Class Price Per Therm	Normalized Revenues and Margin
		(a)	(b)	(c)	(d)	(e)	(f)
	Revenues						
	Sales Volumes and Revenues						
1	**Residential**	404,515,331	0.99552	$402,704,982	385,050,429	1.00706	$387,770,097
2	**Commercial**	249,327,607	0.77906	$194,242,058	232,141,965	0.78444	$182,100,457
3	**Industrial Firm**	32,038,469	0.61621	$19,742,418	32,708,089	0.61644	$20,162,497
4	**Interruptible**	52,632,463	0.39246	$20,656,157	51,150,158	0.39066	$19,982,556
5	**Total Sales of Gas Revenues**	738,513,869		$637,345,615	701,050,641		$610,015,606
	Transportation Volumes and Revenues						
6	**Firm**	92,768,587	0.09467	$8,782,266	96,582,618	0.08970	$8,663,501
7	**Interruptible**	215,149,370	0.03168	$6,814,944	196,967,402	0.03145	$6,194,584
8	**Special Contracts - Firm**	62,180,633	0.02366	$1,471,371	60,875,713	0.02403	$1,462,735
9	**Special Contracts - Interruptible**	14,312,593	0.02247	$321,576	18,288,504	0.01783	$326,133
10	**Total Transportation**	384,411,183		$17,390,156	372,714,237		$16,646,954
11	**Total Deliveries and Revenues**	1,122,925,052		$654,735,771	1,073,764,878		$626,662,560
12	**Decoupling Base Period**			$11,599,161			$12,068,346
13	**WARM Base Period**			($16,622,000)			
14	**Total Revenue**			$649,712,933			$638,730,906
	Gas Costs						
15	**Demand Charges**			$80,205,729			$76,015,833
16	**Commodity Charges**			211,555,262			200,837,676
17	**Total Cost of Gas**			$291,760,991			$276,853,509
18	**Total Margin**			$357,951,942			$361,877,397

NW Natural
Oregon Jurisdictional Rate Case
Miscellaneous Revenues Detail
Test Year Twelve Months Ended October 31, 2019
Base Year Twelve Months Ended September 30, 2017 (Proxy for Base)

Line No.		12 Months Ended September 2015 (a)	12 Months Ended September 2016 (b)	12 Months Ended September 2017 (c)	Test Year (d)
1	FORFEITED DISCOUNTS-LATE PAYMENT CHARGE	2,020,819	1,921,841	2,061,492	2,001,384
2	MISC SERVICE REVENUES-AUTOMATED PAYMENT	55,968	41,588	38,858	38,858
3	MISC SERVICE REVENUES-DELINQ RECONN FEE	289,830	277,430	273,040	273,040
4	MISC SERVICE REVENUES-FIELD COLLECTION C	380,105	328,520	321,595	321,595
5	MISC SERVICE REVENUES-GAS DIVERSIONS	-	-	9,222	9,222
6	MISC SERVICE REVENUES-RECONN CHG-CR-AFTE	2,360	2,740	2,700	2,600
7	MISC SERVICE REVENUES-RECONN CHG-CR-DURI	268,690	243,750	231,620	231,620
8	MISC SERVICE REVENUES-RECONN CHG-SEAS-AF	130	160	240	240
9	MISC SERVICE REVENUES-RECONN CHG-SEAS-DU	14,700	15,060	12,720	14,160
10	MISC SERVICE REVENUES-RETURNED CHECK CHA	94,305	92,310	101,355	95,990
11	MISC SERVICE REVENUES-SEAS RECONN FEE	23,300	15,700	16,300	18,433
12	MISC SERVICE REVENUES-SUMMARY BILL SVCS	11,112	11,421	12,333	12,333
13	OTHER GAS REVENUES-METER RENTALS	188,115	186,838	178,602	178,602
14	OTHER GAS REVENUES-MULTIPLE CALL OUT FEE	27,849	71,566	38,376	45,931
15	OTHER GAS REV-LNG SALES & OTHER MISC REV	80,019	56,971	10,749	10,749
16	RENT FROM GAS PROPERTY-RENT - UTILITY PR	245,490	338,517	253,082	169,387
17	Non-AMR Install/Remove Charge	516	344	-	-
18	Non-AMR Read Charge	1,566	2,124	2,044	1,912
19	**Total Miscellaneous Revenues**	$3,704,874	$3,606,881	$3,564,328	$3,426,055

Note: Excludes Billing Amortization Offsets, WARM deferrals, Washington Misc Revenues

NW Natural
Oregon Jurisdictional Rate Case
Uncollectible Accounts Adjustments
Test Year Twelve Months Ended October 31, 2019
Base Year Twelve Months Ended December 31, 2017 (Actual and Estimate)
($000)

Line No.		12 Months Ended September Amounts 2015 - 2017 Total	2015 Actual	2016 Actual	2017 Actual
		(a)	(b)	(c)	(d)
	Gas Revenues				
1	Residential	1,272,470	415,278	403,024	454,168
2	Commercial	644,547	216,220	200,519	227,808
3	Industrial	68,642	24,526	21,308	22,808
4	Interruptible	74,182	31,769	20,174	22,240
5	Total	2,059,842	687,793	645,025	727,024
	Net Write-Offs				
6	Residential	1,950	649	607	695
7	Commercial	253	64	94	95
8	Industrial	149	0	122	27
9	Interruptible	-	-	-	-
10	Total	2,352	713	822	817
	Write-Off % - 3-Year Average				
11	Residential	0.153%	0.156%	0.150%	0.153%
12	Commercial	0.039%	0.030%	0.047%	0.042%
13	Industrial	0.217%	0.000%	0.573%	0.119%
14	Interruptible	0.000%	0.000%	0.000%	0.000%
15	Weighted Total	0.114%	0.104%	0.127%	0.112%
	Oregon Normalized Revenues (Test Year)				
16	Residential	387,770			
17	Commercial	182,100			
18	Industrial	20,162			
19	Interruptible	19,983			
20	Total	610,016			
	Normalized Uncollectible				
21	Residential	$594			
22	Commercial	72			
23	Industrial	44			
24	Interruptible	0			
25	Total Normalized Uncollectible	$710			
26	**In Base O&M**	$0			
27	**Adjustment (Test Year)**	$710			
28	**Uncollectible rate for normalizaing adjustments**	0.114%			
29	**Uncollectible expense in Base Year (estimated)**	716			

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019
Base Year Twelve Months Ended December 31, 2017
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	BASE YEAR System (a)	BASE YEAR Oregon (b)
1		Natural Gas Storage		
2		Underground Storage Expense		
3		Operation		
4	816	Wells Expense	$288,426	$261,574
5	818	Compressor Station Expense	95,316	86,442
6	819	Compressor Station Fuel	0	0
7	820	Measuring and Regulator Station Expense	2,284,400	2,072,675
8	821	Purification Expense	65,585	59,649
9		Maintenance		
10	832	Wells Expense	324,748	294,514
11		Total Underground Storage Expense	3,058,476	2,774,855
12		Other Storage Expense		
13		Operation		
14	840	Supervision and Engineering	152,417	138,227
15		Total Other Storage Expense	152,417	138,227
16		Liquified Natural Gas Expense		
17		Operation		
18	844	Supervision and Engineering	1,679,932	1,523,530
19	845	LNG Fuel	-	-
20		Maintenance		
21	847	Supervision and Engineering	1,037,421	940,837
22		Total Liquified Natural Gas Expense	2,717,353	2,464,367
23		Total Natural Gas Storage	5,928,246	5,377,449
24		Transmission Expense		
25		Operation		
26	856	Mains Expense	1,976,836	1,856,343
27		Maintenance		
28	863	Maintenance of Mains	211,101	193,967
29		Total Transmission Expense	2,187,936	2,050,311
30		Distribution Expense		
31		Operation		
32	870	Supervision and Engineering	3,066,919	2,799,861
33	874	Mains and Services Expense	13,437,705	12,094,610
34	875	Measuring and Regulator Station Expense - General	316,162	284,972
35	877	Measuring and Regulator Station Expense - City Gate	462,884	423,835
36	878	Meter and House Regulator Expense	5,976,513	5,331,344
37	879	Customer Installation Expense	10,636,487	9,491,013
38	880	Other Expense	2,310,439	2,043,290
39	881	Rents	215,700	188,771

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019
Base Year Twelve Months Ended December 31, 2017
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	BASE YEAR System	BASE YEAR Oregon
			(a)	(b)
40		Maintenance		
41	885	Supervision and Engineering	7,785,191	7,485,845
42	887	Mains	2,830,295	2,586,489
43	889	Measuring and Regulator Station Expense - General	1,627,345	1,487,894
44	891	Measuring and Regulator Station Expense - City Gate	184,387	170,588
45	892	Services	668,847	629,157
46	893	Meters and House Regulators	3,172,310	2,865,860
47	894	Other Equipment	22,650	20,802
48		Total Distribution Expense	52,713,835	47,904,330
49		Customer Accounts Expense		
50		Operation		
51	901	Supervision	1,678,781	1,496,468
52	902	Meter Reading Expenses	860,184	767,018
53	903	Customer Records and Collection Expense	18,812,078	16,783,116
54	904	Uncollectible Accounts (per adjustment calculation)	-	-
55		Total Customer Accounts Expense	21,351,042	19,046,602
56		Customer Service and Informational		
57		Operation		
58	907	Supervision	1,616	1,439
59	908	Customer Assistance Expense	2,487,008	2,200,112
60	909	Customer Information Expense	2,701,715	2,408,308
61	910	Miscellaneous Customer Service Expense	232,631	207,088
62		Total Customer Service and Informational	5,422,969	4,816,947
63		Sales Expense		
64		Operation		
65	911	Supervision	186,188	165,968
66	912	Demonstration and Selling Expense	3,889,789	3,468,208
67	913	Advertising	667,240	594,778
68	916	Miscellaneous Sales Expense	-	-
69		Total Sales Expense	4,743,217	4,228,953
70		Administrative and General Expense		
71		Operation		
72	921	Office Salaries and Expense	60,041,661	53,589,980
73	922	Administrative Expenses Transferred - Credit	(20,102,946)	(18,011,060)
74	924	Property Insurance Premium	3,253,000	2,923,471
75	925	Injuries and Damages	245,747	220,852
76	926	Employee Pensions and Benefits	(1,282,249)	(1,832,239)
77	928	Regulatory Commission Expense	-	-
78	930	Miscellaneous General Expense	3,111,730	2,796,017
79	931	Rents	4,796,707	4,315,560
80		Maintenance		
81	935	Maintenance of General Plant	4,380,096	3,916,473
82		Total Administrative and General Expense	54,443,746	47,919,054
83		Total O&M Expense	146,790,991	131,343,647
84	407	Environmental Rider	5,000,000	5,000,000
85		Total O&M Expense including Environmental Rider	151,790,991	136,343,647

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019
Base Year Twelve Months Ended December 31, 2017
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	TEST YEAR System (a)	TEST YEAR Oregon (b)
1		Natural Gas Storage		
2		Underground Storage Expense		
3		Operation		
4	816	Wells Expense	$302,647	$274,470
5	818	Compressor Station Expense	108,475	98,376
6	819	Compressor Station Fuel	0	0
7	820	Measuring and Regulator Station Expense	2,209,830	2,005,017
8	821	Purification Expense	68,201	62,029
9		Maintenance		
10	832	Wells Expense	290,831	263,755
11		Total Underground Storage Expense	2,979,985	2,703,647
12		Other Storage Expense		
13		Operation		
14	840	Supervision and Engineering	151,127	137,057
15		Total Other Storage Expense	151,127	137,057
16		Liquified Natural Gas Expense		
17		Operation		
18	844	Supervision and Engineering	1,626,783	1,475,330
19	845	LNG Fuel	-	-
20		Maintenance		
21	847	Supervision and Engineering	1,067,691	968,289
22		Total Liquified Natural Gas Expense	2,694,474	2,443,619
23		Total Natural Gas Storage	5,825,586	5,284,323
24		Transmission Expense		
25		Operation		
26	856	Mains Expense	1,962,000	1,842,412
27		Maintenance		
28	863	Maintenance of Mains	206,609	189,840
29		Total Transmission Expense	2,168,610	2,032,253
30		Distribution Expense		
31		Operation		
32	870	Supervision and Engineering	2,890,744	2,639,027
33	874	Mains and Services Expense	13,500,666	12,151,278
34	875	Measuring and Regulator Station Expense - General	281,465	253,697
35	877	Measuring and Regulator Station Expense - City Gate	464,201	425,040
36	878	Meter and House Regulator Expense	5,830,824	5,201,382
37	879	Customer Installation Expense	10,900,139	9,726,271
38	880	Other Expense	2,141,613	1,893,985
39	881	Rents	225,324	197,194

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019
Base Year Twelve Months Ended December 31, 2017
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	TEST YEAR System (a)	TEST YEAR Oregon (b)
40		Maintenance		
41	885	Supervision and Engineering	8,040,935	7,731,755
42	887	Mains	2,660,056	2,430,914
43	889	Measuring and Regulator Station Expense - General	1,536,803	1,405,111
44	891	Measuring and Regulator Station Expense - City Gate	181,668	168,073
45	892	Services	639,467	601,520
46	893	Meters and House Regulators	2,992,735	2,703,632
47	894	Other Equipment	22,309	20,488
48		Total Distribution Expense	52,308,948	47,549,368
49		Customer Accounts Expense		
50		Operation		
51	901	Supervision	1,583,983	1,411,965
52	902	Meter Reading Expenses	833,698	743,401
53	903	Customer Records and Collection Expense	17,974,714	16,036,065
54	904	Uncollectible Accounts (calculated separately)	-	-
55		Total Customer Accounts Expense	20,392,394	18,191,431
56		Customer Service and Informational		
57		Operation		
58	907	Supervision	1,688	1,502
59	908	Customer Assistance Expense	2,582,752	2,284,812
60	909	Customer Information Expense	2,275,503	2,028,384
61	910	Miscellaneous Customer Service Expense	226,150	201,319
62		Total Customer Service and Informational	5,086,094	4,516,017
63		Sales Expense		
64		Operation		
65	911	Supervision	177,769	158,463
66	912	Demonstration and Selling Expense	4,131,640	3,683,847
67	913	Advertising	516,168	460,112
68	916	Miscellaneous Sales Expense	-	-
69		Total Sales Expense	4,825,577	4,302,422
70		Administrative and General Expense		
71		Operation		
72	921	Office Salaries and Expense	64,165,205	57,270,436
73	922	Administrative Expenses Transferred - Credit	(20,391,417)	(18,269,513)
74	924	Property Insurance Premium	3,914,550	3,518,006
75	925	Injuries and Damages	238,216	214,085
76	926	Employee Pensions and Benefits	8,961,559	6,873,874
77	928	Regulatory Commission Expense	103,742	103,742
78	930	Miscellaneous General Expense	3,260,782	2,929,946
79	931	Rents	4,976,654	4,477,457
80		Maintenance		
81	935	Maintenance of General Plant	4,983,374	4,455,896
82		Total Administrative and General Expense	70,212,666	61,573,928
83		Total O&M Expense	160,819,875	143,449,742
84	407	Environmental Rider	5,000,000	5,000,000
85		Total O&M Expense including Environmental Rider	165,819,875	148,449,742

NW Natural
Oregon Jurisdictional Rate Case
Tax Provision
Test Year Twelve Months Ended October 31, 2019
Base Year Twelve Months Ended December 31, 2017
($000)

Line No.		BASE YEAR State Taxes (a)	BASE YEAR Federal Taxes (b)	TEST YEAR State Taxes (c)	TEST YEAR Federal Taxes (d)
1	Operating Revenues	$653,277	$653,277	$642,157	$642,157
2	Operating Revenue Deductions	428,821	428,821	427,211	427,211
3	Property & Other Taxes	43,656	43,656	45,696	45,696
4	Book Depreciation	71,412	71,412	73,605	73,605
5	Interest (Rate Base * Cost of Debt)	28,482	28,482	31,133	31,133
6	Remove Equity Flotation			(1,198)	(1,198)
7	State Tax Deduction	0	6,696	0	5,500
8	Subtotal	80,906	74,210	65,710	60,210
9	Permanent Differences 1/	7,213	6,477	6,652	5,965
10	Taxable Income	88,118	80,687	72,362	66,176
11	Tax Rate	7.60%	35.00%	7.60%	35.00%
12	Tax Before Credits	6,697	28,241	5,500	23,161
13	Credits (R&D)	(1)	(126)	0	(76)
14	Total Tax	$6,696	$28,115	$5,500	$23,085

1/ Federal Permanent Differences allocated using depreciation factor

NW Natural
Oregon Jurisdictional Rate Case
Proforma Cost of Capital and Revenue Sensitive Costs

	Weighted Average Cost of Capital	% of Total Capital	Average Cost	Weighted Cost
1	Long Term Debt	50.0%	5.233%	2.617%
2	Common Stock	50.0%	10.000%	5.000%
3	Total	100.0%		7.617%

	Revenue Sensitive Costs	
4	Gas Sales	96.81%
5	Transportation	2.64%
6	Other	0.54%
7	Subtotal	100.00%
8	O & M - Uncollectible	0.11%
9	Franchise Taxes at	2.37%
10	OPUC Fee	0.30%
11	State Taxable Income	97.22%
12	State Income Tax	7.39%
13	Federal Taxable Income	89.83%
14	Federal Income Tax	31.44%
15	Utility Operating Income	58.39%
16	Total Revenue Sensitive Costs	41.61%
17	Net-to-gross factor	171.27%
18	Rate of Return on Equity	10.00%
19	Federal Tax Rate	35.00%
20	State Tax Rate	7.60%
21	Combined Tax Rate	39.94%
22	Franchise Fees	2.370%
23	Uncollectible Accounts	0.114%
24	Regulatory Fees	0.300%
25	Interest Coordination Factor	2.617%

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019
Base Year Twelve Months Ended December 31, 2017 (Actual and Estimate)
Forecast of Other Taxes

Line No.		Actual 2016 (a)	Actual 2017 (b)	Average (c)	Test Year Normalized (d)	Base Year Normalized (e)
	Property Taxes					
1	Taxes Paid	19,714,452	21,181,813			20,448,132
2	Net Plant December 31 of prior year	1,346,458,075	1,411,512,000			
3	Effective Rate on Prior Year-End Net Plant	1.464%	1.501%	1.489%		
4	Net Plant 12/31/17				1,468,348,757	
5	2018 Payment Forecast (line 4 * line 3)				21,857,987	
6	Net Plant 12/31/18				1,573,899,735	
7	2019 Payment Forecast (line 6 * line 3)				23,429,229	
8	Test Period Expense (8/12 of line 5 + 4/12 of line 7)				22,381,734	
	Other Taxes					
9	Franchise				15,219,120	15,482,671
10	Payroll				5,837,520	5,404,495
11	Regulatory Fee				1,926,471	1,959,832
12	Department of Energy				818,134	832,302
13	Other				226,834	199,125
14	Storage Property Tax Offset				(713,373)	(670,080)
15	Other Taxes Excluding Property Taxes				23,314,705	23,208,343

NW Natural
Oregon Jurisdictional Rate Case
Rate Base & Depreciation Expense - Oregon and System
Test Year Twelve Months Ended October 31, 2019
Base Year Twelve Months Ended December 31, 2017
($000)

Line No.	Rate Base	Test Year Oregon (a)	Test Year System (b)	Base Year Oregon (c)	Base Year System (d)
1	Utility Plant in Service	2,844,623	3,202,578	2,576,151	2,889,584
2	Accumulated Depreciation	(1,257,248)	(1,401,983)	(1,143,056)	(1,272,803)
3	Net Utility Plant	1,587,375	1,800,594	1,433,095	1,616,781
4	Aid in Advance of Construction	(3,476)	(4,263)	(3,298)	(3,885)
5	Customer Deposits	(3,849)	(4,222)	(4,189)	(4,595)
6	Gas Inventory (Working and Cushion)	35,373	39,099	54,775	60,544
7	Materials & Supplies	10,399	12,082	9,087	10,558
8	Accumulated Deferred Income Taxes - Depreciation	(421,796)	(463,917)	(391,372)	(430,481)
9	Accumulated Deferred Income Taxes - Other	(14,145)	(15,598)	(9,542)	(10,530)
10	Total Rate Base	1,189,882	1,363,775	1,088,556	1,238,393

1/ Test Year Depreciation DTL per Proration Methodology

	Depreciation Expense	Test Year Oregon	Test Year System	Base Year Oregon	Base Year System
11	Intangible - Software	5,496	6,175	2,663	2,992
12	Transmission	3,652	3,741	4,928	4,962
13	Distribution	54,030	61,667	49,558	56,287
14	General	4,205	4,624	7,322	8,159
15	Storage and Storage Transmission	6,221	6,788	6,941	7,583
16	Total	73,605	82,995	71,412	79,983

NW Natural
Oregon Jurisdictional Rate Case
State Allocation Factors

Line No.	Allocation Factors - Summary	Oregon	Washington
1	Customers-all	89.01%	10.99%
2	Customers-Residential	88.89%	11.11%
3	Customers-Commercial	90.15%	9.85%
4	Customers-Industrial	92.49%	7.51%
5	Customers-The Dalles	74.84%	25.16%
6	3-factor	89.06%	10.94%
7	firm volumes	90.47%	9.53%
8	sales volumes	90.21%	9.79%
9	sendout volumes	91.82%	8.18%
10	sales/sendout volumes	91.02%	8.98%
11	Customers Portland/Vancouver	84.95%	15.05%
12	Customers Portland/Vancouver 80%	87.96%	12.04%
13	Customers Portland/Vancouver Commercial	85.44%	14.56%
14	Payroll	89.94%	10.06%
15	Admin Transfer	88.63%	11.37%
16	Employee Cost	89.65%	10.35%
17	Regulatory	70.00%	30.00%
18	Telemetering	91.30%	8.70%
19	Direct-Wa	0.00%	100.00%
20	Direct-Or	100.00%	0.00%
21	Gross plant direct assign	89.06%	10.94%
22	Transmission	98.86%	1.14%
23	Depreciation	89.68%	10.32%
24	Rate Base	87.25%	12.75%
25	Distribution	86.07%	13.93%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Direct Testimony of Frank Burkhartsmeyer

COST OF CAPITAL
EXHIBIT 300

December 2017

EXHIBIT 300 – DIRECT TESTIMONY– COST OF CAPITAL

Table of Contents

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Frank Burkhartsmeyer. I am Senior Vice President and Chief Financial Officer of NW Natural.

Q. Please state your experience and educational background.

Prior to joining NW Natural, I was the President and Chief Executive Officer (CEO) of Avangrid Renewables, which is a subsidiary of Avangrid and part of the Iberdrola Group. I was with Avangrid Renewables from October 2005, serving as Senior Vice President of Finance, and Vice President of Strategy Planning and Market Fundamentals prior to assuming the role of Director, President and CEO in April 2015. Prior to joining Avangrid Renewables, I served as Managing Director of Strategic Planning at ScottishPower. I also held a variety of roles, including Director of Treasury, at PacifiCorp, prior to its acquisition by ScottishPower. Prior to that, I spent seven years in the commercial banking industry in a variety of corporate development and financial analysis roles.

I hold a Bachelor of Liberal Arts degree from the University of Montana and a Masters in Business Administration from the University of Oregon.

Q. Please summarize your testimony.

///

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. In my testimony I discuss the Company's appropriate capital structure and overall rate of return, the cost of long-term debt, and the Company's credit ratings. More specifically, I:

- Present NW Natural's request for a capital structure of 50 percent common equity and 50 percent long-term debt, with an overall rate of return (ROR) on rate base of 7.62 percent;
- Explain how I determined that the proposed capital structure is appropriate;
- Describe NW Natural's plan to maintain its proposed ratios of equity and debt;
- Explain how I calculated the Test Year cost of debt, including an explanation of how I calculated costs associated with a debt issuance expected prior to the beginning of the Test Year, and issuances during the Test Year; and
- Discuss the Company's current credit ratings and why it is important for the Company to maintain its current credit ratings.

II. RECOMMENDED CAPITAL STRUCTURE AND RATE OF RETURN

Q. What is NW Natural's current Commission-authorized ratemaking capital structure and overall ROR?

///

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. In the Company's last general rate case (Order No.12-408 in Docket UG 221), the Commission adopted the following capital structure, capital costs and overall ROR:

NW NATURAL'S CAPITAL STRUCTURE AND RATE OF RETURN
ORDER NO. 12-408

Component	Ratio	Cost	Weighted Cost
Long-term Debt	50%	6.06%	3.028%
Common Equity	50%	9.50%	4.750%
Total	**100%**		**7.778%**

Q. What is NW Natural's recommended capital structure for ratemaking purposes in this proceeding?

A. NW Natural is requesting a continued capital structure of 50 percent equity and 50 percent long-term debt, with an overall ROR on rate base of 7.62 percent, based upon a 5.23 percent embedded cost of long-term debt and a 10.0 percent cost of equity. The following table presents the proposed capital structure along with the calculation of the Company's ROR for the test year:

PROPOSED CAPITAL STRUCTURE AND RATE OF RETURN

Component	Ratio	Cost	Weighted Cost
Long-term Debt	50%	5.23%	2.62%
Common Equity	50%	10.00%	5.00%
Total	**100%**		**7.62%**

Q. Does NW Natural always maintain exactly a 50/50 capital structure?

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. No. Although NW Natural's target capital structure has for a long time been, and continues to be 50/50, there is a natural fluctuation in these numbers on a temporary basis over time. These fluctuations do not, however, represent a meaningful departure from our targeted capital structure. For example, in 2019, NW Natural forecasts to have an average equity ratio of almost exactly 50 percent (49.8 percent to be precise) but that number will fluctuate over and under 50/50 throughout the year.

Q. Why is maintaining a 50/50 capital structure at the utility important?

A. Maintaining a 50 percent utility common equity ratio is important for several reasons. This equity ratio demonstrates the Company's commitment to a strong and stable balance sheet, which helps maintain the Company's current "A" category credit ratings. Strong investment grade credit ratings provide the Company with financing flexibility and liquidity, thereby ensuring timely, efficient, and cost-effective access to capital markets, which in turn helps to lower the cost of capital for utility customers and shareholders, as is explained in further detail below. With a 50 percent common equity ratio, NW Natural has been able to maintain its A-category ratings ("AA-" for S&P and A1 for Moody's) on long-term and short-term debt ("A-1" for S&P and "P-2" for Moody's).

The converse is true, too. Generally, companies with higher debt ratios are considered more risky. By maintaining a long-term debt ratio at 50 percent, the Company is maintaining its risk profile in line with its historical risk profile and with other peer group LDCs. If the Company were to increase its debt ratio

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

beyond 50 percent, it is likely that the rating agencies would view this action negatively. In the event our ratings were downgraded as a result, the Company could face more difficulty accessing capital markets and higher costs of debt – potentially causing detriment to both our shareholders and our customers.

Q. How does NW Natural's proposed utility capital structure compare with the natural gas peer group?

A. The Company's proposed capital structure has a slightly lower equity to capital ratio than that of our peer group identified by Dr. Villadsen in the Company's Return on Equity Testimony (*NW Natural/400, Villadsen*). The average equity to capital ratio of our peers is 53 percent.

III. COMMON EQUITY

Q. Did NW Natural issue common equity shares through a public offering on November 16, 2016?

A. Yes. The Company issued 1,012,000 shares of common stock, with total net proceeds of $52.8 million. The timing and amount issued were based on financial forecasts for the purpose of maintaining our equity exposure within a target range. The amount of proceeds from this offering were added to the general funds of NW Natural and used for corporate purposes, primarily to fund, in part, NW Natural's ongoing utility construction program and for general corporate purposes.

Q. What is NW Natural's plan to maintain the target utility common equity ratio over the next few years?

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. The Company's plan includes taking a number of steps. In addition to the expected increase in common equity due to retained earnings growth each year, the Company intends to: (1) continue issuing new shares of common stock to investors through its ongoing Dividend Reinvestment and Optional Cash Payment Plan; and (2) sell new common shares to investors through public offerings, as needed. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** dependent upon planned utility capital expenditures.

IV. <u>LONG-TERM DEBT</u>

Q. How was the cost of long-term debt calculated for the Test Year?

A. *NW Natural/301, Burkhartsmeyer/1* presents the details of the Company's long-term debt outstanding ($779.7 million) and the corresponding weighted average cost (5.233 percent) forecasted for the Test Year. The cost of long-term debt includes existing debt and forecasted debt. The weighted average cost of long-term debt was calculated by multiplying the debt outstanding, including future projected debt issuances, by the average cost for each debt issue.

Column "s" of *NW Natural/301*, *Burkhartsmeyer/1* shows the annualized expense of each individual issue in terms of an effective interest rate, which represents the total cost of issue, including coupon rate, premiums or discounts, underwriter's commissions, gains and losses on interest rate hedges, and other expenses related to the issue such as legal fees and unamortized debt discounts

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

and early redemption premiums assigned to refunding issues. Unamortized debt discounts and early redemption premiums from previously outstanding debt issues are added to the new debt issuance because the Company was able to achieve a lower annualized cost of debt due to net present value savings from the early redemption.

Q. Are new debt issuances forecast prior to, and during, the Test Year?

A. Yes, a $50 million debt issuance is forecast to occur in June, 2018, prior to the start of the Test Year. Additionally, two $25 million debt issuances are forecast to occur in 2019, during the Test Year.

Q. How did you determine the tenor of the forecast issuances?

A. The expected mid-year 2018 $50 million issuance is assumed to have a tenor of 30 years, while the two 2019 issuances are expected to be split between 10-year and 30-year tenors. The tenors selected are based on the company's current strategy to extend its long-term debt portfolio weighted average maturity (WAM) and take advantage of current market conditions, as the Treasury curve has recently flattened, which provides an opportunity to extend tenors while minimizing the marginal cost.

The Company's current WAM is approximately 11.2 years, which is below our peer group's WAM of 16 years and one of the reasons we are leaning toward longer tenured issues. Our most recent $100 million issue in September 2017 was split, with more weight given to the 30-year tenor. $75 million was allocated to the 30-year tenor and $25 million was allocated to the 10-year tenor. The

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Company could have allocated the full $100 million to a 30-year tenor, but we also try to limit the impact of redemptions in any one year. The impact of using this approach and the tenors discussed will increase the Company's WAM to close to 13 years in the Test Year.

Q. How was the rate on the forecasted issuances determined?

A. The forecast uses the "implied forward yield" of United States Treasury (UST) bonds forecasted out to the quarter in which we expect to issue long-term debt, plus estimated credit spreads which vary by the tenor of the planned debt issuance. *NW Natural/302, Burkhartsmeyer/1* shows the forecast used for 10 and 30 year issuances.

Q. How did you estimate the credit spreads for the future debt issuances?

A. The methodology used to forecast future credit spreads utilized recent NW Natural transactions completed since 2011 to construct forecasts for 10-year and 30-year tenors. The Company's most recent issuance established credit spreads for the early forecasted periods and the historical average credit spread was used to forecast credit spreads for the last quarter of the Test Year. The following tables display historical data and forecasts for each tenor:

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

10 Year Historical Data

Issue	Credit Spread (bps)
$50 Million 3.176% Due 2021	115
$50 Million 3.542% Due 2023	83
$35 Million 3.211% Due 2026	90
$25 Million 2.822% Due 2027	75
Average	91 bps

30 Year Historical Data

Issue	Credit Spread (bps)
$50 Million 3.176% Due 2042	130
$40 Million 3.542% Due 2046	115
$75 Million 3.211% Due 2047	100
Average	115 bps

10 & 30 Year Credit Spread Forecast

Tenor	17Q4	18Q1	18Q2	18Q3	18Q4	19Q1	19Q2	19Q3
10 Year	75	80	80	85	85	85	85	90
30 Year	100	105	105	110	110	110	110	115

Q. How did you calculate the coupon rate for the future debt issuances?

A. The estimated coupon rate is the sum of the forward implied treasury rate and either the 10 or 30-year forecasted credit spreads. The following table displays the estimated debt amounts, tenor, UST yield, credit spread and coupon rate:

Year	Debt Amt.	Tenor	UST Yield	Credit Spreads	Coupon Rate
2018	$50MM	30 Yr.	2.94%	1.05%	3.99%
2019	$25MM	10 Yr.	2.68%	0.85%	3.53%
2019	$25MM	30 Yr.	3.02%	1.10%	4.12%

Q. How did you validate the estimated coupon rate?

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Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. I compared NW Natural's projected long-term secured debt issuances against current market rates for other comparable utilities. *NW Natural/303, Burkhartsmeyer/2* shows three recent 30-year first mortgage bonds, also summarized below:

Utility	Credit Rating (Moody's/ S&P)	Coupon	Amount	Date of Issuance
Connecticut Light & Power Co	A2/A+	4.300%	$225MM	8/8/2017
Southwestern Public Service Co	A2/A	3.700%	$450MM	8/2/2017
DTE Electric Co.	Aa3/A	3.750%	$440MM	7/31/2017

Transaction size makes a difference on debt prices because investors' demand for liquidity plays a role in secondary bond markets. In order for a debt issuance to regularly trade in secondary markets, and thereby provide investors with market liquidity, the issuance size generally needs to be $300 million or greater. Issuances less than $300 million are likely not going to sell on secondary markets. Therefore investors in smaller issuances will likely require a liquidity premium against comparably rated utilities.

Due to NW Natural's relatively small debt issuance size, investors can be expected to require this premium credit spread, particularly in tight credit markets. While a premium can be expected, we have over the years been successful to limit this premium to around 10 basis points (bps) or less. In fact, in our most recent issuance in September 2017, we were successful in achieving a spread to treasuries on our 10 and 30-year bonds that were consistent with that

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

of larger size issuances.

Q. What expenses are included for the assumed NW Natural debt issuance?

A. Debt issuance costs, such as underwriter fees, have historically been 62.5 bps on issues with 10-year tenors and 75 bps on issues with 30-year tenors. Other issue expenses are estimated to be $312,000 per issue. A combination of historical costs and current market pricing were used to estimate the pro forma debt issue costs.

V. Credit Ratings

Q. What are NW Natural's current debt ratings?

A. The table below and *NW Natural/305, Burkhartsmeyer/1* shows the Company's current ratings for each type of debt security from Moody's Investor Service ("Moody's") and Standard and Poor's Ratings ("S&P"):.

	Moody's	S&P
Corporate	A3	A+
Secured	A1	AA-
Commercial Paper	P-2	A-1
Outlook	Stable	Stable

Q. How does NW Natural's A category debt rating benefit customers?

A. The Company's interest expense, and to a large extent the Company's access to capital during turbulent market conditions depends upon the debt ratings. If the Company's ratings were downgraded, the Company's interest expense would go up on future issuances. Also, lower credit ratings have a direct impact on financial terms the Company is able to negotiate from suppliers, and may limit

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

access to capital markets. In summary, credit ratings affect our cost of debt and subsequently our cost of capital and customer rates.

Q. Please explain the implications of the credit ratings in terms of NW Natural's ability to access capital markets.

A. Generally speaking, companies with higher credit ratings will attract more investors, at better prices. Lower-rated companies may find it difficult to access capital, or potentially pay significantly more, especially in challenging capital market conditions. The capital market environment changes as macro business cycles move up and down, which creates tighter and looser access to capital. In order to ensure that the Company continues to have favorable pricing, or at times, access to capital markets during all market environments, it is imperative that the Company retains a strong credit rating.

Q. Are there other important factors that the rating agencies review in determining NW Natural's ratings?

A. Moody's and S&P rate the Company's debt based on their independent review of the Company's financial condition and credit metrics. Independent credit reviews consist of qualitative and quantitative metrics, for example, the regulatory environment and cash flow metrics. Although each rating agency has a slightly different methodology for analyzing credit risk, many of the key financial ratios are the same, or at least comparable.

The tables below display Moody's and Standard and Poor's benchmark and NW Natural's, as a consolidated company, 2019 year-end (YE) forecast.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Ratio	Moody's "A" Benchmark	NW Natural's 2019 YE Forecast	Comment
Pre-tax Interest Coverage	4.5x to 6.0x	5.3x	Within rating band
Debt Leverage	40%-50%	40.1%	Within rating band
FFO to Debt	19% to 27%	19.4%	Within rating band
Retained Cash Flow	15% to 23%	14.3%	Slightly Unfavorable

Ratio	S&P "A" Benchmark	NW Natural's 2019 YE Forecast	Comment
FFO/Debt	13% - 23%	22.2%	Within rating band
Debt/EBITDA (x)	3x – 4x	3.5x	Within rating band
CFO/Debt	12%-20%	22.8%	Slightly Favorable

FFO = Funds From Operations
EBITDA = Earnings Before Interest, Taxes, Depreciation and Amortization
CFO = Cash Flow from Operations

Q. Have NW Natural's credit ratings changed since the Commission issued its order in the Company's 2012 rate case?

A. Yes, both rating agencies have made changes since the 2012 rate case. Standard and Poor's upgraded the Company's senior secured long-term debt rating from A+ to AA- in March 2013. The reason for the upgrade was due to a change in Standard and Poor's recovery methodology on senior bonds secured by utility real property. NW Natural's recovery rating changed from '1' to '1.5', which aligns with a 'AA-' or better rating. No other changes were made by Standard and Poor's.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Moody's has made two changes since our last rate case. The first change occurred in December of 2012 when Moody's changed the Company's outlook from Stable to Negative and downgraded our short-term debt rating from P-1 to P-2. The reasons Moody's cited for the change in outlook were continued weakness in financial metrics and expectation of further deterioration, the Company's outcome in its 2012 OPUC rate case, negative impact on cash flows from elevated capital expenditures, and stable dividend policy. The reasons cited for the change in short-term rating were primarily due to the change in outlook and alignment with other A3-rated issuers in the utility sector. The second change occurred in February of 2014 when Moody's changed the outlook from Negative to Stable. This change was the result of a more favorable view of U.S. regulation, and the strong support that Oregon regulation offers NW Natural.

The latest Rating Agency credit reports can be found in *NW Natural/304, Burkhartsmeyer/1-13.* Historical ratings for each Rating Agency can be found in *NW Natural/305, Burkhartsmeyer/1*.

Q. Does this conclude your testimony?

A. Yes.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Exhibits of Frank Burkhartsmeyer

COST OF CAPITAL
EXHIBITS 301 - 305

December 2017

EXHIBITS 301-305 – COST OF CAPITAL

Table of Contents

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

NORTHWEST NATURAL GAS COMPANY
EMBEDDED COST OF LONG-TERM DEBT CAPITAL AT
Pro-Forma September 30, 2019

					9/30/2019			Premium or Discount		Underwriter's Commission	Expense of Issue				Net Proceeds				
ln. #	Coupon Rate	Description of Issue	Date Issued	Maturity Date	Years to Maturity	Outstanding	Offered	Amount	Per $ 100 Principal Amount	Amount	Per $ 100 Principal Amount	Amount		Per $ 100 Principal Amount	Amount	Per $100 Principal Amount	Original Term to Maturity Yrs.	Cost of Money (Bond Table)	Annual Cost Out-standing Debt
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
		Medium-Term Notes																	
		First Mortgage Bonds:																	
1	7.630%	7.630% Series	12/9/1999	12/9/2019	0.2	20,000,000	20,000,000	0	0.00	150,000	0.750	45,421		0.23	19,804,579	99.023	20	7.727%	1,545,347
2	5.370%	5.370% Series	3/25/2009	2/1/2020	0.3	75,000,000	75,000,000	0	0.00	468,750	0.625	10,394,058	[5]	13.86	64,137,192	85.516	11	7.327%	5,495,095
3	9.050%	9.050% Series	8/13/1991	8/13/2021	1.9	10,000,000	10,000,000	0	0.00	75,000	0.750	40,333		0.40	9,884,667	98.847	30	9.163%	916,340
4	3.176%	3.176% Series	9/12/2011	9/15/2021	2.0	50,000,000	50,000,000	0	0.00	312,500	0.625	292,655		0.59	49,394,845	98.790	10	3.319%	1,659,546
5	3.542%	3.542% Series	8/19/2013	8/19/2023	3.9	50,000,000	50,000,000	0	0.00	312,500	0.625	325,679		0.65	49,361,821	98.724	10	3.696%	1,847,917
6	5.620%	5.620% Series	11/21/2003	11/21/2023	4.1	40,000,000	40,000,000	0	0.00	372,588	0.931	2,952,850	[4]	7.38	36,674,562	91.686	20	6.360%	2,544,175
7	7.720%	7.720% Series	9/6/2000	9/1/2025	5.9	20,000,000	20,000,000	0	0.00	150,000	0.750	1,136,261	[2]	5.68	18,713,739	93.569	25	8.336%	1,667,197
8	6.520%	6.520% Series	12/1/1995	12/1/2025	6.2	10,000,000	10,000,000	0	0.00	62,500	0.625	27,646		0.28	9,909,854	99.099	30	6.589%	658,931
9	7.050%	7.050% Series	10/15/1996	10/15/2026	7.0	20,000,000	20,000,000	0	0.00	125,000	0.625	50,940		0.25	19,824,060	99.120	30	7.121%	1,424,279
10	3.211%	3.211% Series	12/5/2016	12/5/2026	7.2	35,000,000	35,000,000	0	0.00	218,750	0.625	288,003		0.82	34,493,247	98.552	10	3.383%	1,184,002
11	7.000%	7.000% Series	5/20/1997	5/21/2027	7.6	20,000,000	20,000,000	0	0.00	125,000	0.625	28,906		0.14	19,846,094	99.230	30	7.062%	1,412,411
12	6.650%	6.650% Series	11/10/1997	11/10/2027	8.1	19,700,000	19,700,000	0	0.00	125,000	0.635	37,800	[6]	0.19	19,537,200	99.174	30	6.714%	1,322,729
13	6.650%	6.650% Series	6/1/1998	6/1/2028	8.7	10,000,000	10,000,000	0	0.00	75,000	0.750	23,300		0.23	9,901,700	99.017	30	6.727%	672,666
14	7.740%	7.740% Series	8/29/2000	8/29/2030	10.9	20,000,000	20,000,000	0	0.00	150,000	0.750	1,354,914	[1]	6.77	18,495,086	92.475	30	8.433%	1,686,529
15	7.850%	7.850% Series	9/6/2000	9/1/2030	10.9	10,000,000	10,000,000	0	0.00	75,000	0.750	678,107	[3]	6.78	9,246,893	92.469	30	8.551%	855,067
16	5.820%	5.820% Series	9/24/2002	9/24/2032	13.0	30,000,000	30,000,000	0	0.00	225,000	0.750	165,382		0.55	29,609,618	98.699	30	5.913%	1,773,949
17	5.660%	5.660% Series	2/25/2003	2/25/2033	13.4	40,000,000	40,000,000	0	0.00	300,000	0.750	56,663		0.14	39,643,337	99.108	30	5.723%	2,289,013
18	5.250%	5.250% Series	6/21/2005	6/21/2035	15.7	10,000,000	10,000,000	0	0.00	75,000	0.750	22,974		0.23	9,902,026	99.020	30	5.316%	531,569
19	4.000%	4.000% Series	10/30/2012	10/31/2042	23.1	50,000,000	50,000,000	0	0.00	300,000	0.600	235,479		0.47	49,464,521	98.929	30	4.062%	2,031,041
20	4.136%	4.136% Series	12/5/2016	12/5/2046	27.2	40,000,000	40,000,000	0	0.00	300,000	0.750	307,712		0.77	39,392,288	98.481	30	4.226%	1,690,328
21	2.822%	2.822% Series	9/13/2017	9/13/2027	8.0	25,000,000	25,000,000	0	0.00	150,000	0.600	159,446		0.64	24,690,554	98.762	10	2.966%	741,487
22	3.685%	3.685% Series	9/13/2017	9/13/2047	28.0	75,000,000	75,000,000	0	0.00	562,500	0.750	366,630		0.49	74,070,870	98.761	30	3.754%	2,815,629
23	3.990%	3.990% Series	6/1/2018	6/1/2048	28.7	50,000,000	50,000,000	0	0.00	375,000	0.750	312,000		0.62	49,313,000	98.626	30	4.070%	2,034,862
24	3.530%	3.530% Series	6/1/2019	6/1/2029	9.7	25,000,000	25,000,000	0	0.00	156,250	0.625	312,000		1.25	24,531,750	98.127	10	3.756%	939,102
25	4.120%	4.120% Series	6/1/2019	6/1/2049	29.7	25,000,000	25,000,000	0	0.00	187,500	0.750	312,000		1.25	24,500,500	98.002	30	4.238%	1,059,574
26																			
27																			
	* Forecasted Amount					$779,700,000	$779,700,000	$0		$5,428,838		$19,927,158			$754,344,004			5.233%	$40,798,785
WEIGHTED EMBEDDED COST:						$40,798,785	$779,700,000	EQUALS =	5.233%										

[1] INCLUDES $992,143 PREMIUM, $178,966 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 9.75% SERIES BONDS, AND $148,605 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 15.375% SERIES BONDS ALLOCATED TO THE 7.74% SERIES.
[2] INCLUDES $826,786 PREMIUM, $149,139 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 9.75% SERIES BONDS, AND $123,837 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 15.375% SERIES BONDS ALLOCATED TO THE 7.72% SERIES.
[3] INCLUDES $496,071 PREMIUM, $89,483 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 9.75% SERIES BONDS, AND $74,302 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 15.375% SERIES BONDS ALLOCATED TO THE 7.85% SERIES.
[4] INCLUDES $150,000 PREMIUM AND $405,971 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 7.50% SERIES BONDS, $413,600 PREMIUM AND $1,116,479 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 7.52% SERIES BONDS AND $730,000 PREMIUM AND $136,800 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 7.25% SERIES BONDS ALLOCATED TO 5.62% SERIES.
[5] INCLUDES $10,096,000 COSTS PAID ON INTEREST RATE HEDGE LOSS AND $298,058 UNAMORTIZED COSTS ON SHELF REGISTRATION, ALLOCATED TO 5.37% SERIES.
[6] In November 2009 one investor exercised its right under a one-time put option to redeem $0.3 million of the $20 million outstanding. This one-time put option has now expired, and the remaining $19.7 million remaining principal outstanding is expected to be redeemed at maturity in November 2027.

Market Implied Treasury Forwards

	2017		2018				2019				2020				2021			
Indices	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
Fed Funds	1.16	1.35	1.44	1.52	1.59	1.67	1.68	1.74	1.74	1.74	1.76	1.79	1.82	1.85	1.88	1.90	1.92	1.94
3 Month LIBOR	1.36	1.58	1.69	1.80	1.88	1.92	1.97	2.01	2.04	2.08	2.11	2.14	2.17	2.20	2.22	2.25	2.28	2.31
5 Year UST Note	1.96	2.05	2.11	2.17	2.23	2.29	2.35	2.40	2.46	2.51	2.56	2.61	2.64	2.67	2.69	2.70	2.72	2.74
10 Year UST Note	2.35	2.42	2.46	2.51	2.55	2.59	2.63	2.68	2.72	2.76	2.79	2.83	2.86	2.88	2.90	2.92	2.94	2.97
30 Year UST Bond	2.88	2.91	2.93	2.94	2.96	2.98	3.00	3.02	3.04	3.05	3.07	3.08	3.10	3.11	3.12	3.13	3.14	3.14

Source: Bloomberg, as of October 11, 2017

Senior Secured Utility Bond Issues June 2016 to Current

	11/14/2017	11/13/2017	11/9/2017	11/9/2017	9/18/2017	9/11/2017
Utility Summary	Entergy Texas Inc.	Florida Power & Light Co.	Entergy Mississippi	Duke Energy Carolinas	Oncor Electric Delivery Co.	PECO Energy Co.
	10-year	30-year	10-year	30-year	30-year	30-year
Deal Details						
Coupon (%)	3.450%	3.700%	3.250%	3.700%	3.800%	3.700%
Amount ($mm)	$150	$700	$150	$550	$325	$325
Maturity	Dec 1, 2027	Dec 1, 2047	Dec 1, 2027	Dec 1, 2047	Sep 30, 2047	Sep 15, 2047
Security	FMB	FMB	FMB	FMB	FMB	FMB
Ratings	Baa1/A	Aa2/A/AA-	A2/A	Aa2/A	A3/A/BBB+	Aa3/A-/A
Outlook	S/P	S/S/S	S/P	S/S	S/P/P	S/S/S
Pricing Info (bps)						
IPT	T+115 bps	T+95-100 bps	T+100-105 bps	T+100 bps	T+115 bps	T+115 bps
Guidance	T+115 bps	T+90 bps	-	T+90 bps	T+100 bps	T+100 bps
Range	+/-5 bps	+/-2.5 bps	-	+/-5 bps	+/-5 bps	+/-2 bps
Priced	T+110 bps	T+87.5 bps	T+95 bps	T+90 bps	T+100 bps	T+98 bps
Tightening	(5 bps)	(10 bps)	(7.5 bps)	(10 bps)	(15 bps)	(17 bps)
New Issue Concession	5 bps	5-10 bps	Flat	7 bps	Flat	2 bps
Demand						
Order Books ($mm)	$180	$1,400	$250	$1,270	$1,000	$875
Over Subscription	1.2x	2.0x	1.7x	2.3x	3.1x	2.7x

	9/6/2017	9/6/2017	9/6/2017	9/5/2017	9/5/2017	9/5/2017
Utility Summary	Northwest Natural Gas Co.		Northern States Power Minnesota	Duke Energy Progress		Southern California Edison
	10-year	30-year	30-year	3-year	30-year	30-year
Deal Details						
Coupon (%)	2.822%	3.685%	3.600%	FRN	3.600%	4.000%
Amount ($mm)	$25	$75	$600	$300	$500	$300
Maturity	Sep 13, 2027	Sep 13, 2047	Sep 15, 2047	Sep 8, 2020	Sep 15, 2047	Apr 1, 2047
Security	FMB	FMB	FMB	FMB	FMB	FMB
Ratings	A1/AA-		Aa3/A/A+	Aa3/A		Aa3/A/A+
Outlook	S/S		S/S/S	S/S		S/S/S
Pricing Info (bps)						
IPT	T+90 bps	T+110 bps	T+105 bps	3mL+low 20 bps	T+110 bps	T+100 bps
Guidance	-	-	T+95 bps	3mL+20 bps	T+95 bps	T+90 bps
Range	-	-	+/-2 bps	+/-2 bps	+/-3 bps	+/-2.5 bps
Priced	T+75 bps	T+100 bps	T+93 bps	3mL+18 bps	T+92 bps	T+90 bps
Tightening	(15 bps)	(10 bps)	(12 bps)	(5 bps)	(18 bps)	(10 bps)
New Issue Concession	n/a	n/a	3 bps	Flat	1 bps	2 bps
Demand						
Order Books ($mm)	$126	$150	$900	$450	$825	$700
Over Subscription	5.0x	2.0x	1.5x	1.5x	1.7x	2.3x

Senior Secured Utility Bond Issues June 2016 to Current

	8/16/2017	8/16/2017	8/8/2017	8/2/2017	7/31/2017	6/12/2017
Utility Summary	**Commonwealth Edison Co.**		**Connecticut Light & Power**	**Southwestern Public Service**	**DTE Electric Co.**	**Public Service Co. of Colorado**
	10-year	**30-year**	**30-year**	**30-year**	**30-year**	**30-year**
Deal Details						
Coupon (%)	2.950%	3.750%	4.300%	3.700%	3.750%	3.800%
Amount ($mm)	$350	$650	$225	$450	$440	$400
Maturity	Aug 15, 2027	Aug 15, 2047	Apr 15, 2044	Aug 15, 1947	Aug 15, 2047	Jun 15, 2047
Security	FMB	FMB	FMB	FMB	FMB	FMB
Ratings	A1/A-/A		A2/A+/A+	A2/A/A-	Aa3/A/A+	A1/A/A+
Outlook	S/S/S		S/P/S	S/S/S	S/S/N	S/S/S
Pricing Info (bps)						
IPT	T+85-90 bps	T+105-110 bps	T+100-105 bps	T+105 bps	T+105 bps	T+115 bps
Guidance	T+78 bps	T+98 bps	-	T+90 bps	T+87.5 bps	T+95-100 bps
Range	+/-3 bps	+/-3 bps	-	+/-2 bps	+/-2.5 bps	-
Priced	T+75 bps	T+95 bps	T+85 bps	T+88 bps	T+85 bps	T+ 95 bps
Tightening	(12.5 bps)	(12.5 bps)	(17.5 bps)	(17 bps)	(20 bps)	(20 bps)
New Issue Concession	Flat	3 bps	Flat	Flat	-2 bps	Flat
Demand						
Order Books ($mm)	$1,000	$1,200	$750	$1,500	$1,400	$1,250
Over Subscription	2.9x	1.8x	3.3x	3.3x	3.2x	3.1x

	6/6/2017	6/5/2017	5/17/2017	5/17/2017	5/15/2017	5/9/2017
Utility Summary	**Ameren Union Electric**	**San Diego Gas & Electric Co.**	**Entergy Louisiana**	**Rochester Gar & Electric Corp.**	**Potomac Electric Power Co.**	**Monongahela Power Co.**
	10-year	**30-year**	**10-year**	**10-year**	**30-year**	**10-year**
Deal Details						
Coupon (%)	2.950%	3.750%	3.120%	3.100%	4.150%	3.550%
Amount ($mm)	$400	$400	$450	$300	$200	$250
Maturity	Jun 15, 2027	Jun 1, 2047	Sep 1, 2027	Jun 1, 2027	Mar 15, 2043	May 15, 2027
Security	FMB	FMB	FMB	FMB	FMB	FMB
Ratings	A2/A	Aa2/A+/AA-	A2/A	A1/A/A	A2/A/A-	A3/BBB+/BBB+
Outlook	S/S	S/S/S	S/S	S/S/S	S/S/S	S/N/S
Pricing Info (bps)						
IPT	T+90-95 bps	T+115 bps	T+100 bps	T+100-105 bps	T+110 bps	T+135 bps
Guidance	-	T+95 bps	-	-	-	T+120 bps
Range	-	+/-2 bps	-	-	-	+/-5 bps
Priced	T+ 85 bps	T+93 bps	T+90 bps	T+90 bps	T+100 bps	T+115 bps
Tightening	(7.5 bps)	(22.5 bps)	(10 bps)	(12.5 bps)	(10 bps)	(20 bps)
New Issue Concession	0-5 bps	-2 bps	2.5 bps	2 bps	2 bps	-5 bps
Demand						
Order Books ($mm)	$800	$1,500	$1,000	$850	$350	$625
Over Subscription	2.0x	3.8x	2.2x	2.8x	1.8x	2.5x

Senior Secured Utility Bond Issues June 2016 to Current

Utility Summary	5/9/2017 Entergy Arkansas Inc.	5/8/2017 PPL Electric Utilities Corp.	5/2/2017 Public Service Electric & Gas Co.	4/19/2017 Basin Electric Power Co-Op	3/22/2017 Duke Energy Ohio	3/21/2017 Southern California Edison Co.
	10-year	30-year	10-year	30-year	30-year	30-year
Deal Details						
Coupon (%)	3.500%	3.950%	3.000%	4.750%	3.700%	4.000%
Amount ($mm)	$220	$475	$425	$500	$100	$700
Maturity	Apr 1, 2026	Jun 1, 2047	May 15, 2027	Apr 26, 1947	Jun 15, 2046	Apr 1, 2047
Security	FMB	FMB	FMB	FMB	FMB	FMB
Ratings	A2/A	A1/A	Aa3/A	A3/A/A	A2/A/A	Aa3/A/A+
Outlook	S/P	S/S	S/S	S/N/N	S/S/S	S/S/S
Pricing Info (bps)						
IPT	T+95 bps	T+115 bps	T+85-90 bps	Very Low 200s	T+107 bps	T+105-110 bps
Guidance	T+85 bps	T+100 bps	T+75 bps	T+195 bps	-	-
Range	+/-5 bps	+/-2 bps	+/-2 bps	+/-5 bps	-	-
Priced	T+80 bps	T+98 bps	T+73 bps	T+190 bps	T+107 bps	T+95 bps
Tightening	(15 bps)	(17 bps)	(14.5 bps)	(20 bps)	(0 bps)	(12.5 bps)
New Issue Concession	-1 bps	-2 bps	Flat	n/a	Flat	3 bps
Demand						
Order Books ($mm)	$525	$1,400	$950	$1,100	$350	$1,400
Over Subscription	2.4x	2.9x	2.2x	2.2x	3.5x	2.0x

Utility Summary	3/2/2017 Connecticut Light & Power	2/27/2017 Westar Energy Inc.	2/15/2017 Consumers Energy Co	1/23/2017 MidAmerican Energy Co.	1/23/2017 MidAmerican Energy Co.	1/9/2017 Centerpoint Energy Houston Electric
	10-year	10-year	30-year	10-year	30-year	10-year
Deal Details						
Coupon (%)	3.200%	3.100%	3.950%	3.100%	3.950%	2.500%
Amount ($mm)	$300	$300	$350	$375	$475	$300
Maturity	Mar 15, 2027	Apr 1, 2027	Jul 15, 1947	May 1, 2027	Aug 2, 1947	Feb 1, 2027
Security	FMB	FMB	FMB	FMB	FMB	FMB
Ratings	A2/A+/A+	A2/A	A1/A/A+	Aa2/A+/A+		A1/A/A
Outlook	S/P/P	S/N	P/S/S	S/S/S		S/D/S
Pricing Info (bps)						
IPT	T+90 bps	T+95-100 bps	T+110 bps	T+85-90 bps	T+110-115 bps	T+85 bps
Guidance	T+80 bps	T+80 bps	T+90 bps	T+75 bps	T+100 bps	T+75 bps
Range	+/-5 bps	+/-2.5 bps	+/-2.5 bps	T+5 bps	T+5 bps	T+5 bps
Priced	T+75 bps	T+78 bps	T+87.5 bps	T+70 bps	T+95 bps	T+70 bps
Tightening	(15 bps)	(20 bps)	(22.5 bps)	(17.5 bps)	(17.5 bps)	(15 bps)
New Issue Concession	-1 bps	-8 bps	-3 bps	Flat	Flat	Flat
Demand						
Order Books ($mm)	$1,300	$1,000	$1,450	$1,400	$2,100	$525
Over Subscription	4.3x	3.3x	4.1x	3.7x	4.4x	1.8x

Senior Secured Utility Bond Issues June 2016 to Current

Utility Summary	1/4/2017 Duke Energy Florida 3-year	1/4/2017 Duke Energy Florida 10-year	12/5/116 Delmarva Power & Light 30-year	11/29/2016 Northwest Natural Gas Co. 2-year	11/29/2016 Northwest Natural Gas Co. 10-year	11/29/2016 Northwest Natural Gas Co. 30-year
Deal Details						
Coupon (%)	1.850%	3.200%	4.150%	1.545%	3.211%	4.136%
Amount ($mm)	$250	$650	$175	$75	$35	$40
Maturity	Jan 15, 2020	Jan 15, 2027	May 15, 2045	Dec 5, 2018	Dec 5, 2026	Dec 5, 2046
Security	FMB	FMB	FMB	FMB	FMB	FMB
Ratings	A1/A/A		A2/A/A	A1/AA-		
Outlook	S/N/S		S/S/S	S/S		
Pricing Info (bps)						
IPT	T+55 bps	T+90 bps	T+120 bps	T+50 bps	T+90 bps	T+110 bps
Guidance	T+45 bps	T+80 bps	-	T+50 bps	-	-
Range	T+5 bps	T+5 bps	-	+/-5 bps	-	-
Priced	T+40 bps	T+75 bps	T+105bps	T+45 bps	T+90 bps	T+110 bps
Tightening	(15 bps)	(15 bps)	(15 bps)	(5 bps)	-	-
New Issue Concession	Flat to -5 bps	Flat to -5 bps	Flat	n/a	n/a	n/a
Demand						
Order Books ($mm)	$750	$1,600	$510	$250	$125	$125
Over Subscription	3.0x	2.5x	2.9x	3.3x	3.6x	3.1x

Utility Summary	11/29/2016 Ameren Illinois Co. 30-year	11/14/2016 Duke Energy Carolinas 10-year	9/28/2016 Entergy Louisiana 10-year	9/14/2016 PECo Energy 5-year	9/13/2016 Duke Energy Progress 30-year	9/8/2016 Entergy Mississippi 60-year (NC 5)
Deal Details						
Coupon (%)	4.150%	2.950%	2.400%	1.700%	3.700%	4.900%
Amount ($mm)	$240	$600	$400	$300	$450	$260
Maturity	Mar 15, 2046	Dec 1, 2026	Oct 1, 2026	Sep 15, 2021	Oct 15, 2046	Oct 1, 2066
Security	FMB	FMB	FMB	FMB	FMB	FMB
Ratings	A1/A/A	Aa2/A/AA-	A2/A	Aa3/A-/A	Aa3/A/A+	A3/A
Outlook	S/S/S	S/N/S	S/S	S/S/S	S/N/S	S/S
Pricing Info (bps)						
IPT	T+110 bps	T+87.5 bps	T+110 bps	T+70 bps	T+135-140 bps	4.950%
Guidance	-	-	T+95 bps	T+55 bps	T+125 bps	4.950%
Range	-	-	+/-5 bps	+/-5 bps	+/-2 bps	+/-5 bps
Priced	T+100 bps	T+75 bps	T+90 bps	T+50 bps	T+123 bps	4.900%
Tightening	(10 bps)	(12.5 bps)	(20 bps)	(20 bps)	(14.5 bps)	(5 bps)
New Issue Concession	5 bps	1 bps	-3 bps	-3 bps	3 bps	Flat
Demand						
Order Books ($mm)	$510	$900	$1,200	$1,200	$1,100	n/a
Over Subscription	2.1x	1.5x	3.0x	4.0x	2.4x	n/a

Senior Secured Utility Bond Issues June 2016 to Current

	9/7/2016	9/6/2016	8/15/2016	8/8/2016	8/5/2016	8/1/2016
Utility Summary	**Public Service Electric & Gas**	**Duke Energy Florida**	**Oncor Electric Delivery Co.**	**Centerpoint Energy Houston Electric**	**Southwestern Public Service**	**Consumers Energy**
	10-year	**30-year**	**30-year**	**10-year**	**30-year**	**30-year**
Deal Details						
Coupon (%)	2.250%	3.400%	3.750%	2.400%	3.400%	3.250%
Amount ($mm)	$425	$600	$175 (reopening	$300	$300	$450
Maturity	Sep 15, 2026	Oct 1, 2046	Apr 1, 1945	Sep 1, 2026	Aug 15, 2046	Aug 15, 2046
Security	FMB	FMB	FMB	FMB	FMB	FMB
Ratings	Aa3/A	A1/A/A	A3/A/BBB+	A1/A/A	A2/A/A-	A1/A/A+
Outlook	S/S	S/N/S	P/P/P	S/S/S	S/S/S	P/S/S
Pricing Info (bps)						
IPT	T+low 90s	T+130 bps Area	T+125-130 bps	T+100 bps Area	T+125 bps Area	T+120 bps Area
Guidance	T+75-80 bps	-	T+115 bps	T+85 bps	T+115 bps	T+110 bps
Range	-	-	+/-5 bps	+/-2 bps	+/-5 bps	+/-5 bps
Priced	T+75 bps	T+120 bps	T+110 bps	T+83 bps	T+110 bps	T+105 bps
Tightening	(17 bps)	(10 bps)	(15-20 bps)	(17 bps)	(15 bps)	(15 bps)
New Issue Concession	Flat	-4 bps	-4 bps	-5 bps	flat	-3 bps
Demand						
Order Books ($mm)	$1,800	$1,700	$350	$1,100	$750	$1,800
Over Subscription	4.2x	2.8x	2.0x	3.7x	2.5x	4.0x

	6/20/2016	6/20/2016	6/20/2016	6/20/2016	6/13/2016	6/13/2016
Utility Summary	**Ameren Union Electric Co.**	**Duke Energy Ohio Inc.**	**Commonwealth Edison Co.**		**Entergy Arkansas**	**Westar Energy**
	30-year	**30-year**	**10-year**	**30-year**	**10-year**	**10-year**
Deal Details						
Coupon (%)	3.650%	3.700%	2.550%	3.650%	3.500%	2.550%
Amount ($mm)	$150 (reopening)	$250	$500	$700	$55 (reopening)	$350
Maturity	Apr 15, 2045	Jun 15, 2046	Jun 15, 2026	Jun 15, 2046	Apr 1, 2026	Jul 1, 2026
Security	FMB	FMB	FMB	FMB	FMB	FMB (Green Bonds)
Ratings	A2/A/A	A2/A/A	A2/A-/A		A2/A-	A2/A/A
Outlook	S/S/S	S/N/S	P/S/S		S/P	S/N/N
Pricing Info (bps)						
IPT	T+135-140 bps	T+140 bps Area	T+110 bps Area	T+140 bps Area	T+115 bps Area	T+110 bps Area
Guidance	T+125 bps	T+130 bps	T+95 bps	T+125 bps	T+95 bps	T+100 bps
Range	+/-5 bps	+/-5 bps	+/-5 bps	+/-5 bps	+/-5 bps	+/-5 bps
Priced	T+120 bps	T+125 bps	T+87.5 bps	T+120 bps	T+90 bps	T+95 bps
Tightening	(17.5 bps)	(15 bps)	(22.5 bps)	(20 bps)	(25 bps)	(15 bps)
New Issue Concession	5-10 bps	-5 bps	-2.5 bps	5-10 bps	5 bps	5 bps
Demand						
Order Books ($mm)	$750	$700	$1,700	$2,000	$200	$525
Over Subscription	3.6x	2.8x	3.4x	2.9x	3.6x	1.5x

Senior Secured Utility Bond Issues June 2016 to Current

Utility Summary	6/8/2016 South Carolina Electric & Gas	6/8/2016 South Carolina Electric & Gas	6/6/2016 Public Service Co. of Colorado
	30-year	50-year	30-year
Deal Details			
Coupon (%)	4.100%	4.500%	3.550%
Amount ($mm)	$425	$75	$250
Maturity	Jun 15, 2046	Jun 1, 2064	Jun 15, 1946
Security	FMB	FMB	FMB
Ratings	A3/A		A1/A/A+
Outlook	N/S		S/S/S
Pricing Info (bps)			
IPT	T+165-170 bps	T+210-215 bps	T+115 bps
Guidance	T+165 bps	-	T+105 bps
Range	+/-5 bps	-	+/-5 bps
Priced	T+160 bps	T+210 bps	T+105 bps
Tightening	(7.5 bps)	(2.5 bps)	(10 bps)
New Issue Concession	10 bps	25 bps	flat
Demand			
Order Books ($mm)	$760	$165	$625
Over Subscription	1.8x	2.2x	2.5x

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CREDIT OPINION
24 February 2017

Update

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RATINGS

Northwest Natural Gas Company

Domicile	Portland, Oregon, United States
Long Term Rating	(P)A3
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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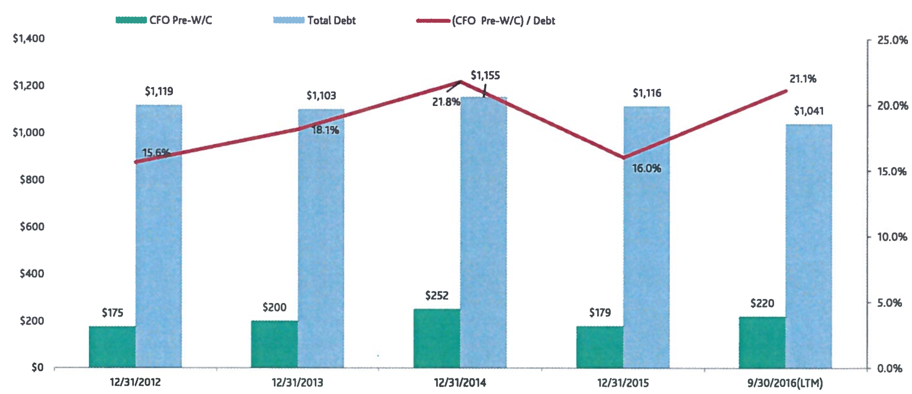
Northwest Natural Gas Company

Largest Local Gas Distribution Company in the Pacific Northwest

Summary Rating Rationale

Northwest Natural Gas' (NWN) A3 senior unsecured rating reflects its low business risk as a local gas distribution company (LDC) and a supportive regulatory environment in Oregon, its primary regulatory jurisdiction. NWN also benefits from stable and predictable cash flow derived from a suite of cost recovery mechanisms, but is challenged by a high payout ratio that exacerbates its weak financial position compared to A3 peers.

Exhibit 1
CFO Pre-W/C, total debt ($ million) and CFO Pre-W/C to debt ratio



Source: Moody's Investors Service

Credit Strengths

» Low business risk local gas distribution company

» Supportive regulatory jurisdiction with timely cost recovery provisions

» Improved financial profile through 3Q16

Credit Challenges

» Weak financial metrics versus peers

» Over 80% dividend payout ratio

» Long-term risks associated with environmental remediation costs

Rating Outlook

NWN's stable rating outlook reflects a supportive regulatory environment in Oregon, low business risk operations and the stable cash flow generation associated with being a gas distribution company. These supportive features help to offset a weak financial profile for its rating.

The outlook also incorporates cash flow from operations before changes in working capital (CFO pre-WC) to debt expectations of around 17% on a sustainable basis.

Factors that Could Lead to an Upgrade

An upgrade would be considered with a material improvement to NWN's financial profile, such that cash flow from operations pre-working capital (CFO pre-WC) to debt is over 20% and CFO pre-WC less dividends to debt is over 15%, on a sustained basis.

Factors that Could Lead to a Downgrade

Since NWN's rating balances strong regulatory support that counterbalances a weak financial profile, any decline in the degree of ongoing OPUC support would likely trigger negative ratings pressure. Also, negative ratings action could take place if NWN were to produce ongoing CFO pre-WC to debt below 16%, or if the company's high dividend payout were to reduce CFO pre-WC less dividends to debt to below 12%, on a sustainable basis.

Key Indicators

Exhibit 2

KEY INDICATORS [1]
Northwest Natural Gas Company

	12/31/2012	12/31/2013	12/31/2014	12/31/2015	9/30/2016(L)
CFO pre-WC + Interest / Interest	4.4x	4.8x	6.0x	4.5x	5.5x
CFO pre-WC / Debt	15.6%	18.1%	21.8%	16.0%	21.1%
CFO pre-WC – Dividends / Debt	11.3%	13.7%	17.4%	11.6%	16.3%
Debt / Capitalization	48.8%	46.2%	47.1%	46.0%	44.2%

All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Detailed Rating Considerations

SUPPORTIVE REGULATORY ENVIRONMENT OFFERS SUITE OF COST RECOVERY MECHANISMS

NWN's low business risk profile is supported by gas distribution operations that receive supportive regulatory treatment from the Oregon Public Utility Commission (OPUC). NWN enjoys a suite of cost recovery mechanisms that provide stability and predictability of cash flow (e.g., there is very little variability around NWN's net income plus depreciation of $150 million over the last four years), which helps to offset a degree of financial weakness compared to similarly rated peers.

These mechanisms include: NWN's use of forward test years for capital expenditures; weather adjusted rate mechanism (WARM); conservation tariff (i.e., revenue decoupling); purchased gas adjustment (PGA); utility gas reserve investments included in rate base; pension balancing account; and a Site Remediation and Recovery Mechanism (SRRM), primarily for the recovery of manufactured gas plant environmental expenditures. These various cost recovery mechanisms help to support the recovery of the most significant costs that NWN faces.

WEAK FINANCIAL PROFILE VERSUS PEERS

NWN's high payout ratio and low cash flow to debt metrics position the company weakly compared to LDC peers. For example, the company's 2012-LTM 3Q16 payout and CFO pre-WC to debt metrics of around 86% and 20% are worse than rated LDC peers averaging 70% and 23%, respectively.

That said, reduced leverage to $1.0 billion as of September 2016, from $1.1 billion as of December 2015 has improved NWN's CFO pre-WC to debt, which is more in-line with peers producing low-20% metrics. Following the 4Q16 issuance of $150 million of debt (see the Liquidity section, below), we expect this ratio to be around 18%. Going forward, we estimate that the company to produce around 17% CFO pre-WC to debt, even if potential tax reform policies of the new executive administration reduce the ongoing benefit of deferred taxes for the company.

We view the very high payout ratio as a sign of a higher-risk financial policy for the company; therefore, we will pay increasing attention to the ratio of CFO pre-WC less dividends ("retained cash flow") to debt when assessing NWN's financial profile. Thorugh LTM 3Q16, NWN had retained cash flow to debt of about 16% (around 14% following the 4Q financing activity), which is more indicative of a Baa1 type metric for a low-risk LDC. Again, due partly to the aforementioned debt reduction, this ratio is improved over the 12% metric produced in 2015.

LONG-TERM RISKS ASSOCIATED WITH ENVIRONMENTAL REMEDIATION COSTS

Like many LDC's NWN is exposed to environmental liabilities belonging to properties that may require a significant amount of environmental remediation. These efforts, and associated costs, are often uncertain and subject to the orders of the Environmental Protection Agency (EPA) and state environmental agencies. The cash outlay for these efforts can be substantial and require an ample amount of liquidity.

While we view the SRRM to be an important mechanism for NWN to address such costs, we note that it does have a limited benefit to the company's near-term cash profile, since cash recovery occurs over a five year period. Therefore, if NWN were to incur a material level of costs in any given year, its cash and financial position would be impaired for some time as it waits for full recovery in authorized rates. We note that the company is able to collect interest on the balance outstanding - a positive.

For NWN, the Portland Harbor site represents its largest uncertainty, as efforts to determine a remediation plan, scope the necessary work and allocate corrective responsibility amongst various parties is ongoing. The range of present value costs estimated by the EPA for site remedial alternatives range from $791 million to $2.45 billion for Portland Harbor. We expect the ultimate plan and identification of NWN costs to be highly contentious with protracted litigation; however, we note that when the matter is resolved and costs are to be incurred, NWN's financial position could be impaired for several years. NWN's credit profile would likely decline commensurately, if the SRRM (or other regulatory provided recovery mechanism) is insufficient to maintain NWN's cash flow at levels to cover debt in the mid-to-high teens.

Liquidity Analysis

We expect NWN to maintain adequate liquidity over the next 12-18 months.

NWN has a $300 million credit facility that expires in December 2019, $100 million of which is available for issuance of letters of credit. At 30 September 2016, NWN had approximately $195 million of commercial paper outstanding. The credit facility has one financial covenant that limits NWN's debt to capitalization ratio to 70%, which the company was in compliance with as of 30 September 2016, at 50.3%.

At 30 September 2016, NWN had approximately $6 million of cash on hand and $218 million of CFO. This compares to about $131 million in capex and $50 million in dividends for the same period. We expect the company to continue to produce around $200 million of cash flow from operations over the next twelve months, which should cover capital expenditures (i.e., an average of roughly $193 million per year through 2019), leaving the need to finance its dividend, which was $50 million for 30 September 2016. NWN's dividend payout ratio has averaged about 86% for the last three years, which we expect to remain consistent going forward.

We also note that in the fourth quarter, the company issued common stock with net proceeds of $53 million and $150 million in aggregate of secured medium term notes.

NWN's next long-term debt maturity is $40 million of senior notes due August 2017, followed by an aggregate $97 million of senior notes in 2018.

Profile

Northwest Natural Gas Company (NWN) is a natural gas local distribution company (LDC), serving over 700,000 customers in Oregon (about 90% of utility margins) and Washington (about 10% of utility margins). NWN is regulated by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC). NWN also operates around 31 Bcf of underground gas storage facilities, contracts for additional gas storage outside its service area, and operates two LNG plants in its service territory.

Rating Methodology and Scorecard Factors

Exhibit 3

Rating Factors				
Northwest Natural Gas Company				
Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 9/30/2016		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.4x	A	5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	20.7%	A	17% - 21%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	16.0%	A	10% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)	45.2%	A	42% - 47%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching	0	0	0	0
a) Indicated Rating from Grid		A2		A2
b) Actual Rating Assigned		(P)A3		(P)A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2016(L).
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Ratings

Exhibit 4

Category	Moody's Rating
NORTHWEST NATURAL GAS COMPANY	
Outlook	Stable
First Mortgage Bonds	A1
Senior Secured	A1
Senior Unsecured MTN	(P)A3
Pref. Shelf	(P)Baa2
Commercial Paper	P-2

Source: Moody's Investors Service

REPORT NUMBER 1060438

S&P Global
Ratings

Research

Summary:
Northwest Natural Gas Co.

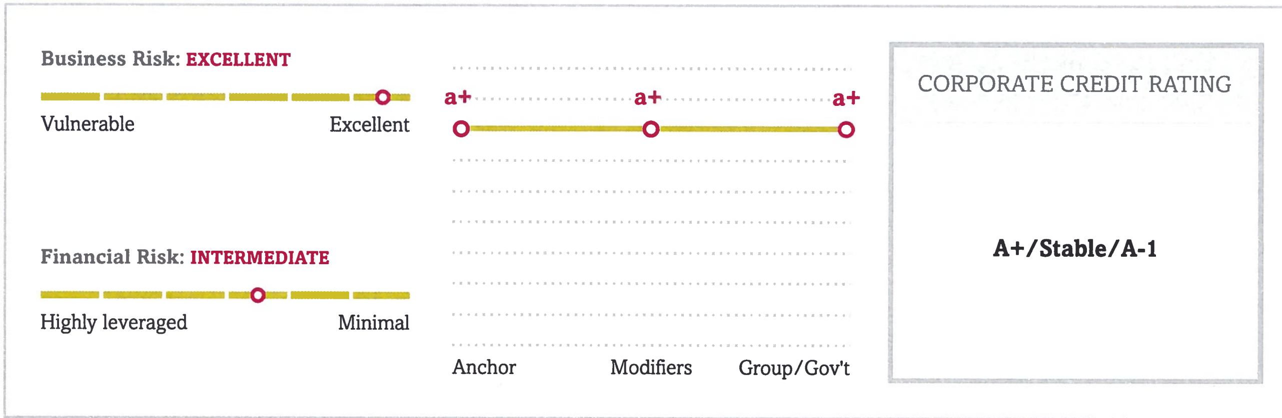
Primary Credit Analyst:
Safina Ali, CFA, New York (1) 212-438-1877; safina.ali@spglobal.com

Secondary Contact:
Gerrit W Jepsen, CFA, New York (1) 212-438-2529; gerrit.jepsen@spglobal.com

Table Of Contents

Summary:

Northwest Natural Gas Co.



Rationale

Business Risk: Excellent	Financial Risk: Intermediate
• Primarily low-risk natural gas distribution operations with limited unregulated storage operations. • Strong service territory with modest regulatory and economic diversity. • Unregulated businesses help mitigate volatility in natural gas pricing, but are subject to some commodity risk. • Multiple regulatory mechanisms help recover costs on a timely basis.	• Leverage and cash flow measures consistent with an intermediate financial risk profile. • Elevated capital spending in 2017 related to the expansion of the Mist storage facility. • Dividend payout ratio moderately higher than industry averages. • Negative discretionary cash flow over the next few years, indicating external funding needs.

Outlook: Stable

S&P Global Ratings' stable rating on Portland, Ore.-based Northwest Natural Gas Co. (NWN) reflects our expectation of strong financial and operating performance and regulatory support over the next two years. We expect funds from operations (FFO) to debt to be between 18% and 20% during this period.

Downside scenario

Ratings pressure could occur over the next two years if FFO to debt consistently drops below 15%. This could occur if the company relies heavily on external financing to fund cash shortfalls, if investments in unregulated operations exceed our expectations, or cash flows suffer due to mismanagement of regulatory risk.

Upside scenario

Although unlikely over the next two years, we could raise the ratings if the company improves financial measures on a sustained basis, including FFO to debt of more than 23%. This could occur through strengthened operating cash flow or reduced debt leverage.

Our Base-Case Scenario

Assumptions

- Low- to mid-single-digit annual-gross-margin growth in 2017 and 2018.
- Capital spending of about $160 million annually with a peak of about $250 million in 2017.
- Dividends in excess of $50 million per year.
- Cost recovery remains adequate through base rates and rate surcharges.
- Debt maturities refinanced.
- Negative discretionary cash flow from 2017 onward indicates external funding needs.

Key Metrics

	2016A	2017E	2018E
FFO to debt (%)	21.3	17-20	17-20
OCF to debt (%)	26.2	17-20	16-19
Debt to EBITDA (x)	3.6	3.9-4.3	3.9-4.3

S&P Global Ratings' adjusted figures. A--Actual. E--Estimate. FFO--funds from operations. OCF--Operating cash flow.

Business Risk: Excellent

We assess NWN's business risk based on the company's very low risk regulated gas distribution operations (accounts for about 90%-95% of consolidated cash flows) and its unregulated natural gas storage business, where we ascribe higher risk. About 90% of NWN's roughly 725,000 customers are in Oregon, primarily in the Salem and Portland metropolitan areas, remainder in Washington. The company benefits from stable and supportive regulatory environments in both of the jurisdictions it operates in, with purchased gas adjustments and environmental cost deferral in both jurisdictions, and decoupling, forward-looking test years, and weather normalization mechanisms in Oregon. These mechanisms reduce regulatory lag in collection of associated costs and help bolster cash flow stability outside of rate cases. The utility's cash flows are further stabilized by a large, stable residential customer base (about 90% of all customers) with limited exposure to more cyclical commercial and industrial customers. A history of safe and reliable services also strengthens the company's business profile.

NWN's non-utility cash flows are mostly from its Mist and Gill Ranch storage facilities, which have contributed between 5% and 10% of annual operating income. The company is expanding its gas storage facility by 2.5 Bcf at Mist, Oregon, to provide storage services to Portland General Electric Co.'s (PGE) natural gas power plants under a 30-year contract with revenues recovered through an established tariff schedule. We consider the cash flow from this asset to be fairly reliable given the essential nature of the service it provides. The investment in the Gill Ranch natural gas storage facility near Fresno, Calif., is riskier because it is outside of Oregon and faces competition. Gill Ranch enters into a mix of short- and medium-term contracts for the large majority of its total storage capacity.

After factoring in these components, we view NWN's business risk profile at the stronger end of the excellent category, supported by the company's ability to effectively manage the regulatory process, which helps support higher and more stable profitability.

Financial Risk: Intermediate

Under our base-case scenario, with elevated capital spending in 2017 to support the Mist expansion, modestly rising dividend payments, and cost recovery through various regulatory mechanisms and rate cases, we expect the company's FFO to debt measures will be about 18%-20% in 2017 and 2018. Since the range of projected FFO to total debt is solidly in the middle of the intermediate financial risk profile category, it supports a modest cushion to the ratings. We assess NWN's financial risk profile based on financial ratios that are measured against the most relaxed benchmarks used for corporate issuers, reflecting the low-risk nature of the company's natural gas distribution operations in supportive regulatory environments. We assume that NWN will continue to manage regulatory risk well and fully recover capital spending on a timely basis.

Liquidity: Adequate

We assess liquidity as adequate for Northwest Natural Gas Co. because we believe sources are likely to cover uses by more than 1.1x over the next 12 months. We also project sources will meet cash outflows even in the event of a 10% decline in EBITDA. The adequate assessment also reflects the company's generally prudent risk management, sound relationships with banks, and generally satisfactory standing in credit markets.

Principal Liquidity Sources	Principal Liquidity Uses
• Forecast cash FFO of about $180 million • Revolving credit facilities of about $300 million.	• Debt maturities, including outstanding commercial paper, of about $90 million • Capital spending of about $225 million • Dividends of about $55 million.

Other Credit Considerations

Other modifiers have no effect on the rating outcome.

Group Influence

NWN is subject to the group rating methodology criteria. We view NWN as the parent and driver of the group credit profile. As a result, NWN's group and stand-alone credit profiles are the same at 'a+'.

Recovery Analysis/Issue Rating

NWN's first mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

The short-term rating on NWN is 'A-1' based on the issuer credit rating and our assessment of its liquidity as at least adequate.

Ratings Score Snapshot

Corporate Credit Rating

A+/Stable/A-1

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Intermediate

- **Cash flow/Leverage:** Intermediate

Anchor: a+

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a+

- **Group credit profile:** a+

Related Criteria And Research

- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19,2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Criteria - Corporates - General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Debt Now Better Reflects Anticipated Absolute Recovery, Nov. 10, 2008
- Utilities: Notching Of U.S. Investment-Grade Investor-Owned Utility Unsecured, Nov. 10, 2008
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	**a+/a**	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

NW Natural
Debt Ratings History
2010-2017

		Credit Ratings				
	Effective Date	Secured	Unsecured	Outlook	Pref Stk	CP
Standard & Poors	**Current**	**AA-**	**A+**	**Stable**		**A-1**
Ratings History	Pre 2010	AA-	AA-	Negative	A	A-1+
Downgrade (1)	1/25/2010	AA-	A+	Stable	A-	A-1
Downgrade (2)	6/16/2010	A+	A+	Stable		A-1
Upgrade Secured Only (3)	3/12/2013	AA-	A+	Stable		A-1
Moody's Investor Service	**Current**	**A1**	**A3**	**Stable**	**Baa2**	**P-2**
Ratings History:	Pre 2010	A1	A3	Stable	Baa2	P-1
Downgrade (4)	12/19/2012	A1	A3	Negative	Baa2	P-2
Upgrade Outlook (5)	2/18/2014	A1	A3	Stable	Baa2	P-2

Explanation for Ratings Changes:

(1) Reason for the corporate credit rating downgrade was expectations for incremental business and financial risks associated with nonregulated investments that are not sufficiently supported by cash flow generation at the 'AA' level.

(2) Reason for the downgrade was a correction by S&P to the calculation of NW Natural's recovery rating on its senior secured debt. S&P had assigned a '1+' recovery rating, but revised their number to '1' in January 2010. NW Natural's net assets pledged ($1.4 billion) to FMB program divided by the maximim FMB's ($1.1 billion) allowed results in a ratio of 1.3x. Results between 1.0 and 1.5 are generally assigned a '1' recovery rating by S&P. Only results above 1.5x are assigned the highest '1+' recovery rating.

(3) Reason for the upgrade was due to a change in Standard and Poor's recovery methodology on senior bonds secured by utility real property. NW Natural's recovery rating changed from '1' to '1.5', which aligns with a 'AA-' or better rating.

(4) Moody's changed outlook to negative and downgrades the short-term rating from P-1 to P-2. The reasons for the change in outlook Moody's cited continued weakness and expectation of further deterioration in finacial metrics, outcome of the 2012 OPUC rate case, negative impact on cashflows from elevated capital expenditures and stable dividend policy. Reasons cited for the change in short-term rating were primarily due to the change in outlook and aligns with other A3-rated issures in the utility sector.

(5) Moody's changed outlook to Stable as a result of a more favorable view of US regulation and the strong support that Oregon regulation offers NWN.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Direct Testimony of Dr. Bente Villadsen

RETURN ON EQUITY
EXHIBIT 400

December 2017

EXHIBIT 400 – DIRECT TESTIMONY - RETURN ON EQUITY

Table of Contents

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

I. INTRODUCTION AND SUMMARY

Q. Please state your name, occupation and relationship with NW Natural Company ("NW Natural").

A. My name is Bente Villadsen and I am a principal at The Brattle Group (Brattle). My business address is The Brattle Group, One Beacon St., Suite 2600, Boston, MA 02108. I have been asked by NW Natural "the Company") to estimate the cost of equity that NW Natural, a natural gas Local Distribution Company (LDC), should be allowed an opportunity to earn on the equity portion of its rate base for the period after November 1, 2018.

My qualifications are included at the end of my testimony.

Q. Please summarize your results.

A. The results I arrived at are detailed in Table 1 below.[1]

Table 1: Summary of ROE Estimates for NW Natural[2]

	Estimates	Reasonable Range
Multi-Stage DCF	9.1% - 10.0%	9.4% - 10.0%
Other DCF	12.5% - 12.9%	Used as directional indicator
Risk Premium Models	10.2% - 10.3%	10.2% - 10.3%
Other Tests	9.9% - 12.2%	9.9% - 10.8%
Recommended Range		**9.7% – 10.3%**

1 The Public Utility Commission of Oregon (Commission) has, in the past, given no weight to the CAPM (Order 01-777, p. 32) and preferred analyses using the Discounted Cash Flow Model (Order 12-437 in UG-221, p. 6). Therefore, I use the CAPM as a check on the other estimates rather than a primary method in this matter.

2 Data cited in Table 1 use all sample companies.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

I understand that the Commission in the past has relied primarily on the Discounted Cash Flow (DCF) model and in particular the multi-stage DCF model, which I estimate at 10.0% for my full sample using a combination of the Office of Management and Budget (OMB) and Blue-Chip GDP long-term growth rate (the results indicate 9.4% using Blue Chip alone and 10.5% using OMB alone).[3] Thus, the multi-stage DCF model results in estimates that are below the range for other methods, but NW Natural's smaller market capitalization warrants a size premium of 20-25 basis points, which, if added to the estimated ROE, would result in a multi-stage DCF result of 9.6% - 10.25%.[4] Other DCF models provide results in the range of 12.5% to 12.9%. I do not explicitly rely on this estimate, but note that it indicates that the multi-stage DCF method may be too low. Therefore, I consider eliminating the lowest multi-stage DCF estimates to be reasonable. The risk premium model in turn results in estimates of 10.2% and 10.3%. My implementation of the CAPM model results in a range of 9.9% to 12.2%, but this range is narrowed to 9.9% - 10.8% if I focus on an implementation that relies on the historic Market Risk Premium (MRP) and eliminates the highest estimate to be conservative. Looking to these results I

[3] I use the consensus forecast of 4.2% for the nominal GDP growth rate for 2024-2028 from the October 2017 Edition of Blue Chip Economic Indicators.

[4] I note that according to Duff and Phelps / Ibbotson, "SBBI 2017 Classic Yearbook," (SBBI 2017) pp. 7-3, NW Natural's market capitalization makes it a decile 3 company, whereas the average of the comparable companies is decile 2 in terms of size. According to page 7-16, the size premium that is warranted for a company of NW Natural's size relative to the comparable companies is 28 basis points.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

consider a range of 9.7% to 10.3%[5] around the Commission's preferred multi-stage DCF model and supported by other methods – in fact, all tests have results within that range with the CAPM and risk premium-based models overlapping the upper half, and the multi-stage DCF results overlapping the lower half. The midpoint of this range is 10%. Therefore, I fully support a Return on Equity of 10.0%. I also note that the average allowed ROE for gas LDCs to date in 2017 is 9.76%.[6] Recently allowed ROE's for gas LDCs have been higher averaging a bit over 10% for September 1 through Nov.

Q. How did you estimate the ROE for NW Natural?

A. To assess the cost of capital for NW Natural, I start by selecting a sample of gas LDCs from Value Line's universe of gas LDCs. The sample companies are selected to be comparable to NW Natural, so I include gas LDCs that have more than 50% regulated assets. In addition, the companies are screened based on financial criteria such as credit ratings and on data availability. For each company, I then estimated the cost of equity using standard methods including two versions of the DCF model, the risk premium model, a review of recently allowed ROE, and, as a test, two versions of the Capital Asset Pricing Model (CAPM). I ensure consistency between the capital structure used to derive the cost of equity estimates and NW Natural's regulatory capital structure and also

---

5 Mathematically, this range narrows the full range listed in Table 1 symmetrically.

6 SNL Financial as of 12/1/2017. Regulatory Research Associates, "Major Rate Case Decisions January – September 2017," October 26, 2017 reports an average of 9.75%.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

evaluate critical risk factors that may differ between NW Natural and the sample. I also note that the average credit rating in my sample is A- using Standard & Poor's (S&P) ratings, while S&P rates NW Natural A+ (Moody's rates NW Natural at A3).[7] Because some companies are in the process of being acquired (e.g., WGL) or have indicated they are considering a merger (New Jersey Resources and South Jersey Industries), I also consider a subsample to check whether the inclusion of these companies has a material impact on the estimation results.

II. COST OF CAPITAL THEORY

A. Cost of Capital and Risk

Q. How is the "cost of capital" defined?

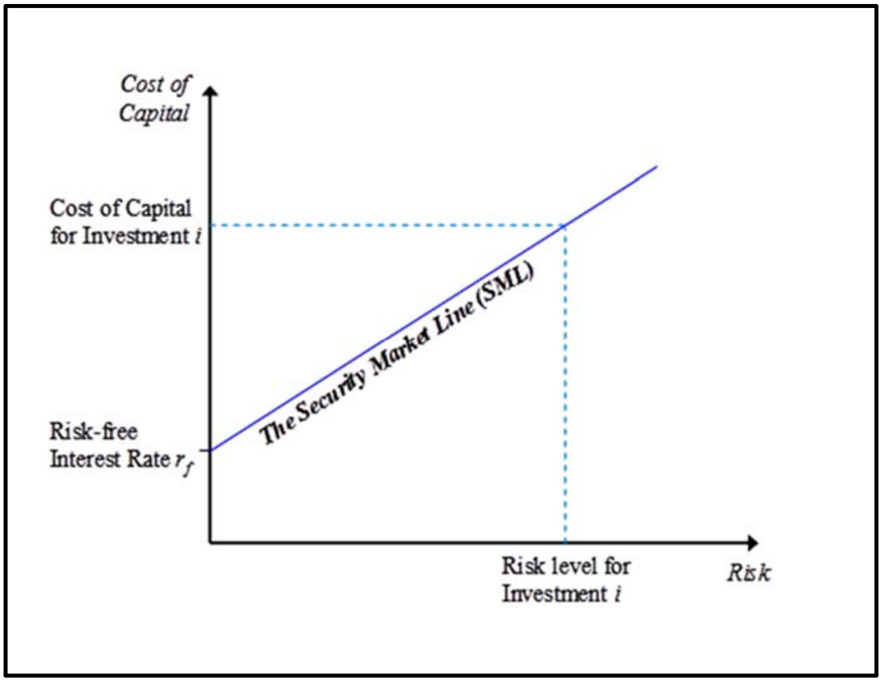
A. The cost of capital is defined as the expected rate of return in capital markets on alternative investments of equivalent risk. In other words, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected," as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

[7] Ratings cited in my work papers are S&P ratings as reported by Bloomberg. I note that a rating of A3 from Moody's typically is viewed as being equivalent to a rating of A-, the average rating for the sample.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

The definition of the cost of capital recognizes a tradeoff between risk and return that can be represented by the "security market risk-return line" or "Security Market Line" for short. This line is depicted in Figure 1 below. The higher the risk, the higher the cost of capital required.

Figure 1: The Security Market Line



Q. Why is the cost of capital relevant in rate regulation?

A. As noted above, the "cost of capital" is the return that investors expect to earn on investments of comparable risk[8] and is viewed as consistent with the U.S. Supreme Court's opinions in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), and *Federal Power*

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[8] See Stewart C. Myers, "Application of Finance Theory to Public Utility Rate Cases," *Bell Journal of Economics & Management Science* 3:58-97 (1972).

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) as well as with Oregon law, ORS 756.040, which, consistent with the Bluefield and Hope, holds that:

> Rates are fair and reasonable for the purposes of this subsection if the rates provide adequate revenue both for operating expenses of the public utility or telecommunications utility and for capital costs of the utility, with a return to the equity holder that is:
>
> (a) Commensurate with the return on investments in other enterprises having corresponding risks; and
>
> (b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital.[9]

From an economic perspective, rate levels that give investors a fair opportunity to earn the cost of capital are the lowest levels that compensate investors for the risks they bear. Over the long run, an expected return above the cost of capital makes customers overpay for service. Regulatory commissions normally try to prevent such outcomes unless there are offsetting benefits (*e.g.*, from incentive regulation that reduces future costs). At the same time, an expected return below the cost of capital does a disservice not just to investors but, importantly, to customers as well. Such a return denies the company the ability to attract capital, to maintain its financial integrity, and to expect a return commensurate with that of other enterprises attended by corresponding risks and uncertainties.

More important for customers, however, are the broader economic consequences of providing an inadequate return to the company's investors. In

[9] 2015 ORS 756.040. Available at http://www.oregonlaws.org/ors/756.040.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

the short run, deviations from the expected rate of return on the rate base from the cost of capital may seemingly create a “zero-sum game”— investors gain if customers are overcharged, and customers gain if investors are shortchanged. But in fact, in the short term, a return below the cost of capital may adversely affect the utility’s ability to provide stable and favorable rates because some potential investments that could reduce cost or otherwise be beneficial to customers may be delayed and the company may be forced to file more frequent rate cases. Moreover, in the long run, inadequate returns are likely to cost customers—and society generally—far more than may be saved in the short run. Inadequate returns lead to inadequate investment, whether for maintenance or for new plant and equipment. Without access to investor capital, the company may be forced to forgo opportunities to maintain, upgrade, and expand its systems and facilities in ways that decrease long run costs.

Indeed, the cost to consumers of an undercapitalized industry can be far greater than any short-run gains from shortfalls in the cost of capital. This is especially true in capital-intensive industries (such as the gas LDC industry), which feature systems that continually need to be replaced or upgraded. Thus, it is in customers’ interest not only to make sure the return investors expect does not exceed the cost of capital, but also to make sure that the return does not fall short of the cost of capital.

The cost of capital cannot be estimated with perfect certainty, and other aspects of the way the revenue requirement is set may mean investors expect to

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

earn more or less than the cost of capital, even if the authorized rate of return exactly equals the cost of capital.

B. The Impact of Risk on the Cost of Capital

Q. Please summarize how you consider risk when estimating the cost of capital.

A. First, I select my comparable sample to have as comparable business risks as possible to NW Natural. Second, as the cost of equity depends on the leverage of the company to which it is applied, I consider the difference in leverage between the data from which I estimate the cost of equity and NW Natural. Third, I consider any NW Natural risk that may help me place the Company within the range of my estimated cost of equity or if unique circumstances dictate it, above or below the range.

Q. Why is capital structure important for the determination of the cost of equity?

A. As shown by Hamada (1969),[10] shareholders in a company with more debt face more equity risk and the return on equity needs to increase. There are several manners in which the impact of financial risk can be taken into account. The manner in which Professor Hamada took this into account is he unlevered the beta estimates in the CAPM to obtain a so-called all-equity or assets beta and then re-levered the beta to determine the beta associated with the target

[10] Robert S. Hamada, "Portfolio Analysis, Market Equilibrium and Corporate Finance," *The Journal of Finance* 24: 13-31 (March 1969).

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Portland, OR 97209-3991
1-503-226-4211

company's capital structure. This requires an estimate of the systematic risk associated with debt (i.e., the debt beta), which is usually quite small. See *NW Natural/402, Villadsen*, Technical Appendix Section III for further technical details related to methods to account for financial risk when estimating the cost of capital. Another way to take the phenomenon into account is to determine the average overall cost of capital for the sample companies and let that figure be constant between the estimate obtained for the sample and the entity to which it is applied. This assumes that the average overall cost of capital is constant for a range that spans the capital structures used to estimate the cost of equity and the regulatory capital structure – usually a range that avoids extreme levels of debt or equity.

Q. Does this approach apply to the risk premium analysis?

A. Yes, to the extent that there are differences between the capital structures of the companies used to determine the benchmark ROE and NW Natural, I need to consider whether I am comparing apples to apples. However, because the allowed ROE usually is applied to book value capital structures, it is the book value capital structure that is relevant for the risk premium method.

Q. Are there Oregon- or other Company-specific risks that impact NW Natural?

A. Yes. Oregon and the City of Portland have climate policy initiatives to reduce the emission of carbon dioxide ("CO_2"), which likely will impact NW Natural. In

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220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

addition, NW Natural is smaller in size as measured by revenue or equity that the comparable companies.

Q. How does climate policy in the state of Oregon create risks for NW Natural?

A. Both the state of Oregon and the city of Portland have initiatives to reduce CO_2 emissions significantly. Because burning natural gas releases CO_2 into the atmosphere, these initiatives create stranded cost risks for NW Natural. Oregon is a founding member of the Pacific Coast Collaborative, which calls for reducing emission levels to two tons per capita by 2050. To this end, Oregon has committed to expand on existing programs to establish a price on CO_2 emissions[11] and to reducing its greenhouse gas emissions by 10% in 2020 and by 75% in 2050 (relative to 1990 levels).[12] Similarly, the city of Portland has committed to reducing CO_2 emissions by 40% in 2030 and by 80% in 2050 (relative to 1990 levels).[13]

In addition to these initiatives, the state of Oregon has a history of pursing policies to reduce CO_2 emissions. In 2010, Oregon's Environmental Quality Commission negotiated a settlement with Portland General Electric (PGE) to close the state's sole coal fired power plant in 2020, rather than continuing its operations through 2040.[14] The state recently passed an aggressive renewable

11 Pacific Coast Action Plan on Climate and Energy, October 28, 2013 and Pacific Coast Climate Leadership Action Plan, June 1, 2016.

12 http://www.keeporegoncool.org/content/roadmap-2020.

13 Climate Action Plan Summary, June 2015, p. 12.

14 Learn, Scott. "PGE's coal-fired Boardman plant gets approval to close in 2020, with fewer pollution controls." *The Oregonian* 9 December 2010.

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Portland, OR 97209-3991
1-503-226-4211

portfolio standard (RPS) requiring utilities to obtain 50% of their energy from renewable sources by 2040. The bill also directs the Public Utilities Commission to exclude all costs related to coal generation from rates after 2035.[15]

State actions to date have focused on reducing coal usage and increasing renewable resource generation, but the policy focus will likely shift towards reducing reliance on natural gas. As an example, Portland recently announced plans to use renewable resources for 100% of the city's energy needs. Additionally, the city opposes plans by PGE to develop new gas-fired electric generation facilities.[16] Initiatives, such as these, designed to decrease demand for natural gas create stranded cost risks for NW Natural.

Q. Have the stranded cost risks you discuss above effected your recommended ROE for NW Natural?

A. No. Although the stranded cost risks are real, I have not adjusted my ROE calculations in any of the methods performed for NW Natural.

Q. What is NW Natural's size relative to the sample companies?

A. The majority of the publicly traded gas LDCs in the U.S., as well as the companies I select for my sample, are larger than NW Natural. For example, the average market capitalization of my sample (including NW Natural) is $3.8 billion.

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[15] Stanfield, Jeff. "Ore. Legislature passes coal phase-out bill that doubles RPS to 50%." *S&P Global* 3 March 2016.

[16] Hering, Garrett. "All-renewable Portland, Ore., 'not just a pipe dream'" S&P Global 12 April 2017.

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Portland, OR 97209-3991
1-503-226-4211

That is twice NW Natural's market capitalization of only $1.9 billion.[17] If I were to consider only NW Natural's Oregon-regulated portion the difference would be even larger.

Q. Why does the size of NW Natural matter?

A. Empirically, investors have required a higher premium to invest in smaller companies than in larger ones. For example, SBBI data indicate that NW Natural's market capitalization puts it in the 3rd size decile, while the average company in the sample falls in the 2nd size decile. Companies in the 3rd size decile on average have a return on equity that is 0.28% higher than companies in the 2nd size decile.[18] Therefore, empirical evidence suggests that investors in smaller companies require a higher return than do investors in larger companies. The majority of gas LDCs (including my sample companies) are materially larger than NW Natural. Only one company in my sample has a market cap below that of NW Natural, while 6 companies have market caps that are at least 90% greater than NW Natural.[19] Empirical evidence suggests that investors in NW Natural require a premium over and above that required for larger companies. Looking specifically to the size deciles reported in SBBI 2017, the data indicate that NW Natural's size merits a size premium of 0.20% to 0.25%.[20]

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[17] See Table 2 in Section IV (B) below for details.

[18] Roger G. Ibbotson, "*2017 SBBI Yearbook*," Duff & Phelps 2017 (SBBI 2017), p. 7-3, 7-16.

[19] See Table 2 in Section IV (B) below for details.

[20] SBBI 2017, pages 7-3 and 7-16.

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220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

Q. What conclusions do you draw from the discussion above?

A. While I do not add a specific number of basis points to my midpoint, I use the fact that NW Natural is smaller than the sample companies to ensure the recommendation, if anything, is conservative.

III. IMPACT OF THE ECONOMY AND MARKETS ON THE COST OF EQUITY

Q. What do you cover in this section?

A. This section focuses on how recent changes in capital market conditions and ongoing volatility in equity and debt markets impact the cost of equity and its estimation. Specifically, this section addresses (i) interest rate developments and the impact on cost of equity, (ii) the development in utility credit spreads and research attempting to explain such developments, (iii) investor perceptions of the market risk premium, and (iv) the current high level of market volatility.

A. Interest Rates

Q. What are the relevant developments regarding interest rates?

A. Interest rates and especially government bond yields have been low since the 2008-2009 financial crisis, but started to increase during the last two months of 2016. At the end of October 2016, 10-Year Treasury Notes yielded approximately 1.6%. By the end of October 2017, the yield on 10-Year Treasury Notes had risen to approximately 2.4%.[21] Forecasters expect the yield on

[21] U.S. Department of the Treasury, Daily Treasury Yield Rates downloaded 15 November 2017.

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Portland, OR 97209-3991
1-503-226-4211

Treasuries to continue rising. Blue Chip Economic Indicators reports a consensus estimate that the yield on 10-year Treasury Notes will rise a further 100 basis points to 3.4% by 2019.[22]

Actions taken by the Federal Reserve (Fed) also point to rising interest rates. The Fed raised the target for the Federal Funds rate on March 15, 2017 and again on June 14, 2017 and has signaled that a December 2017 increase is likely.[23] In September 2017, the Fed also announced it would begin reducing its balance sheet, starting with a $10 billion reduction in October.[24] Increasing the supply of Treasury and mortgage backed securities in circulation will tend to decrease bond prices and thus increase yields.

The recent increase in government bond yields, the increase in the Federal Funds rate, the Fed's decision to reduce its holdings of Treasuries and mortgage backed securities, as well as the projected increase in government bond yields are indicators that the current yield on government bonds is below

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22 Blue Chip Economic Indicators, October 2017.

23 The Federal Reserve increased the target for the federal funds rate from a range of ½% to ¾ percent to a range of ¾ to 1 percent on March 15, 2017 and then to a range of 1 to 1-¼ percent on June 14, 2017.

Source: Federal Reserve Press Release March 15, 2017 and Federal Reserve Press Release June 14, 2017;

https://www.federalreserve.gov/newsevents/pressreleases/monetary20170315a.htm

https://www.federalreserve.gov/newsevents/pressreleases/monetary20170614a.htm

24 Federal Reserve Press Release September 20, 2017;
https://www.federalreserve.gov/newsevents/pressreleases/monetary20170920a.htm

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Portland, OR 97209-3991
1-503-226-4211

investor expectations for the next few years.[25]

Q. How do these developments impact the cost of equity analysis?

A. Because analysts use the yield on government debt as a proxy for the risk-free rate, the expected increase in the yield on government debt will also lead to an increase in cost of equity. Current expectations that interest rates for risk-free securities will rise suggest the fair allowed return on equity for natural gas LDCs will also rise over time.

B. Yield Spreads and the Cost of Equity

Q. What are the relevant developments regarding interest rates?

A. The spread between utility bond yields and government bond yields of the same maturity remains higher than historical averages, indicating that either the government bond yield remains suppressed or that investors' required premium to invest in securities that are not risk-free is elevated. While the yield spread has declined as the Federal Funds rate has increased, it remains elevated compared with historical norms.

A. Figure 2 shows BBB rated utility and Government bond yields from 2002 to the present.[26] It is evident that the yield spread (the difference between the yield on

[25] The expectation of increasing bond yields has been slower to materialize than most forecasting services have predicted over the last few years. Researchers from the Federal Reserve Bank of St. Louis found that forecasts of U.S. T-bill rates tended to under-predict the increase when yields were increasing and over-predict when yields were declining, so that the results were closer-to-normal prediction than what materialized. They found no evidence that expectations were systematically too high or too low. See R.W. Hafer and S.E. Hein. "Comparing Futures and Survey Forecasts of Near-Term Treasury Bill Rates." *Federal Reserve Bank of St. Louis Review.* May/June, (1989), 33-42.

[26] For clarity "BBB rated" refers to bonds in the range of BBB- through BBB+ and "A rated" refers to bonds in the range of A- through A+. The majority of gas LDCs are A or high BBB rated.

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NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

BBB rated utility bonds and government bonds) is higher than its historical average.[27]

Figure 2: BBB Utility Bond and Government Bond Yields: 2002 – September 2017

Source: Bloomberg.

Q. How does the current spread between utility and government bond yields compare to the historical spread?

A. As shown in Figure 2 above, the spread between BBB rated utility bond yields and government bond yields is elevated. Over the last half of October 2017, the BBB spread stood at 1.60%, which is approximately 40 basis points higher than

27 Bloomberg data summarized in *NW Natural/407, Villadsen* shows that the spread between BBB rated utility bond yields and government bond yields averaged 1.23% between 1991 and 2007 and was only slightly above 1% for the period 2002 to 2007.

prior to the 2008-09 financial crisis. At the same time the A rated utility bond yield spread was 1.23%, for an increase of about 30 basis points over the pre-crisis level.[28] The yield spreads have fallen relative to the recent past, but remain higher than yields spreads were prior to the financial crisis.

Q. Are there explanations for the current elevated level of the yield spread?

A. One possible explanation is that monetary policy is artificially depressing current and near-term expected levels of government bond yields.[29] This can result in the yield on government debt falling below the true risk-free rate. As noted above, the Fed has begun reversing these policies.

An alternative explanation is that the return investors require to invest in securities that are not risk-free has increased, so that the risk premium investors require to hold corporate debt and equity is elevated. The latter explanation indicates the market risk premium is elevated relative to its historical level.

Q. What are the implications of an elevated yield spread?

A. In an environment with an elevated yield spread, estimating the cost of equity based on historical data using the current risk-free rate and market risk premium results in a downward bias for the cost of equity. This is true whether monetary policy or investors' elevated appetite for risk-free securities drives the increase in

[28] Average monthly yields for the indices were retrieved from Bloomberg as of October 30, 2017.

[29] As of Q2, 2017, the Federal Reserve held approximately $1.8 trillion of mortgage-backed securities, whereas the magnitude was less than $0.5 trillion in mid-2009. Source: Federal Reserve Bank of St. Louis Economic Research (FRED) and Federal Reserve Bank, "Combined Quarterly Financial Report," June 30, 2017. Available at https://fred.stlouisfed.org/series/MBST
https://www.federalreserve.gov/aboutthefed/files/quarterly-report-20170630.pdf

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Portland, OR 97209-3991
1-503-226-4211

the yield spread. To eliminate the downward bias, we must either "normalize" the risk-free rate by accounting for the elevated spread or adjust the historical market risk premium based on the yield spread. Alternatively, we could include a portion of the elevated yield spread in the risk-free rate and reflect the remainder in an adjustment to the market risk premium.[30]

C. Risk Premiums

Q. What do elevated yield spreads imply about the risk premium for utility stocks?

A. First, because an elevated yield spread indicates investors require elevated premiums for holding securities other than risk-free government bonds, an elevated yield spread also indicates higher risk premiums currently prevail in capital markets. Investors consider a risk-return tradeoff (like the one displayed in Figure 1 above) and select investments based upon the desired level of risk. Higher yield spreads reflect the fact that the return on corporate debt is higher relative to government bond yields than is normally the case, even for regulated utilities. Because equity is riskier than debt, the spread between the cost of equity and government bond yields must also be higher; *i.e.*, the premium required to hold equity rather than government bonds has increased. If this fact is not recognized, then the traditional cost of capital estimation models will underestimate the cost of capital prevailing in the capital markets.

[30] I note that if a combination interpretation is used, it becomes important to make sure that the overall (total) "normalization" takes into account the elevated yield spread once and only once.

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1-503-226-4211

Second, in times of economic uncertainty (such as the present) investors seek to reduce their exposure to market risk. This precipitates a so-called "flight to safety,"[31] wherein demand for low-risk government bonds rises at the expense of demand for stocks. If yields on bonds are extraordinarily low, however, any investor seeking a higher expected return must choose alternative investments such as stocks, real estate, gold or collectibles. Of course, all of these investments are riskier than government bonds, and investors demand a risk premium (perhaps an especially high one in times of economic uncertainty) for investing in them. Because utilities are considered necessary and subject to regulation, utility stocks may have experienced an inflow of capital that usually would have been invested elsewhere. Moving from more risky to less risky investments is often referred to as a "flight to safety" and utility stock may have experienced this phenomenon to a larger degree than other stock because they traditionally have paid a substantial portion of their earnings as dividends, so that investors' return is less dependent upon the development in markets in general. In other words, the flight to safety may depress recently observed utility equity returns below the going forward cost of equity.

Q. What do you mean when you say investors are demanding a premium higher than the historical premium to hold securities that are not risk-free?

[31] Sometimes referenced as "flight to quality."

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Portland, OR 97209-3991
1-503-226-4211

A. The degree to which investors seek to avoid risk is measured by so-called risk-aversion, which is the recognition that investors dislike risk. Risk aversion means that for any given level of risk, investors must expect to earn an appropriate return to be induced to invest. An increase in risk aversion means that investors now require a higher return for that same level of risk.

Q. Do you have any evidence that the return premium demanded by investors for taking risk is higher than it was prior to the 2008-09 financial crisis?

A. Yes. For most of the period since the financial crisis of 2008-09, both academic research and financial data services such as Bloomberg have found an increase in the expected MRP compared to prior to the financial crisis. For example, an analysis by Duarte and Rosa of the Federal Reserve of New York aggregates the results of many models of the required MRP in the U.S. and tracks them over time. This analysis found a very high MRP not only during but also after the financial crisis of 2008-09.

The analysis estimates the MRP that results from a range of models each year from 1960 through the present.[32] The analysis then reports the average as well as the first principal component of results.[33] The analysis then finds that the models used to determine the risk premium are converging to provide more

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[32] Fernando Duarte and Carlo Rosa, "The Equity Risk Premium: A Review of Models," Federal Reserve Bank of New York, December 2015 (Duarte & Rosa 2015).

[33] Duarte & Rosa emphasize the "first principal component" of the 20 models. This means that the authors used statistics to compute the weighted average combination of the models that captures the most variability among the 20 models over time.

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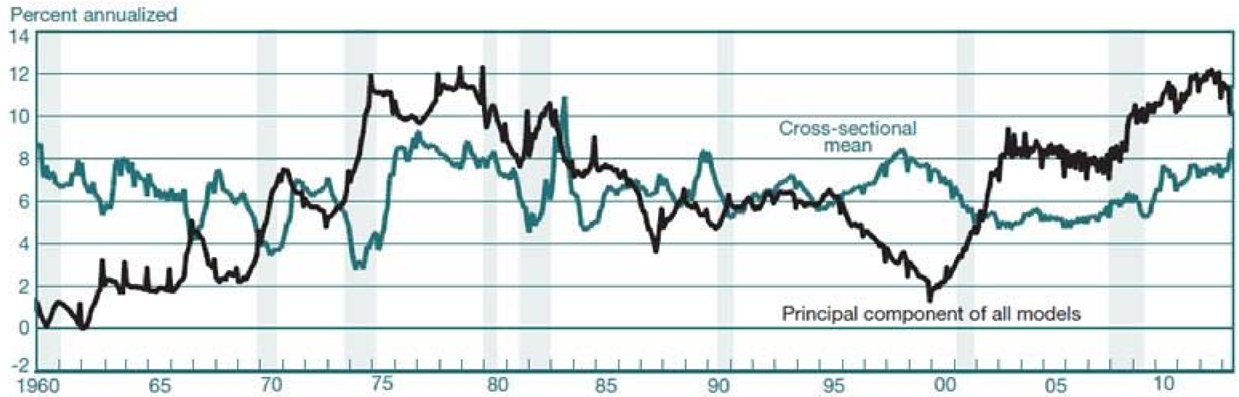
Portland, OR 97209-3991
1-503-226-4211

comparable estimates and that the average annual estimate of the MRP was at an all-time high in 2013. These estimates are reasonably consistent with those obtained from Bloomberg and the consistent elevation of the MRP over the historical figure indicates that the elevated level is persistent. Figure 3 below shows Duarte and Rosa's summary results.

Figure 3
Duarte and Rosa's Chart 3
One-Year Ahead MRP and Cross-Sectional Mean of Models



<u>D. Market Volatility</u>

Q. What is the current evidence regarding market volatility?

A. A measure of the market's expectations for volatility is the VIX, which measures the 30-day implied volatility of the S&P 500 index. This index is also referenced as the "investor fear gauge"[34] in that it provides a market indication how investors in stock index options perceive the likelihood of large swings in the stock market **within the next month**. At present, the VIX index stands at about 10, which is

[34] See Rachel Koning Beals, Stock market 'fear gauge' VIX remains up over 20% in wake of latest North Korean action, MarketWatch, August 29, 2017.

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1-503-226-4211

below the long-term historical volatility of approximately 20.[35]

While near-term expectations for market volatility are therefore lower today than average, examining the recent history of the VIX index (Figure 4) reveals that there can be considerable movements in short-term volatility expectations. For example, within the last two years, the VIX has been as high as 28 and as low as 9.[36]

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35 Bloomberg as of November 10, 2017.

36 Bloomberg as of November 10, 2017.

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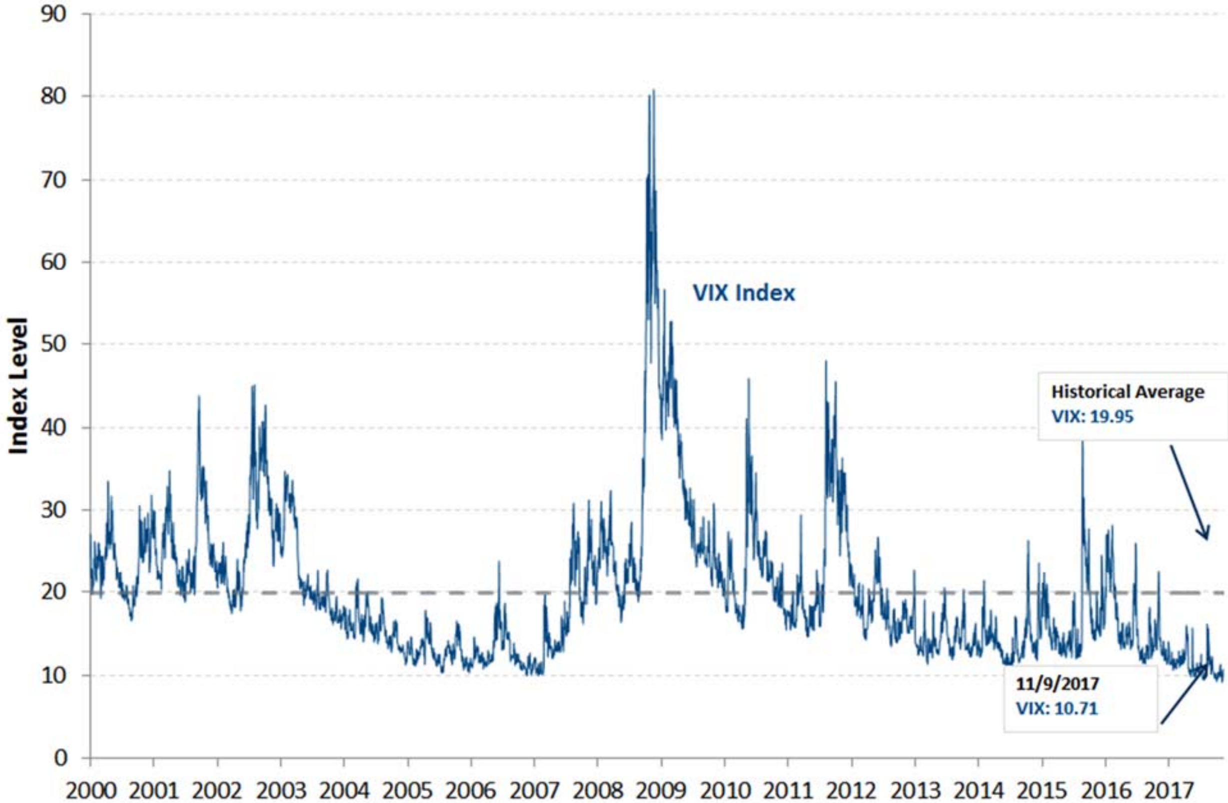
Figure 4
Historical VIX Levels



Source: Bloomberg.

Q. What are the implications of the short-term volatility being lower?

A. Academic research has found that, all else equal, investors demand higher risk premiums during more volatile periods. However, it is important to remember that the VIX measures expectations for market volatility in the *near-term*—specifically over the coming 30 days. By contrast, the MRP that is relevant in this proceeding represents the compensation investors require to take on risk over a long investment horizon. (Theoretically, an equity investment has a perpetual term, but it is typical to approximate this with a multi-decade investment horizon, for example by selecting a 20-year government bond as proxy for the risk free rate of interest). Consequently, while the level of the VIX is a useful indicator of current investor sentiment and uncertainty in equity markets, it is too simplistic to say that lower implied volatility necessarily corresponds to lower risk premiums required by investors. The decline in the VIX has occurred over a very short period of time, but investors have a much longer horizon.

Q. Are there reasons to be wary of interpreting a relatively low VIX Index level as an indicator of long-term market stability?

A. Yes, since May the VIX index closed under 10 points multiple times, which has occurred on less than 1.0% of all trading days since its start in 1990. The prior two cases of a below-10 VIX index before May of 2017 were followed by the great recession beginning at the end of 2007 and by 1994's 4.0% annual advance of real GDP.[37] These examples serve as warnings not to assume that short-term implied volatility is a reliable indicator of sustained long-term stability.

The SKEW index, which measures the market's willingness to pay for protection against negative "black swan" stock market events (*i.e.*, sudden substantial downturns), offers another reason to be cautious of interpreting the low VIX as an indicator of improved capital market certainty over the long term. A SKEW value of 100 indicates outlier returns are unlikely, but as the SKEW increase the probability of outlier returns become more significant. The SKEW

[37] Moody's Analytics, "Much Doubt Surrounds the VIX Index's Optimism", Weekly Market Outlook, May 11, 2017, p. 2.

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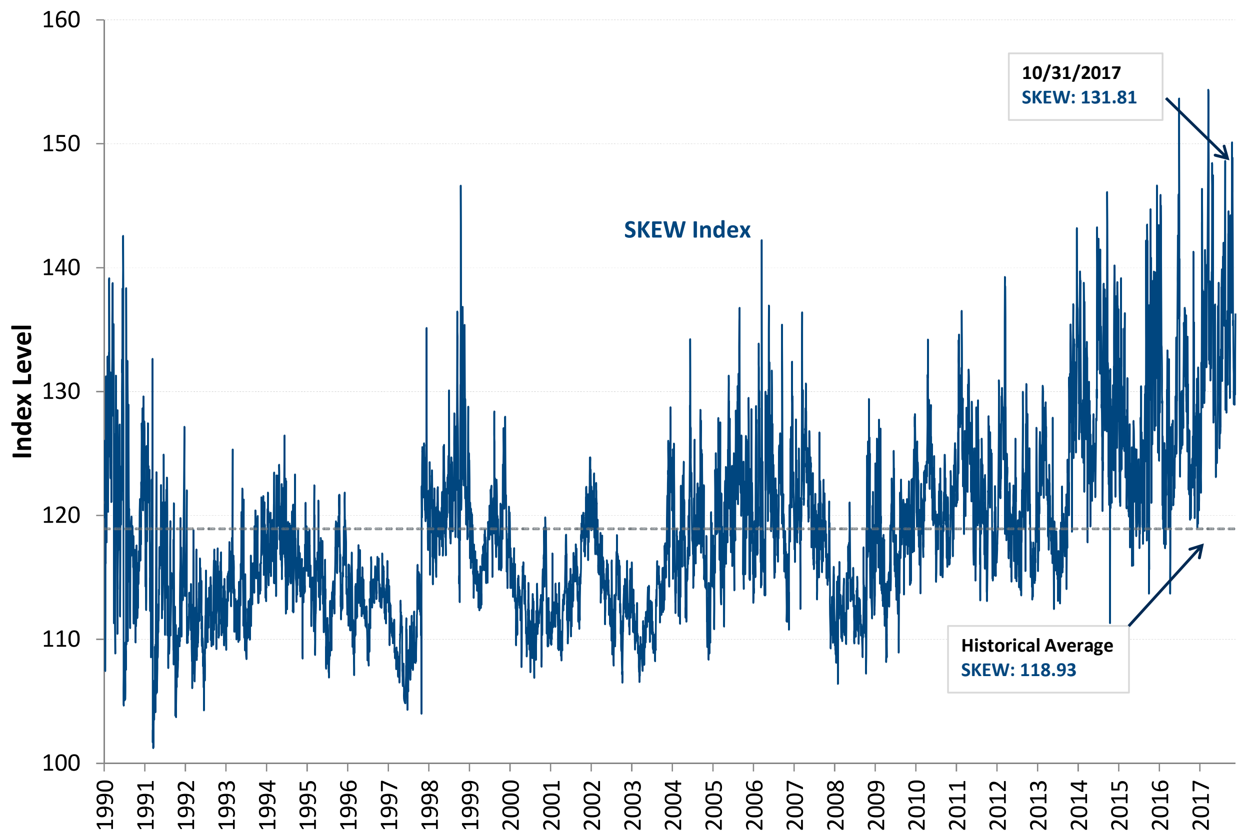
1-503-226-4211

currently stands at almost 132, while the index has averaged 119 over the last 15 years. This indicates that while short-term volatility expectations may be low, investors willing to pay for protection against downside risk and thus are exhibiting signs of elevated risk aversion concerns of downside tail risk.

Figure 5
Historical SKEW Levels



Source: Bloomberg.

Q. Are there reasons why capital markets may continue to exhibit higher than historical volatility?

A. Yes, 2017 has seen a number of events that have or may affect financial markets. Notably, U.S. policy remains in flux as changes to the federal corporate

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1-503-226-4211

income tax have been proposed but not finalized. Similarly, changes to the implementation of financial regulation under Dodd-Frank have been proposed, but not finalized. Overseas, the continued weakness in Europe may well impact financial markets going forward and key policy decisions remain unresolved – for example, when and how the U.K. decision to leave the European Union (Brexit) takes effect.

Furthermore, elevated levels of uncertainty in the global capital markets continue to affect the U.S. economy, which remains sensitive to those disruptions. In other words, major capital markets globally have not yet returned to their pre-credit crisis status, and they continue to affect the U.S. capital markets. The European Central Bank (ECB) continues its accommodative stance, which targets a negative 0.4% interest rate[38] and continues to purchase billions of euros worth of assets each month (50 billion euros of assets purchased in July 2017),[39] and the Bank of Japan's policy, which has maintained negative yields on government bonds since early 2016,[40] represent divergent approaches from that of the Fed, which halted its asset purchases, announced

[38] European Central Bank, Key ECB Interest Rates, EUROPEAN CENTRAL BANK, https://www.ecb.europa.eu/stats/monetary/rates/html/index.en.html (last visitedNov. 17, 2017).

[39] European Central Bank, Asset purchase programmes, EUROPEAN CENTRAL BANK, https://www.ecb.europa.eu/mopo/implement/omt/html/index.en.html (last visited September 15, 2017).

[40] See Takashi Nakamichi and Rachel Rosenthal, *Bank of Japan Sets Bond-Rate Target in Policy Revamp*, WALL ST. J., September 21, 2016, http://www.wsj.com/articles/boj-changes-policy-framework-after-review-of-measures-1474432869 and Bank of Japan, Statement on Monetary Policy, BANK OF JAPAN, October 31, 2017.

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1-503-226-4211

plans to reduce its balance sheet, and has recently decided on a modest increase in interest rates. President Trump has nominated Jerome Powell to replace Janet Yellen as chairman when her term ends in February 2018. While Powell is expected to maintain Yellen's policy of gradual interest rate increases and balance sheet reductions, uncertainty persists concerning how monetary policy may change with the transition.[41]

It is also worth considering that global political and economic uncertainty is quite high at present. Tensions with North Korea and continued unrest in the Middle East (e.g. in Syria, Iraq, and on the Arabian Peninsula) have the potential to cause turmoil that could spill over into capital markets. For example, increased testing of ballistic missiles by North Korea has had noticeable impacts on the market, such as pushing down yields on 10-year U.S. Treasury Bonds as "investors sought safety."[42]

E. Impact on ROE estimation

Q. Please summarize how the economic developments discussed above have affected the return on equity and debt that investors require.

A. Utilities rely on investors in capital markets to provide funding to support their capital expenditure programs and efficient business operations, and investors consider the risk return tradeoff in choosing how to allocate their capital among

[41] See Heather Long, Who is Jerome Powell, Trump's pick for the nation's most powerful economic position?, Washington Post, November 2, 2017.

[42] See *Financial Times* article "Flight to havens after North Korea missile launch", https://www.ft.com/content/5dab7a38-8c56-11e7-a352-e46f43c5825d.

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1-503-226-4211

different investment opportunities. It is therefore important to consider how investors view the current economic conditions; including the plausible development in the risk-free rate and the current MRP.

Investors have been dramatically affected by the credit crisis and ongoing market volatility, so there are reasons to believe that their risk aversion remains elevated relative to pre-crisis periods.

Likewise, the effects of the Federal Reserve's monetary policy have artificially lowered the risk-free rate. As a result, yield spreads on utility debt, including top-rated instruments, have remained elevated. The evidence presented above demonstrates that the risk-free rate is below its normal level.

Q. Does your analysis consider the current economic conditions?

A. Yes. In implementing models that directly rely on the risk-free rate, I consider one scenario that partially normalizes the risk-free rate while using the historical average MRP, and another scenario that uses the current yield on 20-Year Treasury Notes with a partial adjustments to the historical MRP based on the elevated yield spread. Similarly, I consider that the multi-stage DCF is likely downward biased and therefore recommend the upper end of the multi-stage DCF be used (and supported by alternative methods).

IV. <u>ESTIMATING THE COST OF CAPITAL</u>

<u>A. Approach</u>

Q. Please explain the process you used to estimate the cost of equity capital?

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A. First, I select a sample of gas LDCs, whose characteristics resemble those of NW Natural. Second, I estimate the cost of equity for the sample using several estimation methods to ensure that my measure reasonably reflects investor expectations. Third, I determine a reasonable range given the specifics of the estimation and the company's specific characteristics. Finally, I check my recommendation against other measures such as the allowed return on equity for U.S. gas LDCs.

Q. Please summarize each of the steps listed above.

A. To select a comparable sample of gas LDCs, I look to the universe of publicly traded gas utilities as classified by the Value Line Investment Survey.[43] From this group, I kept those that meet the following criteria: (1) have sufficient enough data such that the Value Line reports a beta, (2) have an investment grade rating, (3) have more than 50% of assets being subject to regulation, and (4) have sufficient size such that market data are meaningful. I form a subsample that excludes companies whose data might bias the cost of capital estimation. However, unlike my standard procedure which is to simply exclude companies actively engaged in merger talks, I keep three such companies to ensure a reasonable sample size and instead test whether these companies influence the estimation results.[44]

[43] Value Line lists 17 companies as natural gas utilities, but several have limited data or electric utilities, but 3 (AvanGrid, Wilmington Capital, ITC Holdings) do not operate electric distribution or generation. Thus, I examine only the 45 remaining companies.

[44] These companies are New Jersey Resources, South Jersey Industries, and WGL.

Rates & Regulatory Affairs
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Portland, OR 97209-3991
1-503-226-4211

To estimate the cost of equity for the sample, I rely on two versions of the Discounted Cash Flow (DCF) model and the risk premium model. I further confirm these figures by comparing the estimates to the recently allowed ROE for gas LDCs and to estimates obtained from two versions of the Capital Asset Pricing Model (CAPM). Specifically, I calculate the DCF cost of equity using the standard (single-stage) Gordon growth model and a three-stage DCF model. Further, I implement the risk premium model using authorized returns.

As noted above, the cost of equity capital for a company depends on its financial leverage. As the sample's DCF (and CAPM) measures of cost of equity were estimated using the sample companies' market value capital structure I determine the current capital structure (and the five-year average capital structure). I can then use these figures to convert the sample's cost of equity estimate to an estimate for NW Natural using its 50-50 capital structure. I then look to NW Natural's level of risk relative to the sample

Finally, I consider the reasonableness of the estimated cost of equity for NW Natural in light of recently allowed ROE for gas LDCs.

B. Sample Selection

Q. Please describe how you selected your sample.

A. To select a comparable sample of gas LDCs, I began with the universe of publicly traded gas LDCs as classified by Value Line.[45] From this group, I kept

[45] The companies are from Value Line Investment Analyzer.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

those that are Regulated (at least 80% of assets are regulated) or Mostly Regulated (50-79% of assets are regulated) based on the companies' 10-K filings. In addition, I require that the selected companies have sufficient data available that Value Line can provide a beta estimate, an investment grade rating, and sufficient size that market data are meaningful. I exclude companies with unique circumstances such as companies that had announced dividend cuts or companies with non-investment grade bond ratings.

Q. Please summarize the characteristics of your sample.

A. The sample consists of nine companies that have the majority of their assets dedicated to the regulated distribution of natural gas in the U.S. I also consider a subsample that excludes companies that are currently in merger or acquisition discussions. Table 2 reports the sample companies' annual revenues for the trailing twelve months ended September 2017[46] and the percentage of their assets devoted to regulated activities. It also displays each company's Market Capitalization and S&P Credit Rating in 2017, as well as its Value Line beta and the company's growth rate. The latter is the weighted average long-term earnings growth rate estimate from Thomson Reuters IBES and Value Line.

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[46] Southwest Gas data only extends through the end of June 2017. For that reason, we use the trailing twelve months data ending June 2017 for Southwest Gas.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

Table 2: Gas Sample and Its Characteristics[47]

U.S. Gas Sample

Company	CAPM Subsample	DCF Subsample	Annual Revenues (USD million)	Regulated Assets	Market Cap. 2017 Q3 (USD million)	Betas	S&P Credit Rating (2016)	Long Term Growth Est.
Atmos Energy	*	*	$2,895	R	$9,074	0.70	A	6.8%
Chesapeake Utilities	*	*	$576	M	$1,294	0.70	A-	10.7%
Northwest Natural Gas	*	*	$762	R	$1,888	0.70	A+	6.4%
ONE Gas Inc.	*	*	$1,520	R	$3,902	0.70	A	6.3%
Southwest Gas	*	*	$2,397	R	$3,756	0.75	BBB+	6.4%
Spire Inc.	*	*	$1,733	R	$3,632	0.70	A-	4.8%
New Jersey Resources			$2,213	M	$3,679	0.80	A	5.6%
South Jersey Inds.			$1,223	M	$2,793	0.85	BBB+	12.2%
WGL Holdings Inc.			$2,406	R	$4,327	0.80	A	5.1%
Full Sample Average			**$1,747**		**$3,816**	**0.74**		**7.1%**
Subsample Average			**$1,647**		**$3,924**	**0.71**		**6.9%**

Notes: R – Regulated (at least 80% of assets are regulated), M (50-79% of assets are regulated). S&P Credit Ratings are from Research Insight as of 2017 Q3NJR's credit rating based off of New Jersey Gas Co.'s rating reported by SNL. Chesapeake Utilities is given the average Credit Rating of the rest of the sample.

The average sample company devotes over 80% of its assets to regulated activities, which are primarily related to the local distribution of natural gas. Therefore, these sample companies are nearly pure-plays in the natural gas distribution industry.

My standard sample selection criteria would normally lead me to eliminate ONE Gas because only 3 years of historical data are available. However, because of the small sample size I include ONE Gas in the sample. New Jersey Resources and South Jersey Industries announced a merger on April 4th, 2017, and therefore would be excluded following my standard

[47] Sources: *Value Line Investment Survey* as of October 27, 2017, and Bloomberg as of October 30, 2017.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

screening criteria.[48] Similarly, AltaGas Ltd. announced in January 2017 that it would be acquiring WGL Holdings. Given the size of this pending transaction, my standard sample selection criteria would normally lead me to eliminate WGL from the current sample.

However, because of the small number of gas LDCs, I include New Jersey Resources, South Jersey Industries, and WGL Holdings in the full sample. To determine whether the inclusion of the three companies that are the subject of major M&A introduces any bias to the results, I have also constructed a subsample that excludes New Jersey Resources, South Jersey Industries, and WGL Holdings.

Q. How does the sample compare to NW Natural?

A. The sample was selected to consist of companies with more than 50% of their assets dedicated to regulated activities. As can be seen from Table 2, the majority of the sample companies are Regulated (80% or more of assets are rate regulated) as is NW Natural. The average credit rating is slightly lower than that of NW Natural at an average of A- while NW Natural maintains an A+ rating from S&P (A3 from Moody's). I note that NW Natural in Table 2 above refers to the consolidated NW Natural and not the Oregon-regulated gas LDC.

48 South Jersey Industries announced on October 16, 2016 that it is acquiring Elizabethtown Gas and Elkton Gas from Southern Company Gas.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

C. Capital Structure

Q. What regulatory capital structure is NW Natural requesting in this proceeding?

A. NW Natural has requested a regulatory capital structure consisting of 50% equity and 50% debt,[49] which was also the capital structure used in NW Natural's last rate case; the UG 221 proceeding.[50] This capital structure is broadly consistent with the book value capital structures of the sample companies. The sample averages about 53% equity on a book basis. The highest percentage of book equity for the companies in the sample is 62% equity (ONE Gas) and the lowest is 47% equity (WGL Holdings).[51] However, the market value capital structure includes an average of about 70% equity as of Q3 2017.[52] My recommended range for ROE is a function of the requested capital structure, the sample average cost of capital estimates and the relative risk of NW Natural compared to the sample.

V. COST OF CAPITAL ESTIMATES

Q. How do you estimate the sample companies' costs of equity?

A. As noted earlier, I employ three general methodologies: Discounted Cash Flow (DCF), Capital Asset Pricing Models (CAPM), and risk premium models. All

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49 The calculation of the capital structure is available in *NW Natural/300, Burkhartsmeyer.*

50 Order 12-437, issued November 16, 2012, p. 3.

51 See *NW Natural/403, Villadsen*.

52 The CAPM would use a five-year average to be consistent with the beta estimate. The five-year average is lower at approximately 65% equity.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

methods are commonly used in U.S. state regulatory proceedings and have been presented to the Commission previously by NW Natural. For the DCF estimates, I present two models: the standard Gordon growth model (or the single-stage DCF) and a three-stage DCF model. I implement the three-stage DCF model using two different long-term growth rates: the consensus Blue Chip forecast and an average of the estimate from OMB and Blue Chip. Further, I estimate the ROE from a version of the risk premium method: a regression analysis of allowed return on bond rates. Finally, I estimate two versions of the CAPM as a check on my results: the traditional CAPM and two versions of the Empirical CAPM.[53] Because the cost of equity cannot be measured precisely, it is important to consider more than one method. Further, each method has its strengths and weaknesses, which may be more or less prevalent at any given time. It is therefore necessary to evaluate the estimated cost of equity in the light of the prevalent market conditions and the relative strengths and weaknesses of the model to take these factors into account. I also cross-check my estimates against recently allowed ROEs in other jurisdictions, although I do not use this as an input to my recommendation.

[53] The CAPM is a commonly used cost of capital estimation model in corporate finance and I usually include it among my methods. However, the Commission has historically not relied upon the CAPM, so I present it only as a check on other results in this proceeding.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

A. DCF Based Estimates

Q. Please describe the discounted cash flow approach to estimating the cost of equity.

A. The DCF model takes the first approach to cost of capital estimation described above, i.e., to attempt to estimate the cost of capital in one step instead of estimating the cost of capital for the entire market and then determining the cost of capital for an individual investment. The DCF method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P = \frac{D_1}{(1+r)} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \quad (1)$$

where "P" is the market price of the stock; "D_i" is the dividend cash flow expected at the end of period i; "r" is the cost of capital; and "T" is the last period in which a dividend cash flow is to be received. The formula just says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received.

The standard DCF application goes on to make the assumption that the growth rate remains constant forever, which simplifies the standard formula, so that it can be rearranged to estimate the cost of capital. Specifically, if investors expect a dividend stream that will grow forever at a steady rate, then the market price of

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

the stock will be given by the formula,

$$P = \frac{D_1}{(r - g)} \tag{2}$$

where "D_1" is the dividend expected at the end of the first period, "g" is the perpetual growth rate, and "P" and "r" are the market price and the cost of capital, as before. Equation (3) is a simplified version of equation (2) that can be solved to yield the well-known "DCF formula" for the cost of capital:

$$\begin{aligned} r &= \frac{D_1}{P} + g \\ &= \frac{D_0 \times (1+g)}{P} + g \end{aligned} \tag{3}$$

where "D_0" is the current dividend, which investors expect to increase at rate g by the end of the next period, and the other symbols are defined as before. Equation (4) says that if equation (3) holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends. I refer to this as the Gordon DCF model.

Q. Are there models other than the Gordon DCF model?

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Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

A. Yes. There are many alternatives, notably, (i) multi-stage models and (ii) models that use cash flow rather than dividends or combinations of (i) and (ii).[54] One such alternative expands the Gordon DCF model to three stages.[55] In the multistage model, earnings and dividends can grow at different rates, but must grow at the same rate in the final, constant growth rate period.

Q. What is your assessment of the DCF model?

A. The DCF approach is grounded in solid financial theory. It is widely accepted by regulatory commissions and provides useful insight regarding the cost of capital based on forward-looking metrics. DCF estimates of the cost of capital complement those of the Risk Premium or CAPM because the methods rely on different inputs and assumptions. The DCF method is particularly valuable in the current economic environment, because of the effects on capital market conditions of the Fed's efforts to maintain interest rates at historically low levels which bias the Risk Premium (and CAPM-based) estimates downward.

However, I recognize that the DCF model, like most models, relies upon assumptions that do not always correspond to reality. This is why the reliance on multiple methods is important.

[54] The Surface Transportation Board uses a cash flow based model with three stages. See, for example, Surface Transportation Board, "Ex Parte No. 664 (Sub-No. 1)," Issued January 23, 2009. Confirmed in EP 664 (Sub-No. 2), issued October 31, 2016.

[55] I note that because investors are interested in cash flow, it is technically important to include all cash flow that is distributed to shareholders. Notably, many companies distribute cash through share buybacks in addition to dividends and therefore, I would include this type of distribution. However, among the comparable companies share buybacks is not a large. Therefore, I ignore this aspect for this proceeding.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

Q. What growth rate information do you use?

A. The first step in my DCF analysis (either constant growth or multistage formulations) is to examine a sample of investment analysts' forecasted earnings growth rates from Bloomberg and from Value Line for companies in the gas LDC sample. For the long-term growth rate for the final, constant-growth stage of the multistage DCF estimates, I use two estimates: (i) the most recent long-run GDP growth forecast from Blue Chip Economic Indicators and (ii) the average of the OMB and Blue Chip long-term estimate.[56]

Q. How do these growth rates correspond to the theoretical criteria you discuss above?

A. The constant-growth formulation of the DCF model, in principle, requires forecasted growth rates, but it is also necessary that the growth rates used extend far enough into the future so that it is reasonable to believe that investors expect a stable growth path afterwards. Under current economic conditions, I believe the forecasted growth rates of investment analysts provide the best available representation of the longer term, steady-state growth rate expectations of investors.

Q. Does the multistage DCF improve upon the simple DCF?

A. Potentially, but the multistage method assumes a particular smoothing pattern and a long-term growth rate afterwards. These assumptions may not be a more

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[56] *Blue Chip Economic Indicators*, October 2017.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

accurate representation of investor expectation than those of the simple DCF. The smoother growth pattern, for example, might not be representative of investor expectations, in which case the multistage model would not increase the accuracy of the estimates. Indeed, amidst uncertainty in capital markets, assuming a simple constant growth rate may be preferable to attempting to model growth patterns in greater detail over multiple stages. While it is difficult to determine which set of assumptions comprises a closer approximation of the actual conditions of capital markets, I believe both forms of the DCF model provide useful information about the cost of capital.

Q. What are your DCF estimates?

A. Looking at the full sample, the ROE estimate is 12.9% for the Gordon (single-stage) DCF model and 10.0% for the multistage model using the Blue Chip forecast. Table 3 below summarizes the results from the DCF models.

Table 3: DCF Estimates on the Cost of Equity

Single-stage	12.9%
Multi-stage using Blue Chip GDP Growth:	9.4%
Multi-stage using average of Blue Chip and OMB GDP Growth:	10.0%

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

Q. What conclusions do you draw from the DCF analysis?

A. The estimates from the DCF models have a wide range but looking to the multi-stage model, the model indicates a range of 9.4% to 10.0%. Because the single-stage DCF is substantially higher and because the estimates from other models are higher, I would emphasize the 10% obtained from the multi-stage model using a combination of the Blue Chip and OMB growth.

B. Risk Premium Methods

Q. Do you estimate the Cost of Equity that result from risk premium analysis?

A. Yes, I estimate the risk premium using a statistical regression approach. Specifically, I calculate the statistical relationship between the allowed ROE for natural gas LDCs and the 20-year government bond rate using quarterly data. This results in an estimated ROE of 10.2% to 10.3%.

Q. Please explain the implementation and data underlying your risk premium analysis.

A. Using quarterly data from Regulatory Research Associates from Q1 1990 to Q3 2017,[57] I estimate the equation:

$$\text{Risk Premium} = A_0 + (A_1 \times \text{Treasury Bond Yield})$$

The equation is estimated using ordinary least squares and the parameters are statistically significant (details are in *NW Natural/404, Villadsen*). Using this approach, I estimate a risk premium, which is then added to the forecasted 20-

[57] SNL Financial, as of November 2017.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

year yield in 2019 as NW Natural's rates are expected to go into effect in near the end of 2018. *I.e.,*

Estimated ROE = Forecast Risk-Free Rate + Risk Premium

The forecasted 20-year yield is 3.94% and the risk premium is 6.28%, if the currently elevated yield spread is not taken into account. If an elevated yield spread of 20 basis points is assumed to remain, the forecasted 20-year yield is 4.14% and the risk premium is 6.17%.[58] Using these two forecasts for the risk-free rate, I obtain cost of equity estimates of 10.2% and 10.3%, respectively. Because it is plausible that the yield spread will moderate as the government bond yield increases, I consider the range of 10.2% to 10.3% to be a reasonable estimate for the risk premium model. This estimate is also consistent with recently allowed ROEs once the likely increase in interest rates is considered. Gas LDC authorized ROEs to date in 2017 have averaged 9.76% and government bond yields are expected to increase by almost 90 basis points over the two years.[59]

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[58] *Blue Chip Economic Indicators Forecast*, October 2017.

[59] SNL Financial as of 12/1/2017

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

Table 4: Risk Premium Estimate on the Cost of Equity

Risk Premiums Determined by Relationship Between Authorized ROEs[1] and Long-term Treasury Bond Rates During the Period 1990-2017

Equity Cost Estimate for Gas LDC		Predicted Risk Premium		Expected Treasury Bond Rate[2]	
10.3%	=	6.17%	+	4.14%	[3]
10.2%	=	6.28%	+	3.94%	[4]

Sources and Notes:
[1]: Authorized ROE Data sourced from SNL Financial.
[2]: Blue Chip consensus forecast 2019 10-yr T-bill Yield plus maturity premium
[3]: Estimate with expected treasury bond rate normalized with 0.20% utility yield spread adjustment
[4]: Estimate without treasury bond rate normalization.
See regression results for derivation of regression coefficients A_0 and A_1.

Q. Is this estimate consistent with NW Natural's regulatory capital structure of 50% equity and 50% debt?

A. Yes, the authorized ROE pertains to the regulated capital structure of the entities for which state regulatory commissions allowed an ROE. The regulatory capital structures have on average contained close to 50% equity since 2003 (the first year for which RRA reports the equity percentage in its recent publication).[60] Therefore, the estimated ROE is consistent with NW Natural's capital structure.

Q. What conclusions do you draw from the analysis?

60 SNL Financial, RRA Regulatory Focus, October 26, 2017. Except in 2004, RRA reports average capital structures with equity percentages between 47.2 and 52.5 percent.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

A. The risk premium analysis results in an ROE estimate that is consistent with the upper end of my multi-stage DCF results and consistent with the lower range of my CAPM results. I consider a range of 10.2% to 10.3% reasonable for the risk premium model.

Q. Is there other relevant evidence regarding the current Cost of Equity for gas LDCs?

A. Yes, looking at the recently authorized ROE for regulated gas LDCs, I find an average of 9.76% for 2017 year-to-date but the allowed ROEs has increased non-trivially in the last three months or so. For example, the average since September has been 10.07% for all gas LDCs and 9.88% if the highest and lowest award is eliminated.[61]

Finally, I estimate the cost of equity using the Capital Asset Pricing Model, which determines the cost of equity as follows:

$$r_S = r_f + \beta_S \times MRP \tag{4}$$

where r_s is the cost of capital for investment S; r_f is the risk-free rate; β_S is the beta risk measure for the investment *S*; and *MRP* is the market risk premium. The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities. I estimate this model using Value Line betas, the risk-free rate that Blue Chip forecasts for 2019 (as in the risk-premium analyses above), and the historical MRP for the period 1926-2016

[61] SNL Financial, 12/1/2017.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

as reported by the 2017 Duff & Phelps Valuation Handbook.[62] I also implement two variations of the model that relies on the empirical observation that the intercept in Figure 1 is higher than in the theoretical CAPM, but the slope is lower. The CAPM and the empirical CAPM result in cost of equity estimates in the range of 10.3% to 12.2% for the full sample and 9.9% to 11.6% for the subsample.

Table 5: Summary Results from CAPM-Based Models

	Estimated Range	Recommended Range[63]
CAPM, Sample	10.3% - 11.7%	10.3% - 10.8%
CAPM, Subsample	9.9% - 11.1%	9.9% - 10.3%
ECAPM, Sample	10.5% - 12.2%	10.5% - 10.8
ECAPM, Subsample	10.1% - 11.6%	10.1% - 10.4%
Recommended Range		10% - 10.5%

The recommended range of 10 to 10.5 percent for the CAPM-Based methods includes the majority of the recommended estimates from both the sample and subsample and also overlaps both the recommended DCF estimate and the risk premium estimates.

62 *Blue Chip Economic Indicators*, October 2017; Duff & Phelps, "*2017 SBBI Yearbook: Stocks, Bonds, Bills, and Inflation,*" p. 10-7.

63 The recommended range is based on Scenario 1, which use the historical average MRP. It further eliminated the highest estimate to be conservative.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

VI. CONCLUSIONS

Q. Please summarize the evidence from the sample regarding the ROE for a gas LDC of average risk?

A. The estimated ranges are summarized in Table 3 (DCF), Table 4 (Risk Premium), and Table 5 (CAPM) along with the recommended range. Overall the range is wide from 9.4% to 10.8% but I consider a narrower range that includes the majority of the overlapping ranges to be the most reasonable. Consequently, I consider a range of approximately 9.7 to 10.3 percent to be reasonable given that the multi-stage DCF result using the Blue Chip and OMB forecast falls at the midpoint, the risk premium and CAPM based results are in the upper end to above the range while the allowed ROEs are within the range. Taking into consideration that NW Natural is of smaller size that the average gas LDC and that the sample was selected to consist of companies that pre-dominantly engage in natural gas distribution, I consider that NW Natural's risks are such that the Company should be awarded an ROE towards the midpoint or slightly above the range discussed above.

Overall, I believe NW Natural's request for an ROE of 10.0% is reasonable.

VII. QUALIFICATIONS

Q. Dr. Villadsen, please state your educational background and experience.

A. I hold a Ph.D. from Yale University's School of Management with a concentration in accounting. I have a joint degree in mathematics and economics (BS and MS)

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

from University of Aarhus in Denmark. Prior to joining The Brattle Group, I was a Professor of Accounting at the University of Iowa, University of Michigan, and at Washington University in St. Louis where I taught financial and cost accounting. I have also taught graduate classes in econometrics and quantitative methods. I have worked as a consultant for Risoe National Laboratories in Denmark.

My work concentrates in the areas of regulatory finance and accounting. My recent work has focused on accounting issues, damages, cost of capital and regulatory finance. In the regulatory finance area, I have testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and decoupling on cost of capital and earnings. I have been involved in accounting disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. I have estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and railroad industry. I have filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions. My testimonies and expert reports pertain to accounting issues, damages, discount rates and cost of capital for regulated entities.

Q. Does this conclude your testimony?

A. Yes.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Exhibits of Dr. Bente Villadsen

RETURN ON EQUITY
EXHIBITS 401-407

December 2017

EXHIBITS 401 - 407 – RETURN ON EQUITY

Table of Contents

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

EXHIBIT NW NATURAL 401:

RESUME OF DR. BENTE VILLADSEN

Dr. Bente Villadsen's work concentrates in the areas of regulatory finance and accounting. Her recent work has focused on accounting issues, damages, cost of capital and regulatory finance. Dr. Villadsen has testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and de-coupling on cost of capital and earnings. Among her recent advisory work is the review of regulatory practices regarding the return on equity, capital structure, recovery of costs and capital expenditures as well as the precedence for regulatory approval in mergers or acquisitions. Dr. Villadsen's accounting work has pertained to disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. Dr. Villadsen has estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and rail road industry. She has filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions on accounting issues, damages, discount rates and cost of capital for regulated entities.

Dr. Villadsen holds a Ph.D. from Yale University's School of Management with a concentration in accounting. She has a joint degree in mathematics and economics (BS and MS) from University of Aarhus in Denmark. Prior to joining The Brattle Group, she was a Professor of Accounting at the University of Iowa, University of Michigan, and at Washington University in St. Louis where she taught accounting. She has also taught graduate classes in econometrics and quantitative methods. Dr. Villadsen currently serves as the president of the Society of Utility Regulatory Financial Analysts.

AREAS OF EXPERTISE

- Regulatory Finance
  - Cost of Capital
  - Cost of Service (including prudence)
  - Energy Efficiency, De-coupling and the Impact on Utilities Financials
  - Relationship between regulation and credit worthiness
  - Risk Management
  - Regulatory Advisory in Mergers & Acquisitions
- Accounting and Corporate Finance
  - Application of Accounting Standards
  - Disclosure Issues
  - Credit Issues in the Utility Industry
- Damages and Valuation
  - Utility valuation
  - Lost Profit

EXPERIENCE

Regulatory Finance

- On behalf of the Association of American Railroads, Dr. Villadsen appeared as an expert before the Surface Transportation Board (STB) and submitted expert reports on the determination of the cost of equity for U.S. freight railroads. The STB agreed to continue to use two estimation methods with the parameters suggested.
- For several electric, gas and transmission utilities in Alberta, Canada, Dr. Villadsen filed evidence and appeared as an expert on the cost of equity and appropriate capital structure for 2015-17. Her evidence was heard by the Alberta Utilities Commission.
- For the Ontario Energy Board Staff, Dr. Villadsen submitted evidence on the appropriate capital structure for a power generator that is engaged in a nuclear refurbishment program.
- She has estimated the cost of equity on behalf of Anchorage Municipal Light and Power, Arizona Public Service, Portland General Electric, Anchorage Water and Wastewater, American Water, California Water, and EPCOR in state regulatory proceedings. She has also submitted testimony before the Bonneville Power Authority. Much of her testimony involves not only cost of capital estimation but also capital structure, the impact on credit metrics and various regulatory mechanisms such as revenue stabilization, riders and trackers.
- In Australia, she has submitted led and co-authored a report on cost of equity and debt estimation methods for the Australian Pipeline Industry Association. The equity report was filed with the Australian Energy Regulator as part of the APIA's response to the Australian Energy Regulator's development of rate of return guidelines and both reports were filed with the Economic Regulation Authority by the Dampier Bunbury Pipeline. She has also submitted a report on aspects of the WACC calculation for Aurizon Network to the Queensland Competition Authority.
- In Canada, Dr. Villadsen has co-authored reports for the British Columbia Utilities Commission and the Canadian Transportation Agency regarding cost of capital methodologies. Her work consisted partly of summarizing and evaluating the pros and cons of methods and partly of surveying Canadian and world-wide practices regarding cost of capital estimation.
- Dr. Villadsen worked with utilities to estimate the magnitude of the financial risk inherent in long-term gas contracts. In doing so, she relied on the rating agency of Standard & Poor's published methodology for determining the risk when measuring credit ratios.

- She has worked on behalf of infrastructure funds, pension funds, utilities and others on understanding and evaluating the regulatory environment in which electric, natural gas, or water utilities operate for the purpose of enhancing investors ability to understand potential investments. She has also provided advise and testimony in the approval phase of acquisitions.
- On behalf of utilities that are providers of last resort, she has provided estimates of the proper compensation for providing the state-mandated services to wholesale generators.
- In connection with the AWC Companies application to construct a backbone electric transmission project off the Mid-Atlantic Coast, Dr. Villadsen submitted testimony before the Federal Energy Regulatory Commission on the treatment the accounting and regulatory treatment of regulatory assets, pre-construction costs, construction work in progress, and capitalization issues.
- On behalf of ITC Holdings, she filed testimony with the Federal Energy Regulatory Commission regarding capital structure issues.
- Testimony on the impact of transaction specific changes to pension plans and other rate base issues on behalf of Balfour Beatty Infrastructure Partners before the Michigan Public Service Commission.
- On behalf of financial institutions, Dr. Villadsen has led several teams that provided regulatory guidance regarding state, provincial or federal regulatory issues for integrated electric utilities, transmission assets and generation facilities. The work was requested in connection with the institutions evaluation of potential investments.
- For a natural gas utility facing concerns over mark to market losses on long term gas hedges, Dr. Villadsen helped develop a program for basing a portion of hedge targets on trends in market volatility rather than on just price movements and volume goals. The approach was refined and approved in a series of workshops involving the utility, the state regulatory staff, and active intervener groups. These workshops evolved into a forum for quarterly updates on market trends and hedging positions.
- She has advised the private equity arm of three large financial institutions as well as two infrastructure companies, a sovereign fund and pension fund in connection with their acquisition of regulated transmission, distribution or integrated electric assets in the U.S. and Canada. For these clients, Dr. Villadsen evaluated the regulatory climate and the treatment of acquisition specific changes affecting the regulated entity, capital expenditures, specific cost items and the impact of regulatory initiatives such as the FERC's incentive return or

specific states' approaches to the recovery of capital expenditures riders and trackers. She has also reviewed the assumptions or worked directly with the acquirer's financial model.

- On behalf of a provider of electric power to a larger industrial company, Dr. Villadsen assisted in the evaluation of the credit terms and regulatory provisions for the long-term power contract.
- For several large electric utility, Dr. Villadsen reviewed the hedging strategies for electricity and gas and modeled the risk mitigation of hedges entered into. She also studies the prevalence and merits of using swaps to hedge gas costs. This work was used in connection with prudence reviews of hedging costs in Colorado, Oregon, Utah, West Virginia, and Wyoming.
- She estimated the cost of capital for major U.S. and Canadian utilities, pipelines, and railroads. The work has been used in connection with the companies' rate hearings before the Federal Energy Regulatory Commission, the Canadian National Energy Board, the Surface Transportation Board, and state and provincial regulatory bodies. The work has been performed for pipelines, integrated electric utilities, non-integrated electric utilities, gas distribution companies, water utilities, railroads and other parties. For the owner of Heathrow and Gatwick Airport facilities, she has assisted in estimating the cost of capital of U.K. based airports. The resulting report was filed with the U.K. Competition Commission.
- For a Canadian pipeline, Dr. Villadsen co-authored an expert report regarding the cost of equity capital and the magnitude of asset retirement obligations. This work was used in arbitration between the pipeline owner and its shippers.
- In a matter pertaining to regulatory cost allocation, Dr. Villadsen assisted counsel in collecting necessary internal documents, reviewing internal accounting records and using this information to assess the reasonableness of the cost allocation.
- She has been engaged to estimate the cost of capital or appropriate discount rate to apply to segments of operations such as the power production segment for utilities.
- In connection with rate hearings for electric utilities, Dr. Villadsen has estimated the impact of power purchase agreements on the company's credit ratings and calculated appropriate compensation for utilities that sign such agreements to fulfill, for example, renewable energy requirements.
- Dr. Villadsen has been part of a team assessing the impact of conservation initiatives, energy efficiency, and decoupling of volumes and revenues on electric utilities financial

performance. Specifically, she has estimated the impact of specific regulatory proposals on the affected utilities earnings and cash flow.

- On behalf of Progress Energy, she evaluated the impact of a depreciation proposal on an electric utility's financial metric and also investigated the accounting and regulatory precedent for the proposal.
- For a large integrated utility in the U.S., Dr. Villadsen has for several years participated in a large range of issues regarding the company's rate filing, including the company's cost of capital, incentive based rates, fuel adjustment clauses, and regulatory accounting issues pertaining to depreciation, pensions, and compensation.
- Dr. Villadsen has been involved in several projects evaluating the impact of credit ratings on electric utilities. She was part of a team evaluating the impact of accounting fraud on an energy company's credit rating and assessing the company's credit rating but-for the accounting fraud.
- For a large electric utility, Dr. Villadsen modeled cash flows and analyzed its financing decisions to determine the degree to which the company was in financial distress as a consequence of long-term energy contracts.
- For a large electric utility without generation assets, Dr. Villadsen assisted in the assessment of the risk added from offering its customers a price protection plan and being the provider of last resort (POLR).
- For several infrastructure companies, Dr. Villadsen has provided advice regarding the regulatory issues such as the allowed return on equity, capital structure, the determination of rate base and revenue requirement, the recovery of pension, capital expenditure, fuel, and other costs as well as the ability to earn the allowed return on equity. Her work has spanned 12 U.S. states as well as Canada, Europe, and South America. She has been involved in the electric, natural gas, water, and toll road industry.

Accounting and Corporate Finance

- On behalf of a construction company in arbitration with a sovereign, Dr. Villadsen filed an expert report report quantifying damages in the form of lost profit and consequential damages.
- In arbitration before the International Chamber of Commerce Dr. Villadsen testified regarding the true-up clauses in a sales and purchase agreement, she testified on the

distinction between accruals and cash flow measures as well as on the measurement of specific expenses and cash flows.

- On behalf of a taxpayer, Dr. Villadsen recently testified in federal court on the impact of discount rates on the economic value of alternative scenarios in a lease transaction.
- In an arbitration matter before the International Centre for Settlement of Investment Disputes, she provided expert reports and oral testimony on the allocation of corporate overhead costs and damages in the form of lost profit. Dr. Villadsen also reviewed internal book keeping records to assess how various inter-company transactions were handled.
- Dr. Villadsen provided expert reports and testimony in an international arbitration under the International Chamber of Commerce on the proper application of US GAAP in determining shareholders' equity. Among other accounting issues, she testified on impairment of long-lived assets, lease accounting, the equity method of accounting, and the measurement of investing activities.
- In a proceeding before the International Chamber of Commerce, she provided expert testimony on the interpretation of certain accounting terms related to the distinction of accruals and cash flow.
- In an arbitration before the American Arbitration Association, she provided expert reports on the equity method of accounting, the classification of debt versus equity and the distinction between categories of liabilities in a contract dispute between two major oil companies. For the purpose of determining whether the classification was appropriate, Dr. Villadsen had to review the company's internal book keeping records.
- In U.S. District Court, Dr. Villadsen filed testimony regarding the information required to determine accounting income losses associated with a breach of contract and cash flow modeling.
- Dr. Villadsen recently assisted counsel in a litigation matter regarding the determination of fair values of financial assets, where there was a limited market for comparable assets. She researched how the designation of these assets to levels under the FASB guidelines affect the value investors assign to these assets.
- She has worked extensively on litigation matters involving the proper application of mark-to-market and derivative accounting in the energy industry. The work relates to the proper

valuation of energy contracts, the application of accounting principles, and disclosure requirements regarding derivatives.

- Dr. Villadsen evaluated the accounting practices of a mortgage lender and the mortgage industry to assess the information available to the market and ESOP plan administrators prior to the company's filing for bankruptcy. A large part of the work consisted of comparing the company's and the industry's implementation of gain-of-sale accounting.
- In a confidential retention matter, Dr. Villadsen assisted attorneys for the FDIC evaluate the books for a financial investment institution that had acquired substantial Mortgage Backed Securities. The dispute evolved around the degree to which the financial institution had impaired the assets due to possible put backs and the magnitude and estimation of the financial institution's contingencies at the time of it acquired the securities.
- In connection with a securities litigation matter she provided expert consulting support and litigation consulting on forensic accounting. Specifically, she reviewed internal documents, financial disclosure and audit workpapers to determine (1) how the balance's sheets trading assets had been valued, (2) whether the valuation was following GAAP, (3) was properly documented, (4) was recorded consistently internally and externally, and (5) whether the auditor had looked at and documented the valuation was in accordance with GAAP.
- In a securities fraud matter, Dr. Villadsen evaluated a company's revenue recognition methods and other accounting issues related to allegations of improper treatment of non-cash trades and round trip trades.
- For a multi-national corporation with divisions in several countries and industries, Dr. Villadsen estimated the appropriate discount rate to value the divisions. She also assisted the company in determining the proper manner in which to allocate capital to the various divisions, when the company faced capital constraints.
- Dr. Villadsen evaluated the performance of segments of regulated entities. She also reviewed and evaluated the methods used for overhead allocation.
- She has worked on accounting issues in connection with several tax matters. The focus of her work has been the application of accounting principles to evaluate intra-company transactions, the accounting treatment of security sales, and the classification of debt and equity instruments.

- For a large integrated oil company, Dr. Villadsen estimated the company's cost of capital and assisted in the analysis of the company's accounting and market performance.
- In connection with a bankruptcy proceeding, Dr. Villadsen provided litigation support for attorneys and an expert regarding corporate governance.

Damages and Valuation

- For the Alaska Industrial Development and Export Authority, Dr. Villadsen co-authored a report that estimated the range of recent acquisition and trading multiples for natural gas utilities.
- On behalf of a taxpayer, Dr. Villadsen testified on the economic value of alternative scenarios in a lease transaction regarding infrastructure assets.
- For a foreign construction company involved in an international arbitration, she estimated the damages in the form of lost profit on the breach of a contract between a sovereign state and a construction company. As part of her analysis, Dr. Villadsen relied on statistical analyses of cost structures and assessed the impact of delays.
- In an international arbitration, Dr. Villadsen estimated the damages to a telecommunication equipment company from misrepresentation regarding the product quality and accounting performance of an acquired company. She also evaluated the IPO market during the period to assess the possibility of the merged company to undertake a successful IPO.
- On behalf of pension plan participants, Dr. Villadsen used an event study estimated the stock price drop of a company that had engaged in accounting fraud. Her testimony conducted an event study to assess the impact of news regarding the accounting misstatements.
- In connection with a FINRA arbitration matter, Dr. Villadsen estimated the value of a portfolio of warrants and options in the energy sector and provided support to counsel on finance and accounting issues.
- She assisted in the estimation of net worth of individual segments for firms in the consumer product industry. Further, she built a model to analyze the segment's vulnerability to additional fixed costs and its risk of bankruptcy.

- Dr. Villadsen was part of a team estimating the damages that may have been caused by a flawed assumption in the determination of the fair value of mortgage related instruments. She provided litigation support to the testifying expert and attorneys.

- For an electric utility, Dr. Villadsen estimated the loss in firm value from the breach of a power purchase contract during the height of the Western electric power crisis. As part of the assignment, Dr. Villadsen evaluated the creditworthiness of the utility before and after the breach of contract.

- Dr. Villadsen modeled the cash flows of several companies with and without specific power contract to estimate the impact on cash flow and ultimately the creditworthiness and value of the utilities in question.

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“FASB Accounting Rules and Implications for Natural Gas Purchase Agreements,” (with Fiona Wang), *American Clean Skies Foundation*, February 2011.

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"Beta Distributed Market Shares in a Spatial Model with an Application to the Market for Audit Services" (with M. Hviid), *Review of Industrial Organization*, Vol. 10, 1995.

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"Transmission: The Interplay Between FERC Rate Setting at the Wholesale Level and Allocation to Retail Customers," (with Mariko Geronimo Aydin) presented at *Law Seminars International: Electric Utility Rate Cases*, March 16-17, 2017.

"Capital Structure and Liability Management," *American Gas Association and Edison Electric Institute Public Utility Accounting Course*, August 2015-2017.

"Current Issues in Cost of Capital," *Edison Electric Institute Advanced Rate School*, July 2013-2017.

"Alternative Regulation and Rate Making Approaches for Water Companies," *Society of Depreciation Professionals Annual Conference*, September 2014.

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"Accounting for Power Plant," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"GAAP / IFRS Convergence," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"International Innovations in Rate of Return Determination," *Society of Utility Financial and Regulatory Analysts' Financial Forum*, April 2012.

"Utility Accounting and Financial Analysis: The Impact of Regulatory Initiatives on Accounting and Credit Metrics," 1.5 day seminar, EUCI, Atlanta, May 2012.

"Cost of Capital Working Group Eforum," *Edison Electric Institute webinar*, April 2012.

"Issues Facing the Global Water Utility Industry" Presented to Sensus' Executive Retreat, Raleigh, NC, July 2010.

"Regulatory Issues from GAAP to IFRS," NASUCA *2009 Annual Meeting*, Chicago, November 2009.

"Subprime Mortgage-Related Litigation: What to Look for and Where to Look," *Law Seminars International: Damages in Securities Litigation*, Boston, May 2008.

"Evaluating Alternative Business / Inventive Models," (with Joe Wharton). *EEI Workshop, Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*, Washington DC, December 2007.

"Deferred Income Taxes and IRS's NOPR: Who should benefit?" *NASUCA Annual Meeting*, Anaheim, CA, November 2007.

"Discussion of 'Are Performance Measures Other Than Price Important to CEO Incentives?'" *Annual Meeting of the American Accounting Association*, 2000.

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Direct Testimony on wholesale water rates for Petitioner Cities, *Texas Public Utility Commission*, November 2017

Affidavit on Lifting the Dividend Restriction for Anchorage Water Utility for AWWU, *Regulatory Commission of Alaska*, U-17-095, November 2017.

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Expert Report on damages (quantum) in exit arbitration (with Dan Harris), *International Center for the Settlement of Investment Disputes*, October 2016.

Direct Testimony on capital structure, embedded cost of debt, and income taxes for Detroit Thermal, Michigan Public Service Commission, Docket No. UE-18131, July 2016.

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Expert Report on cost of equity, non-recovery of operating cost and asset retirement obligations on behalf of oil pipeline in arbitration, April 2013. (*Confidential*)

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Direct Testimony on regulatory assets and FERC accounting before the *Federal Energy Regulatory Commission* on behalf of AWC Companies, EL11-13-000, December 2010.

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Direct Testimony on cost of capital and carrying charge on damages, U.S. Department of Energy, *Bonneville Power Administration*, BPA Docket No. WP-07, March 2008.

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Exhibit NW Natural 402:

Technical Appendix

Contents

Exhibit NWN 402: Technical Appendix

This technical appendix contains details on the DCF and CAPM / ECAPM methods as well as on the financial leverage used to determine the cost of equity for a company with NWN's leverage.

I. DCF Models

A. DCF Estimation of Cost of Equity

The DCF method for estimating the cost of equity capital assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \tag{1}$$

where P_0 is the current market price of the stock; D_t is the dividend cash flow expected at the end of period t; r is the cost of equity capital; and T is the last period in which a dividend cash flow is to be received. The formula simply says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received. Since the current market price is known, it is possible to infer the cost of equity that corresponds to that price and a forecasted pattern of expected future dividends. In terms of Equation (1), if P_0 is known and $D_1, D_2, \dots D_T$ are estimated, an analyst can "solve for" the cost of equity capital r.

B. Details of the DCF Model

Perhaps the most widely known and used application of the DCF method assumes that the expected rate of dividend growth remains constant forever. In the so-called Gordon Growth Model, the relationship expressed in Equation (1) is such that the present value equation can be rearranged algebraically into a formula for estimating the cost of equity. Specifically, if investors expect a dividend stream that will grow forever at a steady rate, then the market price of the stock will be given by

$$P_0 = \frac{D_1}{r-g} \tag{2}$$

where D_1 is the dividend expected at the end of the first period, g is the perpetual growth rate, and P_0 and r are the market price and the cost of capital, as before. Equation (2) is a simplified version of Equation (1) that can be solved algebraically to yield the well-known "DCF formula" for the cost of equity capital,

$$r = \frac{D_1}{P_0} + g = \frac{D_0 \times (1+g)}{P_0} + g \tag{3}$$

There are other versions of the DCF model that relax this restrictive assumption and posit a more complex or nuanced pattern of expected future dividend payments. For example, if there is reason to believe that investors do *not* expect a company's dividends to grow at a steady rate forever, but rather have different growth rate expectations in the near term (e.g., over the next five or ten years), compared to the distant future (e.g., a period *starting* ten years from the present moment), a "multi-stage" growth pattern can be modeled in the present value formula (Equation (1)).

1. Dividends, Cash Flows, and Share Repurchases

In addition to the DCF model described above, there are many alternative formulations. Notable among these are versions of the model that use cash flows rather than dividends in the present value formula (Equation (1)).[1]

Because investors are interested in cash flow, it is technically important to capture *all* cash flows that are distributed to shareholders when estimating the cost of equity using the DCF method. In some circumstances, investors may expect to receive cash in forms other than dividends. An important example concerns the fact that many companies distribute cash to shareholders through share buybacks in addition to dividends. To the extent such repurchases are expected by investors, but not captured in the forecasted pattern of future dividends; a dividend-based implementation of the DCF model will underestimate the cost of equity.

Similarly, if investors have reason to suspect that a company's dividend payments will not reflect a full distribution of its available cash free cash flows in the period they were generated, it may be appropriate replace the forecasted dividends with estimated free cash flows to equity in the present value formula (Equation (1)). Focusing on *available* cash rather than that actually

[1] For an example in a regulatory context, the U.S. Surface Transportation Board uses a cash flow based model with three stages to estimate the cost of equity for the railroads. See Surface Transportation Board Decision, "STB Ex Parte No. 664 (Sub-No. 1)," Decided January 23, 2009. Confirmed in EP-664 (Sub-No. 2), October 31, 2016.

distributed in the form of dividends can help account for instances when near-term investing and financing activities (e.g., capital expenditures or asset sales, debt issuances or retirements, or share repurchases) may cause dividend growth patterns to diverge from growth in earnings.

Many utility companies such as those included in my samples have long histories of paying a dividend. In fact, as mentioned in Section I of this Appendix, one of my standard requirements for inclusion in my samples is that a company pays dividends for 5-years without a gap or a dividend cut (on per share basis).[2] Additionally, although some gas distribution utility companies have engaged in share repurchase programs, the companies in my samples do not distribute substantial cash flows by means other than dividends.[3]

C. DCF Model Inputs

1. Dividends and Prices

As described above, DCF models are forward-looking, comparing the *current* price of a stock to its expected *future* dividends to estimate the required expected return demanded by the market for that stock (i.e., the cost of equity). Therefore, the models demand the current market price and currently prevailing forecasts of future dividends as inputs.

The stock price input I employ for each sample company is the average of the closing stock prices for the 15 trading days ending on the date of my analysis. This guards against biases that may arise on a single trading day, yet is consistent with using current stock prices.

2. Company Specific Growth Rates

a. Analysts' Forecasted Growth Rates

Finding the right growth rate(s) is usually the "hard part" of applying the DCF model, which is sometimes criticized due to what has been called "optimism bias" in the earnings growth rate forecasts of security analysts. Optimism bias is related to the observed tendency for analysts to forecast earnings growth rates that are higher than are actually achieved. This tendency to overestimate growth rates is perhaps related to incentives faced by analysts that provide rewards

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[2] Because of the small number of companies meeting my standard selection criteria, I have included ONE Gas in my sample even though only 3 years of dividend data are available.

[3] While a number of companies in my samples have or have had share repurchase programs (e.g., Atmos,), the magnitude tends to be relatively small, so that an inclusion of the cash flow from repurchases would likely have a minimal impact on the average results for the samples. However, it is clear that not including such repurchases downwardly biases the estimated cost of equity.

not strictly based upon the accuracy of the forecasts. To the extent optimism bias is present in the analysts' earnings forecasts the cost of capital estimates from the DCF model would be too high.

While academic researchers during the 1990s as well as in early 2000s found evidence of analysts' optimism bias, there is some evidence that regulatory reforms have eliminated the issue. A recent paper by Hovakimina and Saenyasiri (2010) found that recent efforts to curb analysts' incentive to provide optimistic forecasts have worked, so that "the median forecast bias essentially disappeared."[4] Thus, some recent research indicates that the analyst bias may be a problem of the past.

The findings of several academic studies[5] show that analyst earnings forecasts turn out to be too optimistic for stocks that are more difficult to value, for instance, stocks of smaller firms, firms with high volatility or turnover, younger firms, or firms whose prospects are uncertain. Coincidentally, stocks with greater analyst disagreement have higher analyst optimism bias—all of these describe companies that are more volatile and/or less transparent—none of which is applicable to the majority of utility companies with wide analyst coverage and information transparency.

b. Sources for Forecasted Growth Rates

For the reasons described above, I rely on analyst forecasts of earnings growth for the company-specific growth rate inputs to my implementations of the single- and multi-stage DCF models. All of the companies in my sample except South Jersey Industries have coverage from equity analysts reporting to Thomson Reuters IBES, so I use the consensus 3-5 year EPS growth rate provided by that service. I supplement these consensus values with growth rates based on EPS estimates from *Value Line*.[6]

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4 A. Hovakimian and E. Saenyasiri, "Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation," *Financial Analysts Journal*, vol. 66, 2010.

5 These studies include the following: (i) Hribar, P, McInnis, J. "Investor Sentiment and Analysts' Earnings Forecast Errors," *Management Science* Vol. 58, No. 2 (February 2012): pp. 293-307; (ii) Scherbina, A. (2004), "Analyst Disagreement, Forecast Bias and Stock Returns," downloaded from Harvard Business School Working Knowledge: http://hbswk.hbs.edu/item/5418.html; and (iii) Michel, J-S., Pandes J.A. (2012), "Are Analysts Really Too Optimistic?" downloaded from http://www.efmaefm.org.

6 Specifically, I compute the growth rate implied by *Value Line*'s current year EPS estimate and its projected 3-5 year EPS estimate. I then average this in with the IBES consensus estimate as an additional independent estimate, giving it a weight of 1 and weighting the IBES consensus according to the number of analysts who contributed estimates.

II. CAPM and ECAPM

A. The Capital Asset Pricing Model (CAPM)

The Capital Asset Pricing Model (CAPM) is a theoretical model stating that the collective investment decisions of investors in capital markets will result in equilibrium prices for all risky assets such that the returns investors expect to receive on their investments are commensurate with the risk of those assets relative to the market as a whole. The CAPM posits a risk-return relationship known as the Security Market Line (see Figure 1 in my Direct Testimony), in which the required expected return on an asset is proportional to that asset's risk relative to the market as measured by its "beta". More precisely, the CAPM states that the cost of capital for an investment S (e.g., a particular common stock), is given by the following equation:

$$\boldsymbol{r_s} = \boldsymbol{r_f} + \boldsymbol{\beta_s} \times \boldsymbol{MRP} \tag{4}$$

where $\boldsymbol{r_S}$ is the required return on investment S;

$\boldsymbol{r_f}$ is the risk-free interest rate;

$\boldsymbol{\beta_S}$ is the beta risk measure for the investment S; and

$\boldsymbol{MRP}$ is the market equity risk premium.

The CAPM is based on portfolio theory, and recognizes two fundamental principles of finance: (1) investors seek to minimize the possible variance of their returns for a given level of expected returns (or alternatively, they demand higher *expected* returns when there is greater uncertainty about those returns), and (2) investors can reduce the variability of their returns by diversifying—constructing portfolios of many assets that do not all go up or down at the same time or to the same degree. Under the assumptions of the CAPM, the market participants will construct portfolios of risky investments that minimize risk for a given return so that the aggregate holdings of all investors represent the "market portfolio". The risk-return trade-off faced by investors then concerns their exposure to the risk inherent in the market portfolio, as they weight their investment capital between the portfolio of risky assets and the risk-free asset.

Because of the effects of diversification, the relevant measure of risk for an individual security is its *contribution* to the risk of the market portfolio. Therefore, beta (β) is defined to capture the sensitivity of the security's returns to the market's returns. Formally,

$$\boldsymbol{\beta_s} = \frac{covariance(\boldsymbol{r_s}, \boldsymbol{R_m})}{variance(\boldsymbol{R_m})} \tag{5}$$

where $\boldsymbol{R_m}$ is the return on the market portfolio.

Beta is usually calculated by statistically comparing (using regression analysis) the excess (positive or negative) of the return on the individual security over the government bond rate with the excess of the return on a market index such as the S&P 500 over a government bond rate.

The basic idea behind beta is the risk that cannot be diversified away in large portfolios is what matters to investors. Beta is a measure of the risks that *cannot* be eliminated by diversification. It is this non-diversifiable risk, or "systematic risk", for which investors require compensation in the form of higher expected returns. By definition, a stock with a beta equal to 1.0 has average non-diversifiable risk; its returns vary to the same degree as those on the market as a whole. According to the CAPM, the required return demanded by investors (i.e., the cost of equity) for investing in that stock will match the expected return on the market as a whole. Similarly, stocks with betas above 1.0 have more than average risk, and so have a cost of equity greater than the expected market return; those with betas below 1.0 have less than average risk, and are expected to earn lower than market levels of return.

B. Inputs to the CAPM

1. The Risk-free Interest Rate

The precise meaning of a "risk-free" asset according to the finance theory underlying the CAPM is an investment whose return is guaranteed, with no possibility that it will vary around its expected value in response to the movements of the broader market. (Equivalently, the CAPM beta of a risk-free asset is zero.) In developed economies like the U.S., government debt is generally considered have no default risk. In this sense they are "risk-free"; however, unless they are held to maturity, the rate of return on government bonds may in fact vary around their stated or expected yields.[7]

The theoretical CAPM is a single period model, meaning that it posits a relationship between risk and return over a single "holding period" of an investment. Because investors can rebalance their portfolios over short horizons, many academic studies and practical applications of the CAPM use the short-term government bond as the measure of the risk-free rate of return. However, regulators frequently use a version based on a measure of the long-term risk-free rate; e.g., a long-term government bond. I rely on the 20-year Treasury bond as a measure of the risk-free

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[7] This is due to interest rate fluctuations that can change the market value of previously issued debt in relation to the yield on new issuances

asset in this proceeding.[8] I use the term "risk-free rate" as describing the yield on the 20-year Treasury bond.

However, I do not believe the *current* yield on long-term Treasury bonds is a good estimate for the risk-free rate that will prevail over the time period relevant to this proceeding as currently prevailing bond yields are near historic lows for a variety of circumstances that should not be expected to persist for the reasons discussed in my direct testimony. For this reason I rely on Blue Chip's forecast of 3.40% for the yield on a 10-year Treasury bond for 2019.[9] I adjust this value upward by 54 basis points, which is my estimate of the maturity premium for the 20-year over the 10-year Treasury Bond.[10] This gives me a base input of 3.94% for the risk-free rate of interest before considering any downward pressure on government bond yields.

Additionally, it is important to recognize the implications of the elevated level of spread between yields on utility bonds and Treasury bonds of the same horizon. Figure A-1 below shows that this yield spread is about 29 basis points higher now than it was on average prior to the 2008 financial crisis. One way to account for this observation is if the prevailing and near-term expected government bond yields are artificially depressed relative to longer-term market expectations. Therefore, I consider a scenario with the risk-free rate (conservatively) 20 basis points higher at 4.14% when performing my CAPM-based analyses.

Figure A-1

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[8] The use of a 20-year government bond is consistent with the measurement of the Ibbotson MRP and permits me to use a series that has been in consistent circulation since the 1990's (the 30-year government bond was not issued from 2002 to 2006).

[9] Blue Chip Economic Indicators, October 10, 2017.

[10] This maturity premium is estimated by comparing the average excess yield on 20-year versus 10-year Treasury Bonds over the period September 1992 – September 2017, using data from Bloomberg. See BV Workpaper 1.

Spreads between U.S. Utility Bond (20 year maturity) and U.S. Government Bond (20 year maturity) - %			
Periods	A-Rated Utility and Treasury	BBB-Rated Utility and Treasury	Notes
Period 1 - Average Apr-1991 - 2007	0.93	1.23	[1]
Period 2 - Average Aug-2008 - Sep-2017	1.52	1.99	[2]
Period 3 - Average Sep-2017	1.35	1.74	[3]
Period 4 - Average 15-Day (Oct 10, 2017 to Oct 30, 2017)	1.23	1.60	[4]
Spread Increase between Period 2 and Period 1	0.59	0.76	[5] = [2] - [1]
Spread Increase between Period 3 and Period 1	0.42	0.51	[6] = [3] - [1]
Spread Increase between Period 4 and Period 1	**0.29**	**0.37**	[7] = [4] - [1]

Sources and Notes:
Spreads for the periods are calculated from Bloomberg's yield data.
Average monthly yields for the indices were retrieved from Bloomberg as of October 30, 2017.

2. The Market Equity Risk Premium

a. Historical Average Market Risk Premium

Like the cost of capital itself, the market risk premium is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can *expect* to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable, and must be inferred or forecasted based on known market information.

One commonly use method for estimating the MRP is to measure the historical average premium of market returns over the income returns on risk-free government bonds over some long historical period. *Duff and Phelps* performs such a calculation of the MRP using the traditional Ibbotson data. The arithmetic average of annual observed market equity risk premiums from 1926 to the present is 6.94%.[11]

b. Forward Looking Market Equity Risk Premium

An alternative approach to estimating the MRP eschews historical averages in favor of using current market information and forecasts to infer the expected return on the market as a whole, which can then be compared to prevailing government bond yields to estimate the equity risk premium. Bloomberg performs such estimates of country-specific MRPs by implementing the DCF model on the market as a whole—using forecast market-wide dividend yields and current

[11] Duff & Phelps, "2017 SBBI Yearbook," p. 10-21.

level on market indexes; for the U.S. Bloomberg uses the S&P 500 to infer the expected market return.

Bloomberg's estimate of the forward-looking market-implied MRP currently stands at about 7.07%.

c. Yield Spread Adjustments to the Market Equity Risk Premium

Figure A-1 above shows that the yield spreads for A and BBB rated utility debt over Treasury bonds have increased by approximately 29 bps and 37 bps for 20-year maturities relative to its long-term average leading up to the 2008 financial crisis. This means that investors require a higher return on investment grade utility debt relative to the return on T-bonds than they did before the crisis and ensuing economic turmoil.

This information can be used to provide a quantitative benchmark for the implied increase in MRP based on a paper by Edwin J. Elton, et al., which documents that the yield spread on corporate bonds is normally a combination of a default premium, a tax premium, and a systematic risk premium.[12] Of these components, it is the systematic risk premium that likely explains the vast majority of the yield spread increase. In other words, unless the risk-free rate is underestimated as described above, the market equity risk premium has increased relative to its "normal" level.[13] Therefore, I consider a scenario allocating the majority of the 29 bps increase in A-rated utility spreads to an increase in the MRP (which drives the increase in systematic risk premium on A rated debt). As a conservative measure I allocate 20 bps as the downward bias in the current 20-year Treasury bond yield.

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[12] "Explaining the Rate Spread on Corporate Bonds," Edwin J. Elton, Martin J. Gruber, Deepak Agarwal, and Christopher Mann, *The Journal of Finance*, February 2001, pp. 247-277.

[13] In theory, some of the increase in yield spread for A rated debt may be due to an increase in default risk, but the increase in default risk for A rated debt is undoubtedly very small because utilities with A range rated debt have a low default risk. This means that the vast majority—if not all—of the increase in A rated yield spreads is due to a combination of the increased systematic risk premium and the downward pressure on the yields of government debt. Although there is no increase in the tax premium discussed in the Elton et al. paper due to coupon payments, there may be some increase due to a small tax effect resulting from the probability of increased capital gains taxes when the debt matures.

Assuming a beta of 0.25 for A rated debt[14] means that an increase in the MRP of one percentage point translates into a ¼ percentage point increase in the risk premium on A rated debt (i.e., 0.25 (beta) times 1 percentage point (increase in MRP) = ¼ percentage point increase in yield spread). Thus, a 20 bps increase in the yield spread is therefore consistent with a 0.8 percentage point increase in the MRP ($\frac{0.20\%}{0.25} = 0.8\%$). Thus there is evidence that the current MRP is elevated relative to the historical MRP of 6.94%. I therefore implement a second scenario that use a MRP that is 50 basis points higher than the historical MRP, but in that scenario I rely on the forecasted risk-free rate without considering the elevated yield spread.

C. The Empirical CAPM

1. Description of the ECAPM

Empirical research has shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted. A number of variations on the original CAPM theory have been proposed to explain this finding, but the observation itself can also be used to estimate the cost of capital directly, using beta to measure relative risk by making a direct empirical adjustment to the CAPM.

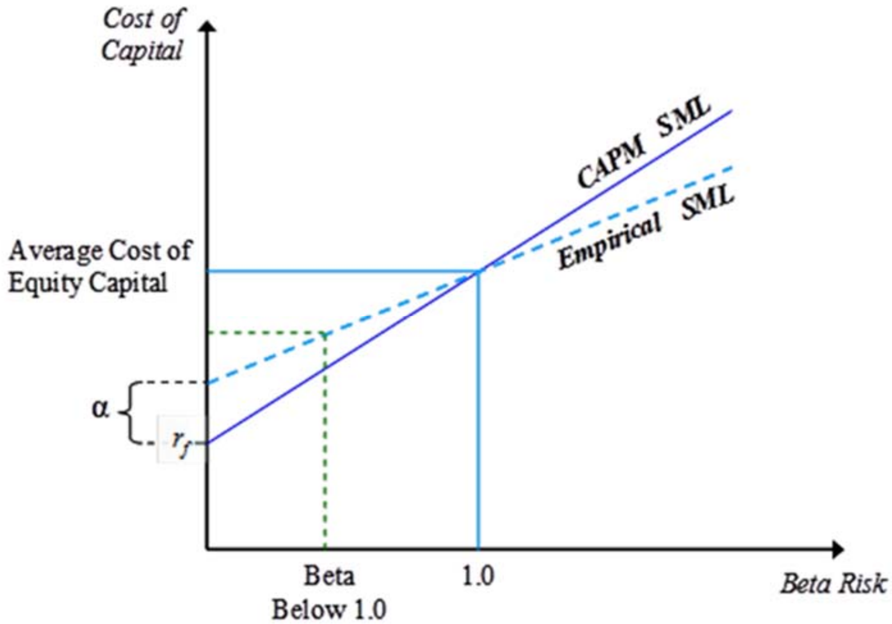
The Empirical CAPM (ECAPM) makes use of these empirical findings. It estimates the cost of capital with the equation,

$$\boldsymbol{r_S = r_f + \alpha + \beta_S} \times (\boldsymbol{MRP - \alpha}) \tag{6}$$

where $\boldsymbol{\alpha}$ is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as for the CAPM (see Equation (4)). The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line, which results in a Security Market Line that more closely matches the results of empirical tests. In other words, the ECAPM produces more accurate predictions of eventual realized risk premiums than does the CAPM.

14 Elton, *et al*. estimates the average beta on BBB-rated corporate debt as 0.26 over the period of their study, and A-rated debt will have a slightly lower beta than BBB-rated debt. I note that 0.25 is a conservatively high estimate of the beta on A-rated utility debt. Most academic estimates, including those presented in *Berk & Demarzo* that I utilize for my Hamada adjustments are significantly lower: in the range of 0.0 – 0.1 percent and would result in a substantially higher MRP estimate.

Figure A-2
The Empirical Security Market Line



2. Academic Evidence on the Alpha Term in the ECAPM

Figure A-3-below summarizes the empirical results of tests of the CAPM, including their estimates of the "alpha" parameter necessary to improve the accuracy of the CAPM's predictions of realized returns.

Figure A-3

EMPIRICAL EVIDENCE ON THE ALPHA FACTOR IN ECAPM*

AUTHOR	RANGE OF ALPHA	PERIOD RELIED UPON
Black (1993)[1]	1% for betas 0 to 0.80	1931-1991
Black, Jensen and Scholes (1972)[2]	4.31%	1931-1965
Fama and McBeth (1972)	5.76%	1935-1968
Fama and French (1992)[3]	7.32%	1941-1990
Fama and French (2004)[4]	N/A	
Litzenberger and Ramaswamy (1979)[5]	5.32%	1936-1977
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 3.91%	1926-1978
Pettengill, Sundaram and Mathur (1995)[6]	4.6%	1936-1990

*The figures reported in this table are for the longest estimation period available and, when applicable, use the authors' recommended estimation technique. Many of the articles cited also estimate alpha for sub-periods and those alphas may vary.

[1]Black estimates alpha in a one step procedure rather than in an un-biased two-step procedure.
[2]Estimate a negative alpha for the subperiod 1931-39 which contain the depression years 1931-33 and 1937-39.
[3]Calculated using Ibbotson's data for the 30-day treasury yield.
[4]The article does not provide a specific estimate of alpha; however, it supports the general finding that the CAPM underestimates returns for low-beta stocks and overestimates returns for high-beta stocks.
[5]Relies on Lizenberger and Ramaswamy's before-tax estimation results. Comparable after-tax alpha estimate is 4.4%.
[6]Pettengill, Sundaram and Mathur rely on total returns for the period 1936 through 1990 and use 90-day treasuries. The 4.6% figure is calculated using auction averages 90-day treasuries back to 1941 as no other series were found this far back.

Sources:
Black, Fischer. 1993. Beta and Return. *The Journal of Portfolio Management* 20 (Fall): 8-18.
Black, F., Michael C. Jensen, and Myron Scholes. 1972. The Capital Asset Pricing Model: Some Empirical Tests, from Studies in the theory of Capital Markets. In *Studies in the Theory of Capital Markets*, edited by Michael C. Jensen, 79-121. New York: Praeger.
Fama, Eugene F. and James D. MacBeth. 1972. Risk, Returns and Equilibrium: Empirical Tests. *Journal of Political Economy* 81 (3): 607-636.
Fama, Eugene F. and Kenneth R. French. 1992. The Cross-Section of Expected Stock Returns. *Journal of Finance* 47 (June): 427-465.
Fama, Eugene F. and Kenneth R. French. 2004. The Capital Asset Pricing Model: Theory and Evidence. *Journal of Economic Perspectives* 18 (3): 25-46.
Litzenberger, Robert H. and Krishna Ramaswamy. 1979. The Effect of Personal Taxes and Dividends on Capital Asset Prices, Theory and Empirical Evidence. *Journal of Financial Economics* XX (June): 163-195.
Litzenberger, Robert H. and Krishna Ramaswamy and Howard Sosin. 1980. On the CAPM Approach to Estimation of a Public Utility's Cost of Equity Capital. *The Journal of Finance* 35 (2): 369-387.

III. Financial Risk and the Cost of Equity

A common issue in regulatory proceedings is how to apply data from a benchmark set of comparable securities when estimating a fair return on equity for the target/regulated company.[15] It may be tempting to simply estimate the cost of equity capital for each of the sample companies (using one of the above approaches) and average them. After-all, the companies were chosen to be comparable in their business risk characteristics, so why would an investor necessarily prefer equity in one to the other (on average)?

The problem with this argument is that it ignores the fact that underlying asset risk (i.e., the risk inherent in the lines of business in which the firm invests its assets) for each company is typically divided between debt and equity holders. The firm's debt and equity are therefore financial derivatives of the underlying asset return, each offering a differently structured claim on the cash flows generated by those assets. Even though the risk of the underlying assets may be comparable, a different capital structure splits that risk differently between debt and equity holders. The relative structures of debt and equity claims are such that higher degrees of debt financing increase the variability of returns on equity, *even when the variability of asset returns remains constant*. As a consequence, otherwise identical firms with different capital structures will impose different levels of risk on their equity holders. Stated differently, increased leverage adds financial risk to a company's equity.[16]

A. The Effect of Financial Leverage on the Cost of Equity

To develop an intuition for the manner in which financial leverage affects the risk of equity, it is helpful to consider a concrete example. Figure A-2 and Figure A-3 below demonstrate the impact of leverage on the risk and return for equity by comparing equity's risk when a company uses no debt to finance its assets, and when it uses a 50-50 capital structure (i.e., it finances 50 percent of its assets with equity, 50 percent with debt). For illustrative purposes, the figures assume that the cash flows will be either $5 or $15 and that these two possibilities have the same chance of occurring (e.g., the chance that either occurs is ½).

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15 This is also a common valuation problem in general business contexts.

16 I refer to this effect in terms of *financial risk* because the additional risk to equity holders stems from how the company chooses to finance its assets. In this context financial risk is distinct from and independent of the *business risk* associated with the manner in which the firm deploys its cash flow generating assets. The impact of leverage on risk is conceptually no different than that faced by a homeowner who takes out a mortgage. The equity of a homeowner who finances his home with 90% debt is much riskier than the equity of one who only finances with 50% debt.

Figure A-2: All Equity Capital Structure

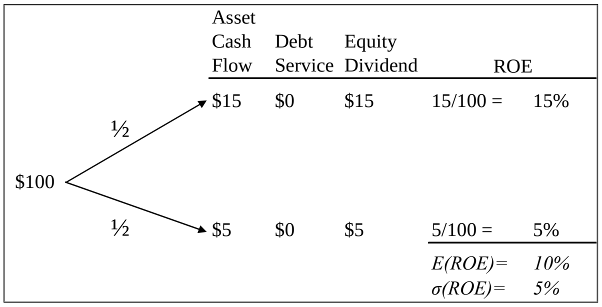
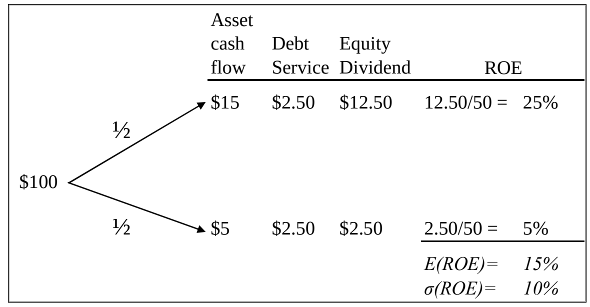


Figure A-3: 50/50 Capital Structure.



In the figures, E(ROE) indicates the mean return and σ(ROE) represents the standard deviation. This simple example illustrates that the introduction of debt increases both the mean (expected) return to equity holders and the variance of that return, even though the firm's expected cash flows—which are a property of the line of business in which its assets are invested—are unaffected by the firm's financing choices. The "magic" of financial leverage is not magic at all—leveraged equity investors can only earn a higher return because they take on greater risk.

B. Methods to Account for Financial Risk

1. Cost of Equity Implied by the Overall Cost of Capital

If the companies in a sample are truly comparable in terms of the systematic risks of the underlying assets, then the overall cost of capital of each company should be about the same across companies (except for sampling error), so long as they do not use extreme leverage or no leverage. The intuition here is as follows. A firm's asset value (and return) is allocated between equity and debt holders.[17] The expected return to the underlying asset is therefore equal to the

[17] Other claimants can be added to the weighted average if they exist. For example, when a firm's capital structure contains preferred equity, the term $\frac{P}{V} \times r_p$ is added to the expression for the overall cost of capital shown in Equation (7), where P refers to the market value of preferred equity, r_P is the cost of preferred equity and $V = E + D + P$. In my analysis, I attribute the same implied yield to the cost of preferred equity as to the cost of debt.

value weighted average of the expected returns to equity and debt holders – which is the overall cost of capital ($\boldsymbol{r}^*$), or the expected return on the assets of the firm as a whole.[18]

$$\boldsymbol{r}^* = \frac{E}{V} \times r_E + \frac{D}{V} \times r_D (1 - \tau_c) \tag{7}$$

where r_D is the market cost of debt,
r_E is the market cost of equity,
τ_c is the corporate income tax rate,
D is the market value of the firm's debt,
E is the market value of the firm's equity, and
$V = E + D$ is the total market value of the firm.

Since the overall cost of capital is the cost of capital for the underlying asset risk, and this is comparable across companies, it is reasonable to believe that the overall cost of capital of the underlying companies should also be comparable, so long as capital structures do not involve unusual leverage ratios compared to other companies in the industry.[19]

The notion that the overall cost of capital is constant across a broad middle range of capital structures is based upon the Modigliani-Miller theorem that choice of financing does not affect the firm's value. Franco Modigliani and Merton Miller eventually won Nobel Prizes in part for their work on the effects of debt.[20] Their 1958 paper made what is in retrospect a very simple point: if there are no taxes and no risk to the use of excessive debt, use of debt will have no effect on a company's operating cash flows (i.e., the cash flows to investors as a group, debt and equity combined). If the operating cash flows are the same regardless of whether the company finances mostly with debt or mostly with equity, then the value of the firm cannot be affected at

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[18] As this is on an after-tax basis, the cost of debt reflects the tax value of interest deductibility. Note that the precise formulation of the weighted average formula representing the required return on the firm's *assets* independent of financing (sometimes called the *unlevered* cost of capital) depends on specific assumptions made regarding the value of tax shields from tax-deductible corporate debt, the role of personal income tax, and the cost of financial distress. See Taggart, Robert A., "Consistent Valuation and Cost of Capital Expressions with Corporate and Personal Taxes," *Financial Management*, 1991; 20(3) for a detailed discussion of these assumptions and formulations. Equation (7) represents the overall cost of capital to the firm, which can be assumed to be constant across a relatively broad range of capital structures.

[19] Empirically, companies within the same industry tend to have similar capital structures, while typical capital structures may vary between industries, so whether a leverage ratio is "unusual" depends upon the company's line of business.

[20] Franco Modigliani and Merton H. Miller (1958), "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48, pp. 261-297.

all by the debt ratio. In cost of capital terms, this means the overall cost of capital is constant regardless of the debt ratio, too.

Obviously, the simple and elegant Modigliani-Miller theorem makes some counterfactual assumptions: no taxes and no cost of financial distress from excessive debt. However, subsequent research, including some by Modigliani and Miller,[21] showed that while taxes and costs to financial distress affect a firm's incentives when choosing its capital structure as well as its overall cost of capital,[22] the latter can still be shown to be constant across a broad range of capital structures.[23]

This reasoning suggests that one could compute the overall cost of capital for each of the sample companies and then average to produce an estimate of the overall cost of capital associated with the underlying asset risk. Assuming that the overall cost of capital is constant, one can then re-arrange the overall cost of capital formula to estimate what the implied cost of equity is at the target company's capital structure on a book value basis.[24]

2. Unlevering and Relevering Betas in the CAPM (Hamada Adjustment)

An alternative approach to account for the impact of financial risk is to examine the impact of leverage on beta. Notice that this means working within the CAPM framework as the methodology cannot be applied directly to the DCF models.

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[21] Franco Modigliani and Merton H. Miller (1963), "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53, pp. 433-443.

[22] When a company uses a high level of debt financing, for example, there is significant risk of bankruptcy and all the costs associated with it. The so called costs of financial distress that occurs when a company is over-leveraged can increase its cost of capital. In contrast a company can generally decrease its cost of capital by taking on reasonable levels of debt, owing in part to the deductibility of interest from corporate taxes.

[23] This is a simplified treatment of what is generally a complex and on-going area of academic investigation. The roles of taxes, market imperfections and constraints, etc. are areas of on-going research and differing assumptions can yield subtly different formulations for how to formulate the weighted average cost of capital that is constant over all (or most) capital structures.

[24] Market value capital structures are used in estimating the overall cost of capital for the sample companies.

Recognizing that under general conditions, the value of a firm can be decomposed into its value with and without a tax shield, I obtain:[25]

$$V = V_U + PV(ITS) \tag{8}$$

where $V = E + D$ is the total value of the firm as in Equation (7),

V_U is the "unlevered" value of the firm—its value if financed entirely by equity

$PV(ITS)$ represents the present value of the interest tax shields associated with debt

For a company with a fixed book-value capital structure and no additional costs to leverage, it can be shown that the formula above implies:

$$r_E = r_U + \frac{D}{E}(1 - \tau_c)(r_U - r_D) \tag{9}$$

where r_U is the "unlevered cost of capital"—the required return on assets if the firm's assets were financed with 100% equity and zero debt—and the other parameters are defined as in Equation (7).

Replacing each of these returns by their CAPM representation and simplifying them gives the following relationship between the "levered" equity beta β_L for a firm (i.e., the one observed in market data as a consequence of the firm's actual market value capital structure) and the "unlevered" beta β_U that would be measured for the same firm if it had no debt in its capital structure:

$$\beta_L = \beta_U + \frac{D}{E}(1 - \tau_c)(\beta_U - \beta_D) \tag{10}$$

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[25] This follows development in Fernandez (2003). Other standard papers in this area include Hamada (1972), Miles and Ezzell (1985), Harris and Pringle (1985), Fernandez (2006). (See Fernandez, P., "Levered and Unlevered Beta," IESE Business School Working Paper WP-488, University of Navarra, Jan 2003 (rev. May 2006); Hamada, R.S., "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stock," *Journal of Finance*, 27, May 1972, pp. 435-452; Miles, J.A. and J.R. Ezzell, "Reformulating Tax Shield Valuation: A Note," *Journal of Finance*, XL5, Dec 1985, pp. 1485-1492; Harris, R.S. and J.J. Pringle, "Risk-Adjusted Discount Rates Extensions form the Average-Risk Case," *Journal of Financial Research*, Fall 1985, pp. 237-244; Fernandez, P., "The Value of Tax Shields Depends Only on the Net Increases of Debt," IESE Business School Working Paper WP-613, University of Navarra, 2006.) Additional discussion can be found in Brealey, Myers, and Allen (2014).

where β_D is the beta on the firm's debt. The unlevered beta is assumed to be constant with respect to capital structure, reflecting as it does the systematic risk of the firm's assets. Since the beta on an investment grade firm's debt is much lower than the beta of its assets (i.e., $\beta_D < \beta_U$), this equation embodies the fact that increasing financial leverage (and thereby increasing the debt to equity ratio) increases the systematic risk of *levered* equity (β_L).

An alternative formulation derived by Harris and Pringle (1985) provides the following equation that holds when the market value capital structures (rather than book value) are assumed to be held constant:

$$\beta_L = \beta_U + \frac{D}{E}(\beta_U - \beta_D) \tag{11}$$

Unlike Equation (10), Equation (11) does not include an adjustment for the corporate tax deduction. However, both equations account for the fact that increased financial leverage increases the systematic risk of equity that will be measured by its market beta. And both equations allow an analyst to adjust for differences in financial risk by translating back and forth between β_L and β_U. In principal, Equation (10) is more appropriate for use with regulated utilities, which are typically deemed to maintain a fixed book value capital structure. However, I employ both formulations when adjusting my CAPM estimates for financial risk, and consider the results as sensitivities in my analysis.

It is clear that the beta of debt needs to be determined as an input to either Equation (10), or Equation (11). Rather than estimating debt betas, I rely on the standard financial textbook of Professors Berk & DeMarzo, who report a debt beta of 0.05 for A rated debt and a beta of 0.10 for BBB rated debt.[26]

Once a decision on debt betas is made, the levered equity beta of each sample company can be computed (in this case by Value Line) from market data and then translated to an unlevered beta at the company's market value capital structure. The unlevered betas for the sample companies are comparable on an "apples to apples" basis, since they reflect the systematic risk inherent in the assets of the sample companies, independent of their financing. The unlevered betas are averaged to produce an estimate of the industry's unlevered beta. To estimate the cost of equity for the regulated target company, this estimate of unlevered beta can be "re-levered" to the

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[26] Berk, J. & DeMarzo, P., *Corporate Finance, 2nd Edition.* 2011 Prentice Hall, p. 389.

regulated company's capital structure, and CAPM reapplied with this levered beta, which reflects both the business and financial risk of the target company.

Hamada adjustment procedures—so-named for Professor Robert S. Hamada who contributed to their development[27]—are ubiquitous among finance practitioners when using the CAPM to estimate discount rates.

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[27] Hamada, R.S., "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stock", *The Journal of Finance*, 27(2), 1971, pp. 435-452.

EXHIBIT NW NATURAL 403
CAPITAL STRUCTURE
DCF COST OF EQUITY

Table No. BV-GAS-2

Classification of Companies by Assets

Company	Company Category
Atmos Energy	R
New Jersey Resources	M
Northwest Natural Gas	R
South Jersey Inds.	M
Southwest Gas	R
WGL Holdings Inc.	R
Chesapeake Utilities	M
ONE Gas Inc.	R
Spire Inc.	R

Sources and Notes:
Percent regulated determined based on respective company 2016 10-K information.
R = Regulated (greater than 80 percent of total assets are regulated).
M = Mostly Regulated (50 to 80 percent of total assets are regulated).
D = Diversified (less than 50 percent of total assets are regulated).

Table No. BV-GAS-3

Market Value of the U.S. Gas Sample

Panel A: Atmos Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	$3,902	$3,902	$3,463	$3,195	$3,086	$2,580	$2,359	[a]
Shares Outstanding (in millions) - Common	106	106	104	104	100	91	90	[b]
Price per Share - Common	$87	$86	$75	$56	$49	$42	$36	[c]
Market Value of Common Equity	$9,174	$9,074	$7,799	$5,817	$4,908	$3,764	$3,217	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$9,174	$9,074	$7,799	$5,817	$4,908	$3,764	$3,217	[f]= [d]
Market to Book Value of Common Equity	2.35	2.33	2.25	1.82	1.59	1.46	1.36	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$534	$534	$682	$626	$776	$683	$828	[j]
Current Liabilities	$746	$746	$1,788	$1,155	$911	$978	$1,276	[k]
Current Portion of Long-Term Debt	$0	$0	$250	$0	$500	$0	$0	[l]
Net Working Capital	($211)	($211)	($857)	($529)	$365	($295)	($448)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$259	$259	$830	$458	$197	$368	$571	[n]
Adjusted Short-Term Debt	$211	$211	$830	$458	$0	$295	$448	[o] = See Sources and Notes.
Long-Term Debt	$3,067	$3,067	$2,189	$2,438	$2,456	$2,456	$1,956	[p]
Book Value of Long-Term Debt	$3,278	$3,278	$3,269	$2,895	$2,956	$2,751	$2,404	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,845	$2,845	$2,669	$2,770	$2,676	$2,426	$2,561	
Carrying Amount	$2,460	$2,460	$2,460	$2,460	$2,460	$1,960	$2,213	
Adjustment to Book Value of Long-Term Debt	$385	$385	$209	$310	$216	$466	$348	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$3,663	$3,663	$3,478	$3,205	$3,172	$3,217	$2,753	[s] = [q] + [r].
Market Value of Debt	$3,663	$3,663	$3,478	$3,205	$3,172	$3,217	$2,753	[t] = [s].
MARKET VALUE OF FIRM	$12,837	$12,737	$11,277	$9,022	$8,081	$6,981	$5,970	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	71.47%	71.24%	69.16%	64.48%	60.74%	53.92%	53.89%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	28.53%	28.76%	30.84%	35.52%	39.26%	46.08%	46.11%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of October 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 10/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-GAS-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-GAS-3

Market Value of the U.S. Gas Sample

Panel B: New Jersey Resources

($MM)

	DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	$1,285	$1,285	$1,167	$1,107	$966	$887	$814	[a]
Shares Outstanding (in millions) - Common	86	86	86	86	84	84	83	[b]
Price per Share - Common	$44	$43	$34	$28	$25	$22	$23	[c]
Market Value of Common Equity	$3,766	$3,679	$2,906	$2,409	$2,138	$1,829	$1,920	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$3,766	$3,679	$2,906	$2,409	$2,138	$1,829	$1,920	[f]= [d]
Market to Book Value of Common Equity	2.93	2.86	2.49	2.18	2.21	2.06	2.36	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$638	$638	$607	$488	$683	$746	$647	[j]
Current Liabilities	$776	$776	$572	$436	$791	$852	$653	[k]
Current Portion of Long-Term Debt	$186	$186	$61	$11	$35	$69	$8	[l]
Net Working Capital	$48	$48	$97	$63	($74)	($37)	$2	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$263	$263	$122	$66	$301	$366	$280	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$74	$37	$0	[o] = See Sources and Notes.
Long-Term Debt	$898	$898	$1,064	$844	$598	$513	$525	[p]
Book Value of Long-Term Debt	$1,084	$1,084	$1,125	$855	$707	$619	$533	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$732	$732	$584	$587	$557	$530	$416	
Carrying Amount	$708	$708	$583	$558	$530	$480	$380	
Adjustment to Book Value of Long-Term Debt	$24	$24	$1	$29	$27	$50	$37	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,108	$1,108	$1,126	$884	$733	$669	$570	[s] = [q] + [r].
Market Value of Debt	$1,108	$1,108	$1,126	$884	$733	$669	$570	[t] = [s].
MARKET VALUE OF FIRM	$4,874	$4,786	$4,032	$3,293	$2,871	$2,498	$2,489	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	77.27%	76.86%	72.07%	73.16%	74.46%	73.21%	77.12%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	22.73%	23.14%	27.93%	26.84%	25.54%	26.79%	22.88%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of October 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 10/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-GAS-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-GAS-3

Market Value of the U.S. Gas Sample

Panel C: Northwest Natural Gas

($MM)

	DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	$865	$865	$779	$759	$752	$730	$718	[a]
Shares Outstanding (in millions) - Common	29	29	28	27	27	27	27	[b]
Price per Share - Common	$66	$66	$61	$44	$43	$41	$49	[c]
Market Value of Common Equity	$1,879	$1,888	$1,674	$1,212	$1,178	$1,115	$1,311	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$1,879	$1,888	$1,674	$1,212	$1,178	$1,115	$1,311	[f]= [d]
Market to Book Value of Common Equity	2.17	2.18	2.15	1.60	1.57	1.53	1.83	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$192	$192	$211	$277	$248	$196	$198	[j]
Current Liabilities	$235	$235	$403	$385	$386	$342	$345	[k]
Current Portion of Long-Term Debt	$62	$62	$65	$0	$40	$60	$0	[l]
Net Working Capital	$19	$19	($127)	($109)	($98)	($87)	($147)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$195	$225	$190	$141	$176	[n]
Adjusted Short-Term Debt	$0	$0	$127	$109	$98	$87	$147	[o] = See Sources and Notes.
Long-Term Debt	$658	$658	$530	$614	$622	$682	$642	[p]
Book Value of Long-Term Debt	$720	$720	$722	$723	$759	$828	$789	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$793	$793	$667	$757	$806	$835	$809	
Carrying Amount	$719	$719	$602	$662	$742	$692	$682	
Adjustment to Book Value of Long-Term Debt	$74	$74	$65	$95	$65	$143	$127	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$794	$794	$788	$818	$824	$971	$916	[s] = [q] + [r].
Market Value of Debt	$794	$794	$788	$818	$824	$971	$916	[t] = [s].
MARKET VALUE OF FIRM	$2,674	$2,682	$2,461	$2,030	$2,002	$2,086	$2,227	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	70.30%	70.39%	67.99%	59.72%	58.85%	53.44%	58.86%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	29.70%	29.61%	32.01%	40.28%	41.15%	46.56%	41.14%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of October 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 10/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-GAS-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-GAS-3

Market Value of the U.S. Gas Sample

Panel D: South Jersey Inds.

($MM)

	DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	$1,279	$1,279	$1,267	$947	$864	$757	$696	[a]
Shares Outstanding (in millions) - Common	80	80	79	69	66	64	62	[b]
Price per Share - Common	$34	$35	$30	$24	$27	$29	$26	[c]
Market Value of Common Equity	$2,691	$2,793	$2,355	$1,642	$1,803	$1,853	$1,628	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$2,691	$2,793	$2,355	$1,642	$1,803	$1,853	$1,628	[f]= [d]
Market to Book Value of Common Equity	2.10	2.18	1.86	1.73	2.09	2.45	2.34	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$356	$356	$358	$479	$426	$365	$324	[j]
Current Liabilities	$734	$734	$812	$807	$604	$710	$553	[k]
Current Portion of Long-Term Debt	$16	$16	$232	$78	$74	$21	$25	[l]
Net Working Capital	($362)	($362)	($223)	($250)	($104)	($324)	($204)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$296	$296	$230	$351	$149	$378	$315	[n]
Adjusted Short-Term Debt	$296	$296	$223	$250	$104	$324	$204	[o] = See Sources and Notes.
Long-Term Debt	$1,067	$1,067	$809	$956	$955	$580	$566	[p]
Book Value of Long-Term Debt	$1,379	$1,379	$1,263	$1,284	$1,134	$925	$795	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,081	$1,081	$1,079	$1,059	$713	$682	$533	
Carrying Amount	$1,047	$1,047	$1,036	$1,009	$701	$626	$426	
Adjustment to Book Value of Long-Term Debt	$33	$33	$43	$49	$12	$56	$107	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,412	$1,412	$1,307	$1,333	$1,146	$981	$902	[s] = [q] + [r].
Market Value of Debt	$1,412	$1,412	$1,307	$1,333	$1,146	$981	$902	[t] = [s].
MARKET VALUE OF FIRM	$4,103	$4,205	$3,661	$2,975	$2,949	$2,833	$2,530	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	65.58%	66.41%	64.31%	55.18%	61.15%	65.38%	64.34%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	34.42%	33.59%	35.69%	44.82%	38.85%	34.62%	35.66%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of October 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 10/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-GAS-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-GAS-3

Market Value of the U.S. Gas Sample

Panel E: Southwest Gas

($MM)

	DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	$1,717	$1,717	$1,625	$1,550	$1,454	$1,363	$1,266	[a]
Shares Outstanding (in millions) - Common	48	48	47	47	47	46	46	[b]
Price per Share - Common	$80	$79	$71	$55	$50	$48	$44	[c]
Market Value of Common Equity	$3,821	$3,756	$3,360	$2,625	$2,344	$2,246	$2,033	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$3,821	$3,756	$3,360	$2,625	$2,344	$2,246	$2,033	[f]= [d]
Market to Book Value of Common Equity	2.23	2.19	2.07	1.69	1.61	1.65	1.61	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$484	$484	$544	$479	$451	$348	$350	[j]
Current Liabilities	$490	$490	$613	$495	$394	$406	$465	[k]
Current Portion of Long-Term Debt	$27	$27	$49	$20	$11	$11	$5	[l]
Net Working Capital	$21	$21	($19)	$4	$68	($47)	($110)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$3	$3	$0	$0	$0	$33	$0	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$33	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,686	$1,686	$1,593	$1,540	$1,438	$1,280	$1,256	[p]
Book Value of Long-Term Debt	$1,713	$1,713	$1,642	$1,560	$1,449	$1,324	$1,261	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,680	$1,680	$1,646	$1,796	$1,463	$1,482	$1,319	
Carrying Amount	$1,550	$1,550	$1,551	$1,657	$1,392	$1,319	$1,253	
Adjustment to Book Value of Long-Term Debt	$130	$130	$94	$139	$71	$164	$66	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,843	$1,843	$1,737	$1,699	$1,520	$1,488	$1,327	[s] = [q] + [r].
Market Value of Debt	$1,843	$1,843	$1,737	$1,699	$1,520	$1,488	$1,327	[t] = [s].
MARKET VALUE OF FIRM	$5,663	$5,598	$5,096	$4,325	$3,864	$3,734	$3,360	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	67.46%	67.08%	65.92%	60.71%	60.66%	60.15%	60.51%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	32.54%	32.92%	34.08%	39.29%	39.34%	39.85%	39.49%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of October 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 10/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-GAS-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-GAS-3

Market Value of the U.S. Gas Sample

Panel F: WGL Holdings Inc.

($MM)

	DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	$1,521	$1,521	$1,376	$1,243	$1,247	$1,275	$1,270	[a]
Shares Outstanding (in millions) - Common	51	51	51	50	51	52	52	[b]
Price per Share - Common	$86	$84	$63	$55	$43	$42	$40	[c]
Market Value of Common Equity	$4,387	$4,327	$3,222	$2,719	$2,169	$2,167	$2,074	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$4,387	$4,327	$3,222	$2,719	$2,169	$2,167	$2,074	[f]= [d]
Market to Book Value of Common Equity	2.88	2.84	2.34	2.19	1.74	1.70	1.63	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$28	$28	$28	$28	$28	$28	$28	[h]
Market Value of Preferred Equity	$28	$28	$28	$28	$28	$28	$28	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$962	$962	$843	$749	$836	$820	$833	[j]
Current Liabilities	$1,434	$1,434	$1,027	$983	$1,020	$950	$757	[k]
Current Portion of Long-Term Debt	$250	$250	$0	$25	$20	$67	$0	[l]
Net Working Capital	($222)	($222)	($183)	($209)	($165)	($63)	$76	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$539	$539	$331	$332	$454	$373	$248	[n]
Adjusted Short-Term Debt	$222	$222	$183	$209	$165	$63	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,236	$1,236	$1,444	$944	$679	$524	$589	[p]
Book Value of Long-Term Debt	$1,707	$1,707	$1,628	$1,179	$864	$654	$589	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,642	$1,642	$1,058	$809	$630	$759	$721	
Carrying Amount	$1,444	$1,444	$944	$679	$524	$589	$587	
Adjustment to Book Value of Long-Term Debt	$198	$198	$114	$130	$106	$170	$134	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,905	$1,905	$1,741	$1,309	$970	$824	$723	[s] = [q] + [r].
Market Value of Debt	$1,905	$1,905	$1,741	$1,309	$970	$824	$723	[t] = [s].
MARKET VALUE OF FIRM	$6,320	$6,260	$4,992	$4,056	$3,167	$3,019	$2,825	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	69.42%	69.12%	64.55%	67.04%	68.48%	71.78%	73.41%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.45%	0.45%	0.56%	0.69%	0.89%	0.93%	1.00%	[w] = [i] / [u].
Debt - Market Value Ratio	30.14%	30.43%	34.88%	32.27%	30.63%	27.29%	25.59%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of October 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 10/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-GAS-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-GAS-3

Market Value of the U.S. Gas Sample

Panel G: Chesapeake Utilities

($MM)

	DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	$462	$462	$438	$353	$296	$270	$250	[a]
Shares Outstanding (in millions) - Common	16	16	16	15	15	14	14	[b]
Price per Share - Common	$81	$79	$62	$49	$43	$35	$31	[c]
Market Value of Common Equity	$1,320	$1,294	$1,007	$755	$622	$506	$448	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$1,320	$1,294	$1,007	$755	$622	$506	$448	[f]= [d]
Market to Book Value of Common Equity	2.86	2.80	2.30	2.14	2.10	1.88	1.79	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$102	$102	$102	$88	$88	$98	$86	[j]
Current Liabilities	$272	$272	$263	$237	$169	$195	$131	[k]
Current Portion of Long-Term Debt	$12	$12	$12	$9	$11	$8	$8	[l]
Net Working Capital	($157)	($157)	($149)	($140)	($70)	($89)	($36)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$146	$146	$154	$127	$71	$91	$31	[n]
Adjusted Short-Term Debt	$146	$146	$149	$127	$70	$89	$31	[o] = See Sources and Notes.
Long-Term Debt	$202	$202	$144	$156	$165	$107	$109	[p]
Book Value of Long-Term Debt	$359	$359	$304	$292	$246	$204	$148	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$162	$162	$165	$181	$137	$133	$142	
Carrying Amount	$146	$146	$154	$162	$122	$110	$119	
Adjustment to Book Value of Long-Term Debt	$16	$16	$11	$19	$15	$23	$24	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$375	$375	$316	$311	$261	$227	$171	[s] = [q] + [r].
Market Value of Debt	$375	$375	$316	$311	$261	$227	$171	[t] = [s].
MARKET VALUE OF FIRM	$1,694	$1,669	$1,323	$1,066	$882	$734	$620	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	77.87%	77.54%	76.12%	70.80%	70.47%	69.00%	72.32%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	22.13%	22.46%	23.88%	29.20%	29.53%	31.00%	27.68%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of October 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 10/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-GAS-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-GAS-3

Market Value of the U.S. Gas Sample

Panel H: ONE Gas Inc.

($MM)

	DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	$1,932	$1,932	$1,862	$1,811	$1,771	n/a	n/a	[a]
Shares Outstanding (in millions) - Common	52	52	52	52	52	n/a	n/a	[b]
Price per Share - Common	$75	$75	$62	$44	$36	n/a	n/a	[c]
Market Value of Common Equity	$3,930	$3,902	$3,251	$2,275	$1,866	n/a	n/a	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$3,930	$3,902	$3,251	$2,275	$1,866	n/a	n/a	[f]= [d]
Market to Book Value of Common Equity	2.03	2.02	1.75	1.26	1.05	n/a	n/a	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	n/a	n/a	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$446	$446	$377	$417	$505	$392	n/a	[j]
Current Liabilities	$392	$392	$259	$233	$274	$572	n/a	[k]
Current Portion of Long-Term Debt	$0	$0	$0	$0	$0	$0	n/a	[l]
Net Working Capital	$53	$53	$118	$184	$231	($180)	n/a	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$174	$174	$41	$0	$0	$342	n/a	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$180	n/a	[o] = See Sources and Notes.
Long-Term Debt	$1,193	$1,193	$1,192	$1,201	$1,201	$1,029	n/a	[p]
Book Value of Long-Term Debt	$1,193	$1,193	$1,192	$1,201	$1,201	$1,209	n/a	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,200	$1,200	$1,200	$1,300	$1,200	$1,300	n/a	
Carrying Amount	$1,200	$1,200	$1,200	$1,200	$1,000	$1,000	n/a	
Adjustment to Book Value of Long-Term Debt	$0	$0	$0	$100	$200	$300	n/a	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,193	$1,193	$1,192	$1,301	$1,401	$1,509	n/a	[s] = [q] + [r].
Market Value of Debt	$1,193	$1,193	$1,192	$1,301	$1,401	n/a	n/a	[t] = [s].
MARKET VALUE OF FIRM	$5,123	$5,095	$4,444	$3,576	$3,268	n/a	n/a	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	76.71%	76.58%	73.17%	63.61%	57.12%	n/a	n/a	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	n/a	n/a	[w] = [i] / [u].
Debt - Market Value Ratio	23.29%	23.42%	26.83%	36.39%	42.88%	n/a	n/a	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of October 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 10/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-GAS-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-GAS-3

Market Value of the U.S. Gas Sample

Panel I: Spire Inc.

($MM)

	DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	$2,028	$2,028	$1,768	$1,574	$1,508	$1,046	$602	[a]
Shares Outstanding (in millions) - Common	48	48	46	43	43	33	23	[b]
Price per Share - Common	$77	$75	$64	$52	$47	$44	$42	[c]
Market Value of Common Equity	$3,717	$3,632	$2,936	$2,265	$2,043	$1,448	$953	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$3,717	$3,632	$2,936	$2,265	$2,043	$1,448	$953	[f]= [d]
Market to Book Value of Common Equity	1.83	1.79	1.66	1.44	1.35	1.38	1.58	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$629	$629	$570	$530	$628	$476	$343	[j]
Current Liabilities	$910	$910	$1,161	$854	$786	$353	$252	[k]
Current Portion of Long-Term Debt	$0	$0	$250	$80	$0	$0	$25	[l]
Net Working Capital	($281)	($281)	($342)	($244)	($158)	$123	$116	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$451	$451	$399	$338	$287	$74	$40	[n]
Adjusted Short-Term Debt	$281	$281	$342	$244	$158	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,925	$1,925	$1,834	$1,772	$1,851	$913	$339	[p]
Book Value of Long-Term Debt	$2,206	$2,206	$2,425	$2,095	$2,009	$913	$364	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,257	$2,257	$1,944	$1,937	$954	$453	$444	
Carrying Amount	$2,084	$2,084	$1,852	$1,851	$913	$364	$364	
Adjustment to Book Value of Long-Term Debt	$173	$173	$93	$86	$41	$88	$79	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,379	$2,379	$2,518	$2,182	$2,050	$1,001	$444	[s] = [q] + [r].
Market Value of Debt	$2,379	$2,379	$2,518	$2,182	$2,050	$1,001	$444	[t] = [s].
MARKET VALUE OF FIRM	$6,096	$6,011	$5,454	$4,446	$4,093	$2,449	$1,397	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	60.97%	60.42%	53.83%	50.94%	49.91%	59.13%	68.24%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	39.03%	39.58%	46.17%	49.06%	50.09%	40.87%	31.76%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of October 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 10/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-GAS-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-GAS-4

Capital Structure Summary

			DCF Capital Structure			5-Year Average Capital Structure		
Company	DCF Analysis	CAPM Analysis	Common Equity - Value Ratio [1]	Preferred Equity - Value Ratio [2]	Debt - Value Ratio [3]	Common Equity - Value Ratio [4]	Preferred Equity - Value Ratio [5]	Debt - Value Ratio [6]
Atmos Energy	*	*	71.5%	0.0%	28.5%	62.2%	0.0%	37.8%
New Jersey Resources			77.3%	0.0%	22.7%	74.0%	0.0%	26.0%
Northwest Natural Gas	*	*	70.3%	0.0%	29.7%	60.9%	0.0%	39.1%
South Jersey Inds.			65.6%	0.0%	34.4%	62.3%	0.0%	37.7%
Southwest Gas	*	*	67.5%	0.0%	32.5%	62.2%	0.0%	37.8%
WGL Holdings Inc.			69.4%	0.4%	30.1%	68.6%	0.8%	30.6%
Chesapeake Utilities	*	*	77.9%	0.0%	22.1%	72.3%	0.0%	27.7%
ONE Gas Inc.	*	*	76.7%	0.0%	23.3%	66.3%	0.0%	33.7%
Spire Inc.	*	*	61.0%	0.0%	39.0%	55.6%	0.0%	44.4%
Average			70.8%	0.0%	29.2%	64.9%	0.1%	35.0%
Subsample Average			70.8%	0.0%	29.2%	63.3%	0.0%	36.7%

Sources and Notes:
[1], [4]: Supporting Schedule #1 to Table No. BV-GAS-4.
[2], [5]: Supporting Schedule #2 to Table No. BV-GAS-4.
[3], [6]: Supporting Schedule #3 to Table No. BV-GAS-4.
Values in this table may not add up exactly to 100% because of rounding.

Table No. BV-GAS-5

Estimated Growth Rates

Company	ThomsonOne IBES Estimate		Value Line			
	Long-Term Growth Rate	Number of Estimates	EPS Year 2017 Estimate	EPS Year 2020-2022 Estimate	Annualized Growth Rate	Combined Growth Rate
	[1]	[2]	[3]	[4]	[5]	[6]
Atmos Energy	7.3%	2	$3.60	$4.50	5.7%	6.8%
New Jersey Resources	6.0%	1	$1.75	$2.15	5.3%	5.6%
Northwest Natural Gas	4.0%	1	$2.25	$3.15	8.8%	6.4%
South Jersey Inds.	n/a	n/a	$1.20	$1.90	12.2%	12.2%
Southwest Gas	4.0%	1	$3.40	$4.75	8.7%	6.4%
WGL Holdings Inc.	7.0%	1	$3.30	$3.75	3.2%	5.1%
Chesapeake Utilities	8.1%	1	$2.55	$4.20	13.3%	10.7%
ONE Gas Inc.	5.5%	2	$2.95	$4.00	7.9%	6.3%
Spire Inc.	3.7%	2	$3.55	$4.65	7.0%	4.8%

Sources and Notes:

[1] - [2]: Updated from ThomsonOne as of Oct 30, 2017.

[3] - [4]: From Valueline Investment Analyzer as of Oct 27, 2017.

[5]: ([4]/[3])^(1/4) - 1, where 4 is the number of years between 2021, the middle year of Value Line's 3-5 year forecast, and our study year 2017.

[6]: Weighted average growth rate.

Table No. BV-GAS-6

DCF Cost of Equity of the U.S. Gas Sample

Panel A: Simple DCF Method (Quarterly)

Company	Stock Price [1]	Most Recent Dividend [2]	Quarterly Dividend Yield (t+1) [3]	Combined Long-Term Growth Rate [4]	Quarterly Growth Rate [5]	DCF Cost of Equity [6]
Atmos Energy	$86.50	$0.45	0.53%	6.8%	1.7%	9.0%
New Jersey Resources	$43.56	$0.27	0.63%	5.6%	1.4%	8.3%
Northwest Natural Gas	$65.57	$0.47	0.73%	6.4%	1.6%	9.5%
South Jersey Inds.	$33.83	$0.27	0.83%	12.2%	2.9%	15.8%
Southwest Gas	$80.29	$0.50	0.63%	6.4%	1.6%	9.0%
WGL Holdings Inc.	$85.66	$0.51	0.60%	5.1%	1.3%	7.6%
Chesapeake Utilities	$80.73	$0.33	0.41%	10.7%	2.6%	12.5%
ONE Gas Inc.	$75.19	$0.42	0.57%	6.3%	1.5%	8.7%
Spire Inc.	$77.02	$0.53	0.69%	4.8%	1.2%	7.7%

Sources and Notes:
[1]: Supporting Schedule #1 to Table No. BV-GAS-6.
[2]: Supporting Schedule #2 to Table No. BV-GAS-6.
[3]: ([2] / [1]) x (1 + [5]).
[4]: Table No. BV-GAS-5, [6].
[5]: {(1 + [4]) ^ (1/4)} - 1.
[6]: {([3] + [5] + 1) ^ 4} - 1.

Table No. BV-GAS-6

DCF Cost of Equity of the U.S. Gas Sample

Panel B: Multi-Stage DCF (Using Blue Chip Economic Indicators, October 2017 U.S. GDP Growth Forecast as the Perpetual Rate)

Company	Stock Price	Most Recent Dividend	Combined Long-Term Growth Rate	Growth Rate: Year 6	Growth Rate: Year 7	Growth Rate: Year 8	Growth Rate: Year 9	Growth Rate: Year 10	GDP Long-Term Growth Rate	DCF Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Atmos Energy	$86.50	$0.45	6.78%	6.35%	5.92%	5.49%	5.06%	4.63%	4.20%	6.8%
New Jersey Resources	$43.56	$0.27	5.64%	5.40%	5.16%	4.92%	4.68%	4.44%	4.20%	7.1%
Northwest Natural Gas	$65.57	$0.47	6.39%	6.02%	5.66%	5.29%	4.93%	4.56%	4.20%	7.7%
South Jersey Inds.	$33.83	$0.27	12.17%	10.85%	9.52%	8.19%	6.86%	5.53%	4.20%	9.7%
Southwest Gas	$80.29	$0.50	6.36%	6.00%	5.64%	5.28%	4.92%	4.56%	4.20%	7.2%
WGL Holdings Inc.	$85.66	$0.51	5.12%	4.97%	4.82%	4.66%	4.51%	4.35%	4.20%	6.9%
Chesapeake Utilities	$80.73	$0.33	10.69%	9.61%	8.53%	7.45%	6.36%	5.28%	4.20%	6.8%
ONE Gas Inc.	$75.19	$0.42	6.30%	5.95%	5.60%	5.25%	4.90%	4.55%	4.20%	6.9%
Spire Inc.	$77.02	$0.53	4.82%	4.71%	4.61%	4.51%	4.41%	4.30%	4.20%	7.2%

Sources and Notes:
[1]: Supporting Schedule #1 to Table No. BV-GAS-6.
[2]: Supporting Schedule #2 to Table No. BV-GAS-6.
[3]: Table No. BV-GAS-5, [6].
[4]: [3] - {([3] - [9])/ 6}.
[5]: [4] - {([3] - [9])/ 6}.
[6]: [5] - {([3] - [9])/ 6}.
[7]: [6] - {([3] - [9])/ 6}.
[8]: [7] - {([3] - [9])/ 6}.
[9]: Blue Chip Economic Indicators, October 2017 U.S. This number is assumed to be the perpetual growth rate.
[10]: Supporting Schedule #3 to Table No. BV-GAS-6.

Table No. BV-GAS-7

Overall After-Tax DCF Cost of Capital of the U.S. Gas Sample

Panel A: Simple DCF Method (Quarterly)

Company	Subsample	3rd Quarter, 2017 Bond Rating [1]	3rd Quarter, 2017 Preferred Equity Rating [2]	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	NWN Representative Income Tax Rate [9]	Overall After-Tax Cost of Capital [10]
Atmos Energy	*	A	-	9.0%	71.5%	-	0.0%	3.9%	28.5%	39.9%	7.11%
New Jersey Resources		A	-	8.3%	77.3%	-	0.0%	3.9%	22.7%	39.9%	6.95%
Northwest Natural Gas	*	A	-	9.5%	70.3%	-	0.0%	3.9%	29.7%	39.9%	7.36%
South Jersey Inds.		BBB	-	15.8%	65.6%	-	0.0%	4.2%	34.4%	39.9%	11.25%
Southwest Gas	*	BBB	-	9.0%	67.5%	-	0.0%	4.2%	32.5%	39.9%	6.89%
WGL Holdings Inc.		A	A	7.6%	69.4%	3.9%	0.4%	3.9%	30.1%	39.9%	6.03%
Chesapeake Utilities	*	A	-	12.5%	77.9%	-	0.0%	3.9%	22.1%	39.9%	10.24%
ONE Gas Inc.	*	A	-	8.7%	76.7%	-	0.0%	3.9%	23.3%	39.9%	7.21%
Spire Inc.	*	A	-	7.7%	61.0%	-	0.0%	3.9%	39.0%	39.9%	5.61%
Simple Full Sample Average				9.8%	70.8%	3.9%	0.0%	3.9%	29.2%	39.9%	7.63%
Simple Subsample Average				9.4%	70.8%	NA	0.0%	3.9%	29.2%	39.9%	7.40%

Sources and Notes:
[1]: S&P Credit Ratings from Research Insight.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. BV-GAS-6; Panel A, [6].
[4]: Table No. BV-GAS-4, [1].
[5]: Supporting Schedule #2 to Table No. BV-GAS-11, Panel C.
[6]: Table No. BV-GAS-4, [2].
[7]: Supporting Schedule #2 to Table No. BV-GAS-11, Panel B.
[8]: Table No. BV-GAS-4, [3].
[9]: NWN Effective Corporate Tax Rate.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 100 basis points.

Table No. BV-GAS-7

Overall After-Tax DCF Cost of Capital of the U.S. Gas Sample

Panel B: Multi-Stage DCF (Using Blue Chip Economic Indicators, October 2017 U.S. GDP Growth Forecast as the Perpetual Rate)

Company	Subsample	3rd Quarter, 2017 Bond Rating [1]	3rd Quarter, 2017 Preferred Equity Rating	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	NWN Representative Income Tax Rate [9]	Overall After-Tax Cost of Capital [10]
Atmos Energy	*	A	-	6.8%	71.5%	-	0.0%	3.9%	28.5%	39.9%	5.52%
New Jersey Resources		A	-	7.1%	77.3%	-	0.0%	3.9%	22.7%	39.9%	6.01%
Northwest Natural Gas	*	A	-	7.7%	70.3%	-	0.0%	3.9%	29.7%	39.9%	6.10%
South Jersey Inds.		BBB	-	9.7%	65.6%	-	0.0%	4.2%	34.4%	39.9%	7.22%
Southwest Gas	*	BBB	-	7.2%	67.5%	-	0.0%	4.2%	32.5%	39.9%	5.7%
WGL Holdings Inc.		A	A	6.9%	69.4%	3.9%	0.4%	3.9%	30.1%	39.9%	5.48%
Chesapeake Utilities	*	A	-	6.8%	77.9%	-	0.0%	3.9%	22.1%	39.9%	5.79%
ONE Gas Inc.	*	A	-	6.9%	76.7%	-	0.0%	3.9%	23.3%	39.9%	5.8%
Spire Inc.	*	A	-	7.2%	61.0%	-	0.0%	3.9%	39.0%	39.9%	5.3%
Multi Full Sample Average				7.4%	70.8%	3.9%	0.0%	3.9%	29.2%	39.9%	5.9%
Multi Subsample Average				7.1%	70.8%	NA	0.00%	3.9%	29.2%	39.9%	5.7%

Sources and Notes:
[1]: S&P Credit Ratings from Research Insight.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. BV-GAS-6; Panel B, [10].
[4]: Table No. BV-GAS-4, [1].
[5]: Supporting Schedule #2 to Table No. BV-GAS-11, Panel C.
[6]: Table No. BV-GAS-4, [2].
[7]: Supporting Schedule #2 to Table No. BV-GAS-11, Panel B.
[8]: Table No. BV-GAS-4, [3].
[9]: NWN Effective Corporate Tax Rate.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 100 basis points.

Table No. BV-GAS-8

DCF Cost of Equity at Representative Deemed Capital Structure

	Overall After -Tax Cost of Capital [1]	NWN Representative Base Deemed % Debt [2]	Representative Cost of A Rated Utility Debt [3]	NWN Representative Income Tax Rate [4]	NWN Representative Base Deemed % Equity [5]	Estimated Return on Equity [6]
Full Sample						
Simple DCF Quarterly	7.6%	50.0%	3.9%	39.9%	50.0%	12.9%
Multi-Stage DCF - Using Long-Term GDP Growth Forecast as the Perpetual Rate	5.9%	50.0%	3.9%	39.9%	50.0%	9.4%
Subsample						
Simple DCF Quarterly	7.4%	50.0%	3.9%	39.9%	50.0%	12.5%
Multi-Stage DCF - Using Long-Term GDP Growth Forecast as the Perpetual Rate	5.7%	50.0%	3.9%	39.9%	50.0%	9.1%

Sources and Notes:

[1]: Table No. BV-GAS-7; Panels A-B, [10].

[2]: NWN Assumed Capital Structure.

[3]: Based on an A rating. Yield from Bloomberg as of October 30, 2017.

[4]: NWN Effective Corporate Tax Rate.

[5]: NWN Assumed Capital Structure.

[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

U.S. Gas Sample

Company	DCF Subsample	Annual Revenues (USD million)	Regulated Assets	Market Cap. 2017 Q3 (USD million)	Betas	S&P Credit Rating (2016)	Long Term Growth Est.
	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Atmos Energy	*	$2,895	R	$9,074	0.70	A	6.8%
New Jersey Resources		$2,213	M	$3,679	0.80	A	5.6%
Northwest Natural Gas	*	$762	R	$1,888	0.70	A+	6.4%
South Jersey Inds.		$1,223	M	$2,793	0.85	BBB+	12.2%
Southwest Gas	*	$2,397	R	$3,756	0.75	BBB+	6.4%
WGL Holdings Inc.		$2,406	R	$4,327	0.80	A	5.1%
Chesapeake Utilities	*	$576	M	$1,294	0.70	A-	10.7%
ONE Gas Inc.	*	$1,520	R	$3,902	0.70	A	6.3%
Spire Inc.	*	$1,733	R	$3,632	0.70	A-	4.8%
Full Sample Average		**$1,747**		**$3,816**	**0.74**		**7.1%**
Subsample Average		**$1,647**		**$3,924**	**0.71**		**6.9%**

Sources and Notes:

[1]-[2]: Denotes companies used in the CAPM and DCF subsamples.

[3]: Bloomberg as of October 30, 2017. Most recent four quarters.

[4]: See Table No. BV-GAS-2. Key:

R - Regulated (More than 80% of assets regulated).

M - Mostly Regulated (50%-80% of assets regulated).

[5]: See Table No. BV-GAS-3 Panels A through I.

[6]: See Supporting Schedule # 1 to Table No. BV-GAS-10.

[7]: S&P Credit Ratings from Research Insight as of 2017 Q3. Research Insight does not report S&P credit ratings for MGE Energy. I use the S&P ratings of MGEE's subsidiary, Madison Gas and Electric Company.

[8]: See Table No. BV-GAS-5.

DCF Return on Equity Summary

	With Leverage Adjustments
Full Sample	
Simple	12.9%
Multi-Stage using Blue Chip GDP Growth:	9.4%
Multi-Stage using average of Blue Chip and OMB GDP Growth:	10.0%
Subsample	
Simple	12.5%
Multi-Stage using Blue Chip GDP Growth:	9.1%
Multi-Stage using average of Blue Chip and OMB GDP Growth:	9.6%

EXHIBIT NW NATURAL 404
RISK PREMIUM ANALYSIS

Risk Premium Model Cost of Equity Inputs

Forecasted 10-Year Government Bond Rate
3.4%
Source: October 2017 Blue Chip consensus forecast for 2019.

Historical Average 10Y to 20Y Maturity Premium
0.54%
Source: Bloomberg

Utility Yield Spread Adjustment
0.20%

Case Type
Gas LDC

Risk Premiums Determined by Relationship Between Authorized ROEs[1] and Long-term Treasury Bond Rates During the Period 1990-2017

Formula: Risk Premium = A_0 + (A_1 x Treasury bond Rate)

R Squared	0.8367
Estimate of intercept (A_0)	8.478%
Estimate of slope (A_1)	-0.5566

Equity Cost Estimate for Gas LDC		Predicted Risk Premium		Expected Treasury Bond Rate[2]	
10.3%	=	6.17%	+	4.14%	[3]
10.2%	=	6.28%	+	3.94%	[4]

Sources and Notes:
[1]: Authorized ROE Data sourced from SNL Financial.
[2]: Blue Chip consensus forecast 2019 10-yr T-bill Yield plus maturity premium
[3]: Estimate with expected treasury bond rate normalized with 0.20% utility yield spread adjustment
[4]: Estimate without treasury bond rate normalization.
See regression results for derivation of regression coefficients A_0 and A_1.

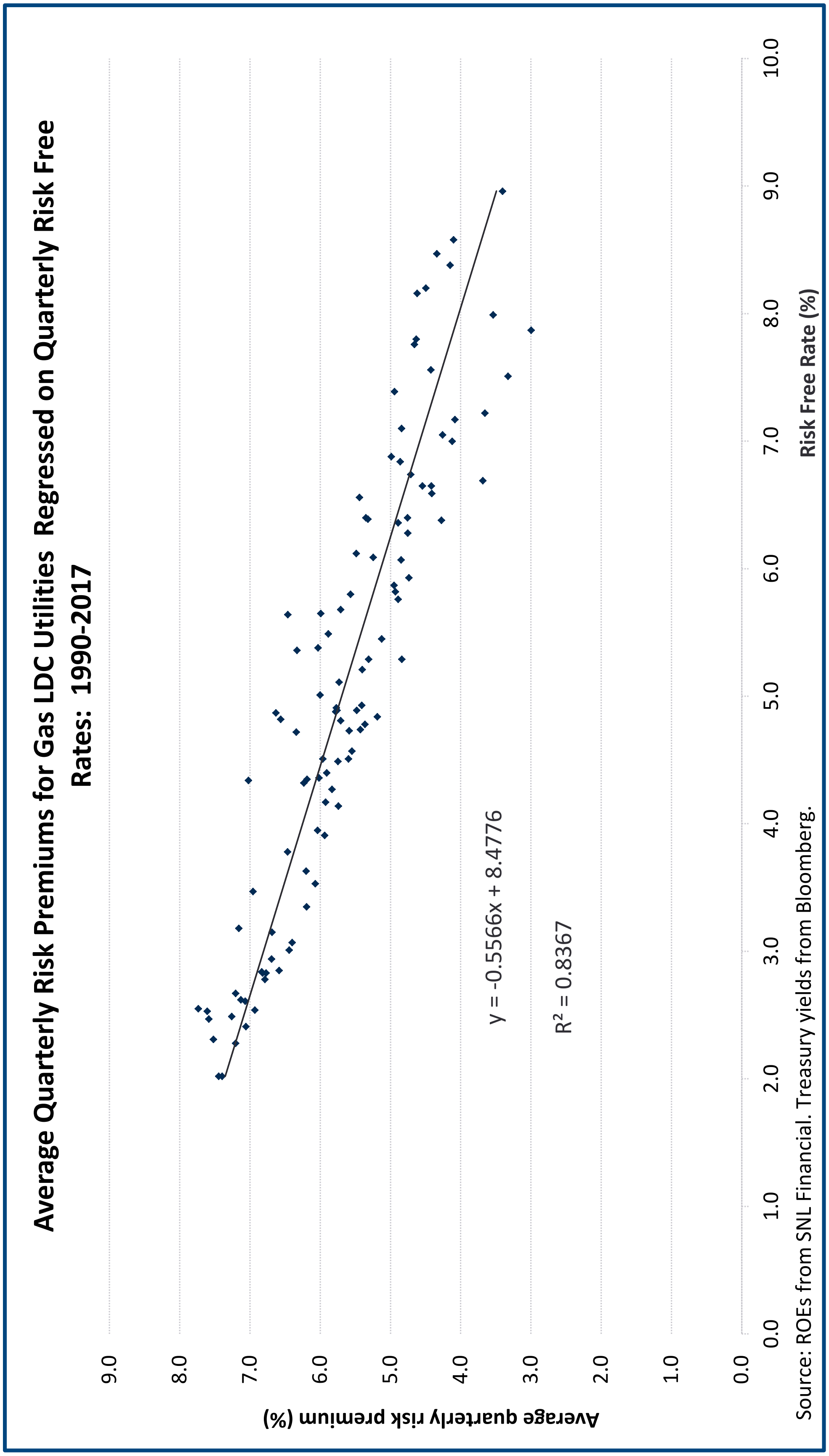
Average Quarterly Risk Premiums for Gas LDC Utilities Regressed on Quarterly Risk Free Rates: 1990-2017
Average quarterly risk premium (%)
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
Risk Free Rate (%)
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
10.0
y = -0.5566x + 8.4776
R² = 0.8367
Source: ROEs from SNL Financial. Treasury yields from Bloomberg.

EXHIBIT NW NATURAL 405
RESULTS FROM THE CAPM

Table No. BV-GAS-9

Risk Free Rate

[1]	Consensus 10-Year Forecast	3.40%
	U.S. Government Bond Yields	
[2]	20-Year	4.87%
[3]	10-Year	4.32%
[4]	Maturity Premium	0.54%
[5]	Consensus 10-Year Forecast Adjusted to 20-year Horizon	3.94%

Sources and Notes:

[1]: Bluechip Consensus Forecast in October 2017.

[2]-[3]: Supporting Schedule # 1 to Table No. BV-GAS-9. Averages of monthly bond yields from September 1992 through September 2017.

[4]: [2] - [3].

[5]: [1] + [4].

Table No. BV-GAS-10

Risk Positioning Cost of Equity of the U.S. Gas Sample

Panel A: Scenario 1 - Long-Term Risk Free Rate of 4.14%, Long-Term Market Risk Premium of 6.94%

Company		Long-Term Risk-Free Rate [1]	Value Line Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
Atmos Energy	*	4.14%	0.70	6.94%	9.0%	9.5%
New Jersey Resources		4.14%	0.80	6.94%	9.7%	10.0%
Northwest Natural Gas	*	4.14%	0.70	6.94%	9.0%	9.5%
South Jersey Inds.		4.14%	0.85	6.94%	10.0%	10.3%
Southwest Gas	*	4.14%	0.75	6.94%	9.3%	9.7%
WGL Holdings Inc.		4.14%	0.80	6.94%	9.7%	10.0%
Chesapeake Utilities	*	4.14%	0.70	6.94%	9.0%	9.5%
ONE Gas Inc.	*	4.14%	0.70	6.94%	9.0%	9.5%
Spire Inc.	*	4.14%	0.70	6.94%	9.0%	9.5%
Average		4.14%	74.44%	6.94%	9.3%	9.7%
Subsample Average		4.14%	70.83%	6.94%	9.1%	9.5%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Bloomberg as of October 30, 2017.
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-GAS-10

Risk Positioning Cost of Equity of the U.S. Gas Sample

Panel B: Scenario 2 - Long-Term Risk Free Rate of 3.94%, Long-Term Market Risk Premium of 7.44%

Company		Long-Term Risk-Free Rate [1]	Value Line Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
Atmos Energy	*	3.94%	0.70	7.44%	9.2%	9.6%
New Jersey Resources		3.94%	0.80	7.44%	9.9%	10.2%
Northwest Natural Gas	*	3.94%	0.70	7.44%	9.2%	9.6%
South Jersey Inds.		3.94%	0.85	7.44%	10.3%	10.5%
Southwest Gas	*	3.94%	0.75	7.44%	9.5%	9.9%
WGL Holdings Inc.		3.94%	0.80	7.44%	9.9%	10.2%
Chesapeake Utilities	*	3.94%	0.70	7.44%	9.2%	9.6%
ONE Gas Inc.	*	3.94%	0.70	7.44%	9.2%	9.6%
Spire Inc.	*	3.94%	0.70	7.44%	9.2%	9.6%
Average		3.94%	74.44%	7.44%	9.5%	9.9%
Subsample Average		3.94%	71.00%	7.44%	9.2%	9.7%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Bloomberg as of October 30, 2017.
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-GAS-11

Overall After-Tax Cost of Capital of the U.S. Gas Sample

Panel A: CAPM Cost of Equity Scenario 1 - Long-Term Risk Free Rate of 4.14%, Long-Term Market Risk Premium of 6.94%

Company		CAPM Cost of Equity [1]	ECAPM (1.5%) Cost of Equity [2]	5-Year Average Common Equity to Market Value Ratio [3]	Weighted - Average Cost of Preferred Equity [4]	5-Year Average Preferred Equity to Market Value Ratio [5]	Weighted-Average Cost of Debt [6]	5-Year Average Debt to Market Value Ratio [7]	NWN Representative Income Tax Rate [8]	Overall After-Tax Cost of Capital (CAPM) [9]	Overall After-Tax Cost of Capital (ECAPM 1.5%) [10]
Atmos Energy	*	9.0%	9.5%	62.2%	-	0.0%	3.94%	37.8%	39.9%	6.5%	6.8%
New Jersey Resources		9.7%	10.0%	74.0%	-	0.0%	3.87%	26.0%	39.9%	7.8%	8.0%
Northwest Natural Gas	*	9.0%	9.5%	60.9%	-	0.0%	3.87%	39.1%	39.9%	6.4%	6.7%
South Jersey Inds.		10.0%	10.3%	62.3%	-	0.0%	4.18%	37.7%	39.9%	7.2%	7.3%
Southwest Gas	*	9.3%	9.7%	62.2%	-	0.0%	4.06%	37.8%	39.9%	6.7%	7.0%
WGL Holdings Inc.		9.7%	10.0%	68.6%	3.87%	0.8%	3.87%	30.6%	39.9%	7.4%	7.6%
Chesapeake Utilities	*	9.0%	9.5%	72.3%	-	0.0%	3.87%	27.7%	39.9%	7.1%	7.5%
ONE Gas Inc.	*	9.0%	9.5%	66.3%	-	0.0%	3.87%	33.7%	39.9%	6.8%	7.1%
Spire Inc.	*	9.0%	9.5%	55.6%	-	0.0%	3.87%	44.4%	39.9%	6.0%	6.3%
Full Sample Average		9.3%	9.7%	64.9%	3.9%	0.1%	3.9%	35.0%	39.9%	6.9%	7.1%
Subsample Average		9.1%	9.5%	63.3%	-	0.0%	3.9%	36.7%	39.9%	6.6%	6.9%

Sources and Notes:

[1]: Table No. BV-GAS-10; Panel A, [4].
[2]: Table No. BV-GAS-10; Panel A, [5].
[3]: Table No. BV-GAS-4, [4].
[4]: Supporting Schedule #2 to Table No. BV-GAS-11, Panel C.
[5]: Table No. BV-GAS-4, [5].
[6]: Supporting Schedule #2 to Table No. BV-GAS-11, Pa
[7]: Table No. BV-GAS-4, [6].
[8]: NWN Effective Corporate Tax Rate
[9]: ([1] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[10]: ([2] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[9]-[10] A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 100 basis points

Table No. BV-GAS-11

Overall After-Tax Cost of Capital of the U.S. Gas Sample

Panel B: CAPM Cost of Equity Scenario 2 - Long-Term Risk Free Rate of 3.94%, Long-Term Market Risk Premium of 7.44%

Company		CAPM Cost of Equity [1]	ECAPM (1.5%) Cost of Equity [2]	5-Year Average Common Equity to Market Value Ratio [3]	Weighted - Average Cost of Preferred Equity [4]	5-Year Average Preferred Equity to Market Value Ratio [5]	Weighted-Average Cost of Debt [6]	5-Year Average Debt to Market Value Ratio [7]	NWN Representative Income Tax Rate [8]	Overall After-Tax Cost of Capital (CAPM) [9]	Overall After-Tax Cost of Capital (ECAPM 1.5%) [10]
Atmos Energy	*	9.2%	9.6%	62.2%	-	0.0%	3.94%	37.8%	39.9%	6.6%	6.9%
New Jersey Resources		9.9%	10.2%	74.0%	-	0.0%	3.87%	26.0%	39.9%	7.9%	8.1%
Northwest Natural Gas	*	9.2%	9.6%	60.9%	-	0.0%	3.87%	39.1%	39.9%	6.5%	6.8%
South Jersey Inds.		10.3%	10.5%	62.3%	-	0.0%	4.18%	37.7%	39.9%	7.3%	7.5%
Southwest Gas	*	9.5%	9.9%	62.2%	-	0.0%	4.06%	37.8%	39.9%	6.8%	7.1%
WGL Holdings Inc.		9.9%	10.2%	68.6%	3.87%	0.8%	3.87%	30.6%	39.9%	7.5%	7.7%
Chesapeake Utilities	*	9.2%	9.6%	72.3%	-	0.0%	3.87%	27.7%	39.9%	7.3%	7.6%
ONE Gas Inc.	*	9.2%	9.6%	66.3%	-	0.0%	3.87%	33.7%	39.9%	6.9%	7.2%
Spire Inc.	*	9.2%	9.6%	55.6%	-	0.0%	3.87%	44.4%	39.9%	6.1%	6.4%
Full Sample Average		9.5%	9.9%	64.9%	3.9%	0.1%	3.9%	35.0%	39.9%	7.0%	7.2%
Subsample Average		9.2%	9.6%	63.3%	-	0.0%	3.9%	36.7%	39.9%	6.7%	7.0%

Sources and Notes:

[1]: Table No. BV-GAS-10; Panel B, [4].
[2]: Table No. BV-GAS-10; Panel B, [5].
[3]: Table No. BV-GAS-4, [4].
[4]: Supporting Schedule #2 to Table No. BV-GAS-11, Panel C.
[5]: Table No. BV-GAS-4, [5].
[6]: Supporting Schedule #2 to Table No. BV-GAS-11, Pa
[7]: Table No. BV-GAS-4, [6].
[8]: NWN Effective Corporate Tax Rate
[9]: ([1] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[10]: ([2] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[9]-[10] A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 100 basis points

Table No. BV-GAS-12

Risk Positioning Cost of Equity at Representative Deemed Capital Structure

	Overall After-Tax Cost of Capital (Scenario 1)	Overall After-Tax Cost of Capital (Scenario 2)	NWN Representative Base Deemed % Debt	Representative Cost of A-Rated Utility Debt	NWN Representative Income Tax Rate	NWN Representative Base Deemed % Equity	Estimated Return on Equity (Scenario 1)	Estimated Return on Equity (Scenario 2)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
CAPM	6.9%	7.0%	50.0%	3.9%	39.9%	50.0%	11.4%	11.7%
ECAPM (1.50%)	7.1%	7.2%	50.0%	3.9%	39.9%	50.0%	11.9%	12.2%
Subsample:								
CAPM	6.6%	6.7%	50.0%	3.9%	39.9%	50.0%	10.9%	11.1%
ECAPM (1.50%)	6.9%	7.0%	50.0%	3.9%	39.9%	50.0%	11.4%	11.6%

Sources and Notes:

[1]: Table No. BV-GAS-11; Panel A, [9] - [10].

[2]: Table No. BV-GAS-11; Panel B, [9] - [10].

Scenario 1: Long-Term Risk Free Rate of 4.14%, Long-Term Market Risk Premium of 6.94%.

Scenario 2: Long-Term Risk Free Rate of 3.94%, Long-Term Market Risk Premium of 7.44%.

[3]: NWN Assumed Capital Structure.

[4]: Based on a A rating. Yield from Bloomberg as of October 30, 2017.

[5]: NWN Effective Corporate Tax Rate.

[6]: NWN Assumed Capital Structure.

[7]: {[1] - ([3] x [4] x (1 - [5])}/ [6].

[8]: {[2] - ([3] x [4] x (1 - [5]))}/ [6].

Table No. BV-GAS-13

Hamada Adjustment to Obtain Unlevered Asset Beta

Company		Value Line Betas [1]	Debt Beta [2]	5-Year Average Common Equity to Market Value Ratio [3]	5-Year Average Preferred Equity to Market Value Ratio [4]	5-Year Average Debt to Market Value Ratio [5]	NWN Representative Income Tax Rate [6]	Asset Beta: Without Taxes [7]	Asset Beta: With Taxes [8]
Atmos Energy	*	0.70	0.06	62.2%	0.0%	37.8%	39.9%	0.46	0.53
New Jersey Resources		0.80	0.05	74.0%	0.0%	26.0%	39.9%	0.60	0.67
Northwest Natural Gas	*	0.70	0.05	60.9%	0.0%	39.1%	39.9%	0.45	0.52
South Jersey Inds.		0.85	0.10	62.3%	0.0%	37.7%	39.9%	0.57	0.65
Southwest Gas	*	0.75	0.08	62.2%	0.0%	37.8%	39.9%	0.50	0.57
WGL Holdings Inc.		0.80	0.05	68.6%	0.8%	30.6%	39.9%	0.56	0.64
Chesapeake Utilities	*	0.70	0.05	72.3%	0.0%	27.7%	39.9%	0.52	0.58
ONE Gas Inc.	*	0.70	0.05	66.3%	0.0%	33.7%	39.9%	0.48	0.55
Spire Inc.	*	0.70	0.00	55.6%	0.0%	44.4%	39.9%	0.39	0.47
Full Sample Average		0.74	0.05	64.9%	0.00	35.0%	39.9%	0.50	0.57
Subsample Average		0.71	0.05	63.3%	0.00	36.7%	39.9%	0.47	0.54

Sources and Notes:

[1]: Supporting Schedule # 1 to Table No. BV-GAS-10, [1].
[2]: Supporting Schedule #1 to Table No. BV-GAS-13, [7].
[3]: Table No. BV-GAS-4, [4].
[4]: Table No. BV-GAS-4, [5].
[5]: Table No. BV-GAS-4, [6].
[6]: NWN Effective Corporate Tax Rate
[7]: [1]*[3] + [2]*([4] + [5]).
[8]: {[1]*[3] + [2]*([4]+[5]*(1-[6]))} / {[3] + [4] + [5]*(1 -[6])}.

Table No. BV-GAS-14

Sample Average Asset Beta Relevered at Representative Deemed Capital Structure

	Asset Beta [1]	Assumed Debt Beta [2]	NWN Representative Base Deemed % Debt [3]	NWN Representative Income Tax Rate [4]	NWN Representative Base Deemed % Equity [5]	Estimated Equity Beta [6]
Full Sample:						
Asset Beta Without Taxes	0.50	0.05	50.0%	39.9%	50.0%	0.96
Asset Beta With Taxes	0.57	0.05	50.0%	39.9%	50.0%	0.89
Subsample:						
Asset Beta Without Taxes	0.47	0.05	50.0%	39.9%	50.0%	0.88
Asset Beta With Taxes	0.54	0.05	50.0%	39.9%	50.0%	0.83

Sources and Notes:

[1]: Table No. BV-GAS-13, [7] - [8].

[2]: Debt Beta estimate for A-rated entities.Corporate Finance, Berk and Demarzo, Second Edition, p. 389.

[3]: NWN Assumed Capital Structure.

[4]: NWN Effective Corporate Tax Rate.

[5]: NWN Assumed Capital Structure.

[6]: [1] + [3]/[5]*([1] - [2]) without taxes, [1] + [3]*(1 - [4])/[5]*([1] - [2]) with taxes.

Table No. BV-GAS-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel A: Scenario 1 - Long-Term Risk Free Rate of 4.14%, Long-Term Market Risk Premium of 6.94%

Company	Long-Term Risk-Free Rate [1]	Hamada Adjusted Equity Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
Asset Beta Without Taxes	4.14%	0.96	6.94%	10.8%	10.8%
Asset Beta With Taxes	4.14%	0.89	6.94%	10.3%	10.5%
Subsample:					
Asset Beta Without Taxes	4.14%	0.88	6.94%	10.3%	10.4%
Asset Beta With Taxes	4.14%	0.83	6.94%	9.9%	10.1%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Table No. BV-GAS-14, [6].
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-GAS-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel B: Scenario 2 - Long-Term Risk Free Rate of 3.94%, Long-Term Market Risk Premium of 7.44%

Company	Long-Term Risk-Free Rate [1]	Hamada Adjusted Equity Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
Asset Beta Without Taxes	3.94%	0.96	7.44%	11.1%	11.1%
Asset Beta With Taxes	3.94%	0.89	7.44%	10.6%	10.7%
Subsample:					
Asset Beta Without Taxes	3.94%	0.88	7.44%	10.5%	10.7%
Asset Beta With Taxes	3.94%	0.83	7.44%	10.1%	10.4%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Table No. BV-GAS-14, [6].
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Parameters Used in CAPM-based Models

	Scenario 1	Scenario 2
Risk-Free Interest Rate	4.1%	3.9%
Market Equity Risk Premium	6.9%	7.4%

EXHIBIT NW NATURAL 406
AUTHORIZED ROE FOR GAS LDCS

Allowed Returns on Equity for Gas LDCs in 2017

	Average	Median	Minimum	Maximum
All 2017	9.76	9.60	8.70	11.88
Past Three Months	10.07	9.88	9.40	11.88

Source: SNL Financial as of 12/1/2017

EXHIBIT NW NATURAL 407
YIELD SPREADS

Spreads between U.S. Utility Bond (20 year maturity) and U.S. Government Bond (20 year maturity) - %

Periods	A-Rated Utility and Treasury	BBB-Rated Utility and Treasury	Notes
Period 1 - Average Apr-1991 - 2007	0.93	1.23	[1]
Period 2 - Average Aug-2008 - Sep-2017	1.52	1.99	[2]
Period 3 - Average Sep-2017	1.35	1.74	[3]
Period 4 - Average 15-Day (Oct 10, 2017 to Oct 30, 2017)	1.23	1.60	[4]
Spread Increase between Period 2 and Period 1	0.59	0.76	[5] = [2] - [1]
Spread Increase between Period 3 and Period 1	0.42	0.51	[6] = [3] - [1]
Spread Increase between Period 4 and Period 1	**0.29**	**0.37**	[7] = [4] - [1]

Sources and Notes:

Spreads for the periods are calculated from Bloomberg's yield data.

Average monthly yields for the indices were retrieved from Bloomberg as of October 30, 2017.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Direct Testimony of Wayne K. Pipes

FACILITIES
EXHIBIT 500

December 2017

EXHIBIT 500 - DIRECT TESTIMONY - FACILITIES

Table of Contents

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with ("NW Natural" or "the Company").

A. My name is Wayne K. Pipes. My business address is 220 NW Second Avenue, Portland, Oregon 97209. I am the Senior Manager, Facilities, Security and Emergency Management for NW Natural. I am responsible for facilities, security and emergency management activities for NW Natural, which includes planning and management of construction, capital projects, maintenance, security and emergency management for NW Natural's facilities.

Q. Please describe your employment and background.

A. I have over 35 years of Facilities Management and Construction experience. I have been employed at NW Natural since 2014. Before assuming my current position at NW Natural in 2014, I worked for New Seasons for a year as Director of Design, Construction, and Facilities Management. I also worked for Knowledge Universe for 15 years as Vice President of Facilities and Development, and for Red Lion Hotels for 17 years as Senior Director of Facilities Management.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of NW Natural's strategic facilities planning and describe major facilities upgrades that have been completed since the Company's last rate case, as well as those that are currently

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NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

in progress and will be completed prior to the effective date of this rate case. These projects are described in greater detail below, and include the Salem Retrofit Project, the Parkrose Retrofit Project, the Eugene Retrofit Project, Coos Bay Retrofit Project, and continued work at NW Natural's Sherwood operations, training and emergency backup facility, which includes a materials testing building.

II. OVERVIEW OF FACILITIES AND STRATEGIC FACILITIES PLANNING

Q. Please provide an overview of NW Natural's business functions and facilities required to provide service to its customers.

A. In order to provide gas distribution services to customers in Western Oregon and parts of Southwest Washington, NW Natural relies on a variety of different business functions, including service support, call center, dispatching, construction, gas regulation, gas storage, engineering and business support services, among others. In order to deliver NW Natural's gas distribution and related services, the Company operates various physical facilities located throughout its service territories. The facilities include resource centers that house our field operations functions, including offices, material and equipment storage, service vehicles and fueling stations. In addition, NW Natural also operates a sizable operations facility in Sherwood, which includes operations services (customer field service and construction), equipment and material storage, maintenance shops, classroom and hands-on training functions, and backup operations such as our emergency operations center, gas control,

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

resource management, emergency call center backup data center and business continuity center. NW Natural also has two liquefied natural gas (LNG) plants, an underground gas storage facility at Mist, several small regulator sites, and some other small properties used for communications and radio towers. NW Natural leases its corporate headquarters building, and that lease will be expiring in May of 2020. NW Natural recently signed a lease for a new headquarters building in Portland. We are not requesting rate recovery for the costs of that new lease in this proceeding since the new lease does not become effective during the Test Year of this rate case.

Q. Has NW Natural engaged in strategic planning to consider how to use its facilities more efficiently?

A. Yes. In 2006, NW Natural conducted a review of its operational practices and redesigned its core operating model around the principles of centralization and standardization to create greater operating efficiencies. To build on the conclusions from the operations review, NW Natural initiated an internal project in March 2007, with the goal of ensuring that the Company makes appropriate strategic and operational decisions as they relate to facilities and properties owned, occupied and/or utilized by the Company to carry out its business. NW Natural also engaged with outside consultants at Parametrix, an engineering, planning, and environmental solutions firm, to evaluate external conditions that may influence the strategic direction of the Company, and to evaluate several of the Company's facilities.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

Q. Did NW Natural articulate a vision statement to guide strategic facilities planning?

A Yes. NW Natural's long-term vision for the future of NW Natural's facilities is:

> To provide adequate facilities for the Company to carry out its evolving business operations while being safe, secure, adequately maintained, sustainable, good neighbors, operationally excellent and adequately representing the image and values of the Company to all stakeholders (management, regulators/customers, employees, local city/communities, shareholders).

Q. What guiding principles does NW Natural follow in its decision-making regarding facilities owned and operated by NW Natural?

A. NW Natural considers the following principles to guide its facilities decision-making:

- Practices should honor NW Natural values and support long-range strategic goals;
- Standardized practices from facility to facility;
- Centralized management of facilities operations;
- Sustainable practices and attention to environmental impact;
- Both the interior and exterior of the facilities should reflect the Company's image of being safe, reliable and customer-focused;
- Provide for efficient and cost effective practices;
- Be good neighbors and members of the community;
- Advance planning for maintenance of facilities and inclusion in budgets;

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

- Encourage use of public transportation to access facilities;
- Technologically enabled;
- Safe and secure facilities; and
- Ensure continuity of operations during unplanned interruptions, hazards, etc.

Q. Please describe NW Natural's strategic direction for facilities resulting from the strategic planning process.

A. At a high level, NW Natural's strategic direction is informed by two goals: (1) achieving the best use of facilities; and (2) achieving the best location and most cost-effective model.

Q. How does NW Natural implement its first goal, achieving the best use of facilities?

A. To achieve the best use of facilities, NW Natural has worked to:

- Develop and implement a Resource Center footprint model, including modifications to certain facilities to reflect decisions to outsource or centralize work;
- Locate, as appropriate, a number of business functions out of Class A office space; and
- Plan and budget for facilities maintenance to ensure safe and secure facilities.

Q. What has NW Natural done to implement its second goal, achieving the best location and most cost-effective model?

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

A. To achieve the best location and most cost-effective model, NW Natural has taken the following actions:

- Developed a plan for the optimal number, size and locations of Resource Centers;
- Reevaluated current business practices and current use of facilities;
- Evaluated home-based reporting and telecommuting to reduce demands for facilities;
- Evaluated options to reduce energy requirements and associated costs; and
- Developed a plan for enhancing the continuity of operations to include backup operations if needed in emergencies caused by earthquake, flooding, power outages, etc.

Q. Has NW Natural relied on its strategic planning vision, guidelines, and direction for its facilities decision-making?

A. Yes. As described below in greater detail in my testimony of NW Natural's significant facilities projects, the Company's strategic planning has guided its decision-making regarding its plans and priorities for facilities.

III. <u>SIGNIFICANT FACILITIES PROJECTS</u>

Q. Please provide a brief summary of the significant facilities projects included since NW Natural's last rate proceeding.

A. Below is a brief summary of these projects, which are all described in further detail later in this testimony:

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

- **Continued investment in the Sherwood Operations, Training, Emergency Backup, and Testing Facility.** The Sherwood Project, a portion of which was completed and included in NW Natural's prior rate case, UG 221, included major remodeling and retrofitting of two buildings, addition of an outside training facility, as well as several projects that were undertaken to further the development of the facility. These additional projects began in 2013 and will be completed by mid-2018. The total cost for the investments in this facility since NW Natural's last rate case is $23.6 million. All projects at Sherwood except the Sherwood Test Building have been completed. Work on the Sherwood Test Building began in June 2016, and is expected to be completed in April 2018. The estimated cost of the Sherwood Test Building is $2.59 million.
- **Salem Retrofit Project.** The Salem Retrofit Project was a remodeling project at NW Natural's Salem Resource Center to address structural and seismic issues, bring the building into code compliance, and address changes in the use of the facilities. The Salem Retrofit Project was initiated in March 2012, and was completed in September 2015. The cost of the Salem Retrofit Project was $9.1 million.
- **Parkrose Retrofit Project.** The Parkrose Retrofit Project was a remodeling project at one of NW Natural's Portland area Resource Centers. The facility was dated, had poor energy efficiency, deteriorating walls and roof, failing plumbing systems, and obsolete lighting and HVAC systems. The cost of the

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

Parkrose project was $2.7M and it was completed in June of 2013.

- **Eugene Retrofit Project.** The Eugene Retrofit Project is a remodel and upgrade to NW Natural's Eugene Resource Center to address deteriorating systems and perform seismic retrofitting. The project also expands the yard to allow for additional functionality. The Eugene Retrofit Project was initiated in September 2016 and will be completed by the end of October 2018. The estimated cost for the Eugene Retrofit Project is $3.69 million.
- **Coos Bay Retrofit Project.** The Coos Bay Resource Center was built in 1964 and purchased by NW Natural in 2005. The facility is dated, functionality is impaired and it does not support operational requirements. The retrofit project will address these issues. The estimated cost of the Coos Bay Retrofit project is $0.76 million.

<u>Sherwood Project</u>

Q. Please describe NW Natural's Sherwood facility.

A. As NW Natural explained in its last rate case, docket UG 221, the Company acquired a property in Sherwood, Oregon in order to construct a multi-purpose facility to meet three functional business needs: (1) an integrated operations facility (2) a field and inside training center and (3) a business continuity center. This allowed NW Natural to consolidate our Tualatin and South Center facilities to avoid the retrofitting of both facilities and eliminate flooding issues we had at the South Center location. We then sold both the Tualatin and South Center locations. The Sherwood Project, discussed in greater detail below, included

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

major remodeling and retrofitting of the two buildings at the facility, "Building A" (which houses operations and training, backup gas control, backup resource management center, backup emergency operations center, backup data center, backup emergency call center and business continuity space for critical operations) and "Building B," (which houses automotive repair and maintenance, fire safety shop, carpenters shop, radio / corrosion shop, and a paint booth) as well as other improvements and new construction at the Sherwood facility to fulfill NW Natural's plan of developing a multi-purpose facility.

Q. Did NW Natural request cost recovery for its investment in the Sherwood property in the last rate case?

A. Yes, in part. In our last rate case, the Company noted that not all of the work would be completed by the time that rates went into effect, and that work would continue on the facility. However, NW Natural was allowed to add into rates the costs of the project related to the portions of it that were in service and functional by the rate effective date of the last case.

Q. What costs are included with NW Natural's current request for cost recovery associated with the Sherwood Project?

A. NW Natural is requesting to add to rates the recovery for its investment in improvements to the Sherwood facility including all of Building A, which had not been completed at the time of the last rate case. The functions in this building include the entire resource center functionality that had existed at South Center, as well as the Meter Shop, Central Stores, Welding and Training functions. All of

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

these functions were previously located at the Tualatin location. The Building A improvements also include backup gas control, backup resource management, emergency operations center, emergency generator and a backup data center, the build-out of the business continuity space and backup emergency call center. NW Natural also seeks to include the retrofit of Building B, the Test Building and other improvements required to implement the Company's plan of an integrated field operation training facility.

Q. What is the purpose of the business continuity center?

A. The business continuity center provides NW Natural with an emergency backup operations center in the event that its headquarters are compromised in the event of a fire, flood, earthquake, or other disruption. As part of its strategic facilities planning, NW Natural planned to develop an alternative site with access to records, data, and a physical plant from which core administrative employees may continue to conduct business.

Q. What is the purpose of the integrated training facility?

A. When NW Natural decided to purchase the Sherwood property, the Company determined that its then-existing training facilities were no longer adequate, and that a more suitable training facility was needed. The integrated training facility provides a training space for field operations and service employees that accommodates a variety of training methods, including classroom, practical, and scenario-based training. NW Natural has also expanded its emergency response training program, as this integrated facility allows for joint NW Natural and fire

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

department training and coordination using live gas in a controlled environment, which has resulted in an improved joint response to gas emergencies.

Q. Did NW Natural have any other specific plans for the Sherwood facility?

A. Yes. When NW Natural acquired the Sherwood property, it planned to consolidate its operations that were being performed at the Tualatin and South Center facilities to the new Sherwood facility.

Q. Has NW Natural consolidated its operations at the Tualatin and South Center facilities and sold these facilities?

A. Yes, NW Natural has moved all of its business functions that were previously performed at the Tualatin and South Center facilities to the Sherwood facility, and has sold the Tualatin and South Center facilities. The proceeds from these sales were credited back to customers, with the approval of the Commission.

Q. Please recap the work that NW Natural performed at Building A since the last rate case.

A. Since NW Natural's last rate case, the Company completed Building A which had not been completed at the time of the last rate case. The work completed includes the Meter Shop, Central Stores, Welding and Training functions, backup gas control, backup resource management, emergency operations center, emergency generator, backup data center and building continuity space, enhancements to the weld shop ventilation, and installation of telemetry.

Q. Please describe the remodeling and renovating work that NW Natural performed at Building B.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

A. The retrofit work on Building B included building out an administrative office space, an automotive repair facility and numerous other shops including: fire safety, carpentry, radio/corrosion, a paint booth and miscellaneous storage areas.

Q. Why was the remodeling and retrofitting work needed?

A. The remodeling and retrofit work was a continuation of the strategic plan for the Sherwood Facility representing work that was not completed before the rate effective date in NW Natural's previous rate case.

Q. Please describe NW Natural's other improvements at its Sherwood facility.

A. In addition to the remodeling work at the Sherwood property, NW Natural initiated several projects in connection with its plans for the facility. The additional projects included performing site work, constructing a fuel shed, a CNG fueling station for NW Natural's own CNG fleet, constructing a vehicle shed, improving ventilation in the welding shop, installing a microwave tower on Building A, and constructing the Sherwood Test Building.

Q. What site improvement work was performed?

A. The Sherwood site work included installing utilities and infrastructure for the exterior training facilities, bio-swales, irrigation, and asphalt work, covered spoils bins, exterior lighting, parking, striping and moving the hazmat shed from Tualatin. The site work was part of the overall plan and was required to support operation of the facility.

Q. Please describe the multi-purpose business continuity center.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

A. NW Natural designed and built a multi-purpose business continuity space to support key business functions to recover critical processes after a disaster or other disruption, and to be available as a meeting space, at other times, for large company meetings and teams working on long-term projects. The actual work performed to complete the business continuity center included completing the roughed-in construction of the second floor, located above the training classrooms in Sherwood Building A. In 2015, the business continuity space was completed to include finishes, data cabling, electrical work and furnishings.

Q. What other improvements were made at the Sherwood facility to allow use as an emergency backup control center?

A. NW Natural created a new backup data center at the Sherwood facility, which included installing HVAC equipment, UPS system, server cabinets, Cat-6 and fiber data connectivity, and the associated network gear to provide back-up data center capability. The Company also installed a bi-fuel (diesel-natural gas) generator to power Building A. The generator provides emergency power to all of NW Natural's emergency backup operations, including the backup data center.

Q. Why did NW Natural decide to develop the Sherwood Test Building?

A. The Test Building was part of the strategic plan for the Sherwood facility. The primary objective of the Sherwood Test Building is to provide a safe facility for pipe and component high-pressure testing, x-ray testing, and sand-blasting at the Sherwood facility. These functions were previously performed at Tualatin in the Transmission Shop, but the proximity of the testing facility to employees was not

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

considered optimal, and the new building has been designed to be located a safe distance away from any other building or groups of employees.

Q. What type of testing will be performed at the Sherwood Test Building?

A. High-pressure pipe and valve assemblies constructed in the Weld Shop are required to be pressure tested and x-rayed. Pressure testing involves increasing the pressure, within a pipe assembly, up to 3000 psi. If the assembly being tested were to fail, it would put employees in neighboring shops at risk and could cause tremendous damage to the interior of Building A. X-ray testing emits radiation requiring all personnel to be removed from the surrounding area during the procedure, which is not practical within Building A. Additionally, pipe assemblies are required to be sand-blasted, and the Test Building provides the location for this to happen.

Q. Does the Sherwood Test Building include any special safety features?

A. Yes. Blast-proof panels will be located over and around the test chamber. Flashing beacons will notify employees when testing is occurring at the new Sherwood Test Building to alert them to remain a safe distance away from the building. And, sand-blasting will take place within the building in a separate enclosed booth for employee safety and environmental compliance.

Q. Please describe the sand-blasting that will occur at the Sherwood Test Building.

A. Sand-blasting enables the paint or other coating to bond to the steel surface, reducing future corrosion and expensive maintenance costs.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

Q. What is the current status of the Sherwood Test Building?

A. Research and design on the Sherwood Test Building began in June 2016, and construction is expected to be completed during the summer of 2018.

Q. What is the estimated cost of the Sherwood Test Building?

A. The estimated cost of the Sherwood Test Building is $2.6 million.

<u>Salem Resource Center Retrofit Project</u>

Q. Please describe the Salem Resource Center Retrofit Project ("Salem Retrofit Project").

A. The Salem Retrofit Project is a remodel of NW Natural's existing Salem facility. The remodeling project was designed to address structural integrity issues, bring the facility into compliance with various state and regulatory standards, and to meet company goals and facility standards.

Q. What were the structural problems associated with the Salem facility?

A. The Salem facility was built in the 1960s and the main building had an unusual design, with the exterior wall built on the inside of the building's frame. The results of a building inspection indicated that the exterior wall lacked reinforcement (poor x-bracing, missing rebar and mortar in the CMU cavities) and as such, the building was not structurally sound. According to the structural engineer, the office building was well below code, as it was three times weaker than the allowable level provided by the International Building Code (IBC) seismic capacity code.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

Q. What changes were made to address NW Natural's goals and facilities standards?

A. The building design changes provided for a more efficient use of space, including the repurposing of some unused space for a training room and retaining the auditorium as a disaster recovery planning option for call center functions. Consistent with NW Natural's Facilities Strategic Plan, the Company's additional design goals were to achieve cost and energy efficiencies, environmental updates and a positive public presence.

Q. What functions are served by the building?

A. The facility is home to several critical business functions, including a secondary Customer Contact Center, Customer Field Services, Engineering, Gas Operations, Construction and Operations Support.

Q. Is the location of the facility optimal, consistent with the Facilities Strategic Plan?

A. Yes. The current location is well situated for serving Salem, adequately situated for serving areas south, west and east of Salem, and allows NW Natural to maintain short response times for emergencies and service appointments.

Q. Did NW Natural request cost recovery for the Salem Retrofit Project in the last rate case, docket UG 221?

A. Yes, NW Natural had planned the work for the Salem Retrofit Project at the time of the last rate case, and initially included the project in its request for recovery. However, NW Natural ultimately determined that it would not request that costs

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

associated with the project be added to rate base at that time, due to permit delays and considerable unexpected design and research work related to seismic upgrades.

Parkrose Resource Center Retrofit Project

Q. Please describe the Parkrose Resource Center and Retrofit Project.

A. The Parkrose Resource Center is a 6,786 square-foot concrete-block building with a wood frame roof, built in 1973. The facility is home to several departments including Customer Field Services, Field Engineering, Gas Operations, Construction and Operational Support. The retrofit project provided necessary upgrades and fixes to the building.

Q. What prompted NW Natural to undertake the Parkrose Retrofit Project?

A. The Parkrose facility was dated and had poor energy efficiency, deteriorating walls and roof, failing plumbing systems, obsolete lighting systems, ineffective HVAC systems and inadequate restroom/shower facilities. The yard also required new spoils, pipes storage and equipment sheds.

Q. Please describe the scope of work completed as part of the project

A. The scope included installing a new roof and building insulation, new windows and doors, Men's and Women's restrooms with showers and lockers, and new lighting and HVAC systems. The scope also included building out new offices, a telephone equipment room and kitchenette, and installing a security system. Exterior work included building covered spoils bins, pipe and equipment sheds, a

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NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

fueling shed, emergency generator, bio-swale, fencing and automatic gates, and repaving and striping the yard asphalt.

Q. When was the project completed?

A. Work was completed in June of 2013.

<u>Eugene Resource Center Retrofit Project</u>

Q. Please describe the Eugene Resource Center Retrofit Project.

A. The Eugene Resource Center is a 12,608 square-foot older concrete-block building with a wood-frame roof built in 1975. The facility is home to several departments including Customer Field Services, Field Engineering, Gas Operations, Construction and Operations Support. The retrofit project provides for necessary upgrades and fixes of the building.

Q. What prompted NW Natural to undertake the Eugene Retrofit Project?

A. The Eugene facility is dated and is suffering from a deteriorated roof, siding, electrical and HVAC systems. The restroom and shower facilities are inadequate and the office space needs to be reconfigured to support current and ongoing operations. In addition, the facility requires seismic retrofitting to current code for life safety. The yard needs to be expanded to enhance functionality and to meet current and future growth. The spoils bins and pipe racks need to be covered, and drainage issues need to be addressed.

Q. Is the Eugene Retrofit Project consistent with NW Natural's strategic facilities planning?

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

A. Yes. The objective of the Eugene Retrofit Project is to repair and modernize the facility, bringing it into compliance with various state, regulatory, and company goals and facility standards. These goals are designed to simultaneously achieve energy efficiencies, environmental updates, enhanced utility, and a positive public presence.

Q. Is construction of the Eugene Retrofit Project underway?

A. Planning and design began in September 2016. NW Natural anticipates that construction will begin in early 2018 and be completed by October 2018.

Q. What is the estimated cost to complete the Eugene Retrofit Project?

A. The estimated cost of the Eugene Retrofit Project is $3.4 million.

<u>Coos Bay Resource Center Retrofit</u>

Q. Please describe the Coos Bay Resource Center Retrofit project

A. The facility, which was pre-existing, was purchased in 2005 to serve as a resource center in the Coos Bay area. The Coos Bay retrofit project is a 3,582 sq. ft. limited scope remodel of the existing Coos Bay facility. The remodeling project is designed to address gaps with business functionality and aging infrastructure.

Q. What are some of the gaps that need to be addressed?

A. The facility is dated and the functionality is impaired. Operational issues include such things as deteriorating walls, failing plumbing, obsolete lighting, ineffective HVAC system, and inadequate breakroom and restroom/shower facilities. The facility suffers from fatigue and does not reflect NW Natural's facilities standards.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

Q. When will the Coos Bay Retrofit Project be completed?

A. The Coos Bay Retrofit project is scheduled to be completed by the Spring of 2018.

Q. What is the estimated cost of the Coos Bay Retrofit Project?

A. The estimated cost of the project is $0.76 million.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Direct Testimony of Jorge Moncayo

OPERATIONS & MAINTENANCE / CAPITAL EXHIBIT 600

December 2017

EXHIBIT 600 – DIRECT TESTIMONY – OPERATIONS & MAINTENANCE / CAPITAL

Table of Contents

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Jorge Moncayo. I am the Budget and Financial Planning Director at NW Natural. I am responsible for producing the annual operations and maintenance (O&M) budget, the capital expenditures (capex) budget, and the income statement budget. I also manage the department that develops short-term and long-term financial forecasts for senior management and supports the organization with financial modeling and analysis.

Q. Please summarize your educational background and business experience.

A. I have Bachelor's degrees in Business Administration and Accounting from Universidad Catolica, Ecuador and a Masters of Business Administration and a Masters of Science in Industrial Engineering from Oregon State University. Since joining NW Natural in 2003 as a market research analyst, I have held positions in Consumer Research and Analysis, Operations Support Services, Business Analysis and Finance. I have been in my current position since 2013.

Q. Please provide a summary of your testimony.

A. In my testimony, I:

- Explain how the Company developed the O&M amount included in the revenue requirement, including an explanation of how the Company calculated O&M costs for the calendar year 2017 base year ("Base

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Year") and used those costs to develop the Oregon-allocated O&M costs for the test period consisting of the 12 months ending October 31, 2019 ("Test Year");

- Discuss the Company's performance in managing O&M expense; and
- Present the Company's ongoing capital expenditures levels.

II. TEST YEAR OPERATIONS AND MAINTENANCE COSTS

Q. What is the Oregon-allocated O&M expense included in NW Natural's revenue requirement in this case?

A. The Oregon-allocated Test Year O&M expense included in the revenue requirement in this case is $148.4 million. This compares to a Company total of $165.8 million of O&M for the Test Year, which is adjusted for state allocations, uncollectible accounts expense (which is developed separately as part of the Revenue Requirement testimony in this case), and amounts that represent O&M for which the Company is not seeking cost recovery in this case. Exhibit *NW Natural/601, Moncayo/1* shows the Base Period O&M expense by Federal Energy Regulatory Commission (FERC) account and exhibit *NW Natural/602, Moncayo/1* shows the Test Year O&M by FERC account.

Q. You state that the Base Year is calendar year 2017. How did NW Natural establish Base Year O&M costs given that this filing is being made in December of 2017?

A. The Company used the actual expenses for January through September 2017 and forecast the expenses for the remaining three months of 2017 to develop the

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

total Base Year O&M expenses. The total Company Base Year O&M, excluding uncollectible accounts expense, is forecast to be $151.8 million, or $136.3 million on an Oregon-allocated basis. The Company adopted the calendar year 2017 as the Base Year because that period reflects the most recent historical information available and allows for a comparison of the Base Year with historical years consisting of the same months. NW Natural took this same approach in its last general rate case, UG 221.

Q. How did NW Natural determine the forecast costs for October through December 2017?

A. The costs for these months are based on a forecast provided by the different business units. Business units prepare an annual budget for the coming year and provide periodic forecast updates throughout the year, the most recent update being in October 2017. The projected O&M and capital by month for the year is based on historical activity levels, in addition to planned projects and activities. NW Natural used actual expenses for the first nine months of 2017 and the forecast from each business unit for the three remaining months of the Base Year to develop total Base Year O&M expense.

Q. How were the Test Year O&M costs developed?

A. O&M is composed of three components: A) O&M Payroll costs; B) O&M Non-Payroll costs; and C) O&M Other Cost Adjustments. The Company started with the Base Year amounts for each of these three components, which were then forecasted to develop the projected Test Year expenses.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

<u>A. O&M Payroll Costs</u>

Q. What was the first step in calculating Test Year O&M payroll costs based on the Base Year costs?

A. The forecasted number of the Company's full-time equivalent positions (FTEs) in the Test Year is the largest factor in the Test Year payroll O&M cost estimate; these costs account for roughly two-thirds of NW Natural's total O&M costs. The year-end 2017 Base Year forecast of 1,117.5 regulated FTEs was used as the planned Test Year FTE count, and these payroll costs are what the Company seeks to recover in rates.

Q. How did you project the number of FTEs at the end of the Base Year?

A. NW Natural's Human Resources Department provided FTE projections for the final three months of 2017 by taking into account actual FTE counts, projected FTE attrition, and projected FTE hires. Projected FTE attrition is based on known retirements and departures, as well as recent trends. Projected FTE hires are based on positions the Company is in the process of hiring, taking into account the stage in hiring process for each position.

Q. Did the projected FTE count take into account projected vacancies and FTEs allocated to non-utility activities?

A. Yes. NW Natural does not seek to recover in rates costs for 51.3 vacant FTE positions and 25.2 FTEs allocated to non-utility activities (termed "non-regulated FTEs" in this testimony). The table below illustrates the adjustments made to the total internally-approved FTEs.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

	Test Year
Approved FTEs	1,194.0
Unfilled FTEs Adjustment	(51.3)
Hired FTEs	**1,142.7**
Non-regulated FTEs Adjustment	(25.2)
Regulated FTEs	**1,117.5**

Q. You state that NW Natural does not seek recovery for non-regulated FTEs in the Test Year. Please explain how non-regulated FTEs are determined.

A. Based on their work portfolio, each utility employee was assigned, either in part or in full, to regulated or non-regulated operations. A total of 25.2 FTEs were assigned to non-regulated activities, which includes time charged to NW Natural's affiliates. The table below shows the calculated FTEs for which the Company does not seek cost recovery:

	Test Year
Appliance Center	(11.1)
Affiliates	(7.0)
Service Solutions	(1.7)
Community Affairs, Public Relations	(1.6)
Business Development and Other Transfers	(3.8)
Non-regulated FTEs Adjustment	**(25.2)**

Q. Do you request rate recovery for any incremental FTEs added after the Base Year?

A. No. While NW Natural may need the addition of incremental FTEs to support customer and operational needs in the future, the Company is only seeking recovery for the costs associated with the FTE count projected at the end of the Base Year.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Q. Please explain your escalation methodology for payroll costs.

A. Bargaining unit (BU) employee payroll costs were escalated for expected wage increases according to the Collective Bargaining Agreement with the Union entered into on June 1, 2014, which will run through November 30, 2019. These increases are expected to be 3.00 percent on December 1, 2017 and 3.00 percent on December 1, 2018. The Company also assumes an additional 0.50 percent for promotions and movements from entry rate to experienced rate as described in the Collective Bargaining Agreement.

Similarly, payroll costs were escalated for expected salary increases for non-bargaining unit (NBU) employees. These increases are expected to be 3.25 percent on March 1, 2018 and 3.50 percent on March 1, 2019. Based on historical trends, the Company also assumes an additional 0.75 percent for NBU employee promotions per year in 2018 and 2019.

Payroll costs were also adjusted for expected changes in benefits costs. The Direct Testimony of Lea Anne Doolittle *NW Natural/700, Doolittle* discusses these salary and benefits cost increases as well.

Q. How were payroll overhead rates calculated for the Test Year?

A. Payroll overhead is used to allocate benefits expense to employee payroll. The payroll overhead rates used are a calculated ratio of the total benefits expense to payroll for the year. These payroll overhead rates are applied to the forecast for executives payroll and non-executives payroll for the Test Year, thereby adjusting payroll to account for benefits expenses. The payroll overhead rates in

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

the Test Year for non-executive employees are 60.30 percent in 2018 and 61.06 percent in 2019. For executives, the payroll overhead rate is 82.94 percent in 2018 and 82.86 percent in 2019.

Q. How did you determine the utility regulated payroll that is allocated to O&M activities?

A. Once the Company determines the regulated utility payroll costs, it allocates utility regulated payroll expenses to O&M and capital. NW Natural uses two approaches to allocate expenses and to charge time for various activities. In the first approach, most employees who directly work on capital activities will track and directly charge their time. In the second approach, employees that are generally supportive of both capital and O&M projects, such as human resources, accounting, or finance, have a portion of their time applied to capital via an administrative transfer. The O&M payroll allocation used in the Test Year is 66.8 percent. The Company calculated this allocation using budget submissions from each departmental manager based on the O&M activity expected in the Test Year.

B. O&M Non-Payroll Costs

Q. Please explain your escalation methodology for non-payroll costs.

A. The Company escalated general non-payroll costs using year-over-year rates of change in the forecast of the Portland-Salem Consumer Price Index (CPI) reported in the September 2017 Oregon Economic and Revenue Forecast,

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

published by the Oregon Office of Economic Analysis (OEA). These escalation rates were applied on January 1, 2018 and January 1, 2019.

A small portion of items were projected to grow at lower or greater rates than the forecasted CPI levels. These items were therefore adjusted for specific growth rates.

Q. Please describe why some items were adjusted at a rate different than CPI.

A. Some items have a higher Base Year expense, but are expected to be lower in the Test Year than would be calculated using CPI. So, estimated expenses for those items were reduced in the Test Year. And in some instances, the converse is true. Some items change as a function of contractual agreements, customer growth, or industry-specific cost trends, so these factors were used as a more accurate measure of Test Year expense.

The items that were adjusted in the Test Year on this basis include: employee protection equipment, current headquarters (Oregon Pacific Square) lease expense, bank merchant fees, contracted locating services, software maintenance, external audit fees, and insurance.

Q. Are Non-Payroll O&M costs adjusted to reflect services provided from NW Natural to its affiliates?

A. Yes. NW Natural's O&M costs are reduced to reflect a credit for expenses associated with services to affiliates, known as "Shared Services." The Company calculates this credit based on departmental budgets of the services expected to be provided to affiliates in the Test Year. The non-payroll portion of

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Shared Services is calculated by imputing an administrative overhead of 27.5 percent to the payroll charges. The non-payroll credit to the utility during the Test Year is $0.2 million.

Q. Does the Test Year include any other adjustments?

A. Yes. Supplemental Executive Retirement Plan and Executive Supplemental Retirement Income Plan costs were removed, as NW Natural is not seeking recovery for these costs. Also, “Category C” advertisement expenses were removed in the Test Year as described in the Direct Testimony of Kim Heiting *NW Natural/1000, Heiting*.

C. O&M Other Cost Adjustments

Q. Once you have calculated O&M payroll and non-payroll expenses, do you perform any further adjustments?

A. Yes. Once payroll and non-payroll expenses are calculated, O&M is adjusted to reflect: a) the Commission-authorized amount of $5.0 million expense related to environmental remediation (See UM 1635 OPUC, Order No. 15-049, where a tariff rider of $5.0 million was established to be applied toward recovery of environmental remediation expense); and b) corporate O&M items.

Q. What items are included in the corporate O&M adjustments?

A. Listed below are the items included in the corporate adjustment:

- Administrative transfer: $14.2 million credit – The Administrative Transfer allocates a portion of administrative employee costs, such as the salaries and expenses of Accounting, Human Resources, and

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

general administration from O&M to construction activities. These costs are categorized as indirect construction overhead because they are not charged directly to specific or individual construction projects.

- Payroll tax: $6.5 million credit – This credit removes payroll tax expense from O&M and transfers it to the "Other Taxes" line of the revenue requirement. This adjustment is required by FERC accounting methodology. The payroll tax expense is included in the revenue requirement in this case under the "Other Taxes" area, and is not included in O&M costs.
- Shared Services overhead: $0.2 million credit – As described above, this credit reflects the overhead for services expected to be provided to affiliates in the Test Year.
- Stock expense: $3.5 million expense – Includes employee stock purchase plan, as well as other employee stock expense compensation.
- Post-retirement medical: $2.0 million expense – This expense represents the direct expense portion of post-retirement medical benefits.
- Pension: $1.2 million expense – This represents the net of the direct pension expense and the pension balancing account. Once this amount is added to the pension portion included in payroll overheads, the Oregon-allocated O&M expense for the Test Year is $3.8 million,

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

which is the level that was approved in the Company's 2002 rate case, Docket UG 152. The pension balancing mechanism is described in the Direct Testimony of Kevin McVay *NW Natural/200, McVay*.

- Uncollected claims and damages: $0.2 million expense – This expense is based on a three-year historical average.

The overall effect of these corporate adjustments is a reduction to Company O&M of $14.0 million.

Q. Does the Test Year include changes to pension accounting?

A. Yes. Effective January 1, 2018, NW Natural will adopt Accounting Standards Update (ASU) 2017-07, modifying the presentation of net periodic cost and net periodic post-retirement benefit cost, and also limiting the portion of defined benefit (DB) pension costs and other post-retirement benefits (OPEB) costs that are eligible for capitalization.

Q. Please explain the mechanics of the changes in pension accounting?

A. Under the current process, all components of DB and OPEB expense are recognized through payroll overheads and capitalized according to the capitalized proportion of total employee wage and salaries described above. After ASU 2017-07 is implemented, only the service cost component of DB and OPEB expense will continue to be recognized through payroll overheads and capitalized according to the O&M/capital mix of the employees' salaries and wages. All other cost components of DB and OPEB will be recognized as expenses. For DB pension costs, the increased expense is reduced by the

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

pension balancing mechanism, negating the impact of additional expense. For OPEB, the new accounting standard will increase the amount of expense as compared to the former accounting guidelines.

Q. What is the expense impact of this change?

A. As stated above, the pension balancing mechanism will negate the increased expense for DB pensions. For OPEB, which is not impacted by the pension balancing mechanism, the new accounting standard is expected to increase Test Year expense by $0.6 million.

Q. Can you provide an illustration of what the expense would have been before and after the pension accounting change?

A. Yes. Exhibit *NW Natural/603, Moncayo/1* provides this illustration.

Q. How did NW Natural allocate O&M expenses to Oregon?

A. After all of the above-described calculations and adjustments, the Company converted its O&M forecast into FERC accounts based on actual historical FERC allocations, to allow for a state allocation based on FERC accounts. NW Natural then applied the relevant Oregon allocation factor to each FERC account to calculate Oregon allocated O&M. The allocation methodology is described in the Direct Testimony of Kevin McVay *NW Natural/200, McVay*.

III. O&M EXPENSE MANAGEMENT AND COMPANY PERFORMANCE

Q. Does NW Natural have cost control protocols and practices in place?

A. Yes. Under the direction of the CFO and CEO, my department engages in an annual budgeting and financial planning process, through which we determine

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

and manage to a company-wide budget. This budget is informed by individual departmental needs, overall company goals, and an ongoing focus on controlling costs. Throughout the year, we provide reporting on budgets to actuals for each department, and engage with departments on their spending levels. We also require justifications for department budgets and significant departures from budgeted amounts.

Q. Please provide your view of NW Natural's O&M levels, and the amounts of O&M reflected in the Test Year.

A. NW Natural's O&M levels have grown at a reasonable rate, reflecting good cost management practices within the Company. As is true with most companies, much of the pressure on our O&M expense levels comes from inflation. Additionally, as the utility adds new customers, O&M expenses naturally rise as well.

The next chart shows that O&M expense per customer (system-wide, including uncollectible, excluding environmental remediation expenses and charges, in nominal dollars) has increased from $186.71 in 2013 to $219.41 for the Test Year, which reflects a compound annual growth rate (CAGR) of 2.8 percent from 2013.

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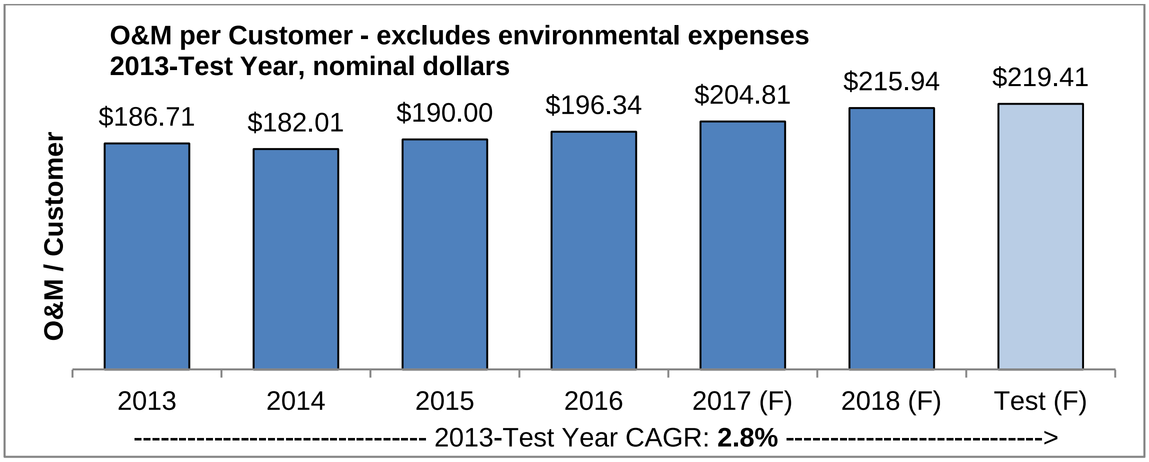
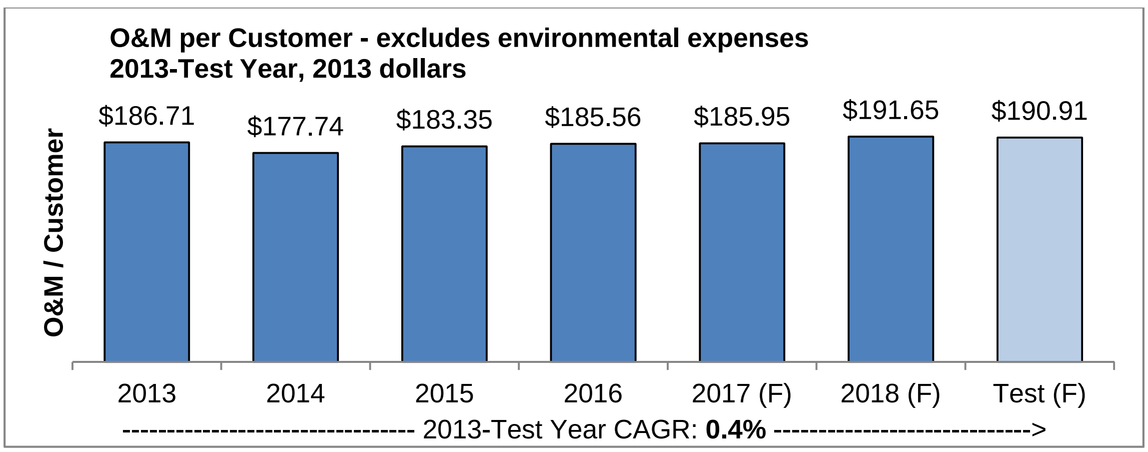
Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211



Expressed in constant 2013 dollars, calculated using the Portland-Salem CPI index from OEA, the Test Year O&M expense per customer is $190.91, a CAGR of 0.4 percent from 2013 as shown in the chart below.



This means that NW Natural's O&M expense levels are essentially flat, after taking into account inflation and customer growth. This reflects good cost management practices at the Company, and that the utility is managing its O&M levels to stabilize rates as much as possible for customers.

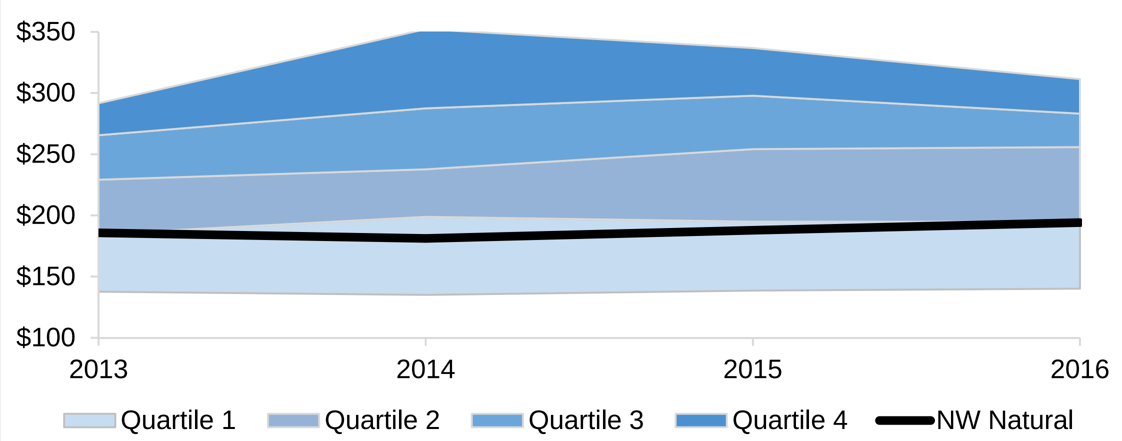
Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Q. Have you compared NW Natural's O&M expense per customer to O&M expenses per customer at comparable utilities?

A. Yes. The following chart provides a comparison of the Company's O&M per customer expense with a panel of similar gas utilities. For comparability purposes, NW Natural excludes expenses related to the environmental docket (UM 1635 OPUC, Order No. 15-049) and production and transmission expenses are excluded for the peer group and NW Natural.

The chart shows that NW Natural is consistently a top performer in O&M expense management. The panel uses customer counts and costs for those companies with FERC Form 2 information available in SNL, and includes the following companies: Atmos, Avista, Cascade Natural Gas, National Fuel Gas, New Jersey Gas, One Gas, South Jersey Gas, and Washington Gas and Light.

O&M per Customer - excludes production and transmission expenses
2013-2016
Source for peers: *S&P Global Market Intelligence*



Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Again, this information shows that NW Natural performs well in managing its O&M expense to keep rates as low as reasonably possible for customers.

IV. CAPITAL EXPENDITURES AND FORECAST

Q. Please describe NW Natural's capital expenditures budgeting process, and how the Company calculates projected capital expenditures.

A. The forecasted capital expenditures are developed using the following steps:

1. Operating units submit a detailed three-year capital forecast.
2. The Financial Planning Department reviews the forecasted capital and verifies that each operating unit has adequately supported its assumptions.
3. The operating units' forecasts are summarized to create the Company's capital requirement by year.
4. The capital requirements are reviewed by their respective executive for completeness and reasonableness, and adjustments are made as appropriate.
5. Once the calendar year forecasts are completed, program and project expenditures are spread by month based on projected project spending schedules.

Q. Please explain how NW Natural selects capital projects to be included in the capital budget and forecast.

A. Projects are selected based on the need to support system reliability and safety, expansion and customer growth, and jurisdictional requirements.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Required and routine programs and projects, which constitute the majority of the capital expenditures, include: emergency, breakage, public works or jurisdictionally mandated work, security, new customer mains and services, or system reliability work. These required projects are included in the planning process with the best estimate of what the work will cost to complete. These estimates take into account recent cost trends, expected change in cost, and volume and complexity of work. Projected capital expenditures are then reviewed and approved by senior management. The Board of Directors then reviews and approves the budget for the upcoming year at the December Board Meeting each year. If additional high priority or required work is identified after the budgeting cycle, these projects are subject to prioritization and review by the Project Management Office (PMO).

Non-routine projects are evaluated, prioritized and managed by a Project Prioritization Committee (PPC). Projects are submitted to the PPC through a tri-annual process and, once approved, are included in the budget and forecast plan. These projects are then reviewed and approved by senior management and the Board of Directors as part of the December Board Meeting.

Q. What are the internal requirements at NW Natural to initiate large projects?

A. Large projects are subject to financial analysis and formal alternatives analysis, as well as approval and review by senior management.

To initiate a large project, a project request memorandum is completed. This document includes a description of the project, sponsors, requestors,

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

business case, resources involved, labor mix, schedule, and capital and O&M budget.

Once submitted, it goes to the PPC for evaluation and prioritization relative to other projects. The PPC takes into consideration availability of funding and resources, and other project criteria such as safety, compliance, customer growth, risk mitigation, etc. Before being approved for execution, an Alternatives Analysis Committee (AAC) reviews the documentation to assure the alternative selected is the most beneficial to customers.

After a project is approved to go into execution, project managers are required to provide monthly updates and to explain variances against budget, schedule, and scope.

Q. What are the primary drivers behind NW Natural's non-routine planned capital expenditures?

A. These drivers are discussed in the Direct Testimonies of Joe Karney *NW Natural/800, Karney* and Wayne Pipes *NW Natural/500, Pipes*.

Q. What are the forecasted capital expenditures for the next three calendar years and the Test Year?

A. The utility capital expenditures planned for calendar year 2017 are $159 million, for 2018 are $187 million, and for 2019 are $174 million. The capital expenditures forecasted for the Test Year are $153 million. These expenditures exclude the investment in the North Mist Expansion Project (NMEP), which is currently estimated to cost $128 million from inception to completion.

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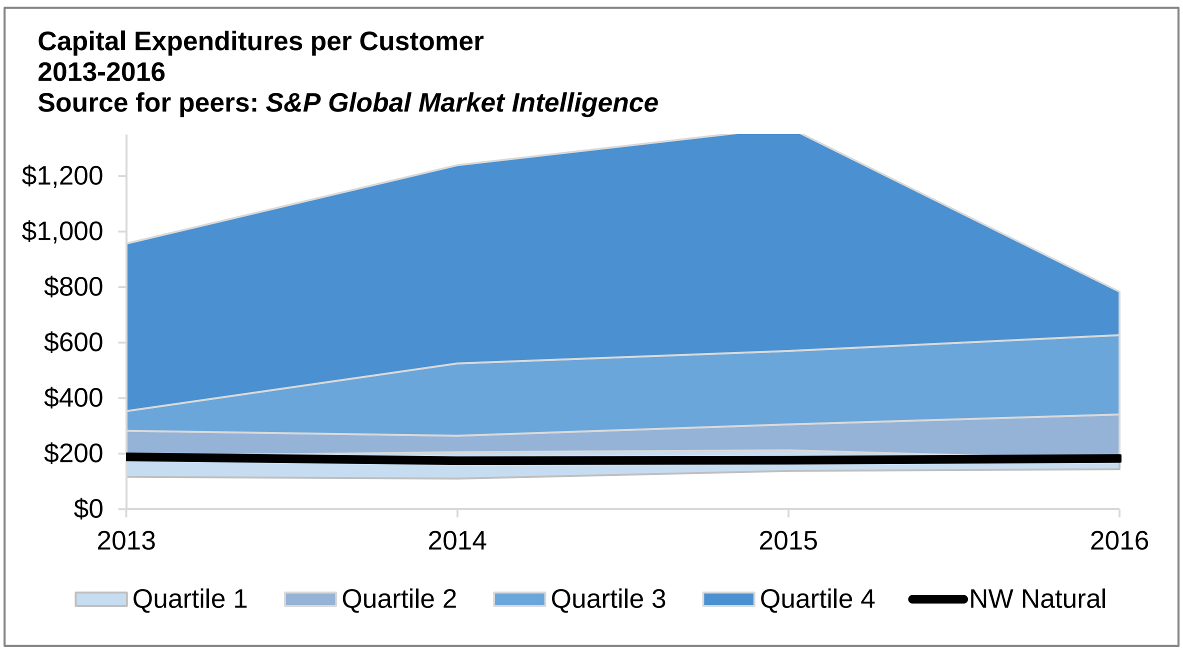
1-503-226-4211

Q. Have you compared NW Natural's capital expenditures to capital expenditures of comparable utilities?

A. Yes. NW Natural's capital expenditures are significantly lower than other comparable utilities. To make a relevant comparison, we evaluated capital expenditures per customer. The chart below provides a comparison of the Company's capital expenditures per customer with a panel of similar gas utilities for the 2013-2016 period. NW Natural excludes investment in the NMEP. The panel includes the following companies: National Fuel Gas, South Jersey Gas, New Jersey Resources, Washington Gas and Light, Atmos, Chesapeake Utilities, Southwest Gas, Spire, and One Gas.



Again, these metrics indicate that NW Natural implements effective cost management procedures, while keeping its system safe and reliable and at rates that are affordable to its customers.

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Portland, Oregon 97209-3991
1-503-226-4211

Q. Does this conclude your direct testimony?

A. Yes, it does.

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220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Exhibits of Jorge Moncayo

OPERATIONS & MAINTENANCE / CAPITAL EXHIBITS 601 - 603

December 2017

EXHIBITS 601 – 603 – OPERATIONS & MAINTENANCE / CAPITAL

Table of Contents

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

NW Natural
Base Year Twelve Months Ended December 31, 2017
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	BASE YEAR System (c)	BASE YEAR Oregon (d)
1		Natural Gas Storage		
2		Underground Storage Expense		
3		Operation		
4	816	Wells Expense	$288,426	$261,574
5	818	Compressor Station Expense	95,316	86,442
6	819	Compressor Station Fuel	0	0
7	820	Measuring and Regulator Station Expense	2,284,400	2,072,675
8	821	Purification Expense	65,585	59,649
9		Maintenance		
10	832	Wells Expense	324,748	294,514
11		Total Underground Storage Expense	3,058,476	2,774,855
12		Other Storage Expense		
13		Operation		
14	840	Supervision and Engineering	152,417	138,227
15		Total Other Storage Expense	152,417	138,227
16		Liquified Natural Gas Expense		
17		Operation		
18	844	Supervision and Engineering	1,679,932	1,523,530
19	845	LNG Fuel	-	-
20		Maintenance		
21	847	Supervision and Engineering	1,037,421	940,837
22		Total Liquified Natural Gas Expense	2,717,353	2,464,367
23		Total Natural Gas Storage	5,928,246	5,377,449
24		Transmission Expense		
25		Operation		
26	856	Mains Expense	1,976,836	1,856,343
27		Maintenance		
28	863	Maintenance of Mains	211,101	193,967
29		Total Transmission Expense	2,187,936	2,050,311
30		Distribution Expense		
31		Operation		
32	870	Supervision and Engineering	3,066,919	2,799,861
33	874	Mains and Services Expense	13,437,705	12,094,610
34	875	Measuring and Regulator Station Expense - General	316,162	284,972
35	877	Measuring and Regulator Station Expense - City Gate	462,884	423,835
36	878	Meter and House Regulator Expense	5,976,513	5,331,344
37	879	Customer Installation Expense	10,636,487	9,491,013
38	880	Other Expense	2,310,439	2,043,290
39	881	Rents	215,700	188,771
40		Maintenance		
41	885	Supervision and Engineering	7,785,191	7,485,845
42	887	Mains	2,830,295	2,586,489
43	889	Measuring and Regulator Station Expense - General	1,627,345	1,487,894
44	891	Measuring and Regulator Station Expense - City Gate	184,387	170,588
45	892	Services	668,847	629,157
46	893	Meters and House Regulators	3,172,310	2,865,860
47	894	Other Equipment	22,650	20,802
48		Total Distribution Expense	52,713,835	47,904,330
49		Customer Accounts Expense		
50		Operation		
51	901	Supervision	1,678,781	1,496,468
52	902	Meter Reading Expenses	860,184	767,018
53	903	Customer Records and Collection Expense	18,812,078	16,783,116
54	904	Uncollectible Accounts	-	-
55		Total Customer Accounts Expense	21,351,042	19,046,602
56		Customer Service and Informational		
57		Operation		
58	907	Supervision	1,616	1,439
59	908	Customer Assistance Expense	2,487,008	2,200,112
60	909	Customer Information Expense	2,701,715	2,408,308
61	910	Miscellaneous Customer Service Expense	232,631	207,088
62		Total Customer Service and Informational	5,422,969	4,816,947
63		Sales Expense		
64		Operation		
65	911	Supervision	186,188	165,968
66	912	Demonstration and Selling Expense	3,889,789	3,468,208
67	913	Advertising	667,240	594,778
68	916	Miscellaneous Sales Expense	-	-
69		Total Sales Expense	4,743,217	4,228,953
70		Administrative and General Expense		
71		Operation		
72	921	Office Supplies and Expense	60,041,661	53,589,980
73	922	Administrative Expenses Transferred - Credit	(20,102,946)	(18,011,060)
74	924	Property Insurance Premium	3,253,000	2,923,471
75	925	Injuries and Damages	245,747	220,852
76	926	Employee Pensions and Benefits	(1,282,249)	(1,832,239)
77	928	Regulatory Commission Expense	-	-
78	930	Miscellaneous General Expense	3,111,730	2,796,017
79	931	Rents	4,796,707	4,315,560
80		Maintenance		
81	935	Maintenance of General Plant	4,380,096	3,916,473
82		Total Administrative and General Expense	54,443,746	47,919,054
83		Total O&M Expense LESS Acct 904 Uncollectible	146,790,991	131,343,647
84		Environmental Remediation Expense	5,000,000	5,000,000
85		Total O&M Expense PLUS Env. Remediation Expense	151,790,991	136,343,647

NW Natural
Test Year Twelve Months Ended October 31, 2019
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	TEST YEAR System (a)	TEST YEAR Oregon (b)
1		Natural Gas Storage		
2		Underground Storage Expense		
3		Operation		
4	816	Wells Expense	$302,647	$274,470
5	818	Compressor Station Expense	108,475	98,376
6	819	Compressor Station Fuel	0	0
7	820	Measuring and Regulator Station Expense	2,209,830	2,005,017
8	821	Purification Expense	68,201	62,029
9		Maintenance		
10	832	Wells Expense	290,831	263,755
11		Total Underground Storage Expense	2,979,985	2,703,647
12		Other Storage Expense		
13		Operation		
14	840	Supervision and Engineering	151,127	137,057
15		Total Other Storage Expense	151,127	137,057
16		Liquified Natural Gas Expense		
17		Operation		
18	844	Supervision and Engineering	1,626,783	1,475,330
19	845	LNG Fuel	-	-
20		Maintenance		
21	847	Supervision and Engineering	1,067,691	968,289
22		Total Liquified Natural Gas Expense	2,694,474	2,443,619
23		Total Natural Gas Storage	5,825,586	5,284,323
24		Transmission Expense		
25		Operation		
26	856	Mains Expense	1,962,000	1,842,412
27		Maintenance		
28	863	Maintenance of Mains	206,609	189,840
29		Total Transmission Expense	2,168,610	2,032,253
30		Distribution Expense		
31		Operation		
32	870	Supervision and Engineering	2,890,744	2,639,027
33	874	Mains and Services Expense	13,500,666	12,151,278
34	875	Measuring and Regulator Station Expense - General	281,465	253,697
35	877	Measuring and Regulator Station Expense - City Gate	464,201	425,040
36	878	Meter and House Regulator Expense	5,830,824	5,201,382
37	879	Customer Installation Expense	10,900,139	9,726,271
38	880	Other Expense	2,141,613	1,893,985
39	881	Rents	225,324	197,194
40		Maintenance		
41	885	Supervision and Engineering	8,040,935	7,731,755
42	887	Mains	2,660,056	2,430,914
43	889	Measuring and Regulator Station Expense - General	1,536,803	1,405,111
44	891	Measuring and Regulator Station Expense - City Gate	181,668	168,073
45	892	Services	639,467	601,520
46	893	Meters and House Regulators	2,992,735	2,703,632
47	894	Other Equipment	22,309	20,488
48		Total Distribution Expense	52,308,948	47,549,368
49		Customer Accounts Expense		
50		Operation		
51	901	Supervision	1,583,983	1,411,965
52	902	Meter Reading Expenses	833,698	743,401
53	903	Customer Records and Collection Expense	17,974,714	16,036,065
54	904	Uncollectible Accounts	-	-
55		Total Customer Accounts Expense	20,392,394	18,191,431
56		Customer Service and Informational		
57		Operation		
58	907	Supervision	1,688	1,502
59	908	Customer Assistance Expense	2,582,752	2,284,812
60	909	Customer Information Expense	2,275,503	2,028,384
61	910	Miscellaneous Customer Service Expense	226,150	201,319
62		Total Customer Service and Informational	5,086,094	4,516,017
63		Sales Expense		
64		Operation		
65	911	Supervision	177,769	158,463
66	912	Demonstration and Selling Expense	4,131,640	3,683,847
67	913	Advertising	516,168	460,112
68	916	Miscellaneous Sales Expense	-	-
69		Total Sales Expense	4,825,577	4,302,422
70		Administrative and General Expense		
71		Operation		
72	921	Office Supplies and Expense	64,165,205	57,270,436
73	922	Administrative Expenses Transferred - Credit	(20,391,417)	(18,269,513)
74	924	Property Insurance Premium	3,914,550	3,518,006
75	925	Injuries and Damages	238,216	214,085
76	926	Employee Pensions and Benefits	8,961,559	6,873,874
77	928	Regulatory Commission Expense	103,742	103,742
78	930	Miscellaneous General Expense	3,260,782	2,929,946
79	931	Rents	4,976,654	4,477,457
80		Maintenance		
81	935	Maintenance of General Plant	4,983,374	4,455,896
82		Total Administrative and General Expense	70,212,666	61,573,928
84		Total O&M Expense LESS Acct 904 Uncollectible	160,819,875	143,449,742
85		Environmental Remediation Expense	5,000,000	5,000,000
86		Total O&M Expense PLUS Env. Remediation Expense	165,819,875	148,449,742

DB Pension Illustration	New ASU 2017-07	Prior Payroll OH Allocation Method
Test Year Total DB Pension Expense	$20,833,200	$20,833,200
DB Pension expense in O&M via Payroll OH	$4,772,402	$13,708,246
DB Pension directly expensed	$13,381,413	$0
Total Pension expense	$18,153,815	$13,708,246
Pension Adminstrative Expenses	($500,000)	($500,000)
DB Pension Exp. applicable to Pension Balancing	$17,653,815	$13,208,246
Oregon Allocation	90%	90%
Oregon DB Pension O&M Amount	$15,888,434	$11,887,421
Oregon DB Pension O&M Amount in Rates	$3,796,055	$3,796,055
Oregon DB Pension Balancing Account Amount	($12,092,379)	($8,091,366)
Oregon DB Pension Amount in Test Year Expense	$15,888,434	$11,887,421
Oregon DB Pension Balancing Account Amount	($12,092,379)	($8,091,366)
Net Oregon DB Pension Expense	**$3,796,055**	**$3,796,055**

OPEB Illustration	New ASU 2017-07	Prior Payroll OH Allocation Method
Test Year Total OPEB Expense	$2,500,100	$2,500,100
OPEB expense in O&M via Payroll OH	$318,456	$1,600,480
OPEB directly expensed	$2,002,641	$0
	$2,321,097	$1,600,480
Oregon Allocation	90%	90%
Oregon OPEB Expense Amount	**$2,088,988**	**$1,440,432**
Increase in OPEB Expense	**$648,556**	

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Direct Testimony of Lea Anne Doolittle

COMPENSATION AND BENEFITS
EXHIBIT 700

December 2017

EXHIBIT 700 – DIRECT TESTIMONY - COMPENSATION AND BENEFITS

Table of Contents

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
503-226-4211

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Lea Anne Doolittle. My title is Senior Vice President and Chief Administrative Officer. I am responsible for overseeing various administrative functions at NW Natural, including Human Resources, Information Technology, Safety, Facilities, Emergency Management and Business Continuity, Project Management, Labor Relations, Security, and Payroll.

Q. Please describe your education and employment background.

A. I received a Master of Business Administration from The Atkinson School at Willamette University in 1980 and a Bachelor of Arts degree in Sociology from the University of Redlands in 1977. Prior to NW Natural, I was employed by PacifiCorp for 10 years as the Director of Compensation and in other human resource management roles. Before joining PacifiCorp, I was the Director of Human Resources and Compensation for eight years at NERCO. I have worked as an officer for NW Natural since I joined the Company in October of 2000.

Q. Please summarize your testimony.

A. In my testimony, I:

- Describe the Company's compensation practices, which result in total compensation that is at the market median for comparable companies;

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

- Describe the employee benefit program offered by NW Natural, and demonstrate that it is aligned with the market, and that the Company has carefully managed these benefits to ensure reasonable costs; and
- Describe the overall level of compensation and benefits costs included in the Company's requested revenue requirement for the November 2018-October 2019 test year ("Test Year").

II. NW NATURAL'S APPROACH TO COMPENSATION FOR EMPLOYEES

Q. What is NW Natural's approach to determining the compensation it provides to its employees?

A. NW Natural's approach is to provide a level of total compensation that is necessary to attract, motivate, and retain qualified employees needed to run a safe and reliable natural gas delivery business, with good customer service and at a cost that is reasonable. In order to do this, we determine and provide a competitive total compensation package for the employees that we need to hire and retain.

Q. Please explain what you mean by "competitive total compensation."

A. Total compensation refers to the combination of base pay, merit-based incentive payments (or "pay-at-risk"), medical benefits, and retirement benefits. Total compensation is competitive when its total value is at the median level for total compensation offered in the marketplace for comparable jobs. It is through offering a competitive total compensation package that NW Natural is able to tap

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

into the job market to attract, hire and retain the employees it requires to run a safe, reliable, customer service-focused gas utility.

Q. How does NW Natural determine that its total compensation is at the median level?

A. As I will explain in my testimony, the Company performs research to ensure that each aspect of its compensation is competitive with the compensation offered by its competitors for labor, for comparable jobs.

Q. Are there established practices that allow you to be confident that you are offering a competitive total compensation, and not more?

A. Yes. There are well-established methodologies that we employ in order to ensure that we offer competitive compensation, based on comparable jobs. I will describe those in more detail in my testimony.

III. BASE PAY

Q. You mentioned that "base pay" is a major component of offering competitive total compensation. How are you defining base pay?

A. Base pay is the guaranteed financial compensation provided to employees for the work performed. It is delivered on either an hourly or salaried basis. It excludes the other important components of compensation (*i.e.* pay-at-risk) that NW Natural offers its employees that are not guaranteed, and not paid on a regular interval.

Q. How does the NW Natural determine its employees' base pay?

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. NW Natural purchases and regularly analyzes comprehensive survey data to ensure that its base pay is aligned with the median of the market for comparable jobs with other companies that would typically compete with NW Natural for employee talent. The results of such analysis, as completed by the Company in 2017, is at *NW Natural/701, Doolittle*. The analysis demonstrates that NW Natural's base pay midpoints for non-bargaining unit (NBU) jobs are at the median of the comparator companies. It is through this well-established process that NW Natural is confident that it offers an appropriate level of base pay to its employees as a component of competitive total compensation.

For bargaining unit (BU) employees, total compensation, including base pay, is determined through a negotiated process. The Company and the union have jointly agreed to utilize selected market survey data sources and union contracts, primarily of Northwest gas utility companies, as the comparators for setting BU wage steps. Using the jointly agreed to sources of competitive pay data, the average is used to determine pay grades. Pay increase trend data and union contracts are consulted when negotiating annual wage increases throughout the term of the contract. As with any labor negotiations, trade-offs are negotiated for other terms and conditions in the contract.

Q. Does NW Natural use median base pay competitive compensation data when setting base pay compensation for Company officers?

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. Yes, however, in the case of officers, the Company hires an independent compensation consultant, who is responsible for performing analysis for officers using peer company and survey data. The results of the competitive analysis completed by the firm, Pay Governance, which demonstrate that the Company's compensation for officers is at the market median are at *NW Natural/702, Doolittle/1.*

Q. What is the cost of utility employees' base pay projected for the Test Year?

A. Table 1 below provides the cost of base pay for the Test Year. This number includes only the cost for utility employees of NW Natural, and represents the base pay for 1,117 full-time equivalents ("FTEs").

Table 1
Utility Employee Total Base Pay (Wages & Salaries) ($000)

Type of Utility Employee	Cost of Base Pay
Bargaining Unit (BU) Employees	$44,143
NBU Hourly Employees	$1,272
NBU Salaried Employees	$49,657
Officers	$3,515
Total	$98,587

Q. How did NW Natural determine the cost of base pay shown above for the Test Year?

A. For NBU employees, the amounts shown were determined by taking base pay costs for the Base Year (calendar year 2017) and escalating them by 4.00 percent in 2018 and 4.25 percent in 2019. This reflects a 3.25 percent and 3.50 percent merit increase, respectively, and an additional 0.75 percent each year to

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

reflect promotions and equity adjustments. This additional amount for promotions and equity adjustments was determined based upon past experience. The merit percentages were derived using the anticipated pay movement of competitor companies as provided in compensation trend surveys.

For BU employees, the costs were escalated according to the agreement negotiated with those employees. The current contract uses a wage increase formula that provides an increase of 3 percent for each remaining year of the current agreement. (There is also a CPI adjuster which only applies if CPI exceeds 4 percent. The 3 percent was applied to the test year calculations given the low level of growth in the CPI). In addition, an additional 0.5 percent was added each year to account for movement through training steps, from the entry rate to the experienced rate and for promotions. This additional amount was determined based upon past experience.

For officers, the amounts shown were determined by taking base pay costs for the Base Year (calendar year 2017) and escalating them by the same percentage increases as used for the NBU employees as described above. These percentages were derived by using the anticipated pay movement of competitor companies as provided in compensation trend surveys.

IV. <u>PAY-AT-RISK</u>

Q. In describing competitive total compensation, you stated that "pay-at-risk" is an important component. Please define what you mean by this term.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. Pay-at-risk is compensation made to employees only if certain performance goals are met within a defined timeframe. Pay-at-risk is not guaranteed for employees, and is intended to foster high performance. It represents an essential part of competitive total compensation,[1] as it is necessary in order for NW Natural to compete in the job market to attract and retain the employees that it requires to run its utility business. NW Natural's total compensation is targeted to align with market median compensation.

Q. Please describe the pay-at-risk that NW Natural provides.

A. NW Natural provides pay-at-risk at a proportion of competitive total compensation that is in line with industry practice, and offers it through a few different programs depending on job classification. The Company offers a "Goals Incentive Program" to NBU non-officer employees. This program recognizes and rewards employees who have demonstrated strong individual performance, and rewards the very highest of performers for the plan year who achieve or exceed their annual performance objectives.

The Company also offers a "Key Goals Program" to Bargaining Unit (BU) employees. This program links employee total compensation to the achievement of company overall goals and clarifies for employees how their job and work group contributes to the company's success. The program has two components:

[1] More information on this topic is presented in response to Standard Data Request 98.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

one related to operating goals, and one related to company financial performance goals. The operating goals component of the Key Goals generally focuses on goals which are within the collective control of employees. Goals such as new meter sets, customer service measures, and Utility O&M per customer are examples of operating goals which benefit customers through improved reliability, improvements in operations and quality customer service. The company financial performance component of Key Goals is a financial goal determined solely by the Company and will pay out only if net income of the business meets or exceeds an established hurdle that is based on exceptional achievement. For the Test Year, there is no cost included for the financial performance component of Key Goals because the Company does not forecast exceeding the hurdle rate built into the program during the Test Year.

In addition to these programs, the Company provides its officers with pay-at-risk. This includes short- and long-term incentive programs. These programs are designed to attract and retain individuals with the experience necessary to manage NW Natural's business, and navigate the challenges facing the utility and its customers. The short-term portion of the Company's executive compensation program consists of an annual incentive cash award contingent upon meeting predetermined individual and Company performance goals. The Company performance goals account for 70 percent of the opportunity while individual goals account for the remaining 30 percent. The long-term portion of

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

the Company's executive compensation program consists of two components: restricted stock units (RSUs) and performance shares.

Q. Can you again summarize why NW Natural provides pay-at-risk?

A. We provide pay-at-risk as a component of total competitive compensation for three reasons. First, pay-at-risk provides a direct way to encourage behaviors that benefit the utility's operations. Second, pay-at-risk is widely employed by our competitors for labor, and is expected by the workforce. Therefore, we believe we need to provide pay-at-risk in order to compete and meet pay expectations of the workforce. Third, pay-at-risk is part of the total cash compensation required to deliver market median competitive pay to employees. Pay-at-risk is preferred by the industry, rather than adding this pay directly to base pay. For the gas industry on average, 81.5 percent of companies have at least one pay-at-risk or incentive plan. See *NW Natural/703, Doolittle/1.*

Q. Does the pay-at-risk portion of competitive total compensation result in total compensation that is above a competitive level?

A. No. When added to base pay, our total cash compensation is at the market median. In other words, if NW Natural did not provide pay-at-risk, its total cash compensation would be below the market median. Without the opportunity to receive this pay, total cash compensation would be below the comparative market.

Q. Is pay-at-risk provided at the same level for all employees?

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. No. To be consistent with competitive market pay practices, targets are differentiated by employee level. Generally, the market practice is to provide higher levels of at-risk compensation to officers, directors, and managers who may have a broader influence on company activities. Table 2 represents the pay-at-risk for our Key Goals and Short-Term Incentive program by employee groups.

Table 2

Incentive Program Type	Participants	Target percent of Pay	Maximum percent of Pay	Amount Requested in Test Year as percent of Pay
Key Goals	All BU employees (excluding NBU and officers)	1.5 percent	7 percent	1.5 percent
NBU Short-Term Incentive	All NBU employees (excluding officers)	7.5 percent- 20 percent Depending on level	15 percent- 40 percent	7.5 percent- 20.0 percent
Officer Short-Term Incentive	Officers	35 percent- 75 percent depending on level	52.5 percent- 112.5 percent	Amounts shown as target.

Q. Given that pay-at-risk is a component of overall competitive compensation, has the Commission generally allowed utility companies to include the costs of pay-at-risk to be recoverable as part of a utility's revenue requirement of providing utility service?

A. No. The Commission has generally adhered to a practice of requiring companies' shareholders to bear the costs of a portion of pay-at-risk, or incentive compensation.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Q. What is your understanding of the reasons why the Commission has had this practice?

A. I believe it is possible that the Commission has historically viewed pay-at-risk as potentially going above and beyond market median pay. Also, I understand that historically the Commission felt that because pay-at-risk is in some instances provided to employees only when certain financial metrics are met, shareholders also benefit from pay-at-risk. Thus, they have required shareholders to bear some of the costs or in the case of officers, the full cost.

Q. Do you believe the Commission's practice regarding pay-at-risk is appropriate? And, if not, why?

A. No. First, I believe that compensation practices within the industry have changed since the time the Commission first instituted its practice. My experience is that the utility industry used to provide "bonuses" and incentives that perhaps were designed to offer certain employees above-market-median pay. However, that has certainly changed in NW Natural's case. Thus, if the Commission's practice is founded on a belief that pay-at-risk provides pay at above market median levels, then I think it should be reconsidered in light of current compensation practices.

Second, I do not believe that the Commission's historical approach is warranted based on the fact that shareholders may benefit from the achievement of certain goals that enable an employee to receive her or his pay-at-risk. This is

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Portland, Oregon 97209-3991
1-503-226-4211

especially true when a utility's pay-at-risk is designed to incent efficiencies that benefit the utility's provision of safe and reliable service at reasonable costs. And, even in cases where pay-at-risk is tied to companies' financial goals, it is important to recognize that customers benefit from, and the Commission should encourage, utilities to maintain good financial metrics. Good financial metrics enable the utility to efficiently raise the capital necessary to operate its business, at rates that are favorable to utility customers, who ultimately pay the utility's cost of capital as part of the utility's revenue requirement.

As described above, pay-at-risk is an important part of competitive total compensation, and a cost that is necessary for a utility to prudently operate its business. Thus, I believe it should be a recoverable component of a utility's revenue requirement to the same extent as other prudent utility expenditures.

Q. For NW Natural, has the Commission's practice actually had a significant effect on the Company?

A. Yes. For NW Natural, about two-thirds of our operation and maintenance costs are actually associated with labor, so the Commission's disallowance of a portion of these is significant for our company. The Commission's policy of disallowing 100 percent of officers' at-risk pay, and requiring companies to bear at least 50 percent of non-officer employees' at-risk pay means that NW Natural would be prevented from recovering around $7 million of costs that are prudently incurred, and relate directly to operating the natural gas distribution company.[2] Thus, it has been substantial enough that the Company has raised its disagreement with the Commission's practice in the past, and has spent considerable time determining if it should modify its behavior in light of the practice.

Q. In what ways has NW Natural considered modifying its behavior in light of the Commission's approach to pay-at-risk?

A. About a year and a half ago, NW Natural undertook an effort to determine if the Company should decrease or eliminate its pay-at-risk for non-officer employees. In other words, we considered whether we should provide competitive total compensation through a greater share of base pay. After several months of looking at this issue and considering the change, we determined that we should not undertake this change because we did not feel that it was a good compensation practice. I raise this point, however, to emphasize that the policy considerations are important enough that they warrant reconsideration by the Commission of whether the historical practice promotes good compensation practice.

Q. Are there other reasons why you believe that the Commission should reconsider its approach to pay-at-risk?

[2] Over $3.5 million of this relates to non-officers' at-risk pay.

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1-503-226-4211

A. Yes. First, NW Natural points out that the Oregon Commission's practice is not shared by all other regulatory jurisdictions. Instead, many other jurisdictions treat the question on a case-by-case basis, with an evaluation to ensure that utilities are paying at market and that the at-risk pay programs are reasonable. It would therefore be appropriate for the Commission to determine if it should modify its view to be more in line with the general regulatory construct in Oregon that allows utilities to recover prudently incurred costs necessary to the provision of utility service.

Second, NW Natural is concerned that Staff and other parties may be seeking to actually *expand* the effects of the Commission's practice in ways that the Commission may never have intended.

Q. In what way does NW Natural believe that Staff or other parties may be seeking to *expand* the negative effects of the Commission's past practice with respect to pay-at-risk?

A. NW Natural has observed that Staff has sought to apply a disallowance to Oregon utilities based on the fact that these utilities, pursuant to established appropriate accounting practices, capitalize labor costs associated with the building of utility infrastructure and plant necessary to provide service. In other words, utilities always capitalize some labor costs associated with the capital projects that they construct. This is in accordance with generally accepted accounting practices. Staff has recently, in two utility cases at least, sought to now disallow or remove

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Portland, Oregon 97209-3991
1-503-226-4211

capital plant amounts from rate base with an argument that this is an appropriate extension of the Commission's practice regarding the expense side of pay-at-risk. NW Natural believes this practice is not justified, and that it would be important for the Commission to review whether it is appropriate. Staff has also asked several questions of NW Natural in recent audits that indicate it is likely seeking to expand the application of the Commission's approach to capital investments.

Q. What is the total cost of at-risk pay that NW Natural has projected for the Test Year in this rate case?

A. That amount, by employee type, is shown in the table below[3]:

Table 3

Utility Employee Target Pay-At-Risk ($000)

Type of Utility Employee	Test Year
Bargaining Unit (BU) Employees	$731
NBU Hourly Employees	$143
NBU Salaried Employees	$6,642
Officers	$3,815
Total	$11,331

Q. Please explain the amount of pay-at-risk included in the table above.

A. The amounts shown above include the target proportion of pay-at-risk for those employees. These target amounts may be delivered through short- and long-term incentive programs.

[3] These amounts are prior to state allocation.

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Q. Is NW Natural asking the Commission to depart from its historical practice regarding pay-at-risk?

A. Yes, for the reasons above, NW Natural believes that the Commission should modify its practice regarding pay-at-risk, and allow its inclusion in revenue requirement in the amounts requested by NW Natural.

Q. Does NW Natural propose any alternatives to its request on this topic?

A. Yes. NW Natural anticipates that the Commission could feel hesitant to depart from its historical practice in this proceeding, because of the fact its approach has generally been enforced on other utilities as well, and because it may desire a different forum for reviewing the policy. If that is the case, NW Natural would request that the Commission create a separate appropriate forum, or investigation, to review the policy to consider whether it should be modified prospectively.

V. LONG-TERM INCENTIVE PLANS

Q. Does NW Natural offer any long-term incentive plans to its employees?

A. Yes, the Company provides RSUs as a long-term incentive for select high-performing managers, officers, and key employees. RSUs involve a grant of stock units that vest over time if certain retention and individual performance threshold conditions are satisfied. When conditions are satisfied, the units are converted to shares of NW Natural stock and delivered to the employee. This approach aligns with standard industry practice.

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Portland, Oregon 97209-3991
1-503-226-4211

The Company believes that all long-term incentive compensation, similar to short-term incentive cost should be allowed for cost recovery.

Q. What other long-term incentives are provided to officers?

A. NW Natural, like other utilities around the country, believes that pay-at-risk is even more critical for the officers of the company. This pay-at-risk opportunity is earned if the executive can deliver results that benefit all stakeholders in the company. The officers of the company receive a portion of their long term incentive opportunity in the form of RSUs (35 percent), as noted above, and another portion in the form of Performance Shares (65 percent).

The Performance Shares are earned over three years if the officers can meet certain financial targets over the three-year period. The Performance Shares benefit both shareholders and the customers by ensuring our investor base stays strong and we have good access to shareholder equity.

Q. How much pay-at-risk is in effect for an officer?

A. The amount of total pay-at-risk varies by officer position and competitive market practice. The CEO typically has about 70 percent of pay-at-risk whereas other officers have about 50 percent of pay-at-risk. In all cases, the total pay-at-risk is comprised of short- and long-term opportunities.

Q. What level of recovery is NW Natural including in the Test Year for performance shares and RSUs?

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Portland, Oregon 97209-3991
1-503-226-4211

A. NW Natural is seeking recovery of the Test Year expenses associated with the executive performance shares ($1.286 million), executive RSUs ($771 thousand), and non-executive RSUs ($942 thousand). NW Natural believes pay-at-risk recovery is appropriate because this represents a reasonable cost for the ability to attract and retain key individuals, including officers, and it is based upon standard industry practice.

VI. MEDICAL BENEFITS

Q. Please describe the medical benefits NW Natural provides to its utility employees?

A. NW Natural needs to provide competitive medical benefits to its employees in order to attract and retain a skilled, reliable workforce and because medical benefits are part of the package required to get to median total compensation levels. Quality medical benefits are also necessary to ensure employees are receiving good care in a timely fashion. Good and timely care prevents the development of more serious health problems that would lead to more costly claims and higher employee absentee rates. Customers depend on receiving the safe, efficient, and reliable service that can only be delivered through a healthy and present workforce.

Q. What medical costs are included in the Test Year?

A. The Company has included $19.61 million of medical benefit costs in the Test Year.

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Q. Have costs increased for medical coverage in the last few years?

A. NW Natural compares renewal rate increases to both national and local trend factors. Based on periodic survey data provided by Willis Towers Watson, the national trend was 5 percent for 2017 and expected to be 6 percent for 2018. See *NW Natural/704, Doolittle/1*. At the local level, the trend was reported at 8.4 percent for Medical PPO plans, (which is the type of plan the majority of NW Natural's employees enroll in) and 6.9 percent for Medical HMO plans[4].

During the last few years, NW Natural's active non-bargaining employees' medical expenses have been increasing at a rate that has overall been in line with trend factors. In 2015 the renewal of 12.2 percent was higher than the trend due to high claims experienced on the PPO Plan, but other years stayed close to trend or came in below trend. See *NW Natural/704, Doolittle/1*. This exhibit also demonstrates that the Company's medical increases for NBU retirees have been below national trends for the last four out of five years. In the case of bargaining unit employees, medical increases have been below the trends for the last three out of four years. Another factor that has impacted renewals is the 1.5 percent State tax to shore up Medicaid and the re-imposition of the Affordable Care Act (ACA) Provider tax, which was added to 2018. These increases represent about

[4] *Willis Towers Watson Periodic Trend Survey of Oregon Fully Insured Plans.*

2 percent of total premium for the non-bargaining plans and almost 5 percent of the BU renewal increase for 2018.

Q. What are the key factors that influence increases in medical costs?

A. The Company's medical rates are greatly influenced by the medical experience of the population being insured. Cigna and Regence increase rates based entirely (100 percent) on the experience for our actual insured population. On the other hand, Kaiser utilizes a combination of both community rating and actual NW Natural experience. They place 80 percent of the formula on their total book of business (community rating) and 20 percent on the actual claims of the plan participants.

In addition to claims experience, we also know that other factors impact medical costs including age, gender, family size, and geography. Based on the 2017 "Willis Towers Watson High Performance Insights in Health Care" report (*NW Natural/705, Doolittle/1-6*), which includes 1,978 companies in 18 industry groups, we know that NW Natural's average age for the pre-65 covered NBU participants in 2017 was 51.8 years old, compared to the database which indicated an average age of 44.8 for the same time period. Having a higher average age means our population is more expensive to insure than a younger workforce and is more likely to have more serious medical issues than would be seen on average with a younger workforce. In addition, the report showed NW Natural has 38 percent female enrollment, versus 41 percent for the database.

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1-503-226-4211

Based on these two factors, the report notes "[t]he custom benchmark will be increased by 13 percent due to age and gender demographics." In addition, we also learn from this report that NW Natural's plan has dependent enrollment of 71 percent compared to the database which has 52 percent. This difference increases the benchmark by 16 percent due to family size of our population.

The final area in which there is a slight variance is the geographic location of the medical providers. NW Natural has a favorable outcome on this comparison with a slightly lower cost than the database, (0.96 versus 1.0). The report notes that the benchmark would be decreased by four percent due to where the NW Natural population lives. The overall results of all of these factors showed that NW Natural's medical premiums are expected to be five to 10 percent higher when compared to the database, depending on the medical plan selected.

Q. Has NW Natural taken any actions to manage medical costs?

A. Yes. The Company has done a number of things to control its health care costs.

First, the Company has a practice of regularly conducting requests for proposals (RFPs) from medical insurance providers to ensure that our providers' prices are competitive. RFPs are generally issued every five years, but will be issued sooner upon notice of a significant increase in premiums from a current medical insurance provider. Both the non-bargaining group and the bargaining group have received fair renewals over the last several years so no RFPs have

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Portland, Oregon 97209-3991
1-503-226-4211

been conducted. Prior to this however, the bargaining group made a carrier change in 2012 from LifeWise to Regence. In addition, they also moved the pharmacy from self-insured to the fully insured medical plan in 2016 to better manage the prescription expenses.

The non-bargaining group moved from LifeWise to Cigna in 2013. At the time the group moved from LifeWise to Cigna, a High Deductible Health Plan (HDHP) with Health Savings Account (HSA) was added as a new option for employees. That change resulted in an overall net decrease to health premiums of 5.2 percent as the HDHP is a lower cost option that promotes more consumer awareness and allows the members to control a portion of their healthcare spending.

In addition to conducting RFPs, the company regularly meets with their benefit broker/consultants, Willis Towers Watson (WTW), to review plan designs offered to ensure they remain market competitive with other utilities and up to date with innovative designs to effectively control rising medical and prescription costs. Based on this review, plan design changes have occurred for non-bargaining plans. See *NW Natural/706, Doolittle/1*. The bargaining unit medical plan has also experienced minor plan design changes over the years in an effort to effectively manage costs, but the most significant change that has occurred relates to premium sharing. Based on the most recent joint accord, effective January 1, 2015, bargaining employees transitioned from contributing a flat dollar

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

amount to paying a percent of the actual premium for medical and dental coverage. Bargaining unit employees pay 20 percent of premiums and the company pays 80 percent. If the employee participates in an annual health screening, the employee only contributes 15 percent of premiums and the company pays 85 percent. Based on this approach, employees experience an increase in cost when their premiums rise, and a decrease in costs when their premiums go down. It provides an incentive to employees to help stay healthy and keep their claims costs down.

Q. What other actions has NW Natural taken to control medical benefit costs?

A. Another key cost management feature put in place was the closure of the retiree medical plans. This plan was closed to new NBU employees hired after December 31, 2006, and to BU employees hired after December 31, 2009. Since that change occurred, only 48 percent of active NBU employees and 54 percent of active BU employees are eligible for retiree medical benefits.

In addition to closing the NBU Retiree Medical Plan to new hires in 2006, the benefits were substantially reduced to align with the competitive market by putting a cap in place to limit spending and control medical costs. The current caps ($2,400 per retiree per calendar year for those over 65 and $4,800 for retirees younger than 65) have not increased since 2006 and, effective April 2016, the post-65 population receives a contribution to their Health Reimbursement Account equal to the cap amount. These cost control measures

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220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

alone have resulted in a reduction in our projected benefit obligation for retirees of approximately $8.5 million.

Incremental increases in medical costs are being covered by increased cost sharing allocations paid by retirees. The Company's cost sharing formula for NBU retirees has NW Natural covering 80 percent of premiums up to the cap and retirees covering the remaining portion. Because 80 percent of the premium is currently above the cap, retirees are picking up well more than 20 percent of the premiums; in some cases the retirees are paying 53 percent of the premium due to the monthly cap. In addition, starting at the beginning of 2015, BU retirees now pay 25 percent of the premium costs versus 20 percent.

In April of 2016, post-65 retiree medical benefits were transitioned to a private exchange. While this was a cost neutral change, this provided the retirees with many more plan options to better meet their individual needs. Instead of contributing towards the cost of the retiree's premiums, the same dollar amount was allocated to a Health Reimbursement Account (HRA) so the retirees could use those funds to purchase the Medicare Supplement that best meet their needs. While this is not a cost savings change, it is an example of the company managing their plans to provide the highest value at the lowest cost.

Finally, the Company is actively promoting preventative care and responsible health management. Most NW Natural employees participate in the Company's annually sponsored health screen, and approximately 76 percent

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NW NATURAL
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Portland, Oregon 97209-3991
1-503-226-4211

participate in a voluntary wellness program offered to encourage employees to adopt a more physically active lifestyle. Many employees using these programs are experiencing improved heath. Based on 2017 data provided by Virgin Pulse that looked at systolic blood pressure, 74.9 percent of members either became healthier or maintained a previously healthy state, showing their blood pressure was moving in the right direction. When analyzing BMI information, there was a shift where 57.9 percent of members either became healthier or maintained previously healthy state. The most significant shift came when tracking increased activity levels. The data showed that 87.7 percent of members either became healthier (more active) or maintained previously health state. See *NW Natural/707, Doolittle/1-4*.

These combined efforts are controlling medical cost increases and demonstrating our prudent management of these expenses. (See *NW Natural/708, Doolittle/1* for an overview of renewal numbers and historical trend data).

Q. How does the design of NW Natural's medical plans compare with that of other companies?

A. WTW completed an analysis of the Company's medical benefits relative to 13 peer utilities and 96 other utility/energy companies in their Energy data base for the non-bargaining group. For the bargaining group, the analysis included 42 energy companies for comparison purposes. In this comparison, WTW utilized

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

the following rating categories: Equal, Worse or Better. NW Natural's medical benefits were rated by WTW on an overall basis to be Equal to both the 13 peer companies and the overall Energy data base. See *NW Natural/709, Doolittle/1-16.* This analysis compared everything from deductibles, to coinsurance (premium sharing) to co-pays for office visits and prescriptions. There was a range of ratings depending upon the specific item being rated, although the overall rating was Equal.

Q. Why does this testimony address only medical benefits and not all components of health benefits?

A. The Company focused on medical benefits (medical and pharmacy) because they make up 95.5 percent of the total health care (medical, pharmacy, dental, vision, life, and disability) costs and have been the area in which significant increases have been experienced in the past 10-plus years.

Q. Are the other health benefits being offered also market competitive?

A. Yes. The same survey source noted above for medical benefits also evaluated the competitiveness of other health care benefits including dental, vision, life, and disability. The majority of benefit plans were rated Equal to both the 13 peer utility companies as well as the overall Energy database provided in the WTW survey. While there were some variations in certain categories, overall the WTW survey indicated the NW Natural's benefit plans were substantially at market when compared to other utilities.

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

VII. RETIREMENT BENEFITS

Q. Please provide an overview of your retirement benefits.

A. Table 4 shows the retirement income benefit programs, which provide market median retirement offerings to employees:

Table 4

Retirement Program	Eligible Employees	Summary Description of Benefit
Retirement K Savings Plan (401k)-Employee Savings	All employees	Defined Contribution Savings plan with match: Match is 50 percent of first 6 percent saved by BU employee and 60 percent of first 8 percent saved by NBU employee
Retirement K Savings Plan (401k)-Enhanced	NBU employees hired after December 31, 2006 and BU employees hired after December 31, 2009 (covers employees not eligible for pension benefits)	Contribution made by company into "Enhanced" account-no employee contribution required Contribution is 5 percent for NBU; 4 percent for BU
NW Natural Retirement Plan for BU and NBU Employees (closed)	Non-bargaining (NBU) and Bargaining (BU) employees	Defined benefit plan that was closed to new NBU employees hired after 12/31/06 and BU hired after 12/31/09.

Q. Has NW Natural made any changes to its retirement income benefits since the Company's last rate case?

A. Yes. The Company withdrew its participation in the Western States Pension Plan for bargaining unit employees since its last case. The Company took this action because this multi-employer pension plan had been moved into critical status. Critical status is when a multi-employer pension plan's unfunded liability is so extreme that it is not expected to recover in the life of the plan without assessing additional surcharges on participating employers. This move to critical

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

status was a result of financial losses in 2007 combined with no new employers joining the Plan, existing participants retiring, and changes to the Pension Protection Act. Given this situation, NW Natural negotiated with the union the ability to withdraw from the plan in a timely manner such that the Company hoped to avoid the plan moving into a mass withdrawal status where further penalties could be imposed.

Q. Why was a withdrawal liability imposed on NW Natural when it withdrew from the Western States Pension Plan?

A. Given that the plan was significantly underfunded (*e.g.*, the actuarial value of the vested benefits exceeded the value of the plan's assets) the law requires that withdrawing employers pay a withdrawal liability. The withdrawal liability imposed upon NW Natural was determined by the plan actuary to represent the Company's portion of the plan's costs that were not funded either through prior contributions or investment returns on those contributions. The withdrawal liability imposed upon the Company is $582,500 per year.

Q. Has the Company made any filings with the Commission with respect to the Western States Pension Plan?

A. Yes. In docket UM 1680, NW Natural requested an accounting order regarding the termination of participation in the plan, confirming that it could seek to recover through revenue requirement an annualized cost related to its expense in

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

terminating participation in the plan. The Commission approved the request for accounting order in Order No. 14-041.

Q. How do NW Natural's retirement benefits compare to the benefits provided by other companies?

A. In 2017, the Company asked WTW to analyze the Company's 401(k) defined contribution retirement benefits relative to other utilities. WTW concluded that NW Natural's 401(k) defined contribution match benefits were Worse for bargained employees when compared to the energy database. They also showed that the non-bargained employees were Equal when compared to the energy database, but Worse when compared to the 13 target companies.

The Enhanced 401(k), for those hired after the Retirement Plan was closed, and the Retirement Plan, for those participating, was shown to be Equal for both the bargaining and non-bargaining groups when compared to both the total database and the 13 target companies used for the non-bargaining population. See *NW Natural/709, Doolittle/1-16.*

Q. Please explain the total utility amount for retirement benefits for the Test Year.

A. Table 5 shows the amount requested for recovery in the Test Year revenue requirement.

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220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Table 5
Utility Total Retirement Benefits ($000)

Component	Test Year
RKSP-Matching Contribution	$4,170
RKSP-Enhanced Contribution	$2,514
Western States Pension-withdrawal liability	$572
Total	**$7,256**

VIII. UTILITY COSTS VERSUS COMPANY COSTS

Q. Are you seeking to recover any costs related to employees of NW Natural subsidiaries?

A. No. All amounts described in this testimony reflect utility-only costs, and not the costs of subsidiaries.

Q. Does this conclude your direct testimony?

A. Yes.

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Exhibits of Lea Anne Doolittle

COMPENSATION AND BENEFITS
EXHIBITS 701 - 709

December 2017

EXHIBITS 701 – 709 – COMPENSATION AND BENEFITS

Table of Contents

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

Exhibit 1 Base Pay Analysis

2017 Salary Structure - Base Pay Analysis

2017 Salary Structure		
NWN Grade	**NWN 2017 Midpoint**	**NWN Midpoint vs. Market Median**
14	$51,950	118%
15	$56,600	110%
16	$61,700	104%
17	$67,200	102%
18	$73,250	104%
19	$79,950	99%
20	$87,100	100%
21	$94,900	98%
22	$109,250	101%
23	$120,400	95%
24	$132,750	94%
25	$145,350	92%
26	$160,000	100%
	Overall	**101%**

Data Source: NW Natural Market Review 2017

Exhibit 2

Pay Governance® Advisory Services to Compensation Committees

Executive Summary

- In aggregate, NW Natural's base salary, target total cash, and target total direct compensation (TDC) are within the competitive range around market 50th percentile of the Peer Group, broader energy industry, and general industry
  - However, there is variation in market positioning by executive which should be examined on an individual basis to determine the appropriate course of action for 2017 pay decisions.

- While NW Natural's pay philosophy is to target total compensation at the market 50th percentile, the market is better represented as a range around the 50th percentile. We consider the following guideline:
  - Base salary: ±10% of the market 50th percentile
  - Cash compensation: ±15% of the 50th percentile
  - Total direct compensation: ±20% of the 50th percentile

	NW Natural Variance to Market								
	Peer Group			Energy Industry - Survey			General Industry - Survey		
Pay Component	25th %ile	50th %ile	75th %ile	25th %ile	50th %ile	75th %ile	25th %ile	50th %ile	75th %ile
Base Salary	2%	-8%	-18%	5%	-7%	-18%	12%	-6%	-19%
Target Total Cash	3%	-8%	-24%	15%	-6%	-20%	10%	-12%	-29%
Long-term Incentives	-6%	-22%	-41%	61%	6%	-33%	34%	-20%	-59%
Target Total Direct	0%	-14%	-31%	26%	-3%	-24%	17%	-15%	-42%

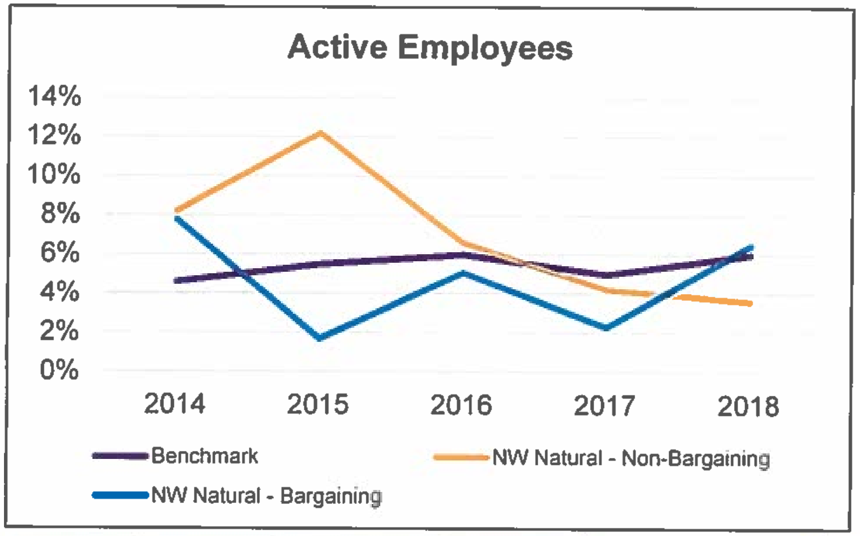
Exhibit 3 Gas Industry Incentive Plans

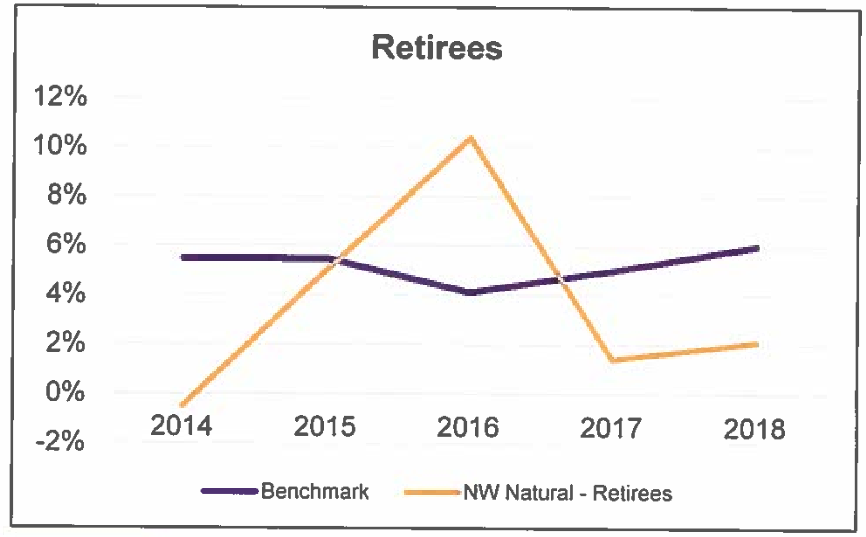
Plan Prevelance - Bonus and Other Variable Pay Programs in which some or all Incumbents are Eligible

	% of Organizations with at Least One Plan	# of Responses
Entire Sample Combined		
Executive	83.0%	53
Management, Excluding Executives	83.0%	53
Exempt, Non-Management	80.8%	52
Nonexempt	79.2%	53

Data Source: 2017 American Gas Association Compensation Survey

Medical Benchmark Trend versus NW Natural Renewals





	2014	2015	2016	2017 (Expected)	2018 (Projected)
Actives					
Benchmark Trends[1]	4.6%	5.5%	6.0%	5.0%	6.0%
NW Natural – Non-Bargaining Employees	8.2%	12.2%	6.6%	4.2%	3.6%
NW Natural – Bargaining Employees	7.8%	1.7%	5.1%	2.3%	6.5%
Retirees					
Benchmark Trends[2]	5.5%	5.5%	4.1%	5.0%	6.0%
NW Natural – Retirees	-0.5%	5.0%	10.4%	1.4%	2.1%

(1)Source: 2017 WTW Best Practices in Health Care Employer Survey. 2016 – 2018 trends specific to companies with 100 to 999 employees.
(2) Source: WTW Emerging Trends in Health Care Survey and WTW Health Care Changes Ahead Survey. Separate retiree trend benchmarks not available for 2017 – 2018.

Willis Towers Watson High Performance Insights in Health Care

2017 Health Care Financial Benchmarks

NW Natural

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Willis Towers Watson

Medical Cost Benchmarks — Developing a Population Adjusted Benchmark

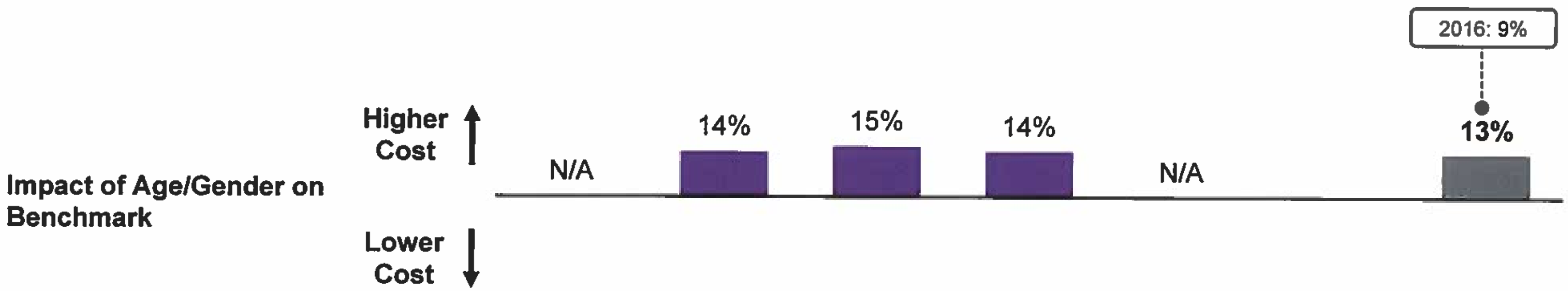
The first step in understanding the cost benchmarks is to understand your population. The average cost for employers in the database is the benchmark.

- The benchmark is adjusted to reflect differences between your organization and the database for each of four key criteria, noted below
- The result of these adjustments is a benchmark that is customized to your population (custom benchmark)
- The custom benchmark is the database cost if the database looked like your population with your plan designs

Age/Gender	The age/gender profile of the population — cost is directly correlated with age. The impact of gender on expected cost varies with age.
Family Size	The estimated number of members covered per employee, expressed in terms of adult cost equivalents — larger-than-average family size is expected to increase costs per employee.
Geography	The underlying cost for basic health care services in an area — provider competition and more prevalent managed care plans may reduce costs in some areas. More enrollment in higher-cost areas is expected to increase costs.
Plan Value	The level of benefits covered under NW Natural's medical plan — plans reimbursing a higher percentage of medical expenses than the database average are expected to increase costs.

Medical Cost Benchmarks — Adjusting for Age/Gender

- What is the cost impact of age/gender in NW Natural's population?
- How different is the impact of demographics by plan?
- If it is significant, why do company averages have a different pattern across plans than the database?

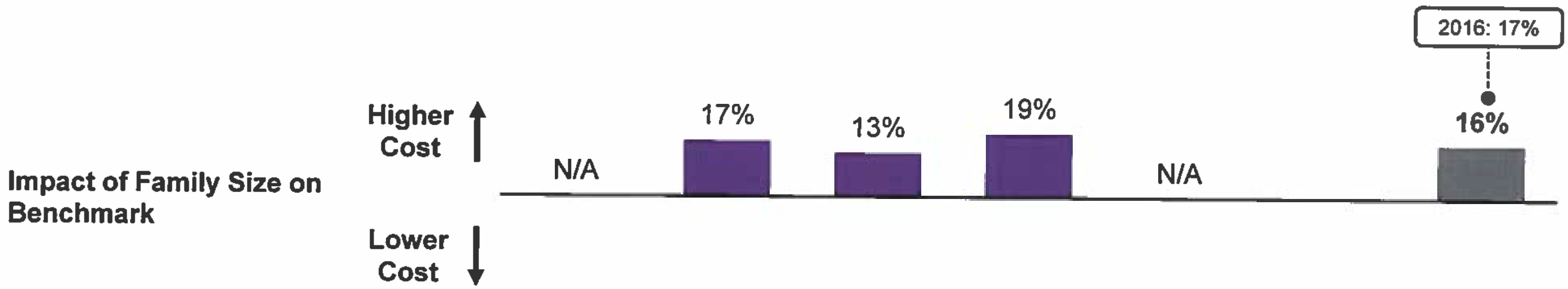


	ABHP w/ HRA	ABHP w/ HSA	PPO/POS	Insured HMO	Self-Ins. HMO/ EPO	Total
Average Age — Database	44.8	43.0	45.9	44.1	45.2	44.8
Average Age — NW Natural's Company	N/A	50.3	53.1	51.7	N/A	51.8 (2016: 49.9)
% Female — Database	44%	38%	42%	41%	46%	41%
% Female — NW Natural's Company	N/A	39%	38%	36%	N/A	38% (2016: 37%)

The custom benchmark will be increased by 13% due to age and gender demographics.

Medical Cost Benchmarks — Adjusting for Family Size

- How different is the impact of family size by plan?
- If it is significant, why do company averages have a different pattern across plans than the database?
- How has this been impacted by contribution strategies of the company?

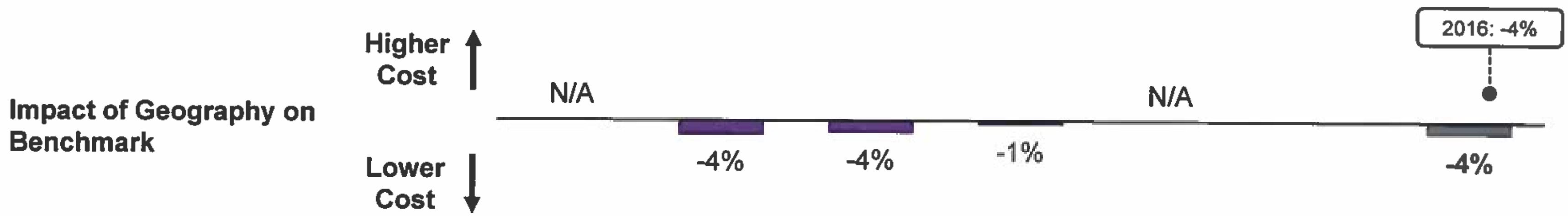


	ABHP w/ HRA	ABHP w/ HSA	PPO/POS	Insured HMO	Self-Ins. HMO/ EPO	Total
Dependents (%) — Database	51%	51%	53%	52%	55%	52%
Dependents (%) — NW Natural's Company	N/A	69%	70%	72%	N/A	71%

The custom benchmark will be increased by 16% due to family size.

Medical Cost Benchmarks — Adjusting for Geography

- How does the geographic footprint of NW Natural's covered population impact NW Natural's costs?
- Does the geographic impact vary by plan?



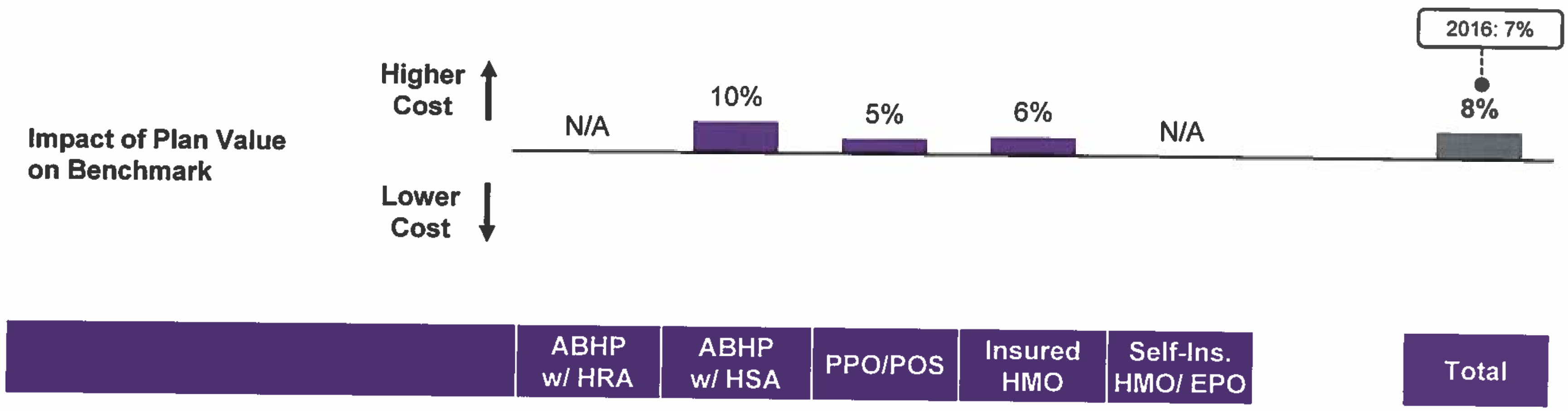
	ABHP w/ HRA	ABHP w/ HSA	PPO/POS	Insured HMO	Self-Ins. HMO/ EPO	Total
Geographic Factors — Database	1.00	1.00	1.00	0.99	1.00	1.00
Geographic Factors — NW Natural's Company	N/A	0.96	0.96	0.98	N/A	0.96

✓ The custom benchmark will be decreased by 4% due to NW Natural's population's geography.

http://natcl.internal.towerswatson.com/clients/604927/NWNatural2017HB/Documents/2017%20Health%20Care%20Financial%20Benchmarks%20-%20NW%20Natural.pptx

Medical Cost Benchmarks Adjusting for Plan Value

How do NW Natural's plan values compare to benchmark?



The custom benchmark will be increased by 8% due to plan value.

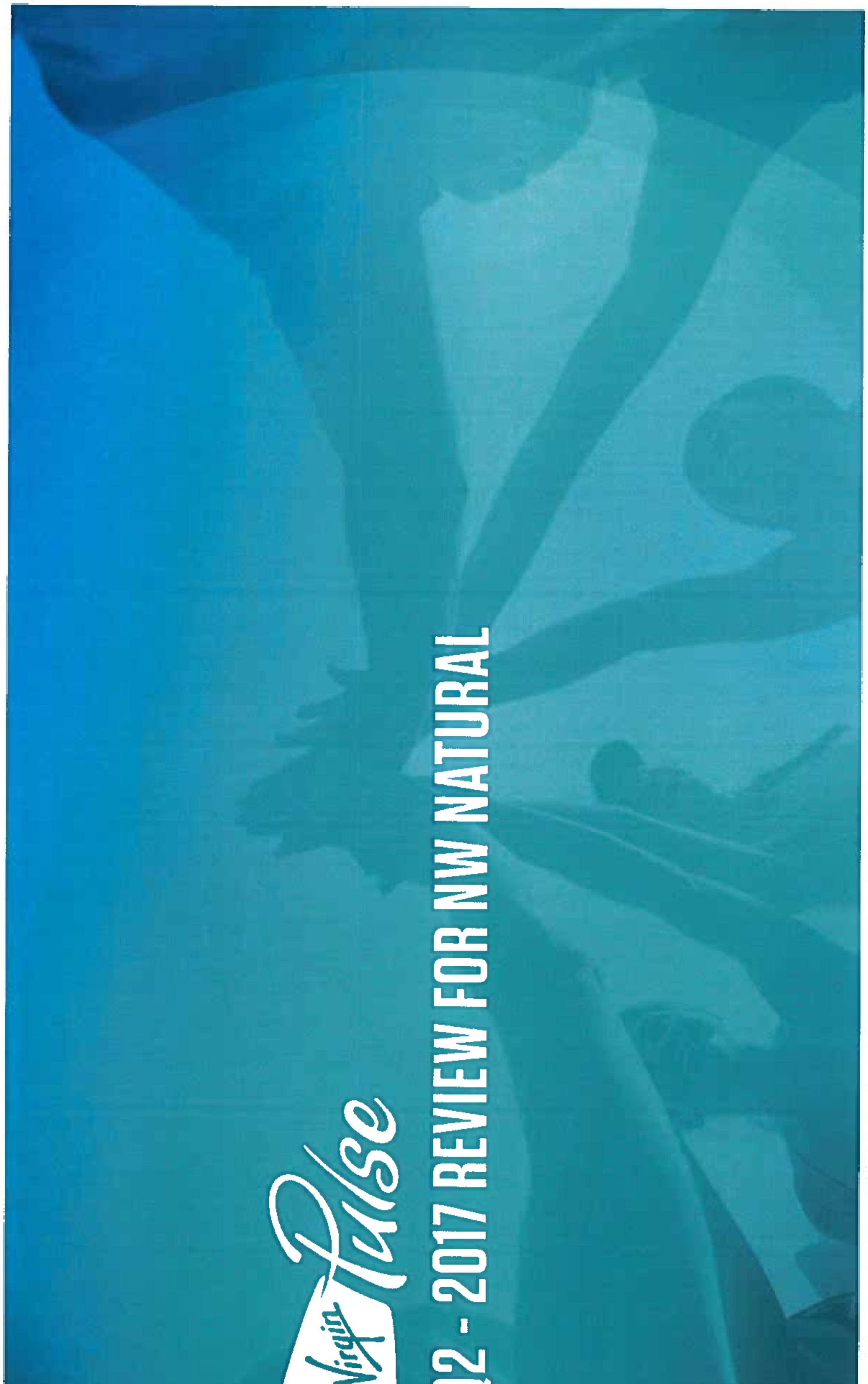
Historical Medical Plan Changes

Non-bargaining plans

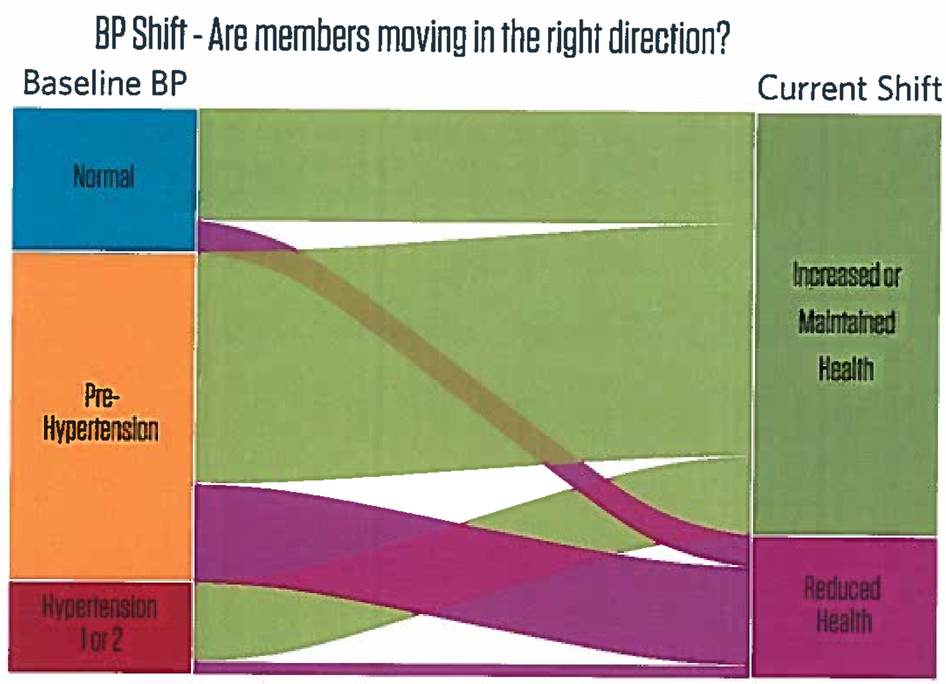
Plan Year	Changes
2015	▪ Increased out-of-pocket maximum on the Cigna PPO ▪ Reduced HSA seed from $1,500/$3,000 to $750/$1,500 (single/family) ▪ Reduced payroll contribution on the HSA plans to encourage enrollment
2016	▪ No benefit plan changes

2017	▪ Added telemedicine services
	▪ Implemented pharmacy provisions to better manage drug spend:
	  ▪ "Member pay difference" logic on brand drugs
	  ▪ Exclusive mail order for specialty pharmacy

2018	▪ Converted the pharmacy design on the Kaiser plans to a copay structure that differentiates between generics, formulary and non-formulary ▪ Aligns to the Cigna plans


Virgin Pulse
Q2 - 2017 REVIEW FOR NW NATURAL

DECREASING SYSTOLIC BLOOD PRESSURE



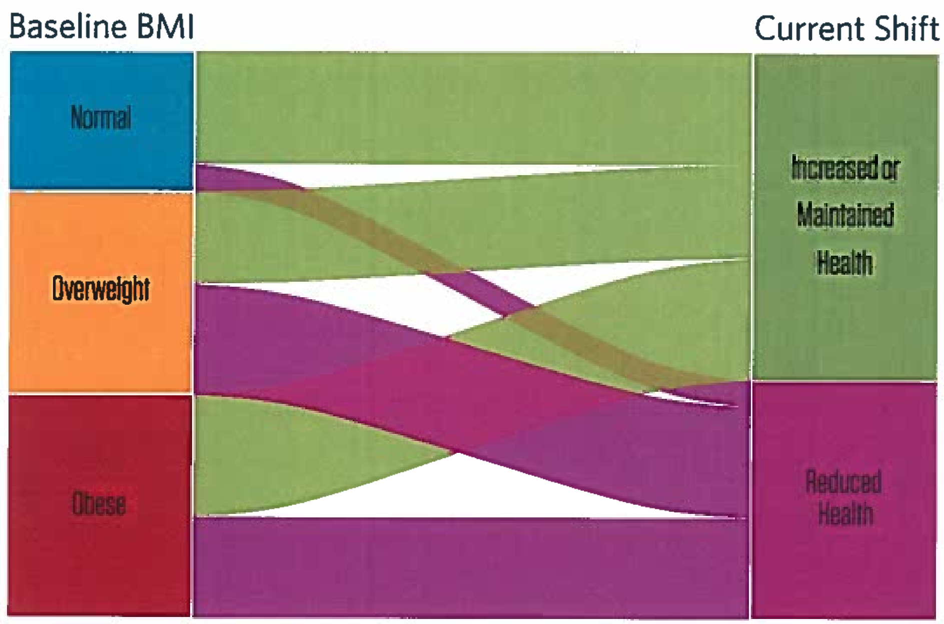
Validated data only. 283 members included in the analysis.
567 members excluded due to lack of data.
Baseline category is calculated from members' first 2 weeks of data. Current shift is as of end of Q2.

- 74.9% of members either became healthier or maintained previously healthy state.

Virgin Pulse

DECREASING BODY MASS

BMI Shift - Are members moving in the right direction?

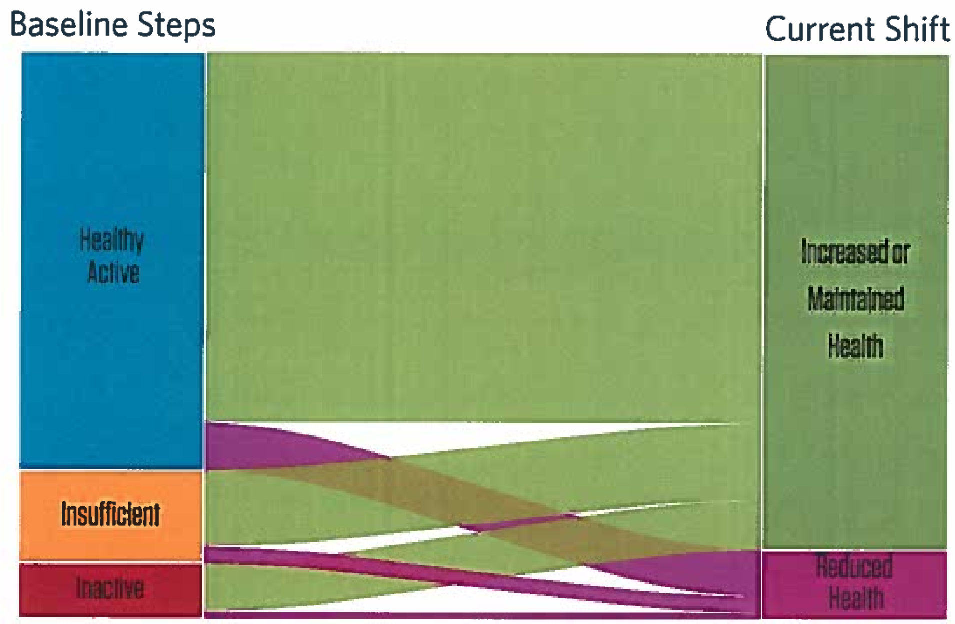


- 57.9% of members either became healthier or maintained previously healthy state.

Validated data only. 292 members included in the analysis.
558 members excluded due to lack of data.
Baseline category is calculated from members' first 2 weeks of data. Current shift is as of end of Q2.

INCREASING ACTIVITY

Step Shift - Are members moving in the right direction?

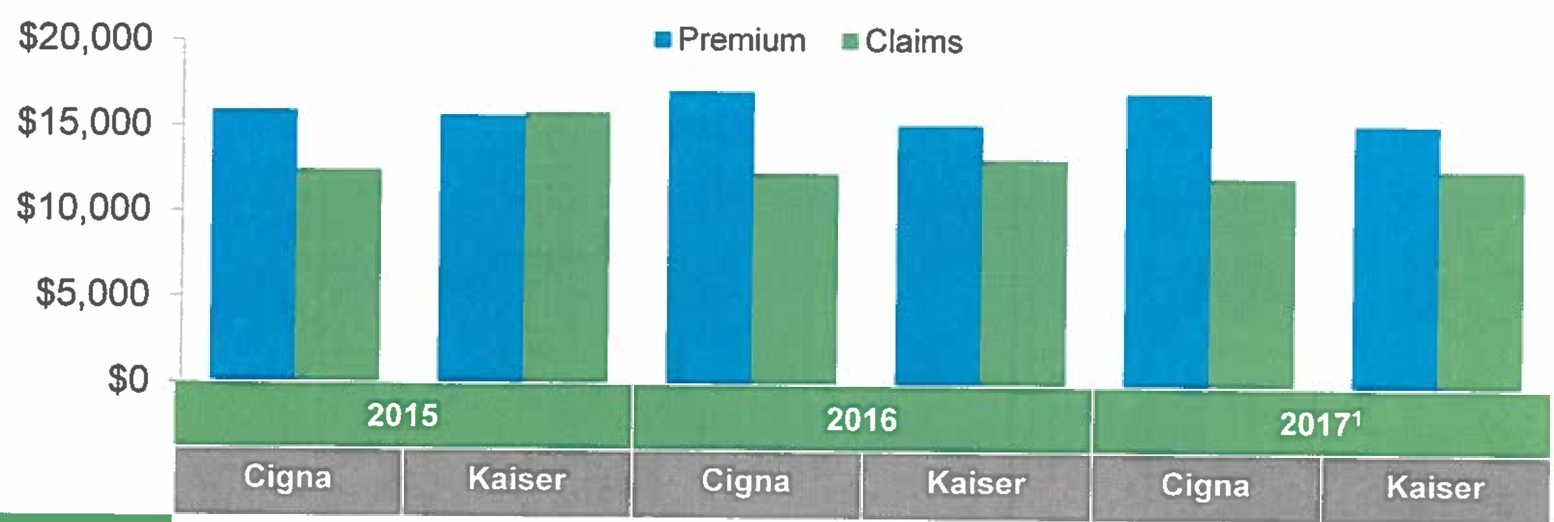


Validated data only. 642 members included in the analysis.
208 members excluded due to lack of data.
Baseline category is calculated from members' first 2 weeks of data. Current shift is as of end of Q2.

- 87.7% of members either became healthier or maintained previously healthy state.

Plan Experience — Actives Plus Pre-65 Retirees

Per Employee Per Year Costs



	2015 Cigna	2015 Kaiser	2016 Cigna	2016 Kaiser	2017[1] Cigna	2017[1] Kaiser
Loss Ratio	78%	101%	72%	87%	72%	83%

- Claims experience has improved over the past three years
  - Cigna 2018 renewal: 0% (renewal based on own experience and book-of-business)
  - Kaiser 2018 renewal: 13.5% (renewal based mostly on Kaiser book-of-business)
- Prior to making any plan design changes, national cost trends are currently 6% – 8%
  - NW Natural's overall 2018 medical cost increase is 3.6%

[1]Cigna based on data through June and annualized. Kaiser based on data through March and annualized.

NW Natural

Non-Bargained and Bargained Benefits Benchmarking Summary

October 25, 2017

Willis Towers Watson

Table of Contents

Methodology and Assumptions

- We compared the 2017 NW Natural new hire benefits for both non-bargained and bargained employees to the following in the Willis Towers Watson database:
  - NW Natural non-bargained:
    - All 96 energy companies in the non-bargained database
    - 13 targeted energy companies in the non-bargained database
      - Includes: ALLETE, Avista, Idaho Power Company, Madison Gas and Electric Company, NorthWestern Energy, ONE Gas, Inc., Otter Tail Power Company, Peoples Natural Gas Company, PNM Resources, Portland General Electric, South Jersey Industries, Inc., Spire Inc., Unitil Corporation
      - 14 companies were added to the targeted company subgroup for the medical benchmarking, due to the number of organizations with PPO benchmarking data available. Includes: CenterPoint Energy, Inc., Consumers Energy Company, Exelon Corporation, LG&E and KU Energy, National Grid, Pacific Gas and Electric Company, PacifiCorp, PPL, Puget Sound Energy, Inc., San Diego Gas & Electric Company, Sempra Energy, Southern California Gas Company, UGI Utilities, Inc., Xcel Energy Inc.
  - NW Natural bargained:
    - All 52 energy companies in the bargained database
    - We were not able to provide a comparison to the 13 targeted energy companies for bargained benefits because there were too few of these companies that either submitted or have separate bargained benefits
- We are providing a comparison for: medical, dental, vision, 401(k), enhanced 401(k)/DB, STD, LTD, basic life, employee supplemental life, dependent life, vacation and holiday
- We are comparing the same plan types for both NW Natural and the database because this ensures an apples-to-apples comparison
  - For example, on the medical comparison we are comparing the PPO plan to the database PPO plans
- We are basing the NW Natural plan design information on NW Natural's 2017 submission into the Willis Towers Watson Benefits Data Source database. For bargained employees, we are basing NW Natural's plan design information on the 2017 annual enrollment materials provided by NW Natural.
- The plan summaries for the energy companies within our database reflect either 2016 or 2017 data depending on final submission by each employer
- When providing as assessment of NW Natural's benefit plans to the peer group, we designated an "equal," "better," or "worse" designation
  - This designation is purely subjective and not at all actuarially based

Executive Summary

- The following table provides an overall comparison summary for each of the benefits that we reviewed
  - The comments reflect how NW Natural's benefits compare to the benchmarks

Plan	Comparison to Non-Bargained Total Database	Comparison to Non-Bargained 13 Target Companies	Comparison to Bargained Total Database
Medical*	Equal	Equal	Equal
Dental	Equal	Equal	Equal
Vision	Equal	Equal	Equal
401(k)	Equal	**Worse**	**Worse**
Enhanced 401(k)/DB Plan	Equal	Equal	Equal
STD	Overall Determination Cannot Be Made — See Details	Overall Determination Cannot Be Made — See Details	Overall Determination Cannot Be Made — See Details
LTD	Equal	Equal	Equal
Basic Life	Overall Determination Cannot Be Made — See Details	Overall Determination Cannot Be Made — See Details	**Worse**
Child Life (paid by employees in the benchmark)	Equal	Equal	Equal
Vacation	Equal	Equal	Equal
Holiday	Equal	Equal	Equal

*Target company group was expanded to 27 companies for medical

Non-Bargained Detailed Summary

Health Benefits — Medical

- The following table provides a comparison of the non-bargained NW Natural PPO plan to both the total energy benchmark and also the benchmark for the targeted company subset
  - We are only comparing PPO plans since this is the highest enrolled plan option within the Willis Towers Watson database and the highest enrolled option for NW Natural
  - PPO benchmarks are available for 10 of the 27 energy companies in the subset
- For comparison purposes, NW Natural employee contributions reflect the full subsidy provided to them by NW Natural
- Overall, we feel the PPO medical plan is equal to both benchmarks

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison	27 Energy Company Subset Benchmark	Comparison
Health Benefits					
Medical	PPO (In-Network Only Shown)	PPO (In-Network Only Shown)	NW Natural to Benchmark	PPO (In-Network Only Shown)	NW Natural to Benchmark
Single Deductible	$500	$250 – $500	Slightly Worse	$300 – $500	Slightly Worse
Single Out-of-Pocket Maximum	$2,000	$2,500	Better	$2,000 - $3,000	Slightly Better
Coinsurance	90%	80%	Better	80%	Better
Office Visits	$15 copay, no deductible	$25 copay, or 80% coinsurance	Better	$20 copay, or 80% coinsurance	Better
Preventive Care	100%	100%	Equal	100%	Equal
Emergency Room	$100 copay, no deductible	$100 – $150 copay, or coinsurance	Equal	$100 – $150 copay, or coinsurance	Equal
Generic Drugs — Retail	$10 copay	$10 copay	Equal	$10 copay	Equal
Brand Formulary Drugs — Retail	$35 copay	$30 copay, or 80% to $50 max copay	Equal	80% coinsurance with min/max	Equal
Brand Non Formulary Drugs — Retail	$50 copay	$50 copay, or 70% to $100 max copay	Equal	60% – 80% coinsurance with min/max	Equal
Monthly Employee Only Contributions	$118	$120+	Equal	$120+	Equal
Monthly Family Contributions	$433	$400+	Worse	$400+	Worse
Overall Assessment			Equal		Equal

http://natcl.internal.towerswatson.com/clients/604927/NWNatural2017HB/Documents/Benchmarking%20Summary_2017%20Updated.pptx

Health Benefits — Dental and Vision

- The following table provides a comparison of the non-bargained NW Natural dental buy-up and the vision plan associated with the PPO medical plan to both the total energy benchmark and also the benchmark for the 13 company subset
- We **did not** assume the $50 per month credit NW Natural employees receive would offset dental contributions, we assumed it would offset medical contributions on the previous slide
- Overall, we feel the dental buy-up PPO and the vision plan are equal to both benchmarks

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison	13 Energy Company Subset Benchmark	Comparison
Health Benefits					
Dental	**PPO (In-Network Only Shown)**	**PPO (In-Network Only Shown)**	**NW Natural to Benchmark**	**PPO (In-Network Only Shown)**	**NW Natural to Benchmark**
Deductible Per Person	$25	$50	Better	$25	Better
Annual Maximum	$2,000	$1,500 to $2,000	Equal	$1,500 to $2,000	Equal
Preventive Coinsurance	100%	100%	Equal	100%	Equal
Basic Coinsurance	80%	80%	Equal	80%	Equal
Major Coinsurance	50%	50%	Equal	50%	Equal
Orthodontia Deductible	Plan Deductible Applies	None	Worse	None or Plan Deductible Applies	Equal
Orthodontia Coinsurance	50%	50%	Equal	50%	Equal
Orthodontia Lifetime Maximum	$1,500	$1,500	Equal	$1,500	Equal
Monthly Employee Only Contributions	$21.62	$10 – $20	Worse (just for buy-up)	Less than $10	Worse (just for buy-up)
Monthly Family Contributions	$62.52	$30 – $50	Worse (just for buy-up)	$25 – $30	Worse (just for buy-up)
Overall Assessment			Equal		Equal
Vision					
Exam	100% after $15 copay	100% after $10 copay	Worse	100% after $10 – $25 copay	Equal
Frames	$200 allowance for all hardware every 12 months	$130 allowance every 24 months	Better	$130 – $150 allowance every 24 months	Better
Lenses	" "	$10 to $25 copay every 12 months	Equal	$10 to $25 copay every 12 months	Equal
Contacts	" "	$130 allowance every 12 months in lieu of frames/lenses	Better	$130 allowance every 12 months in lieu of frames/lenses	Better
Monthly Employee Only Contributions	Included with medical	$5 to $10	N/A	Less than $5	N/A
Monthly Family Contributions	Included with medical	$10 to $30	N/A	Less than $15	N/A
Overall Assessment			Equal		Equal

Retirement Benefits

- The following table provides a comparison of the non-bargained NW Natural retirement plans to both the total energy benchmark and also the benchmark for the 13 company subset
- Overall, we feel the 401(k) plan is equal to the total energy benchmark and worse than the peer company benchmark
- Overall, we feel the enhanced 401(k) plan is equal to both benchmarks

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison	13 Energy Company Subset Benchmark	Comparison
Retirement Benefits					
401(k)					
Employer Match	60% of the first 8%	50% – 100% up to 6% (average employer match of 4.5%)	Equal	100% up to 5% – 6%	Worse
Vesting	Immediate	Immediate	Equal	Immediate	Equal
Overall Assessment			Equal		Worse
Additional Retirement Plans					
Additional Plans Available	Enhanced 401(k)	51 have non-contributory 401(k)		12 have non-contributory 401(k)	
Non-Contributory 401(k) Contribution (if offered)	5% of current annual pay	5% of pay	Equal	5% of pay	Equal

Welfare Benefits — Disability and Life

- The following table provides a comparison of the non-bargained NW Natural disability and life plans to both the total energy benchmark and also the benchmark for the 13 company subset
- We have not made an overall assessment of the short-term disability and basic life plans because it is hard to know how to actuarially weight the various components without running a full benefits valuation
- Overall, we feel the long-term disability and child life benefits are equal to both benchmarks

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison	13 Energy Company Subset Benchmark	Comparison
Welfare Benefits					
Short-Term Disability					
Coverage	70% to 85% depending on years of service	60 – 100% of pay depending on years of service	Equal	60 – 100% of pay depending on years of service	Equal
Waiting Period	4 days	7 days	Better	7 days	Better
Long-Term Disability					
Waiting Period	180 days	180 days	Equal	180 days	Equal
Coverage	60% of pay for Base Plan	60% of pay	Equal	60% of pay	Equal
Monthly Maximum	$10,000	$10,000	Equal	$10,000 to $15,000	Equal
Basic Life					
Coverage	1.25x pay	1x pay to 2x pay	Equal	1x pay	Better
Maximum	$750,000	$750,000	Equal	$1,500,000	Worse
Supplemental Life Coverages					
Child Life	$5,000 (NW Natural paid)	Multiples up to $10,000	Equal	Multiples up to $10,000	Equal

Time Off Benefits — Vacation and Holiday

- The following table provides a comparison of the non-bargained NW Natural vacation and holiday benefits to both the total energy benchmark and also the benchmark for the 13 company subset
- Overall, we feel the vacation benefit is equal to both benchmarks
- Overall, we feel the total holiday benefit is equal to both benchmarks

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison	13 Energy Company Subset Benchmark	Comparison
Time Off					
Vacation*					
Days at Hire	11 days	10 days	Equal	10 days	Equal
Days at Year 3	11 days	11 days	Equal	10 days	Equal
Days at Year 7	16 days	15 to 20 days	Equal	15 to 20 days	Equal
Days at Year 15	21 days	20 days	Equal	20 days	Better
Long-Service — Maximum Days	26 days	25 to 30 days	Equal	25 to 30 days	Equal
Carryover Limit	40 days	5 to 10 days	Better	5 to 10 days	Better
Holiday					
Employer Elected Days	8 days	8 to 10 days	Equal	8 to 10 days	Equal
Employee Elected Days	3 days	1 to 3 days	Equal	2 to 3 days	Equal
Total Days	11 days	10 to 13 days	Equal	11 to 12 days	Equal

*Subtracted 5 days to account for sick days with NW Natural

Bargained Detailed Summary

[redacted]

Health Benefits — Medical

- The following table provides a comparison of the bargained NW Natural PPO plan to the total energy benchmark
  - There were not enough of the target companies that submitted separate bargained benefits to provide a meaningful benchmark
  - We are only comparing PPO plans since this is the highest enrolled plan option within the Willis Towers Watson database
- Overall, we feel the PPO medical plan is equal to the benchmark

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison
Health Benefits			
Medical	**PPO (In-Network Only Shown)**	**PPO (In-Network Only Shown)**	**NW Natural to Benchmark**
Single Deductible	$300	$300	Equal
Single Out-of-Pocket Maximum	$2,300	$2,300	Equal
Coinsurance	80%	90%	Worse
Office Visits	$20 copay, no deductible	$20 copay, no deductible	Equal
Preventive Care	100%	100%	Equal
Emergency Room	$75 copay, deductible & coinsurance	$100 copay	Equal
Generic Drugs — Retail	20%, $10 minimum copay	$5 to $10 copay	Worse
Brand Formulary Drugs — Retail	20%, $20 minimum copay	20%, $20 minimum copay	Equal
Brand Non Formulary Drugs — Retail	50%	30%, $20 minimum copay	Worse
Monthly Employee Only Contributions*	$282	$150+	Worse
Monthly Family Contributions*	$282	$400+	Better
Overall Assessment	$300	$300	Equal

*Lower contribution available for employees who completed the health assessment and biometrics. Includes dental and vision.

Health Benefits — Dental and Vision

- The following table provides a comparison of the bargained NW Natural dental trust indemnity plan and the vision plan associated with the PPO medical plan to the total energy benchmark
  - There were not enough of the target companies that submitted separate bargained benefits to provide a meaningful benchmark
- Overall, we feel that both the dental and vision plans were equal to the benchmark

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison
Health Benefits			
Dental	**PPO (In-Network Only Shown)**	**PPO (In-Network Only Shown)**	**NW Natural to Benchmark**
Deductible Per Person	$10	$50	Better
Annual Maximum	$1,500	$1,800	Worse
Preventive Coinsurance	80%	100%	Worse
Basic Coinsurance	80%	80%	Equal
Major Coinsurance	80%	60%	Better
Orthodontia Deductible	None	None	Equal
Orthodontia Coinsurance	50%	50%	Equal
Orthodontia Lifetime Maximum	$1,000	$1,800	Worse
Monthly Employee Only Contributions	Included with medical	$10+	N/A
Monthly Family Contributions	Included with medical	$35+	N/A
Overall Assessment			Equal
Vision			
Exam	100% after $15 copay	100% after $10 copay	Worse
Frames	$130 allowance every 24 months	$130 allowance every 24 months	Equal
Lenses	100% after $25 copay every 12 months	100% after $15 copay every 12 months	Worse
Contacts	$130 allowance in lieu of frames/lenses	$130 allowance in lieu of frames/lenses	Equal
Monthly Employee Only Contributions	Included with medical	$5+	N/A
Monthly Family Contributions	Included with medical	$15+	N/A
Overall Assessment			Equal

http://natcl.internal.towerswatson.com/clients/604927/NWNatural2017HB/Documents/Benchmarking%20Summary_2017%20Updated.pptx

Retirement Benefits

- The following table provides a comparison of the bargained NW Natural retirement plans to the total energy benchmark
- Overall, we feel the 401(k) plan is worse than the benchmark
- Overall, we feel the Enhanced 401(k) plan is equal to the benchmark

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison
Retirement Benefits			
401(k)			
Employer Match	50% of the first 6%	100% up to 6%	Worse
Vesting	Immediate	Immediate	Equal
Overall Assessment			Worse
Additional Retirement Plans			
Additional Plans Available	Enhanced 401(k)	23 have a non-contributory 401(k) plan	
Non-Contributory 401(k) Contribution (if offered)	4% of current annual pay	4% to 5% of pay	Equal

Welfare Benefits — Disability and Life

- The following table provides a comparison of the bargained NW Natural disability and life plans to the total energy benchmark
  - There were not enough of the target companies that submitted separate bargained benefits to provide a meaningful benchmark
- We have not made an overall assessment of the short-term disability plan because it is hard to know how to actuarially weight the various components without running a full benefits valuation
- Overall, we feel the long-term disability and child life benefits are equal to the benchmark
- Overall, we feel the basic life benefit is worse than the benchmark

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison
Welfare Benefits			
Short-Term Disability			
Coverage	70% to 85% depending on years of service	60 – 100% of pay depending on years of service	Equal
Waiting Period	4 days	5 to 7 days	Better
Long-Term Disability			
Waiting Period	180 days	180 days	Equal
Coverage	60% of pay for Base Plan	60% of pay	Equal
Monthly Maximum	$10,000	$10,000	Equal
Basic Life			
Coverage	$3,000	1x to 2x pay	Worse
Maximum	N/A	$700,000	N/A
Supplemental Life Coverages			
Child Life	$5,000 (NW Natural paid)	Multiples up to $10k	Equal

Time Off Benefits — Vacation and Holiday

- The following table provides a comparison of the bargained NW Natural vacation and holiday benefits to the total energy benchmark
  - There were not enough of the target companies that submitted separate bargained benefits to provide a meaningful benchmark
- Overall, we feel the vacation benefit is equal to the the benchmark
- Overall, we feel the total holiday benefit is equal to the benchmark

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison
Time Off			
Vacation*			
Days at Hire	11 days	5 days	Better
Days at Year 3	11 days	13 days	Worse
Days at Year 7	16 days	15 days	Equal
Days at Year 15	21 days	20 days	Equal
Long-Service — Maximum Days	26 days	28 days	Worse
Carryover Limit	60 days	5 to 10 days	Better
Holiday			
Employer Elected Days	8 days	9 to 10 days	Worse
Employee Elected Days	3 days	2 days	Equal
Total Days	11 days	11 to 12 days	Equal

*Subtracted 5 days to account for sick days with NW Natural

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Direct Testimony of Joe Karney

CAPITAL PROJECTS
Exhibit 800

December 2017

EXHIBIT 800 – DIRECT TESTIMONY - CAPITAL PROJECTS

Table of Contents

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Joe Karney. My business address is 220 NW Second Avenue, Portland, Oregon 97209. I am the Engineering Director for NW Natural. I am responsible for design, construction, operation, and maintenance of the gas distribution system and utility storage plants, and operations support services including work management functions, mapping and compliance.

Q. Please describe your education and employment background.

A. I graduated from the University of Illinois at Urbana-Champaign with a B.S. in Mechanical Engineering, and I am a registered Professional Engineer in the State of Oregon.

Before assuming my current position at NW Natural in 2017, I was the Senior Manager of Code Compliance for the Company, and managed the regulatory compliance department and represented the Company during safety audits performed by the Public Utility Commission of Oregon ("Commission"). I also reviewed and ensured company compliance with pending regulatory changes from the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA"). Prior to holding this position, I managed the Construction and System Operations groups. I started my career at the Company with the Integrity Management group and worked on the development and implementation of the Transmission Integrity Management

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Program ("TIMP") and the Distribution Integrity Management Program ("DIMP"). Before joining NW Natural, I worked as an Integrity Management Engineer for Colonial Pipeline Company for four years.

Q. What is the purpose of your testimony?

A. I provide an overview of the Company's major capital projects that have been completed within NW Natural's physical system since the last rate case or that are currently in progress. These projects are described in greater detail below, and include the Mid-Willamette Valley Feeder Project ("MWVF Project"),[1] the Corvallis Loop Project, the Southeast Eugene Reinforcement Project ("SE Eugene Project"), the Newport Refurbishment, and updates to the Mist Underground Storage Facility ("Mist").

I also discuss the Company's future plans for safety-driven system upgrades, which are planned to meet the requirements of recently updated PHMSA regulations and to promote resiliency in the event of seismic activity, including preparedness for a potential Cascadia subduction zone earthquake. I also discuss the early stages of a plan to retrofit excess flow valves ("EFVs") on service lines that the Company intends to undertake in 2018. These safety-related projects are not included in the Company's request for recovery in this case but may be the foundation of a later request for a Safety Cost Recovery Mechanism.

[1] Although the MWVF Project was completed before NW Natural's last rate case, portions of it have not yet been included in rates, as described in the testimony below.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
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II. MAJOR CAPITAL PROJECTS

Q. Please provide a brief description of the significant capital projects that are included for recovery in this case.

A. The Company is requesting recovery for the following significant capital projects:

- **MWVF Project.** The MWVF Project is a major combined system reinforcement and bare steel replacement project that connects Perrydale along the Central Coast Feeder to the Albany-Corvallis Feeder. The MWVF Project was initiated in 2005 and completed in 2013.
- **Corvallis Loop Project.** The Corvallis Loop Project is a system reinforcement project that increases service capacity and reliability to the Corvallis and Philomath areas. The Corvallis Loop Project was initiated in 2011, and was completed in 2013.
- **SE Eugene Project.** The SE Eugene Project is a 2.5 mile, 12-inch diameter high pressure pipeline, feeding the southeast Eugene distribution area from the South Eugene gate. The SE Eugene Project is scheduled to begin construction in spring or early summer 2018, and is expected to be completed in fall of 2018.
- **Newport Refurbishment Project.** The Newport Refurbishment Project consists of several projects that are designed to extend the life of the Newport LNG facility for 25 to 30 years. All of the projects associated with the Newport Refurbishment Project are scheduled to be complete in fall 2018.

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- **Mist Control Building and Control System.** This project involves the design and construction of a new control building and replacement of the obsolete plant control system at Mist.

My testimony will describe each of these projects in greater detail.

<u>MWVF Project</u>

Q. Please describe the MWVF Project?

A. The MWVF Project is a significant pipeline project that the Company constructed from 2005-2013, connecting NW Natural's system from the Central Coast Feeder near Perrydale to a connection on the Albany-Corvallis Feeder east of Corvallis. The project involved installing a 12-inch diameter, 720 psig transmission system.

The MWVF Project was divided into several different segments, some of which involved the replacement of pipeline that was "bare steel," which the Company has systematically removed throughout our entire pipeline system and replaced for safety reasons. The portion of the MWVF that replaced existing bare steel pipeline is shown in blue in Figure 1, below. NW Natural also installed new pipelines as a part of the MWVF Project. These new pipelines provided system connectivity that otherwise did not exist within NW Natural's system to create an integrated high pressure system, and added the ability to deliver gas in new ways across NW Natural's system. These system reinforcements of the MWVF are shown in red in Figure 1.

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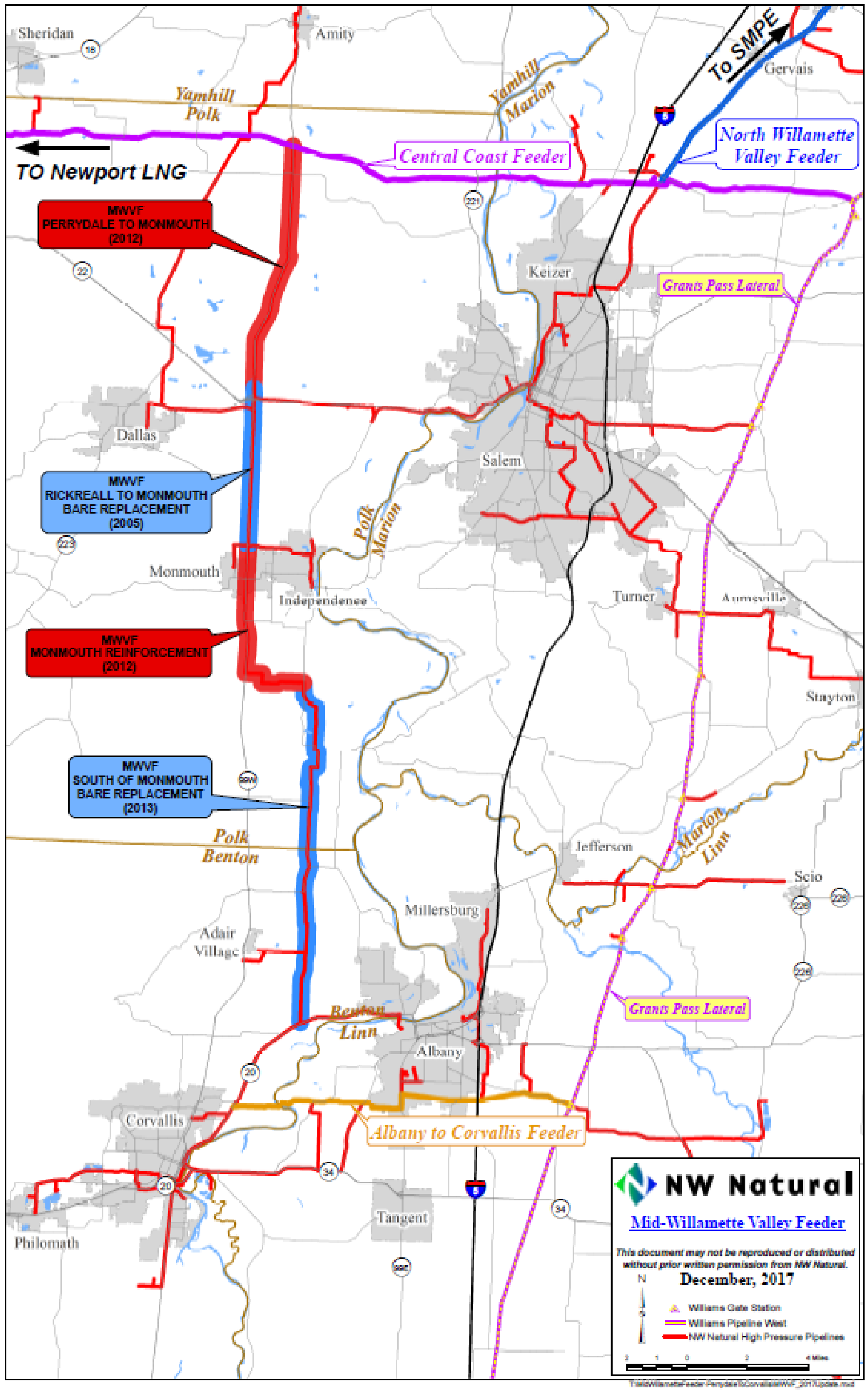
Figure 1. Map of Mid-Willamette Valley Feeder



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Q. Can you briefly recap the history of the Company's plans to build out the MWVF Project, and the Commission's review of the MWVF Project?

A. The Company had planned to build the Mid-Willamette Valley Feeder ("MWVF") for many years, and it was mentioned in past Integrated Resource Plans ("IRP").[2] The Company completed most portions of the project by 2012, and asked for cost recovery related to those in the Company's last general rate case, UG 221.

In that case, OPUC Staff challenged the MWVF Project as potentially not being completed in time to coincide with the establishment of new rates, and also argued that the Company had not established that the project was prudent and necessary to have been built in the timeframe during which it was built. Other parties to the case also supported Staff's position. The Company responded by seeking to demonstrate the benefits of the MWVF Project for customers, and that the project would be used and useful at the time new rates went into effect.

The MWVF Project was, in fact, completed before the beginning date of the new rates. The Commission found, however, that the project should not be included in rate base at that time, reasoning that the project was not needed to meet incremental load growth until 2025, and the Company had failed to justify the project on the grounds of reliability. The Commission did not necessarily dispute that the project resulted in increased reliability on NW Natural's system, but found that the Company had not put sufficient evidence in the record to show

[2] NW Natural's 2000 IRP, Docket No. LC 29; 2004 IRP, Docket LC 67; 2008 IRP, Docket No. LC 45; 2010 IRP, Docket LC 45.

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that the MWVF Project was needed at that time. The Commission also noted that the project had not been fully evaluated in the Company's prior IRPs. The Commission stated that the Company could seek to recover the costs of the pipeline in the future, upon a better showing of need, but that it could only recover the costs on a depreciated basis. In other words, the Company would be denied cost recovery on the MWVF Project until that future showing, and would be required to bear the depreciation expense in the meantime.

Q. What was the Company's response to the Commission's order?

A. While NW Natural believes that the project was well-executed, and that it provides valuable and necessary functions within its gas delivery system, the Company determined that it would seek to learn what it could from the Commission's finding and ensure that it corrected the shortcomings in the approach it had taken to present the project to the Commission in that case.

Q. What were the key takeaways for the Company from the Commission's order in the 2012 rate case?

A. First, the Company determined that the Commission expected a different approach to its IRP process than the Company had taken up to that point. Prior to Commission Order No. 12-437, the Company had generally viewed the IRP as a process for analyzing the Company's options with respect to getting sources of gas *to* its delivery system. It did not generally analyze, within the IRP, the Company's options for delivering gas to the various load areas *within* its system.

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Second, the Company realized that it had not sufficiently documented the decision-making process leading up to its decision to build the MWVF. The Commission expressed that the rationale for the project offered by the Company was not supported with sufficient evidence, and made clear that it will discount descriptions and rationale offered during the course of a proceeding if not also supported with the type of analysis that the Commission expects to see in an IRP.

Q. Did the Company make significant changes to its IRP process as a result of the Commission's order?

A. Yes, the Company made a major shift in how it approached the IRP. It created a new department to conduct Integrated Resource Planning—the Strategic Planning Department. It placed a Senior Director in charge of that team, an Officer to oversee the team, and greatly expanded the Company's staffing on technical matters, to include several qualified economists that work on the IRP and internal company processes. Additionally the Company changed its approach in the IRP, to look more comprehensively at all system supply issues, including those that previously had not been the subject of IRP analyses, such as distribution system planning.

Q. What did the Company do to improve its internal documentation of its capital project decision-making process?

A. The Company instituted new requirements for written alternative analyses to be required as part of the internal approval of capital projects over a certain size.

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Although the Company already performed these analyses, it was more on a decentralized basis, and did not have a high degree of uniformity. This new process ensured that the Company did a better job of documenting its internal decision-making processes in writing, and provided a more centralized approach to that documentation.

Q. Were there any other Company actions taken with respect to the MWVF since the Company's last rate case?

A. Yes, the Company had discussions with Staff about its takeaways, to seek feedback about the MWVF, and to explore whether it would be appropriate to include the MWVF in a future IRP based on new analysis. These discussions yielded a conclusion that Staff would not support the inclusion of new analysis in a future IRP because the project had already been built, and the Commission's determination was that projects that were already constructed are not appropriately vetted in an IRP.

Q. What were the financial consequences to NW Natural of the Commission's determination to not allow the MWVF Project to be placed in rates in 2012?

A. NW Natural has been required to bear the cost of service each year on the project, without any cost recovery. By the time the Company's new rates from this case go into effect, the unrecovered depreciation expense will total $4.6 million. In addition to this expense, the Company has not been able to collect any return on its investment to cover its costs of the debt and equity used to finance it.

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Q. What is the amount of capital investment that remains after depreciation over the last six years, which the Company is proposing to add to rates?

A. The total remaining amount is $20.2 million[3], which represents 81 percent of the original costs of the project of $24.8 million.

Q. Is the Mid-Willamette Valley Feeder being used by the Company today to provide gas service to its customers?

A. Yes. The MWVF has constantly been in service and relied on by the Company to provide service to NW Natural customers since it was installed.

Q. Is the Company seeking now to include the costs of the MWVF in rates?

A. Yes. The Company is requesting that the depreciated cost of the portions of the MWVF not yet included in rates be added at the time the new rates from this case go into effect.

Q. In what ways is the MWVF serving NW Natural's customers, and why does the Company assert that the project should be included in rates as a prudent utility investment?

A. The MWVF is serving multiple critical functions within NW Natural's system. I will describe these below.

First, without the MWVF, NW Natural would not be able to serve the load requirements of its customers at peak times. NW Natural has modeled, using its standard engineering methodologies and its Synergi model (the software and

[3] Because of deferred taxes associated with this asset, the amount of rate base from this project is lowered by an additional $7.3 million.

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modeling package that NW Natural uses to identify pressures under various conditions such as during peak hours), whether it could serve firm customer loads without the connectivity provided for by the MWVF. This modeling shows that pressures in certain areas of NW Natural's system drop below the established design criteria for ensuring adequate pressure to provide service to firm customers.

Second, despite the Company's shortcomings in the last rate case, the MWVF serves a critical reliability function on its system. Without the MWVF, customers within the Albany-Corvallis load center would be dependent on a single-feed system to deliver gas. This would be the single largest area in NW Natural's system where a disruption on a single line could cause widespread outages for customers. The construction of the Mid-Willamette Valley Feeder alleviated this, and made service to customers on a major portion of NW Natural's system significantly more reliable.

Third, the integration of the project into NW Natural's system has fundamentally changed and improved NW Natural's gas transmission and distribution system by supporting new distribution pathways. For example, on a typical day, gas flows from the Central Coast Feeder through the MWVF into the Albany load center. The MWVF also provides the primary distribution path of gas into West Salem, Dallas, Independence, and Monmouth, which has supported growth in that area. Additionally NW Natural can now move gas from Newport

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LNG to Albany, which was not possible prior to the completion of the entire pipeline.

Q. Please explain your statement above that NW Natural would not be able to serve the firm loads of its customers on the peak hour of a design day without the MWVF.

A. NW Natural's Synergi modeling demonstrates that without the connectivity provided by the MWVF between the Independence / Monmouth area and the Central Coast feeder, customers in that area would be experiencing pressures well below design standards, and at pressures that indicate failed service on a peak day. Such a situation would be untenable, and would lead to the inability of customers to heat their homes, or otherwise utilize their gas service on a day when customers would rely on it most. It would also require a vast effort at relighting by the Company, which would come at a high cost. Per its design standards, NW Natural does not allow areas on its firm system to deteriorate to this level of service, and thus is relying on the MWVF to provide service to these customers.

Figure 2 below shows the Synergi model of the Monmouth/Independence area with the MWVF removed. The 4 inch maximum allowable operating pressure ("MAOP") 175 psig high pressure distribution pipeline that existed before the MWVF would experience pressures of less than 60 psig at regulators that feed Monmouth and Independence. This causes pressures in the Class B distribution system in Monmouth and Independence to drop below 5 psig, which

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places customers at risk for losing gas service on a peak day. Those customers are shown in the red shades in the Synergi model. Both of the described drops in system pressure do not meet the Company’s design criteria for providing firm service to customers.

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Figure 2. Synergi Model of Monmouth/Independence Area without the MVWF

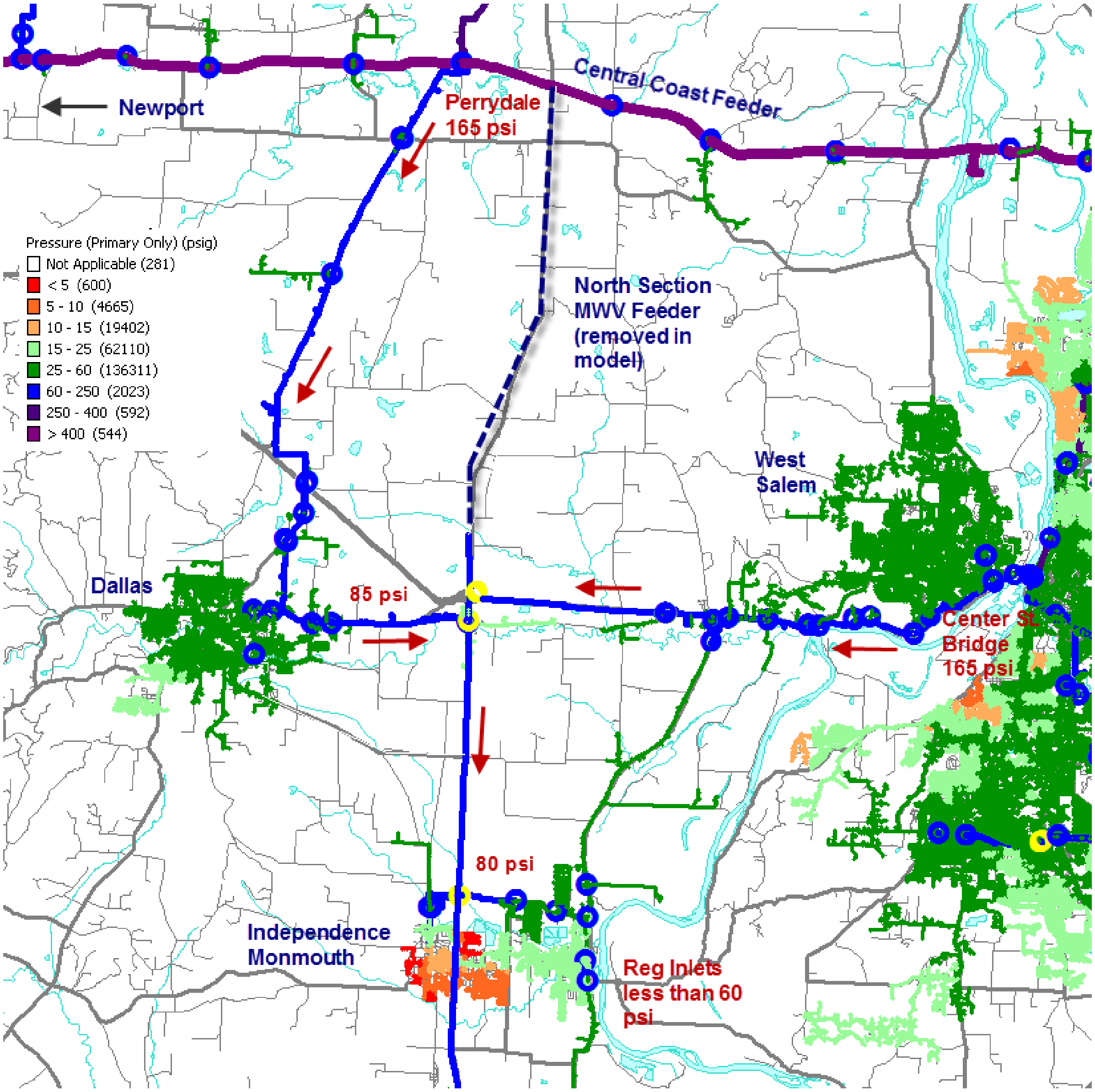

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Figure 3 below shows the same Synergi model of the Monmouth/Independence area with the MWVF installed. Most pressures in the Class B distribution system in Monmouth and Independence increase to above 25 psig. Additionally the 4 inch MAOP 175 psig high pressure distribution pipeline that existed before the MWVF would not experience any significant pressure drops.

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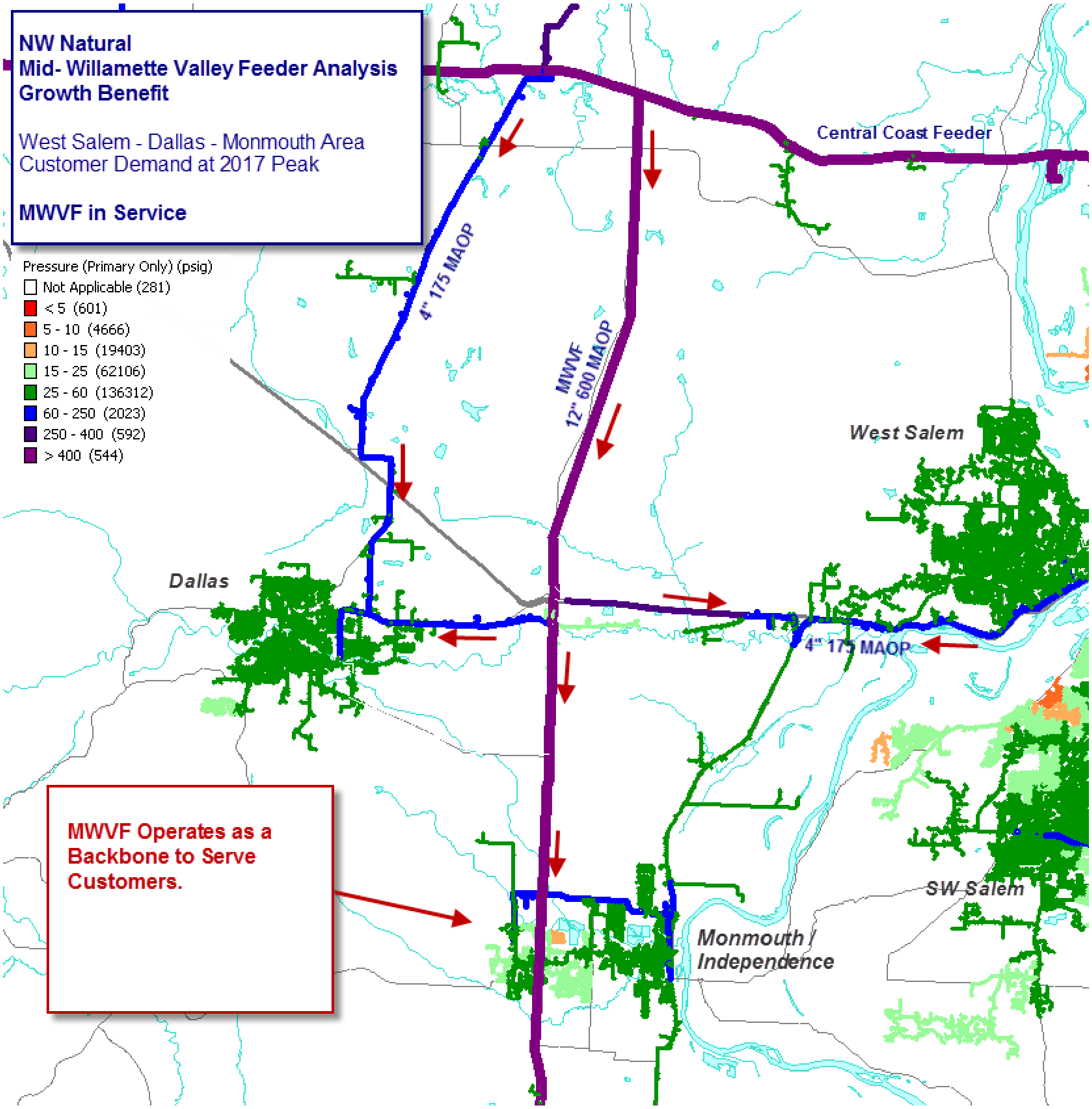
1 Figure 3. Synergi Model of Monmouth/Independence Area with the MWVF.



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Q. If, hypothetically, the MWVF had not been built, what would the Company have been required to build to provide reliable service to customers in those areas that have been identified as problematic without the MWVF?

A. We would have needed to build an additional pipeline to that area, similar to what is provided by the MWVF. The current alignment from the Central Coast Feeder to Monmouth/Independence provides the most direct connection of the additional distribution capacity to the area of low pressure. Another option would be to build a new pipeline from Williams' Grants Pass lateral to Monmouth/Independence. That pipeline would be longer and require a crossing of the Willamette River, which would cause that option to cost more than the existing MWVF. In other words, the MWVF is the most efficient project to have constructed to maintain firm service. Additionally, in light of the fact that the MWVF has been depreciated significantly, this project, once added to rates, represents the most economical way to serve load from customers' perspective.

Q. Please describe your statements that the MWVF is serving an important reliability purpose.

A. Without the project, NW Natural would have approximately 42,000 customers in the Albany-Corvallis area whose service would be wholly dependent on a single-feed system. In other words, these customers could lose service if there were an outage or disruption at the Albany gate station, or on the pipelines upstream or

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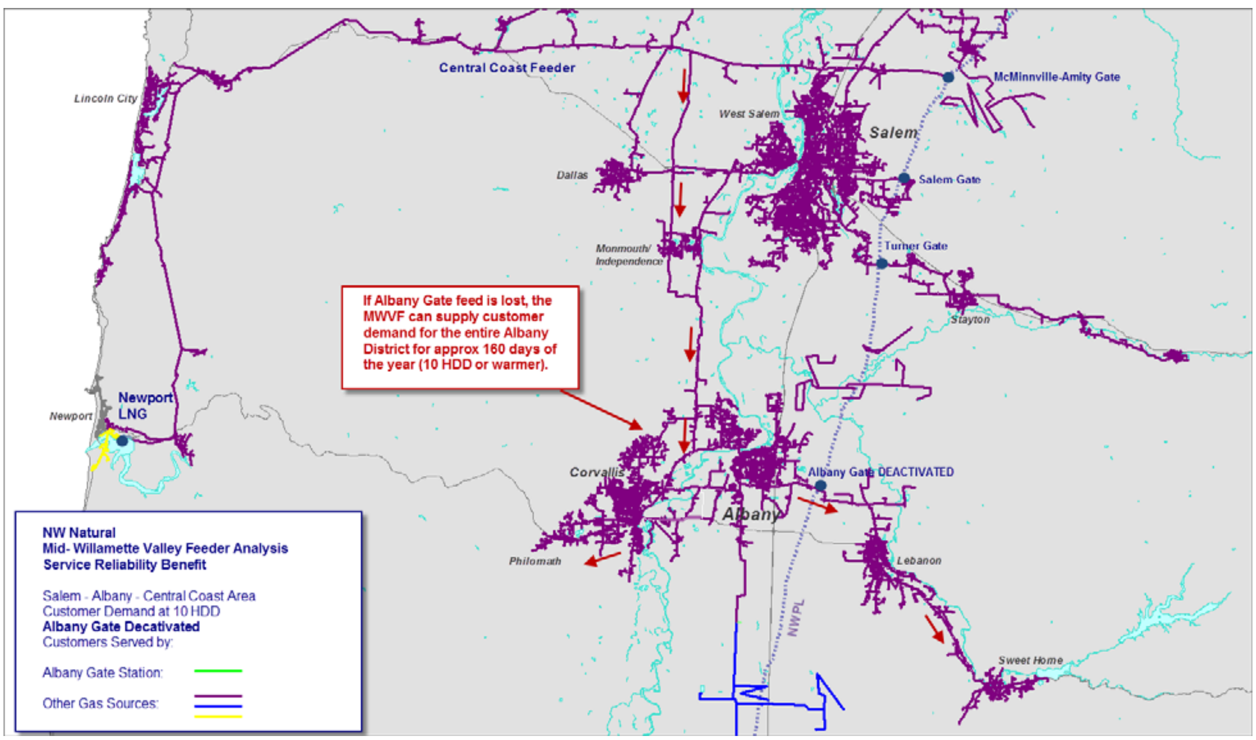
downstream of it. This would constitute the largest single-feed load center in NW Natural's system, and would represent an unreasonable risk.

Q. Can you demonstrate that the MWVF would prevent a widespread outage as described above?

A. Yes, Figure 4 below shows a Synergi model simulating a loss of the Albany gate. The model shows that the entire Albany load center can be completely supported by the MWVF during typical spring, summer, and fall weather, and during typical winter weather, it could support the majority of Albany and Corvallis.

Figure 4 – Synergi Model of simulated loss of Albany Gate



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Q. Are there other areas on NW Natural's system that are comparable in size, to which you can compare the Albany-Corvallis area?

A. Yes. For the Company, Eugene represents a similarly sized load center, with approximately 42,000 customers. Yet Eugene is served from three different gate stations and associated pipelines. This means that it would take three separate outages on separate pipelines in order to cause a complete customer outage in Eugene. Outside of peak days or near-peak days, the customer demand can be met with only two of the gate stations.

In Eugene, for example, the Company is able to service pipe and resolve pipeline issues without compromising service. In the summer of 2017, NW Natural was able to service North Eugene Industrial Transmission pipeline without any service disruptions. This pipeline was taken out of service for several weeks to perform a hydrotest. This important system redundancy to allow for testing and maintenance would not be possible for the Albany-Corvallis area without the Mid-Willamette Valley feeder.

Q. After Albany-Corvallis, what is the next largest single-feed area of NW Natural's system?

A. Astoria, which has about 13,000 customers.

Q. Earlier, you stated that the existence of the MWVF has changed gas flows on NW Natural's system. Can you explain further?

A. Yes, the existence of the MWVF provides a very significant new connection within NW Natural's system that changes the way gas flows between the Salem

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and Albany load centers. This pipeline improves deliverability of natural gas in very significant ways, benefiting the system currently, and will continue to do so into the future. In fact, it is difficult to determine what an “alternative system” would look like in the future without the project in place. And as more and more time passes, the prospect of approximating that alternative construct becomes even more unattainable.

It is important to explain this so that the parties and the Commission can appreciate the current situation with respect to the MWVF. The project clearly is currently important and necessary to be able to serve firm customer loads. And, it provides key connections within the system that the Company had long planned to make its system more robust and able to handle expected outages and problems that can occur in any given area. Beyond these demonstrations, the Company is not able to provide a specific showing that the project “would have been built” at a specific date, or “is not needed until” a specific date. Rather, the project is currently serving as an integral part of the NW Natural’s gas delivery system, and its existence modified, and continues to modify distribution-level projects in the future in significant ways, compared to how those would be constructed without the project.

Some of the major identifiable ways that the MWVF Project changed NW Natural’s system, and provides significant value to customers include the ability to serve firm loads in the Independence area, as well as the reliability benefits for Albany-Corvallis. On a typical day the northern portion of the Albany load center

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is served by gas flowing through the MWVF, representing approximately 10 percent of the total demand for the load center. Additionally, the existence of the pipeline allows Newport LNG to flow from the Central Coast to the Albany load center during vaporization. Figure 5 below shows the gas flowing from the Central Coast feeder in purple and the gas from the Albany gate station in green.

Figure 5. Synergi Model Showing Gas Flows into the Albany/Corvallis Area

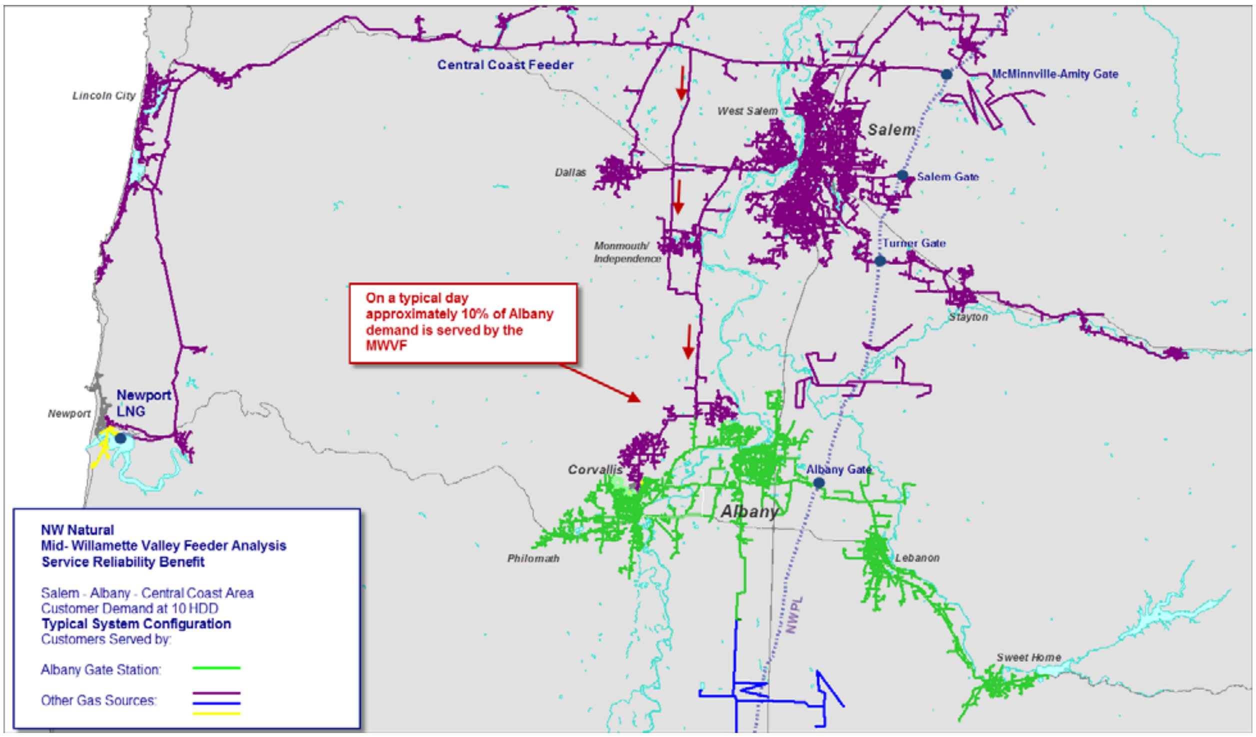

Figure 6 below shows our Synergi Model for the gas flows from the MWVF on a peak day. Gas flows from Newport LNG to the Albany and Salem load center is shown in red. Gas flows from the Grants Pass lateral are shown in green. The purple, pink, and light blue gas flows represent a mix of Newport LNG gas and gas from the Grants Pass lateral.

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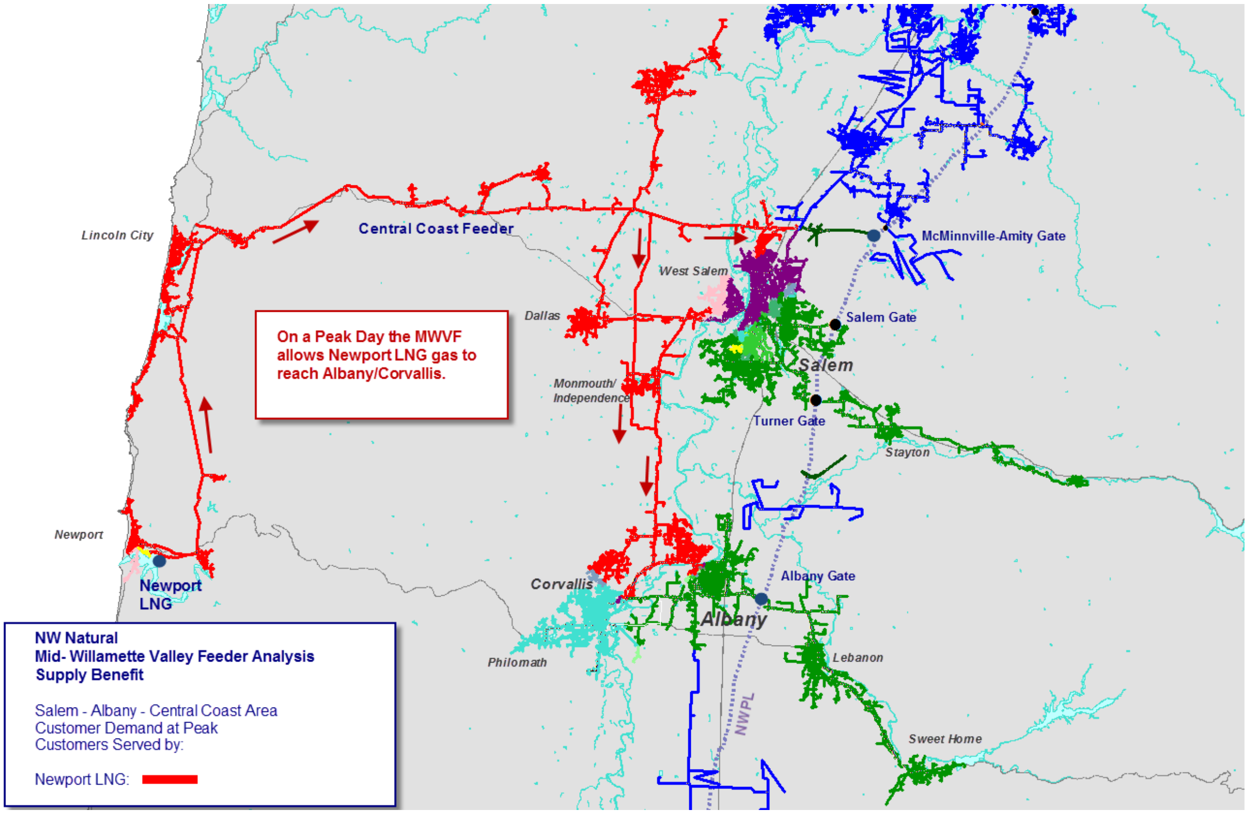
Figure 6. Synergi Model Showing Gas Flows from MWVF on a Peak Day



Q. Can you please summarize NW Natural's request with respect to the MWVF?

A. Yes. The pipeline is providing valuable service to customers both in terms of providing the ability to serve firm loads and in the increased reliability benefits that came about because of the MWVF Project. It is also serving as an integral part of the system, upon which the Company has built and will continue to build its system in the future. For these reasons, the Company now seeks to add the depreciated remaining investment to its total rate base as part of this general rate case application.

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Corvallis Loop Project

Q. Please describe the Corvallis Loop Project.

A. The Corvallis Loop Project (the "Corvallis Loop") is a transmission and high pressure distribution pipeline project located within the Company's Albany load center, designed to reinforce the high pressure distribution feeder serving customers in the Corvallis and Philomath area. The Corvallis Loop has two segments, as shown in Figure 1 below. The first segment of the Corvallis Loop is a 12-inch diameter, 720 psig transmission line that connects to the existing 10-inch diameter Albany-Corvallis Feeder near Riverside Drive and runs south to State Highway 34. The second segment is a 12-inch diameter, 400 psig transmission line that runs west along State Highway 34, crossing the Willamette River and connecting to the existing distribution system serving the west side of Corvallis and Philomath.

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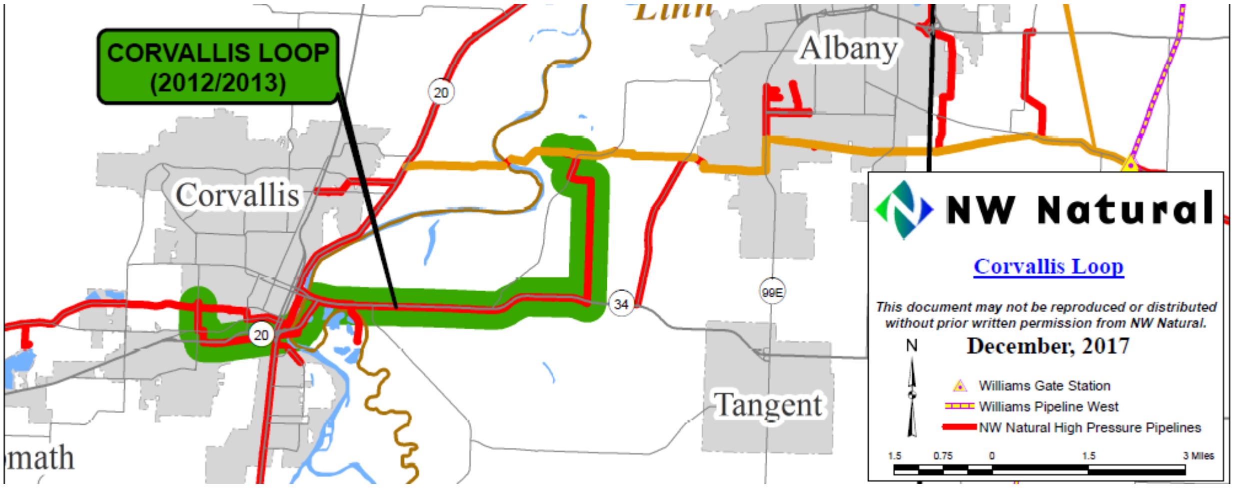
Figure 7. Map of Corvallis Loop



Q. Why did the Company develop the Corvallis Loop Project?

A. The Corvallis Loop was developed because there was insufficient firm capacity on the Company's system to meet its firm demand requirements in the Corvallis and Philomath area. The project also provided capacity to meet requirements associated with long-term growth in this area. The previously existing pipeline infrastructure providing delivery capacity to the area was constructed in 1963 and consisted of a 10-inch diameter, 400 psig transmission line from the Albany gate station to a point in northeast Corvallis, beyond which the facility sequentially reduced in size to an 8-inch and 6-inch, 225 psig transmission line serving Corvallis to Philomath. Steady residential, commercial, and industrial load growth in the Corvallis and Philomath area resulted in the Company experiencing pressure drops during weather conditions at less than design day weather conditions that left firm customers at material risk of outage.

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Prior to the construction of the Corvallis Loop, the pressure drops exceeded the 20 percent design pressure drop at temperatures considerably warmer than those of the 53 heating degree day (HDD) design day, beginning at 35 HDDs for Philomath and at 45 HDDs for Corvallis. These pressure drops placed customers in Corvallis and Philomath at considerable risk that the existing system would not provide reliable service during cold weather events.

Q. Had the Company considered alternative projects to address the pressure drops in the Corvallis and Philomath area?

A. Yes. After studying alternative pipe alignments, the route selected was determined to be the most economical option while minimizing disturbance to the environment and public. The route took advantage of property lines and acquired easements to minimize impact to landowners as well as utilizing existing public and private rights-of-way for cost-effective construction. Directional drilling was also utilized where appropriate to minimize surface disruption and mitigate impact to the local environment and sensitive areas including the Willamette River.

Q. Has the Company completed the Corvallis Loop Project?

A. Yes. Construction on the Corvallis Loop began in 2011, and construction was completed in 2013.

Q. Are customers currently benefiting from the Corvallis Loop Project?

A. Yes, the Corvallis Loop has been operational and serving customers from the time it was placed into operation in 2013. Since that time, the Corvallis and

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Philomath areas have not experienced pressure drops that exceed the design criteria or place customers at risk of outages. In addition, the project provides capacity to meet future customer load growth along the entire service corridor from east of Albany to Philomath.

Q. Was the Corvallis Loop discussed in NW Natural's last rate case?

A. Yes, NW Natural intended to include the Corvallis Loop in utility plant in the 2012 Rate Case, Docket No. UG 221. Additionally, Staff recommended the inclusion of the Corvallis Loop into rate base subject to the in-service requirement of ORS 757.355.

Q. If Staff recommended approval of the Company's request to add the Corvallis Loop into rate base, why was that not done through the last case?

A. The schedule for completing the Corvallis Loop Project was delayed, and the Company then informed the parties that it was therefore removing the request to include the project in rates at that time. The Company determined that it would wait until its next rate case to seek to add the project to rate base.

Q. What was the total capital cost of the investment in the Corvallis Loop?

A. The total capital cost of the Corvallis Loop Project was $28.4 million.

Q. What is the amount of capital investment that remains after depreciation that the Company is proposing to add to rates?

A. $23.9 million, which represents 84 percent of the original project cost.

SE Eugene Project

Q. Please describe the SE Eugene Project.

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A. The SE Eugene Project will consist of 2.5 miles of 12-inch high pressure pipeline from the South Eugene gate into the southeast Eugene distribution area, generally following a route along East 30th Avenue to connect and support the existing distribution system. The new pipeline would extend west from the existing South Eugene Gate and terminate at the connection to the existing 6-inch steel distribution main near Ferry St and East 28th Avenue.

Q. What is the primary driver for the SE Eugene Project?

A. Providing adequate supplies to southeast Eugene has been a growing concern for many years. Residential growth continues to expand south, away from the Company's high pressure supply pipelines, stressing the distribution system to failure. System modeling, verified through cold weather performance checks, projects distribution system pressures of less than 5 psig and, for isolated areas under peak hour conditions, an inability to reliably serve existing firm service customers. This low pressure is shown in red in Figure 8 below. This level of pressure is below the Company's criterion of distribution system reinforcement, being critical at pressures less than 10 psig.

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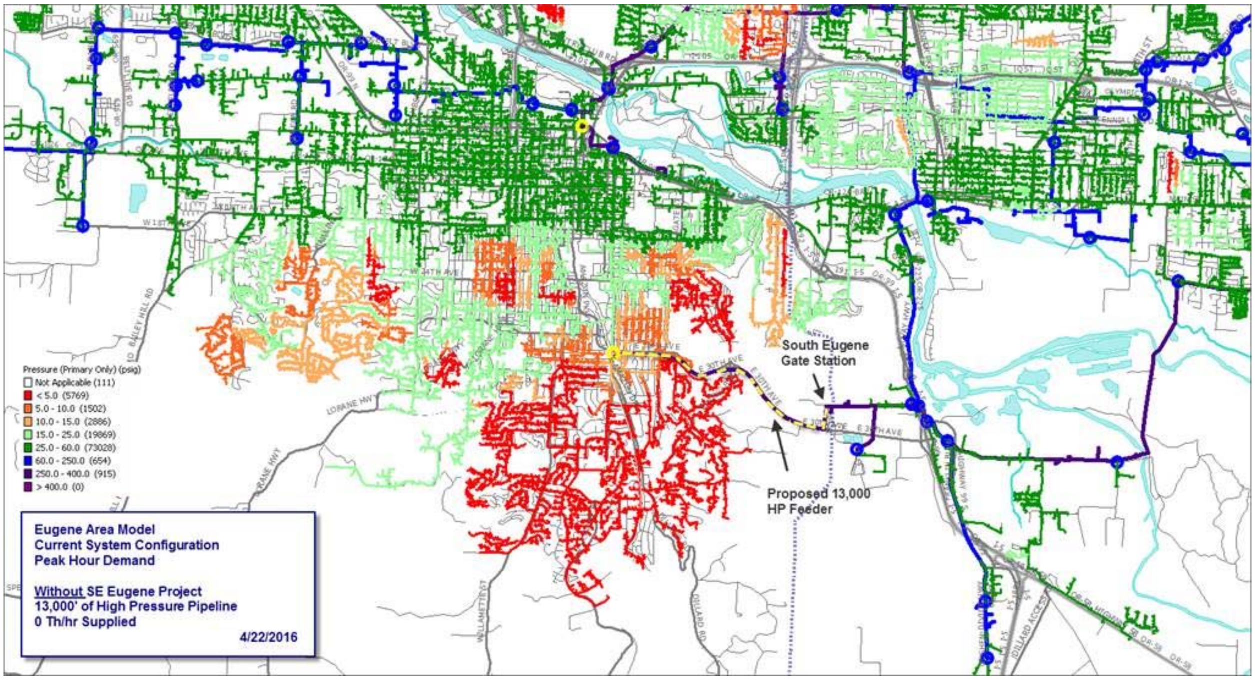
Figure 8 - Synergi model of the existing Eugene system during a peak hour load



The SE Eugene Reinforcement will raise most pressures in the distribution system to above 25 psig during peak hour conditions, as shown in Figure 9 below.

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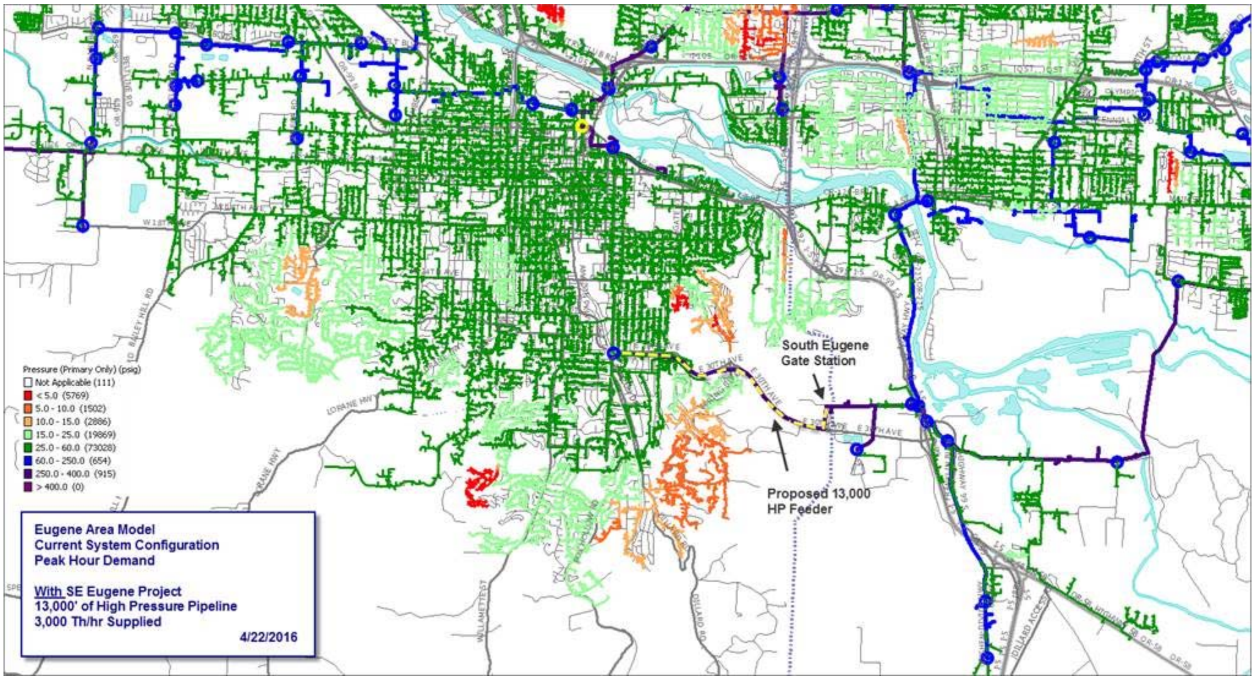
Figure 9. Synergi Model of the Eugene System
During a Peak Hour Load with the SE Eugene Reinforcement



Q. When will construction of the SE Eugene Project begin?

A. Construction on the SE Eugene Project will begin in spring or early summer 2018.

Q. How long will the SE Eugene Project take to complete?

A. The Company anticipates that construction will be complete by the end of the third quarter of 2018, and that the project will be in service for the 2018/2019 heating season.

Q. What is the estimated cost to complete the SE Eugene Project?

A. The cost of this project is estimated at $4.5 million.

Q. Did the Company consider alternatives to the SE Eugene Project?

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A. As described in the Company's 2016 IRP, NW Natural analyzed alternatives to the SE Eugene Project including potential recall agreements and the development of a satellite LNG facility.

Q. Please describe the alternatives that NW Natural analyzed.

A. The Company analyzed whether developing a satellite LNG facility would be a viable alternative, but as described in the 2016 IRP, that project would cost $23.3 million, which is significantly more costly than proceeding with the SE Eugene Project.

Additionally, NW Natural determined that it could avoid the need for the new pipeline through potential recall agreements only if it could achieve a peak-hour reduction of 3,000 therms, and explored two additional non-pipeline alternatives to the proposed high-pressure pipeline facility. NW Natural first evaluated the use of customer-specific, geographically-focused defined interruptibility agreements within the Southeast Eugene area of influence. After considering the number of larger non-Residential firm service customers and their usage with the load reduction necessary to defer construction of new infrastructure, NW Natural concluded customer-specific geographically focused defined interruptibility agreements are not a feasible solution.

Q. Based on the Company's IRP analysis, is the SE Eugene Project the least-cost, least-risk option to address the low pressures issues in the Southeast Eugene area?

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. Yes. As described in the Company's 2016 IRP, the SE Eugene Project is the least-cost, least-risk option to address the low pressures issues in the Southeast Eugene area. In the 2016 IRP proceeding, Staff agreed with NW Natural's analysis, and the Commission acknowledged NW Natural's action plan that included proceeding with the SE Eugene Project.[4]

Newport Refurbishment Project

Q. Please describe the Company's Newport LNG facility.

A. The Newport LNG facility is a peak shaving facility located in Newport, Oregon and consists of a 1,000,000 Dth capacity storage tank, liquefaction facilities capable of processing about 5,500 Dth/day, and vaporization capacity of up to 100,000 Dth/day. This facility was constructed by Chicago Bridge and Iron, and commissioned in 1977.[5]

Q. Please describe the Newport Refurbishment Project.

A. The Newport Refurbishment Project involves plant upgrades designed to extend the operating life of the Newport LNG facility by addressing significant issues with the Company's liquefaction process. The Newport Refurbishment Project activities include: construction and installation of the pretreatment system, liquefaction improvements, turbine modernization, vaporization replacement, and control building and system upgrades.

[4] Order No. 17-059, App. A at 9.

[5] Because the Company's pipeline system limits Newport to serving the central coast and Salem market areas, the full 100,000 Dth/day vaporization rate is not achievable. Instead, 60,000 Dth/day is the effective limit on vaporization at Newport.

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NW NATURAL
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Portland, Oregon 97209-3991
1-503-226-4211

Q. Why is the Newport Refurbishment Project needed?

A. The Newport LNG facility and major process components were designed for a nominal 25 to 30 year life, and the facility is now 40 years old. Due to the age of the facility and need for upgrades, the Newport LNG facility has been experiencing problems with the liquefaction process, including removal of carbon dioxide (CO_2) from the incoming natural gas stream, which has been very gradually collecting in the tank and settling on its floor in solid form (commonly known as "dry ice"). To address the dry ice issue, the Company has reduced the maximum quantity of LNG to be stored there from 1,000,000 Dth down to 900,000 Dth.

In 2012, the Company performed the Newport LNG Reliability Study, which was initiated to review all plant equipment and infrastructure at Newport and identify any issues that would affect safety, regulatory compliance, reliability, and productivity over the next 25 to 30 years. The study identified several projects that are collectively referred to as the Newport Refurbishment Project, which is designed to address the liquefaction process issues, and will enhance reliability, reduce maintenance cost, and extend the operational life expectancy an additional 25 to 30 years.

In addition, the study identified the existing control building as a risk due to proximity of plant operators to two potential hazards: (1) medium-voltage electrical switchgear and (2) the process building for liquefaction and vaporization. Moreover, the existing control building—originally commissioned

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Portland, Oregon 97209-3991
1-503-226-4211

when the plant was constructed in 1977, and now 40 years old—was deteriorating due to constant exposure to harsh conditions in the coastal environment, and needed siding and roofing work, as well as interior mechanical work.

Q. Please describe the pre-treatment system upgrade at the Newport LNG facility?

A. The Newport LNG Reliability Study examined multiple methods for addressing the dry ice issues in the Newport tank. In addition, due to the increased amount of shale gas being delivered to NW Natural, the natural gas has a higher content of CO_2. The selected solution was to install a new molecular sieve system for dehydration and CO_2 removal in the pre-treatment system. The new molecular sieve system replaced the existing CO_2 and dehydration systems at the plant and will result in a reduction of the amount of CO_2 present in the LNG in the storage tank by introducing CO_2-free LNG into the storage tank, which will cause the existing solid CO_2 to eventually dissolve away. The project also included a design, replacement, and/or upgrades of other components of the pretreatment system, including two compressors.

Q. Has the Company completed the replacement of the Newport Pre-Treatment Upgrade Project?

A. Yes. The Company finished the Newport Pre-Treatment Upgrade Project in July 2017. Commissioning and startup of the new system commenced in August 2017.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Q. What was the total cost for the Newport Pre-Treatment Upgrade Project?

A. The total actual cost associated with the Newport Pre-Treatment Upgrade Project was $13.0 million.

Q. Please describe the Turbine Modernization at the Newport LNG facility?

A. This project updated the existing Solar Turbine at the Newport LNG Plant, which is used to compress refrigerant as a part of the “Mixed Refrigerant Loop” process. There are five main systems which were updated: the wet seal system was upgraded to a dry seal system, the control system was updated with a modern version, the starter/fuel gas system was upgraded, the combustion air inlet was replaced, and the fire and gas detection/suppression systems were upgraded to meet current code. The compressor was overhauled to original factory specifications during the dry seal conversion.

Q. Why did the Company perform the Newport Turbine Modernization Project?

A. The Newport LNG Reliability Study identified the existing Solar Turbine as a key component of the liquefaction cycle, which is required to liquefy natural gas into LNG. The control system on the unit is classified by the vendor as “not supported/some limited support available,” and the computer running the system is an early 1990s vintage, with no spare parts available. Thus, the outdated control system presented a risk of failure that would prevent the Newport LNG facility from serving firm customer demand during a peak day event.

Q. Has the Company completed the Newport Turbine Modernization Project?

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. Yes. The Company finished the Newport Turbine Modernization Project in July 2017. Major work on the compressor was completed with the overhauled unit returned and on site construction complete in November 2015. Startup and commissioning coincided with completion of the Pre-Treatment System project, which was completed in July 2017. Final completion of the project occurred after the liquefaction season in December 2017.

Q. What was the total cost for the Newport Turbine Modernization Project?

A. The total actual cost associated with the Newport Turbine Modernization Project was $2.3 million.

Q. Please describe the Vaporizer H-1 project at the Newport LNG facility?

A. The Newport LNG Reliability Study identified that the Submerged Combustion Vaporizer (Vaporizer H-1) had reached its life expectancy. The overall scope of the project was to isolate the vaporization equipment, replace the mechanical components and burners on Vaporizer H-1, modify the building, replace the inlet/outlet piping and upgrade the controls to both vaporizers H-1 and H-2. The vaporizers are necessary for the plant to meet customer demand on a peak day.

Q. Has the Company completed the replacement of the Newport Vaporizer H-1 Project?

A. Yes. The Company finished the Newport Vaporizer H-1 Project in July 2017.

Q. What was the total cost for the Newport Vaporizer H-1 Project?

Rates & Regulatory Affairs
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Portland, Oregon 97209-3991
1-503-226-4211

A. The total actual cost associated with the Newport Vaporizer H-1 Project was $3.4 million.

Q. Are customers currently receiving benefits from the Pre-Treatment System Upgrade, Turbine Modernization Project, and the Newport Vaporizer H-1 Project?

A. Yes. Starting in August 2017, the Company used the new pre-treatment system and turbine at Newport to make an average of 71,000 gallons per day of LNG, for a total of 5.5 million gallons of LNG that the company will use during the winter of 2017-2018 to meet firm customer demand during a peak winter day event. The LNG generated during this time period had a significantly lower CO_2 content, which will start dissolving the existing solid CO_2, and lower the amount in the storage tank. The new Vaporizer H-1 was successfully tested in July 2017 and allows Newport to meet its supply requirements during the 2017-2018 heating season as a peak shaving LNG facility.

Q. Did the Company consider alternatives to these projects?

A. Yes, NW Natural evaluated potential alternatives in its 2014 IRP. The Newport LNG facility is specifically used for peak shaving, and NW Natural therefore requires high availability, reliability, and productivity from the facility. As a potential alternative to proceeding with the Newport Refurbishment Project, NW Natural considered keeping the facility operational until the Company could acquire an alternative supply source for 60,000 Dth/day firm peaking supplies. The Company evaluated two options for alternative supply: (1) contract with

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Portland, Oregon 97209-3991
1-503-226-4211

Northwest Pipeline (“NWP”) for additional pipeline capacity from Sumas south to city gates on NWP’s Grants Pass Lateral, or (2) construct a 25-mile high pressure transmission facility between Newberg and the Central Coast Feeder, coupled with additional Mist Recall.

Q. Were the alternative options less expensive than the Newport Refurbishment Project?

A. No, both alternative options were more expensive than the Newport Refurbishment Project. The first option would require contracting for pipeline capacity at a very high cost, which was estimated at twice the current NWP tariff rate, with the annual cost for 60,000 Dth/day of capacity estimated at $19.3 million. Additionally, the first option would require gate and distribution system upgrades at additional costs in order to integrate the additional capacity into NW Natural’s system. The second option is also more expensive than the Newport Refurbishment Project, with construction costs for 25 miles of a 16-inch high-pressure pipeline estimated at $54 million.

Q. Did the Company perform any modeling to determine whether the Company should pursue the Newport Refurbishment Project or the 25-mile high-pressure transmission pipeline?

A. Yes, NW Natural used the SENDOUT® optimization model to determine whether the Company should refurbish the Newport LNG facility or pursue development of the high pressure transmission facility. NW Natural’s analysis showed that the

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Newport Refurbishment Project was significantly less expensive than the high pressure transmission pipeline.

Q. Please describe the new control building at the Newport LNG facility.

A. The Company designed and completed construction of a new control building at the Newport LNG facility. The new control building is located farther away from potential hazards and electrical equipment. Additionally, the new control building is safer and more resilient, with modern seismic and blast designs.

Q. Did the Company consider any alternatives to constructing a new control building?

A. Yes, the Company considered remodeling the existing control building. The Company determined that performing a remodel of the existing control building would potentially be less expensive than constructing a new control building, but would not fully address the safety concerns regarding the proximity of plant operators to liquefaction and vaporization processes, would not provide blast resistance or seismic reinforcement, would be more disruptive to day-to-day operations, and would not provide as much space. Additionally, the Company considered the possibility of doing nothing, and continuing to use the existing control building as-is, but rejected this option due to safety concerns. After considering alternatives, the Company determined that building a new control building would best meet the Company's objectives from the Newport LNG Reliability Study.

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NW NATURAL
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Portland, Oregon 97209-3991
1-503-226-4211

Q. What is the status of the work on the new control building?

A. Work on the control building began in January 2016 and was completed in December 2016.

Q. What was the total cost for the new control building?

A. The total actual cost for the new control building was $3.1 million.

Q. Are customers currently receiving benefits from the new control building?

A. Yes. The new control building provides a blast-resistant, purpose-built control room for operators to manage the plant, and NW Natural's plant operators have been using the new control building since May 2017.

Q. Is the Company still using the previous control building?

A. Yes. The old control room components were removed, the interior was brought up to current fire code, and was modified to house updated medium- and low-voltage switchgear, the upgraded UPS system, and a new data within which to locate components of the updated Control System. The Company plans to make siding and roofing repairs in 2018.

Q. Please describe the reasons why the Company performed the plant control system upgrade at the Newport LNG facility and the work performed to upgrade the control system.

A. The Newport LNG Reliability Study identified risk attributable to the age of existing plant control system. Specifically, the study concluded that the control system was obsolete, and that the manufacturer of the system no longer provides support or replacement parts. The Company initiated a project to

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NW NATURAL
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Portland, Oregon 97209-3991
1-503-226-4211

replace the plant control system with a new model, which will allow the plant to continue operating for at least another 20 years. The antiquated system that plant operators previously used to monitor and control the system was made up of many disparate systems, each providing a single point of failure. The new control system unified these systems into a single system, and additionally facilitated the transition of the control from the old control room to the new control room. The new system also provides plant operators with new high-performance displays, which allow for increased visibility and easier recognition of plant operating conditions.

Q. Has the Company completed the Newport Plant Control System Project?

A. Yes. The Company has been using the new control system since May 2017 and finished the Newport Plant Control System Project in December 2017.

Q. What was the total cost for the Newport Plant Control System Project?

A. The total actual cost associated with the Newport Plant Control System Project was $3.2 million.

Q. Are customers currently receiving benefits from the Newport Plant Control System Project?

A. Yes. The new control system provides operators with a unified control system, which provides high-performance displays and better visualization of plant processes, allowing increased visibility and easier recognition of abnormal operating conditions. The new control system is modern and has built in

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

redundancy that reduces single points of failure. The Company's LNG plant operators have been using the new control system since May 2017.

Q. What was the estimated total capital cost of the investment in the Newport Refurbishment Project?

A. As described in the Company's 2014 IRP, the estimated capital cost of the Newport Refurbishment Project was approximately $25 million. The estimated costs were broken down by category: $8.0 million for Structures & Improvements; $0.9 million for Gas Holders; $8.9 million for Liquefaction Equipment; $4.4 million for Vaporizing Equipment; $0.3 million for Compressor Equipment; and $0.8 million for LNG Refueling Facilities.

Q. Does the Company have an updated estimate for the costs of the Newport Refurbishment Project?

A. Yes. Based on the construction completed to date and remaining work to be performed, NW Natural expects that the total capital cost of the Newport Refurbishment Project will be around $26 million.

Q. Overall, were the costs of completing the Newport Refurbishment Project reasonable?

A. Yes. The costs were in line with the estimates in the Newport Reliability study and provided to the Commission in the Company's 2014 IRP, which the Commission acknowledged in Order No. 15-064, Docket LC 60. The work performed will provide an additional 25-30 years of reliable service from the

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NW NATURAL
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Portland, Oregon 97209-3991
1-503-226-4211

Newport LNG facility that will allow the Company to meet firm customer demand on a peak winter day.

<u>Updates at Mist</u>

Q. Please describe the Company's recent study of its facility at the Mist gas storage site.

A. On June 10, 2016, the Company completed an engineering facility assessment of the Mist Storage Facility ("Mist Storage Facility Assessment") and identified a number of needed improvements to the facility to improve site reliability, resulting in the Mist Reliability Program. Some of the proposed upgrades will require significant capital expenditures while others are necessary to maintain normal operation as the facility ages. Without many of the suggested upgrades, Miller Station and the Mist Storage operation will likely experience equipment failures, increased O&M costs, cyber threats, and other risks over the next 25 years.

Q. Has the Company initiated any projects to address the recommendations in the Mist Storage Facility Assessment?

A. Yes. As described in greater detail below, the Company has initiated projects to replace the Mist control building and upgrade the instruments and controls in the control building.

Q. Please describe the Company's replacement of the control building at the Mist site ("Mist Control Building Project").

A. The Mist Control Building Project involves the design and construction of a new control building at Miller Station at the Mist Storage Facility. The new control

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

building consists of a control room for the operators to run and monitor the plant, as well as a data center to house all of the new equipment installed as part of the Mist instrument and controls replacement project, which is described in greater detail below.

Q. Why did the Company decide it was necessary to undertake the Mist Control Building Project?

A. The replacement of the Mist control building is part of the Mist Reliability Program. A new control building was required for the installation of the new controls system and data center. Since the storage facility needs to remain operational at all times, a new control system must be installed while the old system remains in place. The controls are then migrated to the new system and the old system is removed. The existing building did not have adequate room to house the old and new system at the same time.

Q. Has the Company completed the Mist Control Building Project?

A. Yes. The Company began work on the new control building in April 2017. The building was completed in September 2017 and the installation of security systems, installation of control equipment, and data center equipment will be completed by the end of 2017. However, the migration of the control system will not be completed until the spring plant shutdown which is scheduled for April 2018. The entire project is scheduled to be completed by May 2018.

Q. What was the total cost for the Mist Control Building Project?

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. The project was completed in early December and the Company is still determining total actual costs for the new control building. The most recent estimate for the costs of the project was $1.7 million.

Q. Is the new Mist control building being used at this time?

A. Yes. The data center portion of the building is operational at this time and the new control system equipment is also installed. However, as noted above, the control migration is scheduled for April 2018.

Q. Did the Company also upgrade the instruments and controls at the Mist facility?

A. Yes. Similar to the control system at the Newport LNG facility, the existing control system at Mist is beyond the end of its design life, and as of July 2017, the manufacturer no longer provides support or replacement parts. Whereas the existing system was made of disparate components, providing multiple points of failure, the new control system will provide a unified system and reduced risk of system failure. The new system will also provide operators with high-performance displays and a modernized console layout that will allow for increased visibility and easier recognition of abnormal operating conditions. The Company also upgraded information technology network security for the control systems and network communications to eliminate existing security deficiencies.

Q. Why did the Company undertake the Mist Instruments and Controls Project?

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. The Mist Instruments and Controls Project is part of the Mist Reliability Program, and will replace the existing obsolete plant control system at Miller Station with a new model designed to provide another 20 years of service. Operator controls will be updated to include new high-performance HMI systems with fewer failure points, better visualization of plant processes, and increased IT network security. Additionally a fiber optic network will be installed at the Flora and Bruer wells to eliminate issues with the existing radio communications at the wells and provide a redundant communications system.

Q. Did the Company consider alternatives to the Mist Instruments and Controls Project?

A. The Company considered continuing to operate the Mist Storage Facility without changes to the control room systems, but determined that this option presented significant risk of equipment failure due to the aged components. Additionally, because new parts are no longer available, repairs would be more difficult and it would likely take more time to source replacement parts. The outdated equipment also presented security and communications issues. The Company ultimately determined that it was necessary to replace the control equipment, and that continuing to operate with the existing control equipment could lead to prolonged outages of the Mist Storage Facility.

Q. What is the current status of the Mist Instruments and Controls Project?

A. The Company initiated the Mist Instruments and Controls Project in November 2016 with scheduled completion in May 2018.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Q. What was the total cost for the Mist Instruments and Controls Project?

A. The most recent estimate for the costs of the project is $3.4 million.

III. SAFETY-RELATED PROJECTS

Q. Is the Company planning safety-related projects?

A. Yes. NW Natural is currently in the planning stages for several safety-related projects. These projects are also discussed in the Company's 2017 Safety Project Plan, filed in docket UM 1900, and are planned to address compliance with new and updated PHMSA rules, and to address seismic risks.

Q. Please describe the anticipated updates to the PHMSA rules.

A. PHMSA has three significant open rulemaking proceedings that the Company is monitoring closely, as the rules adopted in these dockets will inform the Company's safety project priorities. First, in Docket No. PHMSA-2011-0023, PHMSA is undertaking a comprehensive update to the Transmission Integrity requirements. Major changes to the rules include increased requirements for high consequence areas ("HCAs") and in line inspection ("ILI"), material verification, and documentation retention requirements. The final rules in this proceeding are expected to be adopted in late 2018 or early 2019.

Second, in Docket No. PHMSA-2014-0098, PHMSA is proposing to require tracking and traceability for all new plastic pipe installation. Final rules in this proceeding are expected to be adopted in 2018.

Third, in Docket No. PHMSA-2016-0016, PHSMA issued an interim final rule in January 2017, incorporating by reference American Petroleum Institute's

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Recommended Practice 1171 (API RP 1171), which provides significant prescriptive requirements for underground storage operators, including creating a risk model, assessing the integrity of existing wells, and remediating any anomalies discovered to ensure well integrity. The final rule in this docket is expected in early 2018, and may include additional requirements or modify existing requirements from the interim rule.

Q. Please describe NW Natural's plans to address seismic risk.

A. The Company is planning to perform a comprehensive seismic assessment of its system. The seismic assessment will be used to identify, plan, and prioritize projects to address seismic resiliency.

Q. Why is NW Natural performing a seismic assessment?

A. In 2011, the Oregon legislature directed the Oregon Seismic Safety Policy Advisory Commission to prepare the Oregon Resiliency Plan ("ORP") with the purpose of identifying recommendations for how Oregon's critical infrastructure—including energy infrastructure—could be made seismically resilient towards a Cascadia subduction zone earthquake. Upon completion of the ORP, the Oregon legislature passed Senate Bill ("SB") 33, 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

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

recovery for prudent investments related to assessments and mitigation of vulnerabilities identified during those assessments.[6]

Q. Please describe the safety-related projects planned for 2018.

A. So far, the Company has planned for several major safety projects in 2018. These projects include ILI for the Central Coast Feeder, Santiam River Pipe Replacement, and Underground Storage Integrity. Additionally, NW Natural will begin implementation of a new Pipeline Safety Management System to address compliance with API RP 1173.

The ILI of the Central Coast Feeder is the modification of 93 miles of 10-inch and 12-inch pipe to allow for ILI or "pigging" of the pipeline. The Santiam River Pipe Replacement is a replacement of the 4-inch pipeline crossing on the Mill City feeder that was discovered to be exposed during an underwater inspection of the pipeline crossing. The Underground Storage Integrity project is the creation of an Integrity Management Program, including data collection, risk model, assessments, inspections, and remediation of the Company's wells at Miller Station.

Q. Is NW Natural considering any other safety projects?

A. Yes, NW Natural is in early planning stages for several other projects. NW Natural is developing a plan to begin to assess and implement actions to comply with the tracking and traceability portion of PHMSA's forthcoming Plastic Pipe

[6] http://www.oregon.gov/oem/Documents/2014_ORTF_report.pdf

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Rule. NW Natural is also evaluating the adoption of a program to proactively install excess flow valves ("EFVs"), and is considering implementing a pilot program for an EFV installation program in 2018.

Q. What are excess flow valves ("EFVs") and how do they work?

A. An EFV is a device installed in a service line near the point of connection to the gas main. EFVs will "trip" and stop the flow of gas if there is a full line failure, such as a damaged or severed service line.

Q. Why is the installation of EFVs important to increase safety?

A. In the event of a damaged or severed service line, EFVs are effective in mitigating the escape of gas.

Q. How does NW Natural currently approach installation of EFVs?

A. Consistent with federal pipeline safety requirements, NW Natural includes EFVs on all newly installed and fully replaced service lines to single family residences. In addition, we install EFVs on multifamily residences and small commercial customers served by a single service line with a known customer load not exceeding 5,000 SCFH (50 therms/hr). For customers with larger known loads, a shut-off valve, instead of an EFV, is installed on the service.

Q. What is the Company's policy with respect to EFV retrofits on existing service lines?

A. NW Natural provides notice to its customers of their right to request EFV installation, and they are currently installed at the requesting customer's cost.

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NW NATURAL
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Portland, Oregon 97209-3991
1-503-226-4211

The Company provides this notice to customers via its website, annual safety notifications, and new customer welcome packets.

Q. Is the Company prioritizing any particular areas for EFV retrofitting?

A. EFV retrofits will be prioritized by risk using the Distribution Integrity Management Program (DIMP) risk model. Factors that will be included in the DIMP risk model are population density, service size, service material, business districts and seismic data.

Q. Does the Company anticipate requesting cost recovery for EFV retrofitting?

A. Yes, we raise this issue now because we believe that the EFVs provide an important safety function to our customers and the surrounding areas. EFVs are described in the DIMP and provide a clear benefit. However, historically, retrofitted EFVs have not been recovered in base rates of our customers. The Company intends to develop a prioritization plan for retrofitting EFVs and seek inclusion of those costs in rates. We believe that this type of project is likely suitable for inclusion in an SCRM, as the Company plans out a multi-year retrofit strategy for the prioritized service lines. We look forward to working with the parties on this issue to continue our proactive approach to maintaining a safe distribution system.

Q. How does the Company plan to address cost recovery for these projects in the future?

A. Consistent with the Commission’s Order No. 17-084 in docket UM 1722, the Company plans to request a safety cost recovery mechanism (“SCRM”). Until

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

then, the Company will address cost recovery through general ratemaking proceedings.

Q. Why is the Company waiting until after the conclusion of this rate case to request an SCRM?

A. At this time, the Company is still in the planning stages for several of its safety-related projects. Additionally, the PHMSA dockets are not far enough along for the Company to fully estimate the costs associated with compliance of the new regulations. The Company will request authorization for an SCRM after the costs and timelines for developing all of these projects are more definite. Consistent with the SCRM guidelines adopted in Order No. 17-084, an SCRM may be established either in a general rate case or within three years of a general rate case.

Q. Will the Company provide additional information to the Commission about these safety-related projects as they move forward?

A. Yes, the Company will keep the Commission informed as the plans become more definite and NW Natural identifies a timeline for moving forward.

IV. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Direct Testimony of Kyle Walker

RATE ADJUSTMENT MECHANISMS
EXHIBIT 900

December 2017

EXHIBIT 900 – DIRECT TESTIMONY– RATE ADJUSTMENT MECHANISMS

Table of Contents

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Kyle Walker. I am a Senior Rates/Regulatory Analyst in the Rates and Regulatory Affairs Department of NW Natural. I have worked at NW Natural since February 2015. My responsibilities include rate setting, regulatory accounting liaison, development of regulatory reports and rate filings, research relevant to gas rates and regulatory mechanisms, and analysis of gas costs, regulatory deferrals, adjustment mechanisms, and rate base issues.

Q. Please describe your education and employment background.

A. I hold a Bachelor of Science in Business Administration, emphasis in Finance, from Oregon State University and a Masters of Business Administration from Willamette University. I have also obtained an accounting certificate from the University of Washington and am currently licensed as a certified public accountant in the state of Oregon.

Prior to working with NW Natural, I worked for five years in various capacities at the Bonneville Power Administration, including Finance Analyst, Derivative Accountant, Internal Auditor and Risk Management Analyst. I also have experience working as a Financial Analyst at Wells Fargo and Tax Preparer at a small CPA firm.

Q. Please summarize your testimony.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. My testimony covers two main topics: NW Natural's Decoupling mechanism and the Weather Adjustment Rate Mechanism (WARM). I start with describing the history of, and principles underlying the Decoupling and WARM mechanisms. I then describe the current form and impacts of the Decoupling and WARM mechanisms, and propose the following modifications to these mechanisms, summarized below:

- A decoupling weather adjustment methodology change to WARM therms, which replaces the current weather adjustment for all customers in WARM rate schedules, including those customers who are opted out of WARM;
- Inclusion of large commercial firm sales customers in the Decoupling mechanism;
- Creation of four separate groups, or customer classes for the Decoupling mechanism;
- An update of the Decoupling use-per-customer; and
- An update of the WARM normal heating degree days and WARM and Decoupling statistical coefficients.

I then describe the overall impacts to the two mechanisms discussed.

II. <u>DESCRIPTION OF DECOUPLING AND WARM MECHANISMS</u>

Q. Please provide some background information on NW Natural's Decoupling mechanism, and its relation to energy efficiency.

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A. NW Natural's Decoupling mechanism was put in place in 2002. The Decoupling mechanism removes the link between customer usage of natural gas and NW Natural's revenues across specific rate schedules. Under Decoupling, NW Natural is made financially indifferent to the consumption patterns and energy efficiency adoption of its residential and small- to mid-sized commercial customers.

The Decoupling mechanism is important because it essentially allows NW Natural to support increased energy efficiency by allowing it to avoid the negative financial consequences that would otherwise occur as customers reduce their natural gas consumption.

Since Decoupling's inception in 2002[1], NW Natural has collected a public purpose charge from decoupled rate classes to provide funding for enhanced energy efficiency programs developed and administered by the Energy Trust, as well as low-income energy efficiency activities, and low-income bill payment assistance.

NW Natural believes that the Decoupling mechanism serves a very important function, desires to keep the mechanism, and is committed to continuing its strong support of energy efficiency measures related to natural gas usage.

Q. What customers are currently covered by NW Natural's Decoupling mechanism?

[1] Order No. 02-634

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A. The current Decoupling mechanism applies to residential, small commercial and mid-sized commercial firm sales customers taking service under rate schedules 2, 3 and 31, respectively.

Q. Will you describe the calculations that take place under the current Decoupling mechanism?

A. Yes, the monthly Decoupling calculation starts by determining the actual customer counts and usage for each customer class. Customer counts and usage are identified during the closing process that occurs for NW Natural each month. Counts and usage are determined by customer class and broken down into eight separate weather zones across Oregon.

Next, a weather adjustment is added or subtracted (depending on if weather was warmer or colder than normal) from the actual usage, resulting in an adjusted usage figure that represents usage under normal weather.[2] Last, the baseline usage[3] multiplied by the actual customer counts per class is subtracted from the total weather adjusted therms for the month, by customer class, to determine the non-weather therm variance for the month. The non-weather

[2] The Decoupling weather adjustment uses the same normal degree days (25-year daily average) and statistical usage coefficients as the WARM program. For the shoulder months of November and May, the weather adjustment simply takes the WARM mechanism's calculated therms as the weather adjustment. In the months of December through April, the weather adjustment calculation is done in full, and is therefore identical to the WARM mechanism, except that it includes opt-outs. In colder than normal months, the weather adjustment will reduce therms. In warmer than normal months, the weather adjustment will increase therms.

[3] Baseline usage is the use per customer used in rate spread calculations in rate cases.

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therms are then multiplied by the customer class margin rate to derive the Decoupling revenue. This Decoupling revenue represents the amount of revenues that are lost (or gained) from variations in usage per customer, for reasons other than weather. For an example of the Decoupling calculation, please see *NW Natural/901, Walker/1-3.*

Q. Please describe the WARM mechanism.

A. The WARM mechanism was approved by the Commission at the same time as the Decoupling mechanism, in NW Natural's 2002 general rate case (UG 152).[4] The original approval of the program identified the goal of the mechanism as to modify the rate structure on customer bills to recognize the need to separately identify and collect the revenues to cover the Company's embedded fixed costs from the revenues which cover the truly variable-related costs, and to do so in a way that immediately benefits both customers and NW Natural.[5] Specifically, it adjusts customers' bills to reflect changes in usage caused by weather, so that NW Natural does not over-collect its fixed costs when weather is colder than normal, and so that it does not under-collect its fixed costs when weather is warmer than normal.

The WARM mechanism is, in a way, a form of decoupling. Rather than mitigating variations in NW Natural's revenues that come from energy

[4] Order 03-507.

[5] *Id* at 7.

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1-503-226-4211

efficiency, it instead mitigates variations in NW Natural's revenues that come from weather.

Q. What is the impact of WARM on individual customers, and on NW Natural?

A. The WARM program helps even out customer bills when weather deviates from normal. It does this by adjusting bills for variations in customers' usage, by billing cycle, that are caused strictly by weather.

From the Company's perspective, WARM helps mitigate the variations in revenues that otherwise occur because of variations in weather. As a business that delivers natural gas to customers that primarily use it for space heating, sales are greatly affected by a warmer- or colder-than-normal winter. This variation in revenues brings a risk of over- or under-collections of the fixed costs that NW Natural's volumetric rates are designed to recover during a normal weather year.

The WARM program thus benefits NW Natural as well its customers. In adopting the WARM mechanism, the Commission noted these benefits, finding:

> We believe that the Company's WARM plan, with the agreed-upon conditions contained in the WARM Stipulation, reduces the weather-related financial risks for both customers and Company alike. We therefore approve the WARM Stipulation as being in the public interest.[6]

Q. During which months does WARM operate?

[6] Order 03-507, p.7.

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A. WARM operates during December 1 through May 15th (the “WARM Period”).

Q. What customers are covered by NW Natural’s WARM program?

A. The WARM program applies to residential and small commercial customers taking service under Rate Schedules 2 or 3, respectively.

Q. Are customers required to participate in the WARM program?

A. No. As currently structured, WARM is an optional program, and customers are not required to participate. Instead, customers are enrolled in the program unless they “opt out.”

Q. Why was the program structured as an “opt out” program?

A. The degree to which the WARM Program is successful is dependent on customer participation in the program because the objective of WARM is to capture the effects of weather variability on NW Natural’s customers’ usage. For that reason, the Parties agreed to make the WARM Program an “opt-out” program, meaning customers in the applicable rate schedules are automatically enrolled unless, and until, they affirmatively opt-out of the program. This approach helped ensure robust participation in the program, but also gave customers a choice about participation.

Q. What percentage of customers participate in NW Natural’s WARM program?

A. WARM enrollments at the end of the 2016-17 WARM season were 91.4 percent of residential and 88.0 percent of small commercial.

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Q. Can you briefly describe the investigation into WARM following the 2014-2015 winter heating season?

A. Yes, in 2015, the Commission opened an investigative docket (UM 1750) after the Commission Staff received a number of customer complaints about WARM. The Commission opened up the investigation to examine:

- NW Natural's calculation of the WARM Adjustment;
- The factors that led to a high volume of complaints related to the 2014-15 winter heating season, and which of the factors were common to all the complaints; and
- Whether there were targeted and appropriate modifications to WARM that could adequately address the issues raised in the complaints.[7]

Q. What was the outcome of the Commission's investigation into the WARM mechanism?

A. NW Natural, Commission Staff, and CUB (collectively, the "Parties") worked together in 2015-2016 to address the issues identified for investigation by the Commission. After a thorough investigation, the Parties determined that NW Natural correctly calculated the WARM adjustment during the 2014-2015 winter heating season.

To address the higher volume of complaints, the Parties recommended that the caps and floors, which limit the effect of WARM on customers' bills in any

[7] Order 15-264, Appendix A, p. 2.

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given month, be made symmetrical in warmer and colder weather and that WARM adjustments outside the caps and floors would be deferred and either credited or surcharged to customers, coincident with the following year's purchase gas adjustment (PGA).[8] The deferred amounts would get allocated to all customers who belong to the rate schedules within the WARM program. Under the Parties' recommendations, all other aspects of WARM would continue to operate as they had previously.

The Commission adopted the Parties' recommended modifications to the WARM program, in Order No. 16-223. Those changes were implemented beginning in the 2016-17 heating season.

Q. Can you provide a more detailed demonstration of the calculation of the current WARM adjustment?

For an example of the WARM adjustment calculation, please see *NW Natural/902, Walker/1*.

III. PROPOSED DECOUPLING AND WARM MECHANISM MODIFICATIONS

Q. Can you please describe how Decoupling and WARM work together?

A. Each mechanism removes the link between variations in usage, and the ability to collect the Company's revenues for which rates were designed. Specifically,

[8] For residential bills, the maximum WARM adjustment (increase or decrease) that is made to any regular monthly bill during the WARM period is $12 dollars, or 25 percent of the usage portion of that bill, whichever is less. For commercial customers, the maximum WARM adjustment (increase or decrease) that is added to any regular monthly bill during the WARM period is $35 dollars, or 25 percent of the usage portion of that bill, whichever is less.

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WARM removes the link between weather variation and revenues, and Decoupling removes the link between non-weather variations and revenues. Together, they create essentially a full decoupling mechanism. The limitation on this, however, is that to the extent customers have opted out of WARM, the mechanisms do not provide for full decoupling.

Q. You stated earlier in your testimony that NW Natural is proposing some changes to the Decoupling and WARM mechanisms. Has NW Natural's support for the mechanisms changed?

A. No. NW Natural strongly supports and appreciates the mechanisms and the benefits that they provide to customers and the Company. All of our proposed changes to these mechanisms are meant to improve them.

Q. Please summarize the modifications that NW Natural is seeking.

A. NW Natural is proposing three non-routine modifications to the Decoupling mechanism.

Specifically, NW Natural proposes:

- to modify the Decoupling mechanism to capture weather variations for customers that have opted out of WARM,,
- to add large commercial customer rate schedules to the list of those to whom the Decoupling mechanism applies, and
- create four groups of decoupled customer classes, designated by rate schedule, to better align customer characteristics within each class.

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Additionally, as is routine, NW Natural proposes to update the baseline use-per-customer data in the Decoupling calculation to reflect usage in the test year.

<u>A. Changes to Weather-Normalization Calculation in Decoupling</u>

Q. Why are you proposing a change to the weather-normalizing calculations in Decoupling?

A. NW Natural is proposing a change because the current Decoupling mechanism presumes that all of our residential and small commercial customers in decoupled rate classes participate in the WARM program, which means that Decoupling is using weather-adjusted therms for all customers in decoupled rate classes, even if they have opted out of WARM. Generally, all of our decoupled rate classes are fully decoupled from mid-May to November, meaning any variation in usage (including from weather) from our established baselines will be either credited back or surcharged to customers through the Decoupling mechanism. However, during the WARM Period (December through mid-May), for customers who have opted out of WARM, and therefore, are not receiving the real time WARM adjustment on their bills, the Decoupling mechanism is weather-normalizing the opt-out customers, meaning the Company is not decoupled from opt-out customer usage, driven by weather, during this period. Consistent with the purposes of the WARM program, the Company wants to modify the mechanism to ensure that we do not over-or-under recover for our fixed costs based on weather variation for customers who have opted out of WARM.

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Q. What is NW Natural's proposal to improve the weather-normalization calculation in Decoupling?

A. The Company's proposal will weather-normalize the usage for only WARM opted-in customers, rather than for all customers (including opt-outs)[9]. In other words, we are proposing to fully decouple all customers, in all months, that are in the decoupled rate schedules, without making any changes to the WARM program. The current and proposed weather-normalization calculations are shown in *NW Natural/901, Walker/1-3*.

Q. What is the impact of NW Natural's proposed modification to the weather-normalizing calculations in Decoupling?

A. Under NW Natural's proposal, full decoupling would be achieved through the joint operation of the WARM mechanism and the Decoupling mechanism, similar to the result of Avista's and Cascade's decoupling program. Under the proposed modifications, NW Natural's WARM mechanism would continue to provide a decoupling of revenues (and also rate stability for customers) for variations in usage caused by weather. Additionally, the Decoupling mechanism would also continue to provide a decoupling of revenues for variations in non-weather related usage for customers enrolled in WARM. Under the proposed modification, the Decoupling mechanism would decouple revenues for all

[9] This calculation can be performed by taking the WARM revenues accounted for in a month and dividing it by the margin rate to get weather-driven therms. This calculation is currently performed to obtain the Decoupling weather normalization adjustment in November and May.

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variations in usage for customers opted out of WARM, and therefore, between the two mechanisms, result in creating a full decoupling mechanism for residential and small commercial customers, regardless of their participation in the WARM program.

Q. Would NW Natural's proposal be expected to increase NW Natural's revenues?

A. No. NW Natural's proposal would, on an expected basis, neither increase nor decrease its revenues. Instead, it would stabilize the Company's revenues and ensure fixed cost recovery.

Q. What would be the effect on customers of NW Natural's proposed change?

A. If weather was normal in a given year, there would be no impact to customers compared to the current methodology. If weather was colder-than-normal, the amount of margin that NW Natural gains due to the fact that some of its customers are opted out of WARM would be deferred and credited to all customers through the Decoupling mechanism. If weather was warmer-than-normal, the amount of margin that NW Natural under-recovers due to the fact that some of its customers are opted out of WARM would be deferred and collected from all customers through the Decoupling mechanism.

Q. Would the net effect of NW Natural's proposal be that the Company's revenues are fully decoupled?

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A. Yes, but only with respect to the revenues that come from the rate schedules that are included in the Decoupling mechanism.

B. Rate Schedules to Which Decoupling Applies

Q. What rate schedules and customer groups are you proposing to include under the modified Decoupling mechanism?

A. NW Natural proposes four groups, or rate classes:

- Group 1 – Residential (Rate Schedule 2)
- Group 2 – Small Commercial (Rate Schedule 3)
- Group 3 – Mid-sized Commercial (Rate Schedule 31 commercial firm sales)
- Group 4 – Large Commercial (Rate Schedule 32 commercial firm sales)

Q. Why does NW Natural propose to add large commercial customer rate schedules (Group 4) to the list of schedules to which Decoupling applies?

A. Currently, large commercial customers are not covered under Decoupling, despite the fact that they participate in a robust energy efficiency program. Also, their usage tends to vary significantly with changes in weather. We note that the exclusion of large commercial customers from Decoupling is unique to NW Natural, as these customers are included under Avista's and Cascade's decoupling mechanisms.

As currently structured, this means that to the extent these customers'

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1-503-226-4211

usage varies because of energy efficiency measures, or weather, NW Natural experiences volatile revenues. This is contrary to the stated purpose of the Decoupling mechanism, which is to remove the disincentive companies may have toward achieving conservation and to recover NW Natural's fixed costs.

NW Natural supports energy efficiency among all customer classes. We also believe, however, that it would be good policy to ensure that classes of customers for which there is a robust energy efficiency program be included in the Decoupling mechanism.

Q. Please describe the energy efficiency program for large commercial customers?

A. The Energy Trust of Oregon administers NW Natural's Industrial Demand Side Management (DSM) Program, which includes all industrial sales and large commercial sales customers. The Industrial DSM program is intended to provide an economical and effective means of conserving natural gas through the reduction of heat loss in certain commercial and industrial buildings. The Industrial DSM program provides similar energy efficiency incentives as the public purpose charge for smaller residential and commercial customers. Industrial DSM funding dollars and therm savings for the time period of 2012-2019 are below:

	2012	2013	2014	2015	2016	2017*	2018*	2019*
Industrial DSM Funding	$ 1,832,967.60	$ 2,046,619.30	$ 1,729,066.33	$ 1,985,884.46	$ 3,220,644.49	$ 3,603,198.00	$ 4,565,123.40	$ 6,586,393.00
Therm Savings*	991,798	1,070,008	1,245,758	1,800,670	1,844,324	1,964,268	2,216,001	2,216,001

** Forecast*

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Q. Do large commercial customers' usage tend to vary with weather?

A. Yes. A schedule-by-schedule regression analysis shows that commercial schedules 31 and 32 sales customers have a heat response (usage response to cold weather) that is larger than NW Natural realized, creating billing and revenue volatility for customers and the Company. Due to the swings in usage around weather, and without the Decoupling mechanism applied to these schedules, NW Natural fails to collect its fixed costs in years that are warmer than normal, and over-collects in years that are colder than normal. Full decoupling for these schedules will put them in the same position as smaller customers, albeit without the real-time billing effect produced by WARM.

The below table shows the heat-responsiveness of Large Commercial customers, compared to the other customer groups that are currently in WARM, and shows that they also have a significant heat response.

Rate Class	Annual Base Use	Annual Heat Use	Total Annual Use Per Customer	Heat over Total Usage
Residential (Group 1)	184.1	451.6	635.7	71.0%
Small Commercial (Group 2)	1,094.7	1,758.2	2,852.9	61.6%
Mid-sized Commercial (Group 3)	17,414.5	17,030.7	34,445.2	49.4%
Large Commercial (Group 4)	54,889.4	35,747.7	90,637.1	39.4%

Q. Has the Company proposed tariff sheets that show its requested modifications to the Decoupling mechanism?

A. Yes. The proposed tariff sheets for the Decoupling mechanism are found in *NW Natural/903, Walker/1-3*.

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NW NATURAL
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Portland, Oregon 97209-3991
1-503-226-4211

<u>C. Update of Use-Per-Customer</u>

Q. Please describe the routine update to use-per-customer data in decoupling that you mentioned earlier in your testimony.

A. Because the Decoupling mechanism calculates lost margin due to declining use per customer (or increased margin due to increasing use per customer), it is important to reset the baseline data for what use-per-customer is in the Test Year. This update is critical to ensure that decoupling adjusts margin to the amount determined in the rate case for each customer class. *NW Natural/905, Walker/1* displays the results for updated use per customer that NW Natural proposes to use for the Decoupling mechanism and this is further explained in *NW Natural/200, McVay*. This matches the amount used by NW Natural witness Andrew Speer in setting the rates calculated to achieve the Company's authorized revenue requirement.

Q. Does NW Natural propose any modifications to the WARM program?

A. As explained above, NW Natural proposes to keep the WARM program, and to only modify the Decoupling mechanism to mitigate the revenue instability that is caused from the opt-out provisions of WARM. However, as is routine, NW Natural proposes an update of normal heating degree days (May 31, 1992 through May 31, 2017) to capture historical weather from the last rate case and statistical coefficients to capture usage patterns and characteristics. NW Natural does not propose any methodology changes to the WARM mechanism.

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Portland, Oregon 97209-3991
1-503-226-4211

Q. Has NW Natural provided proposed tariff sheets to reflect the updates to WARM?

A. Yes. The proposed Tariff sheets related to WARM are in *NW Natural/906, Walker/1-6*.

Q. What substantive changes are being made to the WARM tariff?

A. No substantive changes are being made to the WARM tariff. Changes to the tariff include only language that would provide customers more clarity without making any changes to how the mechanism works.

IV. COMPARISON TO OTHER NATURAL GAS UTILITIES IN OREGON

Q. Are the customers classes proposed to be covered by your recommended changes to Decoupling similar to those covered by Avista's and Cascade's Decoupling programs?

A. NW Natural is proposing customer groups, or classes, that are different from that of Avista, but the same as Cascade. Avista includes not only large commercial, but industrial sales and transportation customers as well. Cascade includes all residential and commercial firm sales customers.

Q. Can you please explain why the grouping approach you proposed for Decoupling is reasonable?

A. We feel that our grouping approach is a reasonable method through which to apply the decoupling calculation because it allows Rate Schedule 3 to stand alone, as it will have a weather adjustment due to it being included in WARM,

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and keep other commercial customers separate, as they have different usage characteristics.

Q. If NW Natural's proposed modifications were adopted, does that mean that its revenues would be decoupled similarly to Avista's and Cascade's?

A. With the proposed modifications, NW Natural would have a similar result from revenue decoupling as Cascade, but would have less revenue stability than Avista due to fewer schedules being decoupled. For residential and small commercial customers, we would achieve revenue decoupling simply in a different way, because we use two mechanisms – Decoupling and WARM.

Q. Would it be simpler for NW Natural to achieve full decoupling by adopting the approach approved for Cascade and Avista?

A. Yes, that approach would be simpler. However, NW Natural believes that the WARM program, despite its complexity, does provide a benefit to customers by providing a real-time bill adjustment during the winter heating season, which is not available through the Decoupling mechanism alone. In order to keep this benefit, NW Natural is proposing to retain both WARM and Decoupling, but to make the proposed changes to Decoupling so that the Company can achieve the same rate stability and fixed cost recovery available to other natural gas utilities in Oregon through their approved Decoupling mechanisms.

Q. Would NW Natural consider eliminating the WARM program in favor of a single Decoupling mechanism that fully decouples rates?

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1-503-226-4211

A. Yes, if the Commission or Parties would rather NW Natural move to a full stand-alone Decoupling mechanism without the WARM program, the Company would consider removing WARM. However, from the WARM investigation, NW Natural's understanding is that Staff and CUB may also see benefits to the continued application of the WARM program. NW Natural is satisfied that it can both 1) achieve full revenue decoupling for the rate schedules to which Decoupling applies, and 2) retain a weather-related real-time billing adjustment mechanism.

NW Natural does note that in the future, when it replaces its Customer Information System (the IT system that supports customer billing and adjustments), there will be incremental cost to accommodate the WARM program, given the additional programming that would be required to integrate this unique program into the new system. NW Natural therefore proposes that it work with stakeholders and the Commission in the future to determine if those costs should be incurred or, alternatively, the WARM program should be revisited at that time in order to reduce costs of that system for customers.

Q. Does this conclude your testimony?

A. Yes.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Exhibits of Kyle Walker

RATE ADJUSTMENT MECHANISMS
EXHIBITS 901 - 906

December 2017

EXHIBITS 901 – 906 – RATE ADJUSTMENT MECHANISMS

Table of Contents

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

NW Natural
NWN 901
Example of Current Monthly Decoupling Calculation for February

1	**Total Customer Counts by Schedule:**	
2	Schedule 2 - Residential	587,228
3	Schedule 3 & 31- Commercial	58,445
4		
5	**Actual Therm Usage by Schedule:**	
6	Schedule 2 - Residential	67,187,973
7	Schedule 3 & 31- Commercial	33,050,311
8		
9	**Schedule 2 Customer Counts by Weather Zone:**	
10	Albany	37,471
11	Astoria	11,497
12	Coos Bay	1,353
13	Eugene	35,842
14	Lincoln City	9,343
15	Portland	402,344
16	Salem	84,565
17	The Dalles	4,813
18		
19	**Schedule 3 Customer Counts by Weather Zone:**	
20	Albany	4,005
21	Astoria	1,664
22	Coos Bay	356
23	Eugene	5,323
24	Lincoln City	1,239
25	Portland	36,100
26	Salem	8,658
27	The Dalles	1,100
28		
29	**WEATHER ADJUSTMNET:**	
30		
31	**Schedule 2 Normal Degree Days by Weather Zone:**	
32	Albany	424.3
33	Astoria	411.5
34	Coos Bay	323.0
35	Eugene	447.9
36	Lincoln City	319.9
37	Portland	432.9
38	Salem	446.1
39	The Dalles	544.0
40		
41	**Schedule 3 Normal Degree Days by Weather Zone:**	
42	Albany	396.4
43	Astoria	383.6
44	Coos Bay	295.7
45	Eugene	420.0
46	Lincoln City	292.6
47	Portland	404.9
48	Salem	418.1
49	The Dalles	516.0
50		
51	**Schedule 2 Actual Degree Days by Weather Zone:**	
52	Albany	437.0
53	Astoria	456.0
54	Coos Bay	336.0
55	Eugene	448.5
56	Lincoln City	423.5
57	Portland	515.5
58	Salem	451.0
59	The Dalles	672.0
60		
61	**Schedule 3 Actual Degree Days by Weather Zone:**	
62	Albany	410.0
63	Astoria	428.0
64	Coos Bay	308.0
65	Eugene	420.5
66	Lincoln City	395.5
67	Portland	487.5
68	Salem	423.0
69	The Dalles	644.0

Schedule 2 Degree Day Variance by Weather Zone:

Albany	-12.7
Astoria	-44.5
Coos Bay	-13.0
Eugene	-0.6
Lincoln City	-103.6
Portland	-82.6
Salem	-4.9
The Dalles	-128.0

Schedule 3 Degree Day Variance by Weather Zone:

Albany	-13.6
Astoria	-44.4
Coos Bay	-12.3
Eugene	-0.5
Lincoln City	-102.9
Portland	-82.6
Salem	-4.9
The Dalles	-128.0

Statistical Coefficient	
Schedule 2:	Schedule 3:
0.16471	0.85441

Schedule 2 Therm Adjustment by Weather Zone:

Albany	(78,382)
Astoria	(84,268)
Coos Bay	(2,897)
Eugene	(3,542)
Lincoln City	(159,429)
Portland	(5,473,909)
Salem	(68,251)
The Dalles	(101,472)
TOTAL	(5,972,150)

Schedule 3 Therm Adjustment by Weather Zone:

Albany	(46,538)
Astoria	(63,125)
Coos Bay	(3,741)
Eugene	(2,274)
Lincoln City	(108,931)
Portland	(2,547,731)
Salem	(36,248)
The Dalles	(120,301)
TOTAL	(2,928,889)

Schedule 2 Total Normalized Therms:	**61,215,823**
Schedule 3 Total Normalized Therms:	**30,121,422**

DECOUPLING REVENUE CALCULATION:

	Baseline Use Per Customer	Actual Customer Count	Baseline Total Usage	Normalized Therms (Actual for Large Comm.)	Variance	Margin Rate Per Therm	Decoupling Revenue to Defer
Schedule 2 - Residential	85.0	587,228	49,914,380	61,215,823	(11,301,443)	$ 0.44470	$ (5,025,752)
Schedule 3 & 31 - Small Commercial	474.0	58,445	27,702,930	30,121,422	(2,418,492)	$ 0.33079	$ (800,013)

NW Natural
NWN 901
Example of Proposed Monthly Decoupling Calculation for February

1	**Total Customer Counts by Schedule:**	
2	Schedule 2 - Group 1	587,228
3	Schedule 3 - Group 2	57,679
4	Schedule 31 - Group 3	766
	Schedule 32 - Group 4	416
5		
6	**Actual Therm Usage by Schedule:**	
7	Schedule 2 - Group 1	67,187,973
8	Schedule 3 - Group 2	28,749,867
9	Schedule 31 - Group 3	4,300,444
	Schedule 32 - Group 4	5,450,818
10		
11	**WEATHER ADJUSTMNET:**	
12		
13	**Schedule 2 WARM Therms Billed:**	
14	WARM Therms Billed	(5,629,706)
15		
16	**Schedule 3 WARM Therms Billed:**	
17	WARM Therms Billed	(2,860,128)
18		
19		
20	**Schedule 2 Total Normalized Therms:**	**61,558,267**
21		
22		
23	**Schedule 3 Total Normalized Therms:**	**25,889,739**
24		
25		
26	**DECOUPLING REVENUE CALCULATION:**	
27		

28		Baseline Use Per Customer	Actual Customer Count	Baseline Total Usage	Normalized or Actual Therms (Actual Groups 3/4)	Variance	Margin Rate Per Therm	Decoupling Revenue to Defer
29	Schedule 2 - Group 1	84.7	587,228	49,738,212	61,558,267	(11,820,055)	$ 0.53574	$ (6,332,476)
30	Schedule 3 - Group 2	360.6	57,679	20,797,317	25,889,739	(5,092,422)	$ 0.41875	$ (2,132,452)
31	Schedule 31 - Group 3	4,120.1	766	3,155,966	4,300,444	(1,144,478)	$ 0.25416	$ (290,881)
	Schedule 32 - Group 4	10,146.3	416	4,220,844	5,450,818	(1,229,974)	$ 0.12781	$ (157,203)

NW Natural
NWN 902
Example of Monthly WARM Adjustment Calculation

Here is how the WARM adjustment is calculated for a residential Rate Schedule 2 customer where the billing rate is $0.83850 cents per therm, the HDD variance is 50 HDDs colder than normal, and the monthly therm usage is 129.

HDD Differential:	Normal HDDs:	600	HDDs
	Actual HDDs:	650	HDDs
	HDD variance:	600 – 650 =	-50
Equivalent Therms:	HDD variance:	-50	HDDs
	Statistical coefficient:	0.163268	
	Equivalent therms:	-50 x 0.163268 =	-8.1634
Total Warm Adjustment:	Equivalent therms:	-8.1634	therms
	Margin Rate:	$0.53574	
	Total WARM Adj.:	-8.2355 x $0.53574 =	($4.37)
Total WARM Adjustment converted to cents per therm:	Total WARM Adj.	($4.37)	
	Monthly usage:	129	therms
	Cent/therm Adj.:	($4.37)/ 129 =	($0.03388)
Billing Rate per therm:	Current Rate/therm:	$0.83850	
	WARM cent/therm Adj.:	($0.03388)	
	WARM Billing Rate:	$0.83850 + ($0.03388)=	$0.80462
Total WARM Bill:	Customer Charge:	$8.00	
	Usage Charge:	$0.80462	
	Total	(129 x $0.80432) + $8.00 =	$111.80

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Seventh Revision of Sheet 190-1
Cancels Sixth Revision of Sheet 190-1

SCHEDULE 190
DECOUPLING MECHANISM

(C)

PURPOSE:

To describe the calculations used to adjust customer rates under the decoupling mechanism implemented under the authority of ORS. 757.262, and to identify the temporary adjustments applicable to the Rate Schedules listed below under the authority of ORS 757.259, OAR 860-022-0070, and OAR 860-027-300.

DESCRIPTION:

The decoupling mechanism is used to account for under- and over- collections of NW Natural's authorized revenue requirement that result from changes in customer usage due to energy conservation efforts by customers, and for changes in usage due to weather for customers served under a Rate Schedule that is not eligible for the WARM Program under Schedule 195. This Schedule is an "automatic adjustment clause" as defined in ORS 757.210, and is subject to review by the Commission at least once every two years.

The temporary adjustments to rates stated in this Schedule 190 reflect the amortization of deferred balances as of June 30 associated with the Schedule 190 Decoupling Mechanism as authorized by the Commission in Docket UM 1027. All adjustment amounts are in effect for a 12-month period commencing with the stated effective date, or for such other period approved by the Commission. (C)

REGULATORY HISTORY: (N)

Docket UG 143. Commission Order 02-634
Docket UG 163. Commission Order 05-934; 07-426
Docket UG 221. Commission Orders 12-408 and 12-437

DEFINITIONS:

Except as otherwise provided for below, the terms used in this Schedule are defined in the Definitions section of the Tariff of which this Schedule is a part.

Baseline Usage is the average use per customer for each respective rate group. It was established in the Company's most recent prior rate case.

Decoupling means a regulatory mechanism designed to break the link between a utility's earnings and the usage of its customers.

Distribution margin is the amount of revenue per therm needed to cover the cost of service.

Weather-Normalized means adjusting actual usage to remove the effects of weather as calculated in the WARM Program (Schedule 195). (N)

(continue to Sheet 190-2)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Sixth Revision of Sheet 190-2
Cancels Fifth Revision of Sheet 190-2

SCHEDULE 190
DECOUPLING MECHANISM
(continued)

APPLICABLE:
To Sales Service Customers taking service under the following Rate Schedules of this Tariff: (C)

Residential	Commercial
Group 1: Rate Schedule 2	Group 2: Rate Schedule 3 CSF
	Group 3: Rate Schedule 31 CSF
	Group 4: Rate Schedule 32 CSF

RATE ADJUSTMENTS: Effective: November 1, 2018
The adjustments listed below are included in the Billing Rate stated on the respective Rate Schedules. No further adjustment to rates is required.

Group 1: Residential Schedule 2:	$0.xxxxx
Group 2: Commercial Schedule 3CSF:	$0.xxxxx
Group 3: Commercial Schedule 31CFS:	$0.xxxxx
Group 4: Commercial Schedule 32CFS:	$0.xxxxx

TERMS AND CONDITIONS:

1. **PARTIAL DECOUPLING CALCULATION (Rate Schedules 2 and 3 CSF):**

1.1. Each month, the Company will calculate the difference between Weather-Normalized usage and the calculated Baseline Usage for Residential Schedule 2 and Commercial Schedule 3 Customers, respectively. The resulting usage differential shall be multiplied by the per-therm Distribution Margin for the applicable Rate Schedule.

1.2. The Baseline Usage per-customer-per-year is:

Group 1: Residential Rate Schedule 2:	636
Group 2: Commercial Rate Schedule 3CSF:	2,853

1.3. Partial decoupled schedules are Weather Normalized, as they are subject to Schedule 195, WARM Program. The Weather Normalization is described below:

1.3.1. For the heating season months of November through May, actual usage will be normalized by the same therms that derived WARM revenue (Schedule 195).

1.4. The therm variance between actual Weather Normalized usage and baseline usage is multiplied by the Distribution Margin per group.

(C)

(continue to Sheet 190-3)
SCHEDULE 190

Issued
NWN Advice No. OPUC 17-XX

Effective with service on
and after

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Original Sheet 190-3

DECOUPLING MECHANISM
(continued)

(C)

TERMS AND CONDITIONS (continued):
PARTIAL DECOUPLING CALCULATION (Rate Schedules 2 and 3 CSF):

1.5. The per therm distribution margins to be used in the deferral effective November 1, 2018 is $0.53574 per therm for Residential customers (Group 1) and $0.41875 per therm for Commercial schedule 3 customers (Group 2).

2. DECOUPLING CALCULATION (Rate Schedules 31CFS and 32CFS):

2.1. Each month, the Company will calculate the difference between actual usage and the calculated Baseline Usage for Commercial schedules 31CFS and 32CFS customers. The resulting usage differential shall be multiplied by the Therm Distribution Margin for the applicable group.

2.2. The Baseline Usage per-customer-per-year is:

Group 3: Commercial Rate Schedule 31CSF:	34,445
Group 4: Commercial Rate Schedule 32CSF:	90,637

2.3. The therm variance between actual usage and the baseline usage is multiplied by the distribution margin for the group.

2.4. The per therm distribution margin to be used in the deferral calculation effective November 1, 2018 is $0.25416 per therm for Commercial schedule 31 customers (Group 3) and $0.12781 per therm for Commercial schedule 32 customers (Group 4).

3. The Company shall defer and amortize, with interest, 100% of the Distribution Margin differential in a sub-account of Account 186. The deferral will be a credit (accruing a refund to customers) if the differential is positive, or a debit (accruing a recovery by the company) if the differential is negative.

4. The per-Therm Distribution Margin to be used in the deferral calculation is:

Effective Date: November 1, 2018

Residential Rate Schedule 2:	$0.53574 per therm
Commercial Rate Schedule 3:	$0.41875 per therm
Commercial Rate Schedule 31CFS:	$0.25416 per therm
Commercial Rate Schedule 32CFS:	$0.12781 per therm

(C)

Issued
NWN OPUC Advice No.

Effective with service on
and after

NW Natural
NWN 904
Calculation of Group Margin Rates for Decoupling
ALL VOLUMES IN THERMS

Line	Schedule	Block	Rate Case Volumes	Proposed Margin Rate	Proposed Margin
1					
4					C = A*B
5	Schedule	Block	A	B	C
6	2R (GROUP 1)		385,050,429.1	$0.53574	$206,286,917
7	3C Firm Sales (GROUP 2)		166,461,516.2	$0.41875	$69,705,760
8	31C Firm Sales (GROUP 3)	Block 1	12,784,484.5	$0.26550	$3,394,281
9		Block 2	12,605,536.7	$0.24266	$3,058,860
10	32C Firm Sales (GROUP 4)	Block 1	28,058,172.9	$0.13498	$3,787,292
11		Block 2	9,518,065.8	$0.11471	$1,091,817
12		Block 3	1,350,402.6	$0.08101	$109,396
13		Block 4	166,168.4	$0.04726	$7,853
14		Block 5	0.0	$0.01978	$0
		Block 6	0.0	$0.00988	$0
15			615,994,776		$287,442,176
16					
17	**Calculation of Group Margins:**				
18				**Group Margin Rate**	**Group Margin**
19	**GROUP 1**		385,050,429	**$0.53574**	$206,286,917
20	**GROUP 2**		166,461,516	**$0.41875**	$69,705,760
21	**GROUP 3**		25,390,021	**$0.25416**	$6,453,140
22	**GROUP 4**		39,092,810	**$0.12781**	$4,996,359
23			615,994,776		$287,442,176

NW Natural
NWN 905
Decoupling Baseline Usage

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Group 1	Base	16.33	14.75	16.33	15.81	16.33	15.81	13.56	13.56	13.12	16.33	15.81	16.33	184.09
	Heat	89.33	69.95	57.24	37.51	15.44	3.36	0.27	0.24	2.21	23.83	61.36	90.84	451.59
	Total	**105.67**	**84.70**	**73.57**	**53.32**	**31.78**	**19.17**	**13.83**	**13.80**	**15.33**	**40.16**	**77.17**	**107.18**	**635.67**
Group 2	Base	94.58	85.43	94.58	91.53	94.58	91.53	88.22	88.22	85.37	94.58	91.53	94.58	1,094.72
	Heat	354.35	275.14	219.82	139.53	54.47	10.76	1.76	2.27	9.19	88.77	240.62	361.50	1,758.19
	Total	**448.93**	**360.57**	**314.40**	**231.06**	**149.05**	**102.29**	**89.98**	**90.49**	**94.56**	**183.35**	**332.15**	**456.08**	**2,852.92**
Group 3	Base	1,600.35	1,445.48	1,600.35	1,548.73	1,600.35	1,548.73	1,119.06	1,119.06	1,082.96	1,600.35	1,548.73	1,600.35	17,414.48
	Heat	3,438.22	2,674.58	2,149.40	1,378.23	536.27	103.00	8.38	7.94	66.89	838.86	2,323.83	3,505.09	17,030.70
	Total	**5,038.57**	**4,120.06**	**3,749.75**	**2,926.95**	**2,136.62**	**1,651.72**	**1,127.43**	**1,127.00**	**1,149.84**	**2,439.22**	**3,872.56**	**5,105.44**	**34,445.18**
Group 4	Base	5,017.87	4,532.27	5,017.87	4,856.01	5,017.87	4,856.01	3,605.35	3,605.35	3,489.05	5,017.87	4,856.01	5,017.87	54,889.39
	Heat	7,216.89	5,613.99	4,511.63	2,892.92	1,125.65	216.19	17.59	16.68	140.40	1,760.79	4,877.77	7,357.24	35,747.72
	Total	**12,234.76**	**10,146.26**	**9,529.50**	**7,748.92**	**6,143.52**	**5,072.19**	**3,622.93**	**3,622.02**	**3,629.44**	**6,778.66**	**9,733.77**	**12,375.11**	**90,637.11**

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Third Revision of Sheet 195-1
Second Revision of Sheet 195-1

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM (WARM Program)

PURPOSE: (C)
To (a) describe the terms and conditions associated with Customer participation in the weather adjusted rate mechanism ("WARM Program") implemented under the authority of ORS. 757.262, (b) describe the calculations used to adjust customer rates under the WARM Program, and (c) identify the temporary adjustments applicable to the Rate Schedules listed below under the authority of ORS 757.259, OAR 860-022-0070, and OAR 860-027-300.

DESCRIPTION:
The WARM Program is designed to account for under- and over- collections of NW Natural's authorized revenue requirement due to the effect of changes in customer usage due to weather during the months November through May (the WARM Period). WARM is the Company's default billing method for the Rate Schedules to which Schedule 195 applies. A Customer that does not want to participate in the WARM Program may change their participation status in accordance with Provision 3 of the Terms and Conditions of this Schedule 195.

The temporary adjustments to rates stated in this Schedule 195 reflect the amortization of deferred balances as of June 30 associated with the Schedule 195 WARM Program as authorized by the Commission in Docket UM 1750. All adjustment amounts are in effect for a 12-month period commencing with the stated effective date, or for such other period approved by the Commission.

REGULATORY HISTORY:
Docket UG 152. Commission Order 03-507
Docket UG 163. Commission Order 07-426
Docket UG 221. Commission Order 12-408
Docket UM 1750. Commission Order 16-223

DEFINITIONS:
Except as otherwise provided for below, the terms used in this Schedule are defined in the Definitions section of the Tariff of which this Schedule is a part.

WARM Heating-Degree Day (WARM HDD) is the extent by which the daily mean temperature falls below 59 degrees Fahrenheit for the Rate Schedule 2 calculation, and 58 degrees Fahrenheit for the Rate Schedule 3 calculation.
Statistical Coefficient (also known as Usage Coefficient) means the factor used to relate heating degree days to therm usage.

APPLICABLE:
To Residential and Commercial Customers served on the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 3

(C)

(continue to Sheet 195-2)

Issued
NWN OPUC Advice No.

Effective with service on
and after

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Second Revision of Sheet 195-2
First Revision of Sheet 195-2

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM (WARM Program)
(continued)

RATE ADJUSTMENTS: (C)

Monthly WARM Period Adjustments. During the WARM Period, the per-therm Billing Rate stated on WARM participant bills with a meter read date on or after December 1 and on or before May 15, will include the applicable WARM adjustment, subject to the limitations set forth in provision 1 of the Terms and Conditions.

Monthly Temporary Adjustments. The adjustments listed below are included in the Billing Rate stated on the respective Rate Schedules.

Effective November 1, 2018:

Rate Schedule 2:	$	0.xxxxxx
Rate Schedule 3:	$	0.xxxxxx

TERMS AND CONDITIONS:

1. WARM Adjustment Limitations.

    1.1. Residential bills --The maximum amount (increase or decrease) by which the WARM adjustment will impact any WARM participant's monthly bill during the WARM Period will be $12.00, or 25% of the usage portion of that bill, whichever is less. For any billing period in which the total monthly WARM adjustment exceeds either $12.00 or 25% of the usage, the balance of the WARM adjustment will be deferred in accordance with Condition 2 below.

    1.2. Commercial bills--The maximum amount (increase or decrease) by which the WARM adjustment will impact any WARM participant's monthly bill during the WARM Period will be $35.00, or 25% of the usage portion of that bill, whichever is less. For any billing period in which the total monthly WARM adjustment exceeds either $35.00 or 25% of the usage, the balance of the WARM adjustment will be deferred in accordance with Condition 2 below.

2. Deferred Amounts. Any amounts not applied to a Residential or Commercial Customer's bill during the WARM Period due to the limitations described in Provision 1 will be set aside in a respective Residential or Commercial WARM deferral account. Each year, concurrent with the Company's annual Purchased Gas Adjustment (PGA) filing, the balance in the Residential and Commercial WARM deferral accounts will be collected from, or credited to, all Rate Schedule 2 and Rate Schedule 3 customers, respectively, on an equal cent-per-therm basis

3. WARM Program Participation Status Change. Customers are included in the WARM Program unless they opt-out. Any change made to a Customer's WARM participation status will remain in effect on that Customer's account until the Customer makes another status change.

(continue to Sheet 195-3)

(C)

Issued
NWN OPUC Advice No.

Effective with service on
and after

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM (WARM Program)
(continued)

TERMS AND CONDITIONS (continued): (C)

3.1. Existing Customers. Customers will have an opportunity to change their status in the WARM program each year. Customers will be notified annually through a bill insert and bill messages that they may change their status in the program. Customers will have until September 30 to make a status change. Except as provided in Condition 3.3, any request for a status change received after September 30 will not become effective until the effective date of the WARM Period subsequent to the upcoming WARM Period. For example, a status change received on October 1, 2018 would become effective with the WARM Period commencing December 1, 2019.

3.2. New Customers. Any new Customer will have 30 days from the date that the Company's new customer information packet is mailed to the Customer in which to opt-out of the WARM Program. For purposes of this Schedule, a new Customer is a Customer that has not had a gas service account with the Company within the last 12 month period, or is a Customer that has been issued a new service account number by the Company due to a material change to their account.

3.3. Exceptions. Existing Customers will be allowed to change their status in the WARM Program after September 30, upon Customer request, in the following circumstances:

3.3.1. The Company can verify that the Customer does not have natural gas space heating equipment installed at the service address.
3.3.2. The Customer moved from an address that used natural gas for space heating to an address that **does not** use natural gas for space heating.
3.3.3. The Customer moved from an address that did not use natural gas for space heating to an address that **does** use natural gas space heating.
3.3.4. The Customer, or their authorized representative, can provide evidence that the Customer had not received information regarding the WARM Program.
3.3.5. The Customer, or their authorized representative, can provide evidence that the Customer was not capable of understanding the written information describing the program and the opt-out instructions.
3.3.6. The Company can verify that a contact was made with the customer, or their authorized representative, prior to September 30 requesting a change to their WARM status, but for whatever reason, the change was not processed.

3.4. Effective date of status changes made under Provision 3.3. Status changes granted in accordance with Conditions 3.3.1 and 3.3.4 will become effective with the Customer's next regular monthly bill. Status changes granted in accordance with Conditions 3.3.2 and 3.3.3 will become effective with the first day of service at the new address. When status changes are made in accordance with Conditions 3.3.5 and 3.3.6 the Customer's next bill will show revised billing amounts for Customer's account back to the first bill issued following the beginning of the most recent WARM Period. (C)

(continue to Sheet 195-4)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Fourth Revision of Sheet 195-4
Third Revision of Sheet 195-4

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM (WARM Program)
(continued)

TERMS AND CONDITIONS (continued): (C)

4. Historical Billing Information. Upon Customer request, the Company will provide historical billing information that reflects bills with and without the WARM adjustment for any month during the WARM Period.

5. Rate Changes in the WARM Period. Should a change in the margin rate used in the WARM formula occur during the WARM Period, the equivalent therms used in the calculation of the WARM adjustment will be based on the entire billing period, and then prorated based upon the number of days applicable to each margin rate. The pro-rated therms are then multiplied by the applicable margin rate to determine the WARM adjustment for each rate period. For example: If a margin rate change occurred on January 1, a bill with a bill period between December 25 and January 24 would be prorated based upon six days at the prior margin rate and 24 days at the new margin rate. The calculations performed under Conditions 1.1 and 1.2 will apply to each prorated period separately, except that the total WARM adjustment for each bill will not exceed the maximum (increase or decrease) WARM adjustment specified in Conditions 1.1 and 1.2, respectively.

6. Warm Adjustment Calculation. The Formula for the WARM calculation is:

WARM Adjustment = $\sum_{1}^{T}(HDD_{n,t} - HDD_{a,t}) * B * Mrgn$

Where:
T = the days covered by the meter read dates for an individual customer's bill
HDDn = the 25 year WARM HDD for each day (May 31,1992-May 31, 2017) determined using the max and min temperatures published for each day by weather stations described in General Rule 24,
HDDa = the actual heating degree-days for each day based on the individual customer's actual beginning and ending meter read dates
B = the statistical coefficient relating heating degree-days to therm use determined in the most recent general rate case, or other Commission authorized proceeding.
Mrgn = the relevant Rate Schedule margin defined as the current Billing Rate less the current Commodity Rate, Pipeline Capacity Charge, and any Temporary Adjustments.

6.1 Statistical Coefficients. The statistical coefficients used in the calculation of the WARM Adjustment effective with the WARM Period commencing November 1, 2018 are:

Rate Schedule 2: 0.163268	Rate Schedule 3: 0.656334

(C)

(continue to Sheet 195-5)

Issued
NWN OPUC Advice No.

Effective with service on
and after

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 | Sixth Revision of Sheet 195-5
Cancels Fifth Revision of Sheet 195-5

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM (WARM Program)
(continued)

TERMS AND CONDITIONS (continued): (C)

6.2. Margins. The applicable margins used in the calculation of the WARM Adjustment effective with the WARM Period commencing November 1, 2018 are:

Rate Schedule 2:	$0.53574	Rate Schedule 3:	$0.41875

6.3. Weather Data Source. Weather data used in the calculation of actual HDD and WARM HDD for each customer shall be from the same weather stations and weather zones that are used in the determination of thermal units as set forth in General **Rule 24.**

7. Warm Bill Effects**:** The following table depicts the impact on Residential **Rate Schedule 2** and Commercial **Rate Schedule 3** customer bills, respectively, at specified variations in HDDs.

	RESIDENTIAL			COMMERCIAL	
HDD Variance (+ or -)	Equivalent therms	Total Monthly WARM adjustment (+ or -)		Equivalent therms	Total Monthly WARM adjustment (+ or -)
1	0.16327	$0.09		0.65633	$0.27
5	0.81634	$0.44		3.28167	$1.37
10	1.63268	$0.87		6.56334	$2.75
15	2.44902	$1.31		9.84501	$4.12
20	3.26536	$1.75		13.12668	$5.50
25	4.08170	$2.19		16.40835	$6.87
30	4.89804	$2.62		19.69002	$8.25
35	5.71438	$3.06		22.97169	$9.62
40	6.53072	$3.50		26.25336	$10.99
45	7.34706	$3.94		29.53503	$12.37
50	8.16340	$4.37		32.81670	$13.74

To calculate variations beyond or in-between specified levels, multiply the desired HDD variance by the applicable statistical coefficient, and then multiply that sum by the applicable margin.

To obtain the cent per therm effect of the Warm Adjustment, divide the WARM Adjustment by the number of therms used during the billing month. (C)

(continue to Sheet 195-6)

Issued
NWN OPUC Advice No.

Effective with service on
and after

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Original Sheet 195-6

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM (WARM Program)
(continued)

TERMS AND CONDITIONS (continued):

(C)

8. Example Bill Calculation: Below is an example of the WARM adjustment calculation for a residential **Rate Schedule 2** Customer where the billing rate is $0.94681 cents per therm, the HDD variance is 50 HDDs colder than normal, and the monthly therm usage is 129 therms:

HDD Differential:	Normal HDDs:	600 HDDs
	Actual HDDs:	650 HDDs
	HDD variance:	600 - 650 = -50 HDDs
Equivalent Therms:	HDD variance:	-50 HDDs
	Statistical coefficient:	0.163268
	Equivalent therms:	-50 x 0.163268 = -8.1634 therms
Total Warm Adjustment:	Equivalent therms:	-8.1634 therms
	Margin Rate:	$0.53574
	Total WARM Adj.:	-8.1634 x $0.53574 = ($4.37)
Total WARM Adjustment converted to cents per therm:	Total WARM Adj.:	($4.37)
	Monthly usage:	129 therms
	Cent/therm Adj.:	-4.37 ÷ 129 = ($0.03388)
Billing Rate per therm:	Current Rate/therm:	$0.94681
	WARM cent/therm Adj.:	($0.03388)
	WARM Billing Rate:	$0.94681 + -$0.03388 = $0.91293
Total WARM Bill:	Customer Charge:	$8.00
	Usage Charge:	$0.91293
	Total	(129 x $0.91293) + $8.00 =$125.77

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other Schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time. (C)

Issued
NWN OPUC Advice No.

Effective with service on
and after

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Direct Testimony of Kimberly Heiting

CUSTOMER COMMUNICATIONS
Exhibit 1000

December 2017

EXHIBIT 1000 - DIRECT TESTIMONY - CUSTOMER COMMUNICATIONS

Table of Contents

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Kimberly Heiting. I am the Vice President of Communications and Chief Marketing Officer for NW Natural. My responsibilities include customer and employee communications, media relations, advertising, website services, marketing and business analytics. I have worked for NW Natural since 1998.

Q. Describe your education and employment background.

A. I received my undergraduate degree in Communications from the University of Iowa and a Master of Science in Communications from Northwestern University. From 1992 to 1994, I worked as a marketing specialist at a direct-marketing advertising agency, GSP Marketing in Chicago, Illinois. From 1994 to 1997, I worked as corporate communications specialist, then manager, and finally public relations manager for Bank of America's Corporate Banking division in Chicago. From 1997 to 1998, I served as communications and media manager for 360 Communications, a telecommunications subsidiary of Sprint Corporation in Chicago.

Q. Please summarize your testimony.

A. In my testimony, I:

- Describe "Category A" communications as defined in OAR 860-026-0022 and discuss the Company's Category A communications plan for the November 2018-October 2019 test year ("Test Year");

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- Explain why the Company's Category A Test Year expense level is reasonable under OAR 860-026-0022;
- Present the Company's Test Year Category B proposed expense; and
- Describe the level of Category C (corporate imaging) expense the Company has excluded from Test Year expense.

II. CATEGORY A COMMUNICATION PLAN

Q. Please describe Category A customer communications.

A. The Commission's administrative rules categorize utility customer communications and set forth ratemaking standards applicable to each category. Category A communications are defined as "Energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses."

Q. What topics does the Company's Test Year Category A communication plan address?

A. The Company's Test Year Category A communication plan addresses the following topics:

- The efficient use of natural gas;
- Payment options and programs for customers;
- Online customer service options and information;
- Natural gas price changes;
- Cost, performance, and environmental benefits of high-efficiency natural gas equipment;

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- Information about the ways NW Natural's pipeline system and customers can reduce greenhouse gas emissions;
- Phone numbers and contact information.

Q. How does the Company plan to communicate with customers on these topics?

A. The Company plans to continue communicating with customers through bill inserts, our website, customer e-newsletters, new customer information packets, telephone directory advertising, digital advertising, community events and broadcast media.

III. REASONABLENESS OF TEST YEAR CATEGORY A COMMUNICATIONS EXPENSE

Q. How does the Test Year proposal compare to the Category A communications expense established in UG 221, the Company's last rate case ("2011 Rate Case")?

A. The Category A communications expense level approved in our last rate case was $2.19 per-customer. This level matched the same per-customer amount established in the Company's 2002 rate case (UG 152). The proposed Test Year Category A communications expense is $2.52 per customer per year. This level of annual expense represents a 33 cent increase on a per-customer basis over a 16-year period of time.

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Q How does NW Natural's proposed Test Year Category A communications expense compare to the level that is presumed just and reasonable under OAR 860-026-0022?

A. Under OAR 860-026-0022(3)(a), expenditures for Category A advertising up to 0.125 percent of gross retail operating revenues are presumed just and reasonable. In NW Natural's case, that percentage would allow NW Natural $853,000 for Category A communications based on proposed Test Year revenues, which is equivalent to about $1.27 per customer.

Q. Does NW Natural believe that the "gross retail operating revenues" formula provides an amount that is appropriately scaled to NW Natural's customer communications?

A. No, we do not. The gross retail revenue-based formula produces a skewed result because the Company's gross retail revenues are, in part, driven by natural gas commodity costs. This means that when natural gas prices are low (as they currently are), the Company's gross retail revenues will be lower, and in turn, so will the results of the formula. For this reason, we find it difficult to even make a correlation between the amounts presumed reasonable per rule OAR 860-026-0022(3)(a) and the amounts needed to effectively communicate Category A topics to our customers.

Additionally, the revenue-based formula applicable to all energy utilities results in natural gas utilities having far less Category A expense presumed reasonable as compared to electric utilities. For example, based on 2016 data,

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the same formula translates into an allowance of $2.78 per-customer for PacifiCorp and $2.48 per-customer for Portland General Electric Company (PGE) compared to $1.18 per-customer for NW Natural. (See *NW Natural/1001, Heiting/1)*. This funding gap seems inappropriate given NW Natural delivers more energy to our customers on an annual basis than any other Oregon utility.

Q. Does OAR 860-026-0022 prevent NW Natural from recovering more than $1.27 per customer for Category A communications expense?

A. No, it does not. Under OAR 860-026-0022(4), an energy utility seeking to include expenditures in excess of 0.125 percent of revenues bears the burden of demonstrating that the expenditures are just and reasonable. In other words, the rule sets an amount that the Company does not need to support as reasonable, but allows for more to be recovered as long as support is provided and the Commission approves. As in the 2002 and 2011 Rate Cases, NW Natural can demonstrate that its proposed Category A communications expense is just and reasonable, and therefore, it should be included in the Company's revenue requirement.

Q. Please explain why NW Natural is requesting $2.52 per customer for Category A expense.

A. First, our service territory is geographically broad, requiring the Company to enter two distinct media markets (Portland and Eugene) in order to reach our customers throughout the State. Second, media consumption habits have evolved to include computer, smartphone, and tablet as well as TV and other

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traditional media, requiring a larger media investment to effectively reach customers where they seek information. Third, NW Natural has increased its educational and informational communications about the detriments of greenhouse gas emissions, the utility's actions to address them, and the options customers have to take actions themselves.

Q. How does the nature of NW Natural's service territory support a per-customer allocation higher than the amount automatically allowed under OAR 860-026-0022?

A. NW Natural must communicate across 126 cities and towns within its Oregon service territory, *(*see *NW Natural/1002, Heiting/1-6*)*,* making our service territory geographically diverse and more expensive from a communications delivery standpoint*.* The OAR 860-026-0022 formula does not address the differences utilities have in service territories and yet these differences increase the number of media channels and associated costs needed to effectively deliver information to customers.

Q. How has media consumption evolved since NW Natural's 2011 Rate Case?

A. Since the last rate case, media fragmentation has increased. For example, television remains the dominant channel for news and information,[1] but it no longer commands our full attention, as it is often viewed simultaneously with

[1] Pew Research Center, Aug. 2017 Survey
www.pewresearch.org/fact-tank/2017/10/04/key-trends-in-social-and-digital-news-media/

[2] eMarketer, June 2016
https://www.emarketer.com/Article/Growth-Time-Spent-with-Media-Slowing/1014042

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online screens. In fact, thanks to media multitasking, U.S. adults will spend an average of 12 hours per day viewing media of one form or another. That is nearly an hour more than the average in 2011[2], and is primarily due to the increased use of digital and mobile devices. In large part, this move to online information consumption is driven by increased use of social media. For example, in a 2017 survey by the Pew Research Center, nearly 70 percent of adults in the U.S. cited social media as the source of their news. As a result of these trends, the integration of digital media into our overall message delivery strategy is an essential addition to the Company's communications efforts.

In summary, the communications landscape has changed and increased media fragmentation requires a broader, multi-channel investment. To effectively communicate to our customer base, it is essential that the Company utilize a diversified media mix, which includes digital, social networks and website display advertising, in addition to television, radio, community events and print.

Q. How has NW Natural increased its customer communications about environmental issues?

A. NW Natural has increased Utility Information Advertising to educate customers about the emissions profile of the natural gas system and ways NW Natural and our customers can help lower carbon emissions.

Q. Does OAR 860-026-022 include this type of communication in Category A?

A. Yes, it does. The definition of "Utility Information Advertising Expense" (860-026-0022(g) is "advertising expenses, the primary purpose of which is to increase

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1-503-226-4211

customer understanding of 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."

Q. Please describe the purpose and content associated with this addition to your Category A communications.

A. Concern about climate change in our region has increased and continues to escalate. Research conducted by NW Natural in October of 2017 showed 64 percent of customers believe climate change to be a serious problem. (See *NW Natural/1003, Heiting/1*). This concern is also evident when considering the aggressive greenhouse gas reduction goals being established at the county, city and state level in NW Natural's Oregon service territory. (See *NW Natural/1004, Heiting/1*).

In 2016, NW Natural undertook a comprehensive effort to assess the environmental footprint of the direct use of natural gas and identified areas of opportunity for carbon emission reductions. In the context of this strategic work, the Company developed a voluntary carbon savings goal of 30 percent by 2035, based on a 2015 baseline associated with our customers' use. This goal serves as a platform for us to engage our customers and other key stakeholders about the ways we can work together to reduce natural gas use and lower emissions.

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1-503-226-4211

To communicate this information, NW Natural developed a long-term environmental educational initiative - "Less We Can". The Category A utility information delivered through this effort includes:

- The current greenhouse gas emissions footprint of the natural gas system and associated customer use;
- Ways customers can reduce energy use and associated emissions through conservation and energy efficiency, and by offsetting their emissions through the Smart Energy program;
- The efforts NW Natural and others are taking to support renewable natural gas development and technology advancements that can help lower emissions; and
- The role natural gas and renewable natural gas can play to lower the emissions and air pollutants of heavy duty vehicles and associated fleets in the transportation sector.

Q. What action does the Company request the Commission take with respect to Category A communications expense?

A. The Company requests that the Commission find that the proposed level of Test Year Category A communications expense is just and reasonable under OAR 860-026-0022. The Company's 33-cent per-customer increase above the most recently approved amount (which dates back to 2002) is necessary for the Company to effectively deliver Category A communications to customers, and is reasonable given the factors discussed in my testimony.

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IV. CATEGORY B - SAFETY-RELATED COMMUNICATIONS

Q. What are safety-related communications?

A. Safety-related communications are legally mandated messages intended to ensure that NW Natural customers, contractors, public officials, emergency officials, and the communities in which the Company serves know how to use natural gas safely, and know how to recognize, react, and respond to a potential leak or safety issue related to natural gas. Safety-related communications are also referred to as "Category B" communications, as defined in OAR 860-026-0022.

Q. Please identify the legal mandates requiring this expenditure.

A. The Company's Category B communications meet federal Pipeline and Hazardous Materials Safety Administration requirements for Public Safety Awareness Plans outlined in Recommended Practice API 1162 ("RP-1162") and enforced by the OPUC Safety Staff. In compliance with RP-1162, the Company executes a robust public safety awareness plan each year supported by paid media, customer communications, public relations, a schools program and sponsored community events. In addition, the Company distributes audience-specific pipeline safety information to required groups, including emergency officials, first responders, public officials, excavators, multi-family property managers, floating homes, and residents and businesses located along transmission lines, in high-consequence areas, or along rights-of-way.

Q. What Category B communications expenses are included in the Test Year?

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1-503-226-4211

A. The Company has included $810,000 for Category B communications and media outreach expenses in the Test Year.

Q. Please describe any new Category B expenses since NW Natural's last rate case.

A. The primary source of new Category B expense is the addition of a second Public Information Officer (PIO) to the Corporate Communications staff. This position was needed to assist in numerous public safety activities:

- Respond to reporter and social media inquiries about system damages, evacuations, or service issues;
- Provide 24-hour-a-day, 365 days-a-year pager coverage for emergency response;
- Provide coverage for vacations, training and paid time off, ensuring one media-trained PIO is on-call at all times;
- Respond to community and agency requests for in-person safety presentations;
- Provide proactive and reactive media interviews about natural gas safety information;
- Assist in the implementation and tracking of the annual Public Safety Awareness Plan and metrics;
- Conduct ongoing proactive outreach to fire department PIOs to help ensure smooth coordination in the event of a natural gas damage or emergency; and

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Portland, Oregon 97209-3991
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- Participate in Company and local/state agency emergency response trainings and scenario-based planning and drills.

Another new safety communications expense is related to a greater investment in damage prevention education. In recent years, local economic recovery has led to an increase in construction activity, which, in turn, has resulted in a substantial rise in damages to NW Natural pipelines. In fact, from 2012 to 2016, damages to the Company's system in Oregon by contractors and the public have increased by 64 percent, (see *NW Natural/1005, Heiting/1*), despite high awareness of the "Call before You Dig" law. (See *NW Natural/1006, Heiting/1* and *NW Natural/1007, Heiting/1).*

In response, the Company has increased its investment in prevention outreach to encourage behavior change and reduce damages to our system. This enhanced damage prevention effort includes higher levels of paid media across more channels, including television, print, digital and social media as well as radio public service announcements. It also includes additional outreach through customer bill inserts, targeted mailings, online content, first responder training, and community events.

V. CATEGORY C – CORPORATE IMAGING COMMUNICATIONS

Q. Describe the level of Category C (corporate imaging) expense NW Natural has excluded from Test Year expense.

A. An amount of $630,000 in overhead, marketing and advertising activities is budgeted in Category C for the Test Year period, none of which the Company is

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NW NATURAL
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Portland, Oregon 97209-3991
1-503-226-4211

seeking to include in rates. These activities are designed to aid in the retention of customers and attract new customers by promoting the cost and performance benefits of natural gas and a variety of natural gas products.

Q. Does this conclude your direct testimony?

A. Yes.

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1-503-226-4211

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Exhibits of Kimberly Heiting

CUSTOMER COMMUNICATIONS
EXHIBITS 1001 - 1007

December 2017

EXHIBITS 1001 – 1007 – CUSTOMER COMMUNICATIONS

Table of Contents

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

NW Natural®

2016 Category A Per Customer Based on Operating Revenue					
Utility	**Year**	**Operating Revenue**	**CAT A - 0.125%**	**# of Customers**	**CAT A Per Customer**
NW Natural	2016	$607,209,575	$759,011.97	640,853	$1.18
PGE	2016	$1,703,927,642	$2,129,909.55	859,396	$2.48
Pacificorp	2016	$1,274,834,790	$1,593,543.49	574,131	$2.78

Counts of Counties and Cities with active accounts as of 2017 11 30

NWN/502
Heiting/1-

Obs	State	County	Active_Accounts	Count
1	Oregon	Benton	19,435	1
2	Oregon	Clackamas	92,486	2
3	Oregon	Clatsop	13,365	3
4	Oregon	Columbia	8,452	4
5	Oregon	Coos	1,821	5
6	Oregon	Hood River	4,020	6
7	Oregon	Lane	41,319	7
8	Oregon	Lincoln	10,655	8
9	Oregon	Linn	23,852	9
10	Oregon	Marion	66,198	10
11	Oregon	Multnomah	202,196	11
12	Oregon	Polk	14,747	12
13	Oregon	Wasco	2,043	13
14	Oregon	Washington	141,020	14
15	Oregon	Yamhill	12,498	15
16	Washington	Clark	79,582	1
17	Washington	Klicktat	1,514	2
18	Washington	Skamania	513	3

Counts of Counties and Cities with active accounts as of 2017 11 30

Obs	State	City	Active_Accounts	Count
1	Oregon	Adair Village	6	1
2	Oregon	Albany	16,229	2
3	Oregon	Aloha	60	3
4	Oregon	Amity	334	4
5	Oregon	Astoria	4,520	5
6	Oregon	Aumsville	751	6
7	Oregon	Aurora	996	7
8	Oregon	Ballston	1	8
9	Oregon	Banks	444	9
10	Oregon	Barlow	4	10
11	Oregon	Beavercreek	220	11
12	Oregon	Beaverton	47,124	12
13	Oregon	Boring	2,006	13
14	Oregon	Brooks	2	14
15	Oregon	Brownsville	512	15
16	Oregon	Canby	3,615	16
17	Oregon	Cannon Beach	1,451	17
18	Oregon	Carlton	24	18
19	Oregon	Clackamas	6,615	19
20	Oregon	Clatskanie	160	20
21	Oregon	Coberg	1	21
22	Oregon	Coburg	169	22
23	Oregon	Columbia City	659	23
24	Oregon	Coos Bay	890	24
25	Oregon	Coquille	213	25
26	Oregon	Cornelius	2,219	26
27	Oregon	Corvallis	14,901	27
28	Oregon	Cottage Grove	2,582	28
29	Oregon	Creswell	1,314	29
30	Oregon	Dallas	4,242	30
31	Oregon	Damascus	1,879	31
32	Oregon	Dayton	9	32

Counts of Counties and Cities with active accounts as of 2017 11 30

Obs	State	City	Active_Accounts	Count
33	Oregon	Deer Island	31	33
34	Oregon	Depoe Bay	1,387	34
35	Oregon	Donald	181	35
36	Oregon	Dundee	978	36
37	Oregon	Durham	5	37
38	Oregon	Eugene	29,546	38
39	Oregon	Fairview	2,133	39
40	Oregon	Forest Grove	3,433	40
41	Oregon	Foster	4	41
42	Oregon	Gearhart	1,473	42
43	Oregon	Gervais	373	43
44	Oregon	Gladstone	3,064	44
45	Oregon	Gleneden Beach	1,147	45
46	Oregon	Grand Ronde	249	46
47	Oregon	Gresham	17,943	47
48	Oregon	Halsey	254	48
49	Oregon	Hammond	419	49
50	Oregon	Happy Valley	6,252	50
51	Oregon	Harrisburg	643	51
52	Oregon	Hillsboro	24,527	52
53	Oregon	Hood River	4,020	53
54	Oregon	Hubbard	975	54
55	Oregon	Independence	1,726	55
56	Oregon	Jasper	22	56
57	Oregon	Jefferson	805	57
58	Oregon	Junction City	1,541	58
59	Oregon	Keizer	9,011	59
60	Oregon	King City	271	60
61	Oregon	Lafayette	832	61
62	Oregon	Lake Oswego	14,375	62
63	Oregon	Lebanon	5,429	63
64	Oregon	Lincoln City	4,601	64

Counts of Counties and Cities with active accounts as of 2017 11 30

Obs	State	City	Active_Accounts	Count
65	Oregon	Lyons	426	65
66	Oregon	Marion	8	66
67	Oregon	Marylhurst	21	67
68	Oregon	Maywood Park	1	68
69	Oregon	McMinnville	3,358	69
70	Oregon	Mehama	55	70
71	Oregon	Mill City	505	71
72	Oregon	Millersburg	68	72
73	Oregon	Milwaukie	478	73
74	Oregon	Molalla	2,179	74
75	Oregon	Monmouth	1,318	75
76	Oregon	Mount Angel	798	76
77	Oregon	Mulino	128	77
78	Oregon	Myrtle Point	151	78
79	Oregon	Neotsu	207	79
80	Oregon	Newberg	5,816	80
81	Oregon	Newport	2,144	81
82	Oregon	North Bend	567	82
83	Oregon	North Plains	970	83
84	Oregon	Oregon City	11,805	84
85	Oregon	Otis	673	85
86	Oregon	Philomath	1,312	86
87	Oregon	Pleasant Hill	151	87
88	Oregon	Portland	243,966	88
89	Oregon	Rainier	416	89
90	Oregon	Rickreall	69	90
91	Oregon	Rose Lodge	13	91
92	Oregon	Saint Helens	3,402	92
93	Oregon	Salem	47,473	93
94	Oregon	Sandy	3,540	94
95	Oregon	Scappoose	2,509	95
96	Oregon	Scio	330	96

Counts of Counties and Cities with active accounts as of 2017 11 30

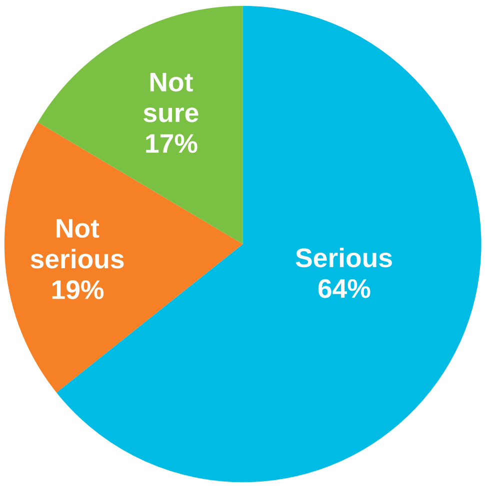
Obs	State	City	Active_Accounts	Count
97	Oregon	Seaside	3,205	97
98	Oregon	Shedd	72	98
99	Oregon	Sheridan	877	99
100	Oregon	Sherwood	6,856	100
101	Oregon	Siletz	175	101
102	Oregon	Silverton	2,992	102
103	Oregon	Sodaville	2	103
104	Oregon	South Beach	5	104
105	Oregon	Springfield	5,993	105
106	Oregon	St Benedict	1	106
107	Oregon	Stayton	1,861	107
108	Oregon	Sublimity	739	108
109	Oregon	Sweet Home	2,304	109
110	Oregon	Tangent	384	110
111	Oregon	The Dalles	2,044	111
112	Oregon	Tigard	1,130	112
113	Oregon	Toledo	332	113
114	Oregon	Tolovana Park	1	114
115	Oregon	Troutdale	4,946	115
116	Oregon	Tualatin	6,962	116
117	Oregon	Turner	786	117
118	Oregon	Vernonia	710	118
119	Oregon	Warren	600	119
120	Oregon	Warrenton	2,251	120
121	Oregon	West Linn	9,574	121
122	Oregon	Westport	21	122
123	Oregon	Willamina	408	123
124	Oregon	Wilsonville	6,485	124
125	Oregon	Wood Village	143	125
126	Oregon	Woodburn	5,589	126
127	Washington	Battle Ground	4,657	1
128	Washington	Bingen	209	2

Counts of Counties and Cities with active accounts as of 2017 11 30

Obs	State	City	Active_Accounts	Count
129	Washington	Brush Prairie	190	3
130	Washington	Camas	7,537	4
131	Washington	Carson	288	5
132	Washington	Dallesport	7	6
133	Washington	Klickitat	118	7
134	Washington	La Center	836	8
135	Washington	Lyle	1	9
136	Washington	North Bonneville	225	10
137	Washington	Ridgefield	3,231	11
138	Washington	Vancouver	59,418	12
139	Washington	Washougal	3,712	13
140	Washington	White Salmon	1,179	14
141	Washington	Woodland	1	15

NW Natural

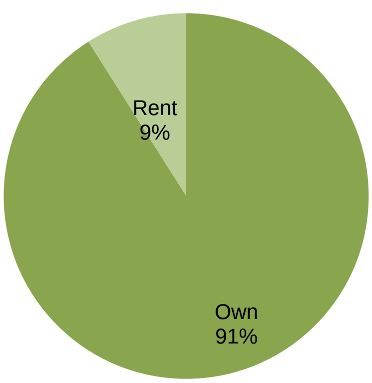
Environmental Issues Customer Research
October, 2017



In your opinion, how serious of a problem is climate change?

<u>RESEARCH DESIGN</u>
Research firm: C & T Marketing Group provided the survey participants
Methodology: Online survey through Qualtrics, fielded in October 2017
Sample size: 322 gas customers
Sample design: 3rd party research panel members who reside within NW Natural service territory
Confidence level: 95%
Margin of error: +/-5%
Demographics:

Homeownership



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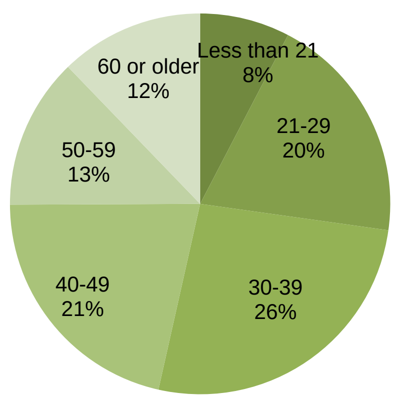

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Oregon Greenhouse Gas Reduction Actions to Address Climate Change and Air Quality

Climate Change

- Governor's Executive Order 17-20, 2017 - "Accelerating Efficiency in Oregon's Built Environment to Reduce Greenhouse Gas Emissions and Address Climate Change."
- Proposed SB 1070 Cap and Invest legislation, 2017 – Introduced for passage of Cap and Trade Legislation during 2018 session.

Voluntary Renewable Energy Goals

- 2017 - The City of Portland and Multnomah County establish a 100 percent renewable energy goal by 2050.

Renewable Natural Gas

- SB 344, 2017 - Requires Oregon Department of Energy to develop and maintain inventory of biogas and renewable natural gas resources available to Oregon.

Clean Fuels Program

- HB 2186, 2009 - The Oregon Legislature authorizes the Oregon Environmental Quality (DEQ) Commission to adopt rules to reduce the average carbon intensity of Oregon's transportation fuels by 10 percent over a 10-year period.
  - The 2015 Oregon Legislature passed SB 324 allowing DEQ to fully implement the Clean Fuels Program in 2016.
  - The 2017 Oregon Legislature passed HB 2017 to include cost containment provisions for the program. The program is codified in ORS 468A.275 and adopted in the Oregon Administrative Rules Chapter 340 Division 253.

Natural Gas Buses

- HB 2017 Section 122n, Subsection 5, 2017 – Legislature passes transportation plan, directs mass transit districts with a population of 200,000 or more to develop public transportation improvement plan for procuring buses that are powered by natural gas or electricity.

VW Settlement Funds to Address Air Quality

- SB 1008, 2017 - Authorizes Oregon DEQ to receive VW Settlement Funds to replace or repower older diesel powered buses, trucks, tugboats, cargo handling equipment, locomotives, and airport ground support equipment.

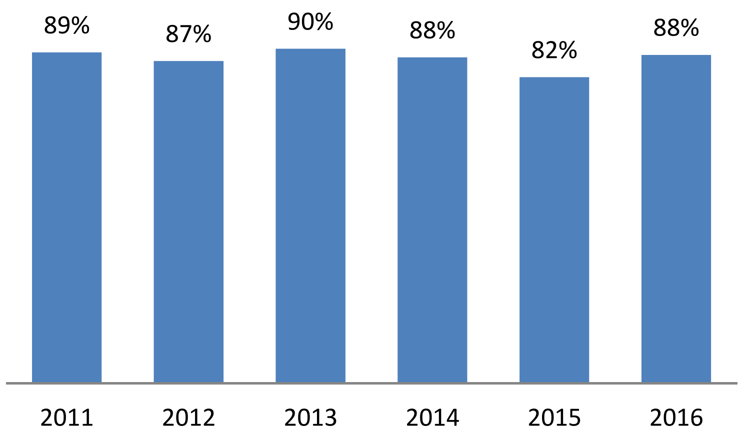
NW Natural®

2012-2016 Damage Summary	
Year	**Total Damages**
2012	487
2013	606
2014	635
2015	762
2016	800

Date: 4.7.17
Source: NW Natural Damage Prevention Records System

NW Natural

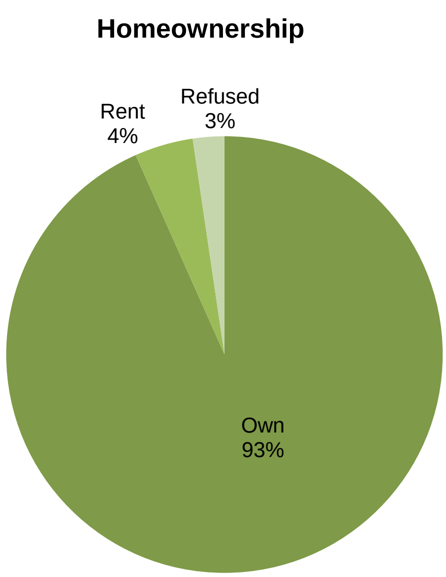
2016 Natural Gas Safety Tracking Survey
December, 2016

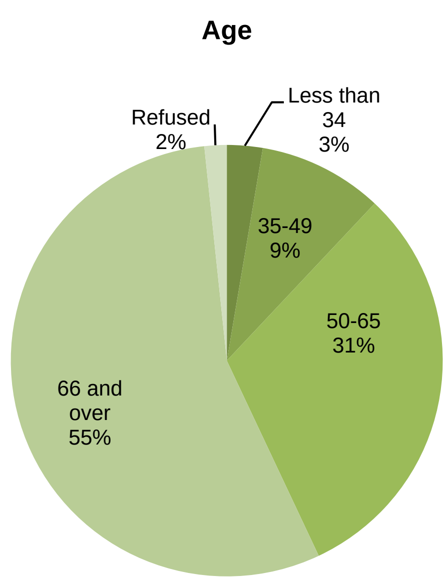


Are you aware it is required to call to have your utilities marked at least two-days before digging?

RESEARCH DESIGN

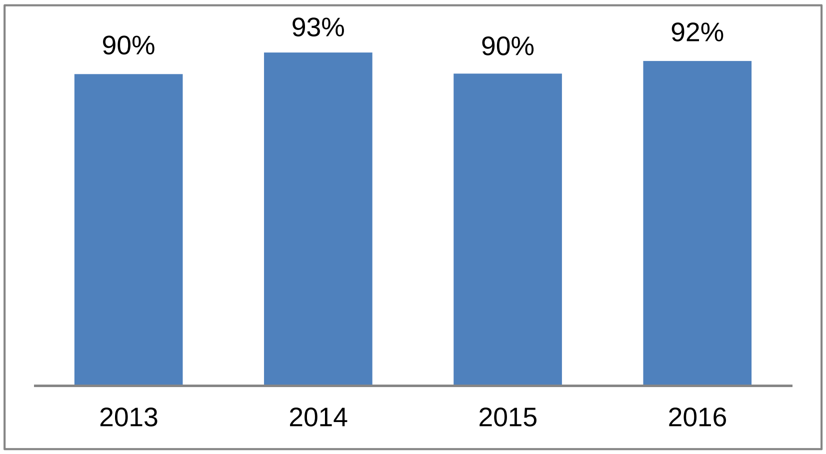
Research firm: James Industry Research Group provided the participants and conducted the phone interviews.
Methodology: Telephone survey fielded in December 2016
Sample size: 300
Sample design: Customers and non-customer samples are randomly selected to represent customers and the general public in NW Natural's service territory.
Confidence level: 95%
Margin of error: +/-8%
Demographics:





NW Natural®

2016 Contractor Safety Tracking Survey
December, 2016



Are you aware that you are required to contact the Utility Notification Center two business days before digging?

RESEARCH DESIGN

Methodology: Direct response mail-in survey
Returned surveys (2016): 322
Sample design: All licensed contractors within the NW Natural service territory received a safety mailing with a self-addressed, postage paid mail in survey
Confidence level: 95%
Margin of error: +/-5%
Demographics: All contractors with a valid contractor license from the State of Oregon

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Direct Testimony of Andrew Speer

LONG RUN INCREMENTAL COSTS AND RATE SPREAD EXHIBIT 1100

December 2017

EXHIBIT 1100 – DIRECT TESTIMONY – LONG RUN INCREMENTAL COSTS AND RATE SPREAD

Table of Contents

Rates & Regulatory Affairs
NW NATURAL
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Portland, Oregon 97209-3991
1-503-226-4211

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company (“NW Natural” or the “Company”).

A. My name is Andrew Speer. My current position is Rates and Regulatory Analyst for Northwest Natural Gas Company, d/b/a NW Natural (“NW Natural” or the “Company”). I am responsible for economic analysis, cost of service and rate design. I have served as a witness and provided technical workpapers on multiple rate and advice filings with the Oregon and Washington utility commissions.

Q. Please summarize your educational background and business experience.

A. I hold a Bachelor and Masters of Science in Economics from Portland State University. Prior to joining NW Natural in 2014 as a Rates and Regulatory Analyst, I was employed at the Bonneville Power Administration (BPA) for five years. While at BPA, I served as witness on two BPA rate proceedings and held positions as an Industry Economist in Power Policy & Rates, Risk Analyst in Enterprise Risk Management, and Account Specialist on BPA’s trading floor, responsible for evaluating the economic impact of long-term power purchase transactions.

Q. What is the purpose of your testimony?

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1-503-226-4211

A. The purpose of my testimony is to present NW Natural's Long-Run Incremental Cost (LRIC) study and rate spread proposal, with the allocated rate increase by rate schedule.

Q. Would you please summarize your testimony?

A. My testimony is made up of two distinct sections: LRIC and rate spread. First, my LRIC testimony will outline NW Natural's LRIC methodology and will show the incremental cost inputs by investment category and rate schedule. Second, my rate spread testimony will show how the Company's incremental revenue requirement is proposed to be spread across rate schedules.

The results of the LRIC study will show the Company's total revenue at current rates, as well as total revenue less commodity and demand gas costs that equals the Company's gross margin revenue (gross margin revenue = capital investment carrying costs, taxes, depreciation expense, and O&M). The LRIC will also calculate the ratio of "relative long-run costs" to gross margin at current rates for each rate schedule.

In the rate spread section, the testimony will describe the methodology for how NW Natural proposes to spread the incremental revenue requirement to customers based on an equal percent of margin basis. Lastly, the rate spread section will show how the final spread of incremental revenue requirement will impact rate schedules and customers' average bills.

Q. Are you introducing any exhibits with your testimony?

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1-503-226-4211

A. Yes. I am sponsoring Exhibits 1101, 1102, and 1103. *NW Natural/1101, Speer/1* is a summary of the Company's long-run incremental costs and revenue requirement allocation by rate schedule. *NW Natural/1102, Speer/1* and *NW Natural/1103, Speer/1* indicate the total revenue increases by rate schedule, as well as the bill impact and rate increase by rate schedule.

II. LONG-RUN INCREMNTAL COST STUDY

A. Long-Run Incremental Cost Study Purpose, Principles, and Inputs

Q. What purpose does the LRIC serve?

A. The overall objective of a cost of service study, including an LRIC, is to apportion the incremental revenue requirement to rate schedules based on each schedule's specific cost of service (whether embedded or long run). By understanding the long run incremental costs by rate schedule, the LRIC methodology is able to apportion a utility's distribution costs or revenue requirement based on cost causation. As a general rule, cost causation is an influential factor in parties' discussions on how to allocate costs to specific rate schedules for rate spread; therefore, it serves the utility well to understand the engineering and economic cost differences between customer classes and/or rate schedules.

The LRIC methodology is an engineering economics exercise that evaluates a company's future incremental capital and operations costs by rate schedule, along with the capital carrying costs to derive the total cost to serve

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Portland, Oregon 97209-3991
1-503-226-4211

customers. The Commission in Order No. 85-832 (Docket No. UG 14) directed that an LRIC study is "preferable" to an embedded cost approach because LRIC is the methodology that best achieves a *Pareto Optimal*[1] outcome for price setting and spreading rates. In other words, it best achieves a situation where individual customers are paying the costs associated with their service.

Q. Please describe the economic principles that underlie LRIC.

A. Economic principles for price setting say that price (P) must equal marginal cost(s) (MC) in order for customers to maximize consumer surplus and for firms to earn their fair rate of return (i.e. P = MC). In the long-run all inputs for MC are changing and in the short-run, one or more inputs are non-variable. However, in practice, the LRIC is neither a short nor long-run cost. Incremental costs coincide with the Company's Test Year so that system costs are evaluated at a reasonable future point in time and are also consistent with the Company's Test Year revenue requirement.

LRIC and cost studies in general allocate costs based on cost causation to identify how the incremental revenue requirement should be allocated to rate schedules in order to move closer to *Pareto Optimality*. The reasonable allocation of costs is determined by understanding the specific long-run incremental investments and customer characteristics associated with each class

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[1] A state of equilibrium where participants cannot be made neither collectively nor individually better off given a change in cost or price.

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1-503-226-4211

and rate schedule in order to equitably allocate costs. LRIC deviates from embedded cost studies through the evaluation of future incremental costs, while embedded cost studies evaluate only historical costs. In general, an embedded cost study will generate the average historical cost per customer but it does not help to achieve the state where P = MC, because it does not anticipate the cost of adding new customers based on short- to long-term marginal costs, but rather assumes historic costs for ongoing customer additions. Therefore a disparity would exist between the welfare of the consumer and the firm (where a firm is earning less than a reasonable return and consumer surplus is too large or vice versa).

As noted above, cost causation in general is the guiding principle for allocating costs; however, theoretical economists have derived the principles of “subsidy-free prices” and “stand-alone costs” (SAC) as a means for achieving *Pareto Optimality*. Subsidy-free pricing is achieved when the price of a good or service exceeds its MC but is less than the SAC. Prices set at a subsidy-free level provide customers an economy of scale given that all customers are paying a portion of the fixed system costs (P > MC) and an equitable cost sharing for fixed costs. While the sharing of fixed system costs is the most equitable outcome for customers, local distribution companies (LDC) must be aware that price does not exceed the SAC to serve customers because customers would in theory be unwilling to take service if prices exceed SAC. The concept of SAC

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Portland, Oregon 97209-3991
1-503-226-4211

says that if price exceeds the SAC of a good or service, customers will not be willing to pay that price, and customers will seek out an alternative good or service instead. Therefore, the level of price is key to ensuring customer equity is achieved between rate classes/schedules with common utility costs fairly distributed.

Q. Please describe the incremental cost categories included in the LRIC.

A. The incremental cost categories evaluated in the LRIC include capital investments and operations and maintenance (O&M). The individual capital investments include:

- Main extension
- Service line
- Meter set & regulator
- Storage

The incremental categories of O&M include:

- Gas Scheduling
- Gas Planning
- Account services (consisting of):
  - o Meter reading
  - o Billing
  - o Account management (call center, service techs, major account service and customer field services)

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220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Q. Please discuss what is considered incremental and non-incremental for purposes of the LRIC.

A. The term “incremental” refers to the cost categories that are attributable to the addition of a single new customer. As noted above, the LRIC cost categories are capital investments and O&M. An example of incremental capital cost versus a non-incremental capital cost would be a meter set and regulator, versus service center buildings or field vehicles. The reason a meter set is an incremental cost is because each customer requires a meter in order to be served. Service center buildings and field vehicles do not fall into the incremental cost category because they serve large areas of service territory and are not a direct function of the number of customers or customer growth.

B. NW Natural’s LRIC Study Inputs and Methodology

Q. Have you prepared an LRIC Study for this proceeding?

A. Yes. *NW Natural/1101, Speer/1* presents NW Natural’s LRIC Study. The exhibit shows the indicated LRIC summary results and the LRIC-indicated spread of NW Natural’s proposed revenue requirement by rate schedule. NW Natural’s LRIC methodology is similar to the methodologies used by Avista Corp and Cascade Natural Gas in their recent natural gas Oregon general rate cases.

1. Incremental Plant Investment

Q. Please outline the specific components of incremental plant investment evaluated in your study.

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1-503-226-4211

A. The plant cost categories evaluated in this study include:

1. Distribution main, which is required for various purposes over time as the system grows, including: a) mains to serve new customers, b) mains related to system reinforcements and capacity increases, and c) mains installed for safety and reliability purposes.
2. Storage, which includes the incremental costs associated with underground storage.
3. Service lines, which includes costs associated with the piping, trenching from meter set to distribution main, and distribution main tie-in.
4. Meter set and regulator assembly, which includes the cost of the meter, regulator, as well as the pipe fittings, bracket assemblies labor, and shop time required for assembly.

Q. How were distribution main costs calculated?

A. The main extension costs were evaluated using nine calendar years (2009 – 2017) of historical accounting data of Oregon main extension job orders. The accounting data includes the total cost and footage installed per job, and is delineated by market segment. The market segments analyzed include:

- Residential-single family
- Commercial
- Industrial

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Portland, Oregon 97209-3991
1-503-226-4211

The study shows a calculated average cost per foot and average main length installed per market segment to derive the average total main extension cost by market segment. The accounting data used in the calculation of the average cost of main extension is in nominal dollars. Therefore, for purposes of the Test Year, the data in nominal dollars by year is escalated using the Handy Whitman Index of Public Utility Construction Cost.

Q. How did you assign the average total main extension cost for each market segment to a rate schedule?

A. I directly assigned the "Residential-single family" market segment to Rate Schedule (RS) 2. The commercial market segment was assigned to RS 3 for both commercial and industrial customers in that rate class. RS 3 industrial customers were assigned the same commercial market segment for main extension because the sizing and overall characteristics of RS 3 industrial are the same as those of a RS 3 commercial customer.

For Rate Schedules 31 and 32, I apply either the commercial or industrial market segment depending on the rate schedule classifications for each customer within the group.

Q. How are service installation costs and average footage installed by rate schedule determined?

A. The calculation of the average cost per foot and the average footage installed was derived using nine years of accounting cost data (2009 – 2017) for customer

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Portland, Oregon 97209-3991
1-503-226-4211

service installations by market segment (Residential-single family, Commercial, and Industrial). The average cost by market segment was calculated using the nominal historical cost per foot for each job included in the sample and escalated to Test Year dollars using the Handy Whitman Index of Public Utility Construction Cost. The average footage installed per job was calculated by averaging the conversion job lengths by market segment.

Q. Please outline how costs were calculated for meters and regulators.

A. A customer query was run out of NW Natural's customer information system (CIS) that included each actively billed customer's meter set model number and delivery pressure. A summary of the CIS information provided the counts of meter set models by rate schedule. NW Natural's Engineering Department maintains an engineering cost memo which provides the assembly and capital cost for each assembled meter set (by meter model number) with regulator. A weighted average cost was calculated using the costs from the engineering cost memo and meter counts by rate schedule to derive the capital investment cost by rate schedule included in the incremental investments and also escalated to the Test Year using the Handy Whitman Utility Index of Public Utility Construction Costs.

Q. What is the source of the incremental storage cost included in the study?

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NW NATURAL
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Portland, Oregon 97209-3991
1-503-226-4211

A. The study applies the avoided cost associated with procuring underground storage as was identified and calculated in NW Natural's 2016 Integrated Resource Plan (IRP) (see Chapter 8, Page 8.4, Table 8.2).

Q. How is the avoided storage cost applied to each rate schedule?

A. The IRP's underground storage avoided cost of $0.0055 per therm for underground storage is applied by dividing $0.0055 by each rate schedule's load factor to account for each rate schedule's load requirements and cost to serve. Each schedule's resulting rate multiplied by each rate schedule's individual customer average annual usage calculates the total incremental investment for underground storage.

Q. What are the methods used to calculate the incremental system capacity and commodity main investment?

A. Incremental system reinforcement costs were calculated using the average of nine years of data (2009 – 2017). The average of NW Natural's system reinforcement capital investment was then multiplied by the "Oregon sendout volumes factor" ("sendout" is defined here to mean all therms, which include: firm and interruptible sales, firm and interruptible transportation, and Company use) to calculate the Oregon-only system reinforcement expenditures. The Oregon-only amount of system reinforcement costs were divided by the total Oregon normalized sales and transportation volumes.

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1-503-226-4211

Q. How are incremental capital costs applied in the LRIC for rate making/allocation purposes?

A. Incremental capital investments are implemented in the LRIC through applying the "investment carrying charge" to calculate the incremental revenue requirement associated with each category of investment by rate schedule. The investment carrying charge includes cost of capital (debt & equity), taxes, and depreciation to calculate the carrying percentage assigned to each category of investment. The investment carrying charge percentage is multiplied by each category of capital investment to calculate each rate schedule's annual revenue requirement. The indicated LRIC revenue requirement by rate schedule, for capital investments and O&M, are the factors for allocating the revenue requirement to each rate schedule based on cost causation.

2. Incremental Operations and Maintenance

Q. What are the categories of operations and maintenance (O&M) that were evaluated in this study?

A. The study incorporates the following categories of O&M which are incremental costs associated with customer additions:

- Gas Scheduling, which includes departments that schedule underground storage injections/withdrawals and manage the distribution system's daily operations.

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1-503-226-4211

- Gas Planning, operations that include, short- and long-term gas acquisitions, planning and analysis.
- Account services, including billing, metering, major account services and construction field services.

Q. How were gas planning and scheduling costs evaluated and assigned to each rate schedule?

A. The gas scheduling and gas planning cost centers were evaluated using the O&M budget cost center for the Gas Scheduling and Planning Department. The cost categories analyzed include changes in total salaries, administrative costs, and changes to FTE counts. Both the scheduling and planning cost centers use the Test Year of each cost center's budget forecast to evaluate the incremental costs for LRIC. In the study, both scheduling costs apply to both sales & transportation classes of service; however, only sales customers are allocated the costs associated with gas planning. This is because transportation customers do not incur gas planning costs because those customers are responsible for procuring their own gas.

Q. How did NW Natural evaluate incremental account service costs?

A. NW Natural conducted a "meter-to-cash" study, which evaluated the incremental costs associated with providing account service to customers. The study evaluated the following cost center groups in the Company that directly serve customers:

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Portland, Oregon 97209-3991
1-503-226-4211

- Account Services (meter reading scheduling, payment processing, collections)
- Contact Center (customer call center)
- Major Account Services (large customer account management)
- Resource Management Center (field services scheduling/dispatch)
- Construction Field Services (field technicians and field scheduling)
- Office Services (bill printing)
- Treasury (costs that pertain only to payment processing)

Interviews with the above groups' cost center managers were conducted to identify the specific actions each workgroup performed to directly serve customers. The information gathered enabled the isolation of incremental costs from each cost center's budget. From the identification of the incremental costs, the study broke out each cost center's budget into four categories:

1. Meter Reading
2. Billing
3. Payment Processing
4. Collections (costs that pertain to payment processing)

Within each category of budget, costs are evaluated as payroll vs. non-payroll. A cost by rate schedule was derived by taking the above categories and apportioning each cost category by the number of customers in each rate schedule to calculate each rate schedule's cost. The customer cost by rate

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

schedule was calculated by taking the apportioned total cost divided by each rate schedule's customer count to derive the individual customer cost by rate schedule.

Q. How is the meter-to-cash study integrated into the LRIC?

A. The LRIC uses the individual cost by rate schedule from the meter-to-cash study and escalates those values using the Handy Whitman Index Public Utility Operations and Maintenance cost escalators to inflate account services costs out to the Test Year.

<u>3. LRIC Insights and Outcomes</u>

Q. What do the results of the LRIC Study show?

A. Firm sales customers (residential, commercial, and industrial) indicated margin to cost ratio is illustrated in the table below. The results show that residential Rate Schedule 2 and commercial Rate Schedule 3 customers both have a ratio below 1, which indicates that both rate schedules are underpaying their LRIC determined cost of service. The results for commercial and industrial firm sales customers show ratios greater than 1 and therefore, these customer classes are paying more than their cost of service at margin rates.

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1-503-226-4211

Table 1

RATE SCHEDULE	02	03CSF	03ISF	27CSF	31CSF	31CTF	31ISF
Relative Margin to Cost at Present Rates	**0.90**	**0.89**	**2.95**	**0.67**	**4.67**	**8.23**	**2.63**

31ITF	32 CSF	32ISF	32TF	32CSI	32ISI	32TI	33T
3.79	**5.44**	**3.64**	**7.22**	**2.84**	**2.02**	**6.45**	**0.00**

III. RATE SPREAD

A. Summary

Q. What is the purpose of the rate spread section?

A. The purpose of this section is to show and summarize:

- NW Natural's incremental revenue requirement request;
- Discuss the results of the LRIC and how it relates to rate spread;
- Show the methodology for how NW Natural proposes to spread revenue; and
- Show the revenue requirement spread by rate schedule and the corresponding average bill impact.

Q. Is NW Natural proposing any rate design changes to their current rate schedule offerings?

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

A. No. NW Natural is not proposing any additions or removals of rate schedules in Oregon and is not proposing to make any changes to the monthly fixed charges for any rate schedule.

Q. What is NW Natural's total incremental revenue requirement?

A. $52.4 million. See *NW Natural/200, McVay/Page 6*.

Q. Of the $52.4 million incremental revenue requirement, how much represents incremental margin for NW Natural and how much is related to the updating of use-per-customer that forms a baseline for the decoupling mechanism?

A. Of the $52.4 million incremental revenue requirement, $40.4 million is new margin related to capital additions and increases to O&M. The remainder of the increase (over $12 million) to the revenue requirement is based on the decoupling rate mechanism and the deferral amount that would have accrued absent this rate case. Customers have already been paying for the decoupling deferral mechanism, so the real impact to customers in total from the case is the $40.4 million. Mr. McVay in his testimony *NW Natural/200, McVay/Page 6*, describes the net effect of decoupling on the revenue requirement increase.

Q. Is any of the $52.4 million of incremental revenue requirement attributable to special contract customers?

A. No. The special contract customers are not allocated any of the incremental revenue requirement given they are under fixed cost contracts.

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Portland, Oregon 97209-3991
1-503-226-4211

B. LRIC and Rate Spread

Q. How does the LRIC study relate to rate spread?

A. LRIC provides the engineering costs, by functional category, and gives insights into cost causation. In general, rate spread (and rate design) tends to deviate from what a strict application of a cost study indicates, given economic principles around “rate shock” and smoothing, as well as interests in equity and avoiding rate volatility; however, the cost study does provide a ‘baseline’ for rate allocation by rate schedule.

Q. What are NW Natural’s thoughts on using the LRIC results to spread revenue requirement?

A. NW Natural values the outputs and indications that LRIC provides as a baseline for revenue rate spread and sees value in using LRIC to spread rates. However, NW Natural believes that, as stated above, there are other important considerations that should be taken into account. In this case, the Company observes that spreading revenue requirement across rate schedules in a way that results in each rate schedule paying its LRIC would result in a large shift in rates among classes. Table 2 below shows the amount of dollars that would need to be spread to each rate schedule in order to put each class in line with paying its long-run incremental costs.

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1-503-226-4211

Table 2

RATE SCHEDULE	LRIC Target Revenue Change by RS
02	$63,448,423
03CSF	$20,824,121
03ISF	($1,085,990)
27CSF	$395,199
31CSF	($6,259,775)
31CTF	($959,518)
31ISF	($1,783,054)
31ITF	($62,827)
32 CSF	($6,962,826)
32ISF	($1,394,170)
32TF	($6,283,992)
32CSI	($1,274,472)
32ISI	($1,054,994)
32TI	($5,099,656)
33T	$0

As seen above, residential customers, for example, would incrementally bear significantly more costs than the Company's total requested incremental revenue requirement in this case.

Given the relatively significant increase in revenue requirement that is being reflected in this case, and the rate pressures that each class will experience even by maintaining each class's relative position with respect to LRIC, NW Natural believes that the factors of fairness, and minimizing rate impact weigh in favor of not using this case as a time to implement a shifting of costs on the basis of aligning classes more closely with the indicated LRIC results.

C. Rate Spread Methodology

Q. What method does NW Natural propose to use to spread the $52.4 million incremental revenue requirement?

A. NW Natural proposes an "equal percent of margin" calculation as the basis for spreading incremental revenue requirement.

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220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

Q. Would you please describe how the equal percent of margin calculation is applied?

A. The equal percent of margin calculation takes the margin revenue by rate schedule at current rates and divides that by NW Natural's total margin to derive a percentage rate. The calculated percentage is then multiplied by the incremental revenue requirement ($52.4 million) to calculate the dollar increase apportioned to each rate schedule.

Q. Does the equal percent of margin calculation change the LRIC study's margin to cost ratio across rate schedules?

A. No. The equal percent of margin calculation will not change the margin to cost ratio. Applying the equal percent of margin calculation will maintain the current margin to cost ratios.

Q. What rate (fixed monthly or volumetric) does NW Natural propose to change to recover the change in revenue?

A. NW Natural proposes to apply the change to the volumetric rate for each customer rate schedule and block. NW Natural does not propose a change to the fixed monthly charge.

D. Results and Bill Impacts

Q. What is the rate impact to firm sales customers?

A. Table 3 below shows the incremental revenue requirement and average bill increase for firm sales customers.

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Portland, Oregon 97209-3991
1-503-226-4211

Table 3

Rate Schedule	Revenue Req. Increase	% Increase to Avg. Cust. Bill
2R	$ 35,053,997	9%
3C Firm Sales	$ 10,709,119	8%
3I Firm Sales	$ 268,611	7%
31C Firm Sales	$ 1,255,180	7%
31I Firm Sales	$ 481,856	6%
32C Firm Sales	$ 1,340,399	6%
32I Firm Sales	$ 312,489	5%

Q. Does your testimony present the revenue and rate changes applicable to all other rate schedules as well?

A. Yes. *NW Natural/1102, Speer/1* shows the revenue increases and average bill impacts by rate schedule, and *NW Natural/1103, Speer/1* contains the volumetric rate increases by rate schedule and block.

Q. Does this conclude your testimony?

A. Yes.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
1-503-226-4211

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

NW Natural

Exhibits of Andrew Speer

LONG RUN INCREMENTAL COSTS AND RATE SPREAD EXHIBITS 1101 – 1103

December 2017

EXHIBITS 1101 – 1103 - LONG RUN INCREMENTAL COSTS AND RATE SPREAD

Table of Contents

Rates & Regulatory Affairs
NW Natural
220 N.W. Second Avenue
Portland, OR 97209-3991
1-503-226-4211

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019
Long-Run Incremental Cost Study
Summary of Results

Line No.	CUSTOMER CLASS / SERVICE TYPE / RATE SCHEDULE	Totals	Residential Sales Firm 02	Commercial Sales Firm 03CSF	Industrial Sales Firm 03ISF	Commercial Sales Firm 27CSF	Commercial Sales Firm 31CSF	Commercial Transportation Firm 31CTF	Industrial Sales Firm 31ISF	Industrial Transportation Firm 31ITF	Commercial Sales Firm 32 CSF	Industrial Sales Firm 32ISF	Transportation Firm 32TF	Commercial Sales Interruptible 32CSI	Industrial Sales Interruptible 32ISI	Transportation Interruptible 32TI	Transportation 33T	Special Contracts
	STATISTICS																	
1	2019 ANNUAL THERM DELIVERIES	1,073,764,878	385,050,429	166,461,516	4,874,416	1,197,618	25,390,021	3,496,586	14,010,541	363,568	39,092,810	13,823,132	92,722,465	23,733,673	27,416,484	196,967,402	-	79,164,217
2	2019 CUSTOMERS	673,269	610,273	58,752	355	1,962	740	74	217	5	433	62	178	58	68	85	-	7
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		631	2,833	13,731	610	34,311	47,251	64,565	72,714	90,284	222,954	520,913	409,201	403,184	2,317,264	-	11,309,174
4	Demand Charges	$76,015,833	$44,619,642	$19,289,561	$564,846	$138,779	$2,942,198	$0	$1,623,544	$0	$4,530,076	$1,601,827	$0	$327,287	$378,073	$0	$0	$0
5	Cost of Gas	$198,888,064	$109,238,807	$47,225,131	$1,382,872	$339,765	$7,203,149	$0	$3,974,789	$0	$11,090,630	$3,921,623	$0	$6,733,242	$7,778,056	$0	$0	$0
6	Total Cost of Gas	$274,903,897	$153,858,449	$66,514,692	$1,947,718	$478,544	$10,145,347	$0	$5,598,333	$0	$15,620,706	$5,523,450	$0	$7,060,529	$8,156,129	$0	$0	$0
7	Account Services (Meter Reading, Billing, etc.)	$26,500,696	$23,676,365	$2,361,734	$14,270	$76,118	$143,459	$14,397	$42,068	$973	$83,943	$12,020	$34,234	$11,244	$13,334	$16,537	$0	$1,362
	Customer Capital Investment Costs																	
8	Meter & Regulators	$31,271,274	$23,199,887	$6,259,399	$156,723	$78,040	$398,513	$39,725	$174,291	$3,648	$415,271	$85,920	$201,874	$83,708	$34,530	$139,745	$0	$11,508
9	Services	$234,118,449	$213,913,778	$18,100,185	$260,111	$687,723	$417,002	$40,236	$125,210	$2,981	$266,931	$34,696	$118,399	$45,969	$40,826	$64,401	$0	$5,304
10	Main Extensions	$315,808,952	$218,871,639	$90,254,775	$545,348	$703,662	$1,136,782	$113,678	$1,209,835	$27,876	$665,171	$345,667	$992,400	$89,099	$379,119	$473,899	$0	$39,027
11	Storage Costs	$2,166,814	$1,110,217	$666,276	$10,340	$3,451	$59,451	$0	$22,906	$0	$92,711	$29,367	$0	$70,795	$101,301	$0	$0	$0
12	Total Customer Capital Investment Costs	$583,365,488	$457,095,521	$115,280,635	$972,523	$1,472,877	$2,011,748	$193,639	$1,532,242	$34,505	$1,440,084	$495,650	$1,312,673	$289,572	$555,776	$678,044	$0	$55,839
13	Total System Reinforcement Cost	$4,751,743	$1,901,185	$1,140,999	$17,709	$5,909	$101,808	$16,856	$39,226	$800	$158,766	$50,299	$263,830	$121,228	$173,495	$759,633	$0	$62,558
14	Long Run Incremental Distribution Cost	$889,521,824	$636,531,520	$185,298,060	$2,952,220	$2,033,448	$12,402,362	$224,892	$7,211,870	$36,278	$17,303,499	$6,081,419	$1,610,737	$7,482,573	$8,898,734	$1,454,214	$0	$119,759
	Proposed Cost by Functional Classification																	
15	Cost of Gas Commodity	$276,853,509	$154,949,610	$66,986,413	$1,961,531	$481,938	$10,217,298	$0	$5,638,036	$0	$15,731,488	$5,562,622	$0	$7,110,602	$8,213,972	$0	$0	$0
16	Account Services (Meter Reading, Billing, etc.) Costs	$48,358,722	$43,204,855	$4,309,714	$26,041	$138,902	$261,785	$26,272	$76,767	$1,775	$153,180	$21,933	$62,470	$20,518	$24,333	$30,177	$0	$48,819
17	Meters & Services Costs	$68,997,521	$61,646,152	$6,333,142	$108,371	$199,088	$212,022	$20,789	$77,866	$1,723	$177,363	$31,358	$83,266	$33,714	$19,591	$53,075	$0	$85,882
18	System Core Main Costs	$262,906,879	$181,066,160	$74,957,966	$461,789	$581,953	$1,015,826	$107,057	$1,024,414	$23,519	$675,750	$324,751	$1,030,293	$172,499	$453,225	$1,011,677	$0	$1,654,166
19	Storage Costs	$20,203,532	$10,351,744	$6,212,408	$96,409	$32,173	$554,326	$0	$213,573	$0	$864,444	$273,821	$0	$660,100	$944,535	$0	$0	$0
20	Proposed Cost	$677,320,162	$451,218,520	$158,799,643	$2,654,141	$1,434,053	$12,261,256	$154,118	$7,030,656	$27,018	$17,602,224	$6,214,485	$1,176,029	$7,997,434	$9,655,656	$1,094,929	$0	$1,788,868
21	**LRIC Based Target Margin**	**$400,466,653**	**$296,268,911**	**$91,813,231**	**$692,610**	**$952,115**	**$2,043,959**	**$154,118**	**$1,392,620**	**$27,018**	**$1,870,737**	**$651,863**	**$1,176,029**	**$886,831**	**$1,441,684**	**$1,094,929**	**$0**	**$1,788,868**
22	Revenue at Current Rates	$624,873,692	$387,770,097	$137,975,522	$3,740,132	$1,038,854	$18,521,031	$1,113,636	$8,813,710	$89,844	$24,565,050	$7,608,655	$7,460,021	$9,271,906	$10,710,650	$6,194,584	$0	$1,788,868
23	**Margin Revenue at Current Rates**	**$351,758,663**	**$233,911,648**	**$71,460,830**	**$1,792,414**	**$560,310**	**$8,375,684**	**$1,113,636**	**$3,215,377**	**$89,844**	**$8,944,344**	**$2,085,205**	**$7,460,021**	**$2,211,377**	**$2,554,521**	**$6,194,584**	**$0**	**$1,788,868**
24	Current Revenue to Proposed Cost (Includes Cost of Gas)	**0.92**	**0.86**	**0.87**	**1.41**	**0.72**	**1.51**	**7.23**	**1.25**	**3.33**	**1.40**	**1.22**	**6.34**	**1.16**	**1.11**	**5.66**	-	-
25	Current Margin Revenue to LRIC Based Target Margin	**0.88**	**0.79**	**0.78**	**2.59**	**0.59**	**4.10**	**7.23**	**2.31**	**3.33**	**4.78**	**3.20**	**6.34**	**2.49**	**1.77**	**5.66**	-	-
	25A **Relative Margin to Cost at Present Rates**	**1.00**	**0.90**	**0.89**	**2.95**	**0.67**	**4.67**	**8.23**	**2.63**	**3.79**	**5.44**	**3.64**	**7.22**	**2.84**	**2.02**	**6.44**	-	-
26	Component LRIC Target Increase by Schedule	$52,446,470	$63,448,423	$20,824,121	($1,085,990)	$395,199	($6,259,775)	($959,518)	($1,783,054)	($62,827)	($6,962,826)	($1,394,170)	($6,283,992)	($1,274,472)	($1,054,994)	($5,099,656)	$0	$0
27	Target Increase as Percent of Total Present Revenue	8.39%	16.36%	15.09%	-29.04%	38.04%	-33.80%	-86.16%	-20.23%	-69.93%	-28.34%	-18.32%	-84.24%	-13.75%	-9.85%	-82.32%	0.00%	0.00%
	27A Target Increase as Percent of Present Margin Revenue	14.91%	27.12%	29.14%	-29.04%	70.53%	-74.74%	-86.16%	-55.45%	-69.93%	-77.85%	-66.86%	-84.24%	-57.63%	-41.30%	-82.32%	0.00%	0.00%

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019
Rate Spread Study
Allocation by Rate Schedule Summary

Line No.	Rate Schedule	Total Revenue at Present Rates	Proposed Revenue Increase	Total Revenue at Proposed Rates	Total Revenue Percentage Increase	Percentage Increase to Average Bill
1	02	$ 387,770,097	$ 35,053,997	$ 422,824,095	9.04%	9.16%
2	03CSF	$ 137,975,522	$ 10,709,119	$ 148,684,641	7.76%	7.87%
3	03ISF	$ 3,740,132	$ 268,611	$ 4,008,743	7.18%	7.29%
4	27CSF	$ 1,038,854	$ 83,968	$ 1,122,822	8.08%	8.20%
5	31CSF	$ 18,521,031	$ 1,255,180	$ 19,776,211	6.78%	6.98%
6	31CTF	$ 1,113,636	$ 166,890	$ 1,280,526	14.99%	14.93%
7	31ISF	$ 8,813,710	$ 481,856	$ 9,295,566	5.47%	5.56%
8	31ITF	$ 89,844	$ 13,464	$ 103,308	14.99%	14.91%
9	32 CSF	$ 24,565,050	$ 1,340,399	$ 25,905,449	5.46%	6.16%
10	32ISF	$ 7,608,655	$ 312,489	$ 7,921,144	4.11%	4.69%
11	32TF	$ 7,460,021	$ 1,117,959	$ 8,577,980	14.99%	19.14%
12	32CSI	$ 9,271,906	$ 331,397	$ 9,603,303	3.57%	4.68%
13	32ISI	$ 10,710,650	$ 382,821	$ 11,093,470	3.57%	4.61%
14	32TI	$ 6,194,584	$ 928,320	$ 7,122,905	14.99%	15.86%
15	33T	$ -	$ -	$ -	0.00%	0.00%
16	**Total**	**$ 624,873,692**	**$ 52,446,470**	**$ 677,320,162**	**8.39%**	

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019
Rate Spread Study
Rates by Rate Schedule & Block

Line No.	Schedule	Block		Volumes	Customers	Current Rates Volumetric Margin	Proposed Revenue Increase	Current/Proposed Rates Monthly Base Charge	Current Rates Base Rate	Change Base Rate Increase	Proposed Rates Base Rate
1	2R		N/A	385,050,429	606,831	$171,231,926	$35,053,997	$8	$0.44470	$0.09104	$0.53574
2	3C Firm Sales		N/A	166,461,516	58,617	$58,997,291	$10,709,119	$15	$0.35442	$0.06433	$0.41875
3	3I Firm Sales		N/A	4,874,416	355	$1,672,510	$268,611	$15	$0.34312	$0.05511	$0.39823
4	27 Dry Out		N/A	1,197,618	1,962	$405,286	$83,968	$6	$0.33841	$0.07011	$0.40852
5	31C Firm Sales	Block 1	2,000	12,784,484	740	$5,197,968	$1,255,180	$325	$0.21386	$0.05164	$0.26550
6		Block 2	all additional	12,605,537					$0.19546	$0.04720	$0.24266
7	31C Firm Trans	Block 1	2,000	1,523,968	74	$603,036	$166,890	$575	$0.18122	$0.05015	$0.23137
8		Block 2	all additional	1,972,618					$0.16570	$0.04586	$0.21156
9	31I Firm Sales	Block 1	2,000	4,299,679	217	$2,208,104	$481,856	$325	$0.16888	$0.03685	$0.20573
10		Block 2	all additional	9,710,862					$0.15261	$0.03330	$0.18591
11	31I Firm Trans	Block 1	2,000	91,578	5	$55,344	$13,464	$575	$0.16403	$0.03991	$0.20394
12		Block 2	all additional	271,990					$0.14825	$0.03607	$0.18432
13	32C Firm Sales1	Block 1	10,000	28,058,173	433	$3,656,050	$1,340,399	$675	$0.09877	$0.03621	$0.13498
14		Block 2	20,000	9,518,066					$0.08394	$0.03077	$0.11471
15		Block 3	20,000	1,350,403					$0.05928	$0.02173	$0.08101
16		Block 4	100,000	166,168					$0.03458	$0.01268	$0.04726
17		Block 5	600,000	-					$0.01978	$0.00000	$0.01978
18		Block 6	all additional	-					$0.00988	$0.00000	$0.00988
19	32I Firm Sales1	Block 1	10,000	5,409,612	62	$1,147,760	$312,489	$675	$0.09753	$0.02655	$0.12408
20		Block 2	20,000	5,816,515					$0.08291	$0.02257	$0.10548
21		Block 3	20,000	2,020,748					$0.05851	$0.01593	$0.07444
22		Block 4	100,000	576,257					$0.03415	$0.00930	$0.04345
23		Block 5	600,000	-					$0.01950	$0.00000	$0.01950
24		Block 6	all additional	-					$0.00980	$0.00000	$0.00980
25	32 Firm Trans	Block 1	10,000	14,881,729	178	$4,592,829	$1,117,959	$925	$0.09698	$0.02361	$0.12059
26		Block 2	20,000	16,126,373					$0.08241	$0.02006	$0.10247
27		Block 3	20,000	10,000,748					$0.05820	$0.01417	$0.07237
28		Block 4	100,000	20,036,765					$0.03395	$0.00826	$0.04221
29		Block 5	600,000	25,892,025					$0.01939	$0.00472	$0.02411
30		Block 6	all additional	5,784,825					$0.00973	$0.00237	$0.01210
31	32C Interr Sales	Block 1	10,000	5,114,441	58	$1,524,771	$331,397	$675	$0.10055	$0.02185	$0.12240
32		Block 2	20,000	6,268,233					$0.08547	$0.01858	$0.10405
33		Block 3	20,000	3,312,192					$0.06033	$0.01311	$0.07344
34		Block 4	100,000	6,448,719					$0.03520	$0.00765	$0.04285
35		Block 5	600,000	2,385,488					$0.02010	$0.00437	$0.02447
36		Block 6	all additional	-					$0.01009	$0.00000	$0.01009
37	32I Interr Sales	Block 1	10,000	6,003,909	68	$1,786,192	$382,821	$675	$0.10033	$0.02150	$0.12183
38		Block 2	20,000	7,358,360					$0.08530	$0.01828	$0.10358
39		Block 3	20,000	3,888,225					$0.06021	$0.01290	$0.07311
40		Block 4	100,000	7,570,236					$0.03512	$0.00753	$0.04265
41		Block 5	600,000	2,800,356					$0.02006	$0.00430	$0.02436
42		Block 6	all additional	-					$0.01005	$0.00000	$0.01005
43	32 Interr Trans	Block 1	10,000	7,385,146	85	$5,251,084	$928,320	$925	$0.09816	$0.01735	$0.11551
44		Block 2	20,000	12,638,632					$0.08344	$0.01475	$0.09819
45		Block 3	20,000	9,591,680					$0.05891	$0.01041	$0.06932
46		Block 4	100,000	30,167,941					$0.03436	$0.00607	$0.04043
47		Block 5	600,000	53,015,711					$0.01965	$0.00347	$0.02312
48		Block 6	all additional	84,168,292					$0.00984	$0.00174	$0.01158
49	33		N/A			$0	$0	$38,000	$0.00566	$0.00000	$0.00566