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NW Natural
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December 30, 2011 NWN Advice No. OPUC 11-19

VIA ELECTRONIC FILING AND PERSONAL DELIVERY

Public Utility Commission of Oregon
550 Capitol Street, NE, Suite 215
Post Office Box 2148
Salem, Oregon 97308-2148

Attention: Filing Center

Re: UG 221
Application of NW Natural for a General Rate Revision

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or "Company"), files herewith its Application for a General Rate Revision. An original and thirty (30) copies of the Application and 3 sets of work papers are included pursuant to OAR 860-001-0170(3).

Included with the Company's Application is Tariff P.U.C. Or. 25 (*See NWN/1700 and NWN/1701*), which will replace in the entirety the currently effective Tariff P.U.C. Or. 24. The proposed Tariff is stated to become effective with service on and after February 1, 2012.

The Company's responses to the Standard Data Requests required pursuant to OAR 860-022-0019(1)(i) are accessible to the Commission in electronic form on an .ftp site. The Company has also posted on this .ftp site copies of this Application in its entirety. The Company will provide .ftp access information to Commission Staff in a separate communication.

This filing requests a general rate increase in the Company's Oregon revenues of $43.7 million, an increase of six percent. The proposed increase is $28.6 million, an increase of four percent, when the decoupling deferral of $15.1 million already in current customer rates is taken into account. The executive summary required by OAR 860-022-0019 is attached.

If approved, this filing would impact customer bills as follows:

Rate Schedule	Current Average Monthly Bill	Proposed Average Monthly Bill	Change in Average Monthly bill ($)	Change in Average Monthly Bill (%)
Schedule 1- Residential	$23.12	$25.55	$2.43	10.5%
Schedule 1 - Commercial	$64.03	$68.57	$4.54	7.1%
Schedule 2 - Residential	$64.85	$70.03	$5.18	8.0%
Schedule 3- Commercial	$221.71	$234.61	$12.90	5.8%
Schedule 3- Industrial	$1,160.99	$1,221.53	$60.54	5.2%
Schedule 31 Firm Sales – commercial	$3,085.27	$3,167.17	$81.90	2.7%
Schedule 31 Firm Transportation – Commercial	$1,200.81	$1,203.41	$2.60	0.2%
Schedule 32 – Interruptible Transportation Service	$9,555.49	$9,312.11	($243.38)	(2.5%)

There are no changes proposed to Schedule 31 Industrial Firm Sales or Industrial Firm Transportation Service, or to Schedule 32 Firm Sales or Firm Transportation service.

If this filing is suspended, the Company requests procedures under which the parties may promptly identify issues so that settlement discussions may produce rate changes before the end of the suspension period.

Copies of this letter, the accompanying filing, and the supporting testimony and exhibits are available in the Company's main and district offices in Oregon. Notices will be published in accordance with the requirements of OAR 860-022-0017.

The Company waives paper service in this proceeding.

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

Lisa Rackner
McDowell Rackner & Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205
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Facsimile: 503-595-3928
Email: lisa@mcd-law.com

E-Filing
NW Natural
220 NW Second Avenue
Portland, OR 97209-3991
Email: e-filing@nwnatural.com

Please call me if you have questions.

Sincerely,

NW NATURAL

Mark R. Thompson
Manager, Rates & Regulatory Affairs

enclosures

NW Natural

CERTIFICATE OF SERVICE

I hereby certify that I served NWN ADVICE No. OPUC 11-19, and the EXECUTIVE SUMMARY IN THE MATTER OF NORTHWEST NATURAL GAS COMPANY APPLICATION FOR A GENERAL RATE REVISION upon the following parties by electronic mail.

G. CATRIONA MCCRACKEN
CITIZENS' UTILITY BOARD OF OREGON
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PAULA E PYRON
NORTHWEST INDUSTRIAL GAS USERS
ppyron@nwigu.org

DATED at Portland, Oregon, this 30th day of December 2011

Kelley C. Miller
Rates & Regulatory Affairs
NW NATURAL
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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UG 221

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 February 1, 2012. With this filing, the Company requests a revision to customer rates that will increase the Company's annual Oregon jurisdictional revenues by $43.7 million, for an increase of 6.2 percent over revenues from current customer rates. The increase is $28.6 million, about a four-percent increase, when the decoupling deferral of $15.1 million already in customers' current rates is taken into account. In addition, the Company is proposing an environmental cost recovery mechanism that would result in an additional increase to 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.

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 674,000 customers, consisting of approximately 611,000 residential, 62,000 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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III. CASE SUMMARY

A. The Test Year

The Company's test year in this case is the twelve months ending October 31, 2013 ("Test Year"). NW Natural provides information for a historical base period of twelve months ending December 31, 2011 ("Base Period"), 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 a test year that closely reflects 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 February 1, 2012. Assuming the addition of the full nine-month statutory suspension period to the 30-day effective date now contained in the tariffs, the new rates would become effective November 1, 2012.

B. Return on Equity

The Company's current return on equity (ROE) is 10.2 percent, as established in the Company's last Oregon general rate case, Docket UG 152 ("2002 Rate Case"). In this case, the Company seeks an ROE of 10.3 percent. This request is necessary to maintain the financial integrity of the Company while ensuring its ability to provide safe, efficient, and reliable service to its Oregon customers with minimal rate impact. At current rate levels, the Company's ROE in the Test Year would be 5.66 percent.

C. Factors Driving Rate Adjustment

1. Compliance with Safety Requirements

One of the key factors driving NW Natural's need for a rate increase is the implementation of new safety regulations that require the Company to increase its workforce and expenditures for pipeline inspection and maintenance. Federal safety requirements have become more stringent over the last several years and will continue to do so. To respond to the existing and expected heightened safety standards, the Company has incurred, and will be incurring additional operations and maintenance (O&M) expenses and capital costs over the levels currently reflected in rates. Increases in O&M resulting from safety requirements account for $9.1 million, or 32 percent, of the Company's proposed $28.6 million revenue requirement increase in this case. In addition, much of the increase to rate base in this case is related to the safety-related investments.

2. Enhanced Customer Service

While NW Natural's overall customer satisfaction is high, the Company is proposing specific improvements in this case to respond to customer needs. In response to customer feedback, NW Natural proposes to make capital investments and to increase O&M expenditures in order to provide four-hour service appointment windows to residential and small commercial customers. The proposed change is intended to respond to customer feedback that the current system of assigning service technicians to respond to customer calls between 8:00 a.m. and midnight is burdensome to customers. In addition, the Company proposes to provide customers with new no-fee options for paying bills. O&M expenses associated with these customer service initiatives account for $5.1 million, or 18 percent, of the Company's proposed $28.6 million revenue requirement increase in this case.

3. Company Contributions to Pension Funds

While the Company's pension funds have been closed to new hires since 2007 in the case of non-bargaining unit employees and 2010 in the case of bargaining unit employees, the Company has continuing obligations to fund pension plans for participating employees. Recent changes in the federal pension laws and conditions in the financial markets over the past several years have required NW Natural to make significant cash contributions to its employees' pension plans—well in excess of the amounts recovered in rates. As a result, the revenue requirement in this case reflects recovery in rate base of the cash contributions that the Company has made above what has been or would be collected in rates absent the Company's proposed rate base treatment. The Company's proposed recovery of cash contributions to pension plans accounts for $7.7 million, or 27 percent, of the Company's proposed $28.6 million revenue requirement increase in this case.

D. Cost Control Efforts

The rate request in this case reflects the Company's efforts since the 2002 Rate Case to aggressively manage its costs, while continuing to provide safe and reliable service.

Beginning in 2006, the Company instituted a number of initiatives intended to hold down capital and operating costs. The most significant of these initiatives was the complete restructuring of the Company's business units known at NW Natural as the Operations Model. Through the Operations Model, the Company centralized its operations to focus on the core processes of acquiring and serving customers. The Operations Model resulted in the Company outsourcing much of the field work consisting of more basic and highly repetitive tasks, allowing the Company to eliminate a number of full-time employee equivalent positions (FTEs). The Company retained FTEs for more challenging and complex construction activities, resulting in a leaner and highly-trained field workforce. During the Operations Model reorganization, the Company also reviewed and restructured its non-operating areas through a Business Services Efficiency Review (BSER). The Operations Model and BSER reduced FTEs by about 200 FTEs.

The second initiative the Company instituted to reduce costs was Automated Meter Reading (AMR). In 2005, NW Natural learned that its joint meter reading agreement with Portland General Electric Company (PGE) would likely be discontinued because PGE was considering a plan to institute advanced meter reading. Shortly thereafter, the Company began instituting AMR in the parts of its service territory that did not overlap with PGE's. In 2008, PGE informed NW Natural that it would end the joint meter reading agreement. The Company determined that instituting AMR throughout its service territory, although more expensive than the joint meter reading with PGE, would be less expensive than returning to manual meter reading. Instituting AMR resulted in a reduction of 64 meter reading positions.

Finally, the Company instituted the Low Growth Initiative in 2009. The Low Growth Initiative was developed to respond to slowing growth in the Company's number of customers. For two decades the Company experienced customer growth in excess of three percent per year, but growth started slowing in 2007 and has been less than one percent per year since 2009. The Company instituted a program to reduce an additional 50 FTEs over those reduced through the Operations Model and BSER to respond to this lower customer growth.

In addition to the three specific initiatives discussed above, the Company has taken additional actions to manage its costs. The Company addressed increases in the costs associated with employee benefits and salaries on a number of fronts. The Company closed its defined benefit pension plans and retiree medical benefits to new employees. The Company also increased employees' health care sharing percentage and capped the Company's contribution towards bargaining unit employee health care costs. In addition, in 2009 the Company eliminated salary increases for officers and constrained salary increases for non-bargaining unit employees to below-market levels.

The Company also managed costs by ensuring that the Company maintained strong credit ratings during the recent financial downturn. The Company's credit ratings have allowed it to access capital markets at very favorable rates even during the most difficult times of the financial crisis. To help maintain these strong ratings, the Company recently issued new debt to reduce interest costs. The Company's proposed ROE balances the Company's need to maintain these strong credit ratings with the need to limit the requested rate increase in this case.

Finally, the Company has made efforts to keep gas commodity costs, a significant portion of customers' rates, low. Combined with the other efforts described above, commodity costs have helped keep average customer bills to levels that are below what they were in 2005, even after the increase proposed in this filing.

The three initiatives and other cost control measures described above helped to keep the Company's costs much lower than they would have been absent the measures. Between 2001 and 2005, the year before the Operations Model was implemented, total O&M increased from $83.5 million to $110.6 million—a compound annual growth rate (CAGR) of 7.3 percent. After implementation of the Operations Model in 2006, O&M grew at a significantly lower CAGR of 2.9 percent between 2006 and the Test Year. If the pre-

Operations Model growth rate of 7.3 percent had persisted through the Test Year, O&M would have been $194 million, rather than the $138 million forecast in this case.

The Company has implemented its cost controls without compromising the safety or reliability of its service, as demonstrated by the Company's excellent record of safety and reliability. The Company's customer service metrics are higher than they have been in the past, with the Company placing first or second in J.D. Powers and Associates' customer satisfaction surveys in each of the last five years. The increase in the Company's revenue requirement in this case includes costs associated with furthering the Company's goals of providing safe and reliable natural gas service and achieving high levels of customer satisfaction.

E. Other Issues Addressed in Filing

In addition to the factors driving the rate increase described above, the testimony addresses other important policy and financial considerations. These include proposing a mechanism to recover costs associated with environmental remediation that have, to date, been deferred for collection, as well as proposing a modification to the Company's current rate design. Under the proposed rate design, the monthly customer charge for residential and certain commercial customers would be increased, with a corresponding decrease to those customers' volumetric charges. The proposed rate design will more closely match the recovery of the Company's fixed costs with fixed charges on customers' bills, and more closely align the collection of variable costs with the volumetric charge on customers' bills.

IV. TESTIMONY SUMMARY

The Company's direct case consists of the testimony and exhibits of 17 witnesses:

- In NWN/100, **Gregg Kantor**, President and Chief Executive Officer, provides a general overview of the case and introduces the Company witnesses and briefly describes their testimony;

- In NWN/200, **David H. Anderson**, Senior Vice President and Chief Financial Officer, summarizes the Company's request for a rate increase, including the key drivers of the requested rate increase, the risks of NW Natural's business, and proposes the return on equity to be applied in this case;
- In NWN/300, **Natasha Siores,** our Revenue Requirement and Regulatory Consultant, and **Kevin McVay**, our Business Development Consultant, present the Company's proposed revenue requirement;
- In NWN/400, **Stephen Feltz**, Treasurer and Controller, discusses the Company's capital structure and cost of capital proposal, and also discusses the Company's proposal for recovery of its cash pension contributions required by the Pension Protection Act that are not included in the Company's current FAS 87 expenses;
- In NWN/500, **Samuel Hadaway**, our consultant from FINANCO, Inc., presents his recommendation for an appropriate range for return on equity;
- In NWN/600, **Grant Yoshihara**, Vice President of Utility Operations and Chief Engineer, discusses several planned capital additions, modifications to the Company's System Integrity Program and additional operations and maintenance expenses required in response to changing federal safety regulations, the work the Company plans for their implementation, and research and development;
- In NWN/700, **John Sohl**, Business and Budget Manager, discusses our O&M and capital expenditures for the test year.
- In NWN/800, **Lea Anne Doolittle**, Senior Vice President, explains the costs related to compensation and benefits included in the case, and a safety training and business continuity facility that the company is purchasing and developing;

- In NWN/900, **David Williams**, Vice President of Utility Services, presents the Company's proposals to improve customer service, including implementation of morning and afternoon service windows, and no-fee bill payment options;
- In NWN/1000, **Kimberly Heiting**, Chief Communications Officer, presents the Company's proposed plan for customer communications for the test year;
- In NWN/1100, **Russell Feingold**, our consultant from Black & Veatch Corporation, presents a long-run incremental cost study and the Company's proposal for changes to its rate design;
- In NWN/1200, **Natasha Siores**, our Revenue Requirement Regulatory Consultant discusses the Company's proposed changes to its current rate mechanisms;
- In NWN/1300, **Robert J. Wyatt**, Environmental Manager, describes the federal and state environmental actions that define the scope of the Company's environmental remediation obligations;
- In NWN/1400, **Sandra K. Hart**, Director of Risk and Land, describes the Company's efforts in pursuing insurance recovery for its environmental remediation obligations;
- In NWN/1500, **C. Alex Miller**, Vice President of Finance and Regulation and Assistant Treasurer, describes the rate mechanism by which the Company proposes to recover its environmental remediation costs;
- In NWN/1600, **Andrew Middleton**, our consultant from Corporate Environmental Solutions, LLC, explains historical manufactured gas operations as well as the Company's operations that resulted in its environmental remediation obligations; and
- In NWN/1700, **Onita King**, Tariffs and Regulatory Consultant, describes and presents the Company's proposed tariffs.

V. CONCLUSION

The Company requests that the Commission issue an order approving of the proposed rate changes and approving the proposed tariffs.

DATED: December 30, 2011.

MCDOWELL RACKNER & GIBSON PC

Lisa F. Rackner
Amie Jamieson

NORTHWEST NATURAL GAS COMPANY

Mark Thompson
Manager, Rates and Regulatory
220 NW Second Ave
Portland, OR 97209

Attorneys for NW Natural

Exhibit A
Summary of Requested General Rate Increase

Oregon Jurisdiction
Filed December 30, 2011

Total Revenues Collected Under Proposed Rates:	$ 742,978,000
Revenue Change Requested:	$ 43,682,000
Revenues Net of any Credits from Federal Agencies:	$ 43,682,000
Percentage Change in Revenues Requested:	6.2%
Percentage Change in Revenues Net of any Credits from Federal Agencies:	6.2%
Test Period:	November 1, 2012 to October 31, 2013
Requested Rate of Return on Capital:	8.28%
Requested Rate of Return on Equity:	10.3%
Proposed Rate Base:	$ 983,685,000

Results of Operation[1]

Before Proposed Rate Change	
Utility Operating Income:	$84,845,000
Average Rate Base:	$967,308,000
Rate of Return on Capital:	8.77%
Rate of Return on Equity:	11.1%
After Proposed Rate Change[2]	
Utility Operating Income:	$81,474,000
Average Rate Base:	$983,685,000
Rate of Return on Capital:	8.28%
Rate of Return on Equity:	10.3%

Bill Effect of Rate Change on Each Customer Class

Schedule 1 - General Sales Service: Residential	10.5%
Schedule 1 - General Sales Service: Commercial	7.1%
Schedule 2 - Residential Sales Service	8.0%
Schedule 3- Basic Firm Non-Residential Sales Service: Commercial	5.8%
Schedule 3- Basic Firm Non-Residential Sales Service: Industrial	5.2%
Schedule 19 - Gas Light Service (FROZEN)	cancelled
Schedule 31: Non-Residential Firm Sales Service: Commercial	2.7%
Schedule 31: Non-Residential Firm Transportation Service: Commercial	0.2%
Schedule 31: Non-Residential Interruptible Sales Service: Commercial	0.0%
Schedule 31: Non-Residential Firm Sales Service: Industrial	0.0%

[1] Based upon the Company's 2010 Report of Operations.

[2] Based upon the Company's 2011 general rate case filing.

Schedule 31: Non-Residential Firm Transportation Service: Industrial	0.0%
Schedule 31: Non-Residential Interruptible Sales Service: Industrial	0.1%
Schedule 32: Large Volume Non-Residential Firm Sales Service: Commercial	0.0%
Schedule 32: Large Volume Non-Residential Firm Sales Service: Industrial	0.0%
Schedule 32: Large Volume Non-Residential Transportation Service: Firm Service	0.0%
Schedule 32: Large Volume Non-Residential Interruptible Sales Service: Commercial	0.0%
Schedule 32: Large Volume Non-Residential Interruptible Sales Service: Industrial	0.0%
Schedule 32: Large Volume Non-Residential Transportation Service: Interruptible Service	-2.5%
Schedule 33: High Volume Non-Residential Firm and Interruptible Transportation Service	0.0%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Gregg Kantor

POLICY
EXHIBIT 100

December 2011

EXHIBIT 100 – DIRECT TESTIMONY – POLICY

Table of Contents

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
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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 Gregg Kantor. I am the President and Chief Executive Officer (CEO) of NW Natural, a position I have held since 2009.

Q. Please summarize your educational background and business experience.

A. I have a Bachelor of Arts degree in Geography and Environmental Studies from the University of California at Santa Barbara, and a Master of Arts degree in Urban Planning from the University of Oregon. Prior to my current position as CEO, I served as President and Chief Operating Officer of NW Natural from May 2007 to December 2008, and as Executive Vice President from December 2006 through April 2007. I also served as Senior Vice President of Public and Regulatory Affairs from 2003 to 2006, as Vice President of Public Affairs and Communications from 1998 to 2003, and as Director of Public Affairs and Communications from 1996 to 1998. Prior to coming to NW Natural, I was a principal in my own government affairs consulting firm, Kantor & Associates, from 1994 to 1996, and the Manager of Community Development at Portland General Electric, from 1991 to 1993.

Q. Please summarize your testimony.

A. In my testimony, I:

- Provide an overview of our rate request in this filing, including a brief explanation as to why we are filing this case and the specific factors driving the rate increase;
- Identify some of the challenges facing the Company and our proposals in this rate case for addressing those challenges;

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- Discuss our primary objectives as a Company; and
- Introduce the witnesses presenting the case.

II. OVERVIEW OF RATE REQUEST

Q. What is NW Natural seeking in this filing?

A. NW Natural is requesting a revenue requirement increase of $43.7 million over what would be produced at current rates. Including projected costs of gas, this increase results in a $743 million revenue requirement for the Test Year, which is the period from November 1, 2012 through October 31, 2013. The $43.7 million increase includes $15.1 million currently being collected through our decoupling deferral, leaving a net increase of $28.6 million. If approved, this revenue requirement will result in an approximately six percent increase over current customer rates, or about a four percent increase after taking into account that the decoupling deferral is already included in those rates. As explained in the testimony of C. Alex Miller, the Company is also proposing an environmental cost recovery mechanism, which would result in an additional increase.

Q. Why is NW Natural filing for a rate increase at this time?

A. Since our last general rate increase in 2003, the Company has been managed in a thoughtful and responsible way. As will be discussed in detail by David H. Anderson, given the challenging economy and, at times volatile gas prices, we have been required to aggressively manage our costs; in fact we have made some very difficult decisions to reduce staffing and expand job duties in order to reach our cost-containment goals. These changes have been difficult on our employees, but we have not pursued cost-cutting at the expense of our customers. On the contrary, we have managed our costs while satisfying our commitment to deliver reliable natural gas service to our customers

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at a reasonable price and maintaining an excellent safety record and good customer service. In fact, over the last several years, NW Natural has consistently been ranked first or second by J.D. Power and Associates in overall customer satisfaction.

Through this disciplined approach we have managed to avoid coming in for a general rate increase for many years, fulfilling our agreement to a rate case moratorium even during a severe economic downturn. As will be explained in testimony provided in this case, certain factors related to changes in the industry and our business are resulting in increasing costs that the Company must recover in order to remain financially strong.

Q. What factors are driving the need for the rate increase?

A. A number of factors are driving the need for the rate increase. As is discussed by the relevant Company witnesses, the most significant are: (1) the implementation of new safety regulations that require the Company to increase its workforce and expenditures for pipeline inspection and maintenance; (2) the Company's proposal to make specific improvements to its customer service; and (3) the Company's proposal to recover the costs associated with its pension contributions that are not addressed in the current FAS 87 balancing account.

Q. Please explain the need to implement new safety regulations.

A. In the past two years, the nation has experienced several tragic natural gas related incidents, including one in San Bruno, California and another in Allentown, Pennsylvania, that have resulted in a heightened national awareness of natural gas pipeline safety. As explained in more detail in the direct testimony of Grant Yoshihara, in response to these incidents, federal safety requirements are becoming more stringent,

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requiring local distribution companies such as NW Natural to attain ever-higher safety standards.

Q. Please explain the Company's proposal to increase customer service.

A. NW Natural has maintained a very strong record of customer service. For the past five years, we have consistently been rated first or second in J.D. Power's overall customer service surveys. Additionally, our internal measures of overall customer satisfaction remain high. However, as the direct testimony of David Williams explains, our customers are telling us that there are important areas in which our customer service can and should improve—specifically, by providing service appointment windows that narrow the period of time in which our customers must make themselves available for a service appointment. We agree with our customers on this point, and we are therefore proposing a significant change to the way we schedule our service appointments. In addition, as will be explained by Mr. Williams, we also propose to provide our customers with new no-fee options for paying bills.

Q. Please explain the Company's need to recover the costs associated with its pension contributions.

A. Our Treasurer and Controller, Stephen Feltz provides detailed testimony on this topic—but the bottom line is this: as a result of changes in federal pension regulations, combined with financial market conditions, over the past several years NW Natural has been required to make cash contributions to our employees' pension funds totaling many millions of dollars beyond what the Company is recovering in rates. Mr. Feltz proposes that the Company be allowed to recover through rate base those contributions that the

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Company has made beyond what has been or will be collected through the current mechanism.

III. ADDITIONAL CHALLENGES FACING NW NATURAL

Q. Does the filing raise any other major issues?

A. Yes. The filing seeks to address two of the major challenges facing the Company today: (1) a large and growing environmental remediation obligation; and (2) a need to improve the Company's rate design.

Q. Please explain the challenge presented by the Company's environmental remediation obligations.

A. Since 2003, the Company has been deferring the costs associated with our clean-up efforts related to the historic operation of manufactured gas plants by the Company's predecessor. At the end of the third quarter of 2011, we have deferred approximately $65 million, and we expect our expenses to increase substantially over the next several years. While, as discussed in the testimony of Sandra K. Hart, we are seeking to recover these expenses from our insurers, given the uncertainty of such recoveries and the substantial sums involved, we think it is important to begin collecting those costs now, especially while gas prices are relatively low. Through the testimony of C. Alex Miller, we have presented a recovery proposal that will recognize our cost obligations and insurance recoveries over time.

Q. Please explain the need to improve upon NW Natural's rate design.

A. As is explained in the testimony of Natasha Siores, the Company is facing declining usage per customer. Our decoupling mechanism addresses this issue in part. However, we feel that our decoupling mechanism—together with our weather

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normalization adjustment mechanism—should be replaced by a more straight-forward and efficient rate design, which is proposed in the direct testimony of Russell Feingold.

Q. Will a change in rate design alter your commitment to working with the Energy Trust of Oregon (ETO) on energy efficiency?

A. We remain committed to working with the ETO and collecting public purpose funding for the ETO as long as the final rate design adopted in this proceeding continues to remove the financial disincentive to the Company of encouraging increased energy efficiency for our customers. Further, the Company is interested in expanding energy efficiency opportunities for its customers and will be developing ideas and discussing them with the parties and the Commission in other forums.

IV. COMPANY OBJECTIVES

Q. Please discuss the Company's overall objectives.

A. It is first important to point out that unlike electric and water utilities, gas service is not provided in every home. Consumers may choose to receive natural gas service or not. As a result, NW Natural must compete for every customer we hook up. That means we must deliver our service efficiently, paying relentless attention to safety and reliability. These are our consistent goals and our Company objectives.

As I mentioned above, our customer service continues to be well received thanks to the women and men that serve our customers every day. We have one of the most proactive pipeline integrity management programs in the country. In the last two years we have stepped up training to expand the number of employee first responders, and are working to make big strides in employee safety. And we have done this while strictly managing costs and capital expenditures.

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We are proud of our successes, and our primary goal is to continue our tradition by maintaining an excellent safety record and improving customer service, all while providing reliable gas service to our customers and aggressively controlling costs. That is what our customers have come to expect from NW Natural, and that is what we intend to deliver. It is worth pointing out that even with our requested rate increase, our expense per customer will remain below our peers, and our number of full-time equivalent employees will remain below our 2006 levels. Just as importantly, we intend to maintain the financial strength and viability of the Company in order to remain a stand-alone gas local distribution company and a vibrant part of the Oregon economy.

V. INTRODUCTION OF WITNESSES

Q. Please introduce the witnesses who are providing direct testimony in this case:

- In NWN/200, **David H. Anderson**, Senior Vice President and Chief Financial Officer, provides an overview of the case, including the key drivers of the requested rate increase, the risks of NW Natural's business, and proposes the return on equity to be applied in this case;
- In NWN/300, **Natasha Siores,** our Revenue Requirement and Regulatory Consultant, and **Kevin McVay**, our Business Development Consultant, present the Company's proposed revenue requirement;
- In NWN/400, **Stephen Feltz**, Treasurer and Controller, discusses the Company's capital structure and cost of capital proposal, and also discusses the Company's proposal for recovery of its cash pension contributions required by the Pension Protection Act, and not included in the Company's current FAS 87 expenses;

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- In NWN/500, **Samuel Hadaway**, our consultant from FINANCO, Inc., presents his recommendation for an appropriate range for return on equity;
- In NWN/600, **Grant Yoshihara**, Vice President of Utility Operations and Chief Engineer, discusses several planned capital additions, modifications to the Company's System Integrity Program and additional operations and maintenance expenses required in response to changing federal safety regulations, the work the Company plans for their implementation, and research and development;
- In NWN/700, **John Sohl**, Business and Budget Manager, discusses our O&M and capital expenditures for the test year.
- In NWN/800, **Lea Anne Doolittle**, Senior Vice President, explains the costs related to compensation and benefits included in the case, and a safety training and business continuity facility that the company is purchasing and developing;
- In NWN/900, **David Williams**, Vice President of Utility Services, presents the Company's proposals to improve customer service, including implementation of morning and afternoon service windows, and no-fee bill payment options;
- In NWN/1000, **Kimberly Heiting**, Chief Communications Officer, presents the Company's proposed plan for customer communications for the test year;
- In NWN/1100, **Russell Feingold**, our consultant from Black & Veatch Corporation, presents a long-run incremental cost study and the Company's proposal for changes to its rate design;
- In NWN/1200, **Natasha Siores**, our Revenue Requirement Regulatory Consultant discusses the Company's proposed changes to its current rate mechanisms;

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- In NWN/1300, **Robert J. Wyatt**, Environmental Manager, describes the federal and state environmental actions that define the scope of the Company's environmental remediation obligations;
- In NWN/1400, **Sandra K. Hart**, Director of Risk and Land, describes the Company's efforts in pursuing insurance recovery for its environmental remediation obligations;
- In NWN/1500, **C. Alex Miller**, Vice President of Finance and Regulation and Assistant Treasurer, describes the rate mechanism by which the Company proposes to recover its environmental remediation costs;
- In NWN/1600, **Andrew Middleton**, our consultant from Corporate Environmental Solutions, LLC, explains historical manufactured gas operations as well as the Company's operations that resulted in its environmental remediation obligations; and
- In NWN/1700, **Onita King**, Tariffs and Regulatory Consultant, describes and presents the Company's proposed tariffs.

Q. Does this conclude your direct testimony?

A. Yes.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of David Anderson

CASE OVERVIEW
EXHIBIT 200

December 2011

EXHIBIT 200 – DIRECT TESTIMONY – CASE OVERVIEW

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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 Senior Vice President and the Chief Financial Officer (CFO) of NW Natural. I also function as the Chief Risk Officer for the Company. As CFO, I am a member of the senior management team reporting to the Chief Executive Officer. My responsibilities include regulatory, financial planning and analysis, treasury, accounting, information services, budgeting, tax, supply chain, and investor relations. I also oversee the Company's Enterprise Risk Management efforts.

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 in Oregon, Washington, and Texas. I have spent over 25 years in the energy and utility industries. I joined NW Natural in 2004 as the Chief Financial Officer. Prior to joining NW Natural, I worked for TXU Corporation (formally 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:

- Summarize the Company's request for a rate increase and explain the primary drivers of the increase, which include: (1) the need to respond to evolving safety

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and training needs; (2) our desire to improve customer service; and (3) the need to recover the Company's costs associated with its pension contributions that are not addressed by the current Financial Accounting Standard (FAS) 87 balancing account;

- Provide an overview of Company operations, including the economic and business factors putting upward pressure on operating costs. I will discuss the various initiatives the Company has taken to control its costs, and in particular how the Company has aggressively managed its costs over the past seven years, allowing us to stay out of a rate case for this extended period of time;
- Discuss what I see as the key risks and challenges facing the Company today: (1) declining use and increased competition; (2) a large and growing environmental remediation obligation connected to historic manufactured natural gas operations; and (3) the ability of the Company to access capital in challenging economic times; and
- Explain why the return on equity (ROE) proposed in this case is necessary to maintain the financial strength of the Company.

II. SUMMARY OF THE COMPANY'S RATE REQUEST

Q. Please describe NW Natural's rate request in this case.

A. NW Natural is proposing a rate increase of $43.7 million, which results in an increase of six percent over current customer rates, or $28.6 million, about a four-percent increase, after taking into account that the decoupling deferral of $15.1 million is already in customers' current rates. The increase is calculated on an overall revenue requirement

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of $743 million, assuming a rate base of $983.7 million, an ROE of 10.3 percent and an overall rate of return of 8.28 percent. In addition, as described in the direct testimony of C. Alex Miller, the Company is proposing an environmental cost recovery mechanism that would result in an additional increase to rates.

Q. What are the primary drivers of the requested rate increase?

A. There are three primary drivers of the requested rate increase. These are: (1) the Company's need to comply with increasingly stringent safety requirements, including an increased workforce to respond more quickly and effectively to potential problems, and increased training facilities and programs; (2) the Company's desire to respond to customer expectations of increased customer service, and in particular service windows; and (3) the Company's proposal to recover its costs associated with its pension contributions that are not addressed in the current FAS 87 balancing account.

The direct testimony of Grant Yoshihara addresses the Company's planned investments in safety programs, the direct testimony of David Williams addresses the Company's planned investments in customer service programs, and the direct testimony of Stephen P. Feltz addresses the Company's proposal for recovery of its investment in pension contributions.

III. OVERVIEW OF COMPANY OPERATIONS AND COST CONTROL INITIATIVES

Q. Please provide an overview of Company operations.

A. NW Natural is a local distribution company (LDC) that is regulated in the states of Oregon and Washington. At year-end 2010, we had approximately 674,000 utility customers, consisting of approximately 611,000 residential, 62,000 commercial, and

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1,000 industrial customers. Approximately 90 percent of our utility customers are located in Oregon and approximately ten percent are located in Washington. For the year ended December 31, 2010, the Company's total assets were $2.6 billion,[1] and net utility plant was $1.6 billion.[2]

Q. Have Company operations changed since the last Oregon rate case, Docket UG 152 ("2002 Rate Case") eight years ago?

A. Yes, they have changed significantly. Since the 2002 Rate Case, the Company has revised and restructured operations in order to hold down operating costs and to compete for customers in an ever-changing business landscape. In particular, we have undergone a complete restructuring of the way that our business units are organized by instituting what we call the Operations Model. In addition, we have deployed Automated Meter Reading (AMI) throughout our service territory, and we adopted our Low Growth Initiative to address the effects of the severe recession. Many other aspects of Company operations have changed in nine years, including two updates to the union contract, changes in benefits, changes in safety programs, and changes made to respond to new laws and regulations, to mention a few. But in terms of cost controls, the three initiatives mentioned above are most important.

[1] NW Natural's 2010 10-K Report, page 37.

[2] *Id*. at 117.

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IV. OPERATIONS MODEL

Q. Please describe the Operations Model.

A. The Operations Model is what the Company named the process by which we restructured our business units—beginning in 2006—in order to hold down capital and operating costs and to allow the Company to thrive in an increasingly competitive market.

Q. Please explain the factors giving rise to the Operations Model.

A. After I was hired in 2005, one of my first tasks was to evaluate the efficiency of the Company's operations and related costs. From 2001 to 2005, the Company saw operational costs increase at a compound annual growth rate of 7.3 percent while O&M costs per customer grew at a rate of 3.8 percent. We were also seeing similar cost pressures in capital expenditures. These trends, combined with other challenges facing the Company, called for immediate action. As a result, we determined to institute actions to both slow the rate of cost increases, and also to make more of our costs variable in nature so that we could more quickly adapt to changing economic and business conditions.

Q. What are the other challenges to which you are referring?

A. In 2006, natural gas commodity costs were increasing and highly volatile, having increased 56 percent since 2000. These increased commodity costs were translating into higher customer rates through the Company's Purchased Gas Adjustment (PGA). The Company did not wish to add steadily increasing O&M and capital costs to customer rates as well.

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Q. How did you go about the cost containment effort?

A. We first composed a team that was led by Mr. Williams and Mr. Yoshihara. The team set about to identify what it viewed as well-run LDCs. Once identified, we studied those LDCs by touring their field operations and offices, and interviewing key employees and management in an effort to determine "best practices" for running an efficient operation.

A. What did you find?

Q. Overall, we determined that NW Natural was very well run. Through the process of comparing our operations with other LDCs, we reconfirmed our confidence in the quality of service that we provide to our customers, the professionalism of our workforce, and the management of our operations. However, the Company's investigation also suggested that we could improve our operations and reduce costs by centralizing our business functions, outsourcing most of our nontechnical construction work, and taking greater advantage of technology.

Q. Please explain.

A. Prior to 2006, NW Natural's operations were primarily run on a district-by-district basis. The Company was divided up into nine district offices, including, for example, the Portland District and Salem District. Certain functions, such as marketing, payment centers, construction, field service and dispatch operations, were conducted separately in each district. In addition, each employee was assigned to a specific district, most of the training was conducted by district, and some policies and procedures were adopted by district. This structure made sense at the time it was adopted. Advances in technology such as centralized dispatching, global positioning location devices on our

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trucks, and other equipment and software enhancements, however, made centralizing these functions a possibility.

Q. What benefits of centralization of business functions did you observe in other LDCs during your investigation?

A. We observed that a centralized structure allows for more company-wide training and consistent and standardized application of policies and procedures. It also provides companies with the ability to forecast and schedule work on a system-wide basis, effectively "borrowing" employees from one geographical area to another when necessary, which allows these companies to maintain overall leaner workforces. Finally, we saw that a centralized structure allows companies to outsource a greater number of functions, which allows them to staff up and staff down as business conditions require.

Q. What did the Company do with this information?

A. The Company, working through teams of employees, developed a plan for restructuring its operations on a Company-wide basis, to move to a centralized model focused on the core processes of acquiring and serving customers.

Q. What are the core processes around which the Company organized its operations?

A. The Company organized itself around three primary processes: "Acquire Customers", "Serve Customers", and "Deliver Gas."

Q. Please describe each of these processes.

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A. Acquire Customers encompasses all activities related to customers up until the time they are hooked up with a service at their home or business. Our employees assigned to this function include those in our Construction, Sales, and Marketing departments.

Serve Customers includes all of the customer-facing activities for existing customers, from the call center to the performance of field work, such as re-lights of customers' gas equipment. Our employees assigned to this function include those in our Meter Reading, Customer Field Services, Customer Contact Center, and Account Services departments.

Deliver Gas involves the operation and maintenance of the gas system, including gas acquisition, system maintenance, pipeline integrity, and system expansion. Our employees assigned to this function include those in our Code Compliance, Gas Operations, Quality Assurance, and Engineering departments.

In addition, there is a supporting Operations Services process for all three core processes that provides centralized workload forecasting, planning, scheduling, and dispatch of field personnel, operations business analytics, business systems support, and centralized equipment and transportation supply and maintenance. Our employees assigned to this function include those in our Resource Management Center, Business Analysis, Business Systems Support, and Operations Support Services departments.

Q. How did the Company implement its organization around the three core processes?

A. Beginning in early 2006, all Company departments and employees were reassigned, and reorganized around these three core processes. For example, the Company

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centralized scheduling and dispatch, developed new training processes, and standardized processes and procedures.

Q. Did the Company make any other changes as a part of the Operations Model?

A. Yes. In addition to organizing the Company around core processes, NW Natural made two additional changes designed to result in a leaner and more flexible workforce. First, the Company implemented another "best practice" identified in its investigation: outsourcing much of its field work consisting of more basic and highly repetitive tasks that require less skill and training, such as the installations of mains and services in new subdivisions. More challenging and complex construction activities like system maintenance, system improvements, and anything to do with the high pressure transmission system were reserved for Company personnel. This allowed the Company to eliminate a number of positions while retaining a leaner, more highly-trained and skilled field workforce that could be deployed across numerous functions.

Second, the Company successfully negotiated with the union for broader job categories, which were ultimately incorporated into the 2009 Joint Accord. This change allowed for a better trained, more flexible workforce. One of the most significant impacts is that the Company has been able to expand the number of employees trained and equipped as emergency first responders to over 314—something that could not have been achieved cost-effectively under the old contract or old structure.

Q. Were any other initiatives completed during this time?

A. Yes. The Company also reviewed its non-operating areas, meaning its support and administrative functions, through a Business Services Efficiency Review (BSER).

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Through BSER, the Company sought to ensure processes were efficient, reduce costs, standardize procedures, centralize functions and make other changes to support the Operations Model.

Q. Did the Company reduce the number of full-time equivalent positions (FTEs) as a result of the Operations Model, and if so, how was the reduction achieved?

A. Yes. In implementing the Operations Model (including the BSER) the Company reduced FTEs without involuntary terminations using a combination of actions. During the restructuring, the Company more vigorously scrutinized all hiring requests. This practice continues today. In addition, the Company offered severance packages to specific employees in areas targeted for reductions, which 110 employees accepted.

Overall the restructurings reduced about 200 FTEs, although it must be kept in mind that a portion of the work performed by the reduced FTEs was outsourced. As a result of the Operations and BSER initiatives, employees per customer reached record levels of 665 per employee in 2010.

V. <u>AUTOMATED METER READING</u>

Q. Please discuss the Automated Meter Reading (AMR) implementation.

A. Historically, NW Natural has kept its overall meter reading costs quite low through a joint meter reading program with Portland General Electric Company (PGE) in those areas where our service territory overlaps. However, in May of 2005, NW Natural learned that PGE was considering a plan to institute Advanced Metering Technology throughout its service territory and that if it did so, it would discontinue the joint meter reading

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program.[3] In addition, through the Operations Model review, the Company learned that other LDCs were implementing AMR programs and achieving cost savings as a result. This information lead NW Natural to evaluate its options, and it soon determined that a transition to AMR would be its most cost-effective option. Accordingly, the Company developed a plan to deploy AMR technology throughout its service territory in two steps.

Q. Please describe these two steps.

A. Beginning in December 1, 2005 the Company instituted the first step by deploying AMR over those portions of the Company's service territory that did not overlap with PGE's. This step covered approximately 240,000 of our total customers, and cost approximately $14.1 million. This first step resulted in a reduction of 30 FTEs, and an estimated $2 million in savings annually that more than offset the costs of installing the new hardware on our meters over the life of the meters.

In 2008, PGE formally notified us that they were ending our joint meter reading agreement as they began their move to advanced metering infrastructure. While AMR was more expensive than joint meter reading, it was much less expensive than moving back to manual meter reading. In this step two, we completed the change-over to AMR for our remaining customers. This eliminated all but seven of the remaining meter reading positions.

Overall the move to AMR permanently reduced 64 meter reading positions. Again, we made every effort to find other jobs for the displaced full-time meter readers

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[3] *Re. NW Natural's Application for Authorization to Defer Expenses Related to the Installation of Automated Meter Reading*, Docket UM 1413, Application at 1 (Jan. 14, 2009).

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and offered career development and a severance program. Utilizing a special agreement with the union, all meter readers that chose to remain with the Company were successful in securing new positions.

VI. LOW GROWTH INITIATIVE

Q. Please explain the circumstances that gave rise to the Low Growth Initiative.

A. By the start of 2009, it became clear that the financial crisis and subsequent recession were going to be very severe and that they were significantly slowing the Company's customer growth. In addition, we had serious concerns that high unemployment and further economic turmoil could eliminate customer growth as it did for some other gas utilities. For two decades, the Company had experienced customer growth in excess of three percent per year—over 20,000 new customers each year by the mid-2000s. In 2007, the customer growth rate started slowing down considerably and has been less than one percent since 2009—or below 6,000 customer additions per year.

Q. What was the Company's response?

A. At the time, the Company was still in the process of implementing the FTE reductions associated with the Operations Model, BSER, and AMR deployment, and had doubts about whether the Company could reduce FTE counts further. Initiatives put in place by the Operations and BSER models partially helped offset the initial impacts of the recession and did add needed flexibility to how we were responding. However, given the significance and severity of the crisis, the Company was concerned that customer growth would continue to decline and that prices would rise, meaning that further FTE

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reductions could be warranted until the recession subsided. After considering all of the factors at issue, the Company reluctantly instituted a program to reduce additional FTEs.

Q. How did the Company proceed?

A. The Company again relied on teams of employees to determine what could be reduced, and where. Ultimately, the Company decided to offer voluntary severance packages to employees in the Acquire Customer processes and those working in field construction. Through this process, an additional approximately 50 positions were eliminated, in addition to those reduced under the other programs.

Q. What was the combined impact of all three initiatives on the Company's FTE numbers?

A. Overall, from 2005 to 2010, the Company went from a level of 1,275 FTEs to 1,015 FTEs.

Q. Were these programs successful in holding down the Company's O&M expenditures?

A. These programs limited the increase in total utility O&M costs from $113.3 million in 2006 to $114.7 million in 2010 (nominal dollars), a compound annual growth rate of 0.4 percent. O&M per customer was about $177.99 in 2006 and decreased to $170.17 in 2010.

Q. Has the 2009 level of FTEs proved sustainable?

A. Not entirely. The Company's Low Growth Initiative was always envisioned as a temporary measure to address a very low or a "no" growth environment caused by the financial crisis and associated severe recession. Changes in safety requirements and

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customer service initiatives require additions to staff to adequately address these required compliance activities. Because of these factors, as explained in the direct testimony of John Sohl, the November 2012-October 2013 test year ("Test Year") revenue requirement reflects 1,130 FTEs. This number reflects additions for enhanced safety and customer service programs as well as minor additions elsewhere. This level is well below the 1,235 to 1,275 FTE level in place before AMR was implemented and our operations were restructured. I believe the 1,130 FTE level reflected in the Company's case reflects a minimal but sustainable level given current operating requirements and economic conditions.

Q. Aside from the major initiatives discussed above, has the Company taken any additional actions to manage its costs?

A. Yes. During the last eight years we have worked hard to control costs that are within our control. Accordingly, we have:

- Closed off the defined benefit pension plan and retiree medical benefits to new employees, as is described in the direct testimony of Lea Anne Doolittle;
- Increased non-bargaining and bargaining unit employees' health care sharing percentage and capped the Company's contribution towards bargaining unit employee health care costs—as also described in Ms. Doolittle's direct testimony;
- Eliminated Company officer salary increases in 2009 and constrained increases for non-bargaining unit employees to below-market levels;

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- Maintained very low bad debt levels by working with customers to minimize write-offs;
- Issued new debt to reduce interest costs;
- Maintained strong credit ratings that allowed the Company access to capital markets at very favorable rates even during the most desperate times of the financial crisis; and
- Worked to keep customers' gas commodity cost low, which has resulted in current rate levels that are lower than 2004 rates.

Q. Has the Company also managed to achieve its operational goals while keeping costs down?

A. Yes. In particular, over the past several years the Company has:

- Achieved an excellent record of safety and reliability, although we are working to move to even higher levels in both public and employee safety;
- Received customer satisfaction awards, placing first or second in J.D. Powers and Associates Customer Satisfaction Studies in each of the last five years, and our internal measures have held steady or increased;
- Offered the first carbon offset program for customers by a stand-alone LDC;
- Continued to meet standards in our Billing and At-Fault Complaints Service Quality Measures;
- Provided billing options to customers including signing on more than 93,000 customers to our Equal Pay Plan, as well as providing custom payment plans to customers in difficult financial times;

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- Managed organizational change from substantial business restructuring downsizing activities in a manner that maintained strong employee engagement;
- Continued our record as a solid member of the communities we serve; and
- Provided reasonable returns to our investors.

This is a record we are proud of and a record that we plan to build on going forward.

Q. Has the reduction in FTEs led to over-earning on an Oregon jurisdictional basis?

A. No. The reductions in workforce have permitted the Company to earn near its authorized rate of return on equity—some years over, some years under. The charts below show the results of the PGA earnings test for the last eight years, both with and without inclusion of the shared portion of the weighted average cost of gas (WACOG) gains and losses. Absent WACOG gains and losses, the Company has on average earned less than its authorized ROE. Including WACOG gains and losses, the Company has earned just above its authorized ROE. It is important to remember that while the Company retained 33 percent, 20 percent, and now ten percent of those gains in positive years, customers received the other 67 percent, 80 percent, and now 90 percent of the benefit in those years.

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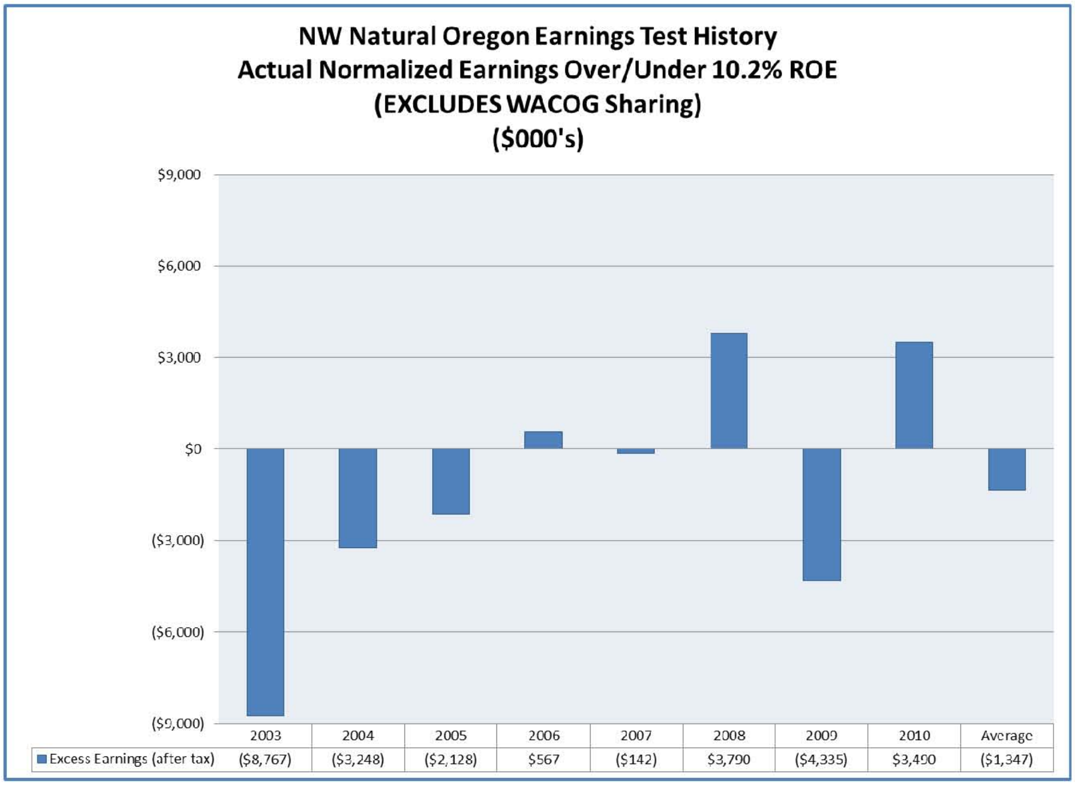

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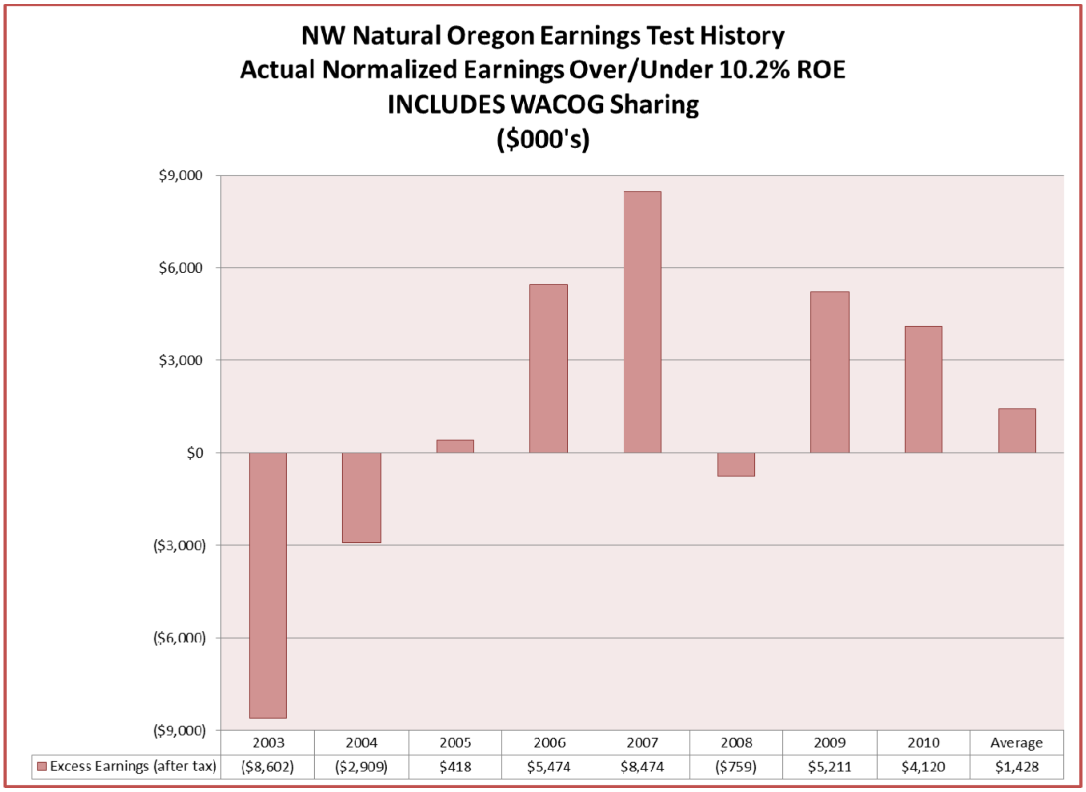

Q. Why have the personnel reductions not led to higher returns?

A. The cost control efforts have allowed the Company to operate within its authorized expense levels despite increases in costs of labor, medical benefits, pension expenses, and now the dramatic decrease in customer growth. As shown in the direct testimony of John Sohl, absent the Company's efforts to control costs, Test Year O&M levels would be higher.

VII. <u>RISKS FACING NW NATURAL</u>

Q. What are some of the major risks facing NW Natural?

A. We face many risks that other businesses face, such as the health of the economy and natural disasters, and others faced by LDCs in particular, such as risk from changing

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safety and environmental regulations, the need to access capital markets, and potential changes in accounting standards. In addition, we face some risks unique to NW Natural such as being served by a single interstate pipeline. However, one of our biggest risks today is the ability to compete for and gain new customers.

Q. Please explain.

A. One factor that is contributing to the Company's risk of being able to gain new customers is the sluggish housing market. In a down housing market such as the one we are experiencing, NW Natural has been unable to achieve historical growth rates.

In addition, the Company faces the risk associated with competing for new customers in the energy market. Unlike the services offered by the electric and water utilities, natural gas service is seen as optional by our customers. Customers may appreciate natural gas as an efficient and low-cost fuel for heating air and water, but they can also heat air and water with electricity. And while we receive revenues from other services, including gas fireplaces and cook-tops, we rely primarily on the space heating market from residential and commercial customers for our revenues and growth.

Additional pressure is likely to come from heat pump water heaters. The water heating market is another important sector of business for stand-alone LDCs.

Q. Do all LDCs face the same competitive risks?

A. No. We see different behaviors in markets where the local utility is a combination electric and natural gas utility as opposed to markets like ours in which the electric and natural gas utilities are separate. Combined planning for combination utilities generally recognizes the important role that the direct use of natural gas plays and these

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combination companies use natural gas space heat and water heating to minimize expensive additions to electric generation and transmission plant. Puget Sound Energy, Inc. (PSE) is an example of a regional natural gas and electric utility that encourages customers to switch from electricity to natural gas for space and water heating.[4] PSE estimates it has a technical potential of 22.1 aMW of electric savings over the next 20 years through natural gas conversions.[5]

Q. Please explain how this competitive risk affects NW Natural as an LDC.

A. When the new housing market picks up in Oregon, if we lose a significant share of the space or water heating market, our growth will not rebound with the economy. Facing sustained low growth and continued cost pressures could result in financial stress and, ultimately, could threaten our ability to remain an independent gas LDC.

Q. Are there other major risks facing NW Natural?

A. Yes. There are two additional major risks. First is the Company's exposure to significant cleanup costs at the Company's historic manufactured gas sites. This exposure is quite substantial as compared to the size of NW Natural. Currently, the Company has a regulatory asset of $122.5 million, which includes $51.8 million of total paid expenditures to date, and costs continue to be incurred. As indicated in our Securities and Exchange Commission filings, NW Natural's exposure in the area is

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[4] *See* http://www.pse.com/savingsandenergycenter/ForHomes/Pages/Converting-to-Natural-Gas.aspx

[5] The Cadmus Group, Inc., Puget Sound Energy's 2011 Integrated Resource Plan, "Appendix K, Comprehensive Assessment of Demand-Side Resource Potential," p. 42.

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material and could negatively affect ongoing operations if not appropriately addressed in this rate proceeding.

Another major risk is the Company's ability to access capital during unstable economic times such as we have seen in recent years. Most economists are forecasting little to no growth until late this decade due to the financial nature of this crisis and associated recession. Oregon is not immune to these issues and has consistently had one of the highest unemployment rates in the country. Our main financial goal is to remain financially strong and well-capitalized—despite our small size—in order to be able to access the capital markets for our customers at very favorable rates. To date, as Mr. Feltz notes in his direct testimony, NW Natural has been able to access markets at favorable rates despite the economic turmoil in the country and the world. But, this could not have been accomplished without the Company's strong financial position and credit ratings.

VIII. REQUIRED RATE OF RETURN ON COMMON EQUITY

Q. What rate of return on equity is the Company proposing in this filing?

A. The Company has proposed a 10.3 percent ROE in this filing. This is at the upper end of the reasonable range developed by Samuel C. Hadaway in his direct testimony. I believe this appropriately reflects the risks faced by NW Natural and also recognizes the uncertainty in the economy and financial markets given that rates will not go into effect for ten months, and that the decision on ROE will not be made until then.

Q. Why are you proposing an increase to your allowed ROE when interest rates are near all-time lows?

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A. It is true that interest rates are currently near all-time lows. The 30-year treasury rate even dipped below three percent in October of 2011. But several factors led me to conclude 10.3 percent is the appropriate level.

First, I must emphasize that we are not setting rates for today, but for the Test Year, which is November 2012 through October 2013, or about one year away. The financial markets are as unsettled as they have ever been. There is great uncertainty about the markets, the state of the world and U.S. economies, and interest rates. Government intervention has played a big role in the current level of interest rates, as we have seen most recently with the Federal Reserve's program called "Operation Twist," which is aimed at lowering long-term interest rates. Removal of this intervention, or further intervention aimed at controlling inflation, could result in dramatically higher rates very quickly.

An additional factor contributing to low treasury rates is the debt crisis in the European Union. This has led to a "flight to safety" and greater investment in U.S. treasury securities. Resolution of this crisis, again led by government action, could send interest rates higher very quickly. These are just two examples of the great uncertainty existing in the markets at the time of filing, and part of the reason the Company chose a rate at the upper end of the range described in Dr. Hadaway's testimony.

Third, the ROE proposed in this case is critical to maintaining the cash flows needed to ensure the financial strength of NW Natural. NW Natural's financial strength allowed us to tap financial markets during the worst periods of the financial crisis. Our commercial paper sold well when less financially robust utilities had to use their credit

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lines at higher cost. We did not experience counterparty credit calls as many of our peer utilities experienced. As a result, credit facilities can be sized smaller which ultimately leads to lower costs for our customers. In addition, our financial strength was an important reason why we were able to live up to our agreement for a rate case moratorium even during the financial crisis and deepest recession since the Great Depression. The proposed ROE will help us maintain that financial strength, help keep costs down for customers, allow us to remain independent, and hopefully allow us to weather whatever the future brings in the financial markets.

Fourth, a company's ROE should be set as a long-term rate and not reflect unsustainably low interest rates, just as they have not reflected unsustainably high interest rates in the past. My selection of the proposed ROE reflects a belief that by the time of the Test Year, interest rates will be moving back to more normal, sustainable levels. If they have not, that will likely be a reflection of a continued economic malaise raising other risks for companies like NW Natural. And, I have already described the risks that come with low growth and increased competition. For all these reasons, an ROE of 10.3 percent is appropriate.

Q. Does this conclude your direct testimony?

A. Yes.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Kevin McVay and Natasha Siores

TEST YEAR / REVENUE REQUIREMENTS EXHIBIT 300

December 2011

EXHIBIT 300 – DIRECT TESTIMONY - TEST YEAR / REVENUE REQUIREMENTS

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I. INTRODUCTION AND SUMMARY

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

A. My name is Kevin S. McVay. My current position is Business Development Consultant. My responsibilities during the 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.

My name is Natasha Siores. I am a Revenue Requirement and Regulatory Consultant in the Rates and Regulatory Affairs department. My responsibilities include regulatory accounting, pricing, development of regulatory reports and rate filings, research relevant to gas rates and regulatory mechanisms, and analysis of revenue requirement, cost of service, and rate base issues.

Q. Mr. McVay, please describe your education and employment background.

A. I received a Bachelor of Science Degree in Accounting in 1981 from George Mason University, Fairfax, Virginia. In 1986, I received a Master of Business Administration degree from George Washington University, Washington, D.C. From 1981 to 1987, 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 in finance and regulatory affairs.

Q. Ms. Siores, please describe your education and employment background.

A. I earned my Bachelor of Science degree in Commerce (Accountancy, honors program) from DePaul University in Chicago in 1993 and am a Registered Certified Public

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Accountant in the state of Illinois. I have previously testified for the Company in a regulatory proceeding.

Prior to NW Natural, I spent ten years working for two subsidiaries of Nicor Inc., including accounting and forecasting positions at the local gas distribution company, Nicor Gas in Naperville, Illinois, and the ocean transportation company Tropical Shipping in Riviera Beach, Florida. I have worked at NW Natural since November 2003.

Q. Please summarize your testimony.

A. In our testimony, we:

- Explain the selection of the historical base period of calendar year 2011 ("Base Period") and the test year of November 1, 2012 to October 31, 2013 ("Test Year");
- Present the revenue requirement needed to yield the Company's proposed overall rate of return (ROR) of 8.28 percent and return on equity (ROE) of 10.3 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;
- 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.

II. BASE PERIOD AND TEST YEAR

Q. Why did the Company use calendar year 2011 as the Base Period?

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A. The Company chose calendar year 2011 as the Base Period because it is the most recent calendar year for which the Company has actual data. While the last three months of 2011 shown in this filing are forecast data, the actual information will be provided to parties as soon as it is available.

Q. Why did the Company choose the period of November 1, 2012 to October 31, 2013 as the Test Year in this case?

A. The Company chose the 12-month period from November 1, 2012 to October 31, 2013 because it best reflects the conditions expected when new rates from this rate case are expected to be in effect. Given a filing date of December 30, 2011 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, 2012. This matches the Test Year used to calculate the revenue requirement in this case.

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 8.28 percent in the Test Year, a revenue requirement increase of $43.7 million over the revenues expected for the Test Year at present rates is necessary, or an approximately six percent increase over current customer rates. This $43.7 million, however, includes $15.1 million currently being collected through our decoupling deferral, leaving a net increase of $28.6 million. The overall increase to rates is about four percent after taking into account that the decoupling deferral is already in customers' current rates.

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

A. At current rate levels, the Company's ROE would be 5.66 percent. This is significantly below the 10.3 percent proposed in this case.

Q. Please describe the cost drivers that would cause the Company to under-earn at current rate levels in the Test Year.

A. The areas of the most significant cost increases from the Base Period to the Test Year are shown at *NWN/301, McVay-Siores/1*. As discussed in the direct testimony of David H. Anderson, the most significant drivers of the requested rate increase relate to the Company's need to comply with safety requirements, the Company's proposed enhancements to customer service, and the Company's proposal to recover its costs associated with its pension contributions that are not addressed in the current FAS 87 balancing account. These factors contribute to the vast majority of the $28.6 million increase net of decoupling. Specifically, safety-related O&M costs account for 32 percent of the increase, customer service-related O&M costs account for 18 percent of the increase, and the proposed recovery of pension costs accounts for 27 percent of the increase. Rate base increases account for another significant portion of the proposed rate increase. Much of the increase to rate base is related to the safety-related investments and a new facility discussed in the direct testimonies of Grant Yoshihara and Lea Anne Doolittle, respectively.

IV. RESULTS OF OPERATIONS

Q. Please explain how the Company calculated the Test Year revenue requirement.

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A. The Company began with actual and forecasted results from the Base Period. We made normalizing and known and measurable changes to Base Period revenues, expenses, and capital to reflect conditions anticipated to be in effect in the Test Year. Our testimony and exhibits explain how these adjustments are reflected in the Test Year revenue requirement. The other witnesses in this case describe some of the changes in more detail.

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

A. Yes. See *NWN/302, McVay-Siores/1* for a summary of the Company's Oregon-allocated Results of Operations for the Test Year.

Q. Please describe Exhibit NWN/302.

A. Column a of *NWN/302, McVay-Siores/1* shows the Oregon-allocated results for the Base Period, including operating revenues, operating revenue deductions, taxes, and rate base. Column b shows the adjustments to Base Period results for each of these categories. Column c shows Test Year results at present rates based on the adjustments to Base Period results. Column d shows the proposed revenue increase necessary to reach the requested ROE. Column e shows Test Year results that reflect the requested ROE.

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

A. The adjustments in Column b show the Company's adjustments from the Base Period to the Test Year. These adjustments reflect adjustments to operating revenues, operating revenue deductions, and taxes.

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

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A. The first two adjustments to operating revenues are for Sale of Gas and Transportation revenues, shown on lines 1 and 2 of *NWN*/302*, McVay-Siores/1*. These adjustments are calculated as the difference between Base Period and Test Year volumes and customers multiplied by current rates.

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

A. Base Period revenues were projected using the latest available actual volumes and customers, which was 12-months ended September 30, 2011 and a proxy for Base Period billing determinants. To calculate Base Period revenues, we multiplied actual customers and volumes for the 12-months ended September 30, 2011 by current rates that became effective November 1, 2011. This calculation is shown in Exhibit 303.

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.

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

A. The Company used different methodologies for forecasting volumes and customers 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, is deducted from the existing customer base. New customers are based on historic regional growth trends, housing starts forecasts and economic and other factors.

The Company then developed a forecast of use per customer by accumulating actual historic use per customer per day and heating degree days (HDDs) for the period

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of January 2007 through July of 2011. A simple linear regression relating use per customer per day as a function of HDD per day was performed, using a 59 degree set point for the residential class and a 58 degree set point for the commercial class. The intercept value from the regression represents customer base load use. The slope is multiplied by the daily HDD value to calculate the heating load. The sum of the base load and heat load results in a daily use per customer value. An annual daily HDD pattern was developed using daily HDD values from a data set spanning 25 years (1986-2010). Use per customer was then reduced by the estimated demand side management savings forecast from the Company's current Integrated Resource Plan (IRP) to project use per customer for the Test Year. The resulting use per customer for the Test Year is 636 therms for residential customers and 3,845 for commercial customers.

Residential and commercial Test Year volumes were calculated by multiplying normalized use per customer by forecasted customer counts. Test Year residential volumes were further reduced to reflect lower usage due to the impact of the estimated use of heat pumps and the estimated loss of low-use customers that may discontinue service if the rate design proposed by witness Russell Feingold is approved.

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

The derivation of sales of gas and transportation revenues is presented in detail by class as *NWN/303, McVay-Siores/1* and is shown in summary at *NWN/302, McVay-Siores/302*, on lines 1 and 2.

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Q. What is the third adjustment to operating revenues?

A. The third adjustment is to Miscellaneous Revenues, identified on line 3 of *NWN/302, McVay-Siores/1*. This adjustment reflects the difference between Base Period Miscellaneous Revenue, which was based on actual totals for the 12-months ended September 30, 2011 as a proxy for Base Period, and the forecast for the Test Year. The adjustment was calculated by adjusting specific categories of Miscellaneous Revenues to reflect average levels of operating activity. The adjustments to specific categories of Miscellaneous Revenues are set forth in *NWN/304, McVay-Siores/1*. In addition, an adjustment was made to reflect the impact of the 2009 Oregon state income tax rate change on the accumulated deferred tax balance. The adjustment reflects a five-year amortization of this increased cost the Company has already recorded on its books.

Q. Please explain the adjustments to Operating Revenue Deductions.

A. The first adjustment to Operating Revenue Deductions is for Gas Purchased, shown on line 5 of *NWN/302, McVay-Siores/1*. This adjustment reflects the difference between Base Period and Test Year volumes multiplied by actual 2011 commodity and demand rates.

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

A. No. The Company's 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, the Company includes gas costs in its total revenue calculation to provide an appropriate expense level relative to the revenues that are forecast for the rate case. This ensures that base

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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 6 of *NWN/302, McVay-Siores/1* in summary, and in detail in *NWN/305, McVay-Siores/1*. The adjustment for Uncollectible Accrual for Gas Sales reflects the difference between the Base Period expense and the Test Year expense derived by taking the three-year historical average of write-offs as a percent of total revenues times the total Test Year revenue.

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

A. The total Oregon O&M expense excluding Uncollectible Accrual for Gas Sales is set forth in detail in *NWN/306, McVay-Siores/1* and in summary at line 7 of *NWN/303, McVay-Siores/1*. The direct testimony of John Sohl explains in detail how the Company calculated its Test Year O&M.

Q. Please explain the adjustments to taxes.

A. The first two adjustments to taxes, shown on lines 9 and 10 of *NWN/302, McVay-Siores/1* reflect adjustments to Federal and State Income Taxes. The calculations are shown in *NWN/307, McVay-Siores/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 taxes is 39.94 percent, derived by adding the federal rate to the state rate net of the federal deduction for state taxes.

Q. Are you proposing modifications to the treatment of permanent differences or the amortization of investment tax credits (ITC)?

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A. Yes. In Docket UM 1335, the Company modified its permanent difference amounts used to calculate the income tax provision.[1] More specifically, the depreciation component related to pre-1981 assets was changed. In this case, the Company proposes to adjust the removal cost component to a level such that the related deferred taxes are amortized over the same period as the depreciation component. Further, a book-tax difference related to property tax was adopted as a flow through item in the last rate case, Docket UG 152 ("2002 Rate Case"). The Company proposes to eliminate this difference and amortize the related deferred taxes over a five-year period.

The Company follows an amortization schedule for ITC, which will be completed in 2017. The amount, included as a reduction of taxes in the revenue requirement, relies on a three-year average of amortization amounts for the years 2013 through 2015. The use of the statutory tax rates as well as the flow-through and ITC amounts combine to produce the federal and state taxes for the Test Year.

Q. Please explain the adjustment to Property Taxes.

A. The adjustment to Property Taxes is shown on line 11 of *NWN/302, McVay-Siores/1*. The calculations are shown in detail in *NWN/308, McVay-Siores/1.* The Base Period Property Tax estimate was derived by taking a simple average of actual taxes paid during 2009 and 2010. Test Year Property Taxes were calculated using the rate resulting from the average of 2009 and 2010 assessed taxes divided by net utility plant at December 31 of the year prior to the assessment. The rate was then applied to net plant at year end 2011 for the 2012 tax assessment and to year end 2012 for the 2013

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

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tax assessment. The forecast assessments for the two years were then combined at a ratio of eight months of 2012 and four months of 2013 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 12 of *NWN/302, McVay-Siores/1*. This adjustment was calculated as follows for the different categories within Other Taxes, the detail of which is shown in *NWN/308, McVay-Siores/1*:

- Franchise fees were derived by applying the effective rate of 2.358 percent to gross sales and transportation revenue to provide a forecast for total franchise fees for both the Base Period 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 and bonuses 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 rate of twenty-five hundredths of one percent multiplied by gross revenues for both the Base Period and Test Year.
- The Oregon Department of Energy fee is a function of gross revenues. For both the Base Period and Test Year, the fee was calculated by first calculating an average effective rate for the three-year period 2008 through 2010, and then applying the average effective rate to total operating revenues.
- Other taxes, such as permit and licensing fees, were forecast based on an average of February 2008 through June 2011 (3.5 years) amounts. The other

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taxes were assigned directly to Oregon and Washington jurisdictions as applicable. The remaining system-related other taxes were allocated to Oregon based on a three-factor allocation of 90.1 percent.

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

Q. Please explain the adjustment to Depreciation and Amortization.

A. The Depreciation and Amortization adjustment is shown on line 13 of *NWN/302, McVay-Siores/1* and in detail in *NWN/309, McVay-Siores/1*. This adjustment reflects the difference in depreciation expense forecast for the Base Period and Test Year. Depreciation expense was developed by using utility plant as of December 31, 2010 as a base and increasing plant accounts for capital expenditures from January 2011 through the end of the Test Year. Applicable account balances were then decreased for expected retirements. 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 the Company have been at the current level since January 1, 2009, the last time a depreciation study for a revision of rates was approved by the Commission in Docket UM 1335.[2] Consistent with the stipulation and resulting Commission order in that docket, the Company has performed a new depreciation study. The results of the new study indicate that a change of depreciation

[2] *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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rates would not be material in terms of revenue requirement impact. The Company is therefore not requesting that the new rates be adopted.

The Test Year also reflects a $4,569,000 amortization related to pension that is described in the direct testimony of Stephen Feltz.

V. RATE BASE

Q. Describe the calculation of rate base.

A. The components of rate base are shown in *NWN/302, McVay-Siores/1* at lines 16-24 and at *NWN/310, McVay-Siores/1.* Rate base is made up of Utility Plant in Service, net of Accumulated Depreciation, with additions and subtractions for Pensions, Aid in Advance of Construction, 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. The starting point for the development of the Utility Plant in Service component of rate base is the December 31, 2010 book balance. A forecast for capital expenditures was developed to primarily reflect new business activity including mains, services, and meters, as well as replacements of existing mains and services. The forecast also provided amounts for specific capital projects, and other additions to general plant and facilities. The capital additions forecast is discussed in the direct testimony of John Sohl.

The Test Year Utility Plant in Service is calculated by first adding together the forecast capital expenditure amounts for 2011, 2012, and 2013. For 2011 and 2012, an annual amount was added, and for 2013, the amount for ten months was added to match the end of the Test Year at October 31, 2013. Once year-end balances were

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generated, the monthly balances for the Test Year were produced by adding 1/12 of the annual change each month for 2012, and 1/10 of the ten-month plant growth for 2013.

Q. How was Accumulated Depreciation derived for the Test Year?

A. The addition of the forecasted capital expenditures to gross plant by FERC account allowed for a precise calculation of annual depreciation, which in turn drove the forecast levels of Accumulated Depreciation. Total depreciation expense was calculated as a function of the depreciation rates and the gross plant balances by plant sub-account, but only if the sub-account balance net of accumulated depreciation was positive. Year-end and Test Year ending Accumulated Depreciation balances were derived using the December 31, 2010 balance and expense amounts for the forecast period. Consistent with Company and industry accounting policy, both the gross plant and Accumulated Depreciation amounts were lowered to reflect projected retirement activity. Monthly balances for Accumulated Depreciation were produced in the same manner as described above for gross utility plant.

Q. Please describe the remaining components of rate base.

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

- **Pension -** The Pension component reflects the proposed rate recovery for cash contributions to the Company's pension plans explained in the direct testimony of Stephen Feltz. The Test Year rate base includes $21,930,000 for Pension cash contributions. The Base Period Pension amount is $15,358,000.
- **Aid in Advance of Construction –** This reduction to rate base represents the amounts of customer-provided contributions of construction costs. The Test

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Year balance is calculated using the 12 months ended September 30, 2011 average of actual monthly balances.

- **Gas Inventory –** This component of rate base includes a 13-month average of stored gas supplies and is composed of three categories. The first, cushion gas, assumes a continuation of the September 30, 2011 balance. Second, working gas inventory was derived by starting with October 1, 2011 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 12, 2011. In addition, recall amounts per the IRP were included via increased injections. Finally, production area storage was forecast by multiplying the average monthly therm level injected by the first of month AECO pricing for the three year period April 2012 through April 2015 and subtracting the average monthly therm level withdrawn valued at the average per-therm inventory value for the same period. Monthly balances of these three 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 $7,565,000 is derived using the three-year average for the period June 2008 through May 2011 of actual Material and Supplies inventory excluding demonstration appliances.
- **Leasehold Improvements –** The Test Year forecast for this element was obtained by taking the existing principal balances net of amortization through

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May 2011 and continuing the consistent monthly amortizations, with an assumption of no new improvements through 2013.

- **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, 2010, 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, most significantly pension and environmental expenses where the book treatment is different than the cash- or tax-related treatment.

  In Docket UM 1335, which reviewed depreciation and flow-through amounts for income taxes, the Company modified its permanent difference amounts used to calculate the income tax provision. More specifically, the depreciation component related to pre-1981 assets was changed.[3] For this rate case, NW Natural proposes to adjust the removal cost component to a level such that the related deferred taxes are amortized over the same period as the depreciation component.

  Further, a book-tax difference related to property tax was adopted as a flow-through item in the 2002 Rate Case. The Company proposes to eliminate this difference and amortize the related deferred taxes over a five-year period.

Q. How did you calculate average rate base balances?

[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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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 pension and deferred taxes. For deferred taxes, where the rate base has traditionally included a simple average of beginning and ending values, the beginning October 2012 number and the ending October 2013 number were derived by interpolation, using the estimated prior year-end values and 10/12 of each current year incremental change. The pension balance was interpolated using projected year-end balances at 2012 and 2013 and combining 2/12 of the December 2012 balance and 10/12 of the December 2013 balance.

VI. STATE ALLOCATION

Q. How did you allocate revenues to Oregon?

A. Gas Sales and Transportation Revenues and Miscellaneous Revenues billed to Oregon customers are directly attributed to Oregon. Utility property rental income within the Miscellaneous Revenue category is allocated based on utility plant directly assigned to each state.

Q. How did you allocate costs to Oregon?

A. The Company has used the same previously-approved methodology since 2000. Gas costs correspond precisely with gas costs collected in billing rates over the period, based on therms sold.

Allocation of O&M expense starts with allocating common costs. The Company's method for allocating common costs begins with an initial identification of non-common costs, with a direct assignment of those costs to the appropriate jurisdiction. The remaining costs are then considered with respect to specific "drivers," or elements such

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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 actual 12-months ended September 30, 2011 O&M expense. The resulting average jurisdictional allocation by FERC account was then applied to the forecasted O&M expenses developed for this case.

The allocation factors are shown in *NWN/312, McVay-Siores/1*.

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

A. The jurisdictional allocation of gross plant and depreciation balances followed the same methodology that has been used since the Company moved to state allocated ratemaking since 2000. The methodology was approved in the Company's filing under Tariff Advice 00-18. Specifically, 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 pensions and aid in advance of construction, the rate base amount was derived specifically for Oregon. Gas inventory was allocated using the firm volume allocation factor. The Materials and

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Supplies amount was allocated using the gross distribution plant factor. Leasehold Improvements were allocated using the three-factor allocation factor. Finally, deferred taxes were developed directly by state.

Q. Does this conclude your direct testimony?

A. Yes.

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Exhibits of Kevin McVay and Natasha Siores

TEST YEAR / REVENUE REQUIREMENTS EXHIBITS 301 - 312

December 2011

EXHIBITS 301 - 312 – TEST YEAR / REVENUE REQUIREMENTS

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Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
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NW Natural
Oregon Jurisdictional Rate Case
Summary of Revenue Requirement Increase
($s in millions)

Decline in Customer Use (Decoupling)	$15.1
O&M Safety Costs	$9.1
O&M Customer Service Costs	$5.1
Recovery of and on Pension Costs	$7.7
Rate Base increases	$5.7
Other O&M and Other	$1.0
Total Requested Rate Increase	$43.7

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2013
Base Year Twelve Months Ended December 31, 2011
Increase in Revenue Requirement
($000)

Line No.		Base Year at Present Rates (a)	Adjustments to Base Year (b)	Test Year at Present Rates (c)	Required Increase (d)	Proposed Total (e)
	Operating Revenues					
1	**Sale of Gas**	$714,784	($31,788)	$682,996	$43,682	$726,679
2	**Transportation**	14,703	(1,833)	12,871	0	12,871
3	**Miscellaneous Revenues**	4,457	(1,028)	3,429	0	3,429
4	**Total Operating Revenues**	733,945	(34,649)	699,296	43,682	742,978
	Operating Revenue Deductions					
5	**Gas Purchased**	414,904	(19,866)	395,039	0	395,039
6	**Uncollectible Accrual for Gas Sales**	1,617	494	2,110	121	2,231
7	**Other Operating & Maintenance Expenses**	102,709	15,510	118,219	0	118,219
8	**Total Operating & Maintenance Expense**	519,230	(3,862)	515,368	121	515,489
9	**Federal Income Tax**	28,228	(10,259)	17,970	12,280	30,250
10	**State Excise**	6,756	(2,487)	4,269	2,886	7,155
11	**Property Taxes**	18,697	907	19,604	0	19,604
12	**Other Taxes**	23,566	(243)	23,323	1,020	24,344
13	**Depreciation & Amortization**	57,302	2,792	60,094	4,569	64,663
14	**Total Operating Revenue Deductions**	653,779	(13,150)	640,629	20,876	661,505
15	**Net Operating Revenues**	$80,166	($21,499)	$58,667	$22,807	$81,474
	Average Rate Base					
16	**Utility Plant in Service**	2,038,286	188,822	2,227,108	0	2,227,108
17	**Accumulated Depreciation**	(895,269)	(95,594)	(990,862)	0	(990,862)
18	**Net Utility Plant**	1,143,018	93,228	1,236,246	0	1,236,246
19	**Pension**	15,358	6,571	21,930	0	21,930
20	**Aid in Advance of Construction**	(1,994)	0	(1,994)	0	(1,994)
21	**Gas Inventory**	69,593	(21,585)	48,008	0	48,008
22	**Materials & Supplies**	6,939	484	7,422	0	7,422
23	**Leasehold Improvements**	1,538	(383)	1,155	0	1,155
24	**Accumulated Deferred Income Taxes**	(263,082)	(66,000)	(329,082)	0	(329,082)
25	**Total Rate Base**	$971,369	$12,316	$983,685	$0	$983,685
26	**Rate of Return**	8.25%		5.96%		8.28%
27	**Return on Common Equity**	10.24%		5.66%		10.30%

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2013
Base Year Twelve Months Ended December 31, 2011
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
Sales Volumes and Revenues		(a)	(b)	(c)	(d)	(e)	(f)
1	**Residential**	368,837,105	1.16034	$427,976,958	350,626,654	1.16503	$408,491,164
2	**Commercial**	231,313,672	0.96106	$222,305,945	222,692,734	0.96106	$214,021,258
3	**Industrial Firm**	34,551,508	0.82019	$28,338,744	33,102,653	0.82397	$27,275,705
4	**Interruptible**	61,717,961	0.58594	$36,162,814	56,230,819	0.59057	$33,208,199
5	**Total Sales**	696,420,246		$714,784,461	662,652,859		$682,996,325
6	**Unaccounted For Gas**	2,249,717			2,140,635		
7	**Total Sales of Gas Revenues**	698,669,963		$714,784,461	664,793,495		$682,996,325
Transportation Volumes and Margins							
8	**Firm**	57,004,680	0.07907	$4,507,396	60,357,269	0.06974	$4,209,581
9	**Interruptible**	202,564,139	0.03413	$6,914,003	213,973,355	0.03200	$6,846,817
10	**Special Contracts - Firm**	69,211,000	0.02234	$1,546,000	67,652,388	0.02227	$1,506,295
11	**Special Contracts - Interruptible**	20,341,000	0.08534	$1,736,000	16,208,223	0.01899	$307,870
12	**Total Transportation**	349,120,819		$14,703,399	358,191,235		$12,870,563
13	**Total Deliveries and Revenues**	1,047,790,782		$729,487,860	1,022,984,729		$695,866,888
Gas Costs							
14	**Demand Charges**			$83,428,968			$79,642,270
15	**Commodity Charges**			331,475,322			315,396,255
16	**Total Cost of Gas**			$414,904,290			$395,038,525

NW Natural
Oregon Jurisdictional Rate Case
Miscellaneous Revenues Detail
Test Year Twelve Months Ended October 31, 2013
Base Year Twelve Months Ended December 31, 2011
(Twelve Months Ending September)

Line No.		Normalized 12 Months Ended September 2009	Normalized 12 Months Ended September 2010	Normalized 12 Months Ended September 2011	11/1/2012 thru 10/31/2013 Test Year	Average Used
		(a)	(b)	(c)	(d)	(e)
1	Reconnection	$601,320	$615,833	$648,534	$621,896	3-year
2	Late Payment Charges	3,004,828	2,585,014	2,590,984	2,587,999	2-year
3	Automated Payment Charge	122,960	124,939	109,824	109,824	1-year
4	Returned Check	129,958	112,648	224,872	155,826	3-year
5	Field Collection	286,470	278,010	314,227	292,902	3-year
6	Meter Rentals	187,775	178,965	188,011	188,011	1-year
7	Utility Property Rental	235,085	377,584	266,765	293,145	3-year
8	Water Heater Program	(74)	10	(225)	-	Set at zero
9	Curtailment Unauthorized Take	-	-	-	-	Set at zero
10	Amortization of State Tax Change - Def Taxes				(895,966)	Assumes 5 year amort
11	Miscellaneous	(29,840)	142,215	114,193	75,523	3-year
12	Total Miscellaneous Revenues	$4,538,482	$4,415,220	$4,457,184	$3,429,159	

NW Natural
Oregon Jurisdictional Rate Case
Uncollectible Accounts Adjustments
Test Year Twelve Months Ended October 31, 2013
Base Year Twelve Months Ended December 31, 2011
($000)

Line No.		12 Months Ended September Amounts 2009 - 2011 Total (a)	2009 Actual (b)	2010 Actual (c)	2011 Actual (d)
	Gas Revenues				
1	Residential	1,541,828	573,491	480,610	487,727
2	Commercial	788,080	304,094	240,576	243,410
3	Industrial	108,419	45,035	32,819	30,566
4	Interruptible	142,684	68,097	39,061	35,526
5	Total	2,581,011	990,717	793,066	797,228
	Net Write-Offs				
6	Residential	6,488	3,384	1,397	1,707
7	Commercial	1,142	768	187	186
8	Industrial	324	164	94	66
9	Interruptible	-	-	-	-
10	Total	7,953	4,316	1,678	1,960
	Write-Off % - 3-Year Average				
11	Residential	0.421%	0.590%	0.291%	0.350%
12	Commercial	0.145%	0.253%	0.078%	0.076%
13	Industrial	0.299%	0.363%	0.286%	0.217%
14	Interruptible	0.000%	0.000%	0.000%	0.000%
15	Weighted Total	0.308%	0.436%	0.212%	0.246%
	Oregon Normalized Revenues				
16	Residential	408,491			
17	Commercial	214,021			
18	Industrial	27,276			
19	Interruptible	33,208			
20	Total	682,996			
	Normalized Uncollectible				
21	Residential	$1,719			
22	Commercial	310			
23	Industrial	81			
24	Interruptible	0			
25	Total Normalized Uncollectible	$2,110			
26	In Base O&M	$2,110			
27	Adjustment	$0			
28	Uncollectible rate for normalizaing adjustments	0.31%			
		Base Year			
29	Uncollectible expense in Base Year	1,617	see Exhibit 306 line 54		

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2013
Base Year Twelve Months Ended December 31, 2011
Operations and Maintenance Expense

NWN/Exhibit 306

Line No.	FERC Acct.	Description	TEST YEAR System (a)	TEST YEAR Oregon (b)	BASE YEAR System (c)	BASE YEAR Oregon (d)
1		Natural Gas Storage				
2		Underground Storage Expense				
3		Operation				
4	816	Wells Expense	$283,483	$255,503	$373,129	$336,302
5	818	Compressor Station Expense	606,153	546,326	441,223	397,674
6	819	Compressor Station Fuel	0	-	0	-
7	820	Measuring and Regulator Station Expense	1,407,503	1,267,665	1,645,044	1,481,606
8	821	Purification Expense	31,069	28,002	50,990	45,957
9		Maintenance				
10	832	Wells Expense	163,814	147,645	253,385	228,376
11		Total Underground Storage Expense	2,492,021	2,245,141	2,763,771	2,489,915
12		Other Storage Expense				
13		Operation				
14	840	Supervision and Engineering	93,064	83,879	86,963	78,380
15		Total Other Storage Expense	93,064	83,879	86,963	78,380
16		Liquified Natural Gas Expense				
17		Operation				
18	844	Supervision and Engineering	2,053,357	1,850,691	1,874,795	1,689,753
19	845	LNG Fuel	(75,180)	(67,759)	(32,368)	(29,173)
20		Maintenance				
21	847	Supervision and Engineering	595,254	536,503	528,778	476,588
22		Total Liquified Natural Gas Expense	2,573,432	2,319,434	2,371,206	2,137,168
23		Total Natural Gas Storage	5,158,517	4,648,454	5,221,940	4,705,462
24		Transmission Expense				
25		Operation				
26	856	Mains Expense	569,104	513,206	623,849	562,574
27		Maintenance				
28	863	Maintenance of Mains	100,629	90,697	123,848	111,624
29		Total Transmission Expense	669,733	603,903	747,697	674,198
30		Distribution Expense				
31		Operation				
32	870	Supervision and Engineering	2,662,812	2,446,825	2,109,613	1,938,498
33	874	Mains and Services Expense	8,940,736	8,262,271	8,324,158	7,692,482
34	875	Measuring and Regulator Station Expense - General	182,983	166,042	170,608	154,813
35	877	Measuring and Regulator Station Expense - City Gate	363,735	335,825	979,703	904,530
36	878	Meter and House Regulator Expense	4,845,191	4,357,080	4,167,138	3,747,335
37	879	Customer Installation Expense	15,703,890	14,093,945	9,145,794	8,208,178
38	880	Other Expense	1,468,624	1,321,896	1,025,623	923,155
39	881	Rents	181,149	163,270	157,558	142,007
40		Maintenance				
41	885	Supervision and Engineering	9,595,665	8,785,558	5,587,680	5,115,945
42	887	Mains	2,679,831	2,436,166	2,752,385	2,502,123
43	889	Measuring and Regulator Station Expense - General	976,959	892,244	783,133	715,225
44	891	Measuring and Regulator Station Expense - City Gate	60,678	55,999	55,998	51,680
45	892	Services	1,233,024	1,133,229	1,293,575	1,188,880
46	893	Meters and House Regulators	2,281,505	2,072,851	1,976,104	1,795,380
47	894	Other Equipment	22,325	20,495	11,362	10,431
48		Total Distribution Expense	51,199,107	46,543,698	38,540,435	35,090,662
49		Customer Accounts Expense				
50		Operation				
51	901	Supervision	1,602,919	1,444,711	1,549,279	1,396,366
52	902	Meter Reading Expenses	706,773	635,177	635,362	571,001
53	903	Customer Records and Collection Expense	18,474,724	16,634,708	16,485,293	14,837,707
54	904	Uncollectible Accounts	-	-	1,803,944	1,616,634
55		Total Customer Accounts Expense	20,784,416	18,714,597	20,473,879	18,421,707
56		Customer Service and Informational				
57		Operation				
58	907	Supervision	307,756	275,639	369,527	330,963
59	908	Customer Assistance Expense	3,971,442	3,583,125	3,702,393	3,340,383
60	909	Customer Information Expense	2,127,658	1,982,731	1,364,077	1,221,817
61	910	Miscellaneous Customer Service Expense	191,686	171,693	198,874	178,132
62		Total Customer Service and Informational	6,598,542	6,013,188	5,634,871	5,071,295
63		Sales Expense				
64		Operation				
65	911	Supervision	339,397	304,283	361,840	324,405
66	912	Demonstration and Selling Expense	2,367,978	2,127,484	2,405,044	2,160,785
67	913	Advertising	787,322	718,977	607,289	554,572
68	916	Miscellaneous Sales Expense	119	107	90	80
69		Total Sales Expense	3,494,816	3,150,850	3,374,263	3,039,842
70		Administrative and General Expense				
71		Operation				
72	921	Office Supplies and Expense	39,828,917	35,757,549	37,458,009	33,628,999
73	922	Administrative Expenses Transferred - Credit	(15,218,234)	(13,621,995)	(15,538,151)	(13,908,355)
74	924	Property Insurance Premium	2,362,014	2,128,883	2,376,453	2,141,897
75	925	Injuries and Damages	1,210,206	1,089,404	1,218,369	1,096,752
76	926	Employee Pensions and Benefits	2,386,810	2,128,494	4,512,471	4,024,102
77	928	Regulatory Commission Expense	234,667	234,667	10,151	-
78	930	Miscellaneous General Expense	3,585,858	3,272,006	3,261,002	2,939,141
79	931	Rents	4,122,645	3,623,907	4,212,823	3,703,175
80		Maintenance				
81	935	Maintenance of General Plant	4,262,006	3,931,840	4,007,169	3,696,744
82		Total Administrative and General Expense	42,774,888	38,544,755	41,518,296	37,322,455
83		Total Operations and Maintenance Expense	130,680,019	118,219,444	115,511,379	104,325,621
84		Total O&M Expense LESS Acct 904 Uncollectible	130,680,019	118,219,444	113,707,435	102,708,987

NW Natural
Oregon Jurisdictional Rate Case
Tax Provision
Test Year Twelve Months Ended October 31, 2013
Base Year Twelve Months Ended December 31, 2011
($000)

Line No.		BASE YEAR		TEST YEAR	
		State Taxes (a)	Federal Taxes (b)	State Taxes (c)	Federal Taxes (d)
1	Operating Revenues	$733,945	$733,945	$699,296	$699,296
2	Operating Revenue Deductions	519,230	519,230	515,368	515,368
3	Property & Other Taxes	42,263	42,263	42,928	42,928
4	Book Depreciation	57,302	57,302	60,094	60,094
5	Interest (Rate Base * Cost of Debt)	30,428	30,428	30,814	30,814
6	State Tax Deduction	0	6,756	0	4,269
7	Subtotal	84,722	77,966	50,092	45,823
8	Permanent Differences	4,172	4,172	6,082	6,082
9	Taxable Income	88,894	82,138	56,174	51,905
10	Tax Rate	7.60%	35.00%	7.60%	35.00%
11	Tax Before Credits	6,756	28,748	4,269	18,167
12	Credits (ITC)	0	(520)	0	(197)
13	Total Tax	$6,756	$28,228	$4,269	$17,970

NW Natural
Oregon Jurisdictional Rate Case
Forecast of Other Taxes
Test Year Twelve Months Ended October 31, 2013
Base Year Twelve Months Ended December 31, 2011

Line No.		Actual 2008 (a)	Actual 2009 (b)	Actual 2010 (c)	Test Year Normalized (d)	Base Year Normalized (e)		Methodology (f)
	Property Taxes							
1	**Taxes Paid**	16,831,701	18,701,824	18,692,000		**18,696,912**		average of 2009 and 2010 taxes paid
2	**Net Plant December 31 of prior year ($000)**		1,111,664	1,140,460				
3	**Effective Rate on Prior Year-End Net Plant**		1.682%	1.639%	1.661%			
4	**Net Plant 12/31/11**				1,156,381,757			
5	**2012 Payment Forecast (line 4 * line 3)**				19,203,539			
6	**Net Plant 12/31/12**				1,228,760,135			
7	**2013 Payment Forecast (line 6 * line 3)**				20,405,496			
8	**Test Period Expense (8/12 of line 5 + 4/12 of line 7)**				**19,604,192**			
	Other Taxes							
9	**Franchise**				16,408,541	17,201,324	[1]	Oregon sales & transportation revenues * 2.358%
10	**Payroll***				5,117,689	4,501,866	[2]	Payroll tax expense from O&M multiplied by O&M factor
11	**Regulatory Fee**				1,748,240	1,834,863	[3]	Oregon gross revenues * 0.25%
12	**Department of Energy**				481,881	505,757	[4]	Direct using rate proxy 0.069% (below) and revenues
13	**Other**				164,352	164,352		3.5 year historical average of actual expense, 3-factor on non-Oregon
14	**Storage Property Tax Offset**				(597,275)	(642,177)		Interstate Storage Long Term Forecast
15	**Other Taxes Excluding Property Taxes**				**23,323,428**	**23,565,984**		

Line No.		Test Year (d)	Base Year (e)	Methodology (f)
16	Calculations:			
17	**[1] Franchise Tax**			
18	Oregon Gross Revenue from Sales & Transportation	695,866,888	729,487,860	Exhibit 302 line 1 + line 2
19	Franchise Tax Rate	2.358%	2.358%	Rate used in revenue sensitive rate in 2011-12 PGA
		16,408,541	17,201,324	
20	**[2] Payroll Tax**			
21	Total Payroll Tax expense from O&M	5,718,088	5,030,018	O&M File - Payroll tax for 2011 year
22	Overall Oregon allocation average	89.50%	89.50%	Payroll allocation factor
		5,117,689	4,501,866	
23	**[3] Regulatory Fee**			
24	Oregon Total Gross Revenue	699,296,047	733,945,044	Exhibit 302 line 4
25	Regulatory fee percentage	0.250%	0.250%	Maximum statutory rate
		1,748,240	1,834,863	
26	**[4] Department of Energy Fee**			
27	Oregon Total Gross Revenue	699,296,047	733,945,044	Exhibit 302 line 4
28	Average effective fee percentage	0.069%	0.069%	Effective rate 2008-2010
		481,881	505,757	

NW Natural
Oregon Jurisdictional Rate Case
Depreciation Expense - Oregon and System
Test Year Twelve Months Ended October 31, 2013
Base Year Twelve Months Ended December 31, 2011
($000)

Line No.		Oregon (a)	System (b)
	2012 Depreciation Expense		
1	Intangible - Software	4,358	4,860
2	Transmission	1,267	1,290
3	Distribution	43,216	48,573
4	General	5,256	5,834
5	Storage and storage transmission	6,094	6,759
6	Total 2012 Depreciation Expense	60,190	67,316
	2013 Depreciation Expense - 10 months, January through October		
7	Intangible - Software	2,565	2,861
8	Transmission	1,056	1,075
9	Distribution	37,420	42,045
10	General	3,966	4,402
11	Storage and storage transmission	5,056	5,608
12	Total 2013 Depreciation Expense (Jan-Oct)	50,062	55,990
13	Test Year Depreciation Expense	60,094	67,210
14	Pension Amortization	4,569	5,076
15	Total Test Year Depreciation & Amortization	64,663	72,286
	Base Year Depreciation Expense:		
16	2011 Depreciation Expense	57,302	64,099

NW Natural
Oregon Jurisdictional Rate Case
Rate Base & Depreciation Expense - Oregon and System
Test Year Twelve Months Ended October 31, 2013
Base Year Twelve Months Ended December 31, 2011
($000)

Line No.		TEST YEAR Oregon (a)	TEST YEAR System (b)	BASE YEAR Oregon (c)	BASE YEAR System (d)	Source Files
1	Utility Plant in Service	2,227,108	2,490,100	2,038,286	2,276,296	Utility Plant Forecast file
2	Accumulated Depreciation	(990,862)	(1,098,162)	(895,269)	(990,332)	Utility Plant Forecast file
3	Net Utility Plant	1,236,246	1,391,938	1,143,018	1,285,963	
4	Pension	21,930	24,367	15,358	17,065	Pension File - System number estimated proxy
5	Aid in Advance of Construction	(1,994)	(2,151)	(1,994)	(2,149)	Contributions and Leasehold Improvements file
6	Gas Inventory	48,008	53,253	69,593	77,197	Gas in Storage & Production Area Storage tabs in this file
7	Materials & Supplies	7,422	8,251	6,939	7,713	Materials and Supplies file
8	Leasehold Improvements	1,155	1,267	1,538	1,687	Contributions and Leasehold Improvements file
9	Accumulated Deferred Income Taxes	(329,082)	(369,418)	(263,082)	(292,211)	Deferred Income Tax file
10	Total Rate Base	983,685	1,107,508	971,369	1,095,265	

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	50.00%	6.265%	3.13%
2	Common Stock	50.00%	10.30%	5.15%
3	Total	100.00%		8.28%

	Revenue Sensitive Costs	
4	Gas Sales	97.67%
5	Transportation	1.84%
6	Other	0.49%
7	Subtotal	100.00%
8	O & M - Uncollectible	0.31%
9	Franchise Taxes at	2.36%
10	OPUC Fee	0.25%
11	State Taxable Income	97.08%
12	State Income Tax	7.38%
13	Federal Taxable Income	89.71%
14	Federal Income Tax	31.40%
15	Utility Operating Income	58.31%
16	Total Revenue Sensitive Costs	41.69%
17	Net-to-gross factor	171.50%
18	Rate of Return on Equity	10.30%
19	Federal Tax Rate	35.00%
20	State Tax Rate	7.60%
21	Combined Tax Rate	39.94%
22	Franchise Fees	2.358%
23	Uncollectible Accounts	0.308%
24	Regulatory Fees	0.250%
25	Interest Coordination Factor	3.133%

NW Natural
Oregon Jurisdictional Rate Case
State Allocation Factors

NWN/Exhibit 312

Line No.		System	Oregon	Washington
1	**Customers**			
2	**Total Customers**			
3	**September 2011**	672,278	602,652	69,626
4	**September 2010**	666,903	598,097	68,806
5	**Average**	669,591	600,375	69,216
6	**% of System**		89.66%	10.34%
7			0.76%	1.19%
8	**Residential Customers**			
9	**September 2011**	609,159	544,988	64,171
10	**September 2010**	604,327	540,890	63,437
11	**Average**	606,743	542,939	63,804
12	**% of System**		89.48%	10.52%
13				
14	**Commercial Customers**			
15	**September 2011**	62,192	56,799	5,393
16	**September 2010**	61,643	56,340	5,303
17	**Average**	61,918	56,570	5,348
18	**% of System**		91.36%	8.64%
19				
20	**Industrial Customers**			
21	**September 2011**	927	865	62
22	**September 2010**	933	867	66
23	**Average**	930	866	64
24	**% of System**		93.12%	6.88%
25				
26	**The Dalles**			
27	**September 2011**	7,254	5,414	1,840
28	**September 2010**	7,193	5,359	1,834
29	**Average**	7,224	5,387	1,837
30	**% of System**		74.57%	25.43%
31				
32	**Portland / Vancouver**			
33	**September 2011**	476,910	409,124	67,786
34	**September 2010**	472,768	405,796	66,972
35	**Average**	474,839	407,460	67,379
36	**% of System**		85.81%	14.19%
37				
38	**Portland / Vancouver Commercial**			
39	**September 2011**	40,353	35,162	5,191
40	**September 2010**	39,939	34,836	5,103
41	**Average**	40,146	34,999	5,147
42	**% of System**		87.18%	12.82%
43				
44	**NW Natural**			
45	**State Allocation Factors**			
46				
47	**Volumes - 12 Months Ended 09/30/11**			
48				
49	**Firm Delivered**	744,802,035	671,404,098	73,397,937
50	**% of System**		90.15%	9.85%
51				
52	**Sales Volumes (exclude Unbilled)**	764,342,841	689,930,578	74,412,263
53	**% of System**		90.26%	9.74%
54				
55	**Sendout Volumes**	1,134,589,879	1,044,678,999	89,910,880
56	**% of System**		92.08%	7.92%
57				
58				
59	**3-factor formula (simple average)**			
60	**Gross Plant Directly Assigned**		89.24%	10.76%
61	**Number of Employees Directly Assigned**		91.40%	8.60%
62	**Number of Customers**		89.66%	10.34%
63				
64	**Average**		90.10%	9.90%
65				
66				
67	**Derivation of factor for 3-factor - Gross Plant Directly Assigned (from Oregon Earnings Test file):**			
68				
69	**December 31, 2010**	**System**	**Oregon**	**Washington**
70	**Intangible - Other**	84,795	84,348	447
71	**Production**	675,198	675,198	0
72	**Transmission**	41,671,188	40,906,285	764,903
73	**Distribution**	1,722,620,050	1,534,390,998	188,229,052
74				
75	**December 31, 2009**	**System**	**Oregon**	**Washington**
76	**Intangible - Other**	84,795	84,348	447
77	**Production**	675,198	675,198	
78	**Transmission**	29,410,425	28,686,985	723,441
79	**Distribution**	1,675,016,919	1,491,335,963	183,680,956
80				
81	**Average**	**System**	**Oregon**	**Washington**
82	**Intangible - Other**	84,795	84,348	447
83	**Production**	675,198	675,198	0
84	**Transmission**	35,540,806	34,796,635	744,172
85	**Distribution**	1,698,818,484	1,512,863,480	185,955,004
86				
87	**Gross Plant Directly Assigned**	1,735,119,284	1,548,419,661	186,699,623
88	**% of System**		89.24%	10.76%
89				
90				
91	**Allocation Factors - Summary**	**Oregon**	**Washington**	
92				
93	**Customers-all**	89.660%	10.340%	
94	**Customers-Residential**	89.480%	10.520%	
95	**Customers-Commercial**	91.360%	8.640%	
96	**Customers-Industrial**	93.120%	6.880%	
97	**Customers-The Dalles**	74.570%	25.430%	
98	**3-factor**	90.100%	9.900%	
99	**firm volumes**	90.150%	9.850%	
100	**sales volumes**	90.260%	9.740%	
101	**sendout volumes**	92.080%	7.920%	
102	**sales/sendout volumes**	91.170%	8.830%	
103	**Customers Portland/Vancouver**	85.810%	14.190%	
104	**Customers Portland/Vancouver 80%**	88.650%	11.350%	
105	**Customers Portland/Vancouver Commercial**	87.180%	12.820%	
106	**Payroll**	89.500%	10.500%	
107	**Admin Transfer**	89.910%	10.090%	
108	**Employee Cost**	89.220%	10.780%	
109	**Regulatory**	70.000%	30.000%	
110	**Telemetering**	89.230%	10.770%	
111	**Direct-Wa**	0.000%	100.000%	
112	**Direct-Or**	100.000%	0.000%	
113	**Gross plant direct assign**	89.240%	10.760%	as of 12/31/10, from Oregon Earings T
114				
115	**Depreciation**	89.410%	10.590%	as of 12/31/10, from Oregon Earings T
116	**Rate Base**	88.391%	11.609%	as of 12/31/10, from Oregon Earings T

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Stephen P. Feltz

COST OF CAPITAL / PENSIONS
EXHIBIT 400

December 2011

EXHIBIT 400 – DIRECT TESTIMONY – COST OF CAPITAL / PENSIONS

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I. INTRODUCTION AND SUMMARY

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

A. My name is Stephen P. Feltz. My current position with NW Natural is Treasurer and Controller. As Treasurer and Controller, I am responsible for treasury operations, accounting, financial reporting, and corporate financing, including external relationships with credit rating agencies and investment banks regarding NW Natural's capital financing requirements.

Q. Please state your educational background and experience.

A. I received a Bachelor of Arts degree in Business Administration from the University of Portland in 1977 with an emphasis in Accounting. From 1977 to 1982, I worked as a certified public accountant (CPA) for a large international accounting firm. I joined NW Natural as an auditor in 1982. Since joining the Company, I served as the Director of Cash Management from 1983 to 1986, as Treasury Manager from 1986 to 1992, as Manager of Customer Account Services and Treasury from 1992 to 1996, as Accounting Manager and Assistant Treasurer from 1996 to 1999, and I have been in my current position as Treasurer and Controller since May 1999. My responsibilities have included accounting for the Company's qualified defined benefit pension plans since 1996. I have also been a member of the Company's Retirement Committee, which oversees the pension plans' assets, since 2003. In addition to having been a CPA, I am a Certified Cash Manager.

Q. Please summarize your testimony.

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A. In my testimony, I discuss the Company's proposed capital structure and issues related to the Company's defined benefit pension plans. With respect to capital structure, I:

- Present the Company'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 8.28 percent;
- Explain how I determined that the proposed capital structure is appropriate and describe how the Company's need to finance environmental remediation expenditures and pension contributions has impacted the Company's November 2012-October 2013 test year ("Test Year") capital structure;
- Discuss recent actual equity ratios, explain why it is important for the Company to maintain a 50 percent equity ratio, and explain the Company's plan to achieve and maintain its proposed equity ratio;
- Explain how I calculated the Test Year cost of debt, including an explanation of how I calculated costs associated with the debt issuance expected prior to the beginning of 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.

With respect to the Company's defined benefit pension plans, I:

- Provide an overview of the Company's defined benefit pension plans, including how pension costs are determined, how pension liabilities are funded, and how pension contributions impact operating costs and funded status;

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- Discuss the rate recovery methodology currently applicable to the Company's pension plan expenses and why that methodology does not provide for recovery of the Company's contributions into the pension plans; and
- Describe the Company's request to include in customer rates the amount of unrecovered investor capital contributed to the employee pension plans.

II. CAPITAL STRUCTURE

A. Summary of Capital Structure and Overall Rate of Return

Q. Please summarize the Company's requested capital structure and overall rate of return.

A. As stated above, the Company is requesting a capital structure of 50 percent common equity and 50 percent long-term debt, with an overall ROR on rate base of 8.28 percent, based upon a 6.265 percent imbedded cost of debt and a 10.30 percent cost of equity. The following table presents the proposed capital structure along with the calculation of the Company's overall ROR for the Test Year.

Test Year Capital Structure:

	% of Capital	Cost	Weighted Cost
Long-Term Debt	50.00%	6.265%	3.13%
Common Equity	50.00%	10.30%	5.15%
TOTAL	100.00%		8.28%

B. Appropriate Capital Structure for the Test Year

Q. What factors did you consider in determining the appropriate capital structure for the Test Year?

A. I took several factors into account in determining the requested capital structure, including:

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- The Company's target capital structure;
- The Company's historic and projected Test Year capital structure;
- The impact of temporary financing provided by investors to fund environmental expenditures and pension contributions on the projected Test Year capital structure; and
- The capital structure of other companies in NW Natural's peer group.

Each of the above factors is an important consideration for maintaining attractive credit ratings and providing reliable access to capital markets at reasonable costs.

Q. What is the Company's target capital structure?

A. The Company's long-term target—on a total Company basis—is to maintain a capital structure in the range of 50 to 55 percent common equity and 45 to 50 percent long-term debt. The long-term target capital structure for the utility—that is, the total Company capital structure adjusted for equity investments in non-utility assets—is 50 percent equity and 50 percent long-term debt.

Q. What was the Company's authorized capital structure in the last Oregon rate case, Docket UG 152 ("2002 Rate Case")?

A. In the 2002 Rate Case, NW Natural was authorized a capital structure of 49.5 percent common equity, 0.5 percent preferred equity, and 50.0 percent long-term debt. When determining the authorized capital structure in the 2002 Rate Case, the Commission adjusted the Company's total capital structure for equity in non-utility investments to arrive at an appropriate capital structure for the utility.

Q. What has the Company's actual common equity been in the years since this capital structure was authorized?

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A. During the seven years since the 2002 Rate Case, the utility's common equity ratio, *i.e.*, the Company's total common equity adjusted for equity investments in non-utility assets, was a high of 54 percent at the end of 2008, a low of 46 percent at the end of 2010, and an average of 52 percent from 2004 through 2010. During that same period, the Company's total common equity ratio was a low of 52 percent at the end of 2004, a high of 55 percent at the end of 2008, and an average of 54 percent between 2004 and 2010.

Q. What is the Company's estimated capital structure for the utility during the Test Year?

A. The Company projects the utility capital structure will be 50.4 percent common equity and 49.6 percent long-term debt for the Test Year. This capital structure—which is quite close to the Company's target long-term capital structure goal—was determined using forecasted balance sheets and income statements for 2012 and 2013, plus expected equity and debt financings between January 1, 2012 and October 31, 2013.

Q. Does your proposed capital structure take into account adjustments for the appropriate level of common equity in the capital structure?

A. Yes. Over the past few years, NW Natural has expended significant sums for environmental investigation and remediation and pension contributions. The Company has increased its long-term debt borrowings to finance these investments, and the result has been a lower equity ratio in the Company's current capital structure. Because we consider these investments to be temporary, we believe that the proposed capital structure better reflects what our actual structure will be going forward.

Q. Why do you consider these investments to be temporary?

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A. We consider these investments to be temporary because we anticipate recovering these costs from customers through mechanisms adopted in this rate case, and as such, we plan to return our capital structure to the percentages it would have been absent these investments.

Q. How are you proposing to recover the costs of these temporary investments?

A. As discussed in the direct testimony of C. Alex Miller, the Company has requested the balance of deferred environmental expenditures be recovered in rates on a rolling five-year basis, reflecting expenditures and recoveries through time. I will describe later in this testimony how the Company proposes to recover the balance of unrecovered investor contributions related to the defined-benefit pension plans, which amounts to approximately $22 million for the Test Year, over eight years.

Q. Please explain the calculation of the pro forma Company capital structure, and the impact on capital structure of investments in environmental expenditures and unrecovered pension contributions.

A. Exhibit 402 shows the projected capital structures at year end for 2011, 2012, and 2013, plus a pro forma calculation of the capital structure for the Test Year. The pro forma capital structure for the Test Year was determined by calculating the average common equity and long-term debt for 2012 and 2013 using the beginning and end-of-year balances for each year, then pro-rating those amounts for the Test Year so that two months of 2012 and ten months of 2013 were included in the final Test Year amount. The result is a common equity ratio of 50.4 percent for the Test Year. If we had adjusted for amounts invested in as yet unrecovered environmental expenditures and pension

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contributions, then the Test Year and prior year utility common equity ratios would have been higher.

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

A. The Company's 50 percent common equity ratio proposed for this rate case is very similar to the 49.9 percent common equity ratio for the Combination Electric and Gas peer group (*see NWN/501, Hadaway/1*, and quite a bit lower than the 56.7 percent common equity ratio for the S&P Gas peer group (*see NWN/410, Feltz/1*and the 56.9 percent common equity ratio for the Value Line Gas peer group (*see NWN/411, Feltz/1)*

C. Common Equity

Q. How does the Company's projected Test Year common equity ratio compare with the Company's actual common equity ratio since the 2002 Rate Case?

A. The 50.4 percent utility common equity ratio is slightly below the actual equity ratio maintained in prior years (average was 52 percent) but in line with the Company's target (50 percent). In addition, the 54.5 percent Company's total common equity ratio is consistent with the actual equity ratio level maintained in prior years (average was 53 percent) and with the Company's target (50 to 55 percent).

Q. What accounts for the lower current utility equity ratio as compared to the proposed Test Year equity ratio?

A. As I explained earlier, one factor contributing to the utility's lower equity ratio is the growing balance of utility expenditures for environmental costs and pension contributions, which have temporarily driven up long-term borrowing requirements. By the end of the Test Year, the Company will have contributed $22 million more after-tax

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than it has included in rates for pension contributions, which to date has been funded by investors. If we were to adjust the utility capital structure for this investment, the utility common equity ratio would increase from 50.4 percent to 51.3 percent for the Test Year. Including the effect of expenditures for environmental costs would further raise the equity ratio.

In addition, the lower current utility equity ratio is due in part to the Company's recent investment in gas storage. In 2008, the Company decided to invest in the development of an underground gas storage facility in California using a combination of debt and equity. This development project was completed by the end of 2010. Equity proceeds, which came from NW Natural's balance of retained earnings, were invested in a new subsidiary, Gill Ranch Storage. NW Natural's retained earnings balance had increased to a level where the Company's equity ratio was at the upper end of the target range. In order to manage the capital structure, between 2005 and 2007, NW Natural used retained earnings to buy back shares of common stock, while also retaining a certain amount of equity capital for potential investment opportunities. Once NW Natural decided to invest in Gill Ranch Storage, the repurchases of common stock were discontinued, and a portion of the Company's retained earnings, along with proceeds from the sale of other non-utility assets and subsidiary debt, were used to fund the investment in gas storage. The subsidiary debt, which came from a private investor, was secured solely by the assets of Gill Ranch Storage, and therefore non-recourse to NW Natural.

Q. Why is maintaining a 50 percent common equity ratio at the utility important?

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A. It is important for several reasons. A target 50 percent 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 such as single A affords the Company financing flexibility and liquidity, thereby ensuring timely, efficient, and cost-effective access to the 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, the Company has been able to maintain its A category ratings on long-term and short-term debt.

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

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. Our forecast anticipates that the Company may need to sell new shares over the next few years to maintain the 50 percent utility equity target level, dependent upon planned utility capital expenditures including the $250 million investment in gas reserves over the next five years.

D. Long-Term Debt

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

A. *NWN/401, Feltz/1* presents the details of the Company's long-term debt outstanding ($626.7 million) and the corresponding weighted average cost (6.265 percent) projected

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for the Test Period. The weighted average cost of debt was calculated by multiplying the debt outstanding by the average cost for each debt issue. *NWN/401, Feltz/1* shows the actual and projected amounts and costs of each debt issue outstanding at the end of the Test Year.

Q. How did you calculate the Test Year cost of long-term debt?

A. Estimating the Company's balances and costs of long-term debt requires only one assumed value—the only new debt issue included in the Test Year, which is shown on Line 24 of *NWN/401, Feltz/1*. Lines 1 to 23 show the existing portfolio of debt issues. The cost of money column (Column (o)) 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 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. What new debt issuances were included in the Test Year debt calculations?

A. Long-term debt outstanding in the Test Year includes an assumed $25 million debt issuance during the third quarter of 2012. For this debt issuance, we estimate a coupon rate of 4.70 percent, an effective yield of 4.795 percent, and a 30-year maturity.

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

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A. For the long-term debt issuance planned in the third quarter of 2012, I determined the coupon rate using the "implied forward yield" for a 30-year U.S. Treasury bond of 3.22 percent projected to July 2012, plus an estimated corporate credit spread of 150 basis points, which resulted in an estimated coupon rate of 4.70 percent (rounded). *See NWN/402, Feltz/1*

Q. How did you validate this estimated coupon rate?

A. I compared NW Natural's projected debt issuance against current market rates for other recent utility debt issues. *NWN/403, Feltz/1* shows three recent 30-year debt transactions issued by utility or power companies as follows:

- AGL Capital Corp. (Baa1/BBB+) = 5.875% ($200m sold on 9/15/11)
- Kansas City P&L (Baa2/BBB) = 5.30% ($400m sold on 9/15/11)
- Southern Power Co (Baa1/BBB+) = 5.15% ($300m sold on 9/14/11)

These debt transactions suggest that NW Natural's 30-year debt issue would sell for around 4.70 percent coupon rate in today's market based on recent rally in treasury markets and the relative strength of NW Natural's credit ratings, partially offset by NW Natural's smaller transaction size. Transaction size makes a difference in today's capital markets because of investor demand for market liquidity. In order for a debt issuance to regularly trade in secondary markets and thereby provide an investor with market liquidity, the issuance size needs to be $250 million or greater. NW Natural's $25 million debt issuance would not be eligible to trade in secondary markets because of size requirements. Because of NW Natural's relatively small debt size, investors will likely require a liquidity premium against comparably rated utilities, particularly in tight credit markets.

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Q. Can you provide an example showing the impact of a relatively smaller debt size on the requirement for a liquidity premium?

A. Yes. As shown above, AGL Capital Corporation (AGL) sold its 30-year bond at a coupon rate of 5.88 percent, as compared to Southern Power Company ("Southern") which sold its 30-year bond at a coupon rate of 5.15 percent only one day earlier. Both AGL and Southern were rated Baa1/BBB+ at the time of sale. Several factors can contribute to pricing differences, but one factor that provided Southern with lower pricing than AGL was the fact it was "index eligible," which meant it could trade in secondary markets because the transaction size was greater than $250 million. AGL's debt size was too small to be "index eligible," and therefore its coupon rate included a liquidity premium, which accounted for a portion of the 73 basis point difference.

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

A. The Company estimates $125,000 or 50 basis points for the agent's commission on a private placement transaction, which is less than the estimated $187,500 or 75 basis points in a public offering. The Company also estimates other expenses related to the private placement issuance of $250,000, including legal costs, which is higher than the estimated $150,000 to $200,000 for a public offering, partly because this would be the Company's first private placement transaction and initial documentation costs are expected to be higher. The Company has assumed a private placement transaction for this debt issuance because of the anticipated pricing benefit and flexibility offered by private placement investors. Specifically, the Company may be able to get better terms in a privately negotiated 30-year transaction, particularly with respect to added flexibility afforded by selling with a delayed settlement at little or no cost.

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Q. Can you explain how you determined the credit spread of 150 basis points, particularly given that it is significantly higher than the credit spread assumed in the last Oregon general rate case?

A. Yes. Although the Company is rated single "A," information is readily available from independent sources for pricing on AA credit spreads. The Company uses this AA spread information to develop its pricing analysis because historically the Company's credit spread on past bond issues have been fairly well correlated to the AA index.

Bloomberg's financial reporting service provides a U.S. AA-rated First Mortgage Utility Index ("Utility Index") for ten-year credit spread. This Utility Index showed credit spreads of 98 basis points at September 30, 2003, the period of our last rate case filing. Since then, the Utility Index spread widened out to a high of 360 basis points as of November 21, 2008, and a low of 56 basis points as of July 29, 2004. As recently as December 9, 2011, the Utility Index was showing a credit spread of 122.943 basis points (*See NWN/404, Feltz/1*). The Company assumes its credit spread would be above the indicated 123 basis point level in the Utility Index partly because of the index's AA-rating and because a longer 30-year term (*i.e.* NW Natural's next issue is expected to have a 30-year maturity) usually carries a wider spread. Adjusting the index to account for the lower credit rating and the 30-year term, the Company determined that a 150 basis point spread was reasonable. That credit spread is reasonable based on recent history of AA-corporate credit spreads (*see* chart at *NWN/405, Feltz/1*).

E. Credit Ratings

Q. What are the Company's current debt ratings?

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A. *NWN/406, Feltz/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 and S&P ratings of the Company's long-term and short-term debt are in the single "A" category, with a stable outlook. The Company's debt ratings have not changed since January 2010.

Q. How does the Company's A category debt rating benefit customers?

A. The Company's interest expense, and to a large extent the Company's access to capital in today's volatile markets, depends upon the debt ratings assigned to those securities by the leading rating agencies. If the Company's credit ratings were downgraded, the Company's interest expense would go up on all future issuances of short-term and long-term debt. Also, lower credit ratings have a direct impact on financial terms the Company is able to negotiate from suppliers and may limit access to capital markets. Specifically, strong credit ratings enabled the Company to negotiate increases in credit thresholds with financial counterparties, which is critical to the utility business because of how heavily the Company relies on financial counterparties to hedge natural gas prices each year.

Q. Are there benefits to maintaining an A category rating for the Company's debt?

A. Yes. The value of maintaining financial strength for customers, shareholders, and communities served is greater today than ever before because of financial market risks and increased volatility. Events in recent years have led capital market investors to seek security issuances of higher credit quality. These events include: the bankruptcy of Lehman Brothers on September 15, 2008, which triggered a financial crisis in the banking sector; the tightening of credit markets and a recession that followed the

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banking crisis; high unemployment levels and global economic weakness; growing U.S. budget deficits and trade imbalances; and a European debt crisis that is affecting world markets today. In capital markets over the past few years, a number of companies found it difficult and expensive to issue debt or equity financing when needed to fund operating and capital requirements. Even investment grade companies at times found it difficult to obtain financing during recent tight credit markets. In 2008 and 2009, several utilities were unable to continue issuing commercial paper to finance working capital requirements, which for some came at the same time they faced large collateral posting requirements related to commodity hedge contracts. Fortunately, NW Natural's capital structure and risk profile allowed the utility to consistently access capital markets, including short-term commercial paper, and to avoid liquidity problems.

As a result of the events described above, individual companies like NW Natural are faced with an extremely volatile credit environment, wider credit spreads, and rating agencies more likely to downgrade issuers on signs that financial measures are weakening. Most recently, rating agencies increased their focus on liquidity and pension risks, issuing warnings that underfunded pension plans could have a significant negative impact on utility companies and their credit ratings. *See NWN/407, Feltz/1*.

With the expectation that financial markets and the economy will continue to struggle for several years, it is important that NW Natural maintain the target equity and long-term debt levels of its capital structure to offset risks the Company faces as it continues to invest in large capital intensive programs and projects over the next few years. In order to fund these projects, the Company must be able to maintain an

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appropriate capital structure and financial flexibility to efficiently and cost-effectively deliver safe and reliable service for customers and reasonable returns to investors.

Q. What would be the likely result of a downgrade of the Company's credit ratings?

A. If the Company's credit ratings were downgraded to "BBB" level, the Company would suffer increased borrowing costs and risks. Immediately, the Company would likely be required to post collateral, which in turn would require an increase in the size of the Company's credit facilities. Counterparties also might begin to force the Company to clear derivative transactions on an exchange, thereby further increasing costs related to gas price hedge transactions which are essential to stabilizing gas costs to customers. Clearing trades on the exchange would be equivalent to having a zero credit limit, which potentially would require tens of millions of dollars, and potentially hundreds of millions, in cash collateral postings.

In addition to managing collateral risks, strong investment grade credit ratings enable the Company to obtain short-term credit facilities, as needed, at low cost. There were several "flight to quality" events in recent years, and as a result, many companies rated lower than NW Natural's A-1/P-1 short-term rating—including several utilities—were shut out of the commercial paper market and had to rely entirely on more expensive bank debt, assuming it was available to them. With its A-1/P-1 short-term debt rating, the Company was able to consistently access short-term debt markets, achieving among the lowest level of interest rates available in the market.

Q. Where does NW Natural currently stand with respect to its credit ratings?

A. Two major rating agencies, S&P and Moody's, rate the Company's debt based on their independent review of the Company's financial condition and credit metrics. Although

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each rating agency has a slightly different method for evaluating credit risk, many of the key financial ratios are the same or at least comparable.

Moody's considers four key financial ratios to analyze the credit quality of investor-owned utilities (*see NWN/408, Feltz/13*). NW Natural's results for each of these four ratios, as projected for the Test Year, are summarized below. These ratios reflect the Company's projected results of operations for the year ended December 31, 2011.

- The Company's pre-tax interest coverage ratio (or cash flow from operations before working capital, plus interest expense, divided by interest expense) is estimated to be above 5.4x for 2011. This ratio is within the range for an A rating. Moody's benchmark suggests this ratio should be in the range of 4.5x to 6.0x for an A rating.
- The Company's debt leverage ratio (total debt divided by total capital) is estimated to be 45.6 percent at year end 2011. The Company's leverage ratio is slightly higher than it should be for an A rating, and that's partly due to the financing requirements related to deferred environmental costs and unrecovered pension contributions discussed earlier. We discuss the regulatory accounting for these costs with the rating agencies so that they understand the corresponding cash flow impact. This is also the reason why we plan to continue issuing new shares to satisfy requirements of our Dividend Reinvestment and Optional Cash Payment Plan, and may consider new equity issuances later on, if necessary, to fund investments in gas reserves and other utility capital expenditure projects. Moody's benchmark suggests the total debt to total capital ratio should in the range of 35 to 45 percent for an A rating.

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- The Company's funds from operations to debt ratio (or cash flow from operations before working capital, divided by total debt) are estimated to be 21.0 percent at year end 2011. Moody's benchmark suggests this ratio should be in the range of 22 to 30 percent.
- Finally, the Company's retained cash flow ratio (or cash flow from operations before working capital, minus dividends, divided by total debt) is estimated at 14.9 percent at year end 2011. Moody's benchmark suggests this ratio should be in the range of 17 to 25 percent for an A rating. The Company's retained cash flow ratio is lower than it should be to support an A rating, but that's again partly due to the deferred environmental costs and unrecovered pension contributions referred to earlier. Even though cash flows are somewhat weaker than suggested by the rating agencies to support an A rating, rating evaluations take into consideration the Company's historically higher-than-industry-average growth and spending levels as long as it is reasonable to expect that these expenditures and investments will be recoverable in future rates.

Q. Have the Company's credit ratings changed since the Commission issued its order in the Company's 2002 Rate Case?

A. Yes. Since the 2002 Rate Case, the Company's long-term secured debt ratings were upgraded twice and downgraded once by S&P, and upgraded once by Moody's. *See NWN/406, Feltz/1*.

On January 4, 2005, the Company's senior secured debt rating was upgraded from A to A+. Then on February 28, 2006, the Company's secured debt rating was

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upgraded again from A+ to AA-. During this time, the Company was holding an increased level of equity in the capital structure.

On January 25, 2010, S&P downgraded the Company's senior secured debt rating one notch from AA- to A+, while maintaining a "stable" outlook. S&P indicated that the Company's rating had been corrected to reflect its default rating score. Most recently, in a report issued on June 29, 2011, S&P affirmed the Company's ratings and outlook, stating that the ratings for NW Natural "reflect the Company's *excellent business risk profile* and *intermediate financial risk profile.*"[1] S&P goes on to say, "[S]upportive regulation, a high-growth service area with a mostly residential customer base, reliable gas supplies provided by significant storage capacity, access to three major gas supply basins, and low operating risk characterize the utility's excellent business profile. Its interconnection with only one major pipeline somewhat moderates these strengths."[2]

On August 3, 2009, the Company's senior secured debt rating was upgraded by Moody's from A2 to A1, while the Company's unsecured debt rating remained unchanged at A3 since the last rate case. Moody's upgrade of the Company's secured debt rating was related to an industry-wide study of default rates for first mortgage bonds issued by utility operating companies. This study was completed in 2009, and a majority of utilities issuing secured mortgage debt were upgraded by one notch, which is what happened to NW Natural. The latest Moody's report, which is dated November 17, 2010, states that the Company's "A3 senior unsecured rating reflects the predictability and stability of its earnings and cash flows from low business risk LDC operations in

[1] Standard & Poor's Research, *Northwest Natural Gas Co.* at 2 (June 29, 2011).
[2] *Id.*

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jurisdictions that provide supportive regulatory treatment. The rating also considers NWN's relatively high reliance on residential and commercial customers, a characteristic that can help mitigate risks associated with the current economic downturn, and incorporates its effective cost controls and attention to liquidity."[3]

III. PENSION PLAN

A. Pension Plan Overview

Q. Please describe NW Natural's qualified defined benefit pension plans.

A. NW Natural sponsored a defined benefit pension plan for its utility employees starting in May of 1950. In 1963, this Plan was amended to provide two separate plans, one for the bargaining unit (BU) employees, and the other for non-bargaining unit (NBU) employees (collectively the "Retirement Plans" or "Plans"). Only NBU employees hired prior to Jan. 1, 2007, and BU employees hired prior to Jan. 1, 2010, remain eligible to participate in the relevant Retirement Plan.

Eligible employees became members of the Plan on the first day of the month following completion of one year of service, and those employees became vested after completing five years of service. An employee's retirement benefit under the Plan depends on several factors, including years of service and final average pay. Normal retirement age under the Plan is 62 for NBU employees and 65 for BU employees.

Q. How are pension liabilities funded?

A. The Company makes contributions into the Retirement Plan's trust account. These contributions are used to pay current benefits or are invested to meet future benefits.

[3] Moody's Investors Service, *Credit Opinion: Northwest Natural Gas Company* (Nov. 17, 2010).

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The amounts contributed each year are determined based on a number of factors, including the valuation of Plan assets and liabilities and federal standards for minimum contribution (or funding) requirements, as set forth in the Internal Revenue Code (IRC). The minimum contribution requirements for a plan year depend to a certain extent on whether the value of Plan assets is more or less than Plan liabilities. The objective of a minimum contribution requirement is to provide for sufficient assets in a defined benefit pension plan so that it can meet its future obligations. If Plan assets are less than Plan liabilities, then the Plan is considered underfunded, and the shortfall must be made up over a period of time.

B. Current Rate Recovery of Pension Plan Expenses

Q. Are Plan contributions per se included in the Company's rates?

A. No. Historically, it has been fairly common for utilities to determine the amount of pension costs to be included in rates based solely on the accounting expense associated with the pension plan based on what is known as Financial Accounting Standard (FAS) 87 accounting methodology. The Company's current recovery of pension-related costs is consistent with this methodology.

Q. Please explain.

A. Under FAS 87, the Company's pension expense is referred to as the net periodic pension cost ("FAS 87 expense"). FAS 87 expense takes into account two components: (1) an estimate of future liabilities, which are benefit obligations created by employee service, and (2) plan assets. Benefit obligations are payments that must be made to retirees in future years. These payments are principally determined by an employee's length of service and salary history. Specific components of FAS 87 expense consist of:

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employee service cost, interest cost, expected income return on plan assets, amortization of prior service cost, and amortization of actuarial gains and losses.

Q. How does the Company calculate its FAS 87 expense?

A. The Company uses a professional actuary to determine pension liabilities and expenses based on assumptions about employees, including wage and salary increases, expected retirement ages, and life expectancies. The FAS 87 expense calculation also requires assumptions about long-term interest rates and expected return on plan assets, which are developed with assistance from the Plans' actuary and a professional investment consultant. Because FAS 87 expense is estimated using these assumptions, any differences between actual and estimated results are captured as actuarial gains and losses. These actuarial gains and losses are not immediately recognized in the Company's income statement, but rather are amortized to expense over an extended period of time. The amortization period for actuarial gains and losses is typically 12 to 14 years, which reflects the average remaining service life of active employees participating in the Plan.

Q. What impact do contributions have on FAS 87 expense?

A. As indicated above, contributions are used to pay current benefits or are invested to satisfy future benefits. When contributions are invested, Plan assets increase, which in turn improves the funded status of the Plan and reduces the future accounting expense (FAS 87) and funding requirements. For example, a $1,000,000 contribution invested in the Retirement Plan trust account reduces the Company's long-term liabilities (funding shortfall) by $1,000,000 and decreases annual FAS 87 expense by $82,500 based on an assumed investment return of 8.25 percent.

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Q. Is the current FAS 87 recovery methodology adequate to allow the Company to recover its prudently incurred pension related costs?

A. No. Changes in financial markets and pension law have required the Company to make substantial contributions to the pension plans that are not recovered through the FAS 87 methodology.

Q. Please explain.

A. In 2006 Congress passed the Pension Protection Act (PPA), which established a new set of funding requirements for defined benefit pension plans. Specifically, PPA set new rules for calculating the value of plan assets and plan liabilities and for accelerating contributions of underfunded plans. In accordance with PPA, plans are now required:

- To achieve funding targets of 100 percent of projected plan liabilities;
- To reduce funding shortfalls over a shorter period (*i.e.* seven years); and
- To impose benefit restrictions and additional fees when a plan falls below certain funding levels.

As a result, the Company has been required to make large cash contributions to its plans to ensure the required levels of funding.

In addition to PPA, financial market factors beyond the Company's control materially affected the Plans' contributions. In 2008 and 2009, the equity and bond markets collapsed, which led to a significant decline in the value of the Plans' assets. The recession that followed also caused a significant reduction in interest rates to historic lows, which dramatically increased Plan liabilities. As a result, the Company went from being overfunded by several million dollars at the end of 2007 to being underfunded by $98 million at the end of 2008, despite the Company having contributed

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nearly $40 million into the Plans in 2004 and 2005. The underfunded pension balance triggered several rounds of Company contributions, totaling $57 million between 2009 and 2011 in accordance with PPA funding requirements. It is these unrecovered cash contributions that the Company seeks to address in this filing.

Q. But doesn't the balancing account approved in Docket UM 1475 provide an appropriate long-term recovery of pension costs?

Q. No, not by itself. When the Company filed its petition in UM 1475, it did so to address two significant issues related to its pension recovery.[4] First, the Company wished to address its concerns about its chronic under-recovery of FAS 87 expense.[5] In the 2002 Rate Case, the Commission had approved FAS 87 expense with the proviso that the Company defer for customers' benefit any recovery in excess of the rate case approved expense.[6] The order did not, however, allow the Company to defer under-recoveries and in fact the Company *had* under-recovered its FAS 87 expense in six out of seven years and projected that it would continue to do so. For that reason, the Company requested permission to defer FAS 87 expenses that it expected to be substantially in excess of those recovered in rates.

Second, the Company also requested that it be allowed to recover its investment costs associated with the very substantial cash contributions that it had been and would

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[4] *Re. NW Natural Gas Co. Application to Defer Pension Costs*, Docket UM 1475, NWN/100, Miller/7 (Sept. 20, 2010).
[5] *Re. NW Natural Gas Co. Application to Defer Pension Costs*, Docket UM 1475, Application at 3-4 (Mar. 15, 2010).
[6] *Re. NW Natural Gas Co. Application for a General Rate Revision*, Docket UG 152, Order No. 03-507 at 4 (Aug. 22, 2003).

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continue to make until its Plans were fully funded.[7] However, after negotiations, the parties entered into a stipulation that created the current balancing account—which addresses only the FAS 87 pension expense.[8] Specifically, the current balancing account allows the Company to defer FAS 87 expense both below and above the amounts recovered it rates. It does not, however, address the recovery of financial costs related to the Company's cash contributions. Thus, the current mechanism provides no way for the Company to recover the investor's capital costs related to the pension contributions in excess of amounts included and collected in customer rates. In fact, when the balancing account for FAS 87 expense reaches zero, expected in 2020, the current approach would indicate that savings from amounts included in rates will accumulate and require refunding to customers, even though much of the FAS expense savings are expected primarily due to unrecovered investor contributions that have generated investment returns that reduce FAS 87 expense. If this happens, the total unrecovered cash contributions made by the Company from 2003 until the Plan is fully funded—which is estimated to be $90 million pre-tax—will become a permanent use of investor capital without compensation.

Q. If using FAS 87 expense as a basis for pension expense recovery does not compensate the utility for pension expenses, why was the methodology used in the past?

A. In the past, FAS 87 accounting allowed for the amortization of actuarial gains and losses over a number of years, which tended to smooth out the FAS 87 expense amount from

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[7] *Re. NW Natural Gas Co. Application to Defer Pension Costs*, Docket UM 1475, NWN/100, Miller/7 (Sept. 20, 2010).

[8] *See Re. NW Natural Gas Co. Application to Defer Pension Costs*, Docket UM 1475, Order No. 11-051 (Feb. 10, 2011).

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year to year. With respect to pension contributions, the IRC also allowed the use of smoothing techniques allowing the employer to make contributions over time that more closely matched the FAS 87 expense recognized over time. With a relatively similar smoothing of both FAS 87 expenses and pension contributions, the difference between these two amounts tended to even out. However, as discussed above, the combination of the PPA and the financial crisis requires the Company to finance significant cash contributions until the plan is fully funded—which is projected to be in 2017. Without a change in rate making for pension contributions, unrecovered investor contributions will become a permanent difference, which means that the Company's investors will get neither a return on nor a return of their capital used to fund these pension liabilities.

Q. Why do you say that the unrecovered contributions were funded by investors?

A. It is a fundamental principle of accounting that all assets must be funded by either debt or equity. Investors, not ratepayers, provide the funding for the Company's debt and equity. When a long-term asset is funded, it means that investors have contributed capital that needs to be recognized in setting rates.

Contributions made to the pension fund were from the same sources of funds the Company uses to make any long-term investment. Investor funds are used to make pension contributions just as investor funds are used to purchase or construct utility plant assets.

Q. How do the Company's contributions into its Plans compare with the amount it has collected from customers for pension expenses?

A. *NWN/409, Feltz/1* shows that between 2004 and 2011, the Company contributed $86,634,634 (adjusted to reflect amounts allocated to Oregon only), as compared to

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$59,684,840 collected from Oregon customers, including amounts recorded to utility plant and pension balancing accounts which will be collected in future years. The roughly $27 million in extra contributions was funded using investor capital ("unrecovered investor contributions").

Q. What does the Company expect with respect to contributions and collections in the future?

A. *NWN/409, Feltz/1* also shows that in 2012 and 2013, the most recent estimates provided by the Company's actuary projects pension contributions totaling $37,800,000 (amount adjusted for Oregon only), compared to an estimated $27,000,000 to be collected from Oregon customers under current methodology, including utility plant and pension balancing amounts. This brings the estimated total of unrecovered investor contributions to roughly $37,750,000 pre-tax or $22,650,000 after-tax.

C. Proposed Change in Rate-Making Methodology for Pensions

Q. How does the Company propose that it recover the unrecovered portion of its contributions to its pension plans?

A. The Company proposes to add unrecovered investor contributions to the pension plans to rate base, thereby allowing utility revenue requirements to recover the appropriate capital costs related to funding employee pension plans. Specifically, the Company proposes to add the average unrecovered investor contribution amount during the Test Year, estimated at $21,929,876 net of deferred taxes, or $36,549,793 pre-tax, to rate base. This amount was determined by taking the after-tax balance of unrecovered investor contributions estimated at year end 2012, pro-rated to reflect two months of the Test Year, and adding the estimated after-tax balance at the end of 2013, pro-rated to

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reflect 10 months of the Test Year. The Company proposes to amortize the pre-tax amount over eight years to recover the investment. The revenue requirement impact of this proposal is estimated to be $4,568,724, or $36,549,793 divided by eight years.

Q. Why did the Company choose an eight-year amortization period?

A. The Company selected an eight-year amortization period because the pension balancing account is projected by the actuary to zero out in the eighth year (2020) after the rate case, based on current assumptions. Once the balancing account and unrecovered investor contributions are zero, the Company would expect the balancing account would be used to defer, and refund or collect, the differences going forward.

Q. Is there precedent for allowing the Company to recover pension costs based on contributions?

A. Yes. Several public utility commissions in other states have begun to use pension contributions as a component in setting rate recovery from utility customers. For example, Hawaii Electric Company, Inc. was allowed to add their pre-paid pension contributions to rate base; Pacific Gas & Electric Company in California was allowed to collect over a three year rate cycle the amount of pension contributions needed to reach 100 percent funded status under PPA; and Wisconsin Electric Power Company was allowed to adjust rate base up or down for the net use of investor capital, including pension contributions. A trend seems to be developing in the direction of providing rate treatment for pension contributions so that utilities can recover the costs related to contributions in excess of FAS 87 expense.

Q. Were the Company's contributions made to the Retirement Plans prudent?

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A. Yes. As discussed earlier, the Company's contributions to the Retirement Plans are subject to federal laws, including recent changes to reflect the new PPA laws. Before PPA, the Company was not required to contribute as much as quickly as it is now because the prior funding rules allowed more smoothing of gains and losses so that contributions were spread over time. Now, PPA requires Plans to fund to 100 percent of projected pension liabilities, which was not a requirement before PPA. This actually increases the risk the Company's Plans could become overfunded after a series of higher contributions during a down market. The Company's funding policy tries to minimize the risk of overfunded plans because that too has negative consequences. Maintaining an appropriate funded status and compliance with federal laws are primary goals of the Company's funding policy in order to minimize costs, preserve liquidity, and maintain financial flexibility and credit quality. The Company's funding policy avoids liquidity and credit risks and other negative consequences that apply to plans that are below 80 percent funded. The Company believes these funding policies are prudent and in compliance with pension laws.

Q. Why is it appropriate to recover a return of unrecovered investor contributions as well as a return on unrecovered investor contributions?

A. It is appropriate to include a return on and a return of the Company's unrecovered investor contributions because:

(1) Inclusion in rates and rate base is consistent with rate-making treatment of other long-term investments in the utility that benefit customers, and is consistent with the accounting methodology originally developed for pension assets, liabilities and expenses under FAS 87;

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(2) Pension contributions reflect prudent investments, funded by investors, that are used and useful in providing services to utility customers of NW Natural;

(3) Pension contributions benefit ratepayers by reducing annual O&M expense and capital expense;

(4) Pension contributions strengthen the Company's balance sheet, liquidity position, and credit profile when plans are well funded;

(5) Pension contributions improve the funded status and reduce liabilities, thereby minimizing any adverse effect on Company credit ratings;

(6) Pension contributions included in rates and rate base provide support of the Company's ability to record pension-related accumulated other comprehensive income (AOCI) as a regulatory asset, thereby avoiding the AOCI charge against common equity, which would adversely affect the Company's capital structure and other financial ratios;

(7) Pension contributions included in rates and rate base compensate the Company's investors for the hidden costs of providing pension benefits to employees; and

(8) Pension contributions included in rates and rate base are consistent with other states that are allowing the cost of investor contributions to be recovered.

Q. Please summarize your recommendation for recovery of pension costs.

A. The following summarizes the Company's recommendations:

(1) Continue to include the same annual amount for FAS 87 expense that was included in the 2002 Rate Case ($3,796,000 allocated to Oregon); this

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recommendation is consistent with the agreement reached in UM 1475 when the pension balancing account was approved;

(2) Continue with the pension balancing account for annual differences between actual FAS 87 O&M expense and the amount included in rates from the 2002 Rate Case; this two-way balancing account serves to protect both ratepayers and shareholders because FAS 87 expenses can fluctuate over time based on many factors beyond the Company's control;

(3) Add to rate base the average unrecovered investor contribution amount during the Test Year, which is estimated to be $21,930,000 net of deferred taxes; and

(4) Include in rates an annual revenue requirement for the return of unrecovered investor contributions amortized over eight years; the annualized amount is estimated to be $4,569,000.

Q. Does the Company's proposed rate treatment account for investor contributions beyond the Test Year?

A. No. Any additional unrecovered investor contributions after the Test Year will need to be addressed in a future rate case.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Exhibits of Stephen P. Feltz

COST OF CAPITAL / PENSIONS
EXHIBITS 401 - 411

December 2011

EXHIBITS 401-411 – COST OF CAPITAL / PENSIONS

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NORTHWEST NATURAL GAS COMPANY
EMBEDDED COST OF LONG-TERM DEBT CAPITAL AT
Pro-Forma PERIOD ENDED October 31, 2013

								Premium or Discou		Underwriter's Commission		Expense of Issue			Net Proceeds		Original	Cost of	Annual
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	Term to Maturity Yrs.	Money (Bond Table)	Cost Out-standing Debt
		(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)	(i)	(j)		(k)	(l)	(m)	(n)	(o)	(p)
		Medium-Term Notes																	
		First Mortgage Bonds:																	
1	8.260%	8.260% Series	09/94	09/14	1.7	10,000,000	10,000,000	0	0.00	40,000	0.400	863,369	[1]	8.63	9,096,631	90.966	20	9.260%	926,000
2	3.950%	3.95 % Series	07/09	07/14	1.5	50,000,000	50,000,000	0	0.00	250,500	0.501	191,076		0.38	49,558,424	99.117	5	4.147%	2,073,500
3	4.700%	4.700% Series	06/05	06/15	2.5	40,000,000	40,000,000	0	0.00	250,000	0.625	91,898		0.23	39,658,102	99.145	10	4.809%	1,923,600
4	5.150%	5.150% Series	12/06	12/16	4.0	25,000,000	25,000,000	0	0.00	156,250	0.625	121,426		0.49	24,722,324	98.889	10	5.294%	1,323,622
5	7.000%	7.000% Series	08/97	08/17	4.6	40,000,000	40,000,000	0	0.00	300,000	0.750	75,600		0.19	39,624,400	99.061	20	7.089%	2,835,600
6	6.600%	6.600% Series	03/98	03/18	5.2	22,000,000	22,000,000	0	0.00	165,000	0.750	1,179,884	[2]	5.36	20,655,116	93.887	20	7.181%	1,579,820
7	8.310%	8.310% Series	09/94	09/19	6.7	10,000,000	10,000,000	0	0.00	40,000	0.400	1,071,757	[1]	10.72	8,888,243	88.882	25	9.479%	947,900
8	7.630%	7.630% Series	12/99	12/19	6.9	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%	1,545,400
9	5.370%	5.370% Series	03/09	02/20	7.1	75,000,000	75,000,000	0	0.00	468,750	0.625	10,394,058	[7]	13.86	64,137,192	85.516	11	7.327%	5,495,250
10	9.050%	9.050% Series	08/91	08/21	8.6	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%	916,300
11	3.176%	3.176% Series	09/11	09/21	8.7	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%	1,659,500
12	5.620%	5.620% Series	11/03	11/23	10.9	40,000,000	40,000,000	0	0.00	372,588	0.931	2,952,850	[6]	7.38	36,674,562	91.686	20	6.360%	2,544,190
13	7.720%	7.720% Series	09/00	09/25	12.7	20,000,000	20,000,000	0	0.00	150,000	0.750	1,136,261	[4]	5.68	18,713,739	93.569	25	8.336%	1,667,200
14	6.520%	6.520% Series	12/95	12/25	12.9	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%	658,900
15	7.050%	7.050% Series	10/96	10/26	13.8	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%	1,424,200
16	7.000%	7.000% Series	05/97	05/27	14.4	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%	1,412,400
17	6.650%	6.650% Series	11/97	11/27	14.9	19,700,000	20,000,000	0	0.00	125,000	0.625	37,800	[8]	0.19	19,837,200	99.186	30	6.714%	1,322,658
18	6.650%	6.650% Series	06/98	06/28	15.4	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%	672,700
19	7.740%	7.740% Series	08/00	08/30	17.7	20,000,000	20,000,000	0	0.00	150,000	0.750	1,354,914	[3]	6.77	18,495,086	92.475	30	8.433%	1,686,538
20	7.850%	7.850% Series	09/00	09/30	17.7	10,000,000	10,000,000	0	0.00	75,000	0.750	678,107	[5]	6.78	9,246,893	92.469	30	8.551%	855,100
21	5.820%	5.820% Series	09/02	09/32	19.7	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%	1,773,943
22	5.660%	5.660% Series	02/03	02/33	20.2	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%	2,289,200
23	5.250%	5.250% Series	06/05	06/35	22.5	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%	531,600
24	4.700%	4.700% Series	07/12	07/42	29.5	25,000,000	25,000,000	0	0.00	125,000	0.500	250,000		1.00	24,625,000	98.500	30	4.795%	1,198,750
						$626,700,000	$627,000,000	0		$4,193,088		$21,153,220			$601,653,692			6.265%	$39,263,871

WEIGHTED EMBEDDED COST: $39,263,871 $626,700,000 EQUALS = 6.265%

[1] INCLUDES PREMIUM AND UMAMORTIZED COST ON EARLY REDEMPTION OF 9.8% SERIES BONDS ($1,044,111 ALLOCATED TO THE 8.31% SERIES, AND $835,723 ALLCOATED TO THE 8.26% SERIES).

[2] INCLUDES $910,800 PREMIUM AND $222,664 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 9.125% SERIES BONDS ALLOCATED TO THE 6.60% SERIES.

[3] 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.

[4] 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.

[5] 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.

[6] 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.

[7] INCLUDES $10,096,000 COSTS PAID ON INTEREST RATE HEDGE LOSS AND $298,058 UNAMORTIZED COSTS ON SHELF REGISTRATION, ALLOCATED TO 5.37% SERIES.

[8] 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.

30-Year Treasury Forecast – December 9, 2011

2-BLOOMBERG

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95) Graph Analysts | 96) Forecast Histogram | Bond Yield Forecast

US 30-Year

Market Yield: 3.09

Recent Updates: No Update Since Last Official Survey

	Q4 11	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Bloomberg Wgt Avg	3.18	3.24	3.41	3.60	3.79	4.02
Implied Forward Yield	3.10	3.14	3.18	3.22	3.25	3.29
Median Forecast	3.10	3.20	3.30	3.43	3.60	3.80
Average Forecast	3.18	3.24	3.41	3.60	3.79	4.02
High Forecast	4.15	4.23	5.00	5.20	5.85	5.88
Low Forecast	2.80	2.30	2.48	2.85	3.05	3.00
Responses	48	48	48	48	45	35
Dec. Survey Median / Nov. Survey Median / Change in Medians	3.20	3.30	3.50	3.60	3.70	3.80

Firm Name	Analyst	As of	Q4 11	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
4) Bank of America	E. Harris	12/09	2.90	2.50	2.70	3.10	3.60	
5) Barclays Capital	D. Maki	12/09	4.00	4.00	4.00	4.00		
6) Canadian Imperial	A. Shenfeld	12/09	2.85	2.95	3.00	3.05	3.40	3.35
7) Chmura Economic	X. Shuai	12/09	4.15	4.23	4.33	4.40	4.47	4.47
8) Credit Suisse Gro	C. Lantz	12/09	3.00	2.50	2.90	3.20	3.50	
9) Desjardins Securi	F. Dupuis	12/09	3.10	3.20	3.30	3.45	3.60	3.80
10) Euler Hermes SA	D. North	12/09	2.80	2.90	3.20	3.50	4.10	4.80
11) Fannie Mae	D. Duncan	12/09	3.26	3.27	3.31	3.35	3.39	3.43
15) Goldman Sachs Gr	E. Mckelvey	12/09	2.90	2.75	3.10	3.15	3.25	3.25
16) Guerrilla Capital	J. Dunham	12/09	3.75	4.00	5.00	5.20	5.85	5.83
17) Heartland	A. Douglas	12/09	2.85	3.25	3.50	4.00	4.00	4.25
26) Moody's Corp	J. Lonski	12/09	3.10	3.10	3.15	3.25	3.40	3.50
27) Moody's Economy	M. Zandi	12/09	3.80	4.14	4.67	5.08	5.50	5.88
28) Morgan Keegan In	D. Ratajczak	12/09	3.07	3.10	3.25	3.36	3.62	
29) Morgan Stanley	D. Greenlaw	12/09	3.05	3.05	3.05	3.05	3.05	3.00
39) SMBC Nikko Secur	H. Shimazu	12/09	3.00	3.25	3.50	4.00	4.50	4.75
40) Scotia Capital	D. Holt	12/09	2.95	3.00	3.15	3.60	3.90	4.00
41) Societe Generale	A. Markowska	12/09	3.05	2.30	2.48	2.85	3.18	
42) UniCredit SpA	R. Kubarych	12/09	3.85	4.00	4.15	4.25		
43) United States Cha	M. Regalia	12/09	3.20	2.90	3.00	3.10	3.20	
44) University of Cali	D. Shulman	12/09	3.00	3.10	3.20	3.40	3.70	3.90
45) University of Cent	S. Snaith	12/09	3.08	3.07	3.23	3.37	3.46	3.57
46) Wayne Hummer C	W. Hummer	12/09	3.20	3.30	3.30	3.40	3.50	3.60
47) Wells Capital Man	G. Schlossberg	12/09	3.01	3.24	3.59	3.78	4.09	4.29
48) Wells Fargo & Co	J. Silvia	12/09	3.10	3.30	3.30	3.40	3.50	3.60

U.S. Utility & Power Debt Capital Markets

Weekly Market Update – 9/26/2011

Contacts: Jake Horstman, Managing Director, (704) 715-8011
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Investment Grade Debt Market Overview

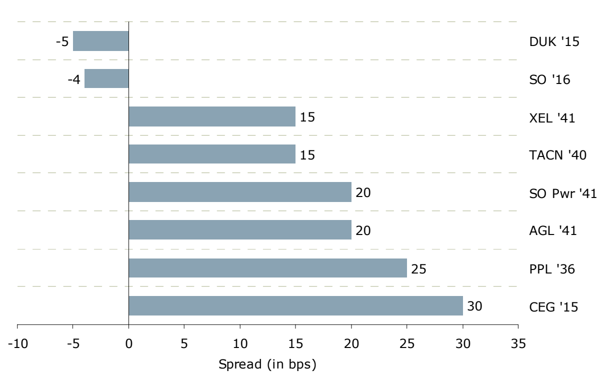
Weekly Commentary

- September is typically the busiest month of the year, making the lack of High Grade issuance last week extremely unusual.
  - Borrowers elected to stay on the sideline as the tone deteriorated over concerns about the European debt crisis and the weakening economic outlook that was highlighted by the FOMC statement released on Wednesday.
- The Federal Reserve announced "Operation Twist," a plan to lower long-term borrowing costs by purchasing $400 billion of 6 to 30 years Treasury notes in the open market and selling securities with maturities less than 3 years.
  - Post announcement, the market focused more on the text of the Fed's statement in regards to the weakness of the global economy.
  - Consequently, the 30-year Treasury note rallied, and its yield decreased as much as 21 bps on Wednesday, and another 19.6 bps on Thursday.
  - The 10-year Treasury note yield set a new record low at an astounding 1.718%.
- Spreads on recent 30-year Utility deals suffered from the recent rally in Treasuries, but overall bond yields continue to drop as spreads have increased at a slower pace than the decline in Treasury yields.
- As investors take a defensive position, demand will be skewed to higher quality defensive credits.

Recent Utility/Power Transactions

Issue Date	Issuer	Security	Ratings Moody's	Ratings S&P	Amount ($ mm)	Tenor	Coupon	Spread At Issue	Market
9/15/11	AGL Capital Corp.	Senior Unsecured	Baa1	BBB+	$300	10.0yrs	3.500%	160 bps	Institutional
9/15/11	AGL Capital Corp. (reopening)	Senior Unsecured	Baa1	BBB+	200	30.0yrs	5.875%	165 bps	Institutional
9/15/11	Kansas City Power and Light Co.	Senior Unsecured	Baa2	BBB	400	30.0yrs	5.300%	200 bps	Institutional
9/14/11	Southern Power Co.	Senior Unsecured	Baa1	BBB+	300	30.0yrs	5.150%	190 bps	Institutional
9/14/11	PSEG Power LLC	Senior Unsecured	Baa1	BBB	250	5.0yrs	2.750%	190 bps	Institutional
9/14/11	PSEG Power LLC	Senior Unsecured	Baa1	BBB	250	10.0yrs	4.150%	215 bps	Institutional
9/13/11	Western Massachusetts Electric Co.	Senior Unsecured	Baa2	BBB+	100	10.0yrs	3.500%	162.5 bps	Institutional
9/12/11	Progress Energy Carolinas	First Mortgage	A1	A	500	10.0yrs	3.000%	110 bps	Institutional
9/7/11	Northwest Natural Gas Co.	First Mortgage	A1	A	50	10.0yrs	3.176%	115 bps	Institutional
9/7/11	Wisconsin Electric Power Co.	Senior Unsecured	A2	A-	300	10.0yrs	2.950%	105 bps	Institutional
9/7/11	Pacific Gas & Electric Co.	Senior Unsecured	A3	BBB+	250	10.0yrs	3.250%	130 bps	Institutional

Weekly Spread Movement in Utility Holding & Generating Company Benchmarks



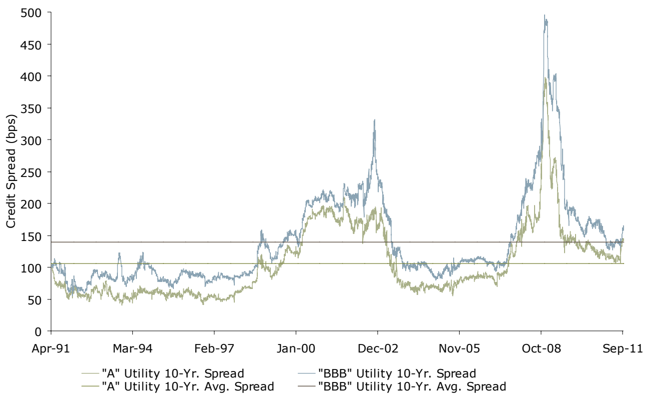
- Higher rated Utility operating companies outperformed last week as economic concerns sent most secondary spreads wider.
- The strong rally in interest rates at the long end of the curve led to additional spread widening in 10-year and 30-year Utility paper.

U.S. Utility & Power Debt Capital Markets

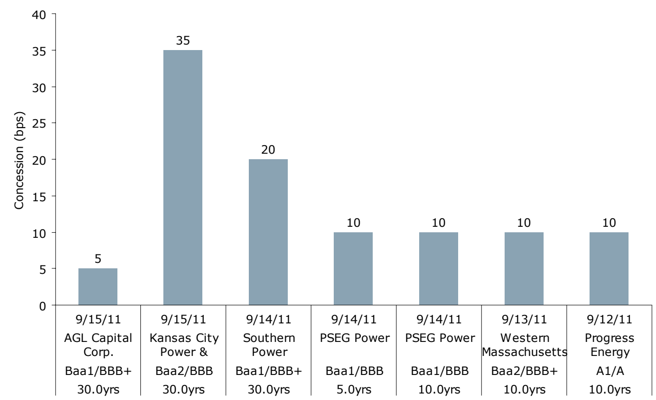
Weekly Market Update – 9/26/2011

Current Market Environment

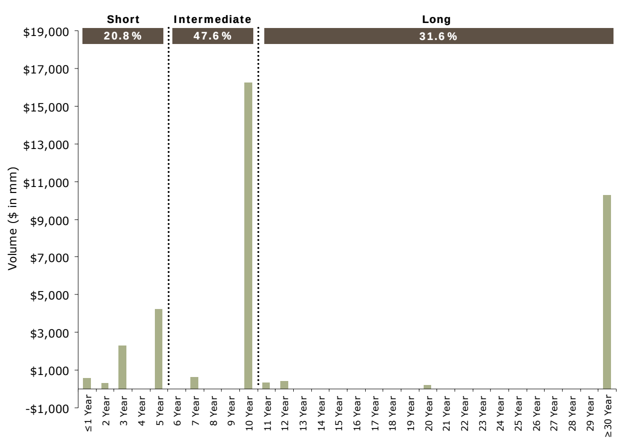
Historical Utility Credit Spreads



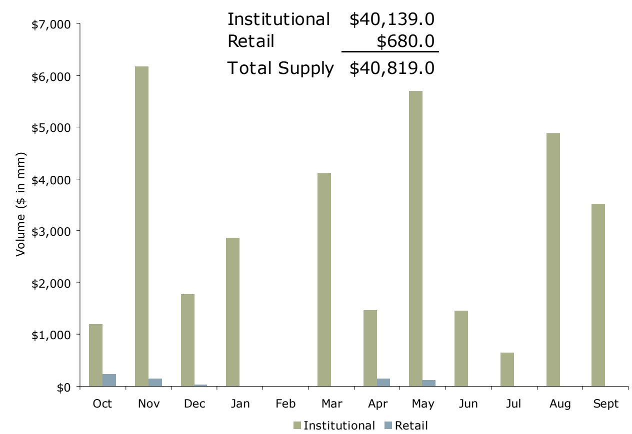
Recent New Issue Concessions



LTM Utility Issuance Volume by Tenor



LTM Utility Issuance Volume by Month



Economic Overview

Upcoming Economic Releases

Event Date	Event	Event Date	Event
9/26	Chicago Fed Natl. Activity	9/29	GDP Annualized
9/26	New Home Sales	9/29	Personal Consumption
9/26	Dallas Fed Mfg. Activity	9/29	Jobless Claims
9/27	S&P/CS Housing Index	9/29	Pending Home Sales
9/27	Consumer Confidence	9/30	Personal Income/Spending
9/28	Durable Goods Orders	9/30	Chicago Purchasing Mgr.

Wells Fargo's Rate Forecast

	Today	Q3 '11	Q4 '11	Q1 '12	Q2 '12
Fed Funds	0.25%	0.25%	0.25%	0.25%	0.25%
3M LIBOR	0.36%	0.30%	0.30%	0.30%	0.30%
5YR UST	0.87%	0.80%	0.80%	0.90%	1.00%
10YR UST	1.83%	1.75%	1.75%	2.00%	2.20%
30YR UST	2.90%	3.10%	2.90%	3.10%	3.30%

Product of Debt Capital Markets

Source: Wells Fargo Securities & Bloomberg

U.S. Utility & Power Debt Capital Markets

Weekly Market Update – 9/26/2011

Secondary Trading Levels

HOLDING COMPANIES Ticker	Ratings	Coupon	Maturity	Spread (bps)	Weekly Change	YTD Change
AEP	Baa2 / BBB	5.250%	6/1/15	125	0	25
AGL	Baa1 / BBB+	3.500%	9/15/21	180	10	N/A
AGL	Baa1 / BBB+	5.875%	3/15/41	200	20	N/A
ATO	Baa1 / BBB+	8.500%	3/15/19	160	5	20
ATO	Baa1 / BBB+	5.500%	6/15/41	155	10	N/A
BRK	Baa1 / BBB+	5.750%	4/1/18	95	0	50
BRK	Baa1 / BBB+	6.500%	9/15/37	165	0	45
CEG	Baa3 / BBB-	4.550%	6/15/15	220	30	60
CEG	Baa3 / BBB-	5.150%	12/1/20	270	5	70
CMS	Ba1 / BB+	6.250%	2/1/20	360	10	95
CNP	Baa3 / BBB-	6.500%	5/1/18	165	0	20
CNP	Baa2 / BBB	4.500%	1/15/21	180	0	60
CNP	Baa2 / BBB	5.850%	1/15/41	195	5	50
D	Baa2 / A-	4.450%	3/15/21	150	0	N/A
D	Baa2 / A-	4.900%	8/1/41	170	5	N/A
DTE	Baa2 / BBB	6.375%	4/15/33	200	5	25
DUK	Baa2 / BBB+	3.350%	4/1/15	92	-5	27
DUK	Baa2 / BBB+	3.550%	9/15/21	165	0	N/A
EIX	Baa2 / BBB-	3.750%	9/15/17	195	5	65
ETR	Baa3 / BBB-	5.125%	9/15/20	325	5	105
EXC	Baa1 / BBB-	4.900%	6/15/15	155	10	15
EXC	Baa1 / BBB-	5.625%	6/15/35	225	5	55
FE	Baa3 / BB+	7.375%	11/15/31	270	10	15
NEE	Baa1 / BBB+	2.600%	9/1/15	145	10	40
NEE	Baa1 / BBB+	4.500%	6/1/21	190	5	N/A
NGGLN	Baa1 / BBB+	6.300%	8/1/16	180	10	25
NI	Baa3 / BBB-	5.450%	9/15/20	230	5	50
NI	Baa3 / BBB-	5.950%	6/15/41	250	10	N/A
NST	A2 / A	4.500%	11/15/19	125	0	55
PCG	Baa1 / BBB	5.750%	4/1/14	155	0	25
PGN	Baa2 / BBB	4.400%	1/15/21	160	0	N/A
PGN	Baa2 / BBB	6.000%	12/1/39	185	5	65
POM	Baa3 / BBB	2.700%	10/1/15	150	0	30
PSD	Ba1 / BB+	6.000%	9/1/21	430	10	N/A
SCG	Baa2 / BBB	4.750%	5/15/21	215	10	N/A
SO	Baa1 / A-	1.950%	9/1/16	111	-4	N/A
SRE	Baa1 / BBB+	6.150%	6/15/18	135	0	70
SRE	Baa1 / BBB+	6.000%	10/15/39	185	5	60
TACN	Baa2 / BBB	6.500%	3/15/40	270	15	75
TE	Baa3 / BBB	5.150%	3/15/20	190	5	55
TEG	Baa1 / BBB	4.170%	11/1/20	185	0	55
XEL	Baa1 / BBB+	4.700%	5/15/20	150	5	65
XEL	Baa1 / BBB+	4.800%	9/15/41	175	15	N/A

GENERATION COMPANIES						
EXC	A3 / BBB	4.000%	10/1/20	210	0	60
EXC	A3 / BBB	5.750%	10/1/41	235	5	55
FE	Baa3 / BBB-	6.050%	8/15/21	295	10	55
FE	Baa3 / BBB-	6.800%	8/15/39	315	10	45
PEG	Baa1 / BBB	2.750%	9/15/16	202	12	N/A
PEG	Baa1 / BBB	4.150%	9/15/21	225	0	N/A
PPL	Baa2 / BBB	6.500%	5/1/18	205	25	70
PPL	Baa2 / BBB	6.000%	12/15/36	285	25	100
SO	Baa1 / BBB+	5.150%	9/15/41	215	20	N/A

HYBRIDS						
D	Baa3 / BBB	6.300%	9/30/66	3885	2093	2977
D	Baa3 / BBB	7.500%	6/30/66	639	40	210
EEP	Baa3 / BB+	8.050%	10/1/37	606	-20	245
EPD	Ba1 / BB	8.375%	8/1/66	640	-23	188
EPD	Ba1 / BB	7.000%	6/1/67	692	-21	307
EPD	Ba1 / BB	7.034%	1/15/68	589	-19	298
NEE	Baa2 / BBB	6.350%	10/1/66	634	3	179
NEE	Baa2 / BBB	6.650%	6/15/67	633	1	308
NEE	Baa2 / BBB	7.300%	9/1/67	593	0	289
PPL	Ba1 / BB+	6.700%	3/30/67	663	-10	303
PSD	Baa3 / BB+	6.974%	6/1/67	632	-10	225
SUG	Ba1 / BB	7.200%	11/1/66	1678	326	-42
TEG	Baa2 / BBB-	6.110%	12/1/66	607	-10	146
TRPCN	Baa1 / BBB	6.350%	5/15/67	561	-20	251
WEC	Baa1 / BBB	6.250%	5/15/67	561	-10	256

OPERATING COMPANIES - UNSECURED Ticker	Ratings	Coupon	Maturity	Spread (bps)	Weekly Change	YTD Change
AEP	A3 / BBB	6.050%	5/1/18	135	5	75
AEP	Baa1 / BBB	5.375%	10/1/21	195	5	75
AEP	Baa2 / BBB	4.600%	3/30/21	185	5	N/A
AEP	Baa3 / BBB	6.200%	3/15/40	225	5	35
BRK	A2 / A-	5.300%	3/15/18	50	0	20
BRK	A2 / A-	5.800%	10/15/36	140	0	35
CEG	Baa2 / BBB+	5.900%	10/1/16	170	10	30
CEG	Baa2 / BBB+	6.350%	10/1/36	170	10	30
D	A3 / A-	5.000%	6/30/19	95	5	45
D	A3 / A-	3.450%	9/1/22	135	5	50
D	A3 / A-	6.350%	11/30/37	145	5	45
DUK	A3 / A-	6.100%	6/1/37	155	0	50
ED	A3 / A-	4.450%	6/15/20	110	0	45
ED	A3 / A-	5.700%	6/15/40	145	5	50
FE	Baa3 / BBB-	5.950%	12/15/36	235	5	45
FE	Baa2 / BBB-	7.350%	2/1/19	135	0	10
FE	Baa2 / BBB-	5.200%	4/1/20	185	0	40
LNT	A3 / BBB+	3.650%	9/1/20	135	10	40
LNT	A2 / A-	4.600%	6/15/20	120	10	35
NGGLN	A3 / A-	4.534%	3/15/20	130	0	45
NGGLN	A3 / A	5.819%	4/1/41	160	5	N/A
NST	A1 / A+	5.500%	3/15/40	135	5	40
PCG	A3 / BBB+	3.250%	9/15/21	155	5	N/A
PCG	A3 / BBB+	5.400%	1/15/40	170	15	70
SO	A2 / A	3.950%	6/1/21	120	5	N/A
SO	A2 / A	5.200%	6/1/41	125	2	N/A
SO	A3 / A	4.750%	9/1/40	140	10	45
TE	Baa1 / BBB+	6.150%	5/15/37	170	10	35
WEC	A2 / A-	2.950%	9/15/21	115	5	70

OPERATING COMPANIES - SECURED						
BRK	A2 / A	3.850%	6/15/21	110	0	N/A
BRK	A2 / A	6.000%	1/15/39	130	0	35
CMS	A3 / BBB+	5.650%	4/15/20	125	0	40
CNP	A3 / BBB+	6.950%	3/15/33	165	5	40
DTE	A2 / A	3.900%	6/1/21	115	0	N/A
DUK	A1 / A	3.900%	6/15/21	110	5	N/A
DUK	A1 / A	5.300%	2/15/40	130	0	45
DUK	A2 / A	3.750%	7/15/20	105	0	35
DUK	A2 / A	6.450%	4/1/39	145	0	45
EIX	A1 / A	3.875%	6/1/21	110	0	N/A
EIX	A1 / A	4.500%	9/1/40	120	0	35
EXC	A1 / A-	5.350%	3/1/18	45	5	15
EXC	Baa1 / A-	3.400%	9/1/21	145	5	N/A
FE	Baa1 / BBB	7.250%	5/1/20	175	10	30
FE	Baa1 / BBB	8.875%	11/15/18	155	5	5
NEE	Aa3 / A	5.550%	11/1/17	135	0	-5
NEE	Aa3 / A	5.125%	6/1/41	125	5	N/A
NU	A2 / A-	5.750%	3/1/37	150	5	40
NVE	Baa2 / BBB	7.125%	3/15/19	145	0	40
NVE	Baa2 / BBB	5.450%	5/15/41	150	5	N/A
PEG	A2 / A-	3.500%	8/15/20	105	0	45
PEG	A2 / A-	5.500%	3/1/40	130	5	40
PGN	A1 / A	5.300%	1/15/19	75	0	40
PGN	A1 / A	6.300%	4/1/38	140	5	50
PGN	A2 / A	3.100%	8/15/21	110	2	N/A
PGN	A2 / A	5.650%	4/1/40	145	0	50
POM	A3 / A	4.350%	4/1/21	130	0	N/A
POM	A3 / A	7.900%	12/15/38	150	5	55
POR	A3 / A-	6.100%	4/15/19	60	10	-5
PPL	A2 / A-	5.125%	11/1/40	135	5	50
PPL	A3 / A-	3.000%	9/15/21	105	-5	N/A
PPL	A3 / A-	5.200%	7/15/41	130	12	N/A
PSD	A3 / A-	5.638%	4/15/41	135	0	0
SCG	A3 / A	5.450%	2/1/41	150	5	N/A
SRE	Aa3 / A+	3.000%	8/15/21	100	5	N/A
SRE	Aa3 / A+	5.125%	11/15/40	120	5	40
TXU	Baa1 / A-	5.250%	9/30/40	165	5	35
WR	Baa1 / BBB+	5.100%	7/15/20	145	0	45
XEL	A1 / A	4.850%	8/15/40	125	5	40
XEL	A2 / A	4.750%	8/15/41	120	10	N/A

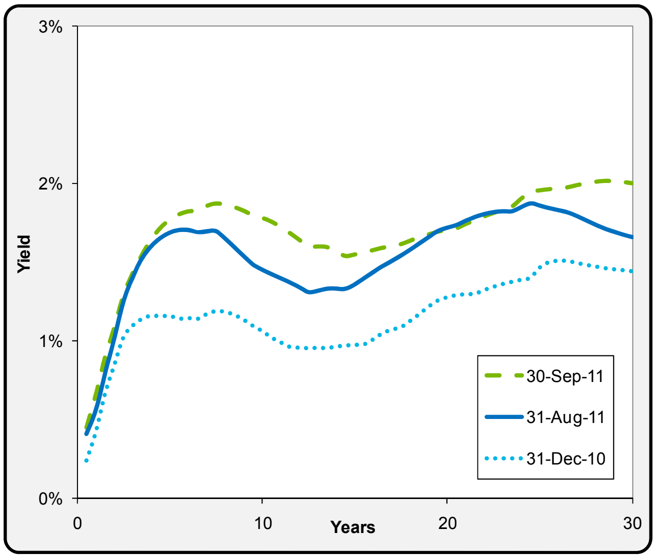
10-Year AA Utility Index Mortgage Spread – December 9, 2011

AON Hewitt

September 30, 2011 Discount Rate Update

Interest Rates Plummet, Partially Offset by Widening Spreads

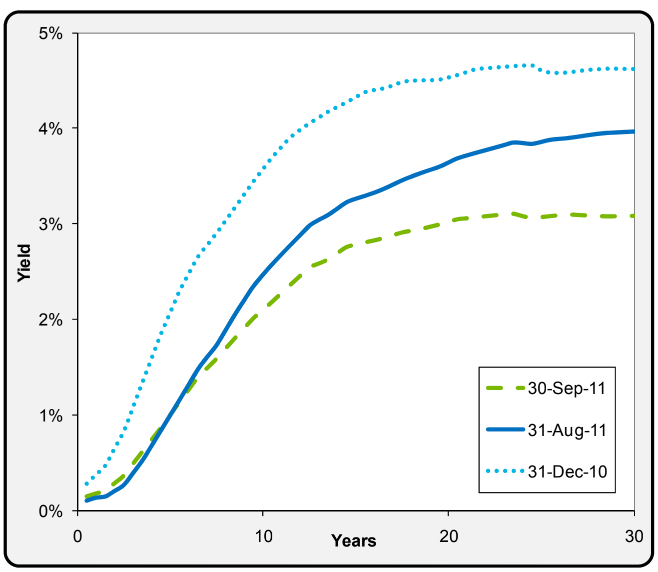
Corporate AA+ Spreads



Note: Hewitt Above Median curves used as representative. Many curves exist.

There was general widening of credit spreads from August to September. Spreads remain 50-70 basis points higher now than at the beginning of the year.

Treasury STRIPS Curve



Treasury yields continued to fall this month, particularly beyond the 10 year maturity range. Risk appetite was muted as investors continued to perceive U.S. government securities as a "safe haven" asset.

Discount Rate Movement

(numbers shown are percentages)

		9/30	8/31	6/30	12/31
STRIPS	▪ Young	2.93	3.61	4.44	4.40
	▪ Average	2.84	3.46	4.28	4.27
	▪ Mature	2.64	3.15	3.98	4.01
US GAAP	▪ Young	4.71	5.16	5.72	5.63
	▪ Average	4.57	4.97	5.52	5.45
	▪ Mature	4.30	4.61	5.15	5.11
PPA	▪ Young	5.23	5.40	5.72	5.92
	▪ Average	5.06	5.21	5.52	5.73
	▪ Mature	4.73	4.86	5.15	5.37

S&P 500 Funded Status (Estimated)

	9/30	8/31	6/30	12/31
▪ Assets	$1,311B	$1,356B	$1,387B	$1,306B
▪ Liabilities	$1,691B	$1,627B	$1,538B	$1,544B
▪ Funded Ratio	77.5%	83.3%	90.2%	84.6%

Check out the Aon Hewitt Pension Risk Tracker
(https://rfmtools.hewitt.com/PensionRiskTracker)

Market volatility remains high. As a result, Treasuries continued to rally as yields fell over the course of September. The European debt saga is center stage as the market (over)reacts to each piece of news coming from German and French politicians. It remains to be seen whether additional liquidity in the European market will lead to increases in market stability. In the U.S. (as with Europe), policy decisions dictate market behavior. The erosion of confidence in U.S. economic growth prospects added to the continuing "risk off" mentality of the market – which in turn, pushes Treasury yields down and has generally led to credit spread widening. Continued weakness in the housing and labor markets added to an already bad situation. To cap the month off, comments (regarding the economy) from the Federal Open Market Committee were worse than anticipated.

Pension Funding Effective Interest Rates

	Sept '10	Jan '11	Sept '11	Jan '12
▪ Young	6.40%	6.13%	5.81%	5.71%
▪ Average	6.32%	6.00%	5.64%	5.54%
▪ Mature	6.16%	5.78%	5.34%	5.22%

Note: Assumes interest rates remain level from now until projection date.

Notes and Disclosures

- US GAAP basis of Discount Rate Movement is the Hewitt Above Median yield curve.
- PPA basis of Discount Rate Movement is the IRC §430 Full Yield Curve.
- S&P 500 Funded Status is based on the US GAAP funded status as estimated by the Aon Hewitt Pension Risk Tracker at https://rfmtools.hewitt.com/PensionRiskTracker
- Standard Populations
  - Young is a hypothetical plan with a primarily active and deferred workforce which exhibits duration of 16–18 years depending on the level of the yield curve.
  - Average is a hypothetical plan with a standard demographic including healthy-sized active and retiree populations, which exhibits duration of 13–15 years depending on the level of the yield curve.
  - Mature is a hypothetical plan with a predominately retiree population, which exhibits duration of 9–11 years.
- Pension Funding Effective Interest Rates table refers to PPA 24-month segment rates for IRC §430 pension valuations. Both historical rates are shown as well as a projection of future rates.

NW Natural
Debt Ratings History
2005-2011

		Credit Ratings			
	Effective Date	Secured	Unsecured	Pref Stk	CP
Standard & Poors	**Current**	**A+**			**A-1**
Ratings History:	Pre 2005	A	A -	BBB+	A-1
Upgrade (1)	1/5/2005	A+	A	A-	A-1
Upgrade (2)	2/28/2006	AA-	A+	A	A-1+
Downgrade (3)	1/25/2010	A+	A+		A-1
Moody's Investor Service	**Current**	**A1**	**A3**	**Baa1**	**P-1**
Ratings History:	Pre 2005	A2	A3	Baa1	P-1
Upgrade Secured Only(4)	8/3/2009	A1	A3	Baa1	P-1

Explanation for Ratings Changes:

(1) Reasons given for the upgrade were good company performance, successful completion of the Mist Pipeline expansion project, issuance of equity in 2004, and an expectation of contiuned strong performance.

(2) Reasons given for the upgrade were NW Natural's weather normalization rate mechanism, a conservative gas hedging strategy, high growth service area, reliable gas supply, and a supportive regulatory environment.

(3) 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.

(4) Moody's issued an upgrade on NW Natural's senior secured debt notching between senior secured debt rating and unsecured debt ratings to two notiches from one previously. The change was made by Moody's based on an analysis of regulated utility defaults, which indicated a lower probability of default for regulated utilities.

MOODY'S
INVESTORS SERVICE

SPECIAL COMMENT

Rise in Utility Unfunded Pensions Are Credit Negative

Increased Debt Eliminates a Portion of Bonus Depreciation Benefit

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Summary

U.S. utility holding companies are losing ground with their pension obligations, as significant increases in the fixed income portion of a pension's portfolio have largely been offset by a sharp decline in equities. Moreover, discount rates have steadily decreased since previous capital market low's in 2008. The combined effect of these market movements is a sizeable decline in the funded status of utility pension plans – we estimate that today's funding level is approximately 73%, down from 2010 year end's 81%.

Our own examination of some 36 large utility parent holding companies confirms that the increase in unfunded pension obligations will have a direct impact on projected utility debt balances, a credit negative. We see the sector's $423 billion debt load for year-end 2010 increasing by approximately $14 billion solely due to rising pension underfunding, and unfunded pension obligations as a percentage of total consolidated debt rising to roughly 8.3% from 5.4%. Other conclusions from our study and ongoing analysis of the sector include:

» On the positive side, utility pension plans reduced under-funded balances at a faster pace than the average corporate industrial peer, mainly due to proportionately higher annual contributions. We expect this trend to continue.

» Many utilities have regulatory tracking mechanisms to recover their pension expense, which could help alleviate potential liquidity stress related to funding requirements.

» The increase in debt attributable to rising pension underfunding is offsetting a portion of the cash flow benefit expected to result from bonus depreciation. For some issuers, negative rating pressure could build going into 2012 if the financial metrics fall below the thresholds necessary to maintain a given rating category.

Illustrating the Pension Problem

The U.S. utility sector is losing ground with the funding status of its sizeable pension plans, a fact that is borne out by our examination of the debt and pension plans of a peer group of 36 large, well known utility parent companies.[1] For the year ended 2010, our 36-member peer group had approximately $423 billion in debt and generated CFO of approximately $75 billion. We found that weak returns associated with the equity components of pension portfolios and falling discount rates have combined to eliminate the effects of above-average annual contributions over the past few years.

From a credit perspective, we view unfunded pension obligations as debt, despite numerous utility rate-trackers that allow for specific recovery.[2] So rising unfunded balances will have a direct impact on rising debt levels, which, in turn, depress several of our key financial credit metrics, including our various cash flow from operations (CFO) to debt ratios[3], a credit negative.

Assuming the sector's debt increased by $14 billion, to $436 billion, as a result of the increase in unfunded pension liabilities, the CFO-to-debt ratio would fall to roughly 17% from 18%. These ratios exclude the positive effects on CFO associated with bonus depreciation. With respect to our illustration, we would expect the CFO-to-debt ratios to be roughly 200 – 300 basis points higher due to bonus depreciation, all else being equal. As a result, we will look for the sector to **report** CFO-to-debt ratios in the 19% - 20% range, but for credit analysis purposes, we would exclude the effects of bonus depreciation[4].

In the table below, we illustrate the potential changes to the sector's CFO-to-debt ratio. We use the 2010 year-end financials and create simple pro-forma adjustments to show the effects of the negative drag associated with higher under-funded pension obligations. This pro-forma illustrations highlight the potential credit risk associated with slippage in key financial credit metrics.

1 See Appendix A for a list of issuers.
2 Technically, debt service also enjoys regulatory recovery – through base rates, but we still count debt as debt at this time.
3 In addition to cash flow from operations (CFO), we examine CFO before the effects of working capital adjustments (CFO pre-w/c), funds from operations (FFO) and retained cash flow (RCF).
4 See "U.S. Investor-Owned Utilities: Bonus Depreciation Provides Material Near-Term Benefit For The Sector But Raises Longer-Term Questions" published in February 2011

FIGURE 1

($ billions)	2010
Debt (unadjusted for pensions)	$399.9
Unfunded Pension adjustment	$ 22.7
Debt	$422.7
CFO	$75.1
CFO / Debt	18%
Debt increase due to estimated 2011 pension under funding	$13.6
Implied 2011E debt (i.e., 2010 pro-forma adjusted)	$436.3
2011E CFO / debt (i.e., 2010 pro-forma adjusted excluding bonus depreciation)	17%

Funding Levels

Lower Discount Rates Biggest Driver of Increased Underfunding

Pension assets generally move in tandem with the broad capital markets. The S&P 500 index returned an impressive 12.5% in 2010, while a broad-based fixed income portfolio returned approximately 8%, with alternative investments remaining largely flat. But for the nine months ended September 30, the numbers were not nearly as impressive. As of that date, the S&P returns were negative 8.5% while a broad-based fixed income portfolio returned approximately 10%. We assume alternative investments lost approximately 5%. Assuming a typical asset mix of 60% equities, 30% fixed income and 10% alternative or "other," we would expect these returns to translate into an overall 2.5% reduction in assets due to market returns.

Although lower interest rates lifted bond portfolio asset values, they also led to rising pension obligations due to lower resulting discount rates. A general rule of thumb is that a 100 bps change in the discount rate would result in an 8%-12% increase in the obligation. Using the Moody's Aa bond index as a rough proxy, we estimate discount rates contracted by approximately 75 bps for the nine months ended September 30. This decrease (in the discount rate) would result in an approximate 7.5% increase in pension obligations, all else equal.

However, what must also be noted is that there has been significant volatility in both discount rates and capital markets since 2009. For example we estimate discount rates contracted by 40-50 bps in September alone. Given this volatility, viewing a snapshot as of a certain date may be misleading to the actual underlying economic position of an issuers pension plan. We will be monitoring this volatility on an ongoing basis and publishing our estimates of funding levels as warranted.

If we assume service cost, benefits paid and contributions remain constant, on a pro-rata basis, these asset and liability movements should contribute to a decline of approximately 9% in the funding levels for the utility industry. For our US utility peer group, this translates to an increase of nearly $14 billion in unfunded pension obligations, which we view as debt.

FIGURE 2

($ billions)

	2010	2010 pro-forma adjusted
Pension Benefit Obligation	$122.4	$133.9
Fair Value of Plan Assets	$99.7	$97.6
% funded status	81%	73%
Unfunded obligation	$22.7	$36.3
Pension as a % debt	5.4%	8.3%

Higher Annual Contributions Expected to Continue

The Sisyphean nature of increasing pension contributions only to see the unfunded obligation rise due to weak asset returns has been a consistent pattern over the past three years. Average discount rates have contracted from 6.5% in 2008 to 5.5% in 2010 to an estimated 4.75% by September 2011. Increases in obligations due solely to discount rate contractions would amount to over $18 billion during this time frame. During the same timeframe we estimate the same issuers experienced a $23 billion increase in asset values.

Despite these problems, by the end of 2010, the utility industry was digging out of its pension funding hole at a faster pace than other US corporate rated issuers.[5] That said, the industry had a weaker starting position. At the end of 2008, the utility industry's funding level was 73% compared to 77% for all other corporate issuers. By the end of 2010, these numbers both stood at 81%.

The apparent driving force behind this catch up is that utilities made proportionately larger contributions, when taken as a percentage of assets. Total contributions have increased during this period from $2.4 billion in 2007 to nearly $7 billion in 2010. By comparison, the broad corporate industrial peers increased contributions from $35 billion in 2007 to $68 billion in 2010. In the table below, we illustrate the annual pension plan contribution as a percentage of the prior year's plan assets for both the utility sector and for the broader US corporate sector.

FIGURE 3

[5] Moody's estimate based on a broad, diversified group of corporate and industrial issuers.

These comparatively higher contribution rates appear to be continuing into 2011 and we expect the relationship to continue over the next several years as several companies announced 2011 contributions in excess of 2010 levels. For example, Energy Future Holdings Corp. (Caa2 CFR) announced an expected contribution of $144 million in 2011 compared to $45 million in 2010. Exelon Corporation (Baa1 Under Review for Possible Downgrade) also announced contributions of $2.1 billion to its plans in January of 2011 compared to $766 million in 2010. Exelon stated that part of the $2.1 billion would be funded using $850 million from the benefits of bonus depreciation and $750 million tax benefit as a result of making the contribution.

Another bright side for plan sponsors is that Moody's central scenario in our global macro outlook[6] predicts a rising interest rate environment in the near to medium term. If this comes to pass, rising interest rates should translate into higher discount rates thus reducing pension obligations. If discount rates were to revert back to 2008 levels, the approximately $23 billion underfunding reported by the industry for the year ended December 2010 would be reduced to approximately $7-8 billion.

Required Pension Contributions to Increase

To help alleviate funding pressures caused by the 2008 market collapse, the U.S. Internal Revenue Service in March 2009 relaxed some of its rules for calculating discount rates used to calculate 2010 required contributions. This rule change effectively allowed companies to cherry-pick the best rates from September, October, November or December, 2008. This one-time allowance significantly reduced required contributions for 2010.

Now that the temporary relief has expired, sponsors must now fund plans using the full scope of the Pension Protection Act of 2006. The rules for calculating a plan's funded status are different for funding purposes than for financial reporting purposes.[7] While a simplification, at the heart of the rules is the concept that a company must have a fully-funded plan within seven years. For example, Great Plains Energy Inc. announced it would contribute over $100 million in 2011 to comply with ERISA requirements, compared to a contribution of $64 million in 2010.

6 See "Global Macro-Risk Scenarios 2011-2012: Strong Headwinds Ahead" published September 2011

7 For a more in-depth analysis of those rules see our special comment "Managing Ratings With Increased Pension Liability" published March 2009.

Appendix A

	Issuer	Rating	Debt	2010 Year End ($ 000's) Service Cost	Interest Cost	Projected Benefit Obligation	Fair Value of Plan Assets	Benefits Paid	Regulatory Recovery	Employer Contribution	2010 Funding Levels	2010 CFO / Debt
1	Ameren Corporation	Baa3	8,718,794	68,000	185,000	3,451,000	2,722,000	(182,000)	Yes	81,000	79%	21%
2	American Electric Power Company	Baa2	21,164,000	111,000	253,000	4,807,000	3,858,000	(480,000)	Yes	515,000	80%	15%
3	CenterPoint Energy, Inc.	Baa3	10,226,000	31,000	102,000	1,969,000	1,501,000	(115,000)	Yes	8,000	76%	14%
4	Cleco Corporation	Baa3	1,680,828	7,451	17,145	330,342	242,513	(12,060)	No	5,000	73%	12%
5	CMS Energy Corporation	Ba1	8,236,933	45,000	104,000	2,014,000	1,401,000	(119,000)	No	381,000	70%	16%
6	Consolidated Edison, Inc.	Baa1	13,521,000	168,000	556,000	10,307,000	7,721,000	(459,000)	Yes	443,000	75%	20%
7	Constellation Energy Group, Inc.	Baa3	5,276,100	37,900	84,700	1,626,100	1,408,100	(82,700)	No	289,100	87%	11%
8	Dominion Resources Inc.	Baa2	18,650,750	102,000	266,000	4,490,000	5,106,000	(211,000)	No	665,000	114%	13%
9	DTE Energy Company	Baa2	9,360,000	64,000	202,000	3,785,000	2,913,000	(215,000)	Yes	206,000	77%	21%
10	Duke Energy Corporation	Baa2	19,323,000	97,000	257,000	5,028,000	4,797,000	(401,000)	Yes	418,000	95%	24%
11	Edison International	Baa2	20,510,000	149,000	210,000	4,080,000	3,235,000	(183,000)	No	127,000	79%	19%
12	Energy Future Holdings Corp.	Caa2	37,537,000	42,000	160,000	3,072,000	2,185,000	(125,000)	Yes	45,000	71%	3%
13	Entergy Corporation	Baa3	13,845,094	104,956	231,200	4,301,200	3,216,300	(166,800)	Yes	454,354	75%	31%
14	Exelon Corporation	Baa1	17,130,500	190,000	660,000	12,524,000	8,859,000	(639,000)	Yes	766,000	71%	34%
15	FirstEnergy Corp.	Baa3	18,462,553	99,000	314,000	5,858,000	4,544,000	(306,000)	No	11,000	78%	17%
16	Great Plains Energy Incorporated	Baa3	4,153,297	30,300	49,300	911,400	557,600	(57,800)	Yes	64,500	61%	16%
17	Mid-American Energy	Baa1	20,829,000	17,000	39,000	738,000	546,000	(37,000)	Yes	24,000	74%	14%
18	NextEra Energy, Inc.	Baa1	19,428,000	59,000	102,000	1,994,000	3,233,000	(149,000)	No	3,000	162%	20%
19	NiSource Inc.	Ba2	8,271,400	39,200	125,700	2,478,400	1,900,000	(187,400)	Yes	161,800	77%	11%
20	Northeast Utilities	Baa2	6,091,660	51,000	152,600	2,820,900	1,977,600	(130,200)	Yes	45,000	70%	18%
21	NRG Energy, Inc.	Ba3	10,456,000	14,000	21,000	404,000	297,000	(12,000)	No	16,000	74%	16%
22	OGE Energy Corp.	Baa1	2,642,000	16,700	31,800	640,900	574,000	(34,400)	Yes	50,000	90%	31%
23	Pepco Holdings, Inc.	Baa3	5,372,917	35,000	110,000	1,970,000	1,632,000	(146,000)	Yes	105,000	83%	17%
24	PG&E Corporation	Baa1	15,561,724	279,000	645,000	12,071,000	10,250,000	(477,000)	Yes	162,000	85%	20%
25	Pinnacle West Capital Corporation	Baa3	4,401,737	59,064	122,700	2,345,100	1,775,600	(76,600)	Yes	200,000	76%	23%
26	PNM Resources, Inc.	Ba2	2,277,472	0	38,199	665,717	453,175	(43,357)	Yes	17,951	68%	17%
27	PPL Corporation	Baa3	15,021,818	64,000	159,000	4,007,000	2,819,000	(127,000)	Yes	148,000	70%	16%
28	Progress Energy, Inc.	Baa2	14,357,860	48,000	140,000	2,609,000	1,891,000	(129,000)	Yes	139,000	72%	18%

	Issuer	Rating	Debt	Service Cost	Interest Cost	Projected Benefit Obligation	Fair Value of Plan Assets	Benefits Paid	Regulatory Recovery	Employer Contribution	2010 Funding Levels	2010 CFO / Debt
				2010 Year End ($ 000's)								
29	Public Service Enterprise Group	Baa2	9,871,000	87,000	231,000	4,353,000	3,555,000	(224,000)	Yes	424,000	82%	23%
30	SCANA Corporation	Baa3	4,917,400	17,900	44,000	811,800	817,200	(38,400)	Yes	1,000	101%	17%
31	Sempra Energy	Baa1	10,938,459	83,000	167,000	3,124,000	2,354,000	(210,000)	Yes	159,000	75%	20%
32	Southern Company (The)	Baa1	22,269,000	172,000	391,000	7,223,000	6,834,000	(296,000)	Yes	644,000	95%	20%
33	TECO Energy, Inc.	Baa3	3,438,000	16,200	33,200	610,300	479,700	(34,200)	No	87,600	79%	22%
34	Westar Energy, Inc.	Baa3	3,496,848	13,926	39,391	747,460	432,233	(27,769)	Yes	22,400	58%	18%
35	Wisconsin Energy Corporation	A3	4,872,573	23,700	68,400	1,222,800	1,059,500	(83,400)	Yes	6,800	87%	20%
36	Xcel Energy Inc.	Baa1	10,367,423	73,147	165,000	3,030,300	2,540,700	(225,400)	Yes	34,132	84%	19%
			422,678,141	2,515,444	6,477,335	122,420,719	99,687,221	(6,442,486)		6,929,637	81%	

Moody's Related Research

Special Comments:

- Lower Discount Rates Hampering Pension Plans More Than Asset Returns, October 2011 (136525)
- Pension Underfunding Remains a Credit Negative for Corporate Issuers, June 2011 (133579)
- U.S. Investor-Owned Utilities: Bonus Depreciation Provides Material Near-Term Benefit For The Sector But Raises Longer-Term Questions, February 2011 (131078)
- Pension Underfunding Continues To Be a Credit Negative for Corporate Issuers, March 2010 (123632)
- Managing Ratings with Increased Pension Liability, March 2009 (115011)
- Pension Deficits: Back on the Agenda, January 2009 (114087)
- Liability-Driven Investing Strategies Gain Traction for U.S. Defined-Benefit Pension Plans, July 2008 (109832)

Rating Methodologies:

- Regulated Electric and Gas Utilities, August 2009 (118481)
- Unregulated Utilities and Power Companies, August 2009 (118508)
- Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations – Part I, February 2006 (96760)
- Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations – Part II, February 2006 (96729)

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MOODY'S
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Rating Methodology

Moody's Global
Infrastructure Finance

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Regulated Electric and Gas Utilities

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Summary

This rating methodology provides guidance on Moody's approach to assigning credit ratings to electric and gas utility companies worldwide whose credit profile is influenced to a large degree by the presence of regulation. It replaces the Global Regulated Electric Utilities methodology published in March 2005 and the North American Regulated Gas Distribution Industry (Local Distribution Companies) methodology published in October 2006. While reflecting similar core principles as these previous methodologies, this updated framework incorporates refinements that better reflect the changing dynamics of the regulated electric and gas industry and the way Moody's applies its industry methodologies.

The goal of this rating methodology is to assist investors, issuers, and other interested parties in understanding how Moody's arrives at company-specific ratings, what factors we consider most important for this sector, and how these factors map to specific rating outcomes. Our objective is for users of this methodology to be able to estimate a company's ratings (senior unsecured ratings for investment-grade issuers and Corporate Family Ratings for speculative-grade issuers) within two alpha-numeric rating notches.

Regulated electric and gas companies are a diverse universe in terms of business model (ranging from vertically integrated to unbundled generation, transmission and/or distribution entities) and regulatory environment (ranging from stable and predictable regulatory regimes to those that are less developed or undergoing significant change). In seeking to differentiate credit risk among the companies in this sector, Moody's analysis focuses on four key rating factors that are central to the assignment of ratings for companies in the sector. The four key rating factors encompass nine specific elements (or sub-factors), each of which map to specific letter ratings (see Appendix A). The four factors are as follows:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength and Liquidity

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Regulated Electric and Gas Utilities

This methodology pertains to regulated electric and gas utilities and excludes regulated electric and gas networks (companies primarily engaged in the transmission and/or distribution of electricity and/or natural gas that do not serve retail customers) and unregulated utilities and power companies, which are covered by separate rating methodologies. Municipal utilities and electric cooperatives are also excluded and covered by separate rating methodologies.

In Appendix A of this methodology, we have included a detailed rating grid for the companies covered by the methodology. For each company, the grid maps each of these key rating factors and shows an indicated alpha-numeric rating based on the results from the overall combination of the factors (see Appendix B). We note, however, that many companies will not match each dimension of the analytical framework laid out in the rating grid exactly and that from time to time a company's performance on a particular rating factor may fall outside the expected range for a company at its rating level. These companies are categorized as "outliers" for that rating factor. We discuss some of the reasons for these outliers in this methodology as well as in published credit opinions and other company-specific analysis.

The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector. The grid provides summarized guidance on the factors that are generally most important in assigning ratings to the sector. While the factors and sub-factors within the grid are designed to capture the fundamental rating drivers for the sector, this grid does not include every rating consideration and does not fit every business model equally. Therefore, we outline additional considerations that may be appropriate to apply in addition to the four rating factors. Moody's also assesses other rating factors that are common across all industries, such as event risk, off-balance sheet risk, legal structure, corporate governance, and management experience and credibility. Furthermore, most of our sub-factor mapping uses historical financial results to illustrate the grid while our ratings also consider forward looking expectations. As such, the grid-indicated rating is not expected to always match the actual rating of each company. The text of the rating methodology provides insights on the key rating considerations that are not represented in the grid, as well as the circumstances in which the rating effect for a factor might be significantly different from the weight indicated in the grid.

Readers should also note that this methodology does not attempt to provide an exhaustive list of every factor that can be relevant to a utility's ratings. For example, our analysis covers factors that are common across all industries (such as coverage metrics, debt leverage, and liquidity) as well as factors that can be meaningful on a company or industry specific basis (such as regulation, capital expenditure needs, or carbon exposure).

This publication includes the following sections:

- **About the Rated Universe**: An overview of the regulated electric and gas industries
- **About the Rating Methodology**: A description of our rating methodology, including a detailed explanation of each of the key factors that drive ratings
- **Assumptions and Limitations**: Comments on the rating methodology's assumptions and limitations, including a discussion of other rating considerations that are not included in the grid

In the appendices, we also provide tables that illustrate the application of the methodology grid to 30 representative electric and gas utility companies with explanatory comments on some of the more significant differences between the grid-implied rating and our actual rating (Appendix C). We also provide definitions of key ratios (Appendix D), an industry overview (Appendix E) and a discussion of the key issues facing the industry over the intermediate term (Appendix F) and regional considerations (Appendix G).

About the Rated Universe

The rating methodology covers investor-owned and commercially oriented government owned companies worldwide that are engaged in the production, transmission, distribution and/or sale of electricity and/or natural gas. It covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution companies, some U.S. transmission-only companies, and local gas distribution companies (LDCs). For the LDCs, we note that this methodology is concerned principally with operating utilities regulated by their local jurisdictions and not with gas companies that have significant non-utility

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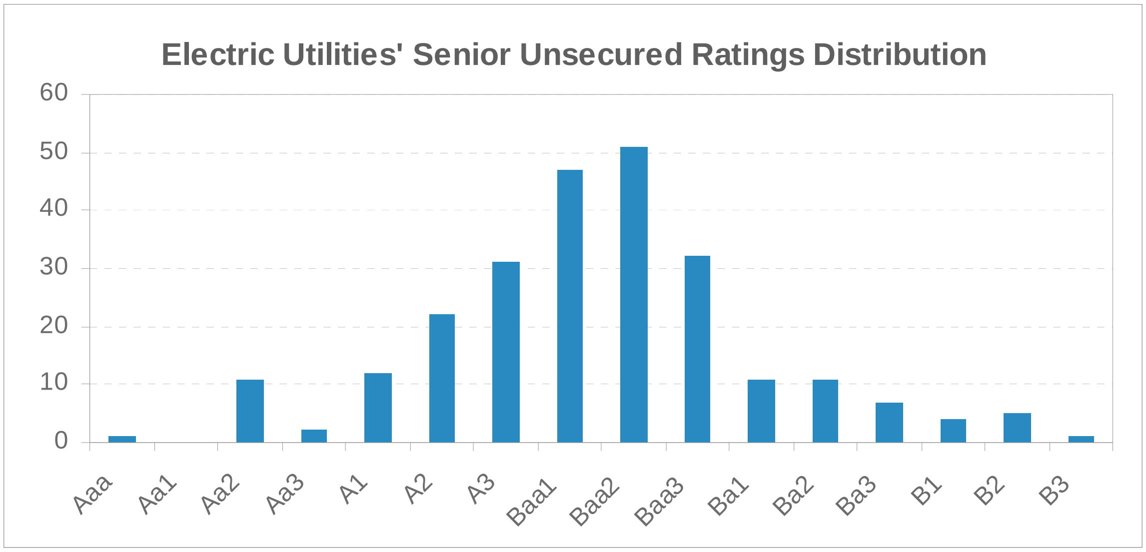
businesses[1]. In addition, this methodology includes both holding companies as well as operating companies. For holding companies, actual ratings may be lower than methodology grid-implied ratings due to the structural subordination of the holding company debt to the operating company debt. In order for a utility to be covered by this methodology, the company must be an investor-owned or commercially oriented government owned entity and be subject to some degree of government regulation or oversight. This methodology excludes regulated electric and gas networks, electric generating companies[2] and independent power producers operating predominantly in unregulated power markets, municipally owned utilities, electric cooperative utilities, and power projects, which are covered in separate rating methodologies.

The rated universe includes approximately 250 entities that are either utility operating companies or a parent holding company with one or more utility company subsidiaries that operate predominantly in the electric and gas utility business. They account for about US$650 billion of total outstanding long-term debt instruments. In general, ratings used in this methodology are the Senior Unsecured ("SU") rating for investment grade companies, the Corporate Family Rating ("CFR") for non-investment grade companies, and the Baseline Credit Assessment ("BCA") for Government Related Issuers (GRI). A subset of 30 of these entities is included in the methodology, representing a sampling of the universe to which this methodology applies.

Geographically, this methodology covers companies in the Americas, Europe, Middle East, Africa, Japan, and the Asia/Pacific region. The ratings spectrum for the sector ranges from Aaa to B3, with the actual rating distribution of the issuers included (both holding companies and operating companies) shown on the following table:



Although all of these companies are affected to some degree by government regulation or oversight, country-by-country regulatory differences and cultural and economic characteristics are also important credit considerations. There is little consistency in the approach and application of regulatory frameworks around the world. Some regulatory frameworks are highly supportive of the utilities in their jurisdictions, in some cases offering implied sovereign support to ensure reliability of electric supply. Other regulatory frameworks are less supportive, more unpredictable or affected by political influence that can increase uncertainty and negatively affect overall credit quality.

1 These companies are assessed under the rating methodology "North American Diversified Natural Gas Transmission and Distribution Companies", March 2007.

2 The six Korean generation companies are included in this methodology as they are subject to regulation and Moody's views them and their 100% parent and sole off-taker KEPCO on a consolidated basis. The Brazilian generation companies are included as they are also subject to regulatory intervention.

About this Rating Methodology

Moody's approach to rating companies in the regulated electric and gas utility sector, as outlined in this rating methodology, incorporates the following steps:

1. Identification of the Key Rating Factors

In general, Moody's rating committees for the regulated electric and gas utility sector focus on a number of key rating factors which we identify and quantify in this methodology. A change in one or more of these factors, depending on its weighting, is likely to influence a utility's overall business and financial risk. We have identified the following four key rating factors and nine sub-factors when assigning ratings to regulated electric and gas utility issuers:

Rating Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%		25%
Ability to Recover Costs and Earn Returns	25%		25%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Liquidity and Key Financial Metrics	40%	Liquidity	10%
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	7.5%
		CFO pre-WC - Dividends / Debt	7.5%
		Debt/Capitalization or Debt / Regulated Asset Value	7.5%
Total	**100%**		**100%**

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

These factors are critical to the analysis of regulated electric and gas utilities and, in most cases, can be benchmarked across the industry. The discussion begins with a review of each factor and an explanation of its importance to the rating.

2. Measurement of the Key Rating Factors

We next explain the elements we consider and the metrics we use to measure relative performance on each of the four factors. Some of these measures are quantitative in nature and can be specifically defined. However, for other factors, qualitative judgment or observation is necessary to determine the appropriate rating category.

Moody's ratings are forward looking and attempt to rate through the industry's characteristic volatility, which can be caused by weather variations, fuel or commodity price changes, cost deferrals, or reasonable delays in regulatory recovery. The rating process also makes extensive use of historic financial statements. Historic results help us understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes. All financial measures incorporate Moody's standard adjustments to income statement, cash flow statement, and balance sheet amounts for (among other things) underfunded pension obligations and operating leases.

3. Mapping Factors to Rating Categories

After identifying the measurement criteria for each factor, we match the performance of each factor and sub-factor to one of Moody's broad rating categories (Aaa, Aa, A, Baa, Ba, and B). In this report, we provide a range or description for each of the measurement criteria. For example, we specify what level of CFO pre-WC plus Interest/Interest is generally acceptable for an A credit versus a Baa credit, etc.

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

For each factor and sub-factor, we provide a table showing how a subset of the companies covered by the methodology maps within the specific factors and sub-factors. We recognize that any given company may perform higher or lower on a given factor than its actual rating level will otherwise indicate. These companies are identified as "outliers" for that factor. A company whose performance is two or more broad rating categories higher than its rating is deemed a positive outlier for that factor. A company whose performance is two or more broad rating categories below is deemed a negative outlier. We also discuss the general reasons for such outliers for each factor.

5. Discussion of Assumptions, Limitations and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings as well as limitations and key assumptions that pertain to the overall rating methodology.

6. Determining the Overall Grid-Indicated Rating

To determine the overall rating, each of the factors and sub-factors is converted into a numeric value based on the following scale:

Ratings Scale

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

Each sub-factor's numeric value is multiplied by an assigned weight and then summed to produce a composite weighted-average score. The total sum of the factors is then mapped to the ranges specified in the table below, and the indicated alpha-numeric rating is determined based on where the total score falls within the ranges.

Factor Numerics

Composite Rating

Indicated Rating	Aggregate Weighted Factor Score
Aaa	< 1.5
Aa1	1.5 < 2.5
Aa2	2.5 < 3.5
Aa3	3.5 < 4.5
A1	4.5 < 5.5
A2	5.5 < 6.5
A3	6.5 < 7.5
Baa1	7.5 < 8.5
Baa2	8.5 < 9.5
Baa3	9.5 < 10.5
Ba1	10.5 < 11.5
Ba2	11.5 < 12.5
Ba3	12.5 < 13.5
B1	13.5 < 14.5
B2	14.5 < 15.5
B3	15.5 < 16.5

For example, an issuer with a composite weighting factor score of 8.2 would have a Baa1 grid-indicated rating. We use a similar procedure to derive the grid-indicated ratings in the tables embedded in the discussion of each of the four broad rating categories.

The Key Rating Factors

Moody's analysis of electric and gas utilities focuses on four broad factors:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength and Liquidity

Rating Factor 1: Regulatory Framework (25%)

Why it Matters

For a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors. The most direct and obvious way that regulation affects utility credit quality is through the establishment of prices or rates for the electricity, gas and related services provided (revenue requirements) and by determining a return on a utility's investment, or shareholder return. The latter is largely addressed in Factor 2, Ability to Recover Cost and Earn Returns, discussed below. However, in addition to rate setting, there are numerous other less visible or more subtle ways that regulatory decisions can affect a utility's business position. These can include the regulators' ability to pre-approve recovery of investments for new generation, transmission or distribution; to allow the inclusion of generation asset purchases in utility rate bases; to oversee and ultimately approve utility mergers and acquisitions; to approve fuel and purchased power recovery; and to institute or increase ring-fencing provisions.

How We Measure It for the Grid

For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that exhibits a high degree of uncertainty or unpredictability. Those utilities operating in a less developed regulatory framework or one that is characterized by a high degree of political intervention in the regulatory process will receive the lowest scores on this factor. Consideration is given to the substance of any regulatory ring fencing provisions, including restrictions on dividends; restrictions on capital expenditures and investments; separate financing provisions; separate legal structures; and limits on the ability of the regulated entity to support its parent company in times of financial distress. The criteria for each rating category are outlined in the factor description within the rating grid.

For regulated electric utilities with some unregulated operations, consideration will be given to the competitive and business position of these unregulated operations[3]. Moody's views unregulated operations that have minimal or limited competition, large market shares, and statutorily protected monopoly positions as having substantially less risk than those with smaller market shares or in highly competitive environments. Those businesses with the latter characteristics usually face a higher likelihood of losing customers, revenues, or market share. For electric utilities with a significant amount of such unregulated operations, a lower score could be assigned to this factor than would be if the utility had solely regulated operations.

Moody's views the regulatory risk of U.S. utilities as being higher in most cases than that of utilities located in some other developed countries, including Japan, Australia, and Canada The difference in risk reflects our view that individual state regulation is less predictable than national regulation; a highly fragmented market in the U.S. results in stronger competition in wholesale power markets; U.S. fuel and power markets are more

[3] For diversified gas companies, the "North American Diversified Natural Gas Transmission and Distribution Company" rating methodology is applied.

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volatile; there is a low likelihood of extraordinary political action to support a failing company in the U.S.; holding company structures limit regulatory oversight; and overlapping or unclear regulatory jurisdictions characterize the U.S. market. As a result, no U.S. utilities, except for transmission companies subject to federal regulation, score higher than a single A in this factor.

The scores for this factor replace the classifications we had been using to assess a utility's regulatory framework, namely, the Supportiveness of Regulatory Environment (SRE) framework, outlined in our previous rating methodology (Global Regulated Electric Utilities, March 2005), which we are phasing out. Generally speaking, an SRE 1 score from our previous methodology would roughly equate to Aaa or Aa ratings in this methodology; an SRE 2 score to A or high Baa; an SRE 3 score to low Baa or Ba, and an SRE 4 score to a B. For U.S. and Canadian LDCs, this factor corresponds to the "Regulatory Support" and "Ring-fencing" factors in our previous methodology (North American Regulated Gas Distribution, October 2006).

Factor 1 – Regulatory Framework (25%)

Aaa	Aa	A	Baa	Ba	B
Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.

Rating Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

Unlike Factor 1, which considers the general regulatory framework under which a utility operates and the overall business position of a utility within that regulatory framework, this factor addresses in a more specific manner the ability of an individual utility to recover its costs and earn a return. The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions. For example, in four of the six major investor-owned utility bankruptcies in the United States over the last 50 years, regulatory disputes culminated in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant. The reluctance to provide rate relief reflected regulatory commission concerns about the impact of large rate increases on customers as well as debate about the appropriateness of the relief being sought by the utility and views of imprudency. Currently, the utility industry's sizable capital expenditure requirements for infrastructure needs will create a growing and ongoing need for rate relief for recovery of these expenditures at a time when the global economy has slowed.

How We Measure It for the Grid

For regulated utilities, the criteria we consider include the statutory protections that are in place to insure full and timely recovery of prudently incurred costs. In its strongest form, these statutory protections provide unquestioned recovery and preclude any possibility of legal or political challenges to rate increases or cost recovery mechanisms. Historically, there should be little evidence of regulatory disallowances or delays to rate increases or cost recovery. These statutory protections are most often found in strongly supportive and protected regulatory environments such as Japan, for example, where the utilities in that country receive a score of Aa for this factor.

More typically, however, and as is characteristic of most utilities in the U.S., the ability to recover costs and earn authorized returns is less certain and subject to public and sometimes political scrutiny. Where automatic cost recovery or pass-through provisions exist and where there have been only limited instances of regulatory challenges or delays in cost recovery, a utility would likely receive a score of A for this factor. Where there may be a greater tendency for a regulator to challenge cost recovery or some history of regulators disallowing or delaying some costs, a utility would likely receive a Baa rating for this factor. Where there are no automatic cost recovery provisions, a history of unfavorable rate decisions, a politically charged regulatory environment, or a highly uncertain cost recovery environment, lower scores for this factor would apply.

For regulated electric utilities that have some unregulated operations, we assess the likelihood that the utility will be able to pass on costs of its unregulated businesses to unregulated customers. Among the criteria we use to judge this factor include the number and types of different businesses the company is in; its market share in these businesses; whether there are significant barriers to entry for new competitors; and the degree to which the utility is vertically integrated. Those utilities with several businesses with large market shares are generally in a better position to pass on their costs to unregulated customers. Those utilities that have lower market shares in their unregulated activities or are in businesses with few barriers to entry will likely be more at risk in passing on costs, and thus would receive lower scores. A high proportion of unregulated businesses or a higher risk of passing on costs to unregulated customers could result in a lower score for this factor than would apply if the business was completely regulated.

For U.S. and Canadian LDCs, this factor addresses the "Sustainable Profitability" and "Regulatory Support" assessments in the previous LDC rating methodology. While LDCs' authorized returns are comparable to those for their electric counterparts, the smaller, more mature LDCs tend to face less regulatory challenges. Purchased Gas Adjustment mechanisms are the norm and they have made strides in implementing alternative rate designs that decouple revenues from volumes sold.

Factor 2 – Ability to Recover Costs and Earn Returns (25%)

Aaa	Aa	A	Baa	Ba	B
Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.

Rating Factor 3 - Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that any one part of the company will have a severe negative impact on cash flow and credit quality. In general, a balance among several different businesses, geographic regions, regulatory regimes, generating plants, or fuel sources will diminish concentration risk and reduce the risk that a company will experience a sudden or rapid deterioration in its overall creditworthiness because of an adverse development specific to any one part of its operations.

How We Measure It For the Grid

For transmission and distribution utilities, local gas distribution companies, and other companies without significant generation, the key criterion we use is the diversity of their operations among various markets, geographic regions or regulatory regimes. For these utilities, the first set of criteria, labeled market diversification, account for the full 10% weighting for this factor. A predominately T&D utility with a high degree of diversification in terms of market and/or regulatory regime is less likely to be affected by adverse or unexpected developments in any one of these markets or regimes, and thus will receive the highest scores for this factor. Smaller T&D utilities operating in a limited market area or under the jurisdiction of a single regulatory regime will score lower on the factor, with those that are concentrated in an emerging market or riskier environment receiving the lowest scores.

For vertically integrated utilities with generation, the diversification factor is broadened to include not only the criteria discussed above, but also takes into consideration the diversity of their generating assets and the type of fuel sources which they rely on. An additional but somewhat related consideration is the degree to which the utility is exposed to (or insulated from) commodity price changes. A utility with a highly diversified fleet of generating assets using different types of fuels is generally better able to withstand changes in the price of a particular fuel or additional costs required for particular assets, such as more stringent environmental compliance requirements, and thus would receive a higher rating for this sub-factor. Those utilities with more limited diversification or that are more reliant on a single type of generation and fuel source (measured by energy produced) will be scored lower on this sub-factor. Similarly, those utilities with a high reliance on coal and other carbon emitting generating resources will be scored lower on this factor due to their vulnerability to potential carbon regulations and accompanying carbon costs.

Generally, only the largest vertically integrated utilities or transmission companies with substantial operations that are multinational or national in scope, or whose operations encompass a substantial region within a single country, will receive scores in the highest Aaa or Aa categories for this factor. In the U.S., most of the largest multi-state or multi-regional utilities are scored in the A category, most of the larger single state utilities are scored Baa, and smaller utilities operating in a single state or within a single city are scored Ba. A utility may also be scored higher if it is a combination electric and gas utility, which enhances diversification.

The diversification factor was not included in the previous North American LDC methodology. Most LDCs are small and tend to have little geographic and regulatory diversity. However, they tend to be highly stable due to their customer base and margins that comprise primarily of a large number of residential and small commercial customers that are captive to the utility. This customer composition tends to result in a more stable operating performance than those that have concentrations in certain industrial customers that are prone to cyclicality or to bypassing the LDC to obtain gas directly from a pipeline. Pure LDCs are scored under the "Market Position" sub-factor for a full 100% under this factor. As with transmission and distribution utilities, no scores are given for "Fuel/Generation Diversification" as this sub-factor would not be applicable.

Factor 3: Diversification (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/ regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

**10% weight for issuers that lack generation   **0% weight for issuers that lack generation*

Rating Factor 4 – Financial Strength and Liquidity (40%)

Why It Matters

Since most electric and gas utilities are highly capital intensive, financial strength and liquidity are key credit factors supporting their long-term viability. Financial strength and liquidity are also important to the maintenance of good relationships with regulators, to assure adequate regulatory responsiveness to rate increase requests and for cost recovery, and to avoid the need for sudden or unexpected rate increases to avoid financial problems. Financial strength is also important due to the ongoing need to invest in generation, transmission, and distribution assets that often require substantial amounts of debt financing. Utilities are among the largest debt issuers in the world and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility.

Although ratio analysis is a helpful way of comparing one company's performance to that of another, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. The relative strength of a company's financial ratios must take into consideration the level of business risk associated with the more qualitative factors in the methodology. *Companies with a lower business risk can have weaker credit metrics than those with higher business risk for the same rating category.*

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Given the long-term nature of many of the capital intensive projects undertaken in the industry and the need to obtain regulatory recovery over an often multi-year time period, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from the historic measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance.

How We Measure It For the Grid

In addition to assigning a score for a utility's overall liquidity position and relative access to funding sources and the capital markets, we have identified four key core ratios that we consider the most useful in the analysis of regulated electric and gas utilities. The four ratios are the following:

- Cash from Operations (CFO) pre-Working Capital Plus Interest / Interest
- Cash from Operations (CFO) pre-Working Capital / Debt
- Cash from Operations (CFO) pre-Working Capital – Dividends / Debt
- Debt/Capitalization or Debt / Regulated Asset Value (RAV)

The use of Debt / Capitalization or Debt / Regulated Asset Value will depend largely on the regulatory regime in which the utility operates, as explained below. These credit metrics incorporate all of the standard adjustments applied by Moody's when analyzing financial statements, including adjustments for certain types of off-balance sheet financings and certain other reclassifications in the income statement and cash flow statement.

These cash flow based ratios replace the earnings based metrics in the previous "North American Local Gas Distribution Company" rating methodology, reducing the impact on the grid results from non-cash items, such as pension expense.

The ratio calculations utilized and published for the companies covered by this methodology (including the 30 representative electric and gas utility companies highlighted) are historical three-year averages for the years 2006-2008. Three-year averages are used in part to smooth out some of the year to year volatility in financial performance and financial statement ratios.

Measurement Criteria

Liquidity

Liquidity analysis is a key element in the financial analysis of electric and gas utilities and encompasses a company's ability to generate cash from internal sources, as well as the availability of external sources of financings to supplement these internal sources. Sources of funds are compared to a company's cash needs and other obligations over the next twelve months. The highest "Aaa" and "Aa" scores under this sub-factor would be assigned to those utilities that are financially robust under all or virtually all scenarios, with little to no need for external funding and with unquestioned or superior access to the capital markets. Most utilities, however, receive more moderate scores of between "A" and "Baa" in this sub-factor as most need to rely to some degree on external funding sources to finance capital expenditures and meet other capital needs. Below investment grade scores on the sub-factor are assigned to utilities with weak liquidity or those that rely heavily on debt to finance investments.

CFO pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is a basic measure of a utility's ability to cover the cost of its borrowed capital and is an important analytical tool in this highly capital intensive industry. The numerator in the ratio calculation is a measure of cash flow excluding working capital movements plus interest expense, which can vary in significance depending on the utility. The use of CFO pre-WC is more comprehensive than Funds from Operations (FFO) under U.S. Generally Accepted Accounting Principles (GAAP) since it also captures the changes in long-term regulatory assets and liabilities. However, under International Financial Reporting Standards (IFRS), the two measures are essentially the same. The denominator in the ratio calculation is interest expense, which incorporates our standard adjustments to interest expense, such as including capitalized interest and re-classifying the interest component of operating lease rental expense. In Brazil, the cash interest amount is adjusted by the variation of non-cash financial expenses derived from foreign exchange and inflation denominated debt.

CFO pre-Working Capital / Debt

This metric measures the cash generating ability of a utility compared to the aggregate level of debt on the balance sheet. This ratio is useful in comparing utilities, many of which maintain a significant amount of leverage in their capital structure. The debt calculation takes into consideration Moody's standard adjustments to balance sheet debt, such as for operating leases, underfunded pension liabilities, basket-adjusted hybrids, guarantees, and other debt-like items.

CFO pre-Working Capital – Dividends / Debt

This ratio is a measure of financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial and can affect the ability of a utility to cover its debt obligations. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. Moody's expects that even the financially strongest utilities will need to issue debt on a regular basis to maintain a target capital structure if their asset bases are growing. If a utility with an expanding asset base funds all of its capital expenditures with internally generated cash flow then, in the extreme, the utility's debt to capitalization will trend toward zero.

Debt/Capitalization or Debt/Regulated Asset Value or RAV

This ratio is a traditional measure of leverage and can be a useful way to gauge a utility's overall financial flexibility in light of its overall debt load. High debt to capitalization levels are not only an indicator of higher interest obligations, but can also limit the ability of a utility to raise additional financing if needed and can lead to leverage covenant violations in bank credit facilities or other financing agreements. The denominator of the debt / capitalization ratio includes Moody's standard adjustments, the most important of which for some utilities is the inclusion of deferred taxes in capitalization, which tempers the impact of our debt adjustment.

While debt/capitalization is used predominantly in the Americas, other regions may use a variation of this ratio, namely, debt/regulated asset value or RAV ratio. The regulated asset base is comprised of the physical assets that are used to provide regulated distribution services and the RAV represents the value on which the utility is permitted to earn a return. RAV can be calculated in various ways, using different rules that can be revised periodically, depending on the regulatory regime. Where RAV is calculated using consistent rules (i.e. Australia and Japan), debt/RAV is viewed as superior to debt / capitalization as a credit measure and will be used for this sub-factor. Where RAV does not exist (i.e. North America and most Asian countries) or the method of calculation is subject to arbitrary or unpredictable revisions, we use debt/capitalization.

Factor 4: Financial Strength, Liquidity and Key Financial Metrics (40%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Rating Methodology Assumptions and Limitations, and other Rating Considerations

The rating methodology grid incorporates a trade-off between simplicity that enhances transparency and greater complexity that would enable the grid to map more closely to actual ratings. The four rating factors in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid is mainly historical. In some cases, our expectations for future performance may be impacted by confidential information that we cannot publish. In other cases, we estimate future results based upon past performance, industry trends, and other factors. In either case, we acknowledge that estimating future performance is subject to the risk of substantial inaccuracy.

In choosing metrics for this rating methodology grid, we did not include certain important factors that are common to all companies in any industry, such as the quality and experience of management, assessments of corporate governance, financial controls, and the quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and ranking them by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental obligations, nuclear decommissioning trust obligations, financial controls, and emerging market risk, where ratings might be constrained by the uncertainties associated with the local operating, political and economic environment, including possible government interference.

Actual assigned ratings may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, although Factors 1 and 2 address regulation and cost recovery, in some instances the effect of a company's financial strength and liquidity in Factor 4 will be given greater consideration in an assigned rating than what is indicated by the weighting in the grid.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

For the 30 representative utilities highlighted, the methodology grid-indicated ratings map to current assigned ratings as follows (see Appendix B for the details):

- 30% or 9 companies map to their assigned rating
- 50% or 15 companies have grid-indicated ratings that are within one alpha-numeric notch of their assigned rating
- 20% or 6 companies have grid-indicated ratings that are within two alpha-numeric notches of their assigned rating

Grid-Indicated Rating Outcomes

Map to Assigned Rating	Map to Within One Notch	Map to Within Two Notches
American Electric Power Company, Inc.	Cemig Distribuicao S.A.	Duke Energy Corporation
Arizona Public Service Company	Consolidated Edison Company of New York	Eesti Energia AS
CLP Holdings Limited	Dominion Resources, Inc.	Eskom Holdings Ltd
Consumers Energy Company	EDP - Energias do Brasil S.A.	Korea Electric Power Corporation
Florida Power & Light Company	Emera Incorporated	Northern Illinois Gas Company
PG&E Corporation	The Empire District Electric Company	Tokyo Electric Power Company
Piedmont Natural Gas Company, Inc.	FirstEnergy Corp.	
The Southern Company	Indianapolis Power & Light Company	
Xcel Energy Inc.	Kyushu Electric Power Company	
	Oklahoma Gas and Electric Co.	
	PECO Energy Company	
	Progress Energy Carolinas, Inc.	
	Southern California Edison Company	
	Westar Energy, Inc.	
	Wisconsin Power and Light Company	

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1: Regulatory Framework

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.	25%

Factor 2: Ability to Recover Costs and Earn Returns

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.	25%

Regulated Electric and Gas Utilities

Factor 3: Diversification

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

*10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Weighting: 40%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/ Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Appendix B: Methodology Grid-Indicated Ratings

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	Aa3	Aaa	Aa	Aa	A	Aaa	A	Aa	Aa	Ba	Ba	Baa
Tokyo Electric Power Company, Incorporated	Aa2	A1	Aaa	Aa	Aa	A	Aaa	Baa	Aa	A	Ba	Ba	Ba
Eesti Energia AS	A1/[8]	A3	Baa	Baa	B	B	B	Aa	Baa	Aaa	Aaa	Aaa	Aa
Florida Power & Light Company	A1	A1	A	A	Baa	Baa	Baa	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	Baa1	Baa	Baa	Baa	Baa	A	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A2	A	A	A	A	A	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa1	Baa	Baa	A	A	N/A	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A3	Baa	A	Baa	Baa	Baa	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A3	A	A	Baa	Baa	Baa	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa1	Baa	A	Baa	Baa	N/A	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	Baa1	Baa	Baa	Baa	Baa	N/A	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	A3	A	A	A	A	N/A	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A2	A	A	Baa	Baa	A	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	Baa1	Baa	Baa	Baa	Baa	A	A	A	A	A	A	Baa
The Southern Company	A3	A3	A	A	Baa	A	Ba	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa1	Baa	Baa	A	Baa	Aa	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa2	Baa	Baa	Baa	A	Ba	Baa	Baa	Baa	Baa	Baa	Ba

Regulated Electric and Gas Utilities

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Arizona Public Service Company	Baa2	Baa2	Ba	Baa	Baa	Baa	Baa	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa2	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A3	Baa	A	Baa	A	Baa	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Baa1	A	A	Ba	Ba	Ba	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa3	Ba	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2[13]	Ba1	Ba	Ba	B	Ba	B	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa1	Baa	A	Ba	Baa	Ba	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	Baa2	Ba	Ba	Ba	Ba	N/A	A	Baa	Aa	Aaa	Aa	Ba
FirstEnergy Corp.	Baa3	Baa2	Baa	Baa	Baa	A	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa2	Baa	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa3	Ba	Ba	Baa	Baa	Baa	Baa	Ba	Baa	Aa	A	A

Positive Outlier

Negative Outlier

Appendix C: Observations and Outliers for Grid Mapping

Results of Mapping Factor 1

Factor 1: Regulatory Framework		
Factor Weight		25%
	Current Rating /BCA	Regulatory Supportiveness
Kyushu Electric Power Company, Incorporated	Aa2	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aaa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	Baa
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	Baa
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	Baa
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Ba
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	Baa
Duke Energy Corporation	Baa2	Baa
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Ba
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	Baa
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

As a utility's regulatory framework is one of the most important drivers of ratings, there are no outliers for this factor among the 30 issuers highlighted for this methodology.

Results of Mapping Factor 2

Factor 2: Ability to Recover Costs and Earn Returns

Factor Weight		25%
	Current Rating/BCA	Rate Adjustment and Cost Recovery Mechanisms
Kyushu Electric Power Company, Incorporated	Aa2	Aa
Tokyo Electric Power Company, Incorporated	Aa2	Aa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	A
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	A
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	A
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Baa
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	A
Duke Energy Corporation	Baa2	A
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Baa
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	A
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

Like Factor 1, Regulatory Framework, the ability to recover costs and earn returns is also an important ratings driver for regulated utilities, and it is not surprising that there are no outliers among the 30 issuers highlighted. For this factor, most of the issuers score exactly at their current rating levels, with the remainder scoring within one notch of their actual rating.

Results of Mapping Factor 3

Factor 3: Diversification

Sub-Factor Weights			5% *	5% **
	Current Rating/BCA	Indicated Factor 3 Rating	Market Position	Generation and Fuel Diversification
Kyushu Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Eesti Energia AS	A1/[8]	B	B	B
Florida Power & Light Company	A1	Baa	Baa	Baa
Korea Electric Power Corporation	A2/[6]	Baa	Baa	A
CLP Holdings Limited	A2	A	A	A
Northern Illinois Gas Company	A2	A	A	N/A
Oklahoma Gas and Electric Company	A2	Baa	Baa	Baa
Wisconsin Power and Light Company	A2	Baa	Baa	Baa
Consolidated Edison Company of New York	A3	Baa	Baa	N/A
PECO Energy Company	A3	Baa	Baa	N/A
Piedmont Natural Gas Company, Inc.	A3	A	A	N/A
Progress Energy Carolinas, Inc.	A3	Baa	Baa	A
Southern California Edison Company	A3	Baa	Baa	A
The Southern Company	A3	Baa	A	Ba
PG&E Corporation	Baa1	A	Baa	Aa
Xcel Energy Inc.	Baa1	A	A	A
American Electric Power Company, Inc.	Baa2	Baa	A	Ba
Arizona Public Service Company	Baa2	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa
Dominion Resources, Inc.	Baa2	A	A	A
Duke Energy Corporation	Baa2	Baa	A	Baa
Emera Incorporated	Baa2	Ba	Ba	Ba
The Empire District Electric Company	Baa2	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	B	Ba	B
Indianapolis Power & Light Company	Baa2	Ba	Baa	Ba
Cemig Distribuição S.A.	Baa3	Ba	Ba	N/A
FirstEnergy Corp.	Baa3	Baa	A	Baa
Westar Energy, Inc.	Baa3	Ba	Baa	Ba
EDP - Energias do Brasil S.A.	Ba1	Baa	Baa	Baa

Observations and Outliers

Of the 30 issuers highlighted, there are three outliers, including PG&E Corporation as a positive outlier, due to their high degree of generation diversification and the lack of coal in their generation mix, and both Eesti Energia AS and The Southern Company as negative outliers. As an Estonian vertically integrated dominant electric utility, Eesti Energia is exposed to considerably high concentration risk as it operates in one of the smallest CEE emerging markets. The concentration risk is further worsened by the company's high reliance on one fuel source as its generation is fully based on internationally rare oil shale. Furthermore, as the oil shale generation is relatively CO2 intensive, Eesti Energia is further exposed to the development of CO2 allowance prices. The Southern Company is one of the largest coal generating utility systems in the U.S., with a high percentage of its generation from carbon fuels.

Regulated Electric and Gas Utilities

Results of Mapping Factor 4

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Sub-Factor Weights			10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-WC / Debt	3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	A	Aa	Aa	Ba	Ba	Baa*
Tokyo Electric Power Company, Incorporated	Aa2	Baa	Aa	A	Ba	Ba	Ba*
Eesti Energia AS	A1/[8]	Aa	Baa	Aaa	Aaa	Aaa	Aa
Florida Power & Light Company	A1	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	A	A	A	A	A	Baa
The Southern Company	A3	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Arizona Public Service Company	Baa2	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	A	Baa	Aa	Aaa	Aa	Ba
FirstEnergy Corp.	Baa3	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa	Ba	Baa	Aa	A	A

**Debt/RAV*

Positive Outlier
Negative Outlier

Observations and Outliers

This factor takes into account historic financial statements. Historic results help us to understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While Moody's rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes.

While the vast majority of utilities' key financial metrics map fairly closely to their ratings, there are several significant outliers, which generally fall into two broad groups. The first group is composed of negative outliers and include several utilities located in stable and supportive regulatory environments and are characterized by very low business risk. In these cases, the utilities may have lower financial ratios and higher leverage than most peer companies on a global basis, but still maintain higher overall ratings. In short, the certainty provided by regulatory stability and low business risk offsets any risks that may result from lower financial ratios. Examples of such negative outliers on the financial strength factor include most of the major Japanese utilities, including Tokyo Electric Power and Kyushu Electric Power.

The second group of outliers is composed of positive outliers, whereby several financial ratios are stronger than the overall Moody's rating. These include several utilities in Latin America, such as Cemig Distribuicao, EDP-Energias do Brasil, and European Eesti Energia, which exhibit strong financial coverage ratios and low debt levels, but where ratings are constrained by a more difficult regulatory or business environment or a sovereign rating ceiling.

Appendix D: Definition of Ratios

Cash Flow Interest Coverage

(Cash Flow from Operations – Changes in Working Capital + Interest Expense) / (Interest Expense + Capitalized Interest Expense)

CFO pre-WC / Debt

(Cash Flow from Operations – Changes in Working Capital) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

CFO pre-WC - Dividends / Debt

(Cash Flow from Operations – Changes in Working Capital – Common and Preferred Dividends) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

Debt / Capitalization or Regulated Asset Value

(Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) / (Shareholders' equity + minority interest + deferred taxes + goodwill write-off reserve + Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) or RAV

Appendix E: Industry Overview

The electric and gas utility industry consists of companies that are engaged in the generation, transmission, and distribution of electricity and/or natural gas. While many utilities remain vertically integrated with operations in all three segments, others have functionally or legally unbundled these functions due to legislatively mandated market restructuring or other deregulation initiatives and may be engaged in just one or two of these activities.

The **generation** of electricity is the first step in the process of producing and delivering electricity to end use customers and typically the most capital intensive, with the largest portion of the industry's assets consisting of generating plants and related hard assets. Electricity is generated from a variety of fuel sources, including coal, natural gas, or oil; nuclear energy; and renewable sources such as hydro, wind, solar, geothermal, wood, and waste.

Transmission is the high voltage transfer of electricity over long distances from its source, usually the location of a generating plant, to substations closer to end use customers in population or industrial centers. Although many utilities own and operate their own transmission systems, there are also several independent transmission companies included in this methodology.

The **distribution** of electricity is the process whereby voltage is reduced and delivered from a high voltage transmission system through smaller wires to the end-users, which consist of industrial, commercial, government, or retail customers of the utility. Most of the utilities covered by this methodology are engaged to some degree in the distribution of electricity through "poles and wires" to their end customers. The distribution of natural gas entails the transport of gas from delivery points along major pipelines to customers in their service territory through distribution pipes.

Regulation Plays a Major Role in the Industry

Because of the essential nature of the utility's end products (electricity and gas), the public policy implications associated with their provision, the demands for high levels of reliability in their delivery, the monopoly status of most service territories, and the high capital costs associated with its infrastructure, the utility industry is generally subject to a high degree of government regulation and oversight. This regulation can take many forms and may include setting or approving the rates or other cost recovery mechanisms that utilities charge for their services (revenue), determining what costs can be recovered through base rates, authorizing returns that utilities earn on their investments, defining service territories, mandating the level and reliability of electricity and gas service that must be provided and enforcing safety standards. From a credit standpoint, the regulators' ability to set and control rates and returns is perhaps the most important regulatory consideration in determining a rating.

In the U.S., the most important utility regulator for most companies is the individual state agency generally known as the Public Utility Commission or the Public Service Commission. The commissions are comprised of elected or appointed officials in each state who determine, among other things, whether utility expenditures are reasonable and/or prudent and how they should be passed on to consumers through their utility rates. While some states have legislatively mandated certain market restructuring or deregulation initiatives with regard to the generation segment of their electricity markets, the majority of states remain fully regulated, and some states that had deregulated are in the process of "re-regulating" their electricity markets.

The key federal agency governing utilities in the U.S. is the Federal Energy Regulatory Commission (FERC), an independent agency that regulates, among other things, the interstate transmission of electricity and natural gas. The FERC's responsibilities include the approval of rates for the wholesale sale and transmission of electricity on an interstate basis by utilities, power marketers, power pools, power exchanges, and independent system operators. The Energy Policy Act of 2005 increased the FERC's regulatory authority in a wide range of areas including mergers and acquisitions, transmission siting, market practices, price transparency, and regional transmission organizations.

Regulated Electric and Gas Utilities

In Europe, following the implementation of specific policies relating to the liberalization of energy supply within the European Union (EU), the electric utility sector has been evolving toward a model targeting complete separation between network activities, regulated in light of their monopoly nature, and supply and production of energy, fully liberalized and hence unregulated. As a result of this process, most Western European utilities currently operate either as fully regulated entities in the networks segment, or largely unregulated integrated companies (albeit some may still maintain some regulated network activity), and are therefore excluded from the scope of this methodology. Nevertheless, there are countries in Europe where regulatory evolution and transition to competition remain at an earlier stage (Central and Eastern European countries and the Baltic states in particular) and/or are characterized by the remoteness and isolation of their systems (the islands in the Azores and Madeira regions for example). In these countries, Governments and/or Regulators maintain greater influence on the bulk of the utilities' revenues, thus supporting their inclusion in this methodology.

In Japan, regulation has been an important positive factor supporting utility credit quality. Japan's regulator makes the maintenance of supply its primary policy objective, followed in priority by environmental protection and finally, allowing market conditions to work. This approach preserves the utilities' integrated operations and makes them responsible for final supply to users in the liberalized market. The Japanese government is gradually deregulating the utility industry and expanding the liberalized market. However, the pace of deregulation has been moderate so that the regulator can monitor the risks and the effects on the power companies, especially in the context of generation supply security.

In Australia, stable and predictable regulatory regimes continue to underpin the investment-grade characteristics of the sector. So far, regulators – which operate independently from the governments – have not adopted an aggressive stance to revenues and returns as they seek a balance between: appropriate returns for utilities; ongoing incentives for network investments; and appropriate prices for consumers. The supportiveness of the regimes will become increasingly important over the medium term as the sector undertakes investments to expand network capacity and replace ageing assets to meet rising demand.

In Asia Pacific (ex-Japan), regulation of electric utilities is overseen by government regulatory bodies in their respective countries. As such, the stability and regulatory framework can vary to a large extent by country with a few utilizing automatic cost pass through mechanisms while the majority operate with ad hoc tariff adjustments. However, power security remains a key policy objective and regulators continue to seek to ensure stability in regulatory and operating environments. Such regulatory environments are critical to attracting investments for both privatizations and for funding expanding electricity projects. Reform of the power industry in Asia remains slow paced and competition is well contained. Regulators have shown that they will reform in a prudent manner and allow tariff adjustment to minimize any material negative impact on the credit profiles of their power utilities. Such a supportive approach enhances stability and provides a stable regulatory regime which in turn remains a key driver in supporting the cash flows of Asia Pacific (ex-Japan) utilities.

In Canada, regulation of electric and gas utilities is overseen by independent, quasi-judicial provincial or territorial regulatory bodies. Accordingly, the transparency and stability of regulation and the timeliness of regulatory decisions can vary by jurisdiction. However, generally the regulatory frameworks in each jurisdiction are well established and there is a high expectation of timely recovery of cost and investments. Furthermore, Moody's considers the overall business environment in Canada to be relatively more supportive and less litigious than that of the U.S. Moody's views the supportiveness of the Canadian business and regulatory environments to be positive for regulated utility credit quality and believes that these factors, to some degree, offset the relatively lower ROEs and higher deemed debt components typically allowed by Canadian regulatory bodies for rate-making purposes. As a result of the relatively low ROEs and higher deemed debt levels that are generally characteristic of Canadian utilities, for a given rating category, these entities often have weaker credit metrics than their international peers.

Regulated Electric and Gas Utilities

In Latin America, there is a perceived lower level of regulatory supportiveness than in other regions. In Argentina, although the generation industry is deregulated, the government continues to intervene in the process of setting prices and tariffs. In addition, collections from sales to the spot market have only been partial and have depended on the government's discretion. Moody's views the current regulatory framework as a relatively high risk factor given the government's interference, the unclear regulations, the lack of support for the companies' profitability, and the lack of incentives for much needed long-term investment. Brazil's power generation companies could also be affected by unfavorable regulatory decisions, since about 75% of its electricity currently goes to the regulated market, but Moody's last year noted improvements in Brazil's regulatory environment, which led to several issuer upgrades. Brazil's regulatory model provides a more supportive environment for acceptable rates of return since the current rules for electric utilities are more transparent and technically driven. Nonetheless, there is a lower assurance of timely recovery of costs and investments in Brazil since the new framework has not yet experienced the stress of high inflation, exchange rate devaluation or electricity rationing. Recent distribution tariff review reductions have typically been in the high-single-digit range, which is considered modest, particularly compared to Moody's rated issuers in El Salvador (14% reduction) and Guatemala (45% reduction) both of which led to downgrades last year. The regulatory framework in Chile, in Moody's opinion, comes closest to the United States in terms of regulatory supportiveness.

Appendix F: Key Rating Issues Over the Intermediate Term

Global Climate Change and Environmental Awareness

Electric and gas utilities will continue to be affected by growing concerns over global climate change and greenhouse gas emissions, which are particularly important in the electricity generation segment which continues to rely on a large number of coal and natural gas fired power plants. There have been significant increases in environmental expenditure estimates among utilities with significant coal fired generation in recent years as policymakers have mandated pollution control measures and emissions limitations in response to public concerns over carbon. These expenditures are likely to continue to increase with the imposition of new and sometimes uncertain requirements with respect to carbon emissions. Utilities may have to implement substantial additional reductions in power plant emissions and could experience progressively higher capital expenditures over the next decade. In the U.S., the planned construction of several new coal plants has been cancelled as a result of opposition from regulators, political leaders, and the public or because cheaper alternatives appeared more compelling due to higher coal plant construction costs.

Large Capital Expenditures and Rising Costs for New Generation and Transmission

While the global recession may have reduced electric demand in certain regions in the short-term, longer-term worldwide demand for electricity is expected to continue to grow and many utilities will incur substantial capital expenditures for new generation, as well as for upgrades and expansions to transmission systems. In the U.S., the Edison Electric Institute projects annual capacity additions among investor-owned utilities to increase to over 15,000 megawatts (MW) in 2009 compared with less than 6,000 MW in 2006. Some of the new plants announced include large, highly capital intensive nuclear plants, which have not been built in the U.S. in many years. In Indonesia, the Fast Track program calls for the addition of 9,000 MW of coal-fired power plants while India plans to build eight ultra-mega power projects (each under 4,000 MW). Similar large nuclear plants are being constructed worldwide in countries as diverse as Bulgaria, China, India, Russia, South Korea, Taiwan and Ukraine. Because of this construction boom, international demand for certain construction materials, plant components and skilled labor has driven up the cost of new nuclear. More recently, the global economic slowdown may relieve some of this cost pressure.

Political and Regulatory Risk

As the utility industry faces higher operating costs, rising environmental compliance expenditures, large capital expenditures for new generation, as well as fuel and commodity price risks, the need for rate relief and other regulatory support will continue to be a key rating factor. In the U.S., political intervention in the regulatory process following particularly large rate increase requests increased risk and negatively affected the credit ratings of utilities in Illinois and Maryland in recent years. In Europe, rising electricity prices two years ago resulted in widespread criticism of utilities in several countries, increasing regulatory and political risk for some of them. In Australia, the transition from state based regulation to a national regulatory framework could pose a moderate level of uncertainty to current regulatory thinking over the longer term. In Asia Pacific (ex-Japan) and Latin America, the governments face political pressure regarding tariff adjustments given their need to balance socio-economic targets and inflationary concerns against the objective of ensuring reliable electricity supply over the long term.

Economic and Financial Market Conditions

Although electric and gas utilities are somewhat resistant (although not immune) to unsettled economic and financial market conditions due partly to the essential nature of the service provided, a protracted or severe recession could negatively affect credit profiles over the intermediate term in several ways. Falling demand for electricity or natural gas could negatively impact margins and debt service protection measures. Poor economic conditions could make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, constrained capital market conditions could severely limit the availability of credit necessary to finance needed capital expenditures, or make such financing plans more expensive.

Appendix G: Regional and Other Considerations

Notching Considerations - Structural Subordination and Holding Company Ratings

Utility corporate structures often include multiple legal entities within a single consolidated organization under an unregulated parent holding company. The holding company typically has one or more regulated operating subsidiaries and may have one or more unregulated subsidiaries as well. Most utility families issue debt at several of these legal entities within the organizational family including the parent holding company and the utility subsidiaries. In such cases, our approach is to assess each issuer on a standalone basis as well as to evaluate the creditworthiness of the consolidated entity. We also consider the interdependent relationships that may exist among affiliates and the degree to which a management team operates its utility subsidiaries as a system. We then assess the degree of legal and regulatory insulation that exists between the generally lower-risk regulated entities and the generally higher-risk unregulated entities.

The degree of notching (or rating differential) between entities in a single family of companies depends on the degree of insulation that exists between the regulated and unregulated entities, as well as the amount of debt at the holding company in comparison to the consolidated entity. If there is minimal insulation or ring-fencing between the parent and subsidiary and little to no debt at the parent, there is typically a one notch differential between the two to reflect structural subordination of the parent company debt compared to the operating subsidiary debt. If there is substantial insulation between the two and/or debt at the parent company is a material percentage of the overall debt, there could be two or more notches between the ratings of the parent and the subsidiary.

U.S. Securitization

Since the late 1990s, legislatively approved stranded cost and other regulatory asset securitization has become an increasingly utilized financing technique among some investor-owned electric utilities. In its simplest form, a stranded cost securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitizations were originally done to reimburse utilities for stranded costs following deregulation, which was primarily related to the actual lower market values of the legacy generation compared to its book value. More recently, securitizations have been done to reimburse utilities for storm restoration costs following two active hurricane seasons in the U.S. in 2004 and 2005, with additional securitizations planned following an active 2008 hurricane season, as well as for environmental equipment. In 2007, Baltimore Gas & Electric used securitization to fund supply cost deferrals. Securitization could also be used to help fund the next generation of nuclear plants to be built in the U.S.

Although it often addresses a major credit overhang and provides an immediate source of cash, Moody’s treats securitization debt of utilities as being on-credit debt. In calculating balance sheet leverage, Moody’s treats the securitization as being fully recourse to the utility as accounting guidelines require the debt to appear on the utility’s balance sheet. In looking at cash flow coverages, Moody’s analysis focuses on ratios that include the securitized debt in the company’s total debt as being the most consistent with the analysis of comparable companies. Securitizations also entail transition or other charges on ratepayer bills that may limit a utility’s flexibility to raise rates for other reasons going forward. While our standard published credit ratios include the securitization debt, we also look at the ratios without the securitization debt and cash flow in our analysis, to distinguish this debt and ensure that the benefits of securitization are not ignored.

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership dominate Asia Pacific (ex-Japan) power utilities and remain one of their key rating drivers. The current majority state ownership levels are expected to remain largely unchanged for the near to medium term, thereby providing rating uplift to a majority of the government-owned Asia Pacific (ex-Japan) utilities under the Joint Default Analysis methodology.

Appendix H: Treatment of Power Purchase Agreements ("PPA's")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, or to fix the cost of power. While Moody's regards these risk reduction measures positively, some aspects of PPAs may negatively affect the credit of utilities.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover debt service and are made irrespective of whether the utility requires the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus analyzed by Moody's as PPAs.[4]

Factors determining the treatment of PPAs

Because PPAs have a wide variety of financial and regulatory characteristics, each particular circumstance may be treated differently by Moody's. The most conservative treatment would be to treat the PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized. Factors which determine where on the continuum Moody's treats a particular PPA are as follows:

- Risk management: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.
- Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.
- Price considerations: The price of power paid by a utility under a PPA can be substantially below the current spot price of electricity. This will motivate the utility to purchase power from the IPP even if it

[4] When take-or-pay contracts, outsourcing agreements, PPAs and other rights to capacity are accounted for as leases under US GAAP or IFRS, they are treated by Moody's as such for analytical purposes.

does not require it for its own customers, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or when the spot price is lower than the PPA price will suffer a financial burden. Moody's will particularly focus on PPAs that have mark-to-market losses that may have a material impact on the utility's cash flow.

- Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. For example, Tenaga, the major Malaysian utility, purchases a large proportion of its power requirement from IPPs under PPAs. PPA payment totaled 42.0% of its operating costs in FY2008. In a high reserve margin environment existing in Malaysia, capacity payment under these PPAs are a significant burden on Tenaga, and some account must be made for these payments in its financial metrics.

- Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. Moody's will examine on a case-by case basis which of these two sets of risk poses greatest concern from a ratings standpoint.

- Default provisions: In most cases, a default under a PPA will not cross-default to the senior facilities of the utility and thus it is inappropriate to add the debt amount of the PPA to senior debt of the entity. The PPA obligations are not senior obligations of the utility as they do not behave in the same way as senior debt. However, it may be appropriate in some circumstances to add the PPA obligation to Moody's debt, in the same way as other off-balance sheet items.[5]

- Accounting: From a financial reporting standpoint, very few PPA's have thus far resulted in IPP's being consolidated by the off taker. Similarly, very few PPA's are treated as lease obligations. Due to upcoming accounting rule changes[6], however, coupled with many contracts being renegotiated and extended over the next several years, we expect to see an increasing number of projects being consolidated or PPA's accounted for as leases on utility financial statements. Many of the factors assessed in the accounting decision are the same as in our analysis, i.e. risk and control. However, our analysis also considers additional factors that the accountants may not, such as the ability to pass through costs. We will consider the rationale behind the accounting decision and compare it to our own analysis and may not necessarily come to the same conclusion as the accountants.

Each of these factors will be weighed by Moody's analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods of accounting for PPAs in our analysis

According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total debt obligations for the utility using one of the methods discussed below.

- Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the debt obligations of the utility. In the event operating costs are consolidated, we will attempt to deconsolidate these costs from a utility's financial statements.

- Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot be quantified otherwise due to limited information.

[5] See "The Analysis of Off-Balance Sheet Exposures – A Global Perspective", Rating Methodology, July 2004.
[6] SFAS 167 "Amendments to FASB Interpretation No. 46(r)" will be effective Q1 2010.

- Net Present Value: Where the analyst has sufficient information, Moody's may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be the cost of capital of the utility.
- Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.
- Mark-to-Market: In situations in which Moody's believes that the PPA prices exceed the spot price and thus a liability is arising for the utility, Moody's may use a net mark-to-market method, in which the NPV of the net cost to the utility will be added to its total debt obligations.
- Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. Again, if the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

In some circumstances, Moody's will adopt more than one method to estimate the potential obligations imposed by the PPA. This approach recognizes the subjective nature of analyzing agreements that can extend over a long period of time and can have a different credit impact when regulatory or market conditions change. In all methods the Moody's analyst will account for the revenue from the sale of power bought from the IPP. We will focus on the term to maturity of the PPA obligation, the ability to pass through costs and curtail payments, and the materiality of the PPA obligation to the overall cash flows of the utility in assessing the effect of the PPA on the credit of the utility.

Moody's Related Research

Industry Outlooks:

- U.S. Regulated Electric Utilities, Six-Month Update, July 2009 (118776)
- U.S. Investor-Owned Electric Utility Sector, January 2009 (113690)
- EMEA Electric and Gas Utilities, November 2008 (112344)
- North American Natural Gas Transmission & Distribution, March 2009 (115150)

Rating Methodologies:

- Unregulated Utilities and Power Companies, August 2009 (118508)
- Regulated Electric and Gas Networks, August 2009 (118786)

Special Comments:

- Credit Roadmap for Energy Utilities and Power Companies in the Americas, March 2009 (115514)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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Moody's Investors Service

NWN Pension Funding Analysis
Proposed Oregon Rate Base Adjustment

		FAS 87 Expense Collected - Oregon				Pension Contributions		Oregon Rate Adjustment Calculations			
		O&M		Cap-Ex							
Year	FAS 87 Expense [1]	UG-152 in Rates [2]	UM 1475 Deferral [3]	Amount Capitalized [4]	Total Ratepayer "Collected"	Total	Amt Allocated to Oregon [6]	Contributions In Excess of Collections	Cumulative Excess Difference	Cumulative Excess Net of Tax	
2004	6,629,242	3,796,055		2,187,914	5,983,969	8,260,704	7,434,634	1,450,665	1,450,665	870,399	Dec-04
2005	6,914,465	3,796,055		2,262,530	6,058,585	31,000,000	27,900,000	21,841,415	23,292,080	13,975,248	Dec-05
2006	8,172,990	3,796,055		2,658,278	6,454,333	-	-	(6,454,333)	16,837,747	10,102,648	Dec-06
2007	6,687,898	3,796,055		2,202,346	5,998,401	-	-	(5,998,401)	10,839,346	6,503,608	Dec-07
2008	4,292,980	3,796,055		1,406,380	5,202,435	-	-	(5,202,435)	5,636,911	3,382,146	Dec-08
2009	14,579,030	3,563,854		4,644,879	8,208,733	25,000,000	22,500,000	14,291,267	19,928,178	11,956,907	Dec-09
2010	11,404,046	3,796,055		3,592,274	7,388,329	10,000,000	9,000,000	1,611,671	21,539,848	12,923,909	Dec-10
2011	15,988,950	3,796,055	5,557,481	5,036,519	14,390,055	22,000,000	19,800,000	5,409,945	26,949,793	16,169,876	Dec-11
Sub-Total	74,669,601	30,136,239	5,557,481	23,991,121	59,684,840	96,260,704	86,634,634	26,949,793			
2012 [5]	16,000,000	3,796,055	5,563,945	5,040,000	14,400,000	20,000,000	18,000,000	3,600,000	30,549,793	18,329,876	Dec-12
2013 [5]	14,000,000	3,796,055	4,393,945	4,410,000	12,600,000	22,000,000	19,800,000	7,200,000	37,749,793	22,649,876	Dec-13
Sub-Total	30,000,000	7,592,110	9,957,890	9,450,000	27,000,000	42,000,000	37,800,000	10,800,000			
Total	104,669,601	37,728,349	15,515,371	33,441,121	86,684,840	138,260,704	124,434,634	37,749,793			

Rate Base Adjustment for a "Return On" Test Year Amount		21,929,876
Total Revenue Requirement for a "Return Of" Test Year Amount	36,549,793	
Annualized Revenue Requirement for a "Return Of" Test Year Amount over 8 years	4,568,724	
Base Year (3 Mo. 2010 + 9 Mo. 2011)		15,358,384

[1] Reflects actual expenses for years 2004-2010 and actuarial estimated expenses for years after 2010.
[2] Assumes Oregon UG-152 revenue requirement for pensions is collected each year, less any automatic refunds.
[3] Reflects estimated balancing account deferral in Oregon starting Jan. 1, 2011.
[4] Assumes FAS 87 expense allocated to cap-ex is recovered in rates in the same year FAS 87 is capitalized, adjusted for 90% allocation to Oregon
[5] Reflects actuarial report dated November 2011, including discount rate and asset return assumptions, and 80% minimum funded status.
[6] Total contribution adjusted to reflect 90% Oregon allocation.

NW Natural Gas Co.
Comparable Company Fundamental Characteristics (S&P Gas Group)

		(1)	(2)		(3)		
					Capital Structure (2010)		
		% Regulated	Credit Rating		Common Equity	Long-Term Debt	Preferred Stock
No.	Company	Revenue	S&P	Moody's	Ratio	Ratio	Ratio
1	Laclede Group	49.8%	A	A2	59.5%	40.5%	0.0%
2	New Jersey Res.	35.5%	A+	Aa3	62.8%	37.2%	0.0%
3	South Jersey Inds.	50.7%	A	A2	62.6%	37.4%	0.0%
4	UGI Corp.	20.9%	NR	A3	56.0%	44.0%	0.0%
5	WGL Holdings	47.9%	A+	A2	65.0%	33.4%	1.6%
6	National Fuel Gas	45.7%	BBB	Baa1	62.5%	37.5%	0.0%
7	ONEOK Inc.	13.9%	BBB	Baa2	39.9%	60.1%	0.0%
8	Questar Corp	80.3%	A	A3	53.6%	46.4%	0.0%
9	Atmos Energy Corp.	65.0%	BBB+	Baa2	54.6%	45.4%	0.0%
10	N.W. Nat'l Gas	94.2%	A+	A1	53.5%	46.5%	0.0%
11	Piedmont Nat'l	100.0%	A	A3	59.0%	41.0%	0.0%
12	Southwest Gas	85.5%	BBB	Baa2	50.9%	49.1%	0.0%
	Average	57.5%	A/A-	A3	56.7%	43.2%	0.1%

Column Sources:

(1) Most recent company 10-Ks.

(2) AUS Utility Reports, Nov 2011.

(3) Value Line Investment Survey: Natural Gas Utility, Natural Gas (Div), Oil/Gas Distribution, Sep 9, 2011.

AGL Resources and NICOR eliminated from the Value Line group due to pending merger activity.

NW Natural Gas Co.
Comparable Company Fundamental Characteristics (Value Line Group)

		(1)	(2)		(3)		
					Capital Structure (2010)		
		% Regulated	Credit Rating		Common Equity	Long-Term Debt	Preferred Stock
No.	Company	Revenue	S&P	Moody's	Ratio	Ratio	Ratio
1	Laclede Group	49.8%	A	A2	59.5%	40.5%	0.0%
2	New Jersey Res.	35.5%	A+	Aa3	62.8%	37.2%	0.0%
3	South Jersey Inds.	50.7%	A	A2	62.6%	37.4%	0.0%
4	UGI Corp.	20.9%	NR	A3	56.0%	44.0%	0.0%
5	WGL Holdings	47.9%	A+	A2	65.0%	33.4%	1.6%
6	Atmos Energy Corp.	65.0%	BBB+	Baa2	54.6%	45.4%	0.0%
7	N.W. Nat'l Gas	94.2%	A+	A1	53.5%	46.5%	0.0%
8	NiSource Inc.	87.5%	BBB-	Baa2	45.3%	54.7%	0.0%
11	Piedmont Nat'l	100.0%	A	A3	59.0%	41.0%	0.0%
12	Southwest Gas	85.5%	BBB	Baa2	50.9%	49.1%	0.0%
	Average	63.7%	A/A-	A3	56.9%	42.9%	0.2%

Column Sources:

(1) Most recent company 10-Ks.

(2) AUS Utility Reports, Nov 2011.

(3) Value Line Investment Survey: Natural Gas Utility, Sep 9, 2011.

AGL Resources and NICOR eliminated from the Value Line group due to pending merger activity.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Samuel C. Hadaway

RATE OF RETURN ON EQUITY
EXHIBIT 500

December 2011

EXHIBIT 500 – RATE OF RETURN ON EQUITY

Table of Contents

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I. INTRODUCTION AND SUMMARY

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

A. My name is Samuel C. Hadaway. I am a Principal in FINANCO, Inc., Financial Analysis Consultants, 3520 Executive Center Drive, Austin, Texas 78731. My qualifications appear at the end of my direct testimony.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Northwest Natural Gas Company ("NW Natural" or "the Company").

Q. Please state your educational background and describe your professional training and experience.

A. I have a Bachelor's degree in economics from Southern Methodist University, as well as MBA and Ph.D. degrees with concentrations in finance and economics from the University of Texas at Austin (UT Austin). I am an owner and full-time employee of FINANCO, Inc. FINANCO provides financial research concerning the cost of capital and financial condition for regulated companies as well as financial modeling and other economic studies in litigation support. In addition to my work at FINANCO, I have served as an adjunct professor in the McCombs School of Business at UT Austin and in what is now the McCoy College of Business at Texas State University. In my prior academic work, I taught economics and finance courses and I conducted research and directed graduate students in the areas of investments and capital market research. I was previously Director of the Economic Research Division at the Public Utility Commission of Texas where I supervised the Commission's finance, economics, and

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accounting staff, and served as the Commission's chief financial witness in electric and telephone rate cases. I have taught courses at various utility conferences on cost of capital, capital structure, utility financial condition, and cost allocation and rate design issues. I have made presentations before the New York Society of Security Analysts, the National Rate of Return Analysts Forum, and various other professional and legislative groups. I have served as a vice president and on the board of directors of the Financial Management Association.

A list of my publications and testimony I have given before various regulatory bodies and in state and federal courts is contained in my resume, which is included as *NWN/506, Hadaway/1-11*.

II. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. In my testimony I:

- Estimate NW Natural's market required rate of return on equity (ROE).
- In Section III, I review general capital market costs and conditions and discuss recent developments in the gas utility industry that may affect the cost of capital.
- In Section IV, I discuss various methods for estimating the cost of equity. In this section, I discuss comparable earnings methods, risk premium methods, and discounted cash flow (DCF) methods.
- In Section V, I present the details of my cost of equity studies.

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- In Section VI, I provide a brief summary and a statement of my conclusions.

Q. Please summarize your cost of equity studies and state your ROE recommendation.

A. My primary recommendation is based on the DCF model. As I have traditionally done, I also provide an equity risk premium analysis. Under present market conditions, however, I discount the risk premium results because they are artificially depressed by the government's ongoing monetary policies and efforts to keep interest rates at record low levels. In the DCF analysis, I apply the alternative versions of the model to a comparable group of gas local distribution companies (LDCs) and combination gas/electric utilities. In my risk premium analysis, I develop ROE estimates from current and projected single-A utility interest rates. This is the appropriate basis for the risk premium analysis, since NW Natural's senior debt is rated single-A by both Moody's Investor Service ("Moody's") and Standard & Poor's ("S&P"). As I will explain, present economic and market conditions make it particularly difficult to interpret the quantitative model results. For this reason, as I did in NW Natural's previous Oregon rate case, Docket UG 152 ("2002 Rate Case"), I offer my best judgment about which portions of the quantitative analyses are most reliable. Whereas in the 2002 Rate Case I recommended an ROE well below the levels indicated by my quantitative analysis, under present conditions I believe an ROE above some of the quantitative results is appropriate. The data sources and the details of my rate of return analyses are contained in *NWN/501-505, Hadaway,* and in accompanying workpapers.

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Based on my quantitative analyses, I estimate the fair cost of equity to be in a range of 9.6 percent-10.3%. From these quantitative results and my review of the current market, industry, and company-specific factors discussed in the remainder of my testimony, I support the point estimate of 10.3 percent that was selected by the Company for use in this case. This estimate is supported by the upper end of my DCF range presented at *NWN/504, Hadaway/1*. My DCF results, in combination with my discussion of the ongoing equity market turbulence that utility investors face, support the Company's 10.3 percent requested ROE as a fair and reasonable rate of return to be applied in the present case.

III. <u>FUNDAMENTAL FACTORS THAT AFFECT THE COST OF EQUITY CAPITAL</u>

Q. What is the current outlook for the U.S. economy?

A. Growth for the U.S. economy is expected to remain slow in the near term. While most economists expect real growth to remain positive, in the 1.5 percent range, unemployment is also expected to remain stubbornly high in the 9 percent range. Forecasts for 2012 indicate continuing, but slow recovery with new job creation a fundamental concern. Equity markets have continued to be extremely volatile and only recently have utility stocks had favorable performance relative to the overall market. As I will explain later in this testimony, the recent positive utility stock performance is not necessarily a reflection of improving economic conditions. Rather it very likely reflects a search for yield by investors discouraged by the federal government's persistent intervention in the fixed income markets. On top of these market dislocations, investors are also concerned about the European sovereign debt crisis and upcoming economic

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decisions in the U.S. All of these factors point to elevated risk aversion, a fundamental lack of equilibrium conditions in the financial markets, and a continuing relatively high cost for equity capital.

Q. What has been the experience in the U.S. capital markets for the past several years?

A. At *NWN/502, Hadaway/1*, I provide a 10-year review of annual interest rates and rates of inflation. During this time period, interest rates and inflation generally have been lower than in the previous decade. Inflation, as measured by the Consumer Price Index (CPI), fluctuated between a low of zero percent (in 2008) and 4.1 percent (caused by the spike in energy costs that occurred in 2007). The decade's average annual inflation rate (2.4 percent) was 130 basis points lower than the longer-term average rate of the past 60 years (see *NWN/503, Hadaway/1*). Interest rates declined steadily over most of the period, with the 2010 average utility rate at its lowest level in more than 30 years (see *NWN/505, Hadaway/1*).

Q. What has been the more recent trend in long-term interest rates?

A. The month-by-month interest rate data for the period since January 2009 are presented in *NWN/502, Hadaway/2*, and summarized below:

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Table 1

Long-Term Interest Rate Trends

Month	Single-A Utility Rate	30-Year Treasury Rate	Single-A Utility Spread
Jan-09	6.39	3.13	3.26
Feb-09	6.30	3.59	2.71
Mar-09	6.42	3.64	2.78
Apr-09	6.48	3.76	2.72
May-09	6.49	4.23	2.26
Jun-09	6.20	4.52	1.68
Jul-09	5.97	4.41	1.56
Aug-09	5.71	4.37	1.34
Sep-09	5.53	4.19	1.34
Oct-09	5.55	4.19	1.36
Nov-09	5.64	4.31	1.33
Dec-09	5.79	4.49	1.30
Jan-10	5.77	4.60	1.17
Feb-10	5.87	4.62	1.25
Mar-10	5.84	4.64	1.20
Apr-10	5.81	4.69	1.12
May-10	5.50	4.29	1.21
Jun-10	5.46	4.13	1.33
Jul-10	5.26	3.99	1.27
Aug-10	5.01	3.80	1.21
Sep-10	5.01	3.77	1.24
Oct-10	5.10	3.87	1.23
Nov-10	5.37	4.19	1.18
Dec-10	5.56	4.42	1.14
Jan-11	5.57	4.52	1.05
Feb-11	5.68	4.65	1.03
Mar-11	5.56	4.51	1.05
Apr-11	5.55	4.50	1.05
May-11	5.32	4.29	1.03
Jun-11	5.26	4.23	1.03
Jul-11	5.27	4.27	1.00
Aug-11	4.69	3.65	1.04
Sep-11	4.48	3.18	1.30
Oct-11	4.52	3.13	1.39
3-Mo Avg	**4.56**	**3.32**	**1.24**
12-Mo Avg	**5.24**	**4.13**	**1.11**

Sources: Mergent Bond Record (Utility Rates); www.federalreserve.gov (Treasury rates). Three month average is for August 2011-October 2011. Twelve month average is for November 2010-October 2011.

The data in Table 1 track the steady decline in corporate interest rates that has occurred since early 2009 and the market turmoil that has existed during this time period. The Federal Reserve's continuing intervention in the financial markets and its efforts to keep short-term rates near zero and yields on longer-term U.S. Treasury bonds at historically low levels are affecting high-quality corporate debt as well. While the effects of these monetary policy efforts are not easily captured in financial models for estimating ROE (models that assume market equilibrium exists), equity market turbulence and the resulting elevated level of risk aversion indicate that any decline in ROE has not been nearly as large as the decline in borrowing costs.

Q. Do the smaller spreads between yields on single-A utility bonds and U.S. Treasury bonds mean that the markets have fully recovered from the economic turmoil that resulted from the financial crisis?

A. No. While markets have stabilized considerably from the conditions that existed in early 2009, investors remain concerned about high unemployment, large federal deficits, the Mideast turmoil, and European as well as domestic economic issues. These factors combined with sluggish growth in gross domestic product (GDP) raise substantial equity market concerns and contribute to heightened investor risk aversion.

Q. What do forecasts for the economy and interest rates show for the coming year?

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A. Interest rates are expected to rise somewhat from currently low levels. In *NWN/502, Hadaway/3)*, I provide S&P's most recent interest rate forecast from its *Trends & Projection*s publication for October 2011. Table 2 below summarizes the interest rate data:

Table 2
Interest Rate Forecasts

	(1) Average 2011 Est.	**(2)** Oct. 2011 Average	**(3)** Average 2012 Est.
Treasury Bills	0.1%	0.0%	0.1%
10-Yr. T-Bonds	2.8%	2.2%	2.3%
30-Yr. T-Bonds	3.9%	3.1%	3.3%
Aaa Corporate Bonds	4.7%	4.0%	4.2%

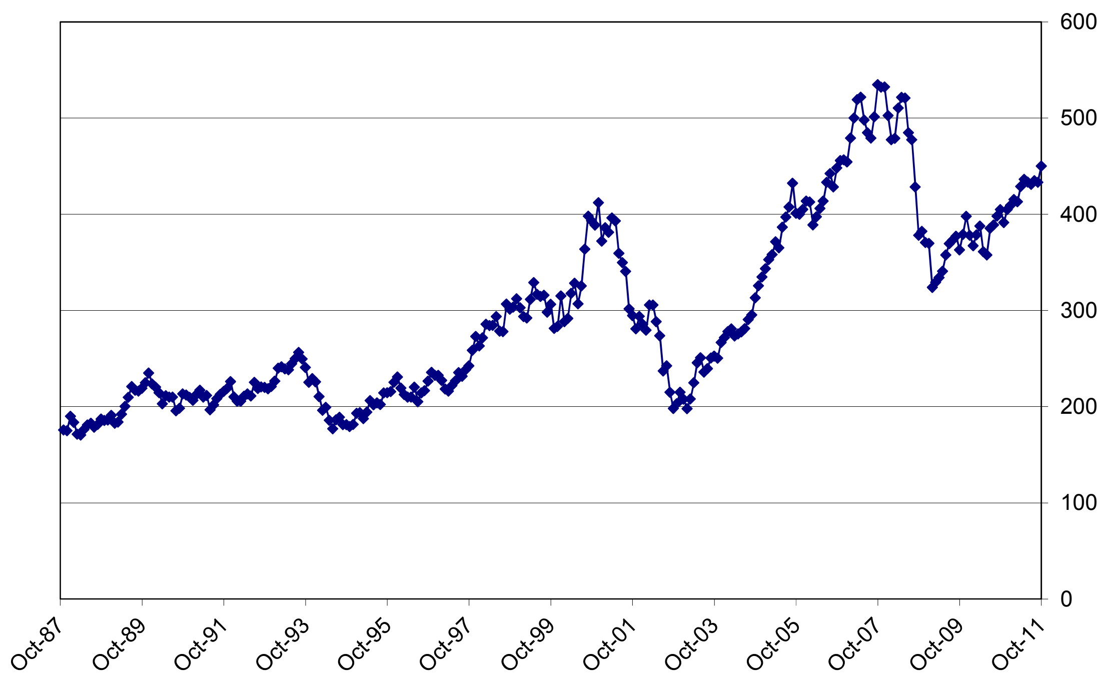
Sources: Column 2, www.federalreserve.gov (current rates); Columns 1 and 3, Standard & Poor's *Trends & Projections*, October 2011, page 8 (projected rates).

These data show that, during 2012, average long-term Treasury interest rates are expected to increase by 20 basis points relative to their record low levels in the October 2011 period. Yields on the other bonds shown in the table are also expected to increase slightly. The small interest rate increases projected by S&P are consistent with a sluggishly improving economy and the government's announced intention to keep interest rates low.

Q. How have utility stocks performed during the past several years?

A. Utility stock prices have been more volatile in recent years as compared to their traditional performance. The wider fluctuations in more recent years are vividly illustrated in the following Graph 1, which depicts Dow Jones Utility Average (DJUA) prices over the past 25 years.

Graph 1
Dow Jones Utility Average
1987-2011



Until the late 1990s, utility stocks were viewed as relatively stable investments. Over the past decade, however, utility stock prices have fluctuated much more widely. In this environment, investors' return expectations and requirements for providing capital to the utility industry remain high relative to the longer-term, traditional view of the utility industry.

Q. How have utility stocks performed since the market low point reached in March 2009?

A. Prior to the last several months (since May 2011), utility stock prices had lagged well behind the general market recovery. Since May, however, fears of potential sovereign

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defaults as well as domestic financial problems have increased overall equity market risk aversion. This situation has made dividend oriented stocks, like utilities, relatively more attractive. For the May-October time period, the DJUA rose over 3 percent (3.2 percent), while the S&P 500 dropped by almost 7 percent (-6.8 percent). The relatively better performance for utilities has produced lower dividend yields in the DCF model; *i.e.*, the DCF model results, with respect to dividend yields, do not reflect the overall market's volatility and heightened risk aversion. In fact, by its very formulation, the DCF model assumes market equilibrium not the disequilibrium and volatility in evidence today. This inability to account for market volatility and heightened risk aversion makes it more difficult to interpret current DCF cost of equity estimates for utility companies. The long-term nature of the DCF model's input requirements simply cannot reflect all the market elements that are currently affecting the cost of equity capital.

Q. How has the "flight to quality" in the traditional fixed income markets (bond markets) affected dividend oriented stocks?

A. As bond yields have fallen (as a result of the government's ongoing policies in the financial markets), investors have looked for income from dividend paying stocks. Consequently, utility stocks have experienced some price support as investors in search of yield have substituted utility common stocks for low-yielding fixed income securities.

Q. Does this imply that the cost of equity capital for utilities has declined as much as the drop in interest rates?

A. No. Equity market risk aversion has increased, not decreased. The domestic economy faces severe challenges—growth in GDP has slowed; unemployment remains

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stubbornly high; job creation is weak. The federal government is responding to this economic distress by artificially depressing interest rates through its ongoing purchases of Treasury bonds and other securities. While this government policy pumps liquidity into the financial markets, it also removes yield opportunities for investors in traditionally lower-risk fixed income investments. Thus, investors are trying to react rationally to a market environment that has many risks but few income opportunities. Such circumstances raise significant questions about the ability of traditional rate of return estimation methods to function reasonably.

Furthermore, as I discuss elsewhere in this testimony, any decline in the ROE should not be as large as the recent decline in borrowing costs. By the same token, any rise in the ROE generally is not nearly as large as the increase in borrowing costs. From a regulatory policy point of view, incremental changes in the embedded cost of debt are gradually applied to the rate base as new debt issues are added to the balance sheet and retiring debt issues are removed from the balance sheet. However, incremental changes in common equity costs, either up or down, are applied to the rate base without moderation. These circumstances can have a material effect on the utility's funds from operations. Thus, tempering incremental changes in common equity costs, either up or down, would be consistent with the way incremental debt cost changes are handled and would be consistent with maintaining the utility's credit quality, financial integrity and access to capital markets.

Q. Has equity market volatility been recognized as a cause for reduced equity capital availability in the U.S.?

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A. Yes. A recent Associated Press article describes this problem in some detail. The article notes that since August, market swings have been particularly troublesome:

> In market-speak, it's called volatility: Large jumps followed by deep dives, within the course of a week or sometimes the same day. The surge in volatility since early August has been blamed for preventing companies from going public and scaring people out of stocks. Some think that even if Europe resolves its debt crisis, large price swings are here to stay.
>
> The long-term trend is toward more volatility. Judging by the number of times in a year the S&P 500 swung 2 percent or more in a single day, markets are much more likely to have large leaps up or dives down, according to S&P's equity research group. Swings of 2 percent occurred an average of five times a year from 1950 to 1999. It's already happened 20 times this year, with three months left to go.[1]

Q. How have recent operating factors affected natural gas companies?

A. The natural gas utility industry has seen significant volatility both in terms of fundamental operating characteristics and the effects of the economy. The economic crisis significantly reduced sales volumes and increased the difficulty of planning for future load requirements. S&P, in its most recent *Gas Utility Industry Survey*, reflects the ongoing market volatility and expected slow growth in end-use demand:

> **Standard & Poor's Industry Surveys**
>
> Despite a decline in volatility in early 2011 compared to multiple price spikes in the past decade, prices remained volatile on a percentage-change basis. Based on data from Bloomberg, after falling to a 2009 closing low of $1.73 per million British thermal units (MMBtu, Henry Hub spot price) on September 4, 2009, natural gas prices quickly rebounded to a closing high of $7.98 per MMBtu on January 7, 2010, before falling 54% to $3.69 on April 1, 2010. Since the latter date, prices in 2010 traded

1 Craft, Matthew. Associated Press/Yahoo Finance, " Wild market ride is driving people out of stocks" (Oct. 02, 2011) *available at* http://finance.yahoo.com/news/Wild-market-ride-is-driving-apf-2513012628.html?x=0&cmtnav=/mwphucmtgetnojspage/headcontent/main/2513012628//date/desc/11/s9622412.

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> within a wide range, from a closing high of $5.17 on June 18 to a closing low of $3.18 on October 25. In 2011 so far, prices have ranged from a closing high of $4.73 on January 21, to a closing low of $3.70 on March 4, and widely within that high-low range since.[2]
>
> In its *Short-Term Energy Outlook* published June 7, 2011, the Energy Information Administration (EIA) projected that total natural gas consumption would increase by 1.4% in 2011 and 0.3% in 2012. The projected growth in total consumption for 2012 is lower than the 1.4% 50-year compound annual growth rate (CAGR) and the 1.3% 25-year rate, but matches the 0.3% 10-year rate; for 2011, it matches the 50-year rate.[3]

Value Line also reflects relatively poor conditions for the natural gas utility industry:

> **Value Line Investment Survey**
>
> Conditions in the United States remain a challenge, partially reflecting softness in the housing market. A persistently high unemployment rate (which is hovering around 9% at present) does not help the situation, either. Indeed, GDP growth was only 1% in the second quarter, and it appears that this modest pace of expansion will persist for some time. Consequently, consumers have kept tight control over their spending habits, spurring energy conservation efforts. Of course, all these trends bode ill for the revenues of the companies in *Value Line's* Natural Gas Utility Industry.[4]

Difficult operating conditions along with market gyrations and the volatility of utility shares demonstrate the increased uncertainties that utility investors face. These uncertainties translate into a relatively higher cost of capital for utilities than was traditionally the case.

---

2 *Standard & Poor's Industry Surveys*, "Natural Gas Distribution" at 1 (July 14, 2011).
3 *Id.* at 4.
4 *Value Line Investment Survey,* "Natural Gas Utility" at 541 (Sept. 9, 2011).

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Q. Please describe the business risk faced by LDCs, in general, and NW Natural in particular.

A. All LDCs, including NW Natural, face increasing business risks created by industry changes—including increased business complexity, competition for customers, and market concerns. In addition, as is described in more detail in the direct testimony of Company witness David H. Anderson, NW Natural faces specific business risks due to its increasing competition for residential load posed by electric suppliers in general and heat pumps in particular, its mounting environmental liabilities resulting from its historic manufactured gas plants, and unrecovered contributions required to be made to its pension fund. All of these translate into a riskier business profile for the Company.

Q. How have changes in the natural gas industry increased the risks faced by NW Natural?

A. As a result of Federal Energy Regulatory Commission nitiatives to restructure the natural gas pipeline industry, the nature of the gas supply function has changed significantly over the past 15 years for LDCs. The changes that have taken place have, among other things, eliminated the pipeline merchant function; completely unbundled the supply, transportation, and storage functions provided by the interstate pipelines; and increased the LDCs' risk of bypass by individual customers located close to the pipelines' facilities.

Q. How have these changes affected natural gas distribution companies?

A. The LDC operating environment has become more complex and more competitive, and the decision-making timeframe has been shortened—all translating into increased risk for these companies, including NW Natural. As the complexity and competitiveness of

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the natural gas industry increases, these risks can be expected to increase further. In addition to the continuing effects of industry unbundling and restructuring, LDCs continue to face direct competition from alternate energy sources. LDCs recently have also experienced the negative effects on industrial demand of a slowing economy as well as warmer-than-normal weather conditions, both of which have negatively affected cash flow. Although some improvement is expected as the economy strengthens, financial results for most companies are not robust.

Q. Is NW Natural affected by these same market uncertainties and concerns?

A. Yes. To varying extents, all utilities are affected by market uncertainties and the changes affecting the energy industry. In the state of Oregon, NW Natural faces competition in retaining existing customers and obtaining new customers; risk of loss of customers or deliveries in economically sensitive industries such as paper and computer chip manufacturing; and risk of margin loss due to customers' migrations from firm to interruptible or from sales to transportation service.

Q. Have you reviewed the Company's current Weather Adjusted Rate Mechanism (WARM) and decoupling mechanism?

A. Yes. The Company's WARM and decoupling mechanism provide partial mitigation for the increasing volatility in the natural gas industry that has developed in recent years. They represent an improved mechanism for recovering at least a portion of NW Natural's fixed distribution costs, without strict dependence on variable sales volumes. This approach is reasonable, and it parallels similar methods for recovering utility fixed costs in other portions of the industry. However, I note that the mechanisms do not protect the

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Company from the effects of customer loss or low customer growth, which are continuing threats to NW Natural. I also note that decoupling and weather normalization mechanisms have become quite standard within the LDC industry since NW Natural's mechanisms were adopted.

Thus, while the overall effects of the Company's WARM and decoupling mechanism are beneficial, relative to more general capital market uncertainties, and other larger potential effects on NW Natural's operating profits, the mechanisms do not measurably reduce the Company's overall investment risk compared to other typical LDCs. And, these mechanisms do not address at all some of the other major risks faced by NW Natural, such as its environmental cost risk that is discussed in the Company witness David H. Anderson's direct testimony and the risk of customer loss from heat load competition and poor economic conditions. The mechanisms' potential risk reduction would not justify setting my ROE recommendation below the ROE requested by the Company.

Q. Have you reviewed the Company's proposed changes to rate design?

A. Yes. My understanding is that the Company's proposed rate design will apply primarily to its residential customer class, and that it will continue to provide a basic separation between the Company's recovery of fixed costs and usage per customer. I also understand that the Company's proposed rate design will not be fully implemented until after a transition period, and that until the rate design is fully implemented, WARM and the decoupling mechanism will apply to the residential class.

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It appears that this new rate design will continue to provide similar beneficial effects as WARM and decoupling. However, similar to my conclusions with respect to WARM and decoupling, I conclude that, relative to more general capital market uncertainties and other larger potential effects on NW Natural's operating profits, the mechanisms do not measurably reduce the Company's overall investment risk compared to other typical LDCs. Like WARM and decoupling, this proposed rate design does not address many of the major risks faced by NW Natural, and mostly continues a separation between fixed cost recovery and per-customer usage that has become more standard in the industry in recent years.

Q. How do capital market concerns affect the cost of equity capital?

A. As I discussed previously in Section III, equity investors respond to changing assessments of risk and financial prospects by changing the price they are willing to pay for a given security. When the risk perceptions increase or financial prospects decline, investors refuse to pay the previously existing market price for a company's securities and market supply and demand forces then establish a new lower price. The lower market price typically translates into a higher cost of capital through a higher dividend yield requirement, as well as the potential for increased capital gains if prospects improve. In addition to market losses for prior shareholders, the higher cost of capital is transmitted directly to the company by the need to issue more shares to raise any given amount of capital for future investment. The additional shares also impose additional future dividend requirements and reduce future earnings per share growth prospects.

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IV. ESTIMATING THE COST OF EQUITY

Q. What is the purpose of this section of your testimony?

A. The purpose of this section is to present a general definition of the cost of equity and to compare the strengths and weaknesses of several of the most widely used methods for estimating the cost of equity. Estimating the cost of equity is fundamentally a matter of informed judgment. The various models provide a concrete link to actual capital market data and assist with defining the various relationships that underlie the ROE estimation process.

Q. Please define the term "cost of equity capital" and provide an overview of the cost estimation process.

A. The cost of equity capital is the profit or rate of return that equity investors expect to receive. In concept it is no different than the cost of debt or the cost of preferred stock. The cost of equity is the rate of return that common stockholders expect, just as interest on bonds and dividends on preferred stock are the returns that investors in those securities expect. Equity investors expect a return on their capital commensurate with the risks they take and consistent with returns that might be available from other similar investments. Unlike returns from debt and preferred stocks, however, the equity return is not directly observable in advance and, therefore, it must be estimated or inferred from capital market data and trading activity.

An example helps to illustrate the cost of equity concept. Assume that an investor buys a share of common stock for $20 per share. If the stock's expected dividend during the coming year is $1.05, the expected dividend yield is 5.25 percent

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($1.05 / $20 = 5.25%). If the stock price is also expected to increase to $21.25 after one year, this $1.25 expected gain adds an additional 6.25 percent to the expected total rate of return ($1.25 / $20 = 6.25%). Therefore, buying the stock at $20 per share, the investor expects a total return of 11.5 percent: 5.25 percent dividend yield, plus 6.25 percent price appreciation. In this example, the total expected rate of return at 11.5 percent is the appropriate measure of the cost of equity capital, because it is this rate of return that caused the investor to commit the $20 of equity capital in the first place. If the stock were riskier, or if expected returns from other investments were higher, investors would have required a higher rate of return from the stock, which would have resulted in a lower initial purchase price in market trading.

Each day market rates of return and prices change to reflect new investor expectations and requirements. For example, when interest rates on bonds and savings accounts rise, utility stock prices usually fall. This is true, at least in part, because higher interest rates on these alternative investments make utility stocks relatively less attractive, which causes utility stock prices to decline in market trading. This competitive market adjustment process is quick and continuous, so that market prices generally reflect investor expectations and the relative attractiveness of one investment versus another. In this context, to estimate the cost of equity one must apply informed judgment about the relative risk of the company in question and knowledge about the risk and expected rate of return characteristics of other available investments as well.

Q. How does the market account for risk differences among the various investments?

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A. Risk-return tradeoffs among capital market investments have been the subject of extensive financial research. Literally dozens of textbooks and hundreds of academic articles have addressed the issue. Generally, such research confirms the common sense conclusion that investors will take additional risks only if they expect to receive a higher rate of return. Empirical tests consistently show that returns from low risk securities, such as U.S. Treasury bills, are the lowest; that returns from longer-term Treasury bonds and corporate bonds are increasingly higher as risks increase; and generally, returns from common stocks and other more risky investments are even higher. These observations provide a sound theoretical foundation for both the DCF and risk premium methods for estimating the cost of equity capital. These methods attempt to capture the well-founded risk-return principle and explicitly measure investors' rate of return requirements.

Q. Can you illustrate the capital market risk-return principle that you just described?

A. Yes. The following graph depicts the risk-return relationship that has become widely known as the Capital Market Line (CML). The CML offers a graphical representation of the capital market risk-return principle. The graph is not meant to illustrate the actual expected rate of return for any particular investment, but merely to illustrate in a general way the risk-return relationship.

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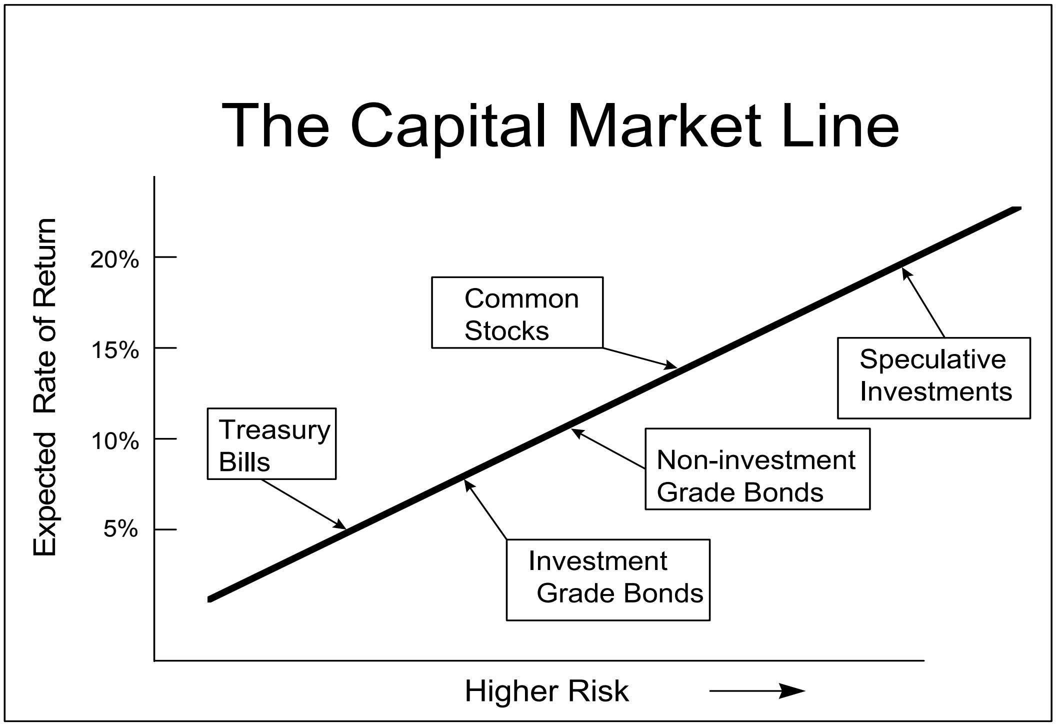
Risk-Return Tradeoffs



As a continuum, the CML can be viewed as an available opportunity set for investors. Those investors with low risk tolerance or investment objectives that mandate a low risk profile should invest in assets depicted in the lower left-hand portion of the graph. Investments in this area, such as Treasury bills and short-maturity, high quality corporate commercial paper, offer a high degree of investor certainty. In nominal terms (before considering the potential effects of inflation), such assets are virtually risk-free.

Investment risks increase as one moves up and to the right along the CML. A higher degree of uncertainty exists about the level of investment value at any point in

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time and about the level of income payments that may be received. Among these investments, long-term bonds and preferred stocks, which offer priority claims to assets and income payments, are relatively low risk, but they are not risk-free. The market value of long-term bonds, even those issued by the U.S. Treasury, often fluctuates widely when government policies or other factors cause interest rates to change.

Farther up the CML continuum, common stocks are exposed to even more risk, depending on the nature of the underlying business and the financial strength of the issuing corporation. Common stock risks include market-wide factors, such as general changes in capital costs, as well as industry and company-specific elements that may add further to the volatility of a given company's performance. As I will illustrate in my risk premium analysis, common stocks typically are more volatile (have higher risk) than high quality bond investments and, therefore, they reside above and to the right of bonds on the CML graph. Other more speculative investments, such as stock options and commodity futures contracts, offer even higher risks (and higher potential returns). The CML's depiction of the risk-return tradeoffs available in the capital markets provides a useful perspective for estimating investors' required rates of return.

Q. How is the fair rate of return in the regulatory process related to the estimated cost of equity capital?

A. The regulatory process is guided by fair rate of return principles established in the U.S. Supreme Court cases, *Bluefield Waterworks* and *Hope Natural Gas*:

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal

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to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. *Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-693 (1923).

From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

Based on these principles, the fair rate of return should closely parallel investor opportunity costs as discussed above. If a utility earns its market cost of equity, neither its stockholders nor its customers should be disadvantaged.

Q. What specific methods and capital market data are used to evaluate the cost of equity?

A. Techniques for estimating the cost of equity normally fall into three groups: comparable earnings methods, risk premium methods, and DCF methods. Comparable earnings methods have evolved over time. The original comparable earnings methods were

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based on book accounting returns. This approach developed ROE estimates by reviewing accounting returns for unregulated companies thought to have risks similar to those of the regulated company in question. These methods generally have been rejected because they assume that the unregulated group is earning its actual cost of capital, and that its equity book value is the same as its market value. In most situations these assumptions are not valid, and, therefore, accounting-based methods generally do not provide reliable cost of equity estimates.

More recent comparable earnings methods are based on historical stock market returns rather than book accounting returns. While this approach has some merit, it too has been criticized because there can be no assurance that historical returns actually reflect current or future market requirements. Also, in practical application, earned market returns tend to fluctuate widely from year-to-year. For these reasons, a current cost of equity estimate (based on the DCF model or a risk premium analysis) is usually required.

The second set of estimation techniques is grouped under the heading of risk premium methods. These methods begin with currently observable market returns, such as yields on government or corporate bonds, and add an increment to account for the additional equity risk. The capital asset pricing model (CAPM) and arbitrage pricing theory (APT) model are more sophisticated risk premium approaches. The CAPM and APT methods estimate the cost of equity directly by combining the "risk-free" government bond rate with explicit risk measures to determine the risk premium required by the market. Although these methods are widely used in academic cost of capital

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research, their additional data requirements and their potentially questionable underlying assumptions have detracted from their use in most regulatory jurisdictions. Also, recent anomalies in the market for U.S. Treasury securities, which are used as a proxy for the CAPM "risk-free rate," have raised further questions about that model's current applicability. The straightforward bond yield plus risk premium approach provides a useful parallel for the DCF model, however, and it assures consistency with other capital market data in estimates of the cost of equity.

The DCF model is the most widely used approach in regulatory proceedings. Like the risk premium method, the DCF model has a sound basis in theory, and many argue that it has the additional advantage of simplicity. I will describe the DCF model in detail below, but in essence its estimate of ROE is simply the sum of the expected dividend yield and the expected long-term dividend (or price) growth rate. While dividend yields are readily available, long-term growth estimates are more difficult to obtain. Because the constant growth DCF model requires very long-term growth estimates (technically to infinity), some argue that its application is subjective and that more explicit multistage growth DCF models are preferred. In the final analysis, ROE estimates are subjective and should be based on sound, informed judgment. To accomplish this task, I apply several versions of the DCF and risk premium models, which results in an ROE range that I believe brackets the fair cost of equity capital.

Q. Please explain the DCF model.

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A. The DCF model is predicated on the concept, or in fact the definition, that a stock's price represents the present value of all future cash flows expected from the stock. In the most general form, the model is expressed in the following formula:

$$P_0 = D_1/(1+k) + D_2/(1+k)^2 + ... + D_\infty/(1+k)^\infty \qquad (1)$$

where P_0 is today's stock price; D_1, D_2, etc. are all expected future dividends and k is the discount rate, or the investor's required rate of return on equity. Equation (1) is a routine present value calculation with the difficult data requirement of estimating all future dividends.[5]

Under the additional assumption that dividends are expected to grow at a constant rate "g," equation (1) can be solved for k and rearranged into the simple form:

$$k = D_1/P_0 + g \qquad (2)$$

Equation (2) is the familiar constant growth DCF model for cost of equity estimation, where D_1/P_0 is the expected dividend yield and g is the long-term expected dividend growth rate.

Under circumstances when growth rates are expected to fluctuate or when future growth rates are highly uncertain, the constant growth model may be questionable, and explicit changing growth estimates may be required. Although the DCF model itself is still valid (equation (1) is mathematically correct), under the assumption of fluctuating growth the simplified form of the model must be modified to capture market expectations accurately.

5 As a practical matter, the present value of dividends expected in the very distant future is typically insignificant, and operationally the DCF model can be reasonably estimated by discounting a finite dividend stream, or with the assumption that the stock will be sold for some estimated price in the foreseeable future.

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Q. How is the DCF model applied when the growth rates fluctuate?

A. When growth rates are expected to fluctuate, the more general version of the model represented in equation (1) should be solved explicitly over a finite "transition" period while uncertainty prevails. The constant growth version of the model can then be applied after the transition period, under the assumption that more stable conditions will prevail in the future. There are two alternatives for dealing with the nonconstant growth transition period.

Under the "Market Price" version of the DCF model, equation (1) is written in a slightly different form:

$$P_0 = D_1/(1+k) + D_2/(1+k)^2 + ... + P_T/(1+k)^T \qquad (3)$$

Where the variables are the same as in equation (1) except that P_T is the estimated Market Price at the end of the transition period T. Under the assumption that constant growth resumes after the transition period, the price P_T is then expected to be based on constant growth assumptions. As with the general form of the DCF model in equation (1), in the Market Price approach the current stock price (P_0) is the present value of expected cash inflows, but the cash flows are comprised of dividends and an ultimate selling price for the stock. The estimated cost of equity, k, is just the rate of return that investors would expect if they bought the stock at today's price, held it, and received dividends through the transition period (until period T), and then sold it for price P_T.

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Under the "Multistage" growth DCF approach, equation (1) is expanded to incorporate two or more growth rate periods, with the assumption that a permanent constant growth rate can be estimated for some point in the future:

$$P_0 = D_0(1+g_1)/(1+k) + \dots + D_0(1+g_2)^n/(1+k)^n + \dots + D_0(1+g_T)^{(T+1)}/(k-g_T) \qquad (4)$$

where the variables are the same as in equation (1), but g_1 represents the growth rate for the first period, g_2 for a second period, and g_T for the period from year T (the end of the transition period) to infinity. The first two growth rates are estimates of fluctuating growth over "n" years (typically 5 or 10 years) and g_T is a constant growth rate assumed to prevail forever after year T.

Although less convenient for exposition purposes, the nonconstant growth models are based on the same valid capital market assumptions as the constant growth version. The nonconstant growth approach simply requires more explicit data inputs and more work to solve for the discount rate, k. Fortunately, the required data are generally available from investment and economic forecasting services, and computer algorithms can easily produce the required solutions. Both constant and nonconstant growth DCF analyses are presented in the following section.

Q. Please explain the risk premium methodology.

A. Risk premium methods are based on the assumption that equity securities are riskier than debt and, therefore, that equity investors require a higher rate of return. This basic premise is well supported by legal and economic distinctions between debt and equity securities, and it is widely accepted as a fundamental capital market principle. For example, debt holders' claims to the earnings and assets have priority over all claims of

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equity investors. The contractual interest on mortgage debt generally must be paid in full before any dividends can be paid to shareholders, and secured mortgage claims must be fully satisfied before any assets can be distributed to shareholders in bankruptcy. Also, the guaranteed, fixed-income nature of interest payments on debt makes year-to-year returns from bonds typically more stable than capital gains and dividend payments on stocks. All these factors support the proposition that stockholders are exposed to more risk and that shareholders should reasonably expect a positive equity risk premium.

Q. Are risk premium estimates of the cost of equity consistent with other current capital market costs?

A. Yes. The risk premium approach is generally useful because it is founded on current market interest rates, which are directly observable. Under normal market conditions, this feature assures that risk premium estimates of the cost of equity begin with a sound basis, which is tied directly to current capital market costs.

Q. Is there similar consensus about how risk premium data should be employed?

A. No. In regulatory practice, there is often considerable debate about how risk premium data should be interpreted and used. Since the analyst's basic task is to gauge investors' required returns on long-term investments, some argue that the estimated equity spread should be based on the longest possible time period. Others argue that market relationships between debt and equity from several decades ago are irrelevant and that recent debt-equity observations should be given more weight in estimating investor requirements. There is no consensus on this issue. Since analysts cannot

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observe or measure investors' actual expectations, it is not possible to know exactly how such expectations are formed or, therefore, exactly what time period is most appropriate in a risk premium analysis.

The important question to answer is the following: "What rate of return should equity investors reasonably expect relative to returns currently available from long-term bonds?" The risk premium studies and analyses I discuss in Section V address this question. My risk premium analysis is based on an intermediate position that avoids some of the problems and concerns that have been expressed about both very long and very short periods of analysis with the risk premium model.

Q. Please explain why you have not provided ROE estimates based on the CAPM.

A. I have not included a CAPM estimate in his case because, under current market conditions, the CAPM does not provide reliable estimates of the cost of equity. This situation is caused by the U.S. Government's intervention in the credit markets and the resulting artificially low U.S. Treasury bond interest rates that have resulted, as well as the recent market turmoil's effects on the CAPM's other required inputs.

The CAPM is based on three principal inputs:

1) the risk-free interest rate (R_f);

2) the expected market risk premium for stocks relative to the risk-free rate $E(R_m) - R_f$; and

3) a measure of market-related, or nondiversifiable, risk (β or beta).

The CAPM estimate of ROE is then calculated as:

$$ROE = R_f + \beta[E(R_m) - R_f]$$

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The market data discussed previously in Section II of this testimony show that, under present market conditions, potentially all three of the CAPM's principal inputs tend to understate ROE. The risk-free rate, R_f, is understated because, due to governmental credit market policies and investors' increased risk aversion, the U.S. Treasury rates used for R_f are artificially low. The second input, the expected market risk premium $[E(R_m) – R_f]$, when based on historical data, may also be understated because such data cannot reflect the heighted investor risk aversion that has resulted from the financial crisis. Finally, utility beta coefficients have declined because until recently utility stocks had far underperformed relative to the broader market index during the recent stock market recovery. All these factors indicate that CAPM estimates of ROE for utilities are currently understated. For this reason, in the present case, I rely on the DCF and other risk premium models to estimate the cost of equity for NW Natural.

Q. Please summarize your discussion of cost of equity estimation techniques.

A. Estimating the cost of equity is a controversial issue in utility ratemaking. Because actual investor requirements are not directly observable, analysts have developed several methods to assist in the process. The comparable earnings method is the oldest but perhaps least reliable. Its use of accounting rates of return, or even historical market returns, may or may not reflect current investor requirements. Differences in accounting methods among companies and issues of comparability also detract from this approach.

The DCF and market-based risk premium methods are more widely accepted in regulatory practice. Under normal market conditions, a combination of the DCF model and a risk premium analysis provides the most reliable approach. While the DCF model

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requires judgment about future growth rates, the dividend yield portion of the model is straightforward, and the model's results are generally consistent with actual capital market behavior. Given current economic conditions, in the present case, I rely principally upon the DCF model.

V. COST OF EQUITY CAPITAL FOR NW NATURAL

Q. What is the purpose of this section of your testimony?

A. The purpose of this section is to present my quantitative studies of the cost of equity capital for NW Natural and to discuss the details of my results.

Q. How are your studies organized?

A. In the first part of my analysis, I apply the DCF model to my comparable group of natural gas LDCs and combination gas and electric utilities. The comparable group includes companies from Value Line's Gas Utility group as well as those combination companies covered by Value Line that provide both gas and electric utility services. To ensure that non-regulated activities are not a significant influence, I also applied an additional selection filter that requires each company to obtain at least 70 percent of its revenues from regulated utility sales. This filter results in a 14-company group that has average regulated utility sales of 86 percent (see *NWN/501, Hadaway/1*). Under present market circumstances, I believe this combination group provides the most reasonable estimate of NW Natural's market cost of equity capital.

In the second part of my analysis, I developed risk premium estimates of ROE. I present my risk premium studies in *NWN/505, Hadaway/1-3*. As discussed previously, given current economic conditions and the artificially low interest rates that have resulted

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from the government's expansionary monetary policies, I discount the risk premium results.

A. <u>Discounted Cash Flow Analysis</u>.

Q. Please summarize your DCF results?

A. The results of my DCF studies are presented in *NWN/504, Hadaway/1*, page 1. The comparable group DCF results support an ROE range of 9.6 percent-10.3 percent.

My DCF analysis is based on three versions of the DCF model. In the first version of the DCF model, I use the constant growth format with long-term expected growth based on analysts' estimates of five-year utility earnings growth. While I continue to endorse a longer-term growth estimation approach based on growth in overall gross domestic product, I show the analyst growth rate DCF results because this is the approach that has traditionally been used by many regulators. In the second version of the DCF model, for the estimated growth rate, I use only the long-term estimated GDP growth rate. Finally, in the third version of the DCF model, I use a two-stage growth approach, with stage one growth based on Value Line's three-to-five-year dividend projections and stage two growth based on long-term projected GDP growth. The dividend yields in all three of the models are from Value Line's projections of dividends for the coming year and stock prices are from the three-month average for the months that correspond to the Value Line editions from which the underlying financial data are taken.

Q. Why do you believe the long-term GDP growth rate should be used to estimate long-term growth expectations in the DCF model?

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A. Growth in nominal GDP (real GDP plus inflation) is the most general measure of economic growth in the U.S. economy. For long time periods, such as those used in the Morningstar/Ibbotson Associates rate of return data, nominal GDP growth has averaged between five percent and eight percent per year. From this observation, Professors Brigham and Houston offer the following observation concerning the appropriate long-term growth rate in the DCF Model:

> Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation). On this basis, one might expect the dividend of an average, or "normal," company to grow at a rate of 5 to 8 percent a year.[6]

Other academic research on corporate growth rates offers similar conclusions about GDP growth as well as concerns about the long-term adequacy of analysts' forecasts:

> Our estimated median growth rate is reasonable when compared to the overall economy's growth rate. On average over the sample period, the median growth rate over 10 years for income before extraordinary items is about 10 percent for all firms. ... After deducting the dividend yield (the median yield is 2.5 percent per year), as well as inflation (which averages 4 percent per year over the sample period), the growth in real income before extraordinary items is roughly 3.5 percent per year. This is consistent with the historical growth rate in real gross domestic product, which has averaged about 3.4 percent per year over the period 1950-1998.[7]

6 Brigham, Eugene F. and Joel F. Houston, *Fundamentals of Financial Management* at 298 (11th Ed. 2007).
7 Louis K. C. Chan, Jason Karceski, and Josef Lakonishok, *The Journal of Finance*, "The Level and Persistence of Growth Rates" at 649 (Apr. 2003).

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> IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons, however, there is little forecastability in earnings, and analysts' estimates tend to be overly optimistic. … On the whole, the absence of predictability in growth fits in with the economic intuition that competitive pressures ultimately work to correct excessively high or excessively low profitability growth.[8]

These findings support the notion that long-term growth expectations are more closely predicted by broader measures of economic growth than by near-term analysts' estimates. Especially for the very long-term growth rate requirements of the DCF model, the growth in nominal GDP should be considered an important input.

Q. How did you estimate the expected long-run GDP growth rate?

A. I developed my long-term GDP growth forecast from nominal GDP data contained in the St. Louis Federal Reserve Bank data base. Those data for the period 1950 through 2010 are summarized in *NWN/503, Hadaway/1*. As shown at the bottom of that exhibit, the overall average for the 60-year period was 6.7 percent. The data also show, however, that after the early 1980s, lower inflation has resulted in lower nominal GDP growth. For this reason I gave more weight to the more recent years in my GDP forecast. My forecast is a weighted average that includes the most recent 10 years six times, the most recent 20 years five times, etc., so that the more recent experience receives much more weight than the data from the earlier periods. Based on this approach, the forecast for future GDP growth is 5.8 percent, which is 90 basis points lower than the long-term average historical GDP growth rate.

8 *Id.* at 683.

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Q. Why do you believe your forecast of GDP growth based on long-term historical data is appropriate in the DCF model?

A. There are at least three reasons. First, most econometric forecasts are derived from the trending of historical data or the use of weighted averages. This is the approach I have taken in *NWN/503, Hadaway/1*. The long-run historical average GDP growth rate is 6.7 percent, but my estimate of long-term expected growth is lower, at 5.8 percent. My forecast is lower because my forecasting method gives much more weight to the more recent time periods.

Second, some currently lower GDP growth forecasts likely understate very long growth rate expectations that are required in the DCF model. Many of those forecasts are currently low because they are based on the assumption of permanently low inflation rates, in the range of two percent. As shown in *NWN/503, Hadaway/1*, the periodic average inflation rate (measured by CPI) has been over three percent in all but the most recent 10- and 20- year periods. Also, as shown in *NWN/503, Hadaway/1*, from December 2008 to December 2009, even with the continuing effects of the economic recession, the CPI increased by 2.8 percent and in 2007 the CPI increased by over four percent. Use of long-term inflation rates of two percent or less to estimate long-term nominal growth in the DCF model is not consistent with reasonable long-term expectations for the U.S. economy or investors' long-term experience.

Finally, the current economic turmoil makes it even more important to consider longer-term economic data in the growth rate estimate. As discussed in the previous section, current near-term forecasts for both real GDP and inflation are severely

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depressed. The longer-term forecasts of professional economists are also depressed. Under these circumstances, a longer-term balance is even more important. For all these reasons, while I am also presenting other growth rate approaches based on analysts' estimates in this testimony, I believe it is appropriate also to consider long-term GDP growth in estimating the DCF growth rate.

B. <u>Risk Premium Analysis</u>.

Q. What are the results of your equity risk premium studies?

A. The details of my equity risk premium studies are shown in *NWN/505, Hadaway/1-3*. These studies indicate an ROE range of 9.52 percent to 9.53 percent. Such results reflect the sharp drop in interest rates that has occurred for high quality borrowers. The Federal Reserve System's continuing expansionary policies have provided renewed liquidity in the credit markets that is reflected in these lower yields. These models, however, cannot capture the current equity market volatility that is occurring or the increased level of risk aversion that exists among equity investors. These circumstances indicate that the cost of equity has not declined to the extent that interest rates on utility debt have dropped or to the extent indicated by the equity risk premium analysis.

Q. How are your equity risk premium studies structured?

A. My equity risk premium studies are divided into two parts. First, I compare gas utility authorized ROEs for the period 1980-2010 to contemporaneous long-term utility interest rates. The differences between the average authorized ROEs and the average interest rate for the year is the indicated equity risk premium. I then add the indicated equity risk

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premium to the forecasted and current single-A utility bond interest rate to estimate ROE. Because there is a strong inverse relationship between equity risk premiums and interest rates (when interest rates are high, risk premiums are low and vice versa), further analysis is required to estimate the current equity risk premium level.

The inverse relationship between equity risk premiums and interest rate levels is well documented in numerous, well-respected academic studies. These studies typically use regression analysis or other statistical methods to predict or measure the equity risk premium relationship under varying interest rate conditions. At *NWN/505, Hadaway/3*, I provide regression analyses of the allowed annual equity risk premiums relative to interest rate levels. The negative and statistically significant regression coefficients confirm the inverse relationship between equity risk premiums and interest rates. This means that when interest rates rise by one percentage point, the cost of equity increases, but by a smaller amount. Similarly, when interest rates decline by one percentage point, the cost of equity declines by less than one percentage point. I use this negative interest rate change coefficient in conjunction with current and forecasted interest rates to establish the appropriate ROE.

Q. Can you illustrate the inverse relationship between equity risk premiums and interest rates without using the statistical analysis described above?

A. Yes. Statistical analysis is often used, especially in academic research, to substantiate certain economic and financial relationships. For equity risk premium analysis, however, the fundamental issue can be observed by simply averaging the data for various time periods without further statistical analysis. The data in Table 3 below show average

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utility bond yields and equity risk premiums for each non-overlapping, five-year period between 1980 and 2010.

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Table 3
Average Five-Year Utility Bond Yields and Equity Risk Premiums
(1980-2010)

Period	Average Utility Bond Interest Rate	Average Equity Risk Premium
1980-1985	13.96%	1.06%
1986-1990	9.86%	3.06%
1991-1995	8.31%	3.41%
1996-2000	7.61%	3.30%
2001-2005	6.75%	4.06%
2006-2010	6.13%	4.13%

Source: *Exhibit NWN/500, Hadaway/5*, page 1.

These data show that equity risk premiums have consistently increased as interest rates have declined, and that they were lower when interest rates were high. This result is a market-based reflection, which shows that required rates of return in the stock market do not move in lockstep with changes in interest rates. Because utilities must compete with other types of equity investments for capital, the ROE for utilities does not change by as much as the observed changes in interest rates. Arguments that unadjusted, long-term average risk premiums can be used with current, historically low interest rates to estimate ROE are mistaken. That approach to equity risk premium analysis will consistently understate the required rate of return.

VI. <u>CONCLUSION</u>

Q. Please summarize the results of your cost of equity analysis.

A. The results of my analysis are presented in Table 4:

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Table 4
Summary of Cost of Equity Estimates

DCF Analysis (see Exhibit NWN/500, Hadaway/4)	Indicated Cost
Constant Growth Model (Analysts' Growth)	9.6%-10.0%
Constant Growth Model (GDP Growth)	10.2%-10.3%
Two-Stage Growth Model	10.0%-10.1%
Indicated DCF Range	9.6%-10.3%
Equity Risk Premium Analysis (see Exhibit NWN/500, Hadaway/5)	
Forecast Utility Yield + Equity Risk Premium	
Equity Risk Premium ROE (4.54%+ 4.98%)	9.52%
Recent Utility Yield + Equity Risk Premium	
Equity Risk Premium ROE (4.56% + 4.97%)	9.53%
NW Natural Fair Cost of Equity Capital	10.3%

Q. How should these results be interpreted to determine the fair cost of equity for NW Natural?

A. Based on my DCF and my review of current market conditions, conditions in the gas utility industry, and factors specific to NW Natural, I believe that the Company's 10.3 percent requested ROE is reasonable and should be applied in the present case.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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NW Natural

Exhibits of Samuel Hadaway

RATE OF RETURN ON EQUITY
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EXHIBITS 501-506 – RATE OF RETURN ON EQUITY

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Northwest Natural Gas Co.
Comparable Company Fundamental Characteristics

		(1)	(2)		(3)		
					Capital Structure (2010)		
		% Regulated	Credit Rating		Common Equity	Long-Term Debt	Preferred Stock
No.	Company	Revenue	S&P	Moody's	Ratio	Ratio	Ratio
1	Alliant Energy Co.	92.4%	A-/BBB+	A2/A3	49.5%	46.3%	4.2%
2	Black Hills Corp	85.7%	BBB+	A3	48.1%	51.9%	0.0%
3	Con. Edison	86.2%	A-	A3/Baa1	50.9%	49.1%	0.0%
4	DTE Energy Co.	77.6%	A	A2	48.7%	51.3%	0.0%
5	N.W. Nat'l Gas	94.2%	A+	A1	53.5%	46.5%	0.0%
6	NiSource Inc.	87.5%	BBB-	Baa2	45.3%	54.7%	0.0%
7	Piedmont Nat'l	100.0%	A	A3	59.0%	41.0%	0.0%
8	Pepco Holdings	71.0%	A	A3	51.0%	49.0%	0.0%
9	SCANA Corp.	72.9%	A-	A3	47.1%	52.9%	0.0%
10	Sempra Energy	75.7%	A+	Aa3	49.6%	49.4%	1.0%
11	Southwest Gas	85.5%	BBB	Baa2	50.9%	49.1%	0.0%
12	Vectren Corp.	73.4%	A-	A2	50.1%	49.9%	0.0%
13	Wisconsin Energy	99.1%	A-	A1	49.0%	50.6%	0.4%
14	Xcel Energy Inc.	99.3%	A	A3	46.3%	53.1%	0.6%
	Average	85.7%	A-	A2/A3	49.9%	49.6%	0.4%

Column Sources:
(1) Most recent company 10-Ks.
(2) AUS Utility Reports, Nov 2011.
(3) Value Line Investment Survey, Electric Utility (East), Aug 26, 2011; (Central), Sep 23, 2011; (West), Nov 4, 2011;
Natural Gas Utility, Sep 9, 2011.

Northwest Natural Gas Co.
Historical Capital Market Costs

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Prime Rate	6.9%	4.7%	4.1%	4.3%	6.2%	8.0%	8.1%	5.1%	3.3%	3.3%
Consumer Price Index	1.6%	2.5%	2.0%	3.3%	3.3%	2.5%	4.1%	0.0%	2.8%	1.4%
Long-Term Treasuries	5.5%	5.4%	5.0%	5.1%	4.7%	5.0%	4.8%	4.3%	4.1%	4.3%
Moody's Avg Utility Debt	7.7%	7.5%	6.6%	6.2%	5.7%	6.1%	6.1%	6.7%	6.3%	5.6%
Moody's A Utility Debt	7.8%	7.4%	6.6%	6.2%	5.7%	6.1%	6.1%	6.5%	6.0%	5.5%

SOURCES:
Prime Interest Rate - Federal Reserve Bank of St. Louis website
Consumer Price Index For All Urban Consumers: All Items (Seasonally Adjusted, December to December) - Federal Reserve Bank of St. Louis website
Long-Term Treasuries - Federal Reserve Bank of St. Louis website; 30-year Treasury bonds 2001 and 2007-2010; 20-year Treasury bonds 2002-2006
Moody's Average Utility Debt - Moody's (Mergent) Bond Record
Moody's A Utility Debt - Moody's (Mergent) Bond Record

Northwest Natural Gas Co.
Long-Term Interest Rate Trends

Month	Single-A Utility Rate	30-Year Treasury Rate	Single-A Utility Spread
Jan-09	6.39	3.13	3.26
Feb-09	6.30	3.59	2.71
Mar-09	6.42	3.64	2.78
Apr-09	6.48	3.76	2.72
May-09	6.49	4.23	2.26
Jun-09	6.20	4.52	1.68
Jul-09	5.97	4.41	1.56
Aug-09	5.71	4.37	1.34
Sep-09	5.53	4.19	1.34
Oct-09	5.55	4.19	1.36
Nov-09	5.64	4.31	1.33
Dec-09	5.79	4.49	1.30
Jan-10	5.77	4.60	1.17
Feb-10	5.87	4.62	1.25
Mar-10	5.84	4.64	1.20
Apr-10	5.81	4.69	1.12
May-10	5.50	4.29	1.21
Jun-10	5.46	4.13	1.33
Jul-10	5.26	3.99	1.27
Aug-10	5.01	3.80	1.21
Sep-10	5.01	3.77	1.24
Oct-10	5.10	3.87	1.23
Nov-10	5.37	4.19	1.18
Dec-10	5.56	4.42	1.14
Jan-11	5.57	4.52	1.05
Feb-11	5.68	4.65	1.03
Mar-11	5.56	4.51	1.05
Apr-11	5.55	4.50	1.05
May-11	5.32	4.29	1.03
Jun-11	5.26	4.23	1.03
Jul-11	5.27	4.27	1.00
Aug-11	4.69	3.65	1.04
Sep-11	4.48	3.18	1.30
Oct-11	4.52	3.13	1.39
3-Mo Avg	**4.56**	**3.32**	**1.24**
12-Mo Avg	**5.24**	**4.13**	**1.11**

Sources: Mergent Bond Record (Utility Rates); www.federalreserve.gov (Treasury Rates).

Three month average is for August 2011-October 2011.

Twelve month average is for November 2010-October 2011.

Economic Indicators

Seasonally Adjusted Annual Rates — Dollar Figures in Billions

2010	E2011	E2012	Annual % Change 2010	Annual % Change E2011	Annual % Change E2012		2011 Q1	2011 RQ2	2011 EQ3	2011 EQ4	E2012 Q1	E2012 Q2	E2012 Q3	E2012 Q4
						Gross Domestic Product								
$14,526.6	$15,097.4	$15,541.2	4.2	3.9	2.9	GDP (current dollars)	$14,867.8	$15,012.8	$15,192.9	$15,316.1	$15,422.4	$15,481.5	$15,574.9	$15,686.1
4.2	3.9	2.9	-	-	-	Annual rate of increase (%)	3.1	4.0	4.9	3.3	2.8	1.5	2.4	2.9
3.0	1.7	1.5	-	-	-	Annual rate of increase–real GDP (%)	0.4	1.3	2.4	1.5	1.3	1.3	1.3	1.7
1.2	2.2	1.4	-	-	-	Annual rate of increase–GDP deflator (%)	2.5	2.5	2.5	1.7	1.5	0.2	1.2	1.1
						***Components of Real GDP**								
$9,220.9	$9,416.7	$9,610.9	2.0	2.1	2.1	Personal consumption expenditures	$9,376.7	$9,392.7	$9,422.7	$9,474.7	$9,533.0	$9,589.5	$9,635.4	$9,685.6
2.0	2.1	2.1	-	-	-	% change	2.1	0.7	1.3	2.2	2.5	2.4	1.9	2.1
1,188.3	1,278.9	1,341.3	7.2	7.6	4.9	Durable goods	1,277.4	1,260.2	1,278.3	1,299.8	1,317.7	1,335.5	1,345.8	1,366.0
2,041.3	2,074.0	2,112.2	2.9	1.6	1.8	Nondurable goods	2,075.4	2,076.6	2,061.0	2,083.1	2,096.1	2,107.4	2,118.7	2,126.7
5,991.8	6,078.5	6,181.0	0.9	1.4	1.7	Services	6,039.1	6,067.0	6,098.2	6,109.7	6,139.5	6,169.5	6,194.9	6,220.3
1,319.2	1,438.6	1,508.7	4.4	9.1	4.9	Nonresidental fixed investment	1,378.9	1,413.2	1,462.5	1,499.9	1,493.3	1,502.4	1,509.6	1,529.6
4.4	9.1	4.9	-	-	-	% change	2.1	10.3	14.7	10.6	(1.7)	2.4	2.0	5.4
1,019.4	1,124.1	1,200.1	14.6	10.3	6.8	Producers durable equipment	1,086.9	1,103.5	1,136.2	1,169.7	1,171.2	1,189.7	1,208.5	1,231.2
321.5	314.2	325.1	(4.6)	(2.3)	3.5	Residental fixed investment	311.5	314.8	316.7	313.8	317.3	322.9	327.2	333.0
(4.6)	(2.3)	3.5	-	-	-	% change	(2.6)	4.2	2.5	(3.6)	4.4	7.4	5.4	7.2
58.8	34.7	37.2	-	-	-	Net change in business inventories	49.1	39.1	28.3	22.4	31.5	38.7	42.3	36.3
2,556.8	2,499.5	2,432.2	0.7	(2.2)	(2.7)	Gov't purchases of goods & services	2,513.9	2,508.2	2,495.0	2,480.8	2,459.4	2,438.0	2,423.0	2,408.3
1,075.9	1,055.0	1,026.4	4.5	(1.9)	(2.7)	Federal	1,053.3	1,058.3	1,053.9	1,054.5	1,042.6	1,031.1	1,020.9	1,010.9
1,487.0	1,450.7	1,411.8	(1.8)	(2.4)	(2.7)	State & local	1,466.4	1,456.1	1,447.3	1,432.9	1,423.1	1,413.1	1,407.9	1,403.1
(421.8)	(408.8)	(407.9)	-	-	-	Net exports	(424.4)	(416.4)	(391.4)	(403.0)	(401.1)	(411.4)	(413.0)	(406.4)
1,663.2	1,774.9	1,836.3	11.3	6.7	3.5	Exports	1,749.6	1,765.0	1,787.3	1,797.6	1,807.6	1,821.0	1,843.4	1,873.1
2,085.0	2,183.6	2,244.2	12.5	4.7	2.8	Imports	2,173.9	2,181.4	2,178.7	2,200.6	2,208.7	2,232.4	2,256.4	2,279.5
						****Income & Profits**								
$12,373.5	$13,009.4	$13,461.5	3.7	5.1	3.5	Personal income	$12,846.9	$12,992.6	$13,042.9	$13,155.2	$13,293.8	$13,407.6	$13,514.6	$13,629.8
11,179.7	11,610.7	11,963.6	3.6	3.9	3.0	Disposable personal income	11,481.0	11,591.5	11,632.3	11,738.2	11,841.8	11,931.3	12,001.2	12,080.3
5.3	4.9	4.7	-	-	-	Savings rate (%)	5.0	5.1	4.5	4.9	4.9	4.9	4.5	4.3
1,819.5	1,890.2	2,024.3	25.0	3.9	7.1	Corporate profits before taxes	1,877.1	1,890.6	1,906.7	1,886.4	2,032.6	2,007.6	2,023.0	2,034.1
1,408.4	1,473.2	1,559.3	19.0	4.6	5.8	Corporate profits after taxes	1,454.8	1,470.1	1,491.5	1,476.3	1,561.4	1,545.1	1,559.2	1,571.4
77.35	88.32	93.17	51.2	14.2	5.5	‡Earnings per share (S&P 500)	81.31	83.87	87.64	88.32	90.00	90.97	91.59	93.17
						†Prices & Interest Rates								
1.6	3.0	1.3	-	-	-	Consumer price index	5.2	4.1	3.1	(0.8)	1.2	0.6	2.4	1.9
0.1	0.1	0.1	-	-	-	Treasury bills	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1
3.2	2.8	2.3	-	-	-	10-yr notes	3.5	3.2	2.4	1.9	2.1	2.3	2.4	2.5
4.3	3.9	3.3	-	-	-	30-yr bonds	4.6	4.3	3.7	2.9	3.1	3.2	3.4	3.5
4.9	4.7	4.2	-	-	-	New issue rate–corporate bonds	5.1	5.0	4.5	4.0	4.1	4.2	4.3	4.3
						Other Key Indicators								
584.9	587.1	654.4	5.6	0.4	11.5	Housing starts (1,000 units SAAR)	582.3	572.3	582.4	611.3	627.6	644.4	642.7	703.1
11.6	12.6	13.5	11.1	9.0	7.5	Auto & truck sales (1,000,000 units)	13.0	12.1	12.4	12.8	13.2	13.4	13.6	13.9
9.6	9.1	9.2	-	-	-	Unemployment rate (%)	8.9	9.1	9.1	9.2	9.2	9.3	9.3	9.2
(3.0)	(5.6)	3.4	-	-	-	§U.S. dollar	(5.7)	(12.2)	1.0	21.8	5.1	(0.4)	(4.9)	(2.8)

Note: Annual changes are from prior year and quarterly changes are from prior quarter. Figures may not add to totals because of rounding. A–Advance data. P–Preliminary. E–Estimated. R–Revised.
*2005 Chain-weighted dollars. **Current dollars. ‡Trailing 4 quarters. †Average for period. §Quarterly % changes at quarterly rates. This forecast prepared by Standard & Poor's.

Northwest Natural Gas Co.
GDP Growth Rate Forecast

	Nominal GDP	% Change	GDP Price Deflator	% Change	CPI	% Change
1950	313.3		15.0		25.0	
1951	347.9	11.0%	15.9	5.6%	26.5	6.0%
1952	371.4	6.8%	16.1	1.5%	26.7	0.9%
1953	375.9	1.2%	16.2	0.8%	26.9	0.6%
1954	389.4	3.6%	16.4	0.8%	26.8	-0.4%
1955	426.0	9.4%	16.8	2.6%	26.9	0.4%
1956	448.1	5.2%	17.3	3.3%	27.6	2.8%
1957	461.5	3.0%	17.8	2.7%	28.5	3.0%
1958	485.0	5.1%	18.3	2.5%	29.0	1.8%
1959	513.2	5.8%	18.4	0.9%	29.4	1.5%
1960	523.7	2.0%	18.7	1.4%	29.8	1.4%
1961	562.6	7.4%	18.9	1.1%	30.0	0.7%
1962	593.3	5.5%	19.1	1.3%	30.4	1.2%
1963	633.5	6.8%	19.4	1.4%	30.9	1.6%
1964	675.6	6.6%	19.7	1.5%	31.3	1.2%
1965	747.5	10.6%	20.1	2.0%	31.9	1.9%
1966	806.9	7.9%	20.8	3.5%	32.9	3.4%
1967	852.7	5.7%	21.4	3.1%	34.0	3.3%
1968	936.2	9.8%	22.4	4.6%	35.6	4.7%
1969	1004.5	7.3%	23.6	5.2%	37.7	5.9%
1970	1052.7	4.8%	24.7	5.0%	39.8	5.6%
1971	1151.4	9.4%	25.9	4.7%	41.1	3.3%
1972	1286.6	11.7%	27.1	4.5%	42.5	3.4%
1973	1431.8	11.3%	28.9	6.8%	46.3	8.9%
1974	1552.8	8.5%	32.0	10.7%	51.9	12.1%
1975	1713.9	10.4%	34.4	7.6%	55.6	7.1%
1976	1884.5	10.0%	36.3	5.4%	58.4	5.0%
1977	2110.8	12.0%	38.7	6.7%	62.3	6.7%
1978	2416.0	14.5%	41.5	7.3%	67.9	9.0%
1979	2659.4	10.1%	45.2	8.7%	76.9	13.3%
1980	2915.3	9.6%	49.6	9.7%	86.4	12.4%
1981	3194.7	9.6%	53.6	8.3%	94.1	8.9%
1982	3312.5	3.7%	56.4	5.2%	97.7	3.8%
1983	3688.1	11.3%	58.3	3.3%	101.4	3.8%
1984	4034.0	9.4%	60.4	3.6%	105.5	4.0%
1985	4318.7	7.1%	62.1	2.8%	109.5	3.8%
1986	4543.3	5.2%	63.5	2.3%	110.8	1.2%
1987	4883.1	7.5%	65.5	3.1%	115.6	4.3%
1988	5251.0	7.5%	67.9	3.7%	120.7	4.4%
1989	5581.7	6.3%	70.3	3.5%	126.3	4.6%
1990	5846.0	4.7%	73.2	4.2%	134.2	6.3%
1991	6092.5	4.2%	75.5	3.2%	138.2	3.0%
1992	6493.6	6.6%	77.1	2.2%	142.3	3.0%
1993	6813.8	4.9%	78.8	2.2%	146.3	2.8%
1994	7248.2	6.4%	80.5	2.1%	150.1	2.6%
1995	7542.5	4.1%	82.1	2.0%	153.9	2.5%
1996	8023.0	6.4%	83.6	1.8%	159.1	3.4%
1997	8505.7	6.0%	85.0	1.6%	161.8	1.7%
1998	9027.5	6.1%	85.9	1.1%	164.4	1.6%
1999	9607.7	6.4%	87.2	1.5%	168.8	2.7%
2000	10129.8	5.4%	89.4	2.5%	174.6	3.4%
2001	10373.1	2.4%	91.2	2.0%	177.4	1.6%
2002	10766.9	3.8%	92.8	1.8%	181.8	2.5%
2003	11416.5	6.0%	94.8	2.1%	185.5	2.0%
2004	12144.9	6.4%	97.9	3.2%	191.7	3.3%
2005	12915.6	6.3%	101.3	3.5%	198.1	3.3%
2006	13611.5	5.4%	104.2	2.9%	203.1	2.5%
2007	14291.3	5.0%	106.9	2.6%	211.4	4.1%
2008	14191.2	-0.7%	109.2	2.1%	211.3	0.0%
2009	14277.3	0.6%	109.7	0.4%	217.2	2.8%
2010	14861.0	4.1%	111.2	1.4%	220.2	1.4%
10-Year Average		3.9%		2.2%		2.4%
20-Year Average		4.8%		2.1%		2.5%
30-Year Average		5.6%		2.7%		3.2%
40-Year Average		6.9%		3.9%		4.4%
50-Year Average		7.0%		3.7%		4.1%
60-Year Average		6.7%		3.4%		3.7%
Average of Periods		5.8%		3.0%		3.4%

Source: St. Louis Federal Reserve Bank, www.research.stlouisfed.org

Northwest Natural Gas Co.
Discounted Cash Flow Analysis
Column Descriptions

Column 1: Three-month Average Price per Share (August 2011-October 2011

Column 2: Estimated 2012 Div per Share from Value Line

Column 3: Column 2 Divided by Column 1

Column 4: "Est'd '08-'10 to '14-'16" Earnings Growth Reported by Value Line

Column 5: "Next 5 Years" Company Growth Estimate as Reported by Zacks.com

Column 6: "Next 5 Years (per annum) Growth Estimate Reported by Thomson Financial Network (at Yahoo Finance)

Column 7: Average of Columns 4-6

Column 8: Column 3 Plus Column 7

Column 9: See Column 1

Column 10: See Column 2

Column 11: Column 10 Divided by Column 9

Column 12: Average of GDP Growth During the Last 10 year, 20 year, 30 year, 40 year, 50 year, and 60 year growth periods. See Schedule SCH-3

Column 13: Column 11 Plus Column 12

Column 14: Estimated 2012 Div per Share from Value Line

Column 15: Estimated 2015 Div per Share from Value Line

Column 16: (Column 15 Minus Column 14) Divided by Three

Column 17: See Column 1

Column 18: See Column 14

Column 19: Column 18 Plus Column 16

Column 20: Column 19 Plus Column 16

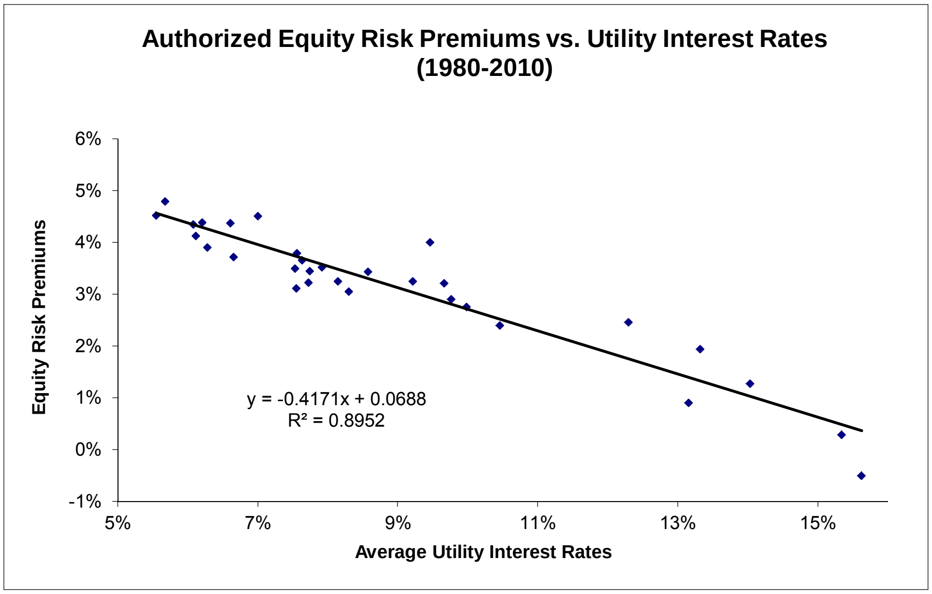
Column 21: Column 20 Plus Column 16

Column 22: Column 21 Increased by the Growth Rate Shown in Column 23

Column 23: See Column 12

Column 24: The Internal Rate of Return of the Cash Flows in Columns 17-22 along with the Dividends for the Years 6-150 Implied by the Growth Rates shown in Column 23

Northwest Natrual Gas Co.
Risk Premium Analysis
Regression Analysis & Interest Rate Change Coefficient



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.946125577
R Square	0.895153607
Adjusted R Square	0.891538214
Standard Error	0.004144593
Observations	31

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.004253103	0.004253103	247.5951145	9.71512E-16
Residual	29	0.000498152	1.71777E-05		
Total	30	0.004751255			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.06876819	0.002483473	27.69033381	2.07972E-22	0.063688918	0.073847462	0.063688918	0.073847462
X Variable 1	-0.417149936	0.026510697	-15.73515537	9.71512E-16	-0.471370399	-0.362929474	-0.471370399	-0.362929474

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SUMMARY OF QUALIFICATIONS

- Principal, Financial Analysis Consultants (FINANCO, Inc.).
- Ph.D. in Finance and Economics.
- Extensive expert witness testimony in court and before regulatory agencies.
- Management of professional research staff in academic and regulatory organizations.
- Professional presentations before executive development groups, the National Rate of Return Analysts' Forum, and the New York Society of Security Analysts.
- Financial Management Association, previously Vice President for Practitioner Services.

EDUCATION

The University of Texas at Austin
Ph.D., Finance and Econometrics
January 1975

Dissertation: *An Evaluation of the Original and Recent Variants of the Capital Asset Pricing Model*.

The University of Texas at Austin
MBA, Finance
June 1973

Thesis: *The Pricing of Risk on the New York Stock Exchange.*

Southern Methodist University
BA, Economics
June 1969

Honors program. Departmental distinction.

OTHER EXPERIENCE

University of Texas at Austin
Adjunct Associate Professor
1985-1988, 2004-Present

Corporate Financial Management, Investments, and Integrative Finance Cases.

Texas State University San Marcos
Associate Professor of Finance
1983-1984, 2003-2004

Graduate and undergraduate courses in Financial Management, Managerial Economics, and Investment Analysis.

Public Utility Commission of Texas
Chief Economist and Director of Economic Research Division
August 1980-August 1983

Lead financial witness. Supervised Commission staff in research and testimony on rate of return, financial condition, and economic analysis.

Assistant Professor of Finance
Texas Tech University
July 1978-July 1980
University of Alabama
January 1975-June 1978

Member of graduate faculty. Conducted Ph.D. seminars and directed doctoral dissertations in capital market theory. Served as consultant to industry, church and governmental organizations.

FINANCIAL AND ECONOMIC TESTIMONY IN REGULATORY PROCEEDINGS (Client in parenthesis)

Cost of Money Testimony

- Texas Public Utility Commission, Docket No. 39896, November 28, 2011, (Entergy Texas, Inc.)
- Idaho Public Utilities Commission, Case No. PAC-E-111-12, May 27, 2011 (Rocky Mountain Power/PacifiCorp).
- Maine Public Utilities Commission, Docket No. 2011-92, May 5, 2011 (Northern Utilities, Inc.)
- New Hampshire Public Utilities Commission, Docket No. DG 11-069, May 4, 2011(Northern Utilities, Inc.)
- Arizona Corporation Commission, Docket No. G-04204A-11-0158, April 8, 2011 (UNS Gas, Inc.)
- Utah Public Service Commission, Docket No. 10-035-124, January 24, 2011 (Rocky Mountain Power/PacifiCorp).
- Massachusetts Department of Public Utilities, D.P.U. 11.01 (Electric) and D.P.U. 11.02 (Gas), January 14, 2011, (Fitchburg Gas and Electric Light Company d/b/a/ Unitil)
- Wyoming Public Service Commission, Docket No. 20000-384-ER-10, November 22, 2010 (Rocky Mountain Power dba/PacifiCorp).
- Illinois Commerce Commission, Docket No. 10-0467, July 28, 2010 (Commonwealth Edison Company).
- Missouri Public Service Commission, Case No. ER-2010-0355, June 4, 2010 (Kansas City Power & Light Company).
- Missouri Public Service Commission, Case No. ER-2010-0356, June 4, 2010 (KCP&L Greater Missouri Operations Company).
- Idaho Public Utilities Commission, Case No. PAC-E-10-07, May 28, 2010 (Rocky Mountain Power/PacifiCorp).
- Washington Utilities and Transportation Commission, Docket UE-100749, May 4, 2010 (PacifiCorp).
- New Hampshire Public Utilities Commission, Docket No. DE 10-055, April 15, 2010 (Unitil Energy Systems)
- Oregon Public Utility Commission, Docket No. UE-217, March 1, 2010 (PacifiCorp).
- Texas Public Utility Commission, Docket No. 37744, December 30, 2009,(Entergy Texas, Inc.)
- Kansas Corporation Commission, Docket No. 10-KCPE-415-RTS, December 17, 2009 (Kansas City Power & Light Company).
- Texas Public Utility Commission, Docket No. 37690, December 9, 2009,(El Paso Electric Company).
- California Public Utilities Commission, Application No. 09-11-015, November 20, 2009 (PacifiCorp).
- Federal Energy Regulatory Commission, Docket No. ER10-230-000, November 6, 2009 (Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company).
- Wyoming Public Service Commission, Docket No. 20000-352-ER-09, October 2, 2009 (Rocky Mountain Power dba/PacifiCorp).
- Arkansas Public Service Commission, Docket No. 09-084-U, September 4, 2009, (Entergy-Arkansas)
- Texas Public Utility Commission, Docket No. 37364, August 28, 2009,(American Electric Power-SWEPCO)
- Utah Public Service Commission, Docket No. 09-035-23, June 23, 2009 (Rocky Mountain Power/PacifiCorp).
- New Mexico Public Regulation Commission, Case No. 09-00171-UT, May 2009, (El Paso Electric Company).
- Oregon Public Utility Commission, Docket No. UE-207, April 2, 2009 (PacifiCorp).

- Arkansas Public Service Commission, Docket No. 09-008-U, February 19, 2009 (American Electric Power-SWEPCO).
- Washington Utilities and Transportation Commission, Docket UE-090205, February 9, 2009 (PacifiCorp).
- Idaho Public Utilities Commission, Case No. PAC-E-08-07, September 19, 2008 (Rocky Mountain Power/PacifiCorp).
- Missouri Public Service Commission, Case No. ER-2009-089, September 5, 2008 (Kansas City Power & Light Company).
- Kansas Corporation Commission, Docket No. 09-KCPE-246-RTS, September 5, 2008 (Kansas City Power & Light Company).
- Missouri Public Service Commission, Case No. ER-2009-090, September 5, 2008 (Aquila, Inc. dba/KCP&L Greater Missouri Operations Company).
- Utah Public Service Commission, Docket No. 08-035-38, July 17, 2008 (Rocky Mountain Power/PacifiCorp).
- Wyoming Public Service Commission, Docket No. 20000-333-ER-08, July 2008 (Rocky Mountain Power dba/PacifiCorp).
- Texas Public Utility Commission, Docket No. 35717, June 27, 2008, (Oncor Electric Delivery Company LLC).
- Washington Utilities and Transportation Commission, Docket UG-080546, March 28, 2008 (NW Natural).
- Washington Utilities and Transportation Commission, Docket UE-080220, February 6, 2008 (PacifiCorp).
- Utah Public Service Commission, Docket No. 07-035-93, December 17, 2007 (PacifiCorp).
- Illinois Commerce Commission, Docket No. 07-0566, October 17, 2007 (Commonwealth Edison Company).
- Texas Public Utility Commission, Docket No. 34800, September 26, 2007, (Entergy Gulf States, Inc.)
- Texas Public Utility Commission, Docket No. 34040, August 28, 2007, (Oncor/TXU Electric Delivery Company)
- Massachusetts Department of Public Utilities, D.P.U. 07-71, August 17, 2007, (Fitchburg Gas and Electric Light Company d/b/a/ Unitil)
- Arizona Corporation Commission, Docket No. E-01933A-07-0402, July 2, 2007, (Tucson Electric Power Company).
- Wyoming Public Service Commission, Docket No. 20000-277-ER-07, June 29, 2007 (Rocky Mountain Power dba/PacifiCorp).
- Idaho Public Utilities Commission, Case No. PAC-E-05-1, June 8, 2007 (Rocky Mountain Power dba/PacifiCorp).
- Kansas Corporation Commission, Docket No. 07-KCPE-905-RTS, March 1, 2007 (Kansas City Power & Light Company).
- New Mexico Public Regulation Commission, Case No. 07-00077-UT, February 21, 2007, (Public Service Company of New Mexico).
- Missouri Public Service Commission, Case No. ER-2006-0291, February 1, 2007 (Kansas City Power & Light Company).
- Texas PUC Docket Nos. 33734, January 22, 2007 (Electric Transmission Texas, LLC).
- Texas PUC Docket Nos. 33309 and 33310, November 2006, (AEP Texas Central Company and AEP Texas North Company).
- Louisiana Public Service Commission, Docket No. U-23327, October 2006 and January 2005 (Southwestern Electric Power Company, American Electric Power Company)
- Missouri Public Service Commission, Case No. ER-2007-0004, July 3, 2006 (Aquila, Inc.).
- New Mexico Public Regulation Commission, Case No. 06-00258-UT, June 30, 2006 (El Paso Electric Company).
- New Mexico Public Regulation Commission, Case No. 06-00210-UT, May 30, 2006 (Public Service Company of New Mexico).

- Texas Public Utility Commission, Docket No. 32093, April 14, 2006 (CenterPoint Energy-Houston Electric, LLC).
- Utah Public Service Commission, Docket No. 06-035-21, March 7, 2006 (PacifiCorp).
- Oregon Public Utility Commission, Case No. UE-179, February 23, 2006 (PacifiCorp).
- Kansas Corporation Commission, Docket No. 06-KCPE-828-RTS, January 31, 2006 (Kansas City Power & Light Company).
- Missouri Public Service Commission, Case No. ER-2006-0314, January 27, 2006 (Kansas City Power & Light Company).
- California Public Utilities Commission, Docket No. 05-11-022, November 29, 2005 (PacifiCorp).
- Texas Public Utility Commission, Docket No. 31994, November 5, 2005 (Texas-New Mexico Power Company).
- New Hampshire Public Utilities Commission, Docket No. DE 05-178, November 4, 2005 (Unitil Energy Systems).
- Wyoming Public Service Commission, Docket No. 20000-ER-05-230, October 14, 2005 (PacifiCorp).
- Minnesota Public Utilities Commission, Docket. No. G-008/GR-05-1380, October 2005 (CenterPoint Energy Minnegasco).
- Texas Railroad Commission, Gas Utilities Division No. 9625, September 2005 (CenterPoint Energy Entex).
- Illinois Commerce Commission, Docket No. 05-0597, August 31, 2005 (Commonwealth Edison Company).
- Washington Utilities and Transportation Commission, Docket ,UE-050684/General Rate Case, May 2005 (PacifiCorp).
- Missouri Public Service Commission, Case No. ER-2005-0436, May 2005 (Aquila, Inc.).
- Idaho Public Utilities Commission, Case No. PAC-E-05-1, January 14, 2005 (PacifiCorp).
- Arkansas Public Service Commission, Docket No. 04-121-U, December 3, 2004 (CenterPoint Energy Arkla).
- Oregon Public Utility Commission, Case No. UE-170, November 12, 2004 (PacifiCorp).
- Texas Public Utility Commission, Docket No. 29206, November 8, 2004 (Texas-New Mexico Power Company).
- Texas Railroad Commission, Gas Utilities Division Nos. 9533 and 9534, October 13, 2004 (CenterPoint Energy Entex).
- Texas Public Utility Commission, Docket No. 29526, August 18 and September 2, 2004 (CenterPoint Energy Houston Electric).
- Utah Public Service Commission, Docket No. 04-2035-, August 4, 2004 (PacifiCorp).
- Oklahoma Corporation Commission, Cause No. PUD-200400187, July 2, 2004, (CenterPoint Energy Arkla).
- Minnesota Public Utilities Commission, Docket No. G-008/GR-04-901, July 2004, (CenterPoint Energy Minnegasco).
- Washington Utilities and Transportation Commission, Docket ,UE-032065/General Rate Case, December 2003 (PacifiCorp).
- Washington Utilities and Transportation Commission, Docket ,UG-031885, November 2003 (Northwest Natural Gas Company.).
- Wyoming Public Service Commission, Docket No. 20000-ER-03-198, May 2003 (PacifiCorp).
- Public Service Commission of Utah, Docket No. 03-2035-02, May 2003 (PacifiCorp).
- Public Utility Commission of Oregon, Case. UE-147, March 2003 (PacifiCorp).
- Wyoming Public Service Commission, Docket No. 20000-ER-00-162, May 2002 (PacifiCorp).
- Public Utility Commission of Oregon, UG-152, November 2002 (Northwest Natural).
- Massachusetts Department of Telecommunications and Energy, D.T.E. 02-24/24, May 2002 (Fitchburg Gas and Electric Light Company).

- New Hampshire Public Utilities Commission, Docket No. DE 01-247, January 2002 (Unitil Corporation).
- Washington Utilities and Transportation Commission, Docket UE-011569,70,UG-011571, November 2001 (Puget Sound Energy, Inc.).
- California Public Utilities Commission, Docket No. 01-03-026, September and December 2001 (PacifiCorp).
- New Mexico Public Regulation Commission, Docket No. 3643, July 2001 (Texas-New Mexico Power Company).
- Texas Natural Resources Conservation Commission, Docket No. 2001-1074/5-URC, May 2001 (AquaSource Utility, Inc.).
- Massachusetts Department of Telecommunications and Energy, Docket No. 99-118, May 2001 (Fitchburg Gas and Electric Light Company).
- Public Service Commission of Utah, Docket No. 01-035-01, January 2001 (PacifiCorp)
- Federal Energy Regulatory Commission, Docket No. ER-01-651, January 2001 (Southwestern Electric Power Company).
- Wyoming Public Service Commission, Docket No. 20000-ER-00-162, December 2000 (PacifiCorp).
- Public Utility Commission of Oregon, Case. UE-116, November 2000, (PacifiCorp)
- Public Utility Commission of Texas, Docket No. 22344, September 2000, (AEP Texas Companies, Entergy Gulf States, Inc., Reliant Energy HL&P, Texas-New Mexico Power Company, TXU Electric Company)
- Public Utility Commission of Oregon, Case UE-111, August 2000, (PacifiCorp)
- Texas Public Utility Commission, Docket Nos. 22352,3,4, March 2000 (Central Power and Light Co., Southwestern Electric Power Co., West Texas Utilities Co.).
- Texas Public Utility Commission, Docket No. 22355, March 2000 (Reliant Energy, Inc.).
- Texas Public Utility Commission, Docket No. 22349, March 2000 (Texas-New Mexico Power Co.).
- Texas Public Utility Commission, Docket No. 22350, March 2000 (TXU Electric).
- Washington Utilities and Transportation Commission, Docket UE-991831, November 1999 (PacifiCorp).
- Public Service Commission of Utah, Docket No. 99-035-10, September 1999 (PacifiCorp)
- Louisiana Public Service Commission Docket No. U-23029, August 1999 (Southwestern Electric Power Company)
- Wyoming Public Service Commission, Docket No. 2000-ER-99-145, July 1999, January 2000 (PacifiCorp, dba Pacific Power and Light Company).
- Texas PUC Docket No. 20150, March 1999 (Entergy Gulf States, Inc.)
- Federal Energy Regulatory Commission Docket No. ER-98-3177-00, May and December 1998 (Southwestern Electric Power Company).
- Public Service Commission of Utah, Docket No. 97-035-01, June 1998 (PacifiCorp, dba Utah Power and Light Company).
- Massachusetts Dept. of Telecommunications and Energy, Docket No. DTE 98-51, May 1998, (Fitchburg Gas and Electric Light Company, a subsidiary of Unitil Corp.)
- Texas PUC, Docket No. 18490, March 1998, (Texas Utilities Electric Company)
- Texas PUC Docket No. 17751, March 1998 and July 1997 (Texas-New Mexico Power Company).
- Federal Energy Regulatory Commission Docket No. RP-97, February 1998 and May 1997 (Koch Gateway Pipeline Company).
- Federal Energy Regulatory Commission Docket No. ER-97-4468-000, December 1997 (Puget Sound Power & Light).
- Oklahoma Corporation Commission, Cause No. PUD 960000214, August 1997 (Public Service Company of Oklahoma).
- Oregon Public Utility Commission Docket No. UE-94, April 1996, (PacifiCorp).
- Texas PUC Docket No. 15643, May and September 1996, (Central Power and Light and West Texas Utilities Company).

- Federal Energy Regulatory Commission Docket No. ER-96, April 1996 (Puget Sound Power & Light).
- Federal Energy Regulatory Commission Docket No. ER96, February 1996, (Central and South West Corporation).
- Washington Utilities & Transportation Commission Docket No. UE-951270, November 1995 (Puget Sound Power & Light).
- Texas PUC Docket No. 14965, November 1995, (Central Power and Light).
- Texas PUC Docket No. 13369, February 1995 (West Texas Utilities).
- Texas PUC Docket No. 12065, July and December 1994, (Houston Lighting & Power).
- Texas PUC, Docket No. 12820, July and November 1994, (Central Power and Light).
- Texas PUC Docket No. 12900, March 1994, and New Mexico PUC Case No. 2531, August 1993, (TNP Enterprises).
- Texas PUC, Docket No. 12815, March 1994, (Pedernales Electric Cooperative).
- Florida Public Service Commission, Docket No. 930987-EI, December 1993, (TECO Energy).
- Iowa Department of Commerce, Docket No. RPU-93-9, December 1993, (US West Communications).
- Texas PUC Dkt. No. 11735, May and September 1993, (Texas Utilities Electric Company)
- Oklahoma Corporation Commission, Cause No. PUD 001342, October 1992 (Public Service Company of Oklahoma).
- Texas PUC Dkt. No. 9983, November 1991, (Southwest Texas Telephone Company).
- Texas PUC Dkt. No. 9850, November 1990, Houston Lighting & Power Company).
- Texas PUC Dkt. Nos. 8480/8482, January 1989; City of Austin Dkt. No. 1, August 1988 and July 1987, (City of Austin Electric Department).
- Missouri Public Service Commission Case No. ER-90-101, July 1990 (UtiliCorp).
- Texas PUC Dkt. No. 9945, December 1990; Texas PUC Dkt. No. 9165, November 1989, (El Paso Electric Company).
- Texas PUC Dkt. No. 9427, July 1990, (Lower Colorado River Authority Association of Wholesale Customers).
- Oregon Public Utility Commission, March 1990, (Pacific Power & Light Company).
- Utah Public Service Commission, November 1989, (Utah Power & Light Company).
- Texas PUC Dkt. No. 5610, September 1988, (GTE Southwest).
- Iowa State Utilities Board, September 1988, (Northwestern Bell Telephone Company).
- Texas Water Commission, Dkt. Nos. RC-022 and RC-023, November 1986, (City of Houston Water Department).
- Pennsylvania PUC Dkt. Nos. R-842770 and R-842771, May 1985, (Bethlehem Steel).

Capital Structure Testimony:

- Federal Energy Regulatory Commission Docket No. RP-97, May 1997 (Koch Gateway Pipeline Company).
- Illinois Commerce Commission Dkt. No. 93-0252 Remand, July 1996, (Sprint).
- California PUC (Appl. No. 92-05-004) April 1993 and May 1993, (Pacific Telesis).
- Montana PSC, Dkt. No. 90.12.86, November 1991, (US West Communications).
- Massachusetts PUC Dkt. No. 86-33, June 1987, (New England Telephone Company).
- Maine PUC Dkt. No. 85-159, February 1987, (New England Telephone Company).
- New Hampshire PUC Dkt. No. 85-181, September 1986, (New England Telephone Company).
- Maine PUC Dkt. No. 83-213, March 1984, (New England Telephone Company).

Regulatory Policy and Other Regulatory Issues:

- Texas PUC Docket No.31056, September 16, 2005, (AEP Texas Central Company).
- New Hampshire PUC Docket No. DE 03-086, May 2003, (Unitil Corporation).

- Texas PUC Docket No. 26194, May 2003 (El Paso Electric Company)
- Texas PUC Docket No. 22622, June 15, 2001 (TXU Electric)
- Texas PUC Docket No. 20125, November 1999 (Entergy Gulf States, Inc.)
- Texas PUC Docket No. 21112, July 1999 and New Mexico Public Regulation Commission Case No. 3103, July 1999 (Texas-New Mexico Power Company)
- Texas PUC Docket No. 20292, May 1999 (Central Power and Light Co.)
- Texas PUC Docket No. 20150, November 1998 (Entergy Gulf States, Inc.)
- New Mexico PUC Case No. 2769, May 1997, (Texas-New Mexico Power Company).
- Texas PUC Dkt. No. 15296, September 1996, (City of College Station, Texas).
- Texas PUC Dkt. No. 14965 Competitive Issues Phase, August 1996 (Central Power and Light Company).
- Texas PUC Dkt. No. 12456, May 1994, (Texas Utilities Electric Company).
- Texas PUC, Dkt. No. 12700/12701 and Federal Energy Regulatory Commission, Docket No. EC94-000, January 1994, (El Paso Electric Company).
- Florida Public Service Commission Generic Purchased Power Proceedings, October 1993 (TECO Energy).
- Texas PUC, Docket No. 11248, December 1992 (Barbara Faskins).
- Texas PUC Dkt. No. 10894, January and June 1992, (Gulf States Utilities Company).
- State Corporation Commission of Kansas, Dkt. No. 175,456-U, August 1991, (UtiliCorp United).
- Texas PUC Dkt. No. 9561, May 1990; Texas PUC Dkt. Nos. 6668/8646, July 1989 and February 1990, (Central Power and Light Company).
- Texas PUC Dkt. No. 9300, April 1990 and June 1990, (Texas Utilities Electric Co.).
- Texas PUC Dkt. No. 10200, August 1991, (Texas-New Mexico Power Company).
- Texas PUC Dkt. No. 7289, May 1987, (West Texas Utilities Company).
- Texas PUC Dkt. No. 7195, January 1987, (North Star Steel Texas).
- New Mexico PSC Case No. 1916, April 1986, (Public Service Company of New Mexico).
- Texas PUC Dkt. No. 6525, March 1986, (North Star Steel Texas).
- Texas PUC Dkt. No. 6375, November 1985, (Valley Industrial Council).
- Texas PUC Dkt. No. 6220, April 1985, (North Star Steel Texas).
- Texas PUC Dkt. No. 5940, March 1985, (West Texas Municipal Power Agency).
- Texas PUC Dkt. No. 5820, October 1984, (North Star Steel Texas).
- Texas PUC Dkt. No. 5779, September 1984, (Texas Industrial Energy Consumers).
- Texas PUC Dkt. No. 5560, April 1984, (North Star Steel Texas).
- Arizona PSC Dkt. No. U-1345-83-155, January 1984 and May 1984 (Arizona Public Service Company Shareholders Association).

Insurance Rate Testimony:

- Texas Department of Insurance, Docket No. 2673, January 2008, (Texas Land Title Association).
- Texas Department of Insurance, Docket No. 2601, December 2006, (Texas Land Title Association).
- Texas Department of Insurance, Docket No. 2394, November 1999, (Texas Title Insurance Agents).
- Senate Interim Committee on Title Insurance of the Texas Legislature, February 6, 1998
- Texas Department of Insurance, Docket No. 2279, October 1997, (Texas Title Insurance Agents).
- Texas Department of Insurance, January 1996, (Independent Metropolitan Title Insurance Agents of Texas).
- Texas Insurance Board, January 1992, (Texas Land Title Association).
- Texas Insurance Board, December 1990, (Texas Land Title Association).

- Texas Insurance Board, November 1989, (Texas Land Title Association).
- Texas Insurance Board, December 1987, (Texas Land Title Association).

Testimony On Behalf Of Texas PUC Staff:

- Texland Electric Cooperative, Dkt. No. 3896, February 1983
- El Paso Electric Company, Dkt. No. 4620, September 1982.
- Southwestern Bell Telephone Company, Dkt. No. 4545, August 1982.
- Central Power and Light Company, Dkt. No. 4400, May 1982.
- Texas-New Mexico Power Company, Dkt. 4240, March 1982.
- Texas Power and Light Company, Dkt. No. 3780, May 1981.
- General Telephone Company of the Southwest, Dkt. No. 3690, April 1981.
- Mid-South Electric Cooperative, Dkt. No. 3656, March 1981.
- West Texas Utilities Company, Dkt. No. 3473, December 1980.
- Houston Lighting & Power Company, Dkt. No. 3320, September 1980.

ECONOMIC ANALYSIS AND TESTIMONY

Antitrust Litigation:

- Marginal Cost Analysis of Concrete Production/Predatory Pricing (Stiles)
- Analysis of Lost Business Opportunity due to denial of Waste Disposal Site Permit (Browning-Ferris Industries, Inc.).
- Analysis of Electric Power Transmission Costs in Purchased Power Dispute, 1995, (City of College Station, Texas).

Contract Litigation:

- Analysis of Cogeneration Contract/Economic Viability Issues(Texas-New Mexico Power Company)
- Definition of Electric Sales/Franchise Fee Contract Dispute (Reliant Energy HL&P)
- Analysis of Purchased Power Agreement/Breach of Contract (Texas-New Mexico Power Company)
- Regulatory Commission Provisions in Franchise Fee Ordinance Dispute (Central Power & Light Company)
- Analysis of Economic Damages resulting from attempted Acquisition of Highway Construction Company (Dillingham Construction Corporation).
- Analysis of Economic Damages due to Contract Interference in Acquisition of Electric Utility Cooperative (PacifiCorp).
- Analysis of Economic Damages due to Patent Infringement of Boiler Cleaning Process (Dowell-Schlumberger/The Dow Chemical Company).
- Analysis of Lost Profits in Highway Construction Dispute, Jones Bros., Plaintiff, v. Flour Daniel, Balfour Beatty, Lambrecht, and Lone Star Infrastructure, LLC, Defendants, 53rd Judicial District Court of Travis County, Texas, Cause No. GN204386, 2005, (Flour, et al)
- Analysis of Lost Profits in Insurance Dispute, Nickelson v. International Shipbreaking Ltd., LLC, et al, 332nd District Court, Hidalgo County, Texas, Cause No. C-482-01-F, 2005, (Great American Insurance Company).
- Analysis of Lost Profits and Other Economic Damages due to Patent Infringement, Climb Tech, Guthrie, & Schwartz Design, Plaintiffs, v. Verble, Hagler, Reeves, Valcor Industries, Inc., Defendants, U.S. District Court, Western District, Austin, Texas, Civil Action No. 1:05-cv-864-LY, 2008, (Verble, Hagler, et al).

Lender Liability/Securities Litigation:

- ERISA Valuation of Retail Drug Store Chain (Sommers Drug Stores Company).
- Analysis of Lost Business Opportunities in Failed Businesses where Lenders Refused to Extend or Foreclosed Loans (FirstCity Bank Texas, McAllen State Bank, General Electric Credit Corporation).
- Usury and Punitive Damages Analysis based on Property Valuation in Failed Real Estate Venture, 1995, (Tomen America, Inc.).

Personal Injury/Wrongful Death/Lost Earnings Capacity Litigation:

- Analysis of Lost Earnings Capacity and Punitive Damages due to Industrial Accident (Worsham, Forsythe and Wooldridge).
- Analysis of Lost Earnings Capacity due to Improper Termination (Lloyd Gosselink, Ryan & Fowler).
- Present Value Analysis of Lost Earnings and Future Medical Costs due to Medical Malpractice (Sierra Medical Center).
- Present Value Analysis of Life Care Plan, U.S. District Court, Eastern District of Texas, Texarkana Division, Chisum v. Ford Motor Company, Civil Action No. 5:05-cv-0045, 2005, (Ford Motor Company).
- Analysis of Lost Earnings Capacity due to Industrial Accident, 122nd District Court, Galveston County, Texas, Trevino v. BP Products North America, Inc., Cause No. 05-cv-0341, 2006, (BP Products North America, Inc.

Product Warranty/Liability Litigation:

- Analysis of Lost Profits due to Equipment Failure in Cogeneration Facility (WF Energy/Travelers Insurance Company).
- Analysis of Economic Damages due to Grain Elevator Explosion (Degesch Chemical Company).
- Analysis of Economic Damages due to failure of Plastic Pipe Water Lines (Western Plastics, Inc.)
- Analysis of Rail Car Repair and Maintenance Costs in Product Warranty Dispute (Youngstown Steel Door Company).
- Analysis of Lost Profits due to Equipment Failure in Electric Power Plant, Houston Casualty Co., Comision Federal de Electricidad, and Seguros Comercial America S.A. de C.V. (Plaintiffs) v. Siemens Power Corporation, et al, District Court of Dallas County Texas, Cause No. DV-99-02749, 2005, (Siemens).
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- Evaluation of Electric Utility Distribution System (Jasper-Newton Electric Cooperative).
- Evaluations of Electric Utility Generating Plants (West Texas Utilities Company).

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PROFESSIONAL PRESENTATIONS

"Fundamentals of Financial Management and Reporting for Non-Financial Managers," Austin Energy, July 2000.
"Fundamentals of Finance and Accounting," the IC^2 Institute, University of Texas at Austin, December 1996 and 1997.
"Fundamentals of Financial Analysis and Project Evaluation," Central and South West Companies, April, May, and June 1997.
"Fundamentals of Financial Management and Valuation," West Texas Utilities Company, November 1995.
"Financial Modeling: Testing the Reasonableness of Regulatory Results," University of Texas Center for Legal and Regulatory Studies Conference, June 1991.
"Estimating the Cost of Equity Capital," University of Texas at Austin Utilities Conference, June 1989, June 1990.
"Regulation: The Bottom Line," Texas Society of Certified Public Accountants, Annual Utilities Conference, Austin, Texas, April 1990.
"Alternative Treatments of Large Plant Additions -- Modeling the Alternatives," University of Texas at Dallas Public Utilities Conference, July 1989.
"Industrial Customer Electrical Requirements," Edison Electric Institute Financial Conference, Scottsdale, Arizona, October 1988.
"Acquisitions and Consolidations in the Electric Power Industry," Conference on Emerging Issues of Competition in the Electric Utility Industry, University of Texas at Austin, May 1988.
"The General Fund Transfer - Is It A Tax? Is It A Dividend Payout? Is It Fair?" The Texas Public Power Association Annual Meeting, Austin, May 1984.
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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Grant Yoshihara

CAPITAL PROJECTS / SAFETY / RESEARCH, DEVELOPMENT AND DEMONSTRATION
EXHIBIT 600

December 2011

EXHIBIT 600 – DIRECT TESTIMONY - CAPITAL PROJECTS / SAFETY / RESEARCH, DEVELOPMENT AND DEMONSTRATION

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I. INTRODUCTION AND SUMMARY

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

A. My name is Grant Yoshihara. I am the Vice President of Utility Operations and Chief Engineer of NW Natural. I am responsible for design, construction, operation, and maintenance of the gas distribution system and utility storage plants, operations support services including work management functions, and operations training and compliance.

Q. Please describe your education and employment background.

A. I graduated from Oregon State University with a Bachelor of Science in Nuclear Engineering in 1977 and a Master of Science in Nuclear Engineering in 1979. I later received a Master of Business Administration from the University of Oregon in 1992. I am a registered Professional Mechanical Engineer in the State of Oregon.

I first joined NW Natural in 1991 as a gas supply analyst and have since held a variety of staff and management positions in major accounts, customer acquisition, customer service, and utility operations. Prior to joining NW Natural, I was employed by Portland General Electric Company for six years and for five years at an energy development subsidiary of NW Natural.

Q. Please provide a summary of your testimony.

A. In my testimony, I:

- Provide an overview of two major capital investments in gas operations that are reflected in the November 2012-October 2013 test year ("Test Year") revenue requirement;
- Discuss the purpose of the Company's System Integrity Program (SIP) and the need to continue the SIP program with certain modifications;

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- Discuss the Company's safety-related public awareness communications; and
- Explain the Company's increasing engagement in industry research, development and demonstration (RD&D) projects to support improvements in safety, operational efficiency, and end-use applications for customers.

II. MAJOR CAPITAL PROJECTS

Q. Please provide a brief description of the significant capital projects specific to gas operations that NW Natural will be undertaking in 2012 and 2013 that are included for recovery in this case.

A. The Company will be making two significant additions to utility plant in 2012 and 2013. The first is a system reinforcement project that increases service capacity and reliability to the Corvallis and Philomath areas ("Corvallis Loop Project"). This project was initiated in 2011 and is scheduled to be completed in the fall of 2012. The second is a major combined system reinforcement and bare steel replacement project between Perrydale along the Central Coast Feeder and the Albany-Corvallis Feeder ("Mid-Willamette Valley Feeder Project"). The Mid-Willamette Valley Feeder Project will be constructed during 2012 and 2013. The Corvallis Loop Project and the Mid-Willamette Valley Feeder Project are closely tied operationally, as will be described later in this testimony.

Q. Please describe the Corvallis Loop Project.

A. The Corvallis Loop Project has two segments. The first is a 12-inch diameter, 720 pounds per square inch gauge (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

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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.

Q. Why is the Corvallis Loop Project needed?

A. The Corvallis Loop Project is driven by the need for increased firm delivery capacity to serve residential, commercial, and firm industrial load, as well as future long-term growth, in this portion of the service territory. The existing delivery capacity to the area was constructed in 1963 and also provides primary service to the Albany area. The existing feeder consists of a 10-inch diameter, 400 psig transmission line from the Albany Gate Station to a point just east of Corvallis, which then sequentially becomes an 8-inch and 6-inch, 225 psig transmission line serving Corvallis and Philomath. Over the past 47 years, steady residential, commercial, and industrial customer load growth has consumed all of the area's firm delivery capacity, and the pressure drop along the feeder during the winter already exceeds normal design requirements. For the past several years, interruptible customers in this area have experienced partial curtailment as temperatures in the area drop below 42 degrees Fahrenheit, with full curtailment generally occurring as temperatures drop below 32 degrees Fahrenheit. For these reasons, the Company determined that it needed to increase capacity to this service area by the fourth quarter of 2012, and also begin to move forward on the Mid-Willamette Valley Feeder Project that will increase peak day delivery capability into the west end of the Albany-Corvallis corridor.

Q. How will customers benefit from this project?

A. Existing customers will have a reduced exposure to service interruption. In addition, the project provides capacity to meet future customer load growth along the entire service

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corridor from east of Albany to Philomath. The first segment of the Corvallis Loop Project is also designed to operate at higher pressures as it will become a segment of the Mid-Willamette Valley Feeder Project that is designed to ultimately support peak day deliveries from the Mist Storage Facility and the Newport liquefied natural gas (LNG) storage plant that increases service reliability to this entire area.

Q. What is the total capital cost of the investment in the Corvallis Loop Project?

A. The estimated capital cost of the Corvallis Loop Project is $12.8 million. The Company seeks to recover the entire investment as a general distribution system reinforcement project.

Q. Please describe the Mid-Willamette Valley Feeder Project.

A. The Mid-Willamette Valley Feeder Project is a four-phase project that is designed to move high pressure gas south from the Central Coast Feeder near Perrydale to a connection on the Albany-Corvallis Feeder east of Corvallis near Riverside Drive, coinciding with where the north end of the Corvallis Loop Project begins. The entire project will be designed as a 12-inch diameter, 720 psig transmission system. The project is broken into these four phases because of permitting and easement acquisition timelines along the route, with one phase specifically focused on the removal of bare steel main.

Q. Please describe the four phases.

A. The first phase is the installation of transmission line from a location just north of Monmouth to a location at the intersection of Haley Road and Albany Road (Granger-Independence Highway) south of Independence. This first phase is an extension of

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existing transmission line that runs from State Highway 18 at Rickreall south to just north of Monmouth and is scheduled for completion in early 2012.

The second phase of the Project is the installation of transmission line from the existing Central Coast Feeder located east of Perrydale south along U.S. Highway 99 to Rickreall. This second phase provides a critical connection between the Central Coast Feeder and the Mid-Willamette Valley Feeder and is currently scheduled for completion in 2012.

The third phase of the Project is the installation of transmission line from the intersection of State Highway 20 and Granger-Independence Highway, crossing the Willamette River, and connecting to the existing Albany-Corvallis Feeder at the same location as the north end of the Corvallis Loop Project. This third phase is currently scheduled for completion in 2013.

The fourth phase is the installation of transmission line from the Albany Road location south of Independence to the intersection of Highway 20 and Granger-Independence Highway. This fourth phase includes the replacement of multiple segments of bare steel main along Granger-Independence Highway and is scheduled for completion in 2013.

Q. Why is the Mid-Willamette Feeder Project needed?

A. The Mid-Willamette Valley Feeder Project will achieve multiple objectives. First, as noted in the previous description of the Corvallis Loop Project, the Mid-Willamette Valley Feeder Project increases winter delivery capability to address existing system limitations in serving customers through the Albany-Corvallis Feeder. Second, it brings us significantly closer to reaching the safety goal of replacing the remaining bare steel in

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the Company's Oregon distribution system. A total of 8.5 miles of bare steel main is in this corridor, with 7.3 miles to be replaced as part of this project under the Company's SIP in 2013. Portions of this existing 6-inch diameter system were installed as early as 1931 and the system is only operated at 60 psig due to its age and condition. Removal of the bare steel in this area affords the opportunity to reinforce delivery capacity along this entire corridor stretching from Salem at the north to Albany, Corvallis and Philomath on the south. Third, completion of the Mid-Willamette Valley Feeder Project will extend on-system storage delivery capability from Mist and Newport LNG as far south as the Corvallis service area, reduce the reliance on Northwest Pipeline's Grant's Pass Lateral for meeting peak day delivery requirements, and reduce the potential consequences of a service disruption on Northwest Pipeline.

Q. How will customers benefit from this project?

A. Customers will benefit through increased service capacity, reliability, and the reduction of risk and consequence due to service reduction or interruption on the interstate pipeline. As noted earlier, the Mid-Willamette Valley Feeder Project is closely tied to the Corvallis Loop Project and extends delivery capacity from on-system storage resources to the entire Albany-Corvallis corridor. At present, the entire service region south of Salem relies solely on deliveries off of Northwest Pipeline's Grant's Pass Lateral. This presents a significant risk to service reliability to all customers in this region. As examples of the impact on reliability and the potential for service interruption, two major unplanned service reductions from Northwest Pipeline down the Grants Pass Lateral occurred—one on February 5, 1990 and the second on January 4, 2004—due to compressor failures at Eugene and Oregon City respectively. The Company was able to

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maintain firm service but was required to rapidly curtail all interruptible service. Had either event happened on a peak day, the ability to continue to provide service to residential and commercial customers south of the Portland metropolitan area would have been severely compromised. A likely outcome would have been loss of service to large groups of customers extending from Salem to Coos Bay. Service to Avista Utilities customers in Southern Oregon also would have been impacted.

Q. What is the total capital cost of the investment in the Mid-Willamette Valley Feeder Project?

A. The estimated capital cost of the Mid-Willamette Valley Feeder Project excluding the bare steel replacement segment is $32.6 million. The bare steel portion of the project is part of the SIP forecast. It is estimated to cost $14.3 million and is scheduled for completion in 2013. Recovery on the investment for the bare steel segment would be through the SIP. The regulatory treatment of the other costs of the project are addressed in the direct testimony of Kevin McVay and Natasha Siores on revenue requirement.

III. SYSTEM INTEGRITY PROGRAM

Q. What is the System Integrity Program?

A. In Commission Order Nos. 09-067 and 11-337, NW Natural was granted authorization to recover costs related to complying with federal pipeline safety regulations; these costs are booked as capital and annually tracked into rates when the Company files its

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Purchased Gas Adjustment (PGA) filing.[1] This cost recovery mechanism is known as the System Integrity Program, or SIP. The SIP is scheduled to expire when rates are implemented as a result of this rate case.[2] The Company is proposing the continuation of SIP in order to address ongoing federal regulations related to pipeline safety.

Q. Please provide background on the SIP.

A. In 2009, the Company initiated the SIP in response to the recognition that its independent pipeline safety programs have closely interrelated goals and work requirements. The Company has had evolving pipeline integrity programs since 1985, which have been developed to comply with the stringent and evolving framework of federal legislation designed to protect the public from the inherent risks associated with the delivery of natural gas.

SIP combines the Bare Steel Replacement Program, Transmission Integrity Management Program (TIMP), and Distribution Integrity Management Program (DIMP) under one comprehensive program for the purposes of prioritization, efficient implementation, and consistent regulatory treatment of costs.

Q. Please briefly describe the work done under SIP.

A. As mentioned, SIP is the compilation of three previously existing programs. I will address each sub-program separately.

<u>Bare Steel Program</u> – Bare steel pipe poses a safety risk because it has no protective exterior coating, thus making it significantly more susceptible to external

[1] *NW Natural Gas Co.'s Application for an Accounting Order*, Docket UM 1406, Order No. 11-337 (Aug. 30, 2011); *NW Natural Gas Co.'s Application for an Accounting Order,* Docket UM 1406, Order No. 09-067 (Mar. 1, 2009).
[2] *See NW Natural Gas Co.'s Application for an Accounting Order*, Docket UM 1406, Order No. 11-337 at 4 (Aug. 30, 2011).

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corrosion. In 2001, the Company began an accelerated replacement of its bare steel pipe. To date, the Company's bare steel replacement program has removed from service approximately 112 miles of bare steel mains and over 27,000 bare steel services. Approximately 22 miles of bare steel main and about 160 service lines currently remain in the Company's Oregon distribution system.

TIMP – In 2003, the Office of Pipeline Safety and the Research and Special Programs Administration issued a new rule, entitled Pipeline Integrity Management in High Consequence Areas ("IMP Rule"),[3] which added incremental requirements on the operators of transmission pipelines. To carry out the work required under the IMP Rule, the Company initiated TIMP. TIMP is a prescriptive program to assess, prioritize, evaluate, mitigate, and validate the integrity of natural gas transmission lines, which in the event of a leak or failure could affect high consequence areas (HCAs). TIMP requires the systematic assessment of pipelines in HCAs using inline inspections, direct assessments, or hydrostatic tests. These inspections are for the purpose of identifying threats to the integrity of transmission pipelines caused by many factors including third party damage and internal or external corrosion.

DIMP – The Pipeline and Hazardous Materials Safety Administration (PHMSA) published the final rule on December 4, 2009 that establishes distribution integrity management requirements for gas distribution pipeline systems.[4] As of August 2, 2011, operators are required to have written and submitted DIMP plans that define procedures for activities including identifying threats, evaluating and prioritizing risks, and

[3] 69 FR 2307 (Jan. 15, 2004).
[4] *See* 74 FR 63906 (Dec. 4, 2009).

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implementing measures to address risks. Full implementation of the DIMP plan began in late 2011.

Q. Please elaborate on the agreed-to regulatory treatment of SIP costs.

A. In Docket UM 1406, NW Natural filed a request for and subsequently received an accounting order that has allowed the Company to track SIP project costs as capital costs into rates each year when the Company files its PGA filing effective November 1. Spending under this agreement has a soft cap of $12 million per PGA year. The $12 million soft cap applies to costs incurred above the $574,000 of operations and maintenance expenses (O&M) that are embedded in rates. In addition, the first $3 million of combined annual bare steel and leakage capital costs and an additional $250,000 of annual SIP capital costs are not eligible under the SIP recovery mechanism. If spending is forecasted to exceed the $12 million soft cap, the Company must seek consent of the parties to UM 1406 in order to raise the cap.[5]

Costs are recovered in accordance with the Company's Schedule 177: System Integrity Program Rate Adjustment. All costs but those pertaining to bare steel projects are allocated for recovery on an equal percent of margin basis. Bare steel costs are treated differently in accordance with Commission Order No. 01-843: 70 percent are spread to residential and commercial customers on an equal cents per therm basis, and the remaining 30 percent is spread to all customer classes on an equal percent of margin basis.

[5] *NW Natural Gas Co.'s Application for an Accounting Order,* Docket UM 1406, Order No. 09-067 Appendix B at 4 (Mar. 1, 2009).

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Q. Does the Company propose to continue the current regulatory treatment of SIP costs?

A. Yes, with some modifications. The Company proposes maintaining the structure that was approved for SIP cost recovery in Commission Order No. 09-067 in Docket UM 1406, and continuing to keep costs subject to a soft spending cap. The exclusion of the first $3.25 million of annual capital spending under SIP would also continue, consistent with the existing mechanism.[6] The soft cap would increase in 2013 to $26.3 million and then reduce to the current $12 million annual capital soft cap with the understanding that anticipated new regulatory requirements may substantially increase this cap and the cap must be reconsidered as new compliance requirements are known. A summary breakdown of the proposed capital and O&M expenditures in the 2013 Test Year is shown in *NWN/601, Yoshihara/1*.

All costs will continue to be amortized for recovery on an equal percent of margin basis across all customers with the exception of bare steel related costs, which will be allocated on a 70/30 percent basis, with 70 percent allocated to Residential and Commercial Customers on an equal cents per therm basis and 30 percent allocated to all customer classes on an equal percent of margin basis. *See Schedule 177, NWN/1701, King*.

Consistent with the Company's current process for formal reporting on SIP, NW Natural will file an annual report that details the projects and expenditures for the prior PGA year and forecast projects and costs for the next PGA year.

[6] In accordance with Commission Order No. 09-067, SIP costs do not include the first $3 million in bare steel leakage capital costs, and the first $250,000 in capital costs. *NW Natural Gas Co.'s Application for an Accounting Order*, Docket UM 1406, Order No. 09-067 Appendix B at 3 (Mar. 1, 2009).

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Q. Why does the Company propose continuing the SIP mechanism rather than embedding ongoing costs in rates?

A. When SIP was developed, the Company believed that it would be certain of ongoing compliance costs. However, since the terms and conditions for SIP were agreed to in 2009, two significant and tragic natural gas related incidents occurred that have resulted in a heightened national awareness in pipeline safety. On August 9, 2010, a natural gas distribution pipeline exploded in a suburban neighborhood in San Bruno, California, killing eight people. Not long after this, on February 9, 2011, a natural gas explosion in Allentown, Pennsylvania, killed five people. These events occurred while both the Senate and House of Representatives were in the process of reauthorizing the 2006 PIPES Act.[7] Since this time, changes have been introduced in Senate and House bills that will update and enhance federal pipeline safety policy in several areas, including integrity management and damage prevention. The Senate reauthorization bill was unanimously approved on October 17, 2011 and with House action pending on its own version, completion of the re-authorization process is expected to be completed in late 2011 or early 2012. Due to the uncertainty of the requirements that will be adopted, the Company believes that the SIP mechanism continues to be an appropriate mechanism to enable the Company to comply with evolving pipeline safety regulations.

Q. Why does the cap increase in 2013?

A. The soft cap for 2013 is $26.3 million, which includes the expected annual SIP capital program expenditures of $12 million and a one-time expenditure of $14.3 million for the

[7] 2006 PIPES Act refers to the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006.

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significant bare main replacement project, discussed earlier, that removes from service 7.3 miles of the remaining 22 miles of bare steel main in the Company's Oregon distribution system.

Q. Please explain the Test Year O&M costs that pertain to SIP.

A. The Test Year includes $4.5 million for ongoing SIP-related O&M costs. This is an increase of $4 million over the existing program allowance of $574,000 of O&M. The increase is a result of three contributing factors.

First, the Company will begin its second round of required pipeline inspections, which will shift costs from capital to O&M activities. In the first cycle, inspections included capital costs to rebuild components of selected pipeline segments to allow passage of internal inspection tools. The modifications completed to date allow the Company to internally inspect approximately 44 percent of our HCA transmission pipelines. Required subsequent inspections of these pipelines do not generally require any additional capital modifications under current regulations, shifting re-inspection costs to O&M.

Second, the Company's DIMP plan was created and filed in August 2011. Management and assessment of the massive data sets required to efficiently model risks and manage records under the program will require additional personnel. The Company will require the addition of two full-time equivalent positions (FTEs) in 2012 to implement, manage, and administer this required program.

And third, under DIMP, additional and accelerated actions are required to mitigate and reduce identified risks. These accelerated actions, such as inspections for

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sewer laterals for cross-bores, are normally considered O&M activities and will significantly increase O&M expenditures.

The Company proposes that, going forward, any SIP-related O&M costs above this $4.5 million amount be capitalized, as is currently the case for SIP-related O&M costs above $574,000.

Q. How were these O&M levels determined?

A. In addition to the $0.574 million, as detailed above, re-assessment of pipelines are projected to cost between $1.35 million and $1.77 million per year. Additional FTEs to administer the programs are projected to be $0.25 million. Since the last rate case, the Company has increased total staffing for damage prevention by four FTEs. Additionally, one FTE performing SIP duties was included in base rates in the last general rate case but was not characterized as a SIP program O&M expense. Because damage prevention is one of the most critical components in meeting federal requirements for DIMP, it is prudent to account for this expense as part of the SIP. The incremental increase in funding for damage prevention and the transferring of costs originally in base rates to SIP will increase the program's O&M requirements by $0.4 million. And finally, DIMP accelerated actions are projected at $2.0 million.

Q. Does the Company foresee exceeding the $12 million dollar soft cap in years following 2013?

A. In subsequent years the Company proposes holding the current $12 million funding level into the near future. However, the completion of the 2006 PIPES Act re-authorization process and the development of new regulations, expected to occur during 2012, are highly likely to increase capital spending requirements. When regulations become final,

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the Company will re-assess the required capital exposure needed to meet any new regulatory requirements. At such time, we would work with the parties to determine appropriate adjustments to the cap, and may ask the Commission to modify the cap in order to address new regulatory requirements.

Q. Do other utilities around the country have mechanisms similar to NW Natural's SIP cost recovery mechanism?

A. Yes, many do. The American Gas Association reported in May 2011 that currently more than 40 utilities in 19 states serving 20 million residential natural gas customers are using full or limited special rate mechanisms to recover their infrastructure replacement investments, and six utilities have such mechanisms pending in three other states.[8] In addition, 13 utilities in six states serving six million customers are recovering these investment costs as part of broader rate stabilization tariffs that include other infrastructure investments.[9] While rate recovery mechanisms will differ due to the type, age, and condition of each utility's distribution system, the SIP has been recognized in other regulatory jurisdictions as an effective approach and model for addressing pipeline safety issues.

Q. How have customers benefited from the SIP program?

A. NW Natural customers and the general public have benefited from the SIP through increased pipeline safety and reliability. The distribution system infrastructure has been upgraded with the complete elimination of cast iron and progressive elimination of bare

[8] American Gas Association, Natural Gas Rate Round-Up, "Infrastructure Cost Recovery" (May 2011) *available at* http://www.aga.org/our-issues/RatesRegulatoryIssues/ratesregpolicy/rateroundup/Documents/Infrastructure%20Cost%20Recovery%20(May%202011).pdf.

9 *Id.*

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steel. Data collected and reported to the Commission on leakage incidents has trended significantly downward. To date, these required transmission line inspections have identified 361 anomalies, ranging from third-party damage to corrosion due to coating failure. While the vast majority of these findings have been minor and easily repairable, the identification, assessment, and elimination of these specific threats lower the ultimate risk of system failure and the uncontrolled release of natural gas.

IV. 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 being "Category B" communications, as defined in OAR 860-026-0022 as a "legally mandated advertising expense." OAR 860-026-0022(3)(a) further states that "Advertising expenses in Category B are presumed to be just and reasonable for rate-making purposes."

Q. What Category B communications expenses are included in the Test Year?

A. The Company has included $650,000 for Category B communications and media outreach expenses in the Test Year.

Q. Please identify the legal mandates requiring this expenditure.

A. This Company's Category B communications meet the regulatory requirements and intent of Recommended Practice API RP-1162 that was developed by the industry in response to the 2002 PIPES Act. In compliance with RP-1162, the Company sends pipeline safety information directly to required audience groups including emergency officials, public officials, excavators, multi-family, floating homes, and residents and businesses located along transmission lines, in HCAs, or along rights-of-way notifying them of nearby pipelines and educating them on how to ensure their safety. Materials contain required information and messages tailored for each audience group and includes contact information for the Company should the recipient have questions.

V. RESEARCH, DEVELOPMENT, AND DEMONSTRATION

Q. Why is utility investment in RD&D important?

A. RD&D has proven to be an important initiative that benefits the customer and the general public by supporting the safe and efficient delivery and utilization of natural gas by contributing to operational efficiency and safety improvements in designing, constructing, inspecting, maintaining, and repairing utility assets, as well as the safe and efficient utilization of natural gas in end-use applications.

Q. Please discuss historical industry funding for RD&D activities.

A. Prior to 1999, funding for industry-wide RD&D was provided through a Federal Energy Regulatory Commission (FERC)-approved pipeline rate assessed to Oregon customers totaling more than $1.3 million annually. These funds were collected by the pipelines and re-distributed to research organizations, including industry-led efforts such as the Gas Research Institute (GRI) and the Institute of Gas Technology.[10] In 1998 a

[10] Reorganization and consolidation of industry resulted in GRI merging with the Institute of Gas Technology (IGT) to form today's Gas Technology Institute (GTI). GTI was also restructured as an overarching RD&D umbrella organization that supports general RD&D functions and provides services to funding agencies and organizations, including the management of targeted RD&D groups.

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settlement resulted in a staged reduction over five years of the FERC RD&D surcharge on the interstate pipeline throughput resulting in a zero assessment for RD&D by 2003.

Ultimately, the loss of RD&D funding through the elimination of the FERC RD&D surcharge resulted in a significant reduction of industry RD&D activity. Funds collected through this mechanism totaled $164 million in 1998 and declined to zero in 2004.[11] Voluntary investment at the utility level through state-approved funding mechanisms was only $26.5 million by early 2011 as reported by the Gas Technology Institute.

In the Company's last general rate case the Company received approval for $308,350 in annual expenditures to be applied to RD&D activities. This current overall funding level is less than 27 percent of funding for RD&D provided from Oregon customers in 1999.

Q. Why is there an increased interest in RD&D?

A. During the recent National Transportation Safety Board (NTSB) findings related to the San Bruno natural gas incident, PHMSA specifically identified in oral testimony that the reduction of long-term funding for RD&D in the natural gas industry may be an indirect but contributing factor to its cause and consequence.[12] This has created additional momentum for key RD&D initiatives in natural gas delivery operations that include pipe locating and protection, advanced inspection technology, new composite materials and coatings, quality control, and improvements in monitoring/automated control capabilities that are expected to be referenced and potentially required in new pipeline safety rule-making. Several of these elements have already been a focus of DIMP plans and have

[11] Federal Energy Regulatory Commission, Docket Nos. RP97-391-000 *et al.*, Stipulation and Agreement Concerning GRI Funding (Jan. 21, 1998).
[12] NTSB Public Hearing on the San Bruno, California Incident (Mar. 1-3, 2011).

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also been specifically identified in the Senate approved Pipeline Safety reauthorization bill.[13]

Most long-term projections forecast increased global energy consumption and subsequent increases in both energy costs and greenhouse gas emissions. This would naturally drive demand for the development of innovative and more efficient end-use applications. The development of improved electric generation technologies for natural gas can also support greenhouse gas emission reductions and the move to more renewable but less reliable electric generation alternatives. With the United States transportation sector being one of the country's largest emitters of air pollutants, natural gas use in vehicles is also re-emerging as a solution. Finally, research into the development and safe use of bio-gas sources is required to ensure that natural methane emissions are captured and utilized without impacting the condition of the distribution system infrastructure.

Q. What is included in the Test Year for RD&D?

A. The Company is planning an increase in the current funding model for RD&D from a fixed rate of $350,000 per year to approximately $750,000 per year. This is equivalent to about $1.25 per customer per year for Oregon customers based on an estimate of 602,000 customers. This compares to $0.58 per customer based on 2003, when the prior funding level was approved. In addition, the total request represents approximately 55 percent of the funding level previously paid by Oregon customers through the FERC RD&D surcharge in 1999.

[13] Pipeline Transportation Safety Improvement Act of 2011, Senate Bill S. 275, sections 5,6 10, & 27, approved by the United States Senate on October 27, 2011

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Q. How has NW Natural used the RD&D funds recovered in rates since the last rate case?

A. The Company has invested a total of $2.8 million for RD&D from 2003 to 2011, or $349,894 average per year since the last rate case. The distribution of investments can be broken down into four categories with the largest being Operations RD&D where a total of $2.1 million has been invested. The other categories are End Use at $418,986, Gas Supply at $220,000, and Other Research Studies at $60,000.

The Company has been able to utilize the Operations Technology Development (OTD) funding model to co-invest with other utilities on operational RD&D activities. There are a wide range of general benefits, such as the development of advanced pipe coating materials for in-field repairs, repair techniques for damaged steel pipelines, yield strength determination on existing pipelines, setting standards for the use of recycled polyethylene materials, and developing standard procedures for measuring fugitive gas emission to meet new EPA requirements. The Company is currently utilizing metallic fitting locators and jack hammer lift assist tools, and testing continuous service meter change-out units that have been developed and commercialized though the OTD investments. It is also using a new industry standard risk model developed through OTD as its basis for DIMP and inspection technology for TIMP pipelines. Next year, the Company expects to be testing new acoustic pipe locating technology to more positively identify non-locatable pipe such as polyethylene, water, and sewer pipelines. In addition, we are expecting to participate in final development of a propane/air mixer to avoid customer shutdowns during maintenance procedures and provide temporary service to priority conversion customers who are without heat.

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End-use investments made through the Energy Solutions Center have resulted in the development and commercialization of advanced technologies such as the super-boiler for industrial plant operations, process waste heat recovery in food processing, and advanced tankless water heaters. Local testing has focused on the analysis of combination residential water/space heating units, combined heat and power residential/small commercial units, and the effectiveness of combination solar/thermal water heating in our market area.

The primary focus of gas supply RD&D recently has been on bio-methane quality and its potential impact on metallic pipe systems and equipment. Through extensive testing and analysis, an industry standard guidance document was developed that identifies maximum critical impurity levels in dairy waste-produced bio-methane. Additional investment has developed mobile field testing capability for bio-methane that was demonstrated at the Three Mile Canyon production facility and is available to assess other bio-methane waste streams.

Q. What future investments are you planning to make in RD&D?

A. Total funding at this level will support effective and selective RD&D in OTD for operations, Sustaining Membership Program for applied research, Utilization Technology Development for residential, commercial, and industrial end-use, and the Energy Solutions Center for end use demonstration/commercialization as well as specific end-use testing and demonstration with customers in our service territory. The advantage of this targeted approach for investment over the earlier FERC funding model is that the Company can specifically designate investments in projects that are most pertinent to its natural gas distribution system and its end use customers' applications. It also

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participates in the identification and prioritization of RD&D efforts. *NWN/602, Yoshihara/1* details the expected allocation of these funds annually.

Q. How will customers benefit from RD&D?

A. All customers will benefit through the identification, development, and implementation of operational products, systems, procedures, and services that improve the safety, extend the life, reduce the cost, and protect the natural gas distribution system. They will also benefit from the development of improved natural gas end-use technology that is safe, more efficient, more reliable, and more effectively meets the specific customer's needs. Investments made include continued improvements to the efficiency of condensing furnaces, testing of combination solar/thermal water heating, and supporting commercialization of industrial super boilers.

Q. Will all customer classes benefit?

A. Yes, all customer classes will benefit from the expanded investment in RD&D as noted above. Investments in end-use applications are specific to each customer class and application. Participation in the previously described end-use technology organizations will allow for the Company to identify and target specific applications for development that apply to its residential and commercial customer groups, the climate trends specific to the Company's service territory, and specific industrial end-use process applications exhibited by NW Natural large industrial customers.

Q. Does this conclude your direct testimony?

A. Yes.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Exhibits of Grant Yoshihara

CAPITAL PROJECTS / SAFETY / RESEARCH, DEVELOPMENT AND DEMONSTRATION EXHIBITS 601 - 602

December 2011

EXHIBITS 601- 602 – CAPITAL PROJECTS / SAFETY / RESEARCH, DEVELOPMENT AND DEMONSTRATION

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Summary of SIP Test Year Expense

	Test Year Expense ($MM)
O&M:	
TIMP Management & Administration	0.57
DIMP Management & Administration	0.25
Damage Prevention	0.40
TIMP Re-inspections	1.78
DIMP Accelerated Actions	2.00
Total O&M	5.00 [(1)]
Capital:	
Bare Steel Main Replacement	3.00
Bare Steel Service Replacement	0.10
Leakage Main Replacement	0.80
Leakage Service Replacement	0.10
TIMP Actions/Improvements	6.00
DIMP Actions/Improvements	2.00
Sub-Total Capital	12.00
Perrydale/Corvallis Bare Steel Main Replacement	14.30
Total Capital	26.30

(1) The proposed amount of O&M in base rates is $4.5 million. Excess O&M expense would be transferred to capital under a proposed continuation of the current SIP accounting practice

RD&D Investment Allocation

Category	Organization	Test Year Expense ($)
Operations	Operations Technology Development	$305,000
End-Use	Utilization Technology for Development	$240,000
End-Use	Energy Solutions Center	$ 20,000
General	Sustaining Membership Program	$ 75,000
Field Testing/Demo	Various	$110,000
Estimated Total Annual Expense		$750,000 (1)

(1) Based on 602,000 estimated Oregon meters at $1.25 per meter per year

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of John Sohl

CAPITAL / OPERATIONS & MAINTENANCE
EXHIBIT 700

December 2011

EXHIBIT 700 – DIRECT TESTIMONY – CAPITAL / OPERATIONS & MAINTENANCE

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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 John Sohl. I am the Business and Budget Manager at NW Natural. I am responsible for production of the annual operations and maintenance (O&M) budget, the capital budget, payroll overhead rates, and the budget income statement. I also manage the department that develops short- and long-term financial forecasts for senior management and performs analysis and interpretation of expenditure variations from budgeted and forecasted levels for reporting to senior management.

Q. Please summarize your educational background and business experience.

A. I have a Bachelor of Science from Allegheny College in Meadville, Pennsylvania and a Master of Business Administration from Penn State University. I joined NW Natural in 2006 as a senior business analyst and have been in my present position since 2007. Previously, I was lead consultant for business planning and strategy at PacifiCorp (2004-2006), manager of estimating and project cost control at Aalborg Industries, a global company with an emphasis on heat recovery steam generators for combined cycle power projects (2000-2003), and held staff positions in operations and marketing at National Fuel Gas from 1988 to 2000.

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 in this case, including an explanation of how the Company

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calculated O&M costs for the calendar year 2011 historic base period ("Base Period") and used those costs to develop the Oregon-allocated O&M costs for the test period consisting of the 12 months ending October 31, 2013 ("Test Year");

- Identify specific drivers of O&M cost differences between the Base Period and the Test Year;
- Explain how the Company's Test Year O&M compares with historic O&M levels; and
- Discuss the amount of capital expense included in the Test Year and how that amount was calculated.

II. TEST YEAR OPERATIONS AND MAINTENANCE COSTS

Q. What is the Oregon-allocated O&M expense included in the Company's revenue requirement in this case?

A. The Oregon-allocated O&M expense included in the revenue requirement in this case is $118.2 million. This amount was calculated for the Test Year based on normalizing and known and measurable changes from the historic Base Period. The total Company O&M for the Test Year is $135.9 million excluding uncollectible accounts expenses. The total Company O&M does not reflect $5.3 million for items that the Company removed because the Commission has previously found they are not recoverable in rates or for which the Company has decided not to seek recovery. NWN/306, McVay-Siores/1 shows the Base Period and Test Year O&M by Federal Energy Regulatory Commission (FERC) account.

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Q. You state that the Base Period is calendar year 2011. How did the Company establish Base Period O&M costs given that this filing is being made in December of 2011?

A. The Company used the actual expenses for January, 2011 through September, 2011 and forecast the expenses for October, 2011 through December, 2011 to develop the total Base Period O&M expenses. The total Base Period O&M expenses are forecast to be $115.5 million. The Company took this approach because it understands that Staff, and likely other parties as well, would like the Base Period to reflect the most recent historical information available and to be able to compare the Base Period with historical years consisting of the same months.

Q. How did the Company determine the forecast costs for October, 2011 through December, 2011?

A. The costs for these months are based on a forecast provided by each department. Each department manager prepares an annual budget for the coming year and provides forecast updates throughout the year. The estimated O&M and capital by month for the coming year is based on historical activity levels and planned projects expected in the coming year. The forecast is updated periodically, the most recent update being in August, 2011. I used actual expenses for the first nine months and the forecast for each department for the three final months of the Base Period to develop total Base Period O&M costs.

Q. Does the Company plan to update the October, 2011 through December, 2011 forecast costs with actual costs?

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A. Yes. The Company will provide this information to parties as soon as it is available.

Q. Do you expect the actuals for these months to differ significantly from the forecast used in your calculations?

A. No, I do not. For the first nine months of 2011, the Company's actual expenditures have been close to the updated forecasts. I anticipate that this trend will continue through the final three months of the year, which are based on the August forecast.

Q. What was the first step in calculating Test Year O&M costs based on the Base Period costs?

A. An important element of calculating Test Year costs for both payroll and non-payroll O&M costs is to determine the number of full-time equivalent positions (FTEs) the Company will have in the Test Year. I increased the Base Period's forecast of 1,072 FTEs by 58 FTEs that the Company expects to add to its workforce between the end of the Base Period and the beginning of the Test Year. The majority of these positions relate to the new safety and compliance programs discussed in the direct testimony of Grant Yoshihara and the new customer service programs discussed in the direct testimony of David Williams.

Q. Please explain your escalation methodology for payroll costs.

A. Payroll costs were escalated for expected salary increases for bargaining unit (BU) employees. These increases are expected to be three percent in June 2012 and June 2013. The Company also assumes an additional 0.25 percent for promotions and movements from entry rate to experienced BU positions. Similarly, payroll costs were escalated for expected salary increases for non-bargaining unit (NBU) employees.

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These increases are expected to be three percent in March, 2012 and March, 2013. The Company also assumes an additional 0.25 percent for NBU employee promotions. Payroll costs were also escalated for expected benefits expense increases. The direct testimony of Lea Anne Doolittle discusses these salary and benefits increases in further detail.

Q. How was the payroll overhead rate 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 and payroll for the year. These payroll overhead rates are applied to the forecast for each payroll category for the Test Year, thereby adjusting payroll to account for benefits expenses.

Q. Please explain your escalation methodology for non-payroll costs.

A. The Company escalated general non-payroll costs included in the Base Period based on indices obtained from the August 12, 2011 Survey of Professional Forecasters, a publication issued by the Federal Reserve Bank of Philadelphia. These escalation indices were applied on January 1, 2012 and January 1, 2013.

After escalating Base Period non-payroll expenses, I included the costs associated with incremental programs and costs included in the Test Year that are described in the Company's filing. Specifically, these costs relate to the no-fee bill payment option, research and development costs, the System Integrity Program (SIP), advertising expenses, safety, service appointment windows, and other O&M costs.

Q. Are the O&M costs adjusted to reflect services provided from NW Natural to its affiliates?

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A. Yes. The Company'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 total credit to the utility during the Test Year is $543,039. This includes a payroll credit of $425,913. The non-payroll Shared Services credit in the Test Year is $117,126. The non-payroll portion of Shared Services is calculated by imputing an administrative overhead of 27.5 percent to the payroll charges.

Q. Once you have calculated total Company utility O&M costs, do you perform any further adjustments?

A. Yes. The utility's departmental O&M of $153.2 million is adjusted to reflect corporate O&M items. Certain of these items increase Company O&M and others decrease, but the overall effect is a reduction to Company O&M of $15.2 million.

Q. What items are included in the corporate O&M adjustments?

A. The largest O&M credit component, $11.3 million, is called Administrative Transfer. This adjustment is the allocation of a portion of administrative employee costs, such as the salaries and expenses of Accounting, Human Resources, and general administration from O&M to construction activities. These costs are categorized as indirect construction overhead because they cannot be identified explicitly with O&M or construction expenses. A method for allocating a relevant portion of these expenses (including expenses in the areas of administrative support, building rents and insurance costs) to construction activities has been developed based on the amount of work that is reasonably applicable to construction activities. It is possible for most employees to

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charge their time directly to either O&M or capital. For these employees, no allocation from O&M costs is necessary because their time is directly booked to capital activities.

Q. What other items are considered corporate O&M adjustments?

A. The next largest item in the corporate O&M adjustments is a $5.7 million credit that removes payroll tax expense from O&M and transfers it to the income statement. This adjustment is required by FERC accounting methodology. The payroll tax expense is included in the revenue requirement in this case, but is not included in the O&M costs. In addition, the pension balancing credit of $5.4 million reduces the Oregon pension O&M expense for the Test Year to the level that was approved in the Company's last rate case ("2002 Rate Case), Docket UG 152. In addition, the non-payroll portion of the Shared Services credit that I describe above is considered a corporate O&M credit adjustment. The corporate O&M adjustments also include a budget for uncollected claims and damages of $350,000 based on historical average levels.

Q. Do the corporate O&M adjustments include executive benefits?

A. The corporate O&M adjustments include executive benefits totaling $4.9 million. This adjustment to total Company O&M removes certain items that the Commission has previously found are not recoverable in rates or for which the Company has decided not to seek recovery. For example, the Company removed all costs associated with its Long Term Incentive Plan and Executive Supplemental Retirement Income Plan from O&M.

Q. Do any of these adjustments reflect a partial removal of some cost items?

A. Yes. The Company removed a portion of the executive incentive bonus. Lea Anne Doolittle discusses this in her direct testimony.

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Q. How did the Company allocate O&M expenses to Oregon?

A. The Company converted its O&M forecast into FERC accounts based on the latest 12 months of history. The incremental FTEs and programs described were then assigned to specific FERC accounts and added. This process was necessary because the Company does not budget or operate by FERC account, but state allocations are based on FERC accounts. The Company applied the relevant Oregon allocation factor to each FERC account to calculate the Oregon allocated O&M. This allocation is described in the direct testimony of Kevin McVay and Natasha Siores. The incremental advertising and research & development expenses discussed in the direct testimonies of Kimberly Heiting and Grant Yoshihara, respectively, are assigned to Oregon only.

III. O&M COST DRIVERS

Q. What are the most significant drivers of O&M cost increases between the Base Period and the Test Year?

A. The primary drivers of the requested rate increase in this case are additional FTEs that the Company needs to comply with evolving safety requirements including the SIP, and additional FTEs to respond to customers' expectations of increased service, and in particular service windows. These drivers combined with scheduled pay increases in 2012 and 2013 translate into increases in O&M costs.

IV. HISTORIC O&M LEVELS

Q. Please explain how the level of O&M included in the Company's revenue requirement in this case compares with the Company's historic O&M levels.

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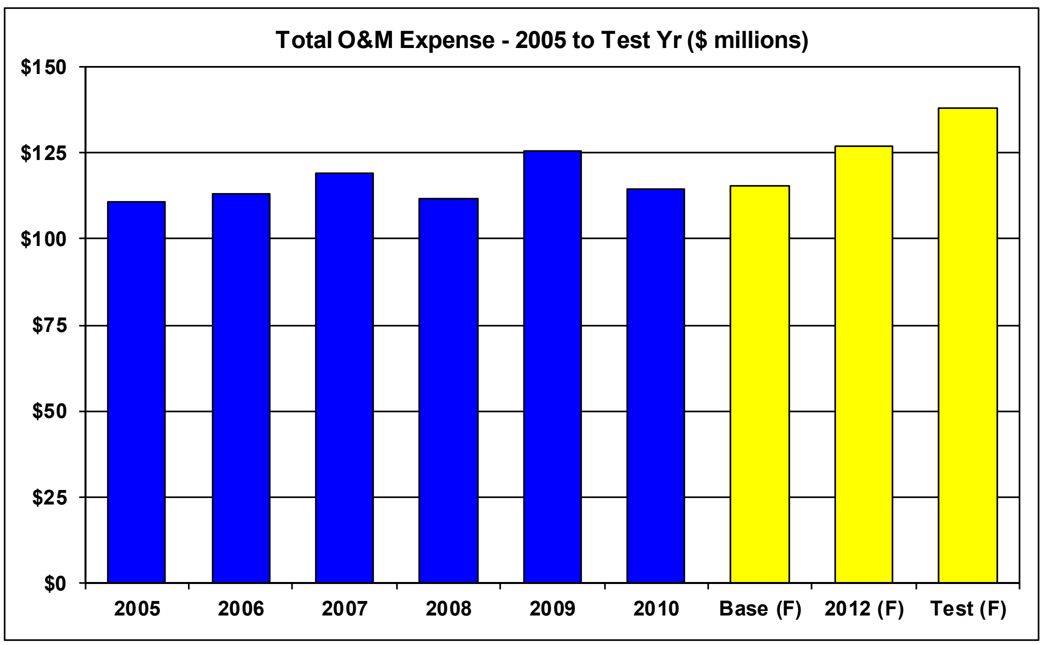
A. The table and accompanying chart below show that total Company O&M (system-wide, including uncollectibles, before exclusions, nominal dollars) has increased from $110.6 million in 2005 to a forecast of $138.0 million for the Test Year, which reflects a compound annual growth rate (CAGR) of 2.8 percent from 2005. Expressed in constant 2005 dollars, the forecast Test Year O&M is $118.6 million, a CAGR of 0.9 percent from 2005.

Total O&M Expense - 2005 to Test Yr ($ millions)

Total O&M	2005	2006	2007	2008	2009	2010	Base (F)	2012 (F)	Test (F)
actuals and forecast	$110.6	$113.3	$119.3	$111.9	$125.7	$114.7	$115.5	$126.7	$138.0
CAGR through Test					2.8%				



The following chart and table illustrate that total O&M increased from $83.5 million in 2001 to $110.6 million in 2005, a CAGR of 7.3 percent. After implementation of the Operations Model in 2006, O&M grew at a significantly lower CAGR of 2.9 percent to a forecast total of $138.0 million for the Base Period. The Operations Model is discussed

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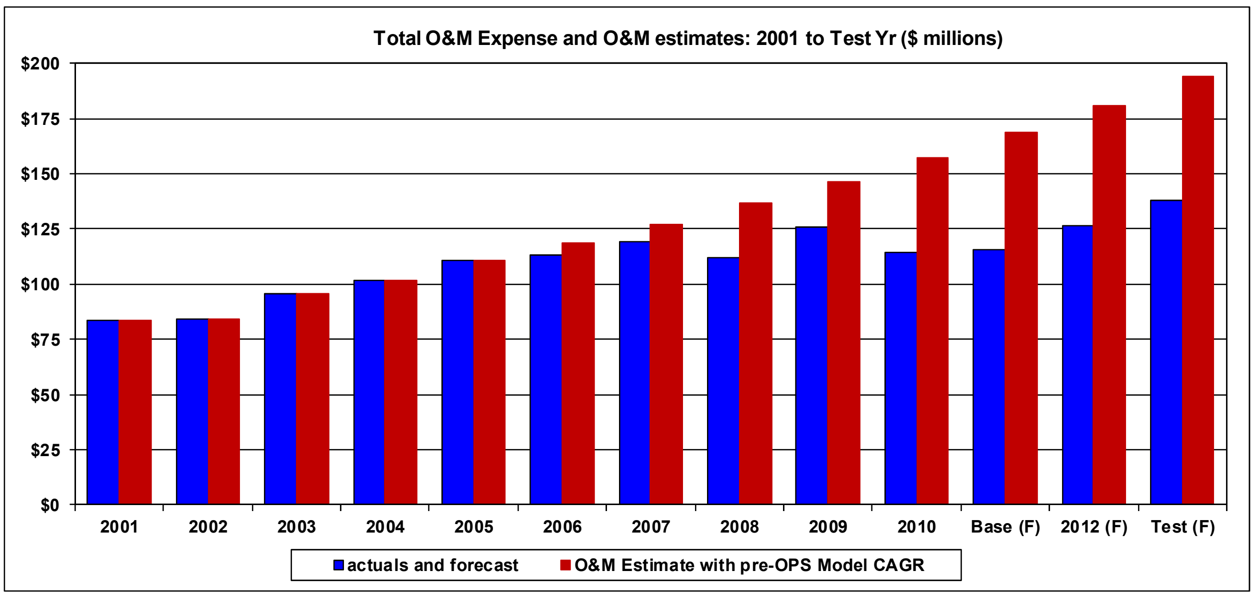
in the direct testimony of David H. Anderson. The chart below also provides an illustration of what the total O&M expense would have been if the pre-Operations Model growth rate of 7.3 percent had persisted through the Base Period ($168.5 million) and on through the Test Year ($194.0 million).

Total O&M Expense and O&M estimates: 2001 to Test Yr ($ millions)

Total O&M	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Base (F)	2012 (F)	Test (F)
actuals and forecast	$83.5	$84.2	$95.7	$101.5	$110.6	$113.3	$119.3	$111.9	$125.7	$114.7	$115.5	$126.7	$138.0
CAGR 2001 through 2005			7.3%										
CAGR 2006 through Test Yr									2.9%				
O&M Estimate with pre-OPS Model CAGR	$83.5	$84.2	$95.7	$101.5	$110.6	$118.6	$127.3	$136.5	$146.5	$157.1	$168.5	$180.8	$194.0



Q. How do current O&M costs per customer compare with historic O&M levels?

A. The table and accompanying chart below show that the Company's total O&M per customer (system wide, before exclusions, nominal dollars) has increased from $179.20 in 2005 to a forecast of $203.79 for the Base Period, a CAGR of 1.6 percent.

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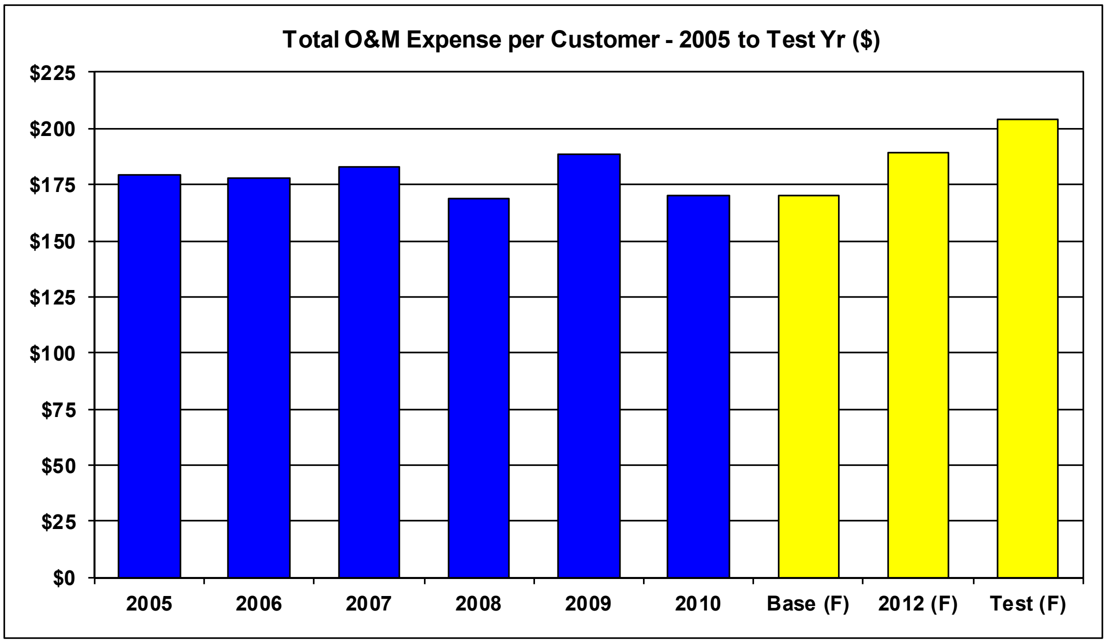
Total O&M Expense per Customer - 2005 to Test Yr ($)

O&M per Customer	2005	2006	2007	2008	2009	2010	Base (F)	2012 (F)	Test (F)
actuals and forecast	$179.20	$177.99	$182.92	$168.95	$188.22	$170.17	$170.11	$189.08	$203.79
CAGR through Test					1.6%				



If the O&M per Customer totals are presented in constant 2005 dollars, there is a reduction from $179.20 in 2005 to a forecast amount of $175.08 for the Test Year.

Q. Have you compared the Company's per customer O&M costs to the per customer O&M costs of comparable utilities?

A. Yes. The following chart provides a comparison of the Company's total O&M-per-customer expense with a panel of similar gas utilities. The chart shows that NWN's forecast Test Year O&M expense of $203.79 per customer was well below the 2010 panel average of $241.47.

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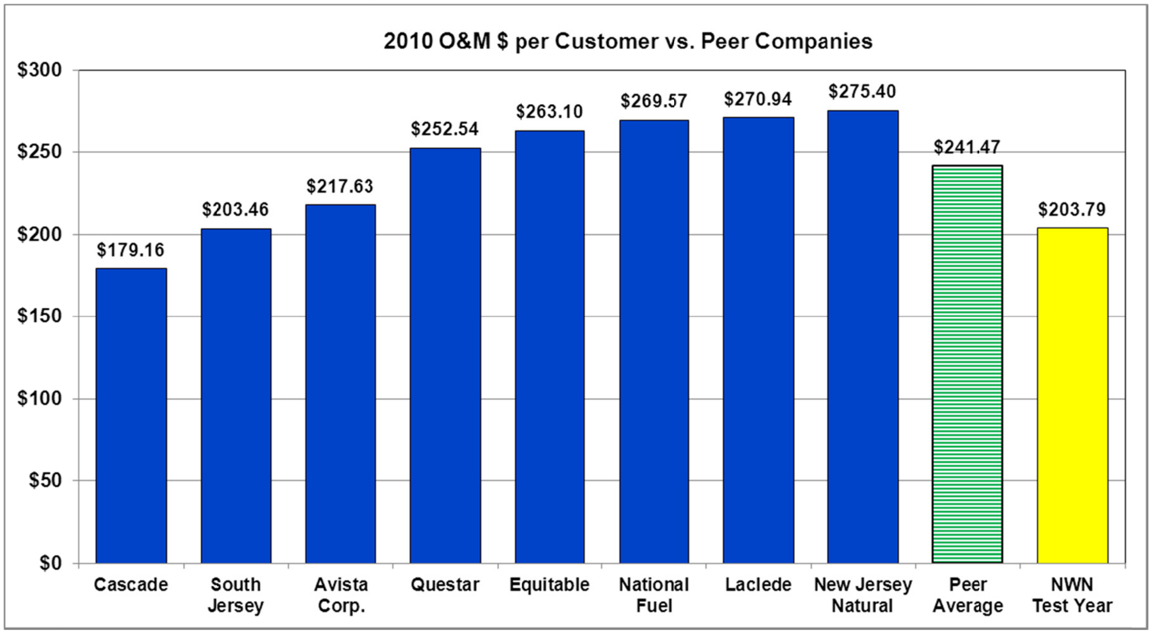
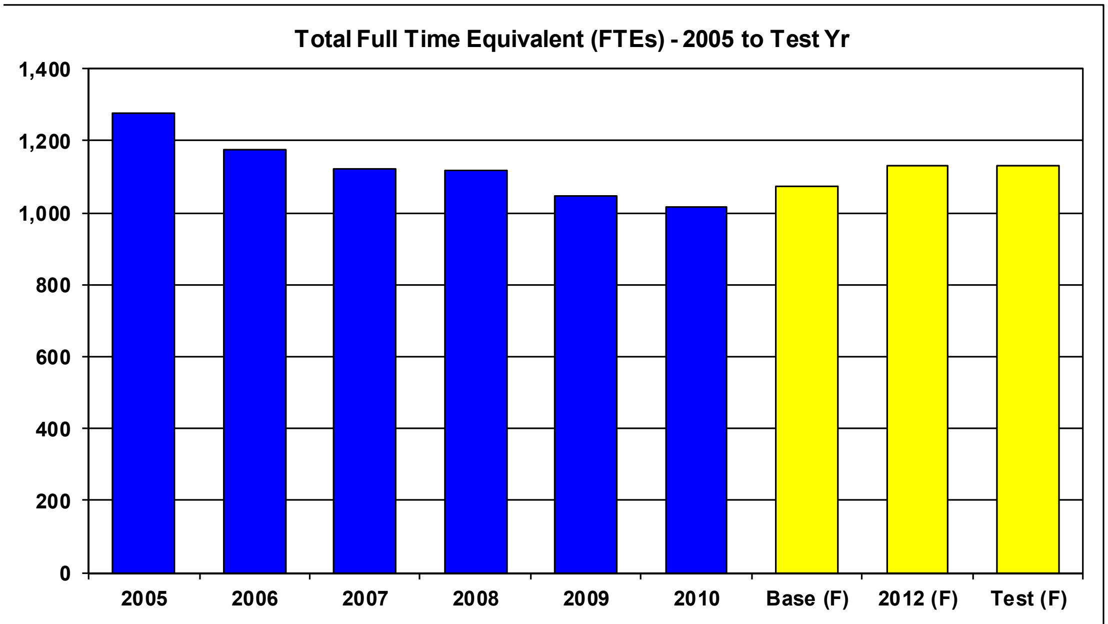


Q. How do current FTE levels compare with historic FTE levels?

A. As the following table and chart illustrate, there were 1,275 FTEs employed with the Company at the end of 2005. Through the Operations Model and Automated Meter Reading program the number of FTEs was reduced by 261 (20.5 percent) to 1,014 in 2010. The forecast Test Year total of 1,130 FTEs represents a reduction of 145 FTEs (11.4 percent) from the 2005 level.

Total FTEs - 2005 to Test Yr

Total FTEs	2005	2006	2007	2008	2009	2010	Base (F)	2012 (F)	Test (F)
FTEs	1,275	1,177	1,123	1,120	1,049	1,015	1,072	1,130	1,130
CAGR 2005 through Test Yr					-1.5%				



V. TEST YEAR CAPITAL EXPENSE

Q. What is the Test Year capital expense included in the revenue requirement?

A. Capital expenditures for the Test Year are forecast to be $98.7 million, which is a blend of two months of 2012 expenditures, and ten months of 2013 expenditures. The capital forecasts for calendar years 2011, 2012, and 2013 are shown in the following table:

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(Dollars in Millions)

		2011	2012	2013
	Total Capital Expenditures			
1	**Customer Acquisition**	$14.1	$14.3	$16.1
2	**Replacements Supported by Revenues**	$4.0	$11.3	$8.8
3	**Replacements Not Supported by Revenues**	$35.1	$58.5	$31.2
4	**Investments Requiring Economic Justification**	$11.4	$39.1	$10.1
5	**Storage**	$0.2	$0.2	$0.0
6	**Construction Overhead**	$28.3	$28.9	$29.6
7		$93.1	$152.3	$95.8

Descriptions of the Capital Expenditure Categories used at NW Natural are as follows:

- **Customer Acquisition** includes the capital costs for new mains, services, meters, and permits required to serve new customers.
- **Replacements Supported by Revenues** includes the Company's SIP, which is comprised of bare steel replacements, leakage reconstruction, and the Company's distribution and transmission integrity programs.
- **Replacements Not Supported by Revenues** includes public works, relocates & abandonments, system reinforcement, damage reconstruction, district regulators, gas supply improvements, and general plant.
- **Investments Requiring Economic Justification** include radio & electronic equipment, information technology, land, and structures.
- **Storage** includes ongoing capital improvements and leaseholds relating to the Company's Mist underground storage facilities.

The forecast Test Year total of $98.7 million is comprised of $15.8 million to support Customer Acquisition, $8.3 million for Replacements Supported by Revenues,

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$31.9 million for Replacements Not Supported by Revenues, and $13.2 million for Information Technology and Structures investments.

Q. Can you explain the primary drivers behind the Company's planned 2012 capital spend?

A. These drivers are the Corvallis Loop Project and Willamette Valley feeder projects discussed in the direct testimony of Grant Yoshihara and the purchase of a new facility in Sherwood discussed in the direct testimony of Lea Anne Doolittle.

Q. Please explain how the Company calculated the Test Year capital expense.

A. The Test Year capital expense was developed using the following steps:

1. Each operating department submits a detailed three-year capital forecast.
2. The Budget Department reviews the forecasted Test Year capital and verifies that each department has adequately supported its assumptions.
3. The departmental forecasts are summarized to create a Company capital requirement by year.
4. The capital requirements are reviewed by their respective executive for completeness and reasonableness. Adjustments are made as needed.
5. Once the calendar year forecasts are completed, the totals for the Test Year are calculated. Program and project expenditures are spread by month based on projected project spending schedules.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Lea Anne Doolittle

COMPENSATION AND BENEFITS / FACILITIES EXHIBIT 800

December 2011

EXHIBIT 800 – DIRECT TESTIMONY - COMPENSATION AND BENEFITS / FACILITIES

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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 of NW Natural. I am responsible for overseeing the following functions at NW Natural: Human Resources, Payroll, Facilities, Occupational Safety, Security, Project Management, and Business Continuity.

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 ten 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 overall level of compensation included in the November 2012-October 2013 test year ("Test Year");
- Explain the Company's approach to compensation, which results in total compensation that is at the market median for comparable companies and are at the level necessary to attract, retain, and motivate the skilled employees required to run the business;

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- Address the four primary components of total compensation by:
    - Demonstrating that the Company's base pay is situated at the median of the market and that our year-over-year growth in base pay is reasonable;
    - Providing an overview of the Company's various incentive programs and rationale for why the Company should be allowed to recover these market median expenses at targeted levels;
    - Demonstrating that our medical benefits are aligned with the market and that the Company has prudently managed these benefits, and
    - Describing the changes the Company has made to retirement programs since the Company's last rate case, Docket UG 152 ("2002 Rate Case"), and why we believe we should be allowed to recover these market competitive benefits; and
- Provide testimony on a facility that the Company is in the process of acquiring that will serve as an integrated training facility and a business continuity center, and provide for the consolidation of current operations at other facilities.

II. OVERALL COMPENSATION AND BENEFITS IN THE TEST YEAR

Q. What is the overall level of compensation and benefits expenses included in the Test Year revenue requirement?

A. My testimony demonstrates that the Company's rates should be based on compensation and benefits expenses for the 1,130 full-time equivalent positions (FTE) in the Test Year as shown in the following Table 1. See the direct testimony of John Sohl for a discussion of the total FTEs included in the Test Year. *See NWN/700, Sohl/12-13.*

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Table 1
Total Company Estimated Total Compensation Costs ($000)

Component	2011 Actual + Projected	2012 Forecast	Test Year
Base Pay	74,075	79,988	84,146
Merit-based incentives	5,231	5,812	6,101
Medical Benefits	15,729	17,337	18,417
Retirement Benefits	3,036	3,389	3,642
Total	98,071	106,526	112,306

Q. Are you seeking to recover any costs related to employees of NW Natural subsidiaries?

A. No. All costs related to base pay, merit-based incentives, heath care (including medical), and retiree benefits of employees of NW Natural subsidiaries are allocated directly to these entities and are not included in the costs the Company seeks to recover in this case.

Q. Are you seeking recovery for the costs associated with NW Natural employees working for NW Natural subsidiaries?

A. No. Each employee who performs work for a subsidiary charges his or her time to the subsidiary. The salary for that employee's salary grade is then loaded with the payroll overhead rate in effect at that time. This transaction generates a credit to the employee's home cost center in the utility.

III. TOTAL COMPENSATION APPROACH

Q. What is NW Natural's approach to total compensation?

A. The Company's policy is to provide competitive total compensation in order to attract, motivate, and retain high-performing, qualified employees necessary to provide safe and reliable gas service at a reasonable price with good customer service.

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Q. Please define "competitive total compensation."

A. Total compensation—which is the combination of base pay, merit-based incentives, medical benefits, and retiree benefits—is competitive when its financial value is at the median level for total compensation offered in the marketplace for comparable jobs.

Q. How does NW Natural determine that its total compensation package 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.

IV. BASE PAY

Q. What is 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.

Q. How does the Company ensure that its employees' base pay is set at a competitive level?

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 September of 2011, is at *NWN/801, Doolittle/1*. The analysis demonstrates that NW Natural's base pay midpoints for non-bargaining unit (NBU) jobs are at the median of the comparator companies.

Q. Is this same method of analysis used to determine median base pay compensation for Company officers?

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A. No. In the case of officers, the Company hires an independent compensation consultant who is responsible for performing similar analysis for officers using survey data. The results of the competitive analysis completed by the firm Towers Watson that demonstrates that the Company's compensation for officers is at the market median is at *NWN/802, Doolittle/1.*

Q. What is the total company amount for base pay projected for the test year?

A. Table 2 below demonstrates the amount of base pay for the 1,130 FTEs included in the Test Year:

Table 2
Total Company Total Base Pay (Wages & Salaries) ($000)

NW Natural Wages & Salaries	2011 Actual + Projected	2012 Forecast	Test Year
Bargaining Unit (BU) Employees	36,417	38,627	40,880
NBU Hourly Employees	1,743	1,683	1,721
NBU Salaried Employees	33,276	36,974	38,768
Officers	2,639	2,704	2,777
Total	74,075	79,988	84,146

Q. Does the amount of base pay shown for the Test Year align with the projected movement in the consumer price index (CPI)?

A. No. NW Natural believes that the CPI is not an appropriate index for calculating base pay increases.

Q. Why not?

A. While CPI reflects the average prices for goods and services over time, our research shows that it does not accurately represent what the Company must pay to attract and retain skilled employees. The cost of labor is influenced by factors other than those used in CPI such as the Company's current base pay relative to market median pay, types of

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skill sets required for certain jobs, and supply and demand for those needed skill sets. For these reasons, we have found that the best method for determining the appropriate growth rate for salaries is to track the anticipated pay movement of competitor companies as provided in compensation trend surveys.

Q. Please compare the CPI to the cost of labor.

A. The historical relationship between CPI and cost of labor base pay increases. *See NWN/803, Doolittle/1.* As can be seen from this exhibit, cost of labor increases to base pay are up to 3.7 percent higher than CPI. This means that for most years, the Company must provide more than a CPI adjustment to attract and retain employees with the necessary and unique skill sets required to run the business.

Q. Since the Company's base pay has increased at a rate that is higher than CPI, how does the Company plan to demonstrate that its spending is prudent?

A. The prudence of the Company's compensation packages for officers and NBU employees is met by showing that the Company's historical wage increases have been aligned with or slightly below both general industry and utility company averages. *See NWN/804, Doolittle/1*. For bargaining unit (BU) employees, total compensation is determined through a negotiated process. Market median base pay provides the basis for the agreed-upon wage increases throughout the term of the negotiated contract. As with any labor negotiations, trade-offs are negotiated for other terms and conditions in the contract. The wage increase formula agreed to in 2009 provides a guaranteed one percent base pay increase and allows for an additional "wage adjuster" of zero to two percent depending upon the change in the CPI for Urban Wage Earners and Clerical Workers (CPI-W). NW Natural's union average annual wage increases have been

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below average increases for general industry or utility companies, which have tracked closer to three percent per year. *See NWN/804, Doolittle/1.* Using the formula of one percent plus the 2011 change CPI-W data, the Company expects that inflationary pressures will likely drive wage increases to the BU contract maximum of three percent in both 2012 and the Test Year.

V. MERIT-BASED INCENTIVES

Q. Please define merit-based incentives.

A. Merit-based incentives are financial payments made to employees if certain performance goals are met within a defined timeframe. Merit-based incentives are not a *guaranteed* amount of total compensation and for that reason are sometimes referred to as "pay-at-risk." Unlike base pay and other benefits, merit-based incentives represent the one component of the total compensation package that must be earned solely through performance.

Q. Does the Company offer merit-based incentive programs?

A. Yes. The Company has four merit-based incentive programs for which we are seeking recovery as described in Table 3 below:

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Table 3

Type of Program	Eligible Participants	Program Objectives	Summary of Key Performance Measures
Key Goals	All NBU and BU employees (excludes officers)	Attract, retain, and motivate employees to perform in the best interest of customers and shareholders.	Customer Satisfaction Productivity Cost Efficiency Earnings Per Share
NBU Short-Term Incentives	All NBU employees (excludes officers)	Attract, retain, and motivate employees to perform in the best interest of customers and shareholders.	Customer Satisfaction Productivity Cost Efficiency Earnings Per Share Return on Invested Capital
Officer Short-term Incentives	Officers (Only requesting partial recovery)	Attract, retain, and motivate employees to perform in the best interest of customers and shareholders	Customer Satisfaction Productivity Cost Efficiency Earnings Per Share Return on Invested Capital
Long-term Incentives	Managers, officers and key employees (Only requesting partial recovery for non-officers)	Attract, retain, and motivate employees to perform in the best interest of customers and shareholders	Long-Term Performance Goals Stock Appreciation

Q. Why do you offer merit-based incentive compensation?

A. We offer merit-based incentives for three reasons. First, merit-based incentives provide a direct way to reward and further encourage behaviors that benefit customers and shareholders alike. Second, merit-based incentives are so widely employed by our competitors for labor, and are viewed so favorably by the workforce, we believe that we must offer them in order to provide an overall compensation package necessary to attract and retain a quality workforce. Third, merit-based incentives are part of the total cash compensation required to deliver market median competitive pay to employees. Merit-based incentives are preferred by the industry to adding this pay directly to base

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pay. For the gas industry on average, 80 percent of companies have at least one incentive plan. *See NWN/805, Doolittle/1.*

Q. Explain why two merit-based incentive programs are offered to NBU employees.

A. The Key Goals incentive program was negotiated with our union and includes a fixed target of 3.5 percent and maximum incentive opportunity of seven percent of earnings. This is a program in which all employees except officers participate and that rewards employees for the achievement of specified Company performance goals. However, our research shows that a targeted 3.5 percent incentive from the Key Goals program is not sufficient to provide market competitive levels of compensation to NBU personnel. Therefore, we created a second incentive program with essentially the same goals, that, when added to the Key Goals portion and base pay, brings cash compensation opportunity up to market median for these NBU employees.

Q. How do customers benefit from the Company's offering of merit-based incentives?

A. Merit-based incentives are paid when targeted goals specific to customer satisfaction, cost efficiency, and productivity are met. As a result, the merit-based incentive offering is an efficient way of encouraging employees to deliver safe, reliable, and cost effective gas service with good customer service. Merit-based incentive goals also include earnings and return measures that benefit shareholders and, in an indirect manner, the Company's customers. As discussed in the direct testimony of David H. Anderson, NW Natural's customers benefit when the financial performance of NW Natural is strong because the Company is able to borrow money at lower rates and raise equity

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necessary to support the gas distribution system enhancements. These lower borrowing costs contribute to keeping rates low for customers.

Q. Does the payment of merit-based incentives result in total compensation that is above a competitive level?

A. No. Our merit-based incentives are designed to provide, when added to base pay, total cash compensation at the market median. In other words, if NW Natural did not provide merit-based incentives, its total cash compensation would be below the market median. Without the opportunity for merit-based incentive compensation, total cash compensation would be below the comparative market.

Q. What are targeted merit-based incentive levels?

A. 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 can have more influence on the attainment of Key Performance Measures (*See* Table 3). Lower-level employees have less compensation "at risk" as their ability to influence outcomes is more limited. Table 4 represents the target incentive levels by employee groups.

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Table 4

Incentive Program Type	Participants	Target percent of Pay	Maximum percent of Pay	Amount Requested in Test Year as percent of Pay
Key Goals	All employees (excluding officers)	3.5 percent	7 percent	3.5 percent
NBU Short-Term Incentive	All NBU employees (excluding officers)	4 percent- 16.5 percent Depending on level	8 percent- 33 percent	4 percent- 16.5 percent
Officer Short-Term Incentive	Officers	35 percent- 70 percent depending on level	70 percent- 140 percent	20 percent (3.5 percent plus 16.5 percent is same total as grade 25/26 managers and using average salary for 25/26 managers)

Q. Given that the Commission has historically disallowed the recovery of officer merit-based incentive compensation expense, why are you requesting such recovery in this filing?

A. The Company acknowledges the Commission's past policies regarding officer incentives, but believes that there is merit in reconsidering this position. We firmly believe that the full amount of incentive compensation for our officers should be recoverable in rates, as it is an essential component of the total competitive compensation that is necessary to attract, retain, and motivate the leaders of the business to perform in the best interest of the Company and its customers. We also acknowledge that our officers are working managers who work for the customers in the same manner as senior managers. Given the Commission's past rulings on executive compensation, we are reducing our request to only a portion of officer incentives. This is the proportion for officer's equivalent to a

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typical Grade 25/26 manager, which is the highest grade level for non-officer management. Further, we are calculating these merit-based incentive amounts for officers using the average base pay for managers in Grade 25 and 26.

Q. Please explain the amount for merit-based incentives that is included in the Test Year forecast.

A. We are requesting 100 percent of the target percentage of pay for each group of employees except for officers, as shown in Table 4 above. As previously explained, the amount for officers is equivalent to what these individuals would be targeted to receive if they were senior managers. In the Test Year the Company has included $6,101,000 in rates as shown below in Table 5 for the Company's 1,130 FTEs. These values are consistent with the percentages of earnings shown in the last column of Table 4 above.

Table 5
Total Company Merit-based incentives ($000)

Merit-based incentives	**2011 Actual + Projected**	**2012 Forecast**	**Test Year**
Short-Term Incentives (BU & NBU)	4,775	5,327	5,598
Short-Term Incentives (Officers)	320	330	339
Long-Term Incentives (Non-officers)	136	155	164
Total	5,231	5,812	6,101

Q. What is the precedent for recovery of such costs?

A. In prior rate cases, the Commission has allowed recovery of only approximately 50 percent of the actual amount utilities have historically spent on merit-based incentives.

Q. Why is the Company requesting recovery of 100 percent of target incentive levels in this rate case?

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A. NW Natural believes that the Commission's policy should be reconsidered. While the current policy may have been established at a time when incentives were considered an "add-on" to already competitive pay levels, this is clearly not the case today, as we have demonstrated. The Company also believes that failure to allow recovery of target levels could have the unintended consequence of encouraging utilities to eliminate their performance based incentive offerings and maintain median levels of compensation by increasing base pay. Given our belief that pay-at-risk is an important motivator for employee performance, this result would be to the detriment of utility customers.

Q. Please describe NW Natural's long-term incentive plans.

A. The Company has used a combination of stock options and performance shares as our long-term incentives for managers, officers, and key employees for about 11 years. In 2012, the Company will replace stock options as part of its regular long-term incentive offerings with performance based Restricted Stock Units (RSUs). RSUs involve a grant of stock units that vest over time if certain retention and performance threshold conditions are satisfied. When conditions are satisfied, the units are converted to shares of NW Natural stock and delivered to the employee. NW Natural is moving from stock options to RSUs because the Company believes that RSUs will be more effective than stock options in promoting the performance and retention of managers, officers, and key employees, and also because they better align with market practice. The annual compensation expense for RSUs is the same as stock options.

The Company also sponsors a performance share long-term incentive plan for officers, which when combined with stock options or RSUs make up the total competitive market median long-term incentive opportunity value for officers. The Company is not

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asking for recovery of either the performance share expense or the RSU expense for officers.

Q. What level of recovery is the Company including in the Test Year?

A. NW Natural is seeking recovery of the Test Year expenses associated with the RSU long-term incentive program for non-officers. NW Natural is requesting 50 percent of the non-officer expense forecasted to be $164,000 in the Test Year.

VI. MEDICAL BENEFITS

Q. Why does NW Natural offer medical benefits to its 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. Table 6 shows the medical benefits costs for which the Company is seeking recovery:

Table 6
Total Company Total Medical Benefits ($000)

Medical Benefit Components	**2011 Actual + Projected**	**2012 Forecast**	**Test Year**
NBU Retiree Medical (FAS 106)	2,589	2,700	2,700
BU Medical Active and Retiree	8,087	8,887	9,369
NBU Active Medical	5,053	5,750	6,348
Total	15,729	17,337	18,417

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Q. How have costs increased for medical coverage in the last few years?

A. Both national and local health care cost increases are compared to the Company's increases over the same period at *NWN/806, Doolittle/1*. *NWN/806, Doolittle/1* shows national and local medical costs have been trending up by nine percent to over 12 percent from 2009 to 2012. Over this same period, NW Natural's active employees' medical expenses have been increasing at rate that has been less than one percent to as high as 13 percent. For three of these four years, NW Natural was significantly below these national and local trends, but the Company has been notified that our 2012 increase will be slightly higher than the forecasted trend for 2012. This exhibit also demonstrates that the Company's medical increases for NBU retirees have been closely aligned with trends for both national and local increases over this four-year period. In the case of BU retirees, medical increases lagged the trends for a couple of years as a result of plan redesign and have exceeded trends in the most recent years.

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. LifeWise increases rates based entirely (100 percent) on the experience for our actual insured population. On the other hand, Kaiser uses a combination of the experience of the population (70 percent factor) and also a factor related to the Company's overall demographics as compared to the community (30 percent factor). Given that the average age of our employees is 49 years old, 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. Based on a 2011 Towers Watson 360 Health Care Report, NW Natural's

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medical premiums are expected to be six percent higher for PPO enrollees and three percent higher for HMO enrollees due to the average age of 49 when compared to other companies.

Q. Has the Company 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 regularly issues requests for proposals (RFPs) from medical insurance providers to ensure that our providers' prices are competitive. RFPs are issued no less than once every five years or upon notice of a significant increase in premiums from a current medical insurance provider. Since 2003, the Company has conducted three medical RFPs for active NBU employees, seven for active and retirees, and 26 for all benefit plans in combination. The Western States Health & Welfare Trust, under which our BU employees receive medical benefits, has also completed three RFPs for the bargained medical plans.

In addition to ensuring that incurred costs are competitive in the market, the Company has also modified its medical offerings. In an effort to manage costs and stay aligned with evolving market practices, retirees and employees are paying a higher percentage of their medical costs than in prior years. In particular, the Company has made the following significant changes to its health care offerings since the Company's last rate case filing in Oregon:

- Retiree medical benefits were closed to new NBU employees hired after December 31, 2006, and to BU employees hired after December 31, 2009.
- Retiree medical benefits for NBU employees were substantially reduced to align with the competitive market.

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  - In 2006, caps were put in place to limit spending and control medical costs. The current caps of $2,400 per retiree per calendar year for those over 65 and $4,800 for retirees younger than 65 have not increased since 2006. This cost control measure alone has resulted in a reduction in our projected benefit obligation for retirees of approximately $4.5 million.
  - Incremental increases in medical costs are being covered by increased cost sharing allocations to 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 more than 20 percent of the premiums.
- The level of health coverage provided to both NBU and BU has been reduced in order to manage costs. This change has resulted in employees being required to contribute more of their own money for health care services. The changes that have been made to the NBU and BU health care plans over the last several years are detailed at *NWN/807, Doolittle/1.*
- The Company included a provision in the 2004 labor agreement for BU employees that limits the amount it will pay monthly for medical coverage. This provision continues to be in effect.
- 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 50 percent participate in a voluntary wellness program offered to encourage employees to adopt a more

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physically active lifestyle. Many employees using these programs are experiencing improved heath, including reduced body weight and lowered blood pressure.

These combined efforts are controlling medical cost increases and demonstrating our prudent management of these expenses.

Q. How does the design of NW Natural's medical plans compare with that of other companies?

A. Towers Watson completed an analysis of the Company's medical benefits relative to 11 peer utilities and 100 other utility/energy companies in their Energy data base. In this comparison, Towers Watson utilized the following rating categories: Equal, Worse or Better. NW Natural's medical benefits were rated by Towers Watson on and overall basis to be Equal to both the 11 peer companies and the overall Energy data base. *See NWN/808, Doolittle/1*. This analysis compared everything from deductibles, to coinsurance (premium sharing) to co-pays for office visits and drugs and there was a wide 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 care benefits?

A. The Company focused on medical benefits (medical and pharmacy) because they make up 82 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 ten plus years.

Q. Are the other health benefits being offered also market competitive?

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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 11 peer utility companies as well as the overall Energy data base provided in the Towers Watson survey. *See NWN/809, Doolittle/1.* While there were some variations from this for certain categories of other health benefits, overall the Towers Watson survey indicated the NW Natural's health benefit plans were substantially at market when compared to other utilities.

VII. RETIREMENT BENEFITS

Q. Please provide an overview of your retirement benefits.

A. Table 7 shows the retirement income benefit programs, which provide market median retirement offerings to employees:

Table 7

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 4 percent saved by BU employee and 60 percent of first 6 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	Contribution made by company into "Enhanced" account-no employee contribution required Contribution is 5 percent for NBU; 4 percent for BU
Western States Pension Plan	All BU employees	Contribution made by company into retirement plan. Contribution is 33 cents per hour.
NW Natural Retirement Plans: NBU Plan and BU Plan	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.

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Q. What change have you made to your retirement income benefits since the Company filed its 2002 Rate Case?

A. The Company has made numerous changes to its retirement income benefit plans since the 2002 Rate Case—all with the goal of reducing expense and expense volatility. Consistent with this goal, the two defined benefit pension plans were closed to new hires and rehires. In their place, the Company provided new employees a contribution of five percent for NBU and four percent for BU into the Retirement K Savings Plan (401k), referred to as the Enhanced contribution.

For BU employees, we added the Western States Pension Plan as an outcome of 2004 negotiations at which time the union successfully demonstrated that their overall retirement benefits were below market competitive levels. Also, consistent with the expense reduction goal, the Company has amended the two defined benefit pension plans for NBU and BU employees to (1) eliminate disability retirement benefits; (2) reduce the types of pay eligible for the pension calculation (post-employment bonuses and cashed-out Paid Time Off/vacation are no longer available); (3) limit bonus amounts; and (4) reduce the early retirement subsidy.

Q. How do NW Natural's retirement benefits compare to the benefits provided by other companies?

A. In August of 2011, the Company asked Towers Watson to analyze the Company's retirement benefits relative to other utilities. Towers Watson concluded that NW Natural's retirement benefits were not as good when compared to the companies in their comparison group. *See NWN/810, Doolittle/1.* In reviewing the Company's benefits relative to the 11 peer utilities and 100 other utility/energy companies in their Energy

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data base, Towers Watson utilized the following rating categories: Equal, Worse or Better. Relative to these other companies, NW Natural's retirement benefits were rated as Worse than the comparison group for the Employer 401k match; Better for short-term employees and Equal to or Worse for longer-term employees for the Defined Benefit Pension Plan and the Enhanced contribution to the 401(k). Their definition of longer-term employees is generally an employee with greater than nine year- of-service. NW Natural's average years-of-service is 15.68 years.

Q. Please explain the total Company amount for retirement benefits for the Test Year.

A. Table 8 shows the amount requested for recovery in the Test Year revenue requirement.

Table 8
Total Company Total Retirement Benefits ($000)

Total Retirement Program Benefits ($000)			
Component	**2011 Actual + Projected**	**2012 Forecast**	**Test Year**
RKSP-Matching Contribution	2,159	2,229	2,342
RKSP-Enhanced Contribution	453	697	824
Western States Pension	424	463	476
Total	**3,036**	**3,389**	**3,642**

Q. Why did the Company exclude the defined benefit pension expenses from this testimony?

A. The defined benefit expenses are addressed in the direct testimony of Stephen P. Feltz.

VIII. FACILITIES

Q. Earlier in your testimony, you stated that you would address an addition to NW Natural's facilities. Please explain what facility addition you will discuss.

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A. NW Natural is in the process of acquiring property in Sherwood, Oregon ("Sherwood Property") that will allow for the construction of a multi-purpose facility. This facility will include an integrated training facility and a business continuity center, and will provide for the consolidation of current operations in our Tualatin and South Center facilities. In turn, these two existing facilities will be sold, thus offsetting a portion of the cost to ratepayers assuming there is a gain on the sale.

Q. What prompted this decision to acquire additional property?

A. The Company identified two functional business needs. One of these was an integrated training facility. The second was a business continuity center. Initially, the Company studied the feasibility of utilizing one of our existing facilities for these purposes. Of the Company's existing facilities, the South Center facility ("South Center") in Tualatin, Oregon was the only logical choice because of its size and location. However, in pursuing due diligence for this site, we learned that the South Center property had been re-designated by governmental authorities as being in a 10-year flood zone, as opposed to a 100-year flood zone as was previously thought. This new designation eliminated South Center as a viable option. For that reason, we conducted a market search for other viable properties to serve the Company's training and business continuity needs. It was during this search that the Sherwood Property was identified.

Simultaneously, the Company has been in the process of repairing several of its facilities due to their deteriorating condition. The Company's Tualatin facility was among the facilities scheduled for retrofit. The Company hired an architectural firm, MulvanyG2, to review and estimate the cost to retrofit this facility. MulvanyG2 estimated $10.5 million would be required to retrofit the Tualatin facility. Hence, when the Sherwood

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Property was identified, the Company saw an opportunity to consolidate two aging or threatened facilities into a single, modernized facility, as well as to satisfy the business needs for a training facility which would also serve as a business continuity center.

Q. What are the costs associated with the Sherwood Property?

A. We have reached an agreement in principle with the seller to purchase the Sherwood Property for $9 million. Initial cost surveys indicate that it will require another $8.5 million to build out the facility to meet the Company's full service requirements. The total amount of approximately $17.5 million will be partially offset through the sale of the Tualatin and South Center facilities if there is a gain on the sale. We are advised by commercial realtors with experience in the area that we could reasonably expect a combined sales price for the Tualatin and South Center properties of approximately $7.3 million. Thus, when net book values are incorporated into the analysis, the net outlay for the Sherwood Property will be approximately $13.9 million.[1] This incremental $3.4 million outlay (the amount over and above a necessary Tualatin retrofit of $10.5 million) will provide suitable space for the combined functionality of two service centers, a training facility, and a business continuity center.

Q. What is the purpose of the integrated training center component of the facility?

A. Effective employee training is essential to providing a safe and reliable gas distribution system for our customers and the communities we serve. The Company's training regimen has always demonstrated the Company's commitment to that tenet. However,

1 This $13.9 million is calculated based upon the estimated sales price of $7.3 million, less our net book value of $3.7 million for the Tualatin and South Center properties, leaving $3.6 million to be applied against the Sherwood property purchase/development.

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the current training facilities are no longer adequate, and we therefore determined that a more suitable training facility is needed.

Q. Please describe the planned training facility.

A. The training facility is intended to function as an integrated training facility for field operations and service employees that accommodates classroom, practical, and scenario-based training. NW Natural has expanded its emergency response training program, and this integrated facility would ensure that training can be designed and delivered in a consistent and more effective way. This facility will also allow for joint NW Natural and fire department training and coordination using live gas in a controlled environment, resulting in improved joint response to gas emergencies.

Q. What is the purpose of the planned business continuity center?

A. If it can be said that a business's ability to operate "is only as strong as its weakest link," then NW Natural's weakest link would likely be One Pacific Square (OPS). All critical business support and data functions operate out of this single building. Put another way, OPS is one single potential point of failure. In the event of a serious fire, flood, or earthquake, NW Natural could be left with no operational hub, without ready access to records, data, or a physical plant from which core administrative employees could conduct business. While some of this could be reconstituted, no place currently exists to accommodate that need, should it arise. A designated business continuity center will meet that need, and will also keep NW Natural in a position that will be better matched with its local utility peers. In the event of an emergency, the business continuity center will expand into the classrooms of the integrated training facility. In this fashion, the Company will be able to leverage existing space for multi-functional purposes.

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Q. What other uses will NW Natural make of the Sherwood Property?

A. As I have noted elsewhere in my testimony, the Company plans to consolidate the Tualatin and South Center operations into a single, multi-purpose facility. Currently, the Tualatin and South Center facilities are the front line in our customer service mission. The qualified technicians at these facilities perform a wide array of duties, including construction services, fleet repair services, customer field services, leak detection services, and gas supply. The Tualatin facility also houses our central storeroom, weld-shop, meter shop, and other functions. All of these functions will be consolidated to the Sherwood Property.

Q. When do you expect the Sherwood Property to be completed?

A. Assuming timely procurement of the property, we expect significant completion of the site by late summer 2012—allowing us to begin training activities and the initial use of the business continuity center soon thereafter. Additional construction will be completed later in the year and perhaps early 2013, with the moves of the Tualatin and South Center sites to follow.

Q. Does this conclude your direct testimony?

A. Yes.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Exhibits of Lea Anne Doolittle

COMPENSATION AND BENEFITS / FACILITIES EXHIBITS 801-810

December 2011

EXHIBITS 801-810 – COMPENSATION AND BENEFITS / FACILITIES

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Exhibit 801 Base Pay Analysis

2012 Salary Structure - Base Pay Analysis

	2012 Salary Structure	
NWN Grade	NWN 2012 Midpoint	NWN Midpoint vs. Market Median
14	$46,600	123%
15	$50,800	99%
16	$55,300	101%
17	$60,300	96%
18	$65,700	100%
19	$71,700	99%
20	$78,100	96%
21	$85,100	100%
22	$98,000	96%
23	$108,000	95%
24	$119,000	95%
25	$130,400	97%
26	$143,500	98%
	Overall	**100%**

Data Source: Boedigheimer Consulting / Market Review September 2011

802 - Total Compensation Review for Top Executives
Results of Competitive Analysis

- NW Natural target total direct compensation is at the 50th percentile of the utility market but (with some exceptions) below the 50th percentile of general industry.

Title	NWN Positioning to Market Median			
	Utility Industry*		General Industry	
	Target Total Cash	Target TDC**	Target Total Cash	Target TDC**
CEO & President	< 50th	50th	< 50th	< 50th
Sr VP Finance & CFO	50th	50th	< 50th	< 50th
VP & General Counsel	50th	50th	< 50th	< 50th
Senior Vice President	> 50th	50th	< 50th	< 50th
VP Business Development & Energy Supply	50th	50th	< 50th	< 50th
Treasurer & Controller	50th	50th	50th	50th
VP Utility Services	50th	50th	50th	50th
VP Utility Operations	50th	50th	< 50th	< 50th
Deputy General Counsel & Corporate Secretary	50th	50th	50th	50th
VP Finance Regulation / Assistant Treasurer	50th	50th	50th	50th

* Represents NWN positioning to market survey data.
* TDC = Total Cash (base plus annual incentives) and long term incentives.

Extracted from study completed by Towers Watson – February, 2011.

Exhibit 803 CPI / Labor Relationship

CPI and Historical Cost of Labor Base Pay Increases

Year	CPI-U[1]	General[2] Industry Increases	Utility[2] Increases	CPI-U[1] vs General[2] Industry Increases	CPI-U[1] vs Utility[2] Increases
2002	1.6%	3.9%	3.4%	2.3%	1.8%
2003	2.2%	3.6%	3.4%	1.4%	1.2%
2004	2.3%	3.6%	3.5%	1.3%	1.2%
2005	3.5%	3.7%	3.5%	0.2%	0.0%
2006	3.5%	3.8%	3.3%	0.3%	-0.20%
2007	2.6%	3.9%	3.7%	1.3%	1.1%
2008	3.9%	3.9%	3.7%	0.0%	-0.20%
2009	-0.7%	2.2%	3.0%	2.9%	3.7%
2010	2.2%	2.5%	3.0%	0.3%	0.8%
2011	3.2%	2.8%	2.8%	-0.4%	-0.4%

[1]Calculated using 12-month change in CPI-U from April to April as published by Bureau of Labor Statistics

[2]World At Work 2011-2012 Salary Budget Survey

Exhibit 804 Wage Increase History

Historical Wage Increases

Year	CPI-U[1]	General[3] Industry	Utilities[3]	NW Natural[4]	
		Increases	Increases	NBU Scheduled Increases	BU Scheduled Increases
2002	1.6%	3.9%	3.4%	3.0%	3.25%
2003	2.2%	3.6%	3.4%	4.25%	3.25%
2004	2.3%	3.6%	3.5%	3.5%	NA[2]
2005	3.5%	3.7%	3.5%	3.3%	3.0%
2006	3.5%	3.8%	3.3%	3.25%	3.0%
2007	2.6%	3.9%	3.7%	3.7%	3.0%
2008	3.9%	3.9%	3.7%	3.6%	3.0%
2009	-0.7%	2.2%	3.0%	1.5%	3.0%
2010	2.2%	2.5%	3.0%	2.75%	1.66%
2011	3.20%	2.8%	2.8%	2.00%	1.72%
Average					
(2009-2011)	1.6%	2.5%	2.9%	2.1%	2.1%
(2002-2011)	2.4%	3.4%	3.3%	3.1%	2.8%

[1]Calculated using 12-month change in CPI-U from April to April as published by Bureau of Labor Statistics

[2]BU jobs re-priced to the market in 2004, resulting in no scheduled increase

[3]World At Work 2011-2012 Salary Budget Survey

[4]Accounts for scheduled regular pay increases for NBU and BU personnel but does not include promotion increases for either NBU or BU and step increases in the case of BU employees.

Exhibit 805 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	82.0%	61
Management, Excluding Executives	82.0%	61
Exempt, Non-Management	78.7%	61
Nonexempt	77.0%	61

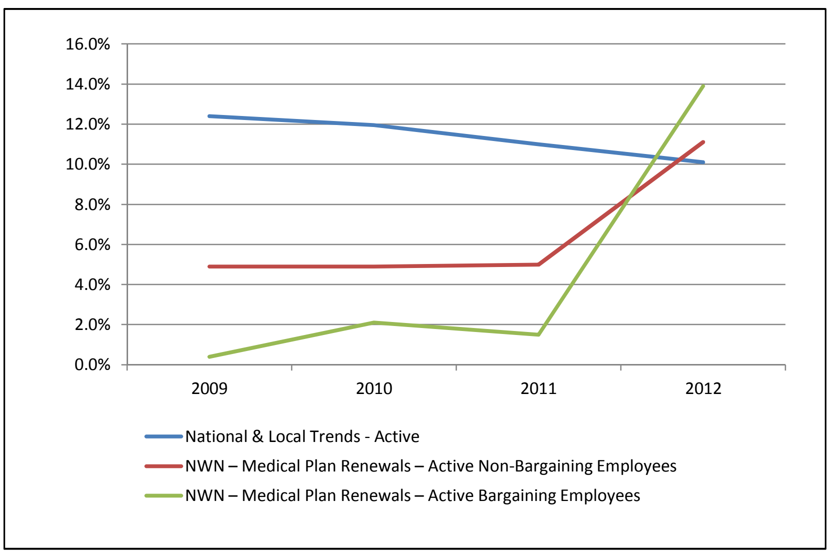
Data Source: 2011 American Gas Association Compensation Survey

Exhibit 806 - Medical Plan Trends Versus Renewals

Sources: Regional-Beecher Carlson Surveys; Segal Health Plan Cost Trend Survey

	2009	2010	2011	2012
ACTIVES				
National & Local Trends - Active	12.40%	11.95%	10.6-11.6%	9.2 - 11.0%
NWN – Medical Plan Renewals – Active Non-Bargaining Employees	4.90%	4.90%	5.00%	11.1%
NWN – Medical Plan Renewals – Active Bargaining Employees	0.40%	2.10%	1.50%	13.9%
RETIREES				
National & Local Trends - Retirees	7.8-8.5%	8.2-9.5%	7.0-7.4%	6.6%
NWN – Medical Plan Renewals - Non-Bargaining Retirees	5.40%	7.20%	8.30%	8.7%
NWN - Medical Plan Renewals - Bargaining Retirees	-9.00%	-9.00%	11.70%	13.40%

Active Employees



Retirees

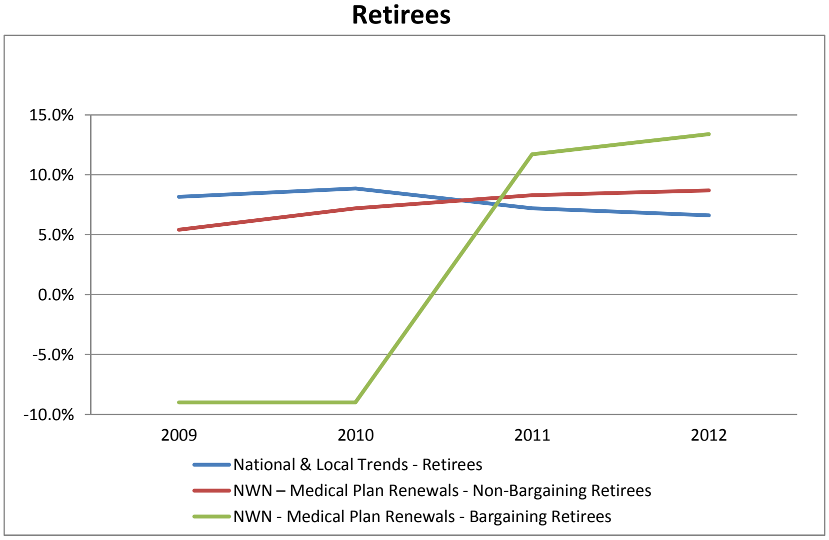


Exhibit 800-7 – Medical Plan Changes

Sources: BP&A Consulting (Bargaining Plans) & Beecher Carlson (Non-bargaining Plans)

Year	Bargaining Plans	Non-Bargaining Plans
2003/2004	Increased co-pays Increased deductible	No benefit plan changes
2004/2005	Increased Annual Out-of-pocket maximum Increased Hospital co-pay Increased Lab and X-Ray co-pays Increased RX co-pays Increased coinsurance Increased deductible	No benefit plan changes
2005/2006	No benefit plan changes	Added annual maximum to annual wellness physical benefit
2006/ 2007	Increased Lab copay RX: member pays difference between generic and brand drug + copay regardless of how prescription was written.	Discontinued offering retiree medical plan to new hires
2008	No changes to medical or RX plan.	Increased out of pocket maximum Increased office visit co-pays Increased co-pays on RX
2009	Increased out-of-pocket max on RX Increased RX copays for brand drugs	No benefit plan changes
2010	Increased deductibles Increased office visit co-pays	Increased premium sharing Increased co-pay on RX
2011	4th quarter carry over provision removed for deductibles	No benefit plan changes

Exhibit 800-8 – Medical Benefits

Source: Towers Watson 2011 Report

- 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 11 company subset[1]
  - We are only comparing PPO plans since this is the highest enrolled plan option within the Towers Watson database
- We have assumed the $100 per month credit NW Natural employees receive would offset the medical contributions for comparison purposes
- Overall we feel the PPO medical plan is equal to both benchmarks

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison	11 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 to $300	Worse	$250 to $300	Worse
Single Out of Pocket Maximum	$1,500	$1,500	Equal	$2,000 to $2,500	Better
Coinsurance	90%	80%	Better	80%	Better
Office Visits	$15 copay, no deductible	$15 to $20 copay, no deductible	Equal	$20 copay, no deductible	Better
Preventive Care	$15 copay, no deductible (some covered 100%)	100%	Slightly Worse	100%	Slightly Worse
Emergency Room	$100 copay, no deductible	Coinsurance or $100 copay	Equal	$100 copay	Equal
Generic Drugs - Retail	$10 copay	$10 copay	Equal	$10 copay	Equal
Brand Formulary Drugs - Retail	$35 copay	80% or $25 copay	Slightly Worse	$25 to $30 copay	Slightly Worse
Brand Non Formulary Drugs - Retail	$50 copay	80% or $40 copay	Slightly Worse	$40 to $50 copay	Slightly Worse
Monthly Employee Only Contributions	$120 ($20 after $100 cash allowance)	$50+	Better	$50+	Better
Monthly Family Contributions	$345 ($245 after $100 cash allowance)	$250+	Equal	$200+	Equal
Overall Assessment			Equal		Equal

- The following table provides a comparison of the **bargained** NW Natural PPO plan to both the total Energy benchmark
  - There were not enough of the 11 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 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	$250 to $300	Equal
Single Out of Pocket Maximum	$2,000	$1,500	Worse
Coinsurance	80%	80%	Equal
Office Visits	$20 copay, no deductible	$15 copay, no deductible	Slightly Worse
Preventive Care	$20 copay, no deductible (some covered 100%)	100%	Slightly Worse
Emergency Room	$75 copay, deductible & coinsurance	Deductible & Coinsurance	Slightly Worse
Generic Drugs - Retail	$10 copay	$5 to $10 copay	Equal
Brand Formulary Drugs - Retail	$20 copay	80% or $20 copay	Equal
Brand Non Formulary Drugs - Retail	50%	80% or $35 copay	Worse
Monthly Employee Only Contributions	$0	$50+	Better
Monthly Family Contributions	$0	$300+	Better
Overall Assessment			Equal

[1]Utility companies represented in survey: Avista, Chesapeake Utilities, Laclede, New Jersey Resources, NiSource, Oneok, Piedmont Natural Gas, PNM Resources, Portland General Electric, UGI Corp, Vectren

Exhibit 800-9 – Health Plan Benchmarking Survey
Source: Towers Watson 2011 Report

- 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 11 Target Companies[1]	Comparison to Bargained Total Database
Medical	Equal	Equal	Equal
Dental	Equal	Equal	Equal
Vision	Equal	Equal	Equal
401(k)	Worse	Worse	Worse
Enhanced 401(k)/DB Plan	Better for short term employees Worse for long term employees	Better for short term employees Worse for long term employees	Better for short term employees Equal for long term employees
STD	Overall Determination Cannot Be Made- See Details	Overall Determination Cannot Be Made- See Details	Overall Determination Cannot Be Made- See Details
LTD	Overall Determination Cannot Be Made- See Details	Overall Determination Cannot Be Made- See Details	Equal
Basic Life	Overall Determination Cannot Be Made- See Details	Overall Determination Cannot Be Made- See Details	Worse
Employee Supplemental Life (paid by employees)	Equal	Equal	Equal
Spouse Life (paid by employees)	Better	Better	Better
Child Life (paid by employees in the benchmark)	Equal	Equal	Equal
Vacation	Equal	Equal	Equal
Holiday	Equal	Equal	Equal

[1]Utility companies represented in survey: Avista, Chesapeake Utilities, Laclede, New Jersey Resources, NiSource, Oneok, Piedmont Natural Gas, PNM Resources, Portland General Electric, UGI Corp, Vectren

Exhibit 800-10 – Retirement Benefits Benchmarking Survey
Source: Towers Watson 2011 Report

- 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 11 company subset[1]
- Overall we feel the 401(k) plan is worse than both benchmarks
- Overall we feel the Enhanced 401(k) plan is better for short term employees and worse for long term employees versus the benchmarks

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison	11 Energy Company Subset Benchmark	Comparison
Retirement Benefits					
401(k)					
Employer Match	60% of the first 6%	100% up to 6%	Worse	100% up to 6%	Worse
Vesting	Immediate	Immediate	Equal	Immediate	Equal
Overall Assessment			Worse		Worse
DB Plan					
Actual DB Plan Available	Enhanced 401(k)	75 of 109 Have Actual DB		5 of 11 Have Actual DB	
Employer Contribution	5% of current annual pay	1.5% of final pay of those that have a plan	Better for short term employees Worse for long term employees	1.5% of final pay of those that have a plan	Better for short term employees Worse for long term employees

- 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 plus the Western State DB plan is better for short term employees and equal for long term employees versus the benchmarks

Coverage Provisions	NW Natural Coverage	Total Energy Benchmark	Comparison
Retirement Benefits			
401(k)			
Employer Match	50% of the first 4%	50% of 6%	Worse
Vesting	Immediate	Immediate	Equal
Overall Assessment			Worse
DB Plan			
Actual DB Plan Available	Enhanced 401(k)	47 of 67 Have	
Employer Contribution	4% of current annual pay 1.2% Western State DB Plan	1.5% of final pay of those that have a plan	Better for short term employees Equal for long term employees

[1]Utility companies represented in survey: Avista, Chesapeake Utilities, Laclede, New Jersey Resources, NiSource, Oneok, Piedmont Natural Gas, PNM Resources, Portland General Electric, UGI Corp, Vectren

BEFORE THE

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NW Natural

Direct Testimony of David Williams

CUSTOMER SERVICE
Exhibit 900

December 2011

EXHIBIT 900 – DIRECT TESTIMONY – CUSTOMER SERVICE

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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 Williams. I am Vice President of Utility Services of NW Natural, which includes the Acquire Customers and Serve Customers Divisions of the Company. I am responsible for the call center, emergency response services, customer billing, meter reading, and field services including service technicians and field compliance services. I also have responsibility for sales, marketing, and new market development. I share labor relations responsibilities with the Senior Vice President in charge of Human Resources.

Q. Please describe your educational and professional background.

A. I received my Bachelors of Science degree from Oregon State University majoring in Business and Social Sciences. I have over 33 years of utility experience working for NW Natural in the areas of marketing, sales, operations, customer service, and labor relations.

Q. Please summarize your testimony.

A. In my testimony, I:

- Describe NW Natural's current business practices for scheduling service calls—which require residential and small commercial customers to be available between 8:00 a.m. and midnight, or as long as 16 hours, for our customer service representatives to arrive—and identify some of the shortcomings of this practice;
- Explain the Company's proposal to remedy these shortcomings by offering our customers four-hour service windows;

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- Describe customers' current options for paying NW Natural bills and the costs to customers associated with those options; and
- Explain the Company's proposal to change bill-paying options by providing no-fee use of community pay stations and bank cards.

Q. Are the Company's proposed customer service improvements contingent on Commission approval of the proposals and associated cost recovery described in my testimony?

A. Yes. While the Company believes that customers will benefit from the enhanced services described in my testimony, the cost of these enhancements is not insubstantial. By presenting these proposed enhancements in a general rate case, the Company hopes to receive the input of customer groups and the Commission on whether they believe those costs are outweighed by the benefits of the improvement in customer service.

II. SERVICE APPOINTMENT WINDOWS

Q. Please explain the concept of service appointment windows.

A. The concept of service appointment windows is to give customers a definitive time frame, or "window," within which the Company will arrive to complete a service call. The Company's proposal is to have two four-hour appointment windows, 8:00 a.m. to Noon, and Noon to 4:00 p.m., Monday through Friday. I explain these windows in more detail later in my testimony.

Q. Please explain how service calls are currently scheduled.

A. There are three separate departments within the Utility Services organization that are involved in the receiving, scheduling, and completion of service calls. They are the

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Customer Contact Center (CCC), which is the Company's in-house call center, the Resource Management Center (RMC), which is a centralized dispatching center for all construction and field service work, and Customer Field Services (CFS), which is the reporting center for all service technicians.

Customer calls are received through the CCC. If the customer requires a service technician, the CCC initiates a work order in the Customer Information System (CIS) and informs the customer that the service technician will arrive on the scheduled date sometime between 8:00 a.m. and midnight. After it is initiated, the work order is automatically routed from CIS to the work order management system.

Once the work order is downloaded to the work management system, it becomes the responsibility of the RMC, which forecasts and reviews the daily workload and makes appropriate adjustments to the automated work leveling system. After the system completes the preliminary work assignments, the work assignments are reviewed again by the RMC. The RMC will also ensure emergency orders and unscheduled service orders are assigned and completed throughout the day.

On any given day, an individual service technician's scheduled work orders will comprise a mix of maintenance and compliance work, customer service work, and emergency response work. All work has an expected due date for completion. The Company schedules work volumes based on customer service call type as well as regulatory requirements and available resources. All of these variables and considerations make the scheduling process challenging and complex. *See NWN/901 Williams/1-2*.

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Q. Once a work ordered is scheduled for a given day, how are service calls scheduled?

A. Each morning, the service technician views his or her scheduled work in the route for the day and decides the order in which he or she will complete the work, with the primary objective being to complete as many orders as possible during normal business hours. To maximize the number of completed service calls, the service technician must minimize drive-time between calls, so the service technician will tend to complete all service calls within close proximity to each other in consecutive order. Additionally, emergency orders may be generated throughout the day causing the service technician to complete those emergency orders immediately, and to vary from his or her original plans. After completing these emergency orders, the service technician will then reorganize the routing of remaining service calls in the most efficient manner, minimizing drive time and accounting for required completion times.

Q. Are the technicians always able to complete their service calls during normal working hours?

A. We make every attempt to complete scheduled service work during regular business hours. However, due to emergencies and seasonal workload, we often need to use the extended hours to get all work completed. Additionally, the Company may choose to work day-shift employees on overtime.

The Company does not fully staff the night shift as these resources are intended primarily for emergency response calls. However, the night shift will pick up work from the day shift if the order must be processed that day and the day shift was unable to complete the work before 5:00 p.m.

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Q. Is the current process working?

A. The current process works well from the Company's perspective as it provides an effective and efficient way to manage field service work. The flexibility of the process has also helped the Company to keep field resource staffing levels fairly low when compared to our utility peers in this region. There are many factors that affect staffing levels, but on a system basis and at today's field resource staffing level and customer counts, the Company currently serves 7,170 customers per service technician, as compared to Avista Corporation ("Avista") at 6,673 customers per service technician and Cascade Natural Gas Corporation ("Cascade") at 3,950 customers per service technician. Intermountain Gas Company and Puget Sound Energy, Inc. are in between Avista and Cascade at 5,237 and 5,691 customers per service technician, respectively. *See NWN/902, Williams/1.*

Q. If the process is working for the Company, why is the Company proposing to change it?

A. We know from customer surveys that, for many of our customers, our current process does not meet *their* needs. We receive regular feedback from these customers that they are busy and in many cases are forced to take entire days off from work in order to obtain needed service. Or, to avoid losing wages or creating problems at work by requesting time off, they may agree to leave a key under the doormat, which causes concerns about security. In essence, while the current system may work well for the Company, it can be inconvenient for many of our customers. These customers expect, and we believe deserve, to have the option of scheduling a service appointment window.

Q. Please explain the service appointment window proposal.

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A. The Company's proposal is to divide each normal business day into two four-hour service appointment windows, an "AM" window (8:00 a.m. to noon) and a "PM" window (noon to 4:00 p.m.). These windows will be in effect Monday through Friday for the purpose of scheduling residential and small commercial customer service calls such as new account activations, high bill investigations, service reconnections following a disconnection of service, calls relating to routine equipment inspections, and other customer service related calls. There is no proposed change to the after-business-hours work schedule.

Q. Please explain the number of AM and PM appointments that will be available each day and how the Company arrived at that number.

A. The Company's proposal is based on an average target of 200 appointments per business day.

The 200 service appointment target is based on 2010 service order data, which shows that on average, our technicians completed 605 service orders each business day. Of the 605 service orders, 199 were service orders that would qualify for a service appointment window under the Company's proposal. A breakdown of the 2010 service orders by type and count is shown in NWN/903, Williams/1.

Q. Based on 200 appointments per business day, does this mean that there will be 100 AM appointments and 100 PM appointments?

A. No. The number of available appointments within each appointment window will likely vary each day based upon the number of appointments scheduled, resource availability, and the type of service work required. For example, some service calls may require only 20 minutes on site, but others may require 45 minutes on site. The mix of service call

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locations, length, and type of call will vary daily. Further, on any day there will also be unscheduled emergency response calls that will need to be completed ahead of any scheduled appointments or maintenance work. In addition, resource availability will vary depending on that day's schedule for mandatory training, company meetings, vacations and holidays, and other activities that would cause a service technician to be unavailable for field service work. It will be the overall mix of service call types combined with resource availability that will determine how many appointments can be offered within each appointment window each day.

Q. What happens if all appointment windows for a day are taken?

A. If all appointment windows are taken, the customer could choose another date for the service call where their preferred appointment window is available. If the customer does not want to choose another date, then the Company will complete the call sometime on that day before midnight. In this circumstance, the service technician will first complete scheduled service appointments before proceeding to that service call.

Q. What changes are required to put service appointment windows in place?

A. A number of changes are required. First, the Company is not sufficiently staffed to accommodate service appointment windows, so an increase in field services staff and related vehicles and equipment is necessary. Second, because the Company's proposal requires a fundamental shift in the way in which field service work is scheduled, it will require technical system enhancements to integrate our service order scheduling system with our customer information system (CIS).

Q. Please explain how you determined the additional staff requirements for the service appointment window proposal.

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A. The Company's Business Analytics department created a model to determine the total resource requirements needed to support the service appointment window proposal. The model was based on 2010 data for service order volume, call completion times, travel time, employee absences, position vacancies, holidays, and training and education time. Travel time was adjusted to account for additional drive time created by the limited ability to control the call completion order due to service appointment commitments. The model shows a resource requirement of 122 full-time equivalent position (FTE) service technicians in a service appointment window structure.

Q. How many FTE service technicians does the Company have today?

A. There are currently 102 total FTE service technicians. Of the 102, 90 FTEs, on average, are dedicated to normal business hours.

Q. Are there any additional FTEs for service technicians included in the Company's November 2012-October 2013 test year ("Test Year") revenue requirement?

A. Yes. An additional seven service technicians are scheduled to be hired in the fourth quarter of 2012, and are included in the Test Year revenue requirement. The addition of these positions is related to a separate service improvement effort around emergency response times. However, if the service appointment window proposal is adopted, these service technicians will be part of the 122 total resources required for service appointment windows, leaving a shortfall of 13 FTE service technicians.

Q. How does the 122 FTEs compare with levels of customers per service technician at other local gas utilities?

A. As stated earlier in my testimony, at the current FTE level, the Company is at 7,170 customers per service technician, which is materially higher than our peer utilities in the

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region. The ratio of customers per service technician would change to 5,571 at an FTE count of 122, which would bring the ratio in line with our peers, who already offer some form of service appointment window to their customers. *See NWN/902, Williams/1.*

Q. What additional changes would the Company need to make in order to implement its service window proposal?

A. NW Natural will need to make some technology enhancements to existing systems to assist with scheduling of service appointments. This will assist in providing appointment availability information to the CCC representatives while talking with the customer. Additionally, the Company wants to make the offering of service appointments through all customer service products including over the telephone and web over time.

Q. How long would it take NW Natural to implement service appointment windows?

A. It takes a minimum of ten months to train a new service technician, so ten months represents the minimum amount of time it would take to fully implement our proposal. Assuming that the Company receives approval from the Commission to implement service appointments in November of 2012, the Company could expect to have a fully integrated service appointment window structure in place about mid-year 2013. However, upon approval of the Company's proposal, efforts will begin immediately to complete the systems programming to support the appointment window structure which would allow for a phase in of the number of available service appointment windows until we are able to meet the targeted average of 200 appointment windows per day.

Q. What are the estimated costs of implementing the Company's Service Appointment Window Proposal?

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A. The estimated incremental annual operations and maintenance (O&M) cost is about $2.2 million on a system basis. In addition, the proposal will require capital investment of about $1.5 million for system upgrades, vehicles, tools, and computers for each new service technician. S*ee NWN/904, Williams/1.* The O&M cost increases are discussed further in the testimony of John Sohl. *See NWN/700, Sohl/8.*

Q. Why has the Company not already spent the money to implement service appointment windows?

A. As stated earlier in my testimony, our customers tell us that they want service appointment windows, but our customers are not aware of the cost or complexities that are involved in doing so. Presenting the issue before the Commission and the public through a general rate proceeding seems to be the most practical forum for evaluating whether or not this additional service is worth the increased cost to customers.

III. BILL PAYMENT OPTIONS

Q. Please describe the bill payment options currently available to customers.

A. There are six ways in which a customer can make a payment on their account. They are: (1) by check sent through the U.S. mail; (2) by electronic payment through the AutoPay program; (3) by electronic payment through a provider of the customer's choosing; (4) by electronic check generated over the telephone or on-line; (5) in cash or by check at a community pay station; or (6) by bank card (debit or credit) over the telephone or on-line. A fee of $2.95 is assessed for Option 4 when the customer requests assistance from a Customer Service Representative (CSR). However, the customer may complete the same transaction over the telephone or on-line at no charge. Options 5 and 6 are offered through third-party providers for a fee to the

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customer. To make a payment at a pay station, the fee is $1.00 or $1.50, depending on the vendor. To make a bank card payment, the fee is $3.95.

Q. What payment options are addressed in your testimony?

A. My testimony addresses the community pay station option and the bank card payment option.

Q. What is a community pay station and when did the Company first make this payment option available to customers?

A. A community pay station is a location where customers can go to pay their utility bill. The Company contracts with vendors to enlist the services of businesses within the Company's service territory to take payments from customers on behalf of the Company. The Company's pay stations are located in a variety of businesses such as grocery stores, drug stores, and convenience stores. Community pay stations allow customers that cannot pay their bills by other means to easily and conveniently make a payment. Payments made at a pay station are transmitted electronically to the Company's CIS within a few minutes, and as such the use of this payment option provides an important service to customers that find they need to make a payment quickly.

The Company implemented the community pay station option in June 2007 when it closed its district office locations to walk-in payments. The Company previously had eight Oregon locations and one Washington district office location available to customers for walk-in payment transactions. There is now a network of about 95 authorized pay station locations throughout the Company's service territory, 91 of which are located in the state of Oregon. The number and location of available pay stations will change from time to time as the vendor adds or closes these locations.

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Q. How many customers use the pay station option?

A. Today, the community pay station option is used by about one percent of the Company's customers. More than 80 percent of all pay station transactions are cash payments. Approximately 25 percent of pay station transactions are associated with a pending disconnection of service following the issuance of a delinquent notice. S*ee NWN/905, Williams/1-2.*

Q. What is the bank card payment option and when did the Company start offering a bank card payment option?

A. The bank card payment option allows the customer to make a payment by debit card or credit card. The Company initiated the third-party structure for bank card payments in 2000, at a time when the use of credit and debit cards for payment of services, like utility bills, was just taking shape. At that time, the availability of online billing and payment options was just evolving and a pay-for-use fee structure was an appropriate solution to meeting customer expectations for more payment options while keeping overall costs low for all customers.

Q. How many customers use the bank card payment option?

A. Today, approximately two percent of the Company's customers use this payment option. Similar to the pay station payment option, approximately 25 percent of payments made by bank card today are associated with a pending disconnection of service following the issuance of a delinquent notice, which compares to approximately three percent for all other payment channels. *See NWN/905, Williams/3-4*

Q. What is the problem with these two payment options?

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A. The problem is that both options require the customers to pay a user fee. In 2010, customers paid $78,000 in pay station payment fees and $535,000 in bank card payment fees.

Q. Why is the fee for the pay station payment option a problem?

A. The transition to the pay station option caused the Company to incur costs that were not previously included in rates. At that time, it was the Company's position that the added cost should be paid for by customers that used the service. We now have data on the type of payments that are made at a pay station that we did not have at the time we implemented this payment option. We now know that this payment option tends to be most utilized by customers whose only option is to pay by cash, and by customers who need to make an urgent payment to avoid disconnection. With this information, combined with the fact that prior to the pay station service customers were able to walk in to pay their bills at a Company office for no extra charge, it is now the Company's position that customers should have free access to this payment option. The Company's Washington customers already have free access to this payment option. So eliminating the fee in Oregon would remove this disparity between our Washington and Oregon customers.

Q. Why are the user fees for the bank card payment option a problem?

A. The user fee deters customers from using this as a regular payment option. Times have changed since the Company first offered the bank card payment option for a fee. Today our customers expect to use their bank card to pay their NW Natural bill, just like they do with nearly every other purchase or bill payment they make.

Q. Please describe the Company's proposal.

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A. The Company proposes to include in base rates the costs associated with customer bill payments made by bank cards (debit and credit cards) and the costs associated with payments made at Company authorized community pay stations.

Q. How much will the proposal increase the Company's O&M costs?

A. The Company expects that the use of the pay station payment option may double from the historical level of use if the transaction fee is eliminated, for an estimated total annual cost of $160,000.

The Company expects that use of the bank card payment option may increase from two percent to 15 percent if the transaction fee is eliminated, for an estimated annual cost of $1.3 million. The 15 percent adoption rate is conservative (that is, could go higher) and assumes that the increase in usage of bank cards will ramp up over a two-to-three year time period.

The net amount included in the Test Year revenue requirement for this proposal is $1.05 million. *See NWN/906, Williams/1 and NWN/909 Williams/1*

Q. Please explain how the Company calculated these costs.

A. The transaction cost of $1.00-$1.50 for the pay station payment option is a pass-through cost and does not change if the Company pays the fee directly. We do not really know how the use of this payment option might change if the customer paid fee is eliminated, but we have assumed at this time that the future use of the pay station payment option will be double the 2010 usage levels.

If the Company pays the fees associated with bank card payments, the cost is reduced to $1.22 per transaction. *See NWN/907, Williams/1.* However, the Company

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expects that the adoption rate for bank card payments will increase from two percent to 15 percent if the customer paid fee is eliminated.

Q. How did the Company come to the 15 percent adoption rate for bank card payments?

A. The Company performed an informal review of other utilities that eliminated the customer paid fee for bank card payments. Most of these utilities reported experiencing a ten percent adoption rate. However, these utilities also placed restrictions on when the bank card could be used. Specifically, many of these utilities elected to restrict the bank card payment option only for residential customers, and only when the customer has enrolled in both automatic recurring payments and electronic billing options where the card is used as the reoccurring payment source. The Company is not proposing to place any restrictions on the use of a bank card for bill payment.

Q. How does the Company's bank card proposal differ from what other utilities offer?

A. The Company's proposal does not restrict the bank card use to only residential customers. The proposal also makes the option available for one-time payment transactions as well as for recurring payments. Further, the Company does not plan to require customers to enroll in electronic billing in order to use their bank card for reoccurring payments.

Q. Why doesn't the Company just lower the pay-for-use charge to $1.22?

A. The Company's plan is to accept Visa, MasterCard, and Discover card payments. The merchant contract for Visa specifically prohibits the Company from surcharging the customer. Seventy-five percent of all bank card payments are of this card type. Although the merchant contracts for MasterCard and Discover do not have a similar

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prohibition, the Company would not want to treat these two card users different from Visa card users. *See NWN/908, Williams/1-4.*

Q. Does the Company anticipate any offsetting cost savings associated with processing bill payments if the use of bank card payments increases?

A. Yes, although these savings cannot be predicted with any certainty. To determine savings from payment processing activities one must first identify which other payment option would be displaced with a bank card payment. Other cost savings could be expected from reduced delinquent payments and reduced disconnections for non-payment, which in turn could reduce miscellaneous charge revenues relating to late payment charges, reconnection charges, and field visit charges. However, since customer behavior will dictate the impact in each of these areas, the Company cannot definitively identify what the cost savings will be. We have prepared an estimate of cost savings based on some assumed behavioral changes, which we believe is somewhat aggressive, that indicate a potential annual cost savings of just over $295,000. Using these same assumptions, we could also expect a potential reduction in Schedule C miscellaneous revenues of just over $361,000. *See NWN/909, Williams/1-2.*

Q. Is there anything else you wish to say in support of the two proposals?

A. Yes. There is a saying, “You can’t expect to meet the challenges of today with yesterday’s tools and expect to be in business tomorrow.” NW Natural’s business focuses on good customer service. Good service today means having choices for customers and meeting expectations. All customers benefit from having a choice, whether it is a choice in how they pay their bill, or a choice when to receive service by

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use of a service appointment window. These are no longer optional services of the past. They are necessary and important services for our business today and into the future.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Exhibits of David Williams

CUSTOMER SERVICE
EXHIBITS 901 - 909

December 2011

EXHIBITS 901-909 –CUSTOMER SERVICE

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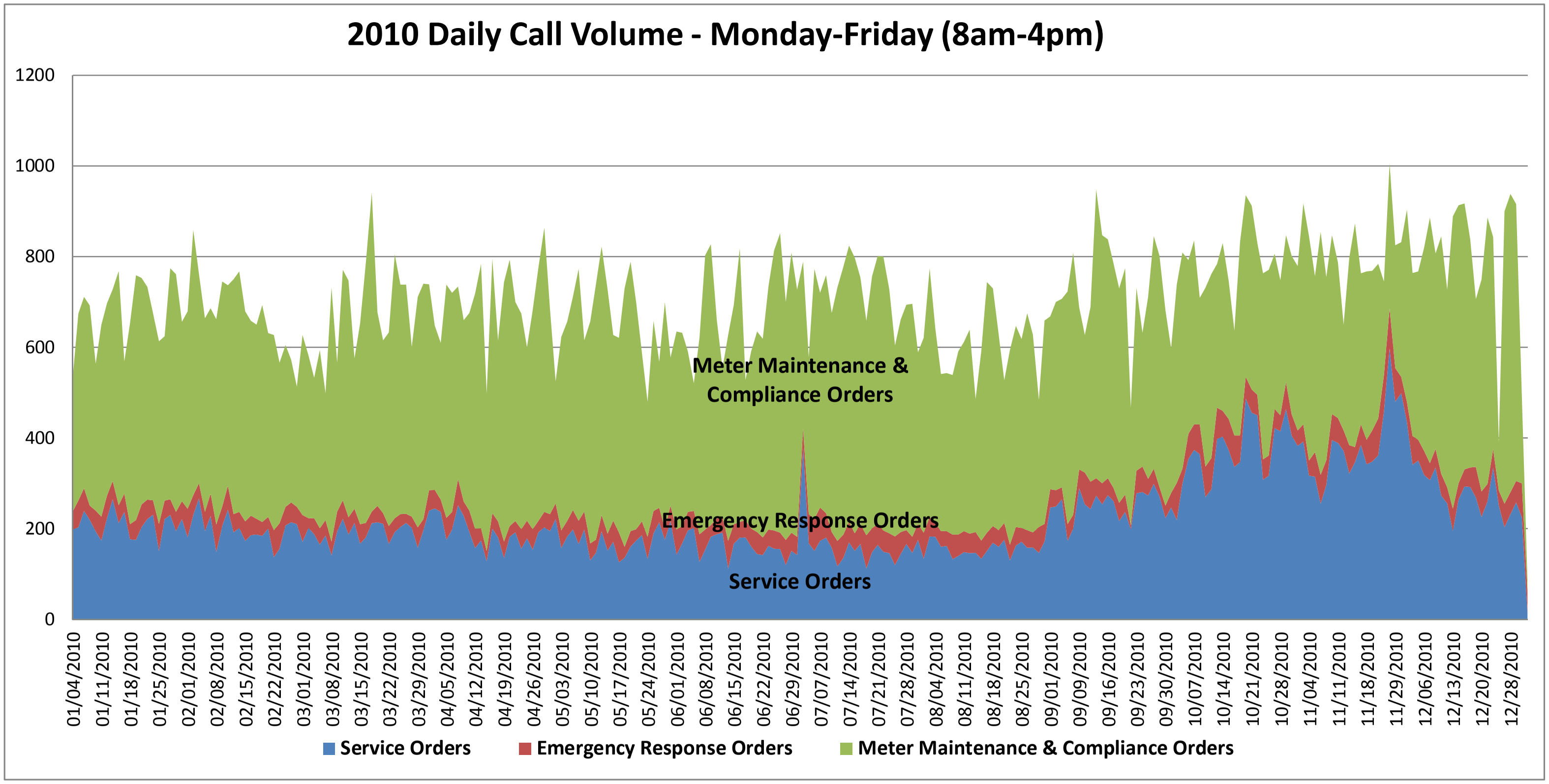
2010 Daily Call Volume - Monday-Friday (8am-4pm)
1200
1000
800
600
400
200
0
Meter Maintenance & Compliance Orders
Emergency Response Orders
Service Orders
01/04/2010
01/11/2010
01/18/2010
01/25/2010
02/01/2010
02/08/2010
02/15/2010
02/22/2010
03/01/2010
03/08/2010
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11/04/2010
11/11/2010
11/18/2010
11/29/2010
12/06/2010
12/13/2010
12/20/2010
12/28/2010
Service Orders
Emergency Response Orders
Meter Maintenance & Compliance Orders

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TECHNICIAN TO CUSTOMER RATIO

Numbers based on 2010 AGA DataSource summary

COMPANY	SERVICE TECHNICIANS	NG CUSTOMER COUNTS	CUST PER TECH	OFFERS AM/PM APPOINTMENTS
NW Natural	**94***	673,997	7,170	No (Operate under an 8am-12am service time frame)
Avista	20	133,450	6,673	Yes (8am-12pm & 1pm-5pm)
Intermountain Gas	59	309,011	5,237	Yes (8am-5pm)
Puget Sound	66	375,595	5,691	Yes (8am-1pm & 1pm-12am)
Cascade NG	66	260,694	3,950	Offers 8am-5pm, and periodically an am/pm 4 hour window for orders such as PCC's

The NW Natural Service Technician number includes vacancies and reflects operational footprint

2013 NW NATURAL TECHNICIAN TO CUSTOMER RATIO			
PRE VS. POST	SERVICE TECHNICIANS	NG CUSTOMER COUNTS**	CUST PER TECH
Pre-Service Window Appts.	109	679,721	6,236
Post-Service Window Appts.	122	679,721	5,571

****Based on forecasted customer growth (.7% 2011, .8% 2012, 1% 2013)***

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2010 Technician Calls by Type

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
Account Services	5,561	5,886	6,306	6,688	6,046	5,411	6,377	5,365	7,750	8,685	8,143	8,549	80,767
High Bill	270	206	124	99	80	61	64	64	53	65	94	165	1,345
Miscellaneous	616	687	882	872	690	712	521	610	646	769	670	1,107	8,782
Re-Reads	121	79	55	38	24	30	33	50	31	21	31	47	560
Turn Off	1,572	1,606	1,934	2,048	2,139	1,986	2,925	1,974	3,190	2,257	1,693	1,950	25,274
Turn On	2,571	2,558	2,909	2,788	2,477	2,549	2,738	2,477	3,460	5,470	5,268	3,775	39,040
Turn Over	411	750	402	843	636	73	96	190	370	103	387	1,505	5,766
AMR				173	242	302	273	279	271	292	261	256	2,349
AMR				173	242	302	273	279	271	292	261	256	2,349
Compliance & Meter Maintenance	2,318	2,085	2,536	2,546	1,662	4,531	3,350	2,840	2,264	1,991	2,202	2,762	31,087
Corrosion Maintenance	207	167	382	430	248	729	1,506	1,201	619	303	402	391	6,585
Meter Change/Removal	482	430	372	318	308	332	348	351	323	318	355	366	4,303
Meter Maintenance	1,624	1,485	1,782	1,798	1,106	3,372	1,288	1,252	1,311	1,328	1,414	1,999	19,759
PCC/PMC	5	3				98	208	36	11	42	31	6	440
Credit & Collection	5,208	5,181	6,723	5,735	5,569	5,753	5,078	4,727	4,058	3,781	3,438	3,923	59,174
Credit Turn Off	3,673	3,667	4,847	4,150	4,218	4,454	3,929	3,705	2,844	2,219	2,070	2,898	42,674
Credit Turn On	1,535	1,514	1,876	1,585	1,351	1,299	1,149	1,022	1,214	1,562	1,368	1,025	16,500
New Meter Installation	563	527	648	686	531	540	417	618	756	772	676	670	7,404
Meter Set	321	285	386	407	263	290	213	314	421	390	364	325	3,979
Pre-Inspect	242	242	262	279	268	250	204	304	335	382	312	345	3,425
Odors & Emergency	1,741	1,663	1,587	1,481	1,575	1,729	1,960	1,616	1,512	2,128	2,285	1,997	21,274
Emergency	35	46	46	49	36	47	47	42	39	55	62	89	593
Odor Call	1,706	1,617	1,541	1,432	1,539	1,682	1,913	1,574	1,473	2,073	2,223	1,908	20,681
Servicing	1,686	1,380	1,574	1,324	1,018	1,052	890	1,026	1,990	3,053	3,374	2,877	21,244
Miscellaneous	59	56	89	101	66	81	88	89	73	106	104	98	1,010
PCC/PMC					1	38	10	1					50
Routine Inspection	271	292	320	227	182	206	218	332	776	925	758	629	5,136
Service Work	1,356	1,032	1,165	996	769	727	574	604	1,141	2,022	2,512	2,150	15,048
Grand Total	**17,077**	**16,722**	**19,374**	**18,633**	**16,643**	**19,318**	**18,345**	**16,471**	**18,601**	**20,702**	**20,379**	**21,034**	**223,299**

Total Tech Calls minus AMR: 220,950
Average per day: 605

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Service Appointment Windows Cost

Capital	*TOTAL*
HARDWARE	*$189,825*
TECHNOLOGY	*$115,857*
VEHICLES	*$883,000*
TOOLS/EQUIPMENT	*$128,177*
INSTALLATION COSTS	*$31,450*
SET-UP COSTS	*$10,759*
CONTINGENCY	*$135,907*
TOTAL	*$1,494,975*

ON-GOING O&M	*TOTAL*
OPERATIONS	*$2,016,979*
LICENSES/MAINTENANCE	*$128,520*
TOTAL	*$2,145,499*

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Pay Station Volume Activity - Oregon

Month	Oregon Check	Oregon Cash	Total	Consumer Fee Assessed Oreg
Jan-10	830	5,551	6,381	$ 6,381
Feb-10	743	5,306	6,049	$ 6,049
Mar-10	878	6,225	7,103	$ 7,103
Apr-10	808	5,619	6,427	$ 6,427
May-10	675	5,058	5,733	$ 5,733
Jun-10	606	4,971	5,577	$ 5,577
Jul-10	528	4,598	5,126	$ 7,689
Aug-10	496	4,455	4,951	$ 7,427
Sep-10	443	4,024	4,467	$ 6,701
Oct-10	367	3,803	4,170	$ 6,255
Nov-10	406	3,764	4,170	$ 6,255
Dec-10	430	4,075	4,505	$ 6,758
Total	7,210	57,449	72,215	$ 78,355
%		80%		

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Fee-Free Payment Options Program Costs

Pay station Payment Costs	Cost	# of Payments
2010 Pay station volume		72,215
At $1.00	$37,270	37,270
At $1.50	$41,084	27,389
Total	$78,354	
Estimated Cost Increase (2x 2010)	$156,707	

Bank Card Payment Costs		
2010 Bankcard payment volume		135,488
Expected Bank Card Volume - Oregon		974,973
Estimated Cost	$1,189,467	

Total Estimated Cost **$1,346,174**

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Bank Card Transaction Calculation

Average Payment Amount:	137
2010 Payment Volume:	7,222,000

		Consumer Credit Card	Regulated Debit Card	Non-Reg Debit Card	Business Credit Card	Total	
Vendor Revised Proposal:							
Interchange (for card issuer- bank)	Flat Fee	$ 0.7500	$ 0.2900	$ 0.6500	$ 1.5000		
Gateway (Cybersource)	Flat Fee	$ 0.1000	$ 0.1000	$ 0.1000	$ 0.1000		
Network (for card assoc. - VISA, Disc, MC)	Flat Fee	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185		
Network (for card assoc. - VISA, Disc, MC)	0.0011	$ 0.1507	$ 0.1507	$ 0.1507	$ 0.1507		
Merchant Acquirer (ATS) - Tier 1	Flat Fee	$ 0.3600	$ 0.3600	$ 0.3600	$ 0.3600		
Merchant Acquirer (ATS) - Tier 2	Flat Fee	$ 0.2000	$ 0.2000	$ 0.2000	$ 0.2000		
Merchant Acquirer (ATS) - Tier 3	Flat Fee	$ 0.1500	$ 0.1500	$ 0.1500	$ 0.1500		Tier Level
Merchant Acquirer (ATS) - Tier 4	Flat Fee	$ 0.1100	$ 0.1100	$ 0.1100	$ 0.1100		
Total Transaction Fee - Tier 1	0 - 225k	$ 1.3792	$ 0.9192	$ 1.2792	$ 2.1292		225000
Total Transaction Fee - Tier 2	225k - 375k	$ 1.2192	$ 0.7592	$ 1.1192	$ 1.9692		375000
Total Transaction Fee - Tier 3	375k - 525k	$ 1.1692	$ 0.7092	$ 1.0692	$ 1.9192		525000
Total Transaction Fee - Tier 4	525k - up	$ 1.1292	$ 0.6692	$ 1.0292	$ 1.8792		
							Avg. Transacton Cost
Payment Mix A 1/		16%	37%	36%	11%	100%	
Direct Cost - Adoption Rate	5%	$ 76,200	$ 114,800	$ 158,500	$ 82,200	$ 431,700	$ 1.196
Direct Cost - Adoption Rate	10%	$ 142,600	$ 206,800	$ 294,900	$ 157,600	$ 801,900	$ 1.110
Direct Cost - Adoption Rate	15%	$ 207,800	$ 296,300	$ 428,600	$ 232,300	$ 1,165,000	$ 1.075
Payment Mix B 2/		20%	20%	40%	20%	100%	
Direct Cost - Adoption Rate	5%	$ 95,300	$ 62,000	$ 176,100	$ 149,400	$ 482,800	$ 1.337
Direct Cost - Adoption Rate	10%	$ 178,300	$ 111,800	$ 327,600	$ 286,600	$ 904,300	$ 1.252
Direct Cost - Adoption Rate	15%	$ 259,800	$ 160,100	$ 476,300	$ 422,300	$ 1,318,500	$ 1.217

1/ Current ratio of card use; debit transactions split evenly between regulated (>$10B in assets) and non-regulated banks as actual
2/ Increased adoption rate expected to increase consumer & business credit card % use; debit cards move toward non-regulated

2.3 Supplemental Materials

You shall update promotional materials and technical applications, and, if you are a Merchant Processor, descriptions of the Processing Services, to include Card Acceptance as part of integrated materials addressing comparable services offered for other cards, in each case in accordance with your regularly scheduled updates.

2.4 Equal Treatment of Cards with Other Payment Cards; Equal Treatment of Card Issuers

Other than with respect to discounts as permitted in Section 2.5, you may not institute or adopt any practice, **including any discount or in-kind incentive,** that unfavorably discriminates against or provides unequal and unfavorable treatment of any Person who elects to pay using a Card versus any other credit card, debit card, prepaid card, or other payment card that you accept (except for any proprietary payment card issued by you or any payment card issued under a formal co-branding relationship between you and a card issuer), **and** you may not in any way discriminate among various Issuers of Cards, **except to the extent such restrictions are prohibited by Requirements of Law or permitted as set forth in Section** 5.12.

2.5 Surcharges and Discounts

You may assess a surcharge on a Card Sale provided that (a) the amount of the surcharge may not exceed the Merchant Fee payable by you to us for the Card Sale and (b) you assess surcharges on Card Sales conducted using other cards accepted by you, **in each case subject to the restrictions in Section** 2.4**; and (c) you otherwise comply with Section** 2.4. You may not assess a surcharge or other penalty fee of any kind other than as set forth above. **Effective upon publication of Release 11.1 of these Operating Regulations, you may offer discounts or in-kind incentives for payment by different tender types (e.g., a discount for payment by cash versus payment by credit card) subject to the restrictions in Section** 2.4**.**

2.6 Test Cards

If we have issued you a test Card or test Card Account in order to test Card Acceptance at your locations, you are responsible for any improper or fraudulent use of such Card or Card Account. You agree to use reasonable efforts to safeguard such Card or Card Account in a secure place. Test Cards are and remain our property.

2.6.1 Test Card Compliance Requirements

You must comply with the following terms and conditions with respect to test Cards and test Card Accounts we create and issue to you:

- You must have an authorized officer sign and return to us the accompanying acknowledgement form upon receipt of the test Cards.
- You must maintain the test Cards in a secure storage place with limited access.
- You must return all test Cards to us immediately upon request.
- You must not conduct a test Card Transaction that exceeds the equivalent of

5.11 Prohibited Practices

An Acquirer must ensure that none of its Merchants engage in any of the prohibited practices set forth in this Rule 5.11.

5.11.1 Discrimination

A Merchant must not engage in any acceptance practice that discriminates against or discourages the use of a Card in favor of any other acceptance brand

Note **An addition to this Rule appears in Chapter 10a, "New Zealand Rules."**

5.11.2 Charges to Cardholders

A Merchant must not directly or indirectly require any Cardholder to pay a surcharge or any part of any Merchant discount or any contemporaneous finance charge in connection with a Transaction. A Merchant may provide a discount to its customers for cash payments. A Merchant is permitted to charge a fee (such as a bona fide commission, postage, expedited service or convenience fees, and the like) if the fee is imposed on all like transactions regardless of the form of payment used, or as the Corporation has expressly permitted in writing. For purposes of this Rule:

1. A surcharge is any fee charged in connection with a Transaction that is not charged if another payment method is used.
2. The Merchant discount fee is any fee a Merchant pays to an Acquirer so that the Acquirer will acquire the Transactions of the Merchant.

Note **Variations to this Rule appear in Chapter 10a, "New Zealand Rules," Chapter 11a, "Canada Region Code of Conduct Related Rules," and Chapter 12, "Europe Region Rules."**

5.11.3 Minimum/Maximum Transaction Amount Prohibited

A Merchant must not require, or indicate that it requires, a minimum or maximum Transaction amount to accept a valid and properly presented Card.

CPS/Small Ticket - U.S. Region

CPS/Small Ticket Merchant Category Codes - U.S. Region (Updated)

Effective 16 October 2010, in the U.S Region, in addition to the exclusions specified in "Visa Easy Payment Service (VEPS) Merchant Category Code Exclusions – U.S. Region," a Visa Easy Payment Service (VEPS) Transaction does not qualify for the CPS/Small Ticket Interchange Reimbursement Fee if the Transaction is one of the following:

- Visa Signature Preferred Transaction
- Commercial Visa Product Transaction
- Visa Debit Card Transaction with one of the following MCCs:
  - 5541, "Service Stations"
  - 5411, "Grocery Stores and Supermarkets"
  - 5499, "Miscellaneous Food Stores — Convenience Stores and Specialty Markets"
- Visa Consumer Card (including Visa Signature Card) Transaction at a Merchant that is eligible for the Performance Threshold Interchange Reimbursement Fee Program. An exception applies to Transactions with MCC 5812, "Eating Places and Restaurants," or MCC 5814, "Fast Food Restaurants"

ID#: 050411-161010-0026011

Industry-Specific Merchant Programs - U.S. Region

Industry-Specific Merchant Program Requirements - U.S. Region

Industry-Specific Merchant Incentive Programs - U.S. Region (Updated)

In the U.S Region, Visa offers incentive programs for Transactions completed by Merchants in specific Merchant segments Visa reserves the right to disqualify a Merchant from participation in, or to modify or discontinue a Merchant incentive program at any time.

ID#: 050411-010100-0025930

Visa Utility Program Interchange Reimbursement Fee Qualification - U.S. Region

In the U.S. Region, only Visa Consumer Card Transactions or Visa Business Card Transactions (including Visa Signature Business Card) completed by a Merchant registered with the Visa Utility Interchange Reimbursement Fee Program may qualify for the Visa Utility Program Interchange Reimbursement Fee as specified in the *U.S. Interchange Reimbursement Fee Rate Qualification Guide* and the *Visa Utility Interchange Reimbursement Fee Program Guide*.

Utility Transactions involving registered Visa Merchants properly assigned Merchant Category Code 4900, "Utilities - Electric, Gas, Water, Sanitary" receive the utility Interchange Reimbursement Fee by meeting certain business requirements. Credit Voucher Transactions are not eligible for this program.

To qualify for the Visa Utility Interchange Reimbursement Fee Program, a U.S. Merchant must:

- Contract directly with an Acquirer to be a Merchant, and the Merchant Outlet must be properly identified in the Authorization and Clearing Records
- Be properly assigned Merchant Category Code 4900, "Utilities - Electric, Gas, Water, Sanitary"
- Accept Visa as a means of payment in all channels where payments are accepted (e.g., Face-to-Face Environments and Card-Absent Environments, as applicable)
- Visually represent the Visa Flag Symbol or Visa Brand Mark or Visa Brand Name on its Website
- **Not** charge a Convenience Fee to a Cardholder for processing a Visa Transaction. This restriction also applies to a third-party agent that processes Transactions for a utility Merchant.
- Feature the opportunity to pay with Visa at least as prominently as all other payment methods
- Be registered with Visa by its Acquirer

Transactions completed by a Merchant providing telecommunication or cable services are **not** eligible to participate in the Visa Utility Interchange Reimbursement Fee Program (Merchant Category Code 4900 is not applicable to such Merchants). Visa reserves the right to disqualify a Merchant from participation in or to modify or discontinue the Visa Utility Interchange Reimbursement Fee Program at any time.

An Acquirer must register the Visa Utility Payment Program Merchant as specified in the *Visa Utility Interchange Reimbursement Fee Program Guide*.

ID#: 081010-010410-0008990

Visa Debt Repayment Program - U.S. Region

In the U.S. Region, Visa Debt Repayment Program Transactions completed by a registered Visa Merchant qualify for the Debt Repayment Program Interchange Reimbursement Fee by meeting the applicable business requirements specified in the *Visa Debt Repayment Program Guide* and the *U.S. Interchange Reimbursement Fee Rate Qualification Guide*.

Transactions must have the following characteristics:

- Transaction is completed with a Visa Debit Card
- Merchant is properly assigned Merchant Category Code 6012, "Financial Institutions - Merchandise and Services," or 6051, "Non-Financial Institutions - Foreign Currency, Money Orders (not Wire Transfer), Travelers Cheques"
- Transaction is a U.S. Domestic Transaction
- The bill payment and existing debt indicators are included in the Authorization Request and Clearing Record

NW Natural
Oregon General Rate Case - December 2011

Potential Savings by offering Bank Card Payments

Volume Assumptions	
2010 Bank Card payment volume	135,488
2010 Payment volume	7,222,023
Adoption Rate	15.0%
Expected Bank Card Volume	1,083,303
Volume increase over current program	947,815
90% Oregon	***853,034***

Transaction Cost Savings	Savings Total	Lock Box	RPPS	AutoPay	Bus Office 1/
2010 Transaction volume by channel		2,986,200	1,757,600	1,291,900	53,500
Transaction cost by channel		$ 0.109	$ 0.020	$ 0.030	$ 0.080
Cost saved @ 100% each channel		$ 103,300	$ 19,000	$ 28,400	$ 75,800
Assumed ratio of:	100%	35%	40%	23%	2%
Volume by channel	853,100	298,600	341,200	196,200	17,100
Transaction cost saved - Oregon	$ 46,600	$ 32,500	$ 6,800	$ 5,900	$ 1,400

1/ Excludes associated internal labor cost

Funds Float Savings		
Average payment amount	$ 144	
Increase payment volume	853,034	
Increased annual bank card collection	$ 122,836,900	
Company's short term investment rate (APR)	0.20%	(per DWA @ 9/27/11)
Interest earned / day payments accellerated - Oregon	$ 670	

Paperless Bill Savings (Assumes 5% of the 15% enrolled - 33%)		Bill Direct Cost Components	Oregon customers converted to paperless
Postage	$ 110,499	$ 0.34000	
Paper stock	$ 6,695	$ 0.02060	
Outgoing Envelope	$ 5,587	$ 0.01719	
Return Envelope	$ 4,709	$ 0.01449	
Unit savings (paper vs. paperless bill)		$ 0.39228	
Annual savings (x 12) - Oregon	$ 127,561	$ 4.71	27,083

Reduction in Mailing of Disconnect notices		
Annual disconnect notices - Oregon only		608,756
Reduction in mailing of notices (10%)		60,876
Cost per mailing		$ 0.40
Annual Savings	**$ 24,350**	

Reduction in Field Disconnection/Reconnection Service Calls		
2010 Annual Service Calls		52,643
2010 Field Service Call Costs		$960,508
Reduction in field calls (10%)	5,264	
Annual Savings	**$96,051**	

TOTAL POTENTIAL ANNUAL COST SAVINGS	**$ 295,232**

NW Natural
Oregon General Rate Case - December 2011

Potential Reductions in Schedule C Miscellaneous Revenues

		Revenues Total	
Late Payment Charges			
2010 Bank Card payment volume	135,488		
2010 Payment volume	7,222,023		
Adoption Rate	15.0%		
Expected Bank Card Volume	1,083,303		
Increase Volume over 2010	947,815		
Avoided Late Payment Charges - Oregon:		$255,910	

1/ 10% of increased bank card volume & late charge of $3.00

Field Visit Charges			
Reduction in field calls			5,264
50% of reduced calls			2632
Reduced field visit charges @ $15 1/		$39,480	

1/ 2010 charge amount

Service Reconnection Charges			
Reduction in field calls			5,264
50% of reduced calls			2,632
Reduced reconnection charges $25 1/		$65,800	

1/ 2010 charge amount - standard reconnect

TOTAL POTENTIAL ANNUAL REDUCTIONS:		$361,190	

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Kimberly Heiting

CUSTOMER COMMUNICATIONS
Exhibit 1000

December 2011

EXHIBIT 1000 – DIRECT TESTIMONY - CUSTOMER COMMUNICATIONS

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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 Chief Communications Officer for NW Natural. My responsibilities include customer and employee communications services, media relations, advertising, and website services. 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 Test Year Category A communications plan; and
- Present the Company's November 2012-October 2013 test year ("Test Year") Category A advertising expense and explain why the level of expense is reasonable under OAR 860-026-0022. In particular, I explain why the calculation of the presumptive level of Category A communications expense in OAR 860-

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026-0022 is not sufficient for NW Natural given the calculation's disproportionately low results for local distribution companies (LDC) as compared with electric utilities, the nature of NW Natural's service territory, and the increase in media costs in recent years.

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 in OAR 860-026-0022(2)(a) as "Energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility services advertising, and utility information advertising expenses."

Q. What topics do 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;
- On-line customer service options and information;
- Natural gas price changes;
- Cost, performance, and environmental benefits of high efficiency natural gas equipment; and
- Phone numbers and contact information.

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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, a customer e-newsletter, new customer information packets, and telephone directory advertising. The plan accommodates higher media costs for television and radio, while allowing for modest exposure in newspaper and online news websites. The plan is supported by research that identifies the media channels customers cite as the most important sources for news and information. *See NWN/1007, Heiting/1-2.*

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 the last rate case ("2002 Rate Case")?

A. The Category A communications expense level currently embedded in rates is approximately $1,160,000, or $2.19 per-customer, based on the Commission's order in the Company's 2002 rate case.[1] The Test Year Category A communications expense is $1,575,000, or $2.55 per-customer per-year. This level of expense represents a 36-cent increase per-year on a per-customer basis.

Q How does NW Natural's proposed Test Year Category A communications expense compare to the level that is presumed 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 operating revenues are deemed just and reasonable. In NW Natural's case, that percentage would allow NW Natural $845,337 for Category A

[1] *Re NW Natural Gas Co.'s Request for a General Rate Revision*, Docket UG 152, Order No. 03-507 (Aug. 22, 2003).

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communications based on 2010 revenues, which is equivalent to about $1.40 per customer.

Q. Does OAR 860-026-0022 prevent NW Natural from recovering more than $1.40 per customer for Category A communications expense?

A. No, it does not. Under OAR 860-026-0022(4), the presumption stated above is rebuttable, and the company seeking to include expenditures in excess of 0.125 percent of revenues bears the burden of demonstrating that the expenditure is just and reasonable. As in the 2002 Rate Case, NW Natural can demonstrate that its proposed Category A communications expense is just and reasonable, and therefore collectible in rates.

Q. Why does NW Natural require a higher level of Category A communications expense than the amount that is automatically deemed just and reasonable per OAR 860-026-0022(3)(a)?

A. As was the case when the Company filed its 2002 Rate Case, using the gross revenue-based formula established by the rule to determine a reasonable level of Category A communications expense for NW Natural is not appropriate for three reasons. First, the revenue-based formula provides LDCs with an unfairly low allocation-per-customer compared to an electric utility. Second, NW Natural's service territory is geographically broad and demographically diverse, requiring additional expense in order to reach all of our customers. Third, media costs have increased since the 2002 Rate Case.

Q. How does the revenue-based formula result in an unfairly low allocation per customer for LDCs?

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A. A gross retail revenue-based formula results in lower allowances for LDCs than for electric utilities because, in part, electric utilities have higher operating revenues per-customer due to the fact that they make more capital investments in generation. For instance, the revenue-based formula translates to $2.39 per-customer for Portland General Electric Company (PGE) and $2.72 per-customer for Idaho Power Company *See NWN/1001, Heiting/1.* As a consequence, the formula treats electric and gas utilities differently; and therefore, electric utilities have more of an ability to communicate to customers than gas utilities.

It is the Company's view that energy consumers are entitled to receive comparable information about their respective utility services. The proposed Test Year expense allows the Company to recover a reasonable amount to provide customer communications about natural gas service at a level similar to the information level electric utility customers receive.

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 124 cities and towns within its Oregon service territory. *See NWN/1002, Heiting/1-7.* In contrast, a utility such as PGE, which has only to communicate to customers within the Portland/Salem area, would be investing in far fewer media channels to reach their target audience. The OAR 860-026-0022 formula does not address the differences utilities have in service territories and customer composition—differences that increase overall message delivery costs.

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Q. How have media costs increased since the 2002 Rate Case?

A. Over the last nine years, costs to deliver customer communications have increased primarily due to higher media costs. For example, from 2005 to 2011, the average Cost Per Point[2] (CPP) for television in the Portland/Salem market has increased 24 percent *See NWN/1003, Heiting/1*. In that same time period, the average CPP for radio in the Portland/Salem market has increased 15 percent. *See NWN/1004, Heiting/1.* Additionally, internet news sites were not major sources of information for customers in 2002. Today, consumers spend about 31 percent of their media-consuming time using the internet or mobile devices, making these channels essential in the Company's communications plan. However, it is important to keep in mind that online information sources have not replaced traditional media, but rather, have only served to increase media fragmentation and message delivery costs. While television, radio, and newspapers remain the dominant channels consumers utilize, customers often access these more traditional media while scanning online information sources simultaneously. *See NWN/1005, Heiting/1* and *NWN/1006, Heiting/1-2*. In summary, higher costs for traditional media and the need to deliver information across more media channels requires a higher multi-channel communications investment.

Q. What action does the Company request the Commission take with respect to Category A communications expense?

[2] Cost Per Point is the cost to reach one percent (one rating point) of the targeted demographic audience.

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A. The Company requests that the Commission find that the level of Test Year Category A communications expense is just and reasonable under OAR 860-026-0022. The Company's 36-cent per-customer increase above the current amount included in rates is necessary for the Company to meet its Category A communication and is reasonable given the factors discussed in my testimony.

Q. Does this conclude your direct testimony?

A. Yes.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Exhibits of Kimberly Heiting

CUSTOMER COMMUNICATIONS
EXHIBITS 1001 - 1007

December 2011

EXHIBITS 1001-1007 – CUSTOMER COMMUNICATIONS EXHIBITS

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Rates & Regulatory Affairs
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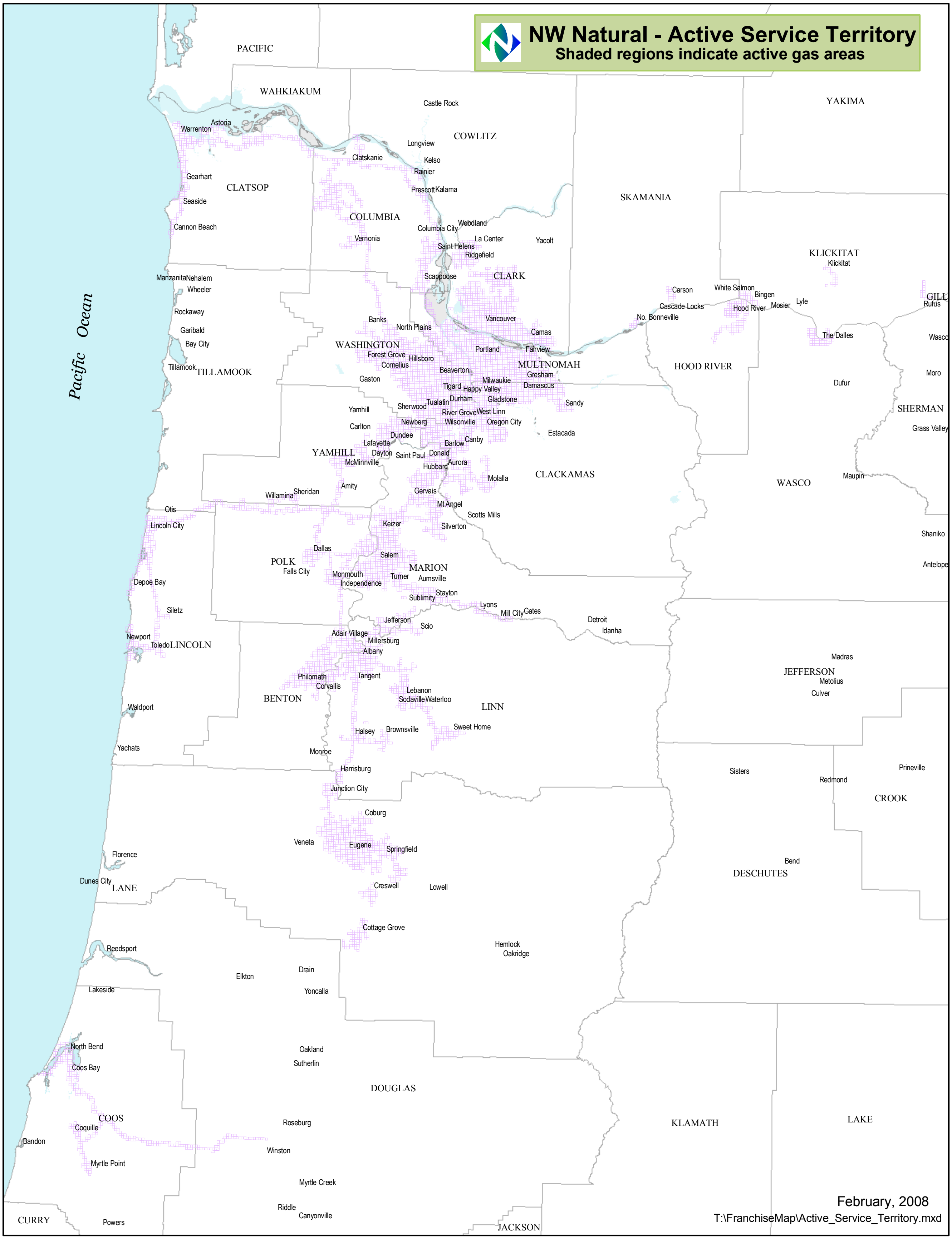
NW Natural®

2010 Utility Per Customer Allowance

Utility	Year	Operating Revenue	CAT A - 0.125%	# of Customers	CAT A Per Customer
NW Natural	2010	$676,269,917	$845,337.40	601,901	$1.40
PGE	2010	$1,568,963,027	$1,961,203.78	820,266	$2.39
Idaho Power	2010	$40,153,902	$50,192.38	18,455	$2.72

Source: OPUC 2010 Utility Statistics


NW Natural - Active Service Territory
Shaded regions indicate active gas areas
Pacific Ocean
PACIFIC
WAHKIAKUM
COWLITZ
SKAMANIA
YAKIMA
KLICKITAT
CLATSOP
COLUMBIA
CLARK
TILLAMOOK
WASHINGTON
MULTNOMAH
HOOD RIVER
WASCO
SHERMAN
YAMHILL
CLACKAMAS
POLK
MARION
LINCOLN
BENTON
LINN
JEFFERSON
CROOK
DESCHUTES
LANE
DOUGLAS
COOS
CURRY
JACKSON
KLAMATH
LAKE
Astoria
Warrenton
Gearhart
Seaside
Cannon Beach
Manzanita
Nehalem
Wheeler
Rockaway
Garibald
Bay City
Tillamook
Castle Rock
Longview
Kelso
Rainier
Clatskanie
Prescott
Kalama
Vernonia
Columbia City
Woodland
La Center
Yacolt
Saint Helens
Ridgefield
Scappoose
Banks
North Plains
Forest Grove
Cornelius
Hillsboro
Gaston
Beaverton
Portland
Vancouver
Camas
Fairview
Gresham
Damascus
Milwaukie
Happy Valley
Tigard
Durham
Tualatin
Gladstone
Sherwood
River Grove
West Linn
Wilsonville
Oregon City
Newberg
Sandy
Estacada
Yamhill
Carlton
Dundee
Lafayette
Dayton
Saint Paul
Donald
Barlow
Canby
McMinnville
Hubbard
Aurora
Molalla
Amity
Sheridan
Willamina
Gervais
Mt Angel
Scotts Mills
Silverton
Keizer
Otis
Lincoln City
Dallas
Salem
Monmouth
Independence
Falls City
Turner
Aumsville
Stayton
Sublimity
Lyons
Mill City
Gates
Detroit
Idanha
Depoe Bay
Siletz
Newport
Toledo
Jefferson
Scio
Adair Village
Millersburg
Albany
Philomath
Corvallis
Tangent
Lebanon
Sodaville
Waterloo
Halsey
Brownsville
Sweet Home
Waldport
Yachats
Monroe
Harrisburg
Junction City
Coburg
Veneta
Eugene
Springfield
Creswell
Lowell
Cottage Grove
Florence
Dunes City
Reedsport
Elkton
Drain
Yoncalla
Hemlock
Oakridge
Lakeside
North Bend
Coos Bay
Coquille
Bandon
Myrtle Point
Powers
Oakland
Sutherlin
Roseburg
Winston
Myrtle Creek
Riddle
Canyonville
Carson
Cascade Locks
No. Bonneville
White Salmon
Bingen
Hood River
Mosier
Lyle
Klickitat
The Dalles
Dufur
Rufus
GILL
Wasco
Moro
Grass Valley
Maupin
Shaniko
Antelope
Madras
Metolius
Culver
Sisters
Redmond
Prineville
Bend
February, 2008
T:\FranchiseMap\Active_Service_Territory.mxd

Counts of Counties and Cities with active accounts as of 2011 12 09

Obs	State	County	Active_Accounts	Count
1	Oregon	Benton	18,379	1
2	Oregon	Clackamas	84,353	2
3	Oregon	Clatsop	12,283	3
4	Oregon	Columbia	7,857	4
5	Oregon	Coos	1,298	5
6	Oregon	Hood River	3,566	6
7	Oregon	Lane	37,933	7
8	Oregon	Lincoln	10,054	8
9	Oregon	Linn	22,527	9
10	Oregon	Marion	62,620	10
11	Oregon	Multnomah	189,571	11
12	Oregon	Polk	13,512	12
13	Oregon	Wasco	1,905	13
14	Oregon	Washington	130,794	14
15	Oregon	Yamhill	11,354	15
16	Washington	Clark	68,131	1
17	Washington	Klicktat	1,375	2
18	Washington	Skamania	483	3

Counts of Counties and Cities with active accounts as of 2011 12 09

Obs	State	City	Active_Accounts	Count
1	Oregon	Adair Village	2	1
2	Oregon	Albany	15,054	2
3	Oregon	Aloha	43	3
4	Oregon	Amity	320	4
5	Oregon	Astoria	4,141	5
6	Oregon	Aumsville	683	6
7	Oregon	Aurora	937	7
8	Oregon	Ballston	2	8
9	Oregon	Banks	433	9
10	Oregon	Barlow	5	10
11	Oregon	Beavercreek	200	11
12	Oregon	Beaverton	44,728	12
13	Oregon	Boring	1,934	13
14	Oregon	Brooks	2	14
15	Oregon	Brownsville	493	15
16	Oregon	Canby	3,240	16
17	Oregon	Cannon Beach	1,349	17
18	Oregon	Carlton	20	18
19	Oregon	Clackamas	6,215	19
20	Oregon	Clatskanie	162	20
21	Oregon	Coburg	127	21
22	Oregon	Columbia City	636	22
23	Oregon	Coos Bay	664	23
24	Oregon	Coquille	139	24
25	Oregon	Cornelius	2,161	25
26	Oregon	Corvallis	14,388	26
27	Oregon	Cottage Grove	2,508	27
28	Oregon	Creswell	1,210	28
29	Oregon	Dallas	3,817	29
30	Oregon	Damascus	1,658	30
31	Oregon	Dayton	7	31
32	Oregon	Deer Island	39	32

Counts of Counties and Cities with active accounts as of 2011 12 09

Obs	State	City	Active_Accounts	Count
33	Oregon	Depoe Bay	1,324	33
34	Oregon	Donald	179	34
35	Oregon	Dundee	930	35
36	Oregon	Durham	2	36
37	Oregon	Eugene	27,098	37
38	Oregon	Fairview	2,065	38
39	Oregon	Forest Grove	2,908	39
40	Oregon	Foster	3	40
41	Oregon	Gearhart	1,348	41
42	Oregon	Gervais	355	42
43	Oregon	Gladstone	2,953	43
44	Oregon	Gleneden Beach	1,138	44
45	Oregon	Grand Ronde	256	45
46	Oregon	Gresham	17,027	46
47	Oregon	Halsey	238	47
48	Oregon	Hammond	359	48
49	Oregon	Happy Valley	1,716	49
50	Oregon	Harrisburg	615	50
51	Oregon	Hebo	3	51
52	Oregon	Hillsboro	22,701	52
53	Oregon	Hood River	3,567	53
54	Oregon	Hubbard	925	54
55	Oregon	Independence	1,630	55
56	Oregon	Jasper	26	56
57	Oregon	Jefferson	769	57
58	Oregon	Junction City	1,362	58
59	Oregon	Keizer	371	59
60	Oregon	King City	30	60
61	Oregon	Lafayette	678	61
62	Oregon	Lake Oswego	13,783	62
63	Oregon	Lebanon	5,142	63
64	Oregon	Lincoln City	3,881	64

Counts of Counties and Cities with active accounts as of 2011 12 09

Obs	State	City	Active_Accounts	Count
65	Oregon	Lyons	423	65
66	Oregon	Marion	8	66
67	Oregon	Marylhurst	20	67
68	Oregon	McMinnville	2,960	68
69	Oregon	Mehama	57	69
70	Oregon	Mill City	488	70
71	Oregon	Millersburg	14	71
72	Oregon	Milwaukie	210	72
73	Oregon	Molalla	2,007	73
74	Oregon	Monmouth	1,196	74
75	Oregon	Mount Angel	759	75
76	Oregon	Mulino	120	76
77	Oregon	Myrtle Point	114	77
78	Oregon	Neotsu	206	78
79	Oregon	Newberg	5,376	79
80	Oregon	Newport	1,981	80
81	Oregon	North Bend	381	81
82	Oregon	North Plains	613	82
83	Oregon	Oregon City	10,782	83
84	Oregon	Otis	1,042	84
85	Oregon	Philomath	1,266	85
86	Oregon	Pleasant Hill	134	86
87	Oregon	Portland	231,491	87
88	Oregon	Rainier	420	88
89	Oregon	Rickreall	68	89
90	Oregon	Rose Lodge	14	90
91	Oregon	Saint Helens	3,220	91
92	Oregon	Salem	52,989	92
93	Oregon	Sandy	3,037	93
94	Oregon	Scappoose	2,202	94
95	Oregon	Scio	293	95
96	Oregon	Seaside	3,024	96

Counts of Counties and Cities with active accounts as of 2011 12 09

Obs	State	City	Active_Accounts	Count
97	Oregon	Shedd	72	97
98	Oregon	Sheridan	845	98
99	Oregon	Sherwood	6,203	99
100	Oregon	Siletz	162	100
101	Oregon	Silverton	2,719	101
102	Oregon	Sodaville	1	102
103	Oregon	South Beach	4	103
104	Oregon	Springfield	5,467	104
105	Oregon	St Benedict	1	105
106	Oregon	Stayton	1,759	106
107	Oregon	Sublimity	683	107
108	Oregon	Sweet Home	2,137	108
109	Oregon	Tangent	365	109
110	Oregon	The Dalles	1,905	110
111	Oregon	Tigard	353	111
112	Oregon	Toledo	343	112
113	Oregon	Troutdale	4,850	113
114	Oregon	Tualatin	6,726	114
115	Oregon	Turner	711	115
116	Oregon	Vernonia	652	116
117	Oregon	Warren	574	117
118	Oregon	Warrenton	2,009	118
119	Oregon	West Linn	9,060	119
120	Oregon	Westport	19	120
121	Oregon	Willamina	382	121
122	Oregon	Wilsonville	5,002	122
123	Oregon	Wood Village	120	123
124	Oregon	Woodburn	5,268	124
125	Washington	Battle Ground	4,018	1
126	Washington	Bingen	194	2
127	Washington	Brush Prairie	157	3
128	Washington	Camas	6,398	4

Counts of Counties and Cities with active accounts as of 2011 12 09

Obs	State	City	Active_Accounts	Count
129	Washington	Carson	270	5
130	Washington	Dallesport	7	6
131	Washington	Klickitat	119	7
132	Washington	La Center	748	8
133	Washington	Lyle	1	9
134	Washington	North Bonneville	212	10
135	Washington	Ridgefield	2,071	11
136	Washington	Vancouver	51,564	12
137	Washington	Washougal	3,173	13
138	Washington	White Salmon	1,055	14
139	Washington	Woodland	1	15
140	Washington	Yacolt	1	16

TV Cost Per Point Analysis

Below is a comparison of the NW Natural rates for Late News in the Portland market from 2005 – 2011 across the four major networks. The rates and ratings were taken from actual negotiated NW Natural schedules. Ratings are derived from Nielsen rating services for the years indicated and the rates were negotiated with each station.

The chart provides the percentage change comparing the cost-per-point (CPP) for each station from 2005 to 2011.

In all cases the CPP has gone up for every station with an overall increase in the market of 23.49%.

Schedules are negotiated based on CPPs to determine each station's efficiencies in reaching the target audience – adults 35-54. In 2011, NW Natural would need to spend 24% more to reach the same TRP levels of 2005.

			2005	2006	2007	2008	2009	2010	2011	% Change
KATU	11p-1135p	CPP	$112.90	$120.37	$90.91	$87.50	$113.64	$196.43	$147.62	23.52%
KGW	11p-1135p	CPP	$130.77	$135.96	$120.00	$104.17	$140.00	$277.78	$195.65	33.16%
KOIN	11p-1135p	CPP	$137.50	$139.06	$108.33	$140.00	$130.43	$142.86	$178.95	23.16%
KPTV	10p-11p	CPP	$147.06	$241.38	$125.00	$141.51	$138.30	$164.06	$175.00	15.97%
Total		CPP	$133.69	$154.83	$114.16	$116.57	$132.48	$188.24	$174.73	23.49%

cmd agency

Prepared by: Patti Cody
Managing Director/Media Group CMD Agency, Portland, OR

Radio Cost Per Point Analysis

Portland Market CPP 2006 – 2011 Radio as reported by SQAD

	2006	2007	2008	2009	2010	2011	% Change
Q1	$131.00	$140.00	$147.00	$134.00	$139.00	$150.00	14.50%
Q2	$134.00	$144.00	$152.00	$138.00	$143.00	$154.00	14.93%
Q3	$144.00	$155.00	$163.00	$148.00	$154.00	$166.00	15.28%
Q4	$145.00	$156.00	$164.00	$159.00	$155.00	$167.00	15.17%
Total Average	$138.50	$148.75	$156.50	$144.75	$147.75	$159.25	14.97%

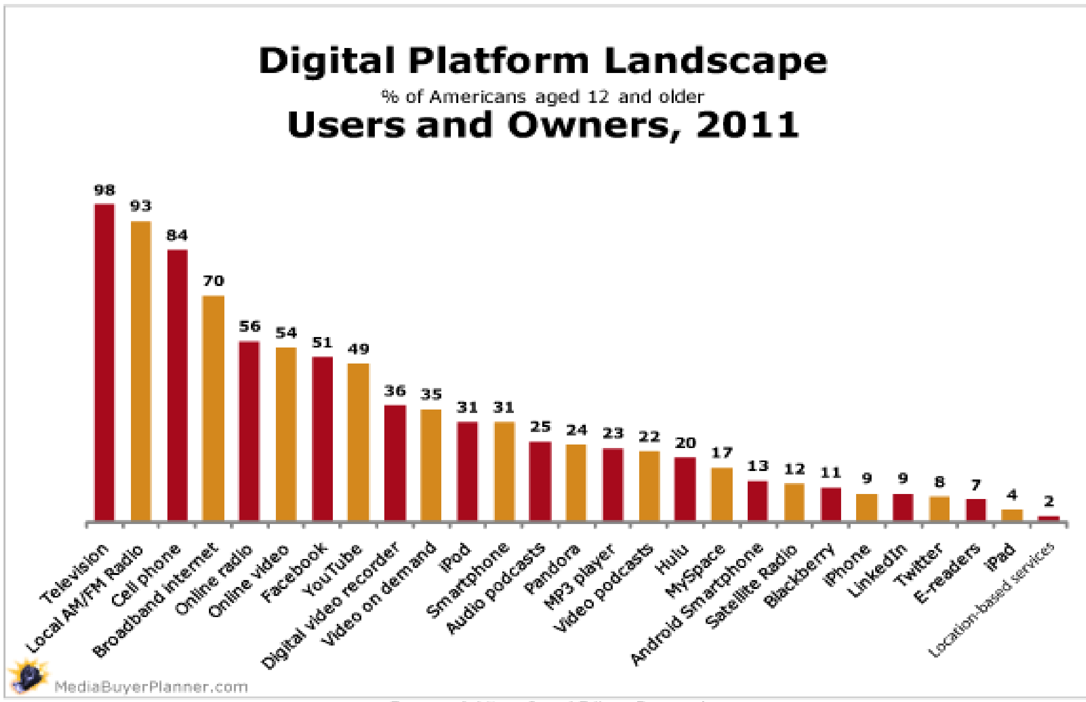
Change from 2005 – 2011
15% increase

cmd agency

Prepared by: Patti Cody
Managing Director/Media Group CMD Agency, Portland, OR

The Challenge of Media Fragmentation

The chart below displays the percentage of Americans that are users of various media channels. The chart helps punctuate the issue of increasing media fragmentation associated with the advent of online and mobile media sources. The chart also underscores that consumers continue to be very strong users of traditional media. Overall, fragmentation is diminishing message reach, forcing advertisers to pursue a multi-channel strategy to reach consumers.



Source: Arbitron Inc. / Edison Research

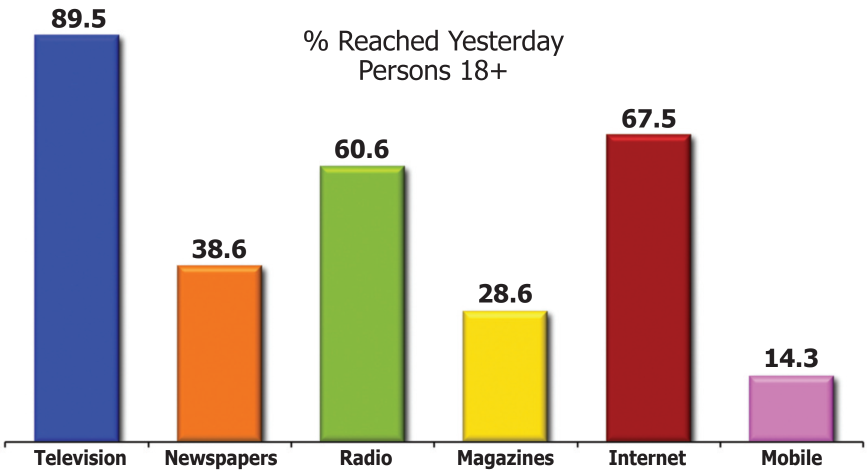
More Fragmentation Requires Greater Message Frequency

According to Yankelovich Partners, a renowned industry consulting firm, consumers are exposed to up to 5,000 messages each day across numerous media delivery channels. The sheer amount of information consumers are being subjected to necessitates greater frequency of message exposure to achieve penetration and recall. *("Coming to Concurrence," J. Walker Smith, Ann Clurman, and Craig Wood, April 2005)*

The research of Dr. Herbert Krugman, author of the "Rule of Three," indicates that in television and radio a consumer needs to be exposed to a message at least 3 times in a single week in order to achieve message penetration (*"Rule of Three," Dr. Herbert Krugman, General Electric 2005).* Achieving higher levels of frequency across more media channels is increasingly necessary and expensive.

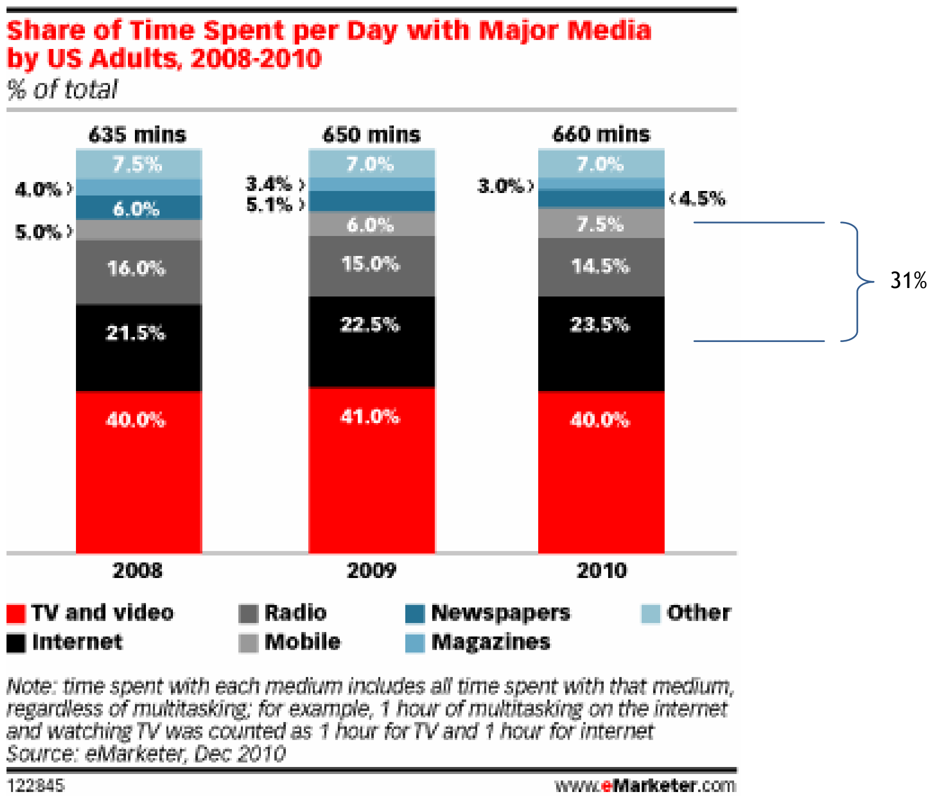
Prepared by: Patti Cody
Managing Director/Media Group
CMD Agency, Portland, OR

Television Reaches More People Each Day Than Any Other Medium



Persons: Reached Yesterday by Major Media (%)

	Television	Newspapers	Radio	Magazines	Internet	Mobile
Age						
18+	89.5	38.6	60.6	28.6	67.5	14.3
18-34	82.4	23.4	57.5	22.8	75.2	23.8
18-49	85.9	30.2	61.7	25.3	75.3	18.9
25-49	87.5	33.2	66.1	26.6	75.3	17.9
25-54	88.0	35.1	67.0	27.9	73.1	16.8
35-64	92.3	43.1	65.0	31.0	66.2	11.3
65+	96.9	62.8	45.7	33.4	49.4	0.3
13-17	86.2	19.8	58.4	24.5	79.0	15.4
Household Income						
Under $25K	91.8	27.2	55.4	21.1	56.0	7.1
$25K-$50K	86.0	40.4	58.8	29.8	62.5	13.7
$50K-$75K	91.7	36.7	60.9	24.8	65.9	11.2
$75K+	88.4	40.9	64.6	33.9	83.3	21.8
$100K+	86.8	37.4	63.6	32.4	81.4	25.0
Education						
<HS Grad	85.9	26.9	46.8	21.7	60.2	9.6
HS Grad	91.9	40.6	60.1	27.6	51.1	6.9
Some College	88.3	36.0	60.0	26.8	76.3	19.2
College Grad+	89.9	42.0	71.9	35.5	85.5	21.2



Prepared by: Patti Cody
Managing Director/Media Group
CMD Agency, Portland, OR

Market Perception Survey Results: Importance of Various Media Sources to Customers

Survey Methodology Summary:

- Online Survey Conducted by CT Marketing Oct. 13 - 16
- Sample: NW Natural Customers Residing in Multnomah, Clackamas, and Washington County
- Sample Size: 401 completes

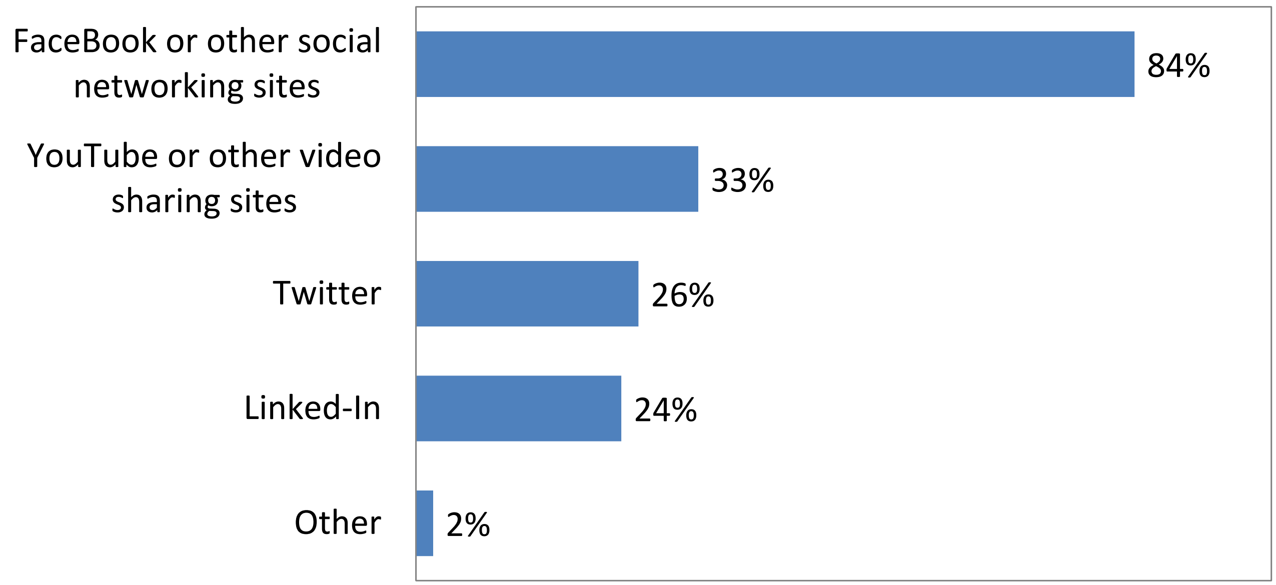
"Please rate how important the following sources of news and information are to you."

	Average Score *	Top 2 boxes
Television	3.48	41%
News sites on the Internet	3.47	54%
Local newspaper	3.13	53%
Radio	3.00	14%
Social media	2.59	17%
Email newsletters	2.46	35%
Blogs	2.12	25%

Note: The score is out of 5 point scale.

Market Perception Survey Results: Social Media Engagement

Do you currently have a profile or account on any of the following?



BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Russell A. Feingold

LONG-RUN INCREMENTAL COST STUDY / RATE DESIGN
EXHIBIT 1100

December 2011

EXHIBIT 1100 – DIRECT TESTIMONY – LONG-RUN INCREMENTAL COST STUDY / RATE DESIGN

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Russell A. Feingold and my business address is 2525 Lindenwood Drive, Wexford, Pennsylvania 15090.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Northwest Natural Gas Company ("NW Natural" or the "Company").

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Corporation (B&V) as a Vice President and I lead the Ratemaking & Financial Planning Services Group of B&V's Management Consulting Division.

Q. Please describe the firm of B&V.

A. B&V has provided comprehensive engineering and management services to utility, industrial, and governmental entities since 1915. Its Management Consulting Division delivers management consulting solutions in the energy and water sectors. Our services include broad-based strategic, regulatory, financial, and information systems consulting. In the energy sector, B&V's Management Consulting Division delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas.

From an industry-wide perspective, Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing,

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gas supply and transportation planning, competitive market analysis, and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline, and other energy-related companies, and through a wide variety of client assignments. B&V has assisted numerous gas distribution companies located in the U.S. and Canada.

Q. What is your educational background?

A. I received a Bachelor of Science Degree in Electrical Engineering from Washington University in St. Louis and a Master of Science Degree in Financial Management from Polytechnic Institute of New York University (formerly Polytechnic University).

Q. What has been the nature of your work in the utility consulting field?

A. I have over 35 years of experience in the utility industry, the last 33 years of which have been in the field of utility management and economic consulting. Specializing in the natural gas industry, I have advised and assisted utility management, industry trade and research organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies, and market planning. I have prepared and presented expert testimony before utility regulatory bodies and have spoken widely on issues and activities dealing with the pricing and marketing of gas utility services. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in Appendix A to my testimony.

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Q. Have you previously testified before any utility regulatory bodies?

A. Yes. I have presented expert testimony before the Federal Energy Regulatory Commission (FERC) and numerous state and provincial regulatory commissions. My expert testimony has dealt with the costing and pricing of energy-related products and services for gas and electric distribution and gas pipeline companies. In addition to traditional utility costing and rate design concepts and issues for gas and electric distribution utilities, and gas pipeline companies, my testimony has addressed revenue decoupling mechanisms and other innovative ratemaking approaches, gas transportation rates, gas supply planning issues and activities, market-based rates, Performance-Based Ratemaking (PBR) concepts and plans, competitive market analysis, gas merchant service issues, strategic business alliances, market power assessment, merger and acquisition analyses, multi-jurisdictional utility cost allocation issues, inter-affiliate cost separation and transfer pricing issues, seasonal rates, cogeneration rates, and pipeline ratemaking issues related to the importation of gas into the United States.

Q. Please summarize your testimony.

A. In my testimony I present NW Natural's Long-Run Incremental Cost (LRIC) Study and discuss its results, and I present the various rate design proposals filed by NW Natural in this proceeding.

My testimony consists of this introduction and summary section and the following additional sections:

- Theoretical Principles of Cost Allocation

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- NW Natural's LRIC Study
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- Summary of NW Natural's Rate Design Proposals
- Fixed Cost Allocation and Full Cost-Based Customer Charges for Residential and Small Commercial Service Customers
- Other Tariff Changes to Align with Full Cost-Based Customer Charges
- Residential Bill Impacts
- Efficiency and Non-Discriminatory Rates Under Full Cost-Based Customer Charges
- Benefits of Full cost-Based Customer Charges
- Rate Design for NW Natural's Other Rate Classes

II. <u>THEORETICAL PRINCIPLES OF COST ALLOCATION</u>

Q. Why do utilities conduct cost allocation studies as part of the regulatory process?

A. There are many purposes for utilities conducting cost allocation studies, ranging from designing appropriate price signals in rates to determining the share of costs or revenue requirements borne by the utility's various rate or customer classes. In this case, an LRIC study is a useful tool for determining the allocation of NW Natural's revenue requirement among its rate schedules. It is also a useful tool for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

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Q. Please describe the various types of cost of service studies that may be useful to a utility for rate design and the allocation of revenue requirements.

A. In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs can be thought of as the change in costs associated with a one unit change in service (or output) provided by the utility. LRIC is a variant of the marginal cost approach that examines changes in costs over a longer time period associated with a multiple unit (*i.e.*, incremental) change in service. As a result of using an incremental change, capacity additions tend to be lumpy and may reflect more capacity additions than those required to serve the increment of load assumed in the analysis. To avoid this issue requires that the computation of the unit cost be based on the amount of capacity added rather than on the level of load that can be served.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period) or the estimated book value of costs for a forecast test year or some combination of historical and future costs. Where a forecast test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

Marginal cost studies do not reflect actually incurred costs, but rely on estimates of the expected changes in cost associated with changes in utility service. Marginal cost studies are forward-looking to the extent permitted by available data. Marginal cost studies are particularly useful for rate design and can also be used as a guide to

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determine how a utility's total revenue requirement should be allocated to its classes of service. Where it is important to send appropriate price signals associated with additional energy consumption by customers, an understanding of marginal cost may be useful. For a gas utility, detailed studies are not required to assess the impact of additional consumption by existing customers since the delivery system is built for design day requirements and energy conservation has reduced those requirements for most customers. Where new customers are added to the system, growth may increase design day requirements above an amount that existing facilities can serve, while the marginal cost of load growth from existing customers is zero. The principal factors driving new main investment are customer growth in new areas and the replacement of bare steel and cast iron mains to provide safe and reliable service for customers. Replacement of existing mains is not an incremental cost and is, therefore, excluded from the LRIC calculation.

Q. Please discuss the reasons that cost of service studies are utilized in regulatory proceedings.

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more classes, or the cost of providing multiple products to the same class, use the same facilities and the use by one class precludes the use by another class.

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In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains and service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, main costs vary with either growing design day demand or a growing number of customers.

As I discuss in greater detail later in my testimony, the minimum size of distribution main installed by NW Natural will serve the design day demands (at standard operating pressure and average system density) of its residential and small commercial customers. For this reason, the customer component of distribution mains represents the total LRIC for distribution mains.

Finally, utility costs exhibit significant economies of scale. Scale economies result in declining average cost as gas throughput increases and marginal costs must be below average costs. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, on either a marginal or embedded cost basis, requires an understanding of the operating characteristics of the utility system. Further, as discussed below, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. Please discuss the application of economic theory to cost allocation.

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A. The allocation of costs using cost of service studies is not a theoretical economic exercise. It is rather a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the information developed in the cost of service study to understand and quantify the allocated costs in each rate class to guide the development of rates is a useful step in the rate design process.

However, the existence of common costs makes any allocation of costs problematic from a strict economic perspective. This is theoretically true for any of the various utility costing methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy-free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy-free so long as the price exceeds marginal cost, but is less than stand alone costs (SAC). The logic for this concept is that if customers' prices exceed marginal cost, those customers make a contribution to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear. Prices must be below the SAC because the customer would not be willing to participate in the service offering if prices exceed SAC.

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SAC is an important concept for NW Natural because certain customers have competitive options for the end uses supplied by natural gas through the use of alternative fuels. As a result, subsidy-free prices permit all customers to benefit from the system's scale and common costs, and all customers are better off because the system is sustainable. If the process of cost allocation results in rates that exceed SAC for some customers, prices must be set below the SAC, but above marginal cost, to ensure that those customers make the maximum practical contribution to the common costs of the utility.

Q. If any allocation of common cost is problematic from a theoretical perspective, how is it possible to meet the practical requirements of cost allocation?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of cost causation. From a cost of service perspective, the best approach is to directly assign costs where costs are incurred for a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate schedule, or class, uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters

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are reflected by using a different meter cost for each class of service. For some classes such as the largest customers, the meter cost may be unique for each customer.

Q. Please discuss the elements of an LRIC analysis.

A. As I introduced earlier, LRIC is a costing method based on principles of marginal costs. Since marginal costs are forward-looking in nature, they require making estimates of future costs with an understanding of the elements that drive those future costs.

To estimate LRIC, the first step requires determining the change in cost associated with the incremental consumption of natural gas. For LRIC, the increment may be defined as the number of customers, the design day demand, or the additional commodity. In this case, there is no reason to estimate the incremental commodity because gas costs are a pass-through cost element. Essentially, LRIC requires an understanding of the utility's system planning process. Often, however, the planning process does not provide all of the information necessary to develop complete LRIC estimates.

The second step in the determination of LRIC relates to the change in capacity requirements as measured by the utility's design day demand. Unlike the commodity determination, there is no competitive market for either the utility's transmission or distribution function. Thus, it is necessary to estimate how customers' demand for design day capacity influences the costs for distribution and transmission. The analysis begins by recognizing that the demand for capacity is different for transmission and distribution because the load diversity increases as the analysis becomes more remote from individual customers. Initially, the capacity requirements for transmission reflect the

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coincident demand for the utility's transmission system as measured by its gas loads. The capacity requirements for the distribution system must reflect the non-coincident demands on the system since delivery must satisfy the local demands of customers that may not be coincident with the system peaks for a number of reasons. Although, for customers who use the utility's gas delivery system for heating as opposed to process usage or interruptible services, their demands tend to be coincident. For process and interruptible customers, LRIC is zero for existing customers unless the customer expands its operations. If expansion occurs, LRIC is the cost incurred to expand capacity to meet the customer's contract demand.

Q. Please explain how the observed trends in gas usage characteristics for NW Natural's residential and commercial service customers cause its capacity requirements to change?

A. NW Natural's residential and commercial service customers exhibit declining use per customer due to the availability and promotion of energy conservation measures and the resulting improved efficiency of capital stock replacement and improvements to the thermal envelope. This trend in declining use per customer creates additional design day capacity within the utility's existing gas system to serve new loads. As a result, the growth in transmission and distribution plant for gas customers reflects the growth in the number of customers using gas service. For existing customers, the marginal distribution and transmission capacity related cost is actually zero.

For LRIC, this same conclusion holds true that LRIC for existing customers is zero. The marginal cost for new customers, associated with plant investment located

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where the utility's gas system must be extended to serve the customer, is the driver for the new investment together with the replacement of aging infrastructure. This same conclusion applies to LRIC, namely the driver of new investment in the long run is either customer growth or the replacement of the utility's aging infrastructure. Replacement of facilities is not, however, a marginal or LRIC because it is not the result of a change in load. Further, for gas service there are substantial economies of scale associated with gas distribution infrastructure such that the unit cost of capacity for gas delivery declines with size at a relatively rapid rate. The resulting LRIC becomes the customer related expansion of mains and services for gas delivery.

Q. Please discuss the scale economies associated with gas distribution service.

A. Scale economies for a gas distribution utility reflect the relationship between the installed cost of pipe by size and type, coupled with the increased capacity from pressure and pipe diameter. Simply doubling the size of the gas main more than doubles the available capacity of the main, at a cost for NW Natural that is less than double the smaller size main. For a low pressure system, increasing pipe size from two-inch to four-inch allows over five times the amount of gas to flow, and the flow rate increases under higher pressure by more than six times in the four-inch pipe compared to the two-inch pipe, all else being equal. The resulting cost causation implies that larger customers impose lower unit costs of design day capacity on the utility's distribution system than do smaller customers.

Table 1 below provides the data for NW Natural on the installed cost per foot of distribution main and the available capacity to serve load based on standard operating

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pressure for its gas system. Further, given the customer density for NW Natural's gas distribution system of 58 customers per mile, the minimum size of pipe installed will serve the design day load characteristics of both its smallest customers and larger customers up to approximately 2,370 therms of gas per year, assuming a 20 percent annual load factor.

Table 1 - Mains Cost Comparison

Size of Main	Total Cost per Foot	Design Day Capacity (1)	Cost per Foot of Design Capacity
Two-inch	$22.97	187.9 Dthd	$0.1222/Dthd
Four-inch	$27.08	1,063.1 Dthd	$0.0255/Dthd

(1) Based on 5,280 feet of main and a 60 psig MAOP and 45 psig NOP system

This means that residential customers using less than about 2,370 therms of gas annually have the same cost as all other residential customers. As a point of reference, the average residential customer served by NW Natural currently uses 639 therms per year. Similarly, small commercial customers using less than 2,370 therms of gas annually have the same cost as residential customers. For larger customers that may be served from a four-inch main, the total investment cost is lower than for smaller customers using up to approximately 9,000 therms of gas annually. Only 14 of NW Natural's residential customers use more than 9,000 therms of gas annually. This means that a single unit rate will recover the cost of distribution for virtually all residential customers, assuming that all of the largest customers are served from the same distribution main segment.

This analysis is made under the most restrictive set of assumptions. In the more likely case, if large and small residential customers are mixed on main segments, or the

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segments are served from multiple points, or the customers are served in the middle of the distribution segment, all of these customers would be able to be served from the two-inch main. As I will discuss below, since delivery service for these customers also requires the availability of large diameter, high pressure mains that comprise NW Natural's gas transmission function, the above conclusion regarding all residential customers' ability to receive service from a two-inch main pertains only to the distribution segment of NW Natural's gas system.

Q. What are the implications of these scale economies on NW Natural's cost of service and rate design?

A. The implication of scale economies for both cost allocation and rate design on NW Natural's gas system are quite important. Namely, the cost to serve residential and the smallest general service customers (excluding gas costs) is the same regardless of the size of customer, since the minimum distribution system installed by NW Natural will serve nearly every customer in these two groups.

Q. What factors cause a gas utility to incur distribution costs?

A. Both marginal and embedded costs for a utility's distribution system are determined by two major factors: (1) the number and location of customers and (2) their demands (albeit, for gas distribution, the impact of demand becomes less important when pipe scale economies for residential and small commercial customers cause the minimum installation to also serve design day demand). Both marginal and embedded cost studies have traditionally attempted to identify a portion of a utility's distribution costs as customer-related and the remaining portion as demand-related. While it is true that

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marginal demand costs play a role in the need for such facilities, the customer considerations play a much larger role since local facilities and policies reflect the underlying customer mix and density. The critical issue for a gas system such as NW Natural is that the system provides sufficient capacity to meet the design day load requirements of customers. For residential and the smallest general service customers, the smallest distribution pipe installed on the system will serve the design day capacity of these customers. As a result, the distribution cost to serve the individual customers in these classes is the same regardless of their design day demand.

III. NW NATURAL'S LRIC STUDY

Q. Have you prepared NW Natural's LRIC Study filed in this proceeding?

A. Yes. *NWN/1101, Feingold/1-13* presents NW Natural's LRIC Study. In particular, *NWN/1101, Feingold/1-2* presents the resulting allocation by rate schedule of NW Natural's proposed revenue requirement based strictly on the results of the LRIC computations included in the Study.

Q. Please describe the methodology used to prepare NW Natural's LRIC Study.

A. NW Natural's LRIC Study has four main components. These components are:

1. The cost to provide additional storage and transmission capacity to the system on a design day;
2. The costs to install distribution mains in order to connect new customers and to provide additional capacity to both new and existing customers;
3. The cost to provide a service line to connect new customers; and
4. The cost to provide a meter and regulator to serve new customers.

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Q. How is the cost of additional design day capacity on NW Natural's gas system determined?

A. The first component of the LRIC Study derives the incremental cost of storage. The embedded cost of storage was used as a proxy for the incremental cost to provide additional capacity to the gas system on a design day since NW Natural has storage capacity that is currently sold in the competitive marketplace. Therefore, when NW Natural requires additional storage capacity for its retail customers, it effectively transfers storage capacity from the competitive market to its retail customers using the actual cost of storage (*i.e.* its embedded costs). Thus, the embedded cost of storage currently represents the LRIC for NW Natural's gas supply-related capacity.

Storage service reflects the physical structure used to store the natural gas underground, the ability to withdraw that gas when needed on a design day, and the ability to transport that gas to NW Natural's gas distribution system on a design day. NW Natural's gas transmission system is currently designed to accommodate its aggregate daily deliverability requirements from storage. Therefore, no additional transmission investment is needed when additional daily deliverability from storage is transferred from the competitive market to NW Natural's retail customers. However, certain new distribution-classified investments by NW Natural are designed to provide enhanced storage deliverability to the more southern portions of its gas system and to accommodate the expected future growth in demand from new customers. These new investments functionally serve as transmission and have been treated as transmission-related incremental costs in NW Natural's LRIC Study.

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The incremental cost of storage was derived by computing the revenue requirements for both the storage capacity and gas deliverability (withdrawal) functions. The amount of gross plant identified to support NW Natural's physical storage capacity and the deliverability of gas on a design day was used as the basis to assign storage costs (such as storage operation and maintenance, property taxes, federal and state income taxes) to these two functions.

Once the storage revenue requirement was derived for both storage capacity and deliverability, the costs were then allocated to NW Natural's rate classes using storage sales volumes for storage capacity and design day volumes for storage deliverability. The derivation of the LRIC for storage is presented in *NWN/1101, Feingold/3.*

Q. Please describe the treatment of NW Natural's new transmission investment in its LRIC Study.

A. In order to include the cost of new plant investment that functionally serves as transmission, NW Natural's LRIC Study includes an additional component related to incremental transmission investment. It is important to note that these facilities are designed to serve much more than NW Natural's current growth in gas load. In fact, it is not unusual for these types of facilities to be designed to serve an LDC's expected load growth for the next 40 years or more.

To properly recognize the longer planning horizon for this type of capital investment, NW Natural's LRIC Study reflects only the total costs associated with the portion of demand growth attributable to the November 2012-October 2013 test year ("Test Year") to properly allocate its current revenue requirements to its rate classes

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using total LRIC. This means that only a portion of NW Natural's total capital costs for these projects are applicable to the load growth for the Test Year. This result is accomplished by calculating the unit cost of capacity for these investments. Once the capital costs attributable to the current LRIC Study are known, an economic carrying charge rate is applied to this investment amount to determine the annual LRIC associated with NW Natural's transmission-related projects.

Q. How is the cost of distribution mains determined?

A. The second component of NW Natural's LRIC Study derives the customer and demand related costs associated with the installation of distribution mains to connect new customers and to provide additional capacity to both new and existing customers. Mains costs that served those two functions were extracted from NW Natural's current capital budget and separated into customer and demand cost components. The customer cost component was computed by taking the average cost per foot of NW Natural's minimum-sized distribution main (two-inch) and multiplying that unit cost by the average number of feet of main installed per new customer. The demand cost component was computed by taking NW Natural's budget amount for distribution mains minus the customer cost component. Once the investment costs were derived, the incremental costs were computed by applying an economic carrying charge rate to the investment costs. The derivation of the LRIC for distribution mains is presented in *NWN/1101, Feingold/4-6*.

Q. Please describe the design day estimation process utilized in NW Natural's LRIC Study.

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A. LRIC includes new capital investment in NW Natural's gas distribution system to provide the design day capacity necessary to maintain system pressures at acceptable operating levels under design day conditions. NW Natural's design day conditions are defined as a system average mean temperature of 12 degrees Fahrenheit (F), or a day with 53 Heating-Degree Days. A "Heating-Degree Day" (HDD) is a standard used by the National Oceanic and Atmospheric Administration (NOAA) to measure the relative coldness of the temperature experienced, based on the extent to which the daily mean temperature falls below 65 degrees F. For example, on a day when the mean temperature is 35 degrees F, there would be 30 HDDs experienced. HDDs provide a basis for determining the amount of energy required to heat the interior of a housing structure.

LRIC includes the capital investment in distribution mains to attach new customers to NW Natural's gas system. Based on historical experience, it was determined that each new customer requires an average of 77 feet of distribution main to connect to NW Natural's gas distribution system. The minimum system component of customer-related costs is a function of the expected installed cost of distribution mains for new residential customers. Since this minimum system will essentially satisfy the design day capacity requirements of all residential customers served by NW Natural, as I explained previously, there is no capacity-related distribution LRIC that is separately computed for residential customers. Therefore, the LRIC for distribution mains for each rate class (other than Rate Schedules 1 and 2) is composed of a customer cost

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component and a capacity (or design day) cost component equal to the annual cost of capacity times the growth in design day capacity in the particular rate class.

Q. How are the costs of services, meters, and regulators determined?

A. NW Natural's LRIC Study derives the incremental costs of installing new services, meters, and regulators using NW Natural's recent actual installation costs escalated to 2011 dollars using the Handy Whitman Index of Public Utility Construction Costs. This Index presents the level of costs (stated as cost index numbers) for different types of utility construction, by geographic region, for each year since 1912. For services, the investment costs are based on the installed cost for customers' particular size and type, adjusted by rate schedule. The investment costs for meters and regulators are based on the installed cost of metering and regulating for each customer class, with no adjustment for unique meter runs for larger customers. Once the investment costs were derived, the incremental costs were computed by applying an economic carrying charge rate to the investment costs. The derivation of the LRIC for services and meters is presented in *NWN/1101, Feingold/7-11*.

Q. Please compare the resulting LRIC estimates to the current rates and associated non-gas revenues for each of NW Natural's rate schedules.

A. Line 22 of *NWN/1101, Feingold/1-2* presents the total LRIC-based revenue requirement for each of NW Natural's rate schedules. Line 24 of this Exhibit presents Test Year revenues by rate schedule under NW Natural's current rates. By comparing these two sets of revenues, one can see the extent to which NW Natural's current rates and non-gas revenues are reflective of LRIC. The revenue-to-cost ratios on lines 25 and 26 of

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this Exhibit portray the relative difference between these two revenue amounts for each rate schedule. A revenue-to-cost ratio of less than 1.00 means that the current rates and revenues of the particular rate schedule are below its indicated LRIC (*e.g.*, Rate Schedule 1R, 1C, or 2R), while a revenue-to-cost ratio of greater than 1.00 means that the rates and revenues of the rate schedule (*e.g.*, Rate Schedule 31 or 32) are above its indicated LRIC. These results provide cost guidelines for use in evaluating a utility's class revenue levels and rate structures. I will describe later in my testimony how these results were used to assign NW Natural's proposed revenue increase to its rate classes.

Q. Please summarize the key differences between NW Natural's LRIC Study submitted in this proceeding and the LRIC Study submitted in its last rate case, Docket UG 152 ("2002 Rate Case").

A. Certain of the key differences between NW Natural's two LRIC Studies result from the need to modify the computational methodology utilized in the current LRIC Study to accommodate the type and availability of data from NW Natural's current accounting systems. Other changes which can be characterized as enhancements to the underlying methodology result from the derivation of specific cost data for use in NW Natural's current LRIC Study that was not quantified at the time of the last LRIC Study. The following is a summary list of the key differences between the two LRIC Studies:

1. The cost data utilized in NW Natural's current LRIC Study did not rely upon the sampling of customers' work orders used in the last LRIC Study to estimate the investment costs for larger commercial and industrial customers because such information was not available from NW Natural's books and records. As a result,

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its current LRIC Study relies upon average historical investment costs by rate schedule, which is a reasonable alternative approach.

2. No demand-related distribution costs are attributable to NW Natural's interruptible customers in its current LRIC Study based on interruptibility associated with the unavailability of supply and/or the inability to deliver customers' gas volumes on NW Natural's gas distribution system. In the previous LRIC Study, customer-specific plant data was available to directly assign the capacity-related costs of distribution mains that were installed to specifically serve these customers.

3. The cost data in the current LRIC Study is based on forward-looking investment cost data related to NW Natural's gas distribution system. In the previous LRIC Study, historical costs were utilized that were adjusted to the then current cost levels. Using forward-looking costs is more consistent with the theoretical underpinnings of LRIC.

4. The investment costs associated with the category of distribution mains is separated between customer-related costs (based on NW Natural's minimum gas distribution system) and demand-related costs (based on the investment costs above the minimum system costs for non-residential customers). In the previous LRIC Study, a minimum system approach was not used so these investment costs were treated only as demand-related costs. This enhancement is consistent with the factual basis for utility system expansion and with the economies of scale in gas distribution systems discussed above.

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5. Since NW Natural's minimum gas distribution system will serve essentially all residential customers, there is no capacity-related LRIC cost for distribution mains for residential customers in its current LRIC Study.

6. Non-revenue producing system costs (*e.g.*, replacement of bare steel mains) are excluded from the LRIC computations in NW Natural's current LRIC Study because these costs are not the result of changes in either the number of customers or their design day demands. In the previous LRIC Study, cost and budgetary data was not used to distinguish between the costs of investments made to replace versus reinforce NW Natural's gas distribution system. Reinforcement costs are specifically related to demand growth and are allocated on design day demand for non-residential rate classes.

7. Operations and maintenance (O&M) expenses are included in the annual carrying charge rate in NW Natural's current LRIC Study based on the relationship between plant type (mains, services, meters, etc.) and O&M expenses applicable to that plant type as a percentage of plant costs. In the previous LRIC Study, the embedded O&M expenses were treated separately and not assigned to rate classes as a "loader" to the assigned investment costs. This enhancement directly matches O&M costs with the associated plant such costs support.

8. For O&M expenses that do not change with output, such as supervision, those expenses were not viewed as LRIC, while in the previous LRIC Study, such costs were not separately identified so they were treated in the same manner as the associated underlying O&M activities that required supervisory support. This

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enhancement results in a LRIC that reflects the actual incremental costs by class of service.

9. The cost of gas supply-related design day capacity is estimated in NW Natural's current LRIC Study based on the embedded cost of the Mist Storage facility since, for the foreseeable future, new capacity requirements will be met with Mist Storage capacity recalled from NW Natural's competitive market. In the previous LRIC Study, this cost element was derived using the economic modeling results that supported the original investment in Mist Storage and did not examine only the incremental investment component.

10. Capacity-related costs are determined directly for each rate class in NW Natural's current LRIC Study based on the estimated design day demand for the particular class rather than on a calculated design day demand based on an annual load factor assumption for each rate class as was done in the previous LRIC Study.

Q. Do these differences in data and methodology produce different results in NW Natural's current LRIC Study compared to its previous LRIC Study?

A. Yes, and this should not be surprising recognizing that NW Natural's evidence supporting its prior LRIC Study indicated that any subsequent study was likely to produce different results. At the same time, though, it is my opinion that each of NW Natural's LRIC Studies provides valid and reasonable results for rate design purposes at the time each Study was conducted. The fact that such results can and do change over time underscores the need to use such cost studies as guides, rather than strict objective indicators, when evaluating a utility's current class revenues and rate design.

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The evolution of the LRIC Studies conducted by NW Natural also reflect improvements in data analysis and additional information related to economies of scale associated with a utility's gas distribution system.

Q. Can you explain why it is likely that the results of LRIC studies will differ from one time period to the next?

A. Yes. For example, if a class of service is not growing, or is declining during a particular time period, and the economy changes during a subsequent time period, the LRIC results are likely to change materially between periods. While such changes in results are inherent in the methodological underpinnings of LRIC studies, it is important to recognize that the results of each LRIC Study reflect the nature of the costs by component and the state of technology at any given time. Just as one example, in NW Natural's current LRIC Study the cost of metering is different from the cost in its prior LRIC Study because the available metering technology has changed to permit a different mix of capital and labor related to the metering function.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design you have relied upon as the basis for NW Natural's rate design proposals.

A. A number of rate design principles or objectives find broad acceptance in utility regulatory and policy literature. These include:

1. Efficiency;
2. Cost of Service;
3. Value of Service;

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4. Stability;
5. Non-Discrimination;
6. Administrative Simplicity; and
7. Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates. Each of these principles plays an important role in analyzing the rate design proposals of NW Natural.

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

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A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service. This principle puts the concept of SAC, discussed above, into practice and is particularly relevant for NW Natural because of the competitive supply alternatives that cap rates under its special contracts.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of

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service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal—rates should be equal and, where costs are different—rates should be different. In this case, this principle is an important requirement that supports NW Natural's proposed use of a single monthly Customer Charge for all customers within certain of its rate schedules, because delivery costs are identical for its residential customers and for its smallest commercial customers.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that I previously discussed from the perspective of customer rates.

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Q. At times, can the objectives inherent in these principles compete with each other?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. For example, as noted above, there are tensions between cost and value of service principles.

Q. Please describe the conflict between marginal cost price signals and the recovery of the utility's revenue requirement.

A. The conflict between proper price signals based on marginal cost and the balanced budget principle arises because marginal cost is below average cost due to economies of scale. Where fixed delivery service costs do not vary with the volume of gas sales, marginal costs for delivery equal zero. Marginal customer costs equal the additional cost of the customer accessing the entire gas delivery system. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost-based pricing will produce either too much or too little revenue to support the utility's total revenue requirement. This suggests that efficient price signals may require a multi-part tariff designed to meet the utility's revenue requirements while sending marginal cost price signals related to gas consumption decisions. Properly designed, a multi-part tariff may include elements such as access charges, facilities charges, demand charges, consumption charges, and the potential for revenue credits.

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In the case of a local distribution company (LDC) such as NW Natural, for residential and small commercial customers, the combination of scale economies and class homogeneity permits the use of a single fixed monthly charge that meets all of the requirements for an efficient rate that recovers the utility's revenue requirement that is derived on an embedded cost basis. For larger customers, a combination of these elements permit proper price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the added complexity of a demand charge is not a concern. Further, for the largest customers, the cost of metering is customer-specific and each customer creates its own unique requirements for gas distribution service based on factors such as distance from the utility's city gate, pressure requirements, and contract demand levels.

Q. Please explain what you mean by class homogeneity.

A. Within a utility's residential and small general service classes, homogeneity refers to both a load and a cost dimension. In fact, it is homogeneity that often is used to define these rate classes. As I have discussed in detail previously, delivery service for these classes consists of the same elements: a two-inch main, a service line, a meter and regulator, with the cost to provide delivery service to these customers being the same, on average. In addition to cost homogeneity, loads are homogeneous as well. Residential and small general service customers have the same peak load characteristics because the design day peak occurs during design weather conditions

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and this design day peak is the basis for their costs together with the same meter and regulator and, on average, the same service line length. These customers also have the same meter reading, billing, and customer service costs. It is important to note that although these customers do not have the same annual load factor because they have different gas-consuming equipment, the level of gas consumption by customers in these two classes only impacts NW Natural's storage, transmission, and gas supply costs.

Annual throughput or sales has no impact on NW Natural's gas distribution costs. Thus, for some gas applications such as dual fuel heat pumps, the lower annual load factor of the customer simply means that even though the design day requirements are exactly the same as for other customers, and the delivery costs are exactly the same as for a regular gas furnace customer, the volumetric recovery of fixed delivery costs results in this customer paying substantially less than the actual cost of service. It is this type of undue price discrimination that both the enabling legislation for utility regulation and the courts have found should be avoided in utility rates. For NW Natural, this type of price discrimination is minimized under the rate design proposals it has filed in this proceeding.

Q. Are there other potential conflicts?

A. Yes. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. Please summarize Bonbright's three primary criteria for sound rate design.

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A. Bonbright identifies the three primary criteria for sound rate design as follows:

- Capital Attraction
- Consumer Rationing
- Fairness to Ratepayers

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. Capital attraction is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. Consumer rationing requires that rates discourage wasteful use and promote all economically efficient use. Fairness to ratepayers reflects avoidance of undue discrimination and equity principles.

Q. How are these principles translated into the design of retail gas rates?

A. The process of developing rates within the context of these principles and conflicts requires a detailed understanding of all the factors that impact rate design. These factors include:

1. System cost characteristics such as LRIC required by the Oregon Public Utility Commission ("Commission"), or embedded customer, demand, and commodity related costs by type of service;
2. Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;
3. Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics, and LDC bypass alternatives; and

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4. Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of underutilized facilities, opportunities to offer new services and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact of modifications to the rates. In each case, a rate design seeks to recover the authorized level of revenue based on the billing determinants expected to occur during the test period used to develop the rates.

The overall rate design process, which includes both the apportionment of the revenues to be recovered among customer classes and the determination of rate structures within customer classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter into the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process has to be, in part, influenced by judgmental evaluations.

V. <u>DETERMINATION OF PROPOSED CLASS REVENUES</u>

Q. Please describe the approach generally followed to allocate NW Natural's proposed revenue increase of $43.7 million to its rate classes.

A. As just described, the apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations.

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These criteria were evaluated for each of NW Natural's rate classes. Based on this evaluation, adjustments to the present revenue levels in each of NW Natural's rate classes were made so that its proposed rates moved class revenues closer to the LRIC of serving each rate class.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of NW Natural's interclass revenue proposal?

A. Yes. Using NW Natural's proposed revenue increase, and the results of its LRIC Study, I evaluated various options for the assignment of that increase among its rate classes and, in conjunction with NW Natural personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The first and benchmark option that I evaluated under NW Natural's proposed total revenue level was to adjust the revenue level for each rate class so that the revenue-to-cost for each class was equal to 1.00. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

The second option I considered was assigning the increase in revenues to NW Natural's rate classes based on an equal percentage basis of its current base (non-gas) revenues. By definition, this option resulted in each rate class receiving an increase in revenues. However, when this option was evaluated against the LRIC Study results (as

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measured by changes in the revenue-to-cost ratio for each rate class); there was no movement towards cost for NW Natural's rate classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). While this option also was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provided me with further guidance to develop NW Natural's class revenue proposal.

Q. What was the next step in the process?

A. After further discussions with NW Natural, I concluded that the appropriate interclass revenue proposal would be one that reflects increases in revenues to certain rate classes, guided by the results of NW Natural's LRIC Study, with increases to these rate classes moderated by establishing a maximum increase level (on a percentage basis) above NW Natural's proposed overall increase in non-gas revenues of 15.2 percent. This approach established a maximum revenue increase to any particular rate class of 19.0 percent (1.25 times 15.2 percent). *NWN/1102, Feingold/1-2* presents the derivation of NW Natural's proposed class revenues by rate schedule.

This preferred revenue allocation approach resulted in reasonable movement of the class revenue-to-cost ratios towards unity or 1.00. That result is reflected in *NWN/1102, Feingold/3*, wherein the revenue-to-cost ratios are shown to converge towards unity or 1.00 compared to the same measure calculated under current rates. In addition, the amounts of the existing rate subsidies among NW Natural's rate classes were reduced for those classes that received increases in revenues. From a class cost

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of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable.

Q. Have you prepared a comparison of NW Natural's present and proposed revenues by rate schedule?

A. Yes. *NWN/1102, Feingold/3* presents a comparison of present and proposed revenues for each of NW Natural's rate schedules.

VI. <u>SUMMARY OF NW NATURAL'S RATE DESIGN PROPOSALS</u>

Q. Please summarize the rate design changes NW Natural has proposed in this rate proceeding.

A. NW Natural has proposed the following rate design changes to its current rate schedules:

- The establishment of a monthly Customer Charge for Rate Schedules 1 and 2 that will reflect, by the third year that the proposed rates are effective, the inclusion of all fixed distribution-related costs of delivery service incurred by NW Natural to serve these customers. Under this rate structure, customers served under these rate schedules will pay a flat monthly fee for the delivery services provided by NW Natural, and will continue to pay on a volumetric basis for storage and transmission related services and for the amount of gas commodity used each month.
- For customers served under Rate Schedules 3, 31, and 32, NW Natural proposes to adjust the monthly Customer Charges toward the indicated LRIC, where appropriate, with commensurate changes in the Volumetric Charges to reflect the underlying costs of providing service and the proposed change in class revenues.

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- Modifications to certain provisions of NW Natural's current Weather Adjusted Rate Mechanism (WARM) and decoupling mechanism.
- Modifications to Rate Schedule 31 to eliminate the interruptible service option, and the development of a new interim weighted average cost of gas for customers on Rate Schedules 31 and 32 switching from transportation service to sales service.
- Modifications to tariff provisions regarding temporary disconnection of service and to General Schedule X - Distribution Facilities Extensions for Applicant-Requested Services and Mains to align it with NW Natural's proposed residential rate design.
- Implementation of new Rate Schedule 27 – Residential Heating Dry-Out Service.

I will present below the specific rate design changes and supporting rationale for certain of NW Natural's proposals, and other NW Natural witnesses will present the remaining components of the proposed rate design.

Q, Have you prepared a revenue proof to show that NW Natural's proposed rates generate the total distribution revenue and total revenue increase it has proposed in this proceeding (*i.e.* its total non-gas revenue)?

A. Yes. *NWN/1102, Feingold/4-7* presents NW Natural's revenue proof for the Test Year and *NWN/1102, Feingold/8-11* presents the revenue proofs for Years 2 and 3 of the phase-in period for NW Natural's rate design proposal for Rate Schedules 1 and 2, which I will explain in detail later in my testimony.

VII. FIXED COST ALLOCATION AND FULL COST-BASED CUSTOMER CHARGES FOR RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS

Q. Please describe NW Natural's current rate structures for Rate Schedules 1 and 2.

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A. NW Natural's Rate Schedule 1 – General Sales Service provides delivery sales service to both residential and commercial customers. The base rate structure consists of a relatively low monthly Customer Charge and a flat Volumetric Charge that differs between residential and commercial customers. Rate Schedule 2 – Residential Sales Service provides delivery sales service to residential customers only, with a base rate structure that consists of a relatively low monthly Customer Charge and a flat Volumetric Charge. Both rate schedules recover NW Natural's costs of its gas distribution system plus certain storage and transmission related fixed costs.

Q. What do you mean by your characterization, "a relatively low" monthly customer charge?

A. I use the term "relatively low" in two ways. First, NW Natural's monthly customer charges are relatively low in the sense that most LDCs have higher monthly customer charges than the current charges of $5.00 and $6.00 under Rate Schedules 1 and 2, respectively. Second, the charge is only about 20 percent of the full LRIC level reflected in NW Natural's LRIC Study for each of these two rate schedules. If we simply calculate the out-of-pocket costs for customer service, the meter, regulator, and service line, a $5.00 or $6.00 per month charge is still far below the indicated LRIC of over $30 per month. The supporting costs are presented in *NWN/1101, Feingold/9*, with the monthly cost computed by summing the annual cost of the service line, meter and regulator, and accounting costs, which totals on average approximately $366.00, and dividing that amount by 12. In addition, the current charges are relatively low if we considered only metering, regulating, and accounting costs which are almost $4.00 per month greater

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than NW Natural's current customer charges. By any of these standards, NW Natural's monthly customer charges are relatively low when viewed against the principles of a sound rate design that I discussed previously.

Q. Are changes to NW Natural's current rate design required to address the principles of a sound rate design that you discussed earlier?

A. Yes. NW Natural's current volumetric rate design should be changed, in my opinion, because it does an inadequate job of aligning the revenue recovered by NW Natural for providing delivery service with the costs incurred to provide that utility service. While I recognize that in the past NW Natural's class revenues and rates were guided by cost of service considerations, it is important that its rates on a going forward basis better reflect the true nature of the costs incurred to provide delivery service. This will directly address the various kinds of discrimination that are inherent in charging volumetric rates to a utility's residential and small commercial customers, which I will discuss below.

Changing NW Natural's current rate design will enhance the long-term provision of efficient, reliable, and cost-effective delivery service. To understand more fully the problems created by a volumetric rate design for gas delivery service, it is important to understand certain basic utility service and cost concepts, which I will discuss below. NW Natural's proposed rate design is also more consistent with its future cost drivers such as infrastructure replacement. The replacement of cast iron and bare steel main requires significant new investment in rate base that is unrelated to demand growth. Rather, this investment is necessary to provide safe, reliable gas service to the utility's existing customers. Allocation of these costs to NW Natural's residential and small

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commercial customers through its new proposed rate structure provides a more reasonable and cost effective rate design.

Q. Please describe the nature of delivery service costs recovered in a utility's gas distribution rates.

A. The delivery service costs for an LDC such as NW Natural are fixed costs and do not vary with gas throughput. An LDC designs and installs a gas distribution system capable of meeting its customers' design day requirements at the time of initial installation. These facilities include the city-gate, distribution mains and pressure regulating facilities, services, meters, and regulators all designed to meet the design day requirements of customers at the time of the installation. Placing these facilities into service permits the LDC to serve the changes in load due to extreme weather (*i.e.*, the design day peak load) or economic conditions. Once facilities are installed to serve customers, the costs associated with these facilities are by their nature fixed and do not vary as a function of the volume of gas consumed by customers.

Q. Please describe the kinds of rate discrimination caused by a volumetric rate design.

A. A utility's volumetric rates create an inequity related to the undue discrimination between customers within a particular rate class. Since the cost of providing delivery service is the same for residential customers based on the same size and cost of main, service line, meter, regulator, and customer service expense, volumetric rates unduly discriminate between low and high use customers. This discrimination violates the principle of horizontal equity I discussed above. In current circumstances, I believe that

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preserving a volumetric rate design for distribution service simply because it has been used historically will work against fundamental regulatory principles when compared to the use of full cost-based Customer Charges, as proposed by NW Natural.

In addition, there is no reason to believe that NW Natural's delivery service costs comprised of the main, service, meter, regulator, and customer service are higher for the areas of its gas system with higher HDDs. Since rates are designed based on average costs for the class, residential customers in higher than average HDD zones will pay a larger share of fixed costs and customers in lower than average HDD zones will pay lesser share of the fixed costs. This climate-related inequity is solely the result of a volumetric recovery of fixed delivery service costs.

Q. Can you please explain in further detail this climate-related inequity in NW Natural's current volumetric rate design?

A. Yes. Very simply, NW Natural's volumetric rates create undue discrimination among its customers on the basis of location. NW Natural has eight different climate zones. Each climate zone has a different number of customers and a different annual HDD level. Although Portland represents the largest number of customers and, thus, dominates the system average, even in Portland, it is possible for there to be locational discrimination because of the heat island effect of the city relative to its more suburban areas. The Environmental Protection Agency (EPA) estimates the heat island effect at between 1.8 and 5.4 degrees F per day, meaning that the measurement of HDD may either over or understate the effects for portions of the largest climate zone. At this rate, about a 150 to 800 HDD difference may apply in the Portland area alone. Given that the system

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zone differences are also quite large, as illustrated by the following table, it is certain that many of the smaller areas in colder climates are providing a subsidy to the Portland area based simply on HDDs.

As Table 2 below illustrates, there is almost a 1,100 HDD difference between the coldest and warmest HDD measurement, and these values also do not include any heat island effect. In addition, the system average is largely driven by Portland and even the differences between the system average and some of the climate zones are relatively large ranging between 953 and -132 HDDs, for a total range of 1,085 HDD. This difference in HDD results in excess recovery of fixed costs from seven of the eight climate zones, even though there is no reason to believe that the underlying delivery service costs are lower in other areas.

Since rates are designed on a system wide basis, the only real option for eliminating this type of undue discrimination between geographic regions is the adoption of the rate design proposed by NW Natural for Rate Schedules 1 and 2

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Table 2 - Comparison of Normal HDDs by Climate Zone

Climate Zone	HDDs	Difference from Average
Albany	4,680	307
Astoria	*4,952*	*579*
Coos Bay	4,475	102
The Dalles	5,326	953
Eugene	4,675	302
Newport	4,923	550
Portland	4,241	-132
Salem	4,576	203
System Average	4,373	0

Q. Please describe the inability of NW Natural's current volumetric rate design to provide economically efficient price signals.

A. When fixed costs are recovered volumetrically, customers who conserve save costs (*i.e.*, experience reduced gas bills) that the utility does not save. This can cause more frequent rate cases and from an economic perspective wastes resources. An economically efficient price signal matches the reduction in cost for the utility with the reduction in cost for the consumer. In the case of NW Natural, the cost reduction from conservation is in the form of lower gas commodity-related costs. Any customer savings in excess of the cost of gas overstates the monetary savings of conservation and results in investments by the customer that do not save the level of societal resources expected

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based on the reduction in customers' gas bills, and creates cross-subsidies among customers. This is the point discussed in detail in a recent National Bureau of Economic Research paper entitled, The Equity And Efficiency of Two-Part Tariffs In U.S. Natural Gas Markets.[1]

Q. Do volumetric rates provide a utility with a reasonable opportunity to collect its approved level of revenue?

A. No. The utility's allowed rate of return together with O&M expenses (excluding gas commodity costs), depreciation expenses, and taxes for a test year constitutes its revenue requirements for gas delivery service. None of these costs vary with the volume of gas consumed by customers. This fact is widely recognized by regulatory bodies because they do not weather normalize any of these costs as would be appropriate if the costs varied with the volume of gas consumed.

The recovery of revenues occurs in a prospective period, the first year referred to as the Rate Effective Period. The dollars that are actually available for the earned return in the Rate Effective Period equal revenue minus all of the costs incurred in that same year, not the level of costs included in the test year and used for ratemaking purposes to establish the utility's revenue requirement. Thus, if rates do not provide a reasonable opportunity of producing the allowed revenue because of changing gas usage patterns, even though costs equal test year costs, the opportunity to earn the allowed rate of return is diminished.

[1] Borenstein, Severin and Lucas W. Davis, "The Equity and Efficiency of Two-Part Tariffs in U.S. Natural Gas Markets," *NBER Working Paper Series*, Working Paper 16653 (Dec. 2010).

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Even if the annual revenue obtained in the Rate Effective Period coincidently matches the authorized revenue, a volumetric rate design still poorly aligns the flow of revenue an LDC receives with the way that costs are incurred to provide its public utility service. Looking at this from a customer's perspective, the volumetric rate design tends to also swing monthly gas bills up or down without regard to the fixed nature of the costs that are being incurred to provide gas delivery service. Thus, a volumetric base rate falsely suggests that a customer that reduces consumption will somehow produce a corresponding effect on the costs of the utility providing gas delivery service.

The fundamental point is that sales volume variation from the level assumed in the test year for ratemaking purposes results in variations in revenue and the actual earned rate of return, either higher or lower than the amount specified for ratemaking purposes. A utility's actual earned rate of return over time does not equal its allowed rate of return, even though earnings vary from year-to-year under a variety of circumstances, including declining use per customer, conservation, price elasticity responses, asymmetric costs, and other relevant factors. Nevertheless, volumetric recovery of fixed costs fails to provide a reasonable basis for cost recovery as well as a reasonable opportunity to earn the allowed rate of return.

Q. How have utilities tried to overcome the problem of the under recovery of fixed costs caused by volumetric delivery service rates?

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A. The revenue shortfall challenge I just described has received much attention from state regulators over the last five years. To effectively mitigate the variability in revenues caused primarily by weather and declining use per customer, and to align utility objectives with key public policy goals such as energy conservation, regulators have implemented a number of ratemaking solutions, including:

1. Revenue decoupling mechanisms that adjust rates for changes in usage caused primarily by weather and energy conservation;
2. Straight Fixed-Variable (SFV) rate structures;
3. Weather Normalization Adjustment (WNA) mechanisms that adjust rates for changes in usage caused by weather;
4. Monthly customer charges that more fully reflect the gas utility's fixed costs of providing delivery service; and
5. A measure of "normal weather" that is an accurate predictor of the weather expected by the utility in future years and a reasonable basis for deriving the gas utility's normalized sales volume in its rate case.

It should be noted that the Commission approved NW Natural's WARM and decoupling mechanism in 2003 and 2002, respectively.[2]

Q. Do any of the rate mechanisms you just described address the root cause of the revenue shortfall problem?

A. No. Such mechanisms effectively compensate for the fact that the utility's underlying rate structure contains volumetric rate components that cause the revenue instability and

[2] The direct testimony of Natasha Siores provides background on these rate mechanisms. See NWN/200 at 2-8.

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fixed cost under recovery in the first place. However, these rate mechanisms do nothing to address the rate design deficiencies I described earlier associated with a volumetric rate design. If a utility's delivery service rates were designed to properly address the principles of a sound rate design, I strongly believe there would be a diminished need for these types of rate mechanisms.

Q. Why is NW Natural's proposed rate design for Rate Schedules 1 and 2 a preferred solution to revenue stability compared to the current combination of its WARM and decoupling mechanism?

A. Very simply, while NW Natural's WARM and decoupling mechanism may solve the revenue stability issue, they fail to address other important rate design deficiencies because of the continued existence of NW Natural's volumetric rate design. NW Natural's rate mechanisms do not eliminate the undue discrimination from volumetric rates and they do not best promote efficient energy conservation from the customer's perspective. Undue or unjust discrimination results from charging larger use residential customers higher rates for the same service, with the same costs, as smaller use customers. Since NW Natural's delivery cost, on average, is the same for all residential customers, the elimination of this undue discrimination is an important consideration that the Commission should undertake to address. In eliminating this aspect of undue discrimination, the Commission should also move NW Natural's rate design to a full two-part, economically efficient, and welfare maximizing rate. The underlying rates become far simpler even though NW Natural retains full revenue decoupling (through a combination of its WARM and decoupling mechanism) that allows it to have a

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reasonable opportunity to recover its total revenue requirement found to be just and reasonable by the Commission. Further, as discussed in the direct testimony of Natasha Siores, these two ratemaking mechanisms will require modification to be efficiently designed and to permit a reasonable transition to more efficient rates.

Q. Do full cost-based Customer Charges as proposed by NW Natural comport with LRIC principles?

A. Yes. This type of rate design reflects LRIC far better than NW Natural's current volumetric rates for the simple reason that the only true incremental costs related to volumetric gas usage are gas commodity costs. This mirrors the pricing approach proposed by NW Natural for Rate Schedules 1 and 2.

Q. Is NW Natural's rate design proposal for Rate Schedules 1 and 2 reflective of Bonbright's sound rate design principles that you discussed earlier?

A. Yes. In my opinion, NW Natural's rate design proposal for these rate schedules satisfies Bonbright's rate design principles of efficiency, cost of service, stability, non-discrimination, administrative simplicity, and a balanced budget.

Q. Please explain why NW Natural has only proposed full cost-based Customer Charges for Rate Schedules 1 and 2.

A. The development of this type of rate structure for NW Natural's Rate Schedules 1 and 2 is an important step in providing more rational delivery service rates, and is a more straightforward approach than the rate design currently used for its other rate schedules.

First, as noted above, Rate Schedules 1 and 2 are NW Natural's most homogeneous classes of service, which enables the use of a simplified rate structure to

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properly track the underlying costs of delivery service. For NW Natural's less homogeneous rate classes, such as Rate Schedules 3 and 31, rates must be more complex (consisting of additional rate components and differentiated charges) to properly reflect the underlying costs.

Second, in order to develop a rate design for rate classes with larger customers that recovers fixed distribution-related delivery costs through fixed charges, it would be necessary to prepare an analysis of the types of meters used in those rate classes. Each size of customer may require not only a different size of meter, but a different type of meter. Residential and small commercial customers almost uniformly have a diaphragm meter installed at their premises. As gas load increases, other types of meters such as rotary, turbine, and orifice meters are used. These meters have different cost characteristics, and these customers can no longer be served with the same size of distribution main and service line. Ultimately, the largest customers are metered with their own uniquely designed metering facilities. This simply means that delivery service costs will vary among these larger customers.

As part of the movement to full cost-based fixed charges, these cost differences must be identified and customers must be grouped initially according to their meter size and type. In addition, a sound rate design for these rate classes will also include a demand charge based on either contract demand or measured maximum demand. This requires conducting more detailed load and customer segmentation analyses as part of a full transition to full cost-based fixed charges. NW Natural intends to complete this

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process for larger customers in the future as it transitions to this type of rate design across its customer base.

Q. Can you explain in more detail why NW Natural's full cost-based Customer Charge concept has not been proposed for Rate Schedules 3 and 31?

A. Yes. As rate schedules become more heterogeneous, as is the case with Rate Schedules 3 and 31, implementing this type of rate structure becomes a more complex undertaking. The conclusion that full cost-based Customer Charges should not be applied to Rate Schedules 3 and 31 is based on my review of NW Natural's annual bill frequency data for Rate Schedule 3, in the aggregate, and by customer segment (commercial, industrial, and commercial-residential). For Rate Schedule 31, I reviewed data for each customer, by customer segment (commercial, industrial, and commercial-residential), and by service category. As a point of reference, "residential-commercial" customers represent residential end-use applications served as commercial customers.

To implement full cost-based Customer Charges for these Rate Schedules would require, at a minimum, different monthly charges for different sizes of customers, and potentially also may require a demand charge as part of the rate structure. When delivery costs are no longer homogeneous due to a diverse mix of customers, it is readily evidenced by reviewing the underlying metering investment costs. For an LDC's residential and small general service customers, the meter is the same type and approximately the same cost for all customers. As customers increase in size, metering investment costs increase, as shown in NW Natural's LRIC Study. As a practical matter, even the meter technology changes as load increases, and this means higher metering

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and service investment costs for larger customers. In addition to developing graduated Customer Charges to reflect different levels of customer-related costs, more heterogeneous rate classes also can require separate demand charges to track the different costs of distribution main capacity, and where applicable, the costs of storage and transmission service.

Q. How did you determine that Rate Schedule 3 is not a homogeneous customer group?

A. I analyzed annual gas consumption for approximately 51,000 customers served by NW Natural under Rate Schedule 3. Just over 96.5 percent of the customers are commercial, and about 3 percent are commercial-residential. For the two commercial groups, there is little difference in the annual distribution of bills indicating that the distinction between pure commercial and commercial-residential identifies minimal differences between the groups. For the remaining 0.5 percent of the customers that consist of industrial customers, however, the bill distribution is significantly different from that of the commercial groups. For example, almost 50 percent of the industrial customers have annual gas usage in excess of 10,000 therms, while only seven percent of the commercial customers have annual gas usage over 10,000 therms. Figure 1 below illustrates the differences by customer group. The customers in the industrial group are uniformly larger in size than customers in either of the two commercial groups.

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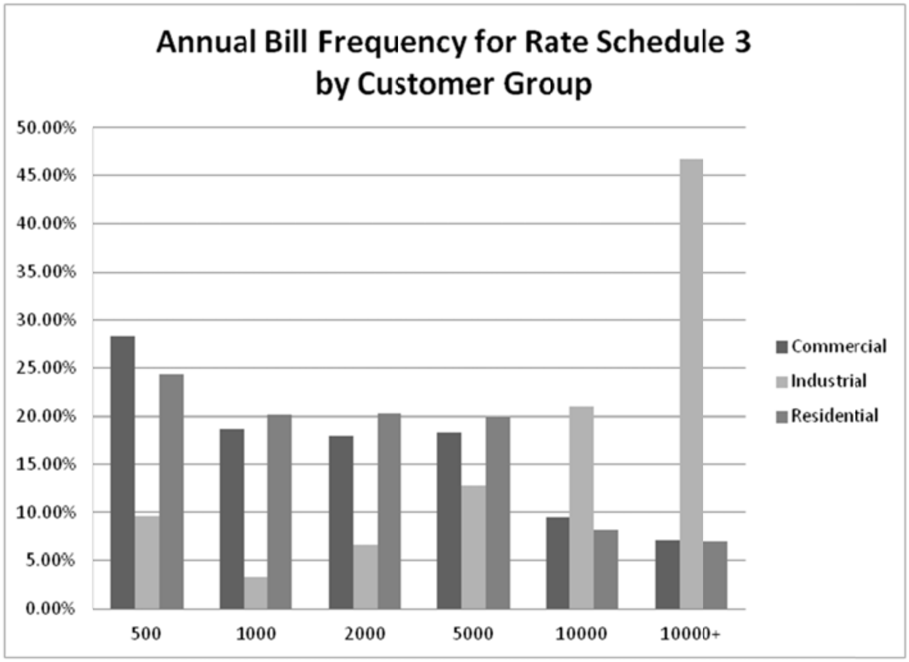
Figure 1



Q. How did you determine that Rate Schedule 31 is not a homogeneous customer group?

A. I analyzed the gas usage characteristics based on the monthly bills for 1,495 customers served by NW Natural under Rate Schedule 31. These customers are far less homogeneous than customers served on Rate Schedules 1 and 2. Table 3 below presents the summary results of this analysis. Based on these results, transportation customers are larger and have a greater standard deviation in mean use than sales customers. This information is indicative of the absence of homogeneity among the customer segments under this Rate Schedule.

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Table 3

Class	Mean Use	Median Use	Max. Use	Min. Use	Standard Deviation
31CSF	50,241	40,632	304,555	0	33,608
31CSI	66,006	31,459	232,304	0	74,440
31CTF	229,674	114,491	593,600	27,106	216,004
31ISF	75,459	59,307	299,920	0	57,428
31ISI	38,789	31,989	103,552	0	30,220

Q. What do you conclude from the analysis of these two Rate Schedules?

A. In the future, it will be necessary for NW Natural to develop additional analyses for Rate Schedules 3 and 31 to properly implement full cost-based fixed charges for these rate classes. For example, it may be appropriate to divide Rate Schedule 3 into a Small General Service - Firm Sales Service and a Medium General Service - Firm Sales and Transportation Service. The new rate schedule could possibly include some of the smaller Rate Schedule 31 customers and combine those with the larger Rate Schedule 3 customers. At some point there could also be a Large General Service - Firm and Interruptible Sales and Transportation Service. Each of the new rate schedules would use graduated monthly customer charges based on installed meter size, and would also have a demand charge based on either the measured demands or contract demands of customers. The choice of the measure of demand would be determined based on the role that contract demand plays in determining the underlying costs.

Q. Does NW Natural propose that its full cost-based Customer Charge concept for Rate Schedules 1 and 2 be fully implemented at the completion of this rate proceeding?

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A. No. NW Natural proposes that its full cost-based Customer Charge concept be adopted by the Commission in this rate proceeding, but that it is fully implemented in rates over a two-year transition period.

Q. How does NW Natural propose to implement the transition to full cost-based Customer Charges for Rate Schedules 1 and 2?

A. Once its revenue requirement is approved by the Commission in this rate proceeding, NW Natural proposes to file a series of compliance rates. The difference between NW Natural's current monthly Customer Charges under Rate Schedules 1 and 2 and the proposed monthly Customer Charges will change yearly by increasing that rate component of the current rate structure and reducing the Volumetric Charges by the same amount of revenue. When NW Natural submits its compliance filing at the conclusion of this rate proceeding, it will file three sets of rates (and tariff pages) for Rate Schedules 1 and 2. The first set of rates will be implemented on the effective date established by the Commission in this rate proceeding, which will be November 1, 2012. The second set of rates will become effective one year later at the start of Year 2, and the third set of rates will become effective one year later at the start of Year 3. Each set of rates will be based on the approved billing determinants established in this rate proceeding. The final set of rates will reflect the full cost-based Customer Charges and the associated Volumetric Charges related to NW Natural's storage and transmission costs. At that time, NW Natural's proposed rate design will be fully implemented for Rate Schedules 1 and 2.

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I should note that this rate transition plan is premised upon the level of NW Natural's revenue requirement proposed in this rate case. As a result, the rates that have been proposed may need to be modified if NW Natural has a future rate case that produces a different revenue requirement during the time period of this rate transition plan.

Q. Why has NW Natural proposed this type of transition from its current rates to full cost-based Customer Charges?

A. NW Natural proposes this type of transition to promote rate stability. Given its current rate design and associated rate levels, NW Natural's low-use customers would experience large increases in their annual gas bills from the immediate implementation of full cost-based Customer Charges. Instead of creating a dramatic one-time increase in rates for these customers, NW Natural's proposed transition process will gradually move gas bills from their current levels to the levels resulting from full implementation of cost-based Customer Charges. By proposing a three-step transition, customers will be moved approximately one-third of the way towards full cost-based Customer Charges in each year of the proposed rate transition plan. Since the ultimate goal is to achieve more efficient rates, and to eliminate the undue discrimination in current rates, a set transition plan is desirable. In my opinion, NW Natural's proposed rate transition plan strikes a reasonable balance between eliminating a significant regulatory concern through cost-based rates while recognizing the magnitude of intra-class cross subsidies that exist today for certain customers under NW Natural's current rates.

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VIII. OTHER TARIFF CHANGES TO ALIGN WITH FULL COST-BASED CUSTOMER CHARGES

Q. Does NW Natural's full cost-based Customer Charge proposal require changes to certain provisions of its Rate Schedule 1?

A. Yes. Rate Schedule 1 is a unique general service rate that serves both residential and small general service customers. One of the unique elements of that rate schedule is its treatment under NW Natural's General Schedule X – Distribution Facilities Extensions for Applicant-Requested Services and Mains. Pursuant to General Schedule X, service under Rate Schedule 1 receives no construction allowance credit. Customers under this Rate Schedule who subsequently change to full service under another rate schedule may receive a refund under Schedule X. Since the purpose of a full cost-based Customer Charge is to recover all distribution-related delivery service costs, the provisions of Schedule X create an issue relative to the proper cost basis for customers under this Schedule. Addressing this issue requires a multi-part solution, as I discuss next.

Q. Please describe the proposed steps to resolve the issues associated with Rate Schedule 1.

A. First, Rate Schedule 1 should be closed to new customers. Under NW Natural's rate design proposal for Rate Schedules 1 and 2, there is no reason for customers to pay a contribution for the total cost of a service or main extension except under the limited circumstances of the customer failing to become a gas service customer. At most, customers should only pay for service or main extensions that require a greater level of investment than the then current monthly Customer Charge would support.

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Second, customers served under Rate Schedule 1 should be gradually transitioned over time to the appropriate rate schedule applicable to their service, with the closed rate schedule eventually eliminated. The rationale behind eliminating this Rate Schedule is that over time the investment paid for by the customer will be replaced by new plant assets provided by NW Natural and, thus, the customer will no longer benefit from the original contribution. As a practical matter, closing Rate Schedule 1 to new customers will prevent a continuing need for a provision under Schedule X that reflects the applicable distribution access costs that have been paid for by the customer. During the transition period, Rate Schedule 1 will have a lower monthly Customer Charge than under Rate Schedule 2, and will continue to recover a portion of the revenue requirement under a volumetric rate subject to the provisions of both WARM and the decoupling mechanism.

Q. How does the proposed rate transition plan under NW Natural's rate design proposal for Rate Schedules 1 and 2 affect WARM and the decoupling mechanism?

A. During the proposed rate transition period, both WARM and the decoupling mechanism are proposed to remain in place to provide continuing incentives for energy conservation and to meet the requirement that NW Natural's volumetric rate design provide a reasonable opportunity to earn its allowed rate of return. NW Natural witness Natasha Siores addresses the details of this transition and describes changes to certain of the current provisions of these rate mechanisms.

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IX. RESIDENTIAL BILL IMPACTS

Q. Please describe the bill impacts for residential customers under NW Natural's rate design proposal.

A. Increasing the cost recovery applicable to lower use customers in order to implement full cost-based Customer Charges for NW Natural's Rate Schedules 1 and 2, and to eliminate the unduly discriminatory nature of the current volumetric rate recovery of distribution costs, will require greater than average increases for low use customers and smaller than average increases, or even decreases, for higher-use customers who currently subsidize low-use customers.

Q. What types of customers make up the lowest-use segment of NW Natural's residential and small commercial rate classes?

A. There is a variety of customer types that comprise NW Natural's low use segment. First, there are a number of bills identified in the low use group that cannot really be considered "customers" at all in the truest sense of the term. For example, a review of NW Natural's annual bill frequency for the latest available twelve month period shows that almost 1,300 customers used no gas at all during that time period. Obviously, this situation is not what one thinks of as constituting a "customer." With a zero annual bill, it is likely that these meters were installed at a vacant dwelling where the customer maintained gas service because of its relatively low cost. In fact, it is a common practice for apartment management companies to maintain active gas service for vacant apartments. This would not only account for zero use bills, but also for very low annual use bills where the apartment is heated at very low levels to protect the facility from

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possible winter damage from cold weather conditions. The same conclusion may also apply to foreclosed or other vacant homes.

Some other low-use customers include heat-only gas customers who have very low or zero use in the summer months. Based on a review of NW Natural's monthly bill frequencies, almost 900,000 monthly bills were for less than 10 therms of gas. Most of these bills would be for heat-only gas service, with about 73 percent of these low-use bills occurring in the months of May through September. Many heat-only customers will have lower-than-average use because of the absence of gas water heating load that creates an annual baseload of gas usage.

Q. What gas usage trends were observed in the highest use segment of NW Natural's residential and small commercial rate classes?

A. In contrast to the above usage characteristics, only about 600 bills are for use in excess of 700 therms per month, with some of those bills occurring in the summer which would suggest a gas use such as pool heating. Customers with pool heaters will typically have much higher annual load factors than other residential customers.

Q. Why is it important to understand the types of low use bills when examining the bill impacts under NW Natural's rate design proposal for Rate Schedules 1 and 2?

A. Understanding the types of low use bills will provide insights into how certain residential customers will respond to NW Natural's rate design proposal and the extent to which NW Natural should make other rate design changes to ensure fixed distribution costs are fairly recovered from the customers causing such costs to be incurred. Like other customers, low-use customers will respond to the price signal associated with full cost-

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based Customer Charges. Typically, zero use and other low-use customers respond by attempting to avoid the higher fixed monthly charge. For example, heat-only customers could turn gas service off during the summer and reestablish service in the first cold month. This approach serves as an attempt to avoid paying the actual cost of service, and can be addressed by the gas utility in one of two ways. Under the first option, the gas utility would reflect the fixed costs of distribution access as an annual charge so that when a customer terminates gas service, the remainder of the annual charge is due for payment by the customer as a termination charge. In addition, there should be a charge for both turn-off and turn-on service based on the actual cost of each service. Under the second option, the charge would be established on a monthly basis, but for customers who reestablish service at the same location in fewer than 12 months, the service establishment charge would be the cost-based turn-on charge plus the monthly charge times the number of months during which the service was turned off. The turn-off charge should also be included in this option as part of the customer's final bill.

Ultimately, this situation could involve the gas utility permanently shutting off gas service to the customer. In this case, the gas utility will actually lose a certain number of customers. Since we know that some customers will choose to cease being gas customers, rather than to pay a fully cost-based charge for service, it is appropriate to make a proforma adjustment to the number of bills to adjust for lost customers. NW Natural has proposed such an adjustment in this rate proceeding based on a forecast of customers who would choose the option of no longer being gas customers.

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Q. Please explain how NW Natural's rate design proposal will impact residential and small commercial customers' bills served under Rate Schedules 1R, 1C, and 2.

A. NW Natural's proposed rate design will increase the average residential and small commercial customer's bills in the summer and shoulder months, when customer bills are at their lowest levels, and will decrease or moderate the increase in customer's bills in the winter months, when bills are at their highest levels. This distinct benefit is depicted in *NWN/1102, Feingold/12-14*. This Exhibit presents monthly and annual bill comparisons for a typical residential and small commercial customer during the two-year transition period in which NW Natural's full cost-based Customer Charge proposal will be implemented.

Q. Have you evaluated the impact of NW Natural's rate design proposal across various sizes of residential customers served under Rate Schedule 2?

A. Yes. *NWN/1102, Feingold/15-17* presents for each year of the rate transition period a bill frequency distribution with the number of bills by consumption interval for NW Natural's Rate Schedule 2 customers in the month of December, which is the month of highest gas consumption for this Rate Schedule during the Test Year. It also provides the average bill change between present and proposed rates for each of the bill ranges presented in the Exhibit. Under NW Natural's proposed rate design (effective November 1, 2012), by the end of the rate transition period, approximately 80 percent of its Rate Schedule 2 customers will experience a bill decrease in the month of December, with the remaining customers (approximately 20 percent) experiencing a bill increase. Moreover, under colder-than-normal weather, these same customers will experience even larger

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decreases in their bills, and there will be additional customers who would also experience decreases in their bills under NW Natural's proposed rate design.

Q. Please discuss the impact of NW Natural's rate design proposal on the bills of its residential customers during months of lower gas usage.

A. As shown in *NWN/1102, Feingold/14*, while NW Natural's residential customers will experience relatively larger percentage changes in monthly bill levels during months of lower gas usage, the absolute dollar changes (during each year of the phase-in period to a full cost-based Customer Charge) will be relatively small compared to these customers' total gas bills. In fact, as depicted in *NWN/1102, Feingold/17*, only a small portion (approximately 20 percent) of NW Natural's total residential customers who consume less gas than the average customer will experience increases greater than approximately $4.50 per month in December, the month of highest gas consumption and highest gas bills. At the same time, this proposed rate structure will cure the chronic cross-subsidy that exists between small and large residential customers caused by the mismatch between their costs of service and base rate revenues.

Q. Please discuss how low-income customers served under Rate Schedules 1 and 2 will be affected by NW Natural's rate design proposal?

A. Based on NW Natural data, the average annual gas usage for customers below the poverty level is about the same as its residential customer population as a whole. Thus, a smaller number of low-income customers will experience benefits under NW Natural's rate design proposal than are typically observed at other gas utilities. Instead, the majority of NW Natural's low-income customers will experience bill impacts that are in

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line with those of its average residential customer. However, those low-income customers who use more than the average annual usage for NW Natural's residential customers will experience lower-than-average gas bills. In addition, NW Natural provides energy assistance programs that will mitigate the impact of its full cost-based Customer Charge proposal on low-income customers.

X. EFFICIENCY AND NON-DISCRIMINATORY RATES UNDER FULL COST-BASED CUSTOMER CHARGES

Q. Does the reduction in the commodity charge associated with moving to full cost-based Customer Charges reduce the incentive for energy conservation?

A. No. Conservation is not the absolute reduction in use. Rather, it is the efficient use of a resource. From economic theory we know that efficient use comes from setting prices equal to short-run marginal cost. For natural gas, short-run marginal cost is determined in the market as the commodity cost of gas. The purpose of a sound rate design with respect to conservation has two dimensions—discourage wasteful use and to encourage efficient use. Unfortunately, volumetric rates produce the opposite result of conservation. Volumetric rates encourage the wasteful use of resources to reduce gas use and discourage efficient uses of natural gas. Full cost-based Customer Charges promote efficient use of all resources related to gas consumption and, thus, result in optimal conservation.

Q. Do volumetric rates potentially frustrate conservation activities?

A. Yes. The simple problem is that when customers base their economic analysis of conservation on current rates, they over estimate the potential savings because the costs recovered through the LDC's volumetric delivery rate component are not saved.

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As a result, when rates are adjusted upward through revenue decoupling or through a new rate case, the expected savings are eroded. This ultimately causes customers to recognize that savings will not occur at the expected level and pace. This rational expectation from the market will likely discourage future conservation efforts. Under full cost-based Customer Charges, the customer will see the full expected benefit in the changes in their gas bills and will be confident about potential savings from additional conservation investments.

Q. Does the volumetric rate component associated with the recovery of storage costs play a role in the conservation price signal?

A. Yes. The volumetric recovery of storage costs is also a sound short run price signal. It reflects the use of Mist storage to provide either more or less design day capacity as needed. This is an appropriate price signal for conservation.

Q. Are there efficient uses of natural gas that are being discouraged by the volumetric price signal?

A. Yes. Natural gas is a cost-effective option for a variety of appliances such as water heating, cooking, and clothes drying. Typically these applications require a greater up-front capital expenditure than for electric alternatives. With the volumetric recovery of fixed costs, customers are often discouraged from making the extra capital expenditure because the marginal cost of operation they face includes a volumetric rate component of approximately $1.09 per therm. This results in an almost six cents per kWh equivalent at NW Natural's current gas cost level of $0.607 per therm. If the gas cost component alone is used, as it should be for marginal cost purposes, the equivalent

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electric cost is just less than two cents per kWh, creating a savings for the gas appliance and allowing the customer to make an economically efficient cost comparison. As a practical matter, some electric competitors have marginal prices below six cents per KWh and only the investor-owned electric utilities have prices significantly above the six cent level. This is an example of how the high volumetric price for gas distribution service discourages economically efficient gas use. This is particularly true for baseload gas applications such as water heating, cooking, and clothes drying.

XI. BENEFITS OF FULL COST-BASED CUSTOMER CHARGES

Q. Please explain the benefits to NW Natural and its customers of a single, fixed monthly Customer Charge under its rate design proposal for Rate Schedules 1 and 2.

A. There are numerous benefits to NW Natural and its customers with a single, fixed monthly bill concept under its proposed rate design for Rate Schedules 1 and 2. They include:

- Ensures customers do not overpay or underpay each month.
- Protects customers least able to pay from higher winter gas bills.
- Offers the most economically efficient alternative to volumetric delivery service rates.
- Addresses intra-class cross subsidization.
- Improves bill stability.
- Achieves bill simplicity and promotes understandability.
- Matches approved level of revenues with costs.

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- Results in similar pricing to other consumer services.
- Simplifies revenue forecasts and adjustments.
- Represents an administratively efficient alternative for revenue instability.
- Provides the opportunity to recover revenue during the Rate Effective Period without the use of a deferral mechanism.
- Eliminates the debate over the definition of normal weather.
- Results in lower annual true-ups for customers on NW Natural's budget billing program.

Q. Please elaborate upon this list of benefits.

A. Many of these benefits have been discussed previously in my direct testimony. Therefore, I will focus on those benefits that have not already been discussed. One important benefit from full cost-based Customer Charges is the protection of low-income customers from higher winter bills. This benefit results from the fact that customers with incomes below the poverty level have gas usage that is more responsive to colder weather than other customers. As a result, when weather is colder than normal, these customers experience far greater gas bills as the result of the volumetric recovery of fixed costs.

I should also point out that some of the same benefits are achieved under NW Natural's WARM and decoupling mechanism, including improved revenue stability and certainty relative to its approved level of revenue, and eliminating the disincentive for NW Natural to actively support and pursue energy efficiency initiatives.

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Q. Why do you say that paying for natural gas delivery services on a flat monthly basis is similar to pricing for other consumer services?

A. NW Natural's customers already are accustomed to paying bills for widely utilized consumer services on a flat monthly basis. There are numerous examples of regular consumer services where the service provider structures its base fees on a flat monthly basis. These include:

- Local and long distance telephone services
- Cellular telephone services
- Cable television and satellite basic service
- Internet access service
- Home alarm services
- Trash removal services
- Automobile leases and loan payments
- Apartment rent

The pricing of NW Natural's gas delivery services under its proposed rate design for Rate Schedules 1 and 2 properly portrays to its customers: (1) the fixed nature of the underlying costs; (2) the delivery-only characteristics of the service; and (3) the fact that natural gas is the real commodity being purchased via NW Natural's gas delivery system.

Q. Given the benefits of a rate structure that emphasizes the recovery of fixed distribution costs through flat monthly charges, why has it only become an issue in the last decade or so?

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A. There may be a number of reasons why LDCs and utility regulators have not focused on the use of this type of pricing historically. First, when LDCs were growing rapidly and the average use per customer increased every year, the block rate structure provided sustainable revenue growth. Second, most of the conceptual work related to the cost basis for this type of rate structure has occurred relatively recently. As LDCs and utility regulators recognize that it costs the same to serve all residential customers, the need to eliminate the undue discrimination within the residential class increased in relative importance, not only for LDCs, but also for utility regulators to meet the mandate for just and reasonable rates. Third, the requirement to provide the LDC with a reasonable opportunity to earn its allowed rate of return has become a far more important issue in the face of declining use per customer and regulatory and legislative mandates to further promote energy conservation.

XII. RATE DESIGN FOR NW NATURAL'S OTHER RATE CLASSES

Q. Please explain the proposed rate design for NW Natural's Rate Schedule 3.

A. NW Natural's current rate structure for this rate class is proposed to be continued. The Customer Charge is proposed at $15.00 per month, with commensurate changes to the current Volumetric Charges to achieve the class revenue level proposed by NW Natural for this rate class.

Q. Please explain the rationale for proposing this type of rate design change.

A. The proposed increase in NW Natural's monthly Customer Charge for Rate Schedule 3 was guided by the customer-related costs for these rate classes indicated in its LRIC Study. The monthly customer-related cost for this rate class ranged between $55.00 (for commercial

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customers) and $252.00 (for industrial customers), however, the vast majority of customers are commercial. Since the monthly Customer Charge is currently $8.00, it was determined that meaningful movement towards the indicated customer-related costs was appropriate while recognizing customer impact considerations and the need to mitigate any expected intra-class revenue shifts for different sized customers served in the class.

Q. Please explain the proposed rate design for NW Natural's Rate Schedule 31.

A. NW Natural's current rate structure for this rate class is proposed to be continued. The Customer Charges are proposed at $260.00 per month, with commensurate changes to the current Volumetric Charges to achieve the class revenue level proposed by NW Natural for this Rate Schedule.

Q. Please explain the rationale for proposing this type of rate design change.

A. The proposed changes in NW Natural's monthly Customer Charges under this Rate Schedule were guided by the customer-related costs for these rate classes indicated in its LRIC Study. The monthly customer-related cost for this rate class ranged between $159.00 and $349.00, with a weighted average cost across the Rate Schedule of approximately $191.00. The proposed charges were set at levels which recognized the current charges of $325.00 per month and the customer-related costs for this Rate Schedule.

Q. Please explain the proposed rate design for NW Natural's Rate Schedule 32.

A. NW Natural's current rate structure for this rate class is proposed to be continued. There are no changes proposed to the current level of the monthly Customer Charges or Volumetric Charges.

Q. Please explain the rationale for proposing this type of rate design change.

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A. NW Natural has proposed no change to the current level of revenues for this Rate Schedule so the charges are not proposed to change as a result.

Q. Have you determined the rate structure and associated rate levels for NW Natural's proposed Rate Schedule 27 – Residential Heating Dry-Out Service?

A. Yes. NW Natural witness Onita King discusses the need for this proposed service offering. The proposed rate structure mirrors the one used in NW Natural's Rate Schedule 2—a monthly Customer Charge and a flat Volumetric Charge. The proposed rate levels for this Rate Schedule recognize the temporary and transitional nature of the service offering and seek to balance the underlying costs of providing service with the utilization of natural gas by residential home builders, developers, and contractors in new residential homes. As a result, NW Natural has proposed that the level for each rate structure component of this new Rate Schedule be established at approximately 75 percent of the comparable proposed rate levels under Rate Schedule 2.

Q. Have you prepared bill comparisons for NW Natural's other rate classes?

A. Yes. *NWN/1102, Feingold/18-31* present bill comparisons for NW Natural's non-residential rate schedules at varying monthly levels of gas usage.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Exhibits of Russell A. Feingold

LONG-RUN INCREMENTAL COST STUDY / RATE DESIGN EXHIBITS 1101 - 1102

December 2011

EXHIBITS 1101-1102 – LONG-RUN INCREMENTAL COST STUDY / RATE DESIGN

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Long-Run Incremental Cost Study
Incremental Distribution Revenue Requirements

		Units	Total	1R	1C	2R	3C Firm Sales	3I Firm Sales	31C Firm Sales	31C Firm Trans	31C Interr Sales	31I Firm Sales	31I Firm Trans
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Number Customers	Customers	601,298	3,764	169	538,601	56,653	285	1,198	6	12	225	8
2	MDDV Volumes	Dth											
3	Winter-4 Storage Volumes-Sales & Transport	Dth	207,362,282	194,861	38,670	132,481,223	49,281,181	569,537	16,449,324	8,064		1,876,983	157,702
4	Winter-4 Storage Volumes-Sales	Dth	203,768,706	194,861	38,670	132,481,223	49,281,181	569,537	16,449,324			1,876,983	
5	Firm DesignDay	Dth/day	849,990	830	131	554,495	191,840	1,516	70,302	175		4,331	353
6	DesignDay-Sales	Dth/day	838,638	830	131	554,495	191,840	1,516	70,302			4,331	
7	C&I Incremental Firm DesignDay	Dth/day	17,459	14	3	9,496	4,531	115	1,660	4	0	327	27
8	Revenues	$	$287,404,942	$577,125	$62,009	$188,891,594	$57,697,369	$1,362,237	$15,322,004	$81,269	$285,292	$3,561,584	$182,560
9													
10	Total Revenue Requirement	$	331,087,253										
11													
12	**Incremental Storage Costs**												
13	Storage Revenue Requirement - Daily Deliverability	$	$46,697,054	$46,244	$7,287	$30,875,387	$10,682,052	$84,420	$3,914,542	$0	$0	$241,171	$0
14	Storage Revenue Requirement - Capacity	$	$8,265,500	$7,904	$1,569	$5,373,856	$1,999,000	$23,102	$667,236	$0	$0	$76,136	$0
15													
16	**Incremental Transmission Costs**												
17	Incremental Transmission Costs per Dth/Design Day	$		$96	$96	$96	$96	$96	$96	$96	$0	$96	$96
18	Incremental Transmission Revenue Requirement	$	$1,677,913	1,367	297	912,625	435,442	11,004	159,572	397	0	31,437	2,560
19													
20	**Incremental Distribution Costs**												
21	Incremental Distribution Costs per Customer	$		$338	$383	$378	$662	$3,022	$1,909	$2,753	$2,535	$4,186	$4,186
22	Incremental Distribution Costs per Dth/Design Day	$		$0	$13	$0	$13	$13	$13	$13	$0	$13	$13
23	Incremental Distribution Revenue Requirement	$	$253,516,016	$1,273,726	$66,510	$203,546,032	$40,057,324	$881,343	$3,214,854	$18,824	$30,415	$998,985	$38,143
24													
25	**Total Incremental Revenue Requirement**	$	$310,156,482										
26													
27	Ratio of Incremental Rev Req to Rev Req		94%										
28	**Total Revenue Requirement - Allocated based on LRIC**	$	$331,087,253	$1,418,944	$80,769	$256,951,964	$56,762,228	$1,067,346	$8,493,124	$20,518	$32,467	$1,438,680	$43,450
29													
30	**Test Year Revenues**	$	$287,404,942	$577,125	$62,009	$188,891,594	$57,697,369	$1,362,237	$15,322,004	$81,269	$285,292	$3,561,584	$182,560
31	Revenue to Cost Ratio		0.87	0.41	0.77	0.74	1.02	1.28	1.80	3.96	8.79	2.48	4.20
32	Unitized Revenue to Cost Ratio		1.00	0.47	0.88	0.85	1.17	1.47	2.08	4.56	10.12	2.85	4.84

NW Natural
Long-Run Incremental Cost Study
Incremental Distribution Revenue Requirements

		31I Interr Sales	32C Firm Sales	32I Firm Sales	32 Firm Trans	32C Interr Sales	32I Interr Sales	32 Interr Trans
		(L)	(M)	(N)	(O)	(P)	(Q)	(R)
1	Number Customers	7	53	45	65	52	66	89
2	MDDV Volumes		1,708,764	1,888,634	3,150,048			
3	Winter-4 Storage Volumes-Sales & Transport		2,351,912	525,017	3,427,811			
4	Winter-4 Storage Volumes-Sales		2,351,912	525,017				
5	Firm DesignDay		13,157	2,036	10,825			
6	DesignDay-Sales		13,157	2,036				
7	C&I Incremental Firm DesignDay	0	311	154	818	0	0	0
8	Revenues	$75,970	$2,060,560	$2,056,408	$3,945,752	$1,749,021	$2,647,371	$6,846,817
9								
10	Total Revenue Requirement							
11								
12	**Incremental Storage Costs**							
13	Storage Revenue Requirement - Daily Deliverability	$0	$732,603	$113,349	$0	$0	$0	$0
14	Storage Revenue Requirement - Capacity	$0	$95,401	$21,296	$0	$0	$0	$0
15								
16	**Incremental Transmission Costs**							
17	Incremental Transmission Costs per Dth/Design Day	$0	$96	$96	$96	$0	$0	$0
18	Incremental Transmission Revenue Requirement	0	29,864	14,775	78,571	0	0	0
19								
20	**Incremental Distribution Costs**							
21	Incremental Distribution Costs per Customer	$4,192	$3,386	$5,030	$6,673	$5,021	$6,677	$16,581
22	Incremental Distribution Costs per Dth/Design Day	$0	$13	$13	$13	$0	$0	$0
23	Incremental Distribution Revenue Requirement	$29,347	$353,104	$253,204	$576,667	$261,110	$440,706	$1,475,722
24								
25	**Total Incremental Revenue Requirement**							
26								
27	Ratio of Incremental Rev Req to Rev Req							
28	**Total Revenue Requirement - Allocated based on LRIC**	$31,327	$1,292,694	$429,796	$699,457	$278,731	$470,447	$1,575,311
29								
30	**Test Year Revenues**	$75,970	$2,060,560	$2,056,408	$3,945,752	$1,749,021	$2,647,371	$6,846,817
31	Revenue to Cost Ratio	2.43	1.59	4.78	5.64	6.27	5.63	4.35
32	Unitized Revenue to Cost Ratio	2.79	1.84	5.51	6.50	7.23	6.48	5.01

NW Natural
Long-Run Incremental Cost Study
Calculation of Incremental Storage Costs (Test Year $)

	(A)	(B)	(C)
Cost of Capital	Percentage	Rate	
Equity	50%	10.30%	
Debt	50%	6.27%	
Weighted Cost of Capital		8.28%	
Weighted Cost of Capital including Taxes		11.74%	
Direct	Plant	O&M	
Storage-Demand	212,416,125	280,999	
Storage-Energy	39,340,908	403,148	
Total	251,757,033	684,148	

(D)	(E)
Tax Rates	
State	7.90%
Federal	35.00%
Combined Tax Rate	40.14%
After Tax Rate	59.87%

Storage Direct Revenue Requirement-(Return on Plant, O&M, Taxes and Depreciation)

Storage-Demand	46,697,054
Storage-Energy	8,265,500

NW Natural
Long-Run Incremental Cost Study
Incremental Demand-Related Transmission Costs (Test Year $)

	Class	Mains Component Investment (A)	ECCR Factor (B)	Annual Cost per Dth/Design Day (C)	Monthly Cost per Dth/Design Day (D)
1	1R	$ 1,107	8.68%	$ 96.11	$ 8.01
2	1C	$ 1,107	8.68%	$ 96.11	$ 8.01
3	2R	$ 1,107	8.68%	$ 96.11	$ 8.01
4	3C Firm Sales	$ 1,107	8.68%	$ 96.11	$ 8.01
5	3I Firm Sales	$ 1,107	8.68%	$ 96.11	$ 8.01
6	31C Firm Sales	$ 1,107	8.68%	$ 96.11	$ 8.01
7	31C Firm Trans	$ 1,107	8.68%	$ 96.11	$ 8.01
8	31C Interr Sales	$ -	8.68%	$ -	$ -
9	31I Firm Sales	$ 1,107	8.68%	$ 96.11	$ 8.01
10	31I Firm Trans	$ 1,107	8.68%	$ 96.11	$ 8.01
11	31I Interr Sales	$ -	8.68%	$ -	$ -
12	32C Firm Sales	$ 1,107	8.68%	$ 96.11	$ 8.01
13	32I Firm Sales	$ 1,107	8.68%	$ 96.11	$ 8.01
14	32 Firm Trans	$ 1,107	8.68%	$ 96.11	$ 8.01
15	32C Interr Sales	$ -	8.68%	$ -	$ -
16	32I Interr Sales	$ -	8.68%	$ -	$ -
17	32 Interr Trans	$ -	8.68%	$ -	$ -

NW Natural
Long-Run Incremental Cost Study
Calculation of Incremental Transmission Mains Costs

		(A)	(B)
	Forecasted Transmission Investment	2011-2013	Units
1	Corvallis Loop Project	$12,800,000	$
2	Mid-Willamette Valley Feeder Project	$32,600,000	$
3	Total Investment	$45,400,000	$
4			
5	Total Additional Design Day Capacity for both Projects*	41,000	Per Dth/Day
	other) the 41,000 Dth/Day is the total for both.		
6			
7			
8	**Forecasted Transmission Investment per Design Day Dth**	$1,107	Per Dth/Day
9			
10	**2013 Forecasted C&I Incremental Design Day Requirements by Revenue Class (Dth per Day)**		
11	Residential	9,510	Per Dth/Day
12	Commercial	6,509	Per Dth/Day
13	Industrial	1,440	Per Dth/Day
14	**2013 Total Forecasted C&I Incremental Design Day Requirements**	17,459	Per Dth/Day

NW Natural
Long-Run Incremental Cost Study
Incremental Demand-Related Distribution Costs (Test Year $)

	Class	Mains Component Investment (A)	ECCR Factor (B)	Annual Cost per Dth/Design Day (C)	Monthly Cost per Dth/Design Day (D)
1	1R	$ -	8.68%	$ -	$ -
2	1C	$ 152	8.68%	$ 13.20	$ 1.10
3	2R	$ -	8.68%	$ -	$ -
4	3C Firm Sales	$ 152	8.68%	$ 13.20	$ 1.10
5	3I Firm Sales	$ 152	8.68%	$ 13.20	$ 1.10
6	31C Firm Sales	$ 152	8.68%	$ 13.20	$ 1.10
7	31C Firm Trans	$ 152	8.68%	$ 13.20	$ 1.10
8	31C Interr Sales	$ -	8.68%	$ -	$ -
9	31I Firm Sales	$ 152	8.68%	$ 13.20	$ 1.10
10	31I Firm Trans	$ 152	8.68%	$ 13.20	$ 1.10
11	31I Interr Sales	$ -	8.68%	$ -	$ -
12	32C Firm Sales	$ 152	8.68%	$ 13.20	$ 1.10
13	32I Firm Sales	$ 152	8.68%	$ 13.20	$ 1.10
14	32 Firm Trans	$ 152	8.68%	$ 13.20	$ 1.10
15	32C Interr Sales	$ -	8.68%	$ -	$ -
16	32I Interr Sales	$ -	8.68%	$ -	$ -
17	32 Interr Trans	$ -	8.68%	$ -	$ -

NW Natural
Long-Run Incremental Cost Study
Calculation of Incremental Distribution Mains Costs

		(A)	(B)
	Forecasted Incremental Design Day Requirements by Revenue Class (Dth per Day)		
		2011	Note
1	Residential	6,840	Residential
2	Commercial	5,535	Commercial
3	Industrial	549	Industrial
4	Commercial & Industrial Service	6,083	Commercial + Industrial
5	Residential	6,840	Residential
6			
7			
8	**New customer meter set without idle and add sets***		
9		2011	
10	Commercial & Industrial Service	423	
11	Residential Conversion Service	2,282	
12	Residential New Service	2,790	
13	Commercial & Industrial Service	423	
14	Residential	5,072	
15	*Idle and add sets are new customers that currently have meter and service connections		
16			
17	**Forecast Capital Expenditure with Construction Overhead**		
18			
19		2011	
20	Residential	$ 843,243.80	
21	Commercial & Industrial	$ 1,289,896.79	
22	Includes Extensions		
23			
24	Cost per Foot	$14.56	
25	Installed Mains Length per New Customer	77	
26			
27	Customer Costs per Customer - All (2011 $)	$1,120	Per Customer
28	Escalation to the Test Year Dollars	1.13	Factor
29	Customer Costs per Customer - All (Test Year $)	$1,271	Per Customer
30			
31	Total Commercial Customer Component	$473,966	Number of New C&I Customers * $1,120
32	Total Commercial Demand Component	$815,931	Com & Ind - Customer Component
33	Commercial & Industrial cost per forecasted new design day requirement (2011 $)	$134	Per Dth/Day
34	Escalation to the Test Year Dollars	1.13	Factor
35	Commercial & Industrial cost per forecasted new design day requirement (Test Year $)	$152	Per Dth/Day

NW Natural
Long-Run Incremental Cost Study
Calculation of Economic Carrying Charge Rate - Mains

(A) (B) (C) (D) (E) (F) (G) (H) (I) (J) (K) (L) (M) (N) (O) (P) (Q) (R) (S) (T) (U) (V)

BOOK DATA:

Book Cost	$100.00
Avg Life	60.00
Salvage Value	-60.00%
Dispersion: (Yes=1, No=0)	0
End of Yr (1) or Avg. Rate Base (0)	1

FEDERAL TAX DATA:

Tax Base	$100.00
Tax Life	20.00
FIT Rate	35.00%
Declining Rate	150.00%
1st Year Adjust	50.00%
Deferred FIT: (Yes=1,No=0)	1

STATE TAX DATA:

State Tax Life	60.00	TAXLIFE_S
State Rate	7.90%	SIT
Declining Rate	200.00%	TDRATE_S
State Tax Method	0	TaxM_S
	SL=0, DDB=1	

OTHER INFORMATION:

	Rate	Starting Year
Property Tax (Percent of Net Plant)	0.61%	2012
O&M (Percent of Gross Plant +Inf)	1.07%	
A&G (Percent of Gross Plant + Inf)	0.00%	
Inflat. (ECCR)	2.10%	
GRT Rate	0.00%	

COST OF CAPITAL AND DISCOUNT RATES

	Cost of Capital		Percent of Capital		Weighted Costs
Debt	6.27%		50.00%		3.13%
Preferred	0.00%		0.00%		0.00%
Common	10.30%		50.00%		5.15%
Total			100.00%		8.28%
Net of Tax or After Tax Cost of Capital:		7.19%	Weighted Cost of Equity:	62%	5.15%
Pre Tax Cost of Capital:		10.20%	Discount Rate:		8.28%

Confidential and Proprietary to Black and Veatch

PRESENT WORTH REVENUE REQUIREMENTS AND CHARGE RATES

TOTAL PRESENT WORTH OF REVENUES:	141.79
TOTAL PRESENT WORTH PLANT:	1,245.76

CHARGE RATES:

	RATES:
LEVELIZED (LACR)	11.38%

ECONOMIC CARRYING CHARGE RATES (ECCR)

	YEARS	FACTOR	ECCR
TAX:	20	0.0859	12.18%
BOOK:	60	0.0612	8.68%
AVERAGE ECCR			10.43%

NW Natural
Long-Run Incremental Cost Study
Incremental Customer-Related Distribution Costs (Test Year $)

		Mains			Services			Meters & Regulators			Accounting	Annual	Monthly
	Rate Schedule	Invest-ment	ECCR Factor	Annual Cost	Invest-ment	ECCR Factor	Annual Cost	Invest-ment	ECCR Factor	Annual Cost	Annual Cost	Cost Per Customer	Cost Per Customer
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(L)	(M)	(N)
1	1R	$1,271	8.68%	$110	$1,595	8.19%	$131	$375	13.50%	$51	$ 46.76	$ 338	$ 28
2	1C	$1,271	8.68%	$110	$1,678	8.19%	$137	$633	13.50%	$85	$ 50.20	$ 383	$ 32
3	2R	$1,271	8.68%	$110	$1,979	8.19%	$162	$435	13.50%	$59	$ 46.76	$ 378	$ 31
4	3C Firm Sales	$1,271	8.68%	$110	$4,764	8.19%	$390	$827	13.50%	$112	$ 50.20	$ 662	$ 55
5	3I Firm Sales	$1,271	8.68%	$110	$9,250	8.19%	$758	$3,409	13.50%	$460	$ 1,694.30	$ 3,022	$ 252
6	31C Firm Sales	$1,271	8.68%	$110	$14,090	8.19%	$1,154	$4,406	13.50%	$595	$ 50.20	$ 1,909	$ 159
7	31C Firm Trans	$1,271	8.68%	$110	$22,862	8.19%	$1,872	$5,334	13.50%	$720	$ 50.20	$ 2,753	$ 229
8	31C Interr Sales	$1,271	8.68%	$110	$20,538	8.19%	$1,682	$5,127	13.50%	$692	$ 50.20	$ 2,535	$ 211
9	31I Firm Sales	$1,271	8.68%	$110	$20,538	8.19%	$1,682	$5,180	13.50%	$699	$ 1,694.30	$ 4,186	$ 349
10	31I Firm Trans	$1,271	8.68%	$110	$20,538	8.19%	$1,682	$5,180	13.50%	$699	$ 1,694.30	$ 4,186	$ 349
11	31I Interr Sales	$1,271	8.68%	$110	$20,538	8.19%	$1,682	$5,228	13.50%	$706	$ 1,694.30	$ 4,192	$ 349
12	32C Firm Sales	$1,271	8.68%	$110	$30,848	8.19%	$2,526	$5,175	13.50%	$699	$ 50.20	$ 3,386	$ 282
13	32I Firm Sales	$1,271	8.68%	$110	$30,848	8.19%	$2,526	$5,175	13.50%	$699	$ 1,694.30	$ 5,030	$ 419
14	32 Firm Trans	$1,271	8.68%	$110	$50,821	8.19%	$4,162	$5,235	13.50%	$707	$ 1,694.30	$ 6,673	$ 556
15	32C Interr Sales	$1,271	8.68%	$110	$50,821	8.19%	$4,162	$5,175	13.50%	$699	$ 50.20	$ 5,021	$ 418
16	32I Interr Sales	$1,271	8.68%	$110	$50,821	8.19%	$4,162	$5,264	13.50%	$710	$ 1,694.30	$ 6,677	$ 556
17	32 Interr Trans	$1,271	8.68%	$110	$171,892	8.19%	$14,078	$5,175	13.50%	$699	$ 1,694.30	$ 16,581	$ 1,382

NW Natural
Long-Run Incremental Cost Study
Incremental Customer Component Costs (Test Year $)

	Rate Schedule	Mains Cust	Mains Demand Per Dthd	Service	Weighted Avg Meter Cost	Average Dth per Customer: February	Average Dth per Customer: Annual	Adjusted Service Costs
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	1R	$ 1,271	$ -	$ 1,595	$ 375	24	202	$ 1,595
2	1C	$ 1,271	$ 152	$ 1,678	$ 633	103	923	$ 1,678
3	2R	$ 1,271	$ -	$ 1,979	$ 435	91	680	$ 1,979
4	3C Firm Sales	$ 1,271	$ 152	$ 4,764	$ 827	368	2,864	$ 4,764
5	3I Firm Sales	$ 1,271	$ 152	$ 9,250	$ 3,409	1,483	14,667	$ 9,250
6	31C Firm Sales	$ 1,271	$ 152	$ 14,090	$ 4,406	5,970	50,562	$ 14,090
7	31C Firm Trans	$ 1,271	$ 152	$ 22,862	$ 5,334	25,262	232,590	$ 22,862
8	31C Interr Sales	$ 1,271	$ -	$ 20,538	$ 5,127	13,673	90,830	$ 20,538
9	31I Firm Sales	$ 1,271	$ 152	$ 1,044	$ 5,180	7,798	80,670	$ 20,538
10	31I Firm Trans	$ 1,271	$ 152	$ -	$ 5,180	13,967	108,138	$ 20,538
11	31I Interr Sales	$ 1,271	$ -	$ 23,280	$ 5,228	6,368	59,122	$ 20,538
12	32C Firm Sales	$ 1,271	$ 152	$ 8,413	$ 5,175	27,193	229,443	$ 30,848
13	32I Firm Sales	$ 1,271	$ 152	$ 30,848	$ 5,175	27,570	289,297	$ 30,848
14	32 Firm Trans	$ 1,271	$ 152	$ -	$ 5,235	76,628	875,672	$ 50,821
15	32C Interr Sales	$ 1,271	$ -	$ 50,821	$ 5,175	45,404	326,506	$ 50,821
16	32I Interr Sales	$ 1,271	$ -	$ 13,595	$ 5,264	40,791	654,251	$ 50,821
17	32 Interr Trans	$ 1,271	$ -	$ 171,892	$ 5,175	206,687	2,327,217	$ 171,892

NW Natural
Long-Run Incremental Cost Study
Calculation of Economic Carrying Charge Rate - Services

(A) (B) (C) (D) (E) (F) (G) (H) (I) (J) (K) (L) (M) (N) (O) (P) (Q) (R) (S) (T) (U) (V)

Row	BOOK DATA:			FEDERAL TAX DATA:		STATE TAX DATA:		
1	Book Cost		$100.00	Tax Base	$100.00			
2	Avg Life		49.00	Tax Life	20.00	State Tax Life	49.00	TAXLIFE_S
3	Salvage Value		-60.00%	FIT Rate	35.00%	State Rate	7.90%	SIT
4	Dispersion: (Yes=1, No=0)		0	Declining Rate	150.00%	Declining Rate	200.00%	TDRATE_S
5	End of Yr (1) or Avg. Rate Base (0)		1	1st Year Adjust	50.00%	State Tax Method	0	TaxM_S
6				Deferred FIT: (Yes=1,No=0)	1		SL=0, DDB=1	

Row	OTHER INFORMATION:	Rate	Starting
8			Year
9	Property Tax (Percent of Net Plant)	0.61%	2012
10	O&M (Percent of Gross Plant +Inf)	0.98%	
11	A&G (Percent of Gross Plant + Inf)	0.00%	
12	Inflat. (ECCR)	2.10%	
13	GRT Rate	0.00%	

Row	COST OF CAPITAL AND DISCOUNT RATES	Cost of Capital		Percent of Capital		Weighted Costs
18	Debt	6.27%		50.00%		3.13%
19	Preferred	0.00%		0.00%		0.00%
20	Common	10.30%		50.00%		5.15%
21	Total			100.00%		8.28%
23	Net of Tax or After Tax Cost of Capital:		7.19%	Weighted Cost of Equity	62%	5.15%
24	Pre Tax Cost of Capital:		10.20%	Discount Rate:		8.28%

PRESENT WORTH REVENUE REQUIREMENTS AND CHARGE RATES

TOTAL PRESENT WORTH OF REVENUES:			130.12
TOTAL PRESENT WORTH PLANT:			1,230.92
CHARGE RATES:			RATES:
LEVELIZED (LACR)			10.57%
ECONOMIC CARRYING CHARGE RATES (ECCR)			
	YEARS	FACTOR	ECCR
TAX:	20	0.0859	11.18%
BOOK:	49	0.0629	8.19%
AVERAGE ECCR			9.69%

27 Confidential and Proprietary to Black and Veatch

NW Natural
Long-Run Incremental Cost Study
Calculation of Economic Carrying Charge Rate - Services

(A) (B) (C) (D) (E) (F) (G) (H) (I) (J) (K) (L) (M) (N) (O) (P) (Q) (R) (S) (T) (U) (V)

Row	BOOK DATA:		FEDERAL TAX DATA:		STATE TAX DATA:		
1	Book Cost	$100.00	Tax Base	$100.00			
2	Avg Life	39.18	Tax Life	20.00	State Tax Life	39.18	TAXLIFE_S
3	Salvage Value	-0.23%	FIT Rate	35.00%	State Rate	7.90%	SIT
4	Dispersion: (Yes=1, No=0)	0	Declining Rate	150.00%	Declining Rate	200.00%	TDRATE_S
5	End of Yr (1) or Avg. Rate Base (0)	1	1st Year Adjust	50.00%	State Tax Method	0	TaxM_S
6			Deferred FIT: (Yes=1,No=0)	1		SL=0, DDB=1	

Row	OTHER INFORMATION:	Rate	Starting
7			
8			
9	Property Tax (Percent of Net Plant)	0.61%	Year
10	O&M (Percent of Gross Plant +Inf)	5.20%	2012
11	A&G (Percent of Gross Plant + Inf)	0.00%	
12	Inflat. (ECCR)	2.10%	
13	GRT Rate	0.00%	
14			

Row	COST OF CAPITAL AND DISCOUNT RATES					
15						
16		Cost of		Percent		Weighted
17		Capital		of Capital		Costs
18	Debt	6.27%		50.00%		3.13%
19	Preferred	0.00%		0.00%		0.00%
20	Common	10.30%		50.00%		5.15%
21	Total			100.00%		8.28%
22						
23	Net of Tax or After Tax Cost of Capital:		7.19%	Weighted Cost of Equity	62%	5.15%
24	Pre Tax Cost of Capital:		10.20%	Discount Rate:		8.28%
25						
26	Confidential and Proprietary to Black and Veatch					

PRESENT WORTH REVENUE REQUIREMENTS AND CHARGE RATES

TOTAL PRESENT WORTH OF REVENUES:	204.49
TOTAL PRESENT WORTH PLANT:	1,199.96

CHARGE RATES:

	RATES:
LEVELIZED (LACR)	17.04%

ECONOMIC CARRYING CHARGE RATES (ECCR)

	YEARS	FACTOR	ECCR
TAX:	20	0.0859	17.57%
BOOK:	39.18143	0.0660	13.50%
AVERAGE ECCR			15.54%

NW Natural
Long-Run Incremental Cost Study
Incremental Customer Account Costs

	Allocator	Total	Residential	Commercial	Industrial
		(A)	(B)	(C)	(D)
1	Number of Customers	608,964	550,746	57,428	790
2			90.4%	9.4%	0.1%
3					
4	Account-Class	Total	Residential	Commercial	Industrial
5	902-All	$ 625,866	$ 566,032	$ 59,022	$ 812
6	902-Ind	$ 19,279			$ 19,279
7	902-Other	$ (14,906)	$ (13,481)	$ (1,406)	$ (19)
8	902-Res	$ 5,457	$ 5,457		
9	903-All	$ 1,495,645	$ 1,352,658	$ 141,046	$ 1,940
10	903-Ind	$ 341,320			$ 341,320
11	903-Other	$ 9,874,222	$ 8,930,229	$ 931,183	$ 12,810
12	903-Res	$ 3,852,255	$ 3,852,255		
13	904-All	$ (41,969)	$ (37,956)	$ (3,958)	$ (54)
14	904-Comm	$ 314,831		$ 314,831	
15	904-Ind	$ 83,319			$ 83,319
16	904-Res	$ 1,188,556	$ 1,188,556		
17	907-Other	$ 32,874	$ 29,731	$ 3,100	$ 43
18	907-Res	$ 234,969	$ 234,969		
19	908-All	$ 67	$ 61	$ 6	$ 0
20	908-Comm	$ 166,017		$ 166,017	
21	908-Ind	$ 671,890			$ 671,890
22	908-Other	$ 230,618	$ 208,571	$ 21,748	$ 299
23	908-Res	$ 1,986,700	$ 1,986,700		
24	909-Other	$ 3,159	$ 2,857	$ 298	$ 4
25	909-Res	$ 1,326,746	$ 1,326,746		
26	910-Other	$ 358	$ 324	$ 34	$ 0
27	910-Res	$ 165,612	$ 165,612		
28	911-All	$ 141,873	$ 128,310	$ 13,379	$ 184
29	911-Other	$ 17,702	$ 16,009	$ 1,669	$ 23
30	911-Res	$ 126,397	$ 126,397		
31	912-All	$ 1,874,692	$ 1,695,468	$ 176,792	$ 2,432
32	912-Comm	$ 64,521		$ 64,521	
33	912-Ind	$ 91			$ 91
34	912-Other	$ 54,557	$ 49,342	$ 5,145	$ 71
35	912-Res	$ 1,176	$ 1,176		
36	913-Comm	$ 550,044		$ 550,044	
37	913-Other	$ 130	$ 118	$ 12	$ 0
38	913-Res	$ 9,762	$ 9,762		
39	916-Other	$ 43	$ 38	$ 4	$ 0
40	916-Res	$ 94	$ 94		
41					
42	Total 2010	$ 25,403,965	$ 21,826,033	$ 2,443,488	$ 1,134,444
43			86%	10%	4%
44					
45	Total Test Year	$ 29,973,481	$ 25,751,972	$ 2,883,008	$ 1,338,501
46					
47		Per Customer	$ 46.76	$ 50.20	$ 1,694.30
48			$ 3.90	$ 4.18	$ 141.19

NW Natural
Rate Design
Proposed Revenue Allocation to Rate Schedules

			Total	1R	1C	2R	3C Firm Sales	3I Firm Sales	31C Firm Sales	31C Firm Trans	31C Interr Sales	31I Firm Sales	31I Firm Trans
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	**Total LRIC - Based Revenue Requirement**		$331,087,253	$1,418,944	$80,769	$256,951,964	$56,762,228	$1,067,346	$8,493,124	$20,518	$32,467	$1,438,680	$43,450
2													
3	**Less: Test Year Revenues**		$287,404,942	$577,125	$62,009	$188,891,594	$57,697,369	$1,362,237	$15,322,004	$81,269	$285,292	$3,561,584	$182,560
4	**Difference**		$43,682,312	$841,820	$18,760	$68,060,371	($935,140)	($294,892)	($6,828,880)	($60,751)	($252,824)	($2,122,904)	($139,110)
5	Revenue to Cost Ratio		0.87	0.40	0.77	0.73	1.02	1.28	1.83	4.02	8.74	2.52	4.46
6	Unitized Revenue to Cost Ratio		1.00	0.47	0.88	0.85	1.17	1.48	2.11	4.63	10.07	2.90	5.14
7	At Proposed Revenues		1.00	0.48	0.88	0.87	1.17	1.47	1.94	3.96	8.79	2.48	4.20
8													
9	Pro Rata Increase Request by Rate Schedule		$43,682,312	$87,716	$9,425	$28,709,393	$8,769,350	$207,045	$2,328,772	$12,352	$43,361	$541,321	$27,747
10	Pro Rata Increase Request by Rate Schedule - Percent Change		15.2%										
11													
12	Allocation of Rate Increase		$43,682,312	$109,654	$9,212	$33,422,665	$8,769,350	$207,045	$1,164,386	$0	$0	$0	$0
13	Percent Change			19.0%	14.9%	17.7%	15.2%	15.2%	7.6%	0.0%	0.0%	0.0%	0.0%
14													
15	Total Revenue Requirement		$331,087,253	$686,779	$71,222	$222,314,258	$66,466,719	$1,569,282	$16,486,390	$81,269	$285,292	$3,561,584	$182,560
16	Total Revenue Requirement (Excluding Storage & Transmission Costs		$266,690,728	$658,096	$62,606	$187,992,107	$50,071,238	$1,383,256	$6,661,636	$79,592	$285,292	$2,639,972	$171,076
17													
18	Current Customer Charge	Scaling		$5.00	$5.00	$6.00	$8.00	$8.00	$325.00	$575.00	$325.00	$325.00	$575.00
19	Requested Customer Charge - Phase-in Year 1	For Rate 1		$8.19	$13.62	$13.70	$15.00	$15.00	$260.00	$510.00	$260.00	$260.00	$575.00
20	Requested Customer Charge - Phase-in Year 2			$11.38	$22.25	$21.39	$15.00	$15.00	$260.00	$510.00	$260.00	$260.00	$575.00
21	Requested Customer Charge - Phase-in Year 3	0.8		$11.65	$24.70	$29.09	$15.00	$15.00	$260.00	$510.00	$260.00	$260.00	$575.00
22													
23			Increase for										
24	Current MDDV Charge		MDDV										
25	Requested MDDV Charge		0.0%										
26													
27	Change in Revenue Requirement for Customer Charge & MDDV - Phase-in Year 1			$144,104	$17,481	$49,766,694	$4,758,851	$23,940	-$934,304	-$4,680	-$9,360	-$175,500	$0
28	Change in Revenue Requirement for Customer Charge & MDDV - Phase-in Year 2			$288,207	$34,983	$99,468,756	$4,758,851	$23,940	-$934,304	-$4,680	-$9,360	-$175,500	$0
29	Change in Revenue Requirement for Customer Charge & MDDV - Phase-in Year 3			$300,404	$39,952	$149,235,451	$4,758,851	$23,940	-$934,304	-$4,680	-$9,360	-$175,500	$0
30													
31	Current Volumetric Charges			$351,257	$51,869	$150,112,351	$52,258,682	$1,334,877	$10,650,486	$39,869	$238,492	$2,684,084	$127,360
32													
33	Phase-in Year 1												
34	Change in Revenue Requirement for Volumetric Charges			-$34,450	-$8,269	-$16,344,029	$4,010,498	$183,105	$2,098,690	$4,680	$9,360	$175,500	$0
35	Percentage Change in Revenue Requirement for Volumetric Charges			-9.81%	-15.94%	-10.89%	7.67%	13.72%	19.71%	11.74%	3.92%	6.54%	0.00%
36													
37	Phase-in Year 2												
38	Change in Revenue Requirement for Volumetric Charges			-$178,553	-$25,771	-$66,046,092	$4,010,498	$183,105	$2,098,690	$4,680	$9,360	$175,500	$0
39	Percentage Change in Revenue Requirement for Volumetric Charges			-50.83%	-49.68%	-44.00%	7.67%	13.72%	19.71%	11.74%	3.92%	6.54%	0.00%
40													
41	Phase-in Year 3												
42	Change in Revenue Requirement for Volumetric Charges			-$190,750	-$30,739	-$115,812,786	$4,010,498	$183,105	$2,098,690	$4,680	$9,360	$175,500	$0
43	Percentage Change in Revenue Requirement for Volumetric Charges			-54.31%	-59.26%	-77.15%	7.67%	13.72%	19.71%	11.74%	3.92%	6.54%	0.00%

NW Natural
Rate Design
Proposed Revenue Allocation to Rate Schedules

			31I Interr Sales	32C Firm Sales	32I Firm Sales	32 Firm Trans	32C Interr Sales	32I Interr Sales	32 Interr Trans
			(L)	(M)	(N)	(O)	(P)	(Q)	(R)
1	**Total LRIC - Based Revenue Requirement**		$31,327	$1,292,694	$429,796	$699,457	$278,731	$470,447	$1,575,311
2									
3	**Less: Test Year Revenues**		$75,970	$2,060,560	$2,056,408	$3,945,752	$1,749,021	$2,647,371	$6,846,817
4	**Difference**		($44,643)	($767,866)	($1,626,613)	($3,246,295)	($1,470,290)	($2,176,925)	($5,271,506)
5	Revenue to Cost Ratio		2.41	1.63	4.94	6.38	6.24	5.60	4.32
6	Unitized Revenue to Cost Ratio		2.78	1.87	5.69	7.34	7.19	6.45	4.98
7	At Proposed Revenues		2.43	1.59	4.78	5.64	6.27	5.63	4.35
8									
9	Pro Rata Increase Request by Rate Schedule		$11,547	$313,182	$312,551	$599,710	$265,831	$402,371	$1,040,639
10	Pro Rata Increase Request by Rate Schedule - Percent Change								
11									
12	Allocation of Rate Increase		$0	$0	$0	$0	$0	$0	$0
13	Percent Change		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14									
15	Total Revenue Requirement		$75,970	$2,060,560	$2,056,408	$3,945,752	$1,749,021	$2,647,371	$6,846,817
16	Total Revenue Requirement (Excluding Storage & Transmission Costs		$75,970	$600,833	$1,293,240	$3,472,606	$1,749,021	$2,647,371	$6,846,817
17									
18	Current Customer Charge	Scaling	$325.00	$675.00	$675.00	$925.00	$675.00	$675.00	$925.00
19	Requested Customer Charge - Phase-in Year 1	For Rate 1	$260.00	$675.00	$675.00	$925.00	$675.00	$675.00	$1,380.00
20	Requested Customer Charge - Phase-in Year 2		$260.00	$675.00	$675.00	$925.00	$675.00	$675.00	$1,380.00
21	Requested Customer Charge - Phase-in Year 3	0.8	$260.00	$675.00	$675.00	$925.00	$675.00	$675.00	$1,380.00
22									
23									
24	Current MDDV Charge			$0.36163	$0.36163	$0.15748			
25	Requested MDDV Charge			$0.36163	$0.36163	$0.15748			
26									
27	Change in Revenue Requirement for Customer Charge & MDDV - Phase-in Year 1		-$5,460	$0	$0	$0	$0	$0	$485,940
28	Change in Revenue Requirement for Customer Charge & MDDV - Phase-in Year 2		-$5,460	$0	$0	$0	$0	$0	$485,940
29	Change in Revenue Requirement for Customer Charge & MDDV - Phase-in Year 3		-$5,460	$0	$0	$0	$0	$0	$485,940
30									
31	Current Volumetric Charges		$48,670	$1,013,320	$1,008,922	$2,728,182	$1,327,821	$2,112,771	$5,858,917
32									
33	Phase-in Year 1								
34	Change in Revenue Requirement for Volumetric Charges		$5,460	$0	$0	$0	$0	$0	-$485,940
35	Percentage Change in Revenue Requirement for Volumetric Charges		11.22%	0.00%	0.00%	0.00%	0.00%	0.00%	-8.29%
36									
37	Phase-in Year 2								
38	Change in Revenue Requirement for Volumetric Charges		$5,460	$0	$0	$0	$0	$0	-$485,940
39	Percentage Change in Revenue Requirement for Volumetric Charges		11.22%	0.00%	0.00%	0.00%	0.00%	0.00%	-8.29%
40									
41	Phase-in Year 3								
42	Change in Revenue Requirement for Volumetric Charges		$5,460	$0	$0	$0	$0	$0	-$485,940
43	Percentage Change in Revenue Requirement for Volumetric Charges		11.22%	0.00%	0.00%	0.00%	0.00%	0.00%	-8.29%

NW Natural
Rate Design
Comparison of Present and Proposed Revenues

	Rate Schedule	Distribution Revenues at Present Rates	Distribution Revenues at Proposed Rates	Cost of Gas Revenues	Test Year Revenues Total	Proposed Revenues Total	Change	Percentage Change	Unitized Revenue to Cost Ratio at Test Year Revenues	Unitized Revenue to Cost Ratio at Proposed Revenues
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Total	$287,404,942	$331,087,254	$395,038,530	$682,443,472	$726,125,784	$43,682,312	6.4%	1.00	1.00
2	1R	$577,125	$686,779	$428,585	$1,005,710	$1,115,364	$109,654	10.9%	0.47	0.48
3	1C	$62,009	$71,224	$66,190	$128,199	$137,414	$9,215	7.2%	0.88	0.88
4	2R	$188,891,594	$222,313,505	$212,345,696	$401,237,290	$434,659,201	$33,421,911	8.3%	0.85	0.86
5	3C Firm Sales	$57,697,369	$66,467,369	$91,335,671	$149,033,040	$157,803,040	$8,770,000	5.9%	1.17	1.17
6	3I Firm Sales	$1,362,237	$1,569,297	$2,539,121	$3,901,358	$4,108,418	$207,060	5.3%	1.48	1.48
7	31C Firm Sales	$15,322,004	$16,486,476	$36,661,818	$51,983,822	$53,148,294	$1,164,472	2.2%	2.11	1.97
8	31C Firm Trans	$81,269	$81,269		$81,269	$81,269	$0	0.0%	4.63	4.02
9	31C Interr Sales	$285,292	$285,292	$675,082	$960,374	$960,374	$0	0.0%	10.07	8.74
10	31I Firm Sales	$3,561,584	$3,561,584	$10,185,355	$13,746,939	$13,746,939	$0	0.0%	2.90	2.52
11	31I Firm Trans	$182,560	$182,560		$182,560	$182,560	$0	0.0%	5.14	4.46
12	31I Interr Sales	$75,970	$75,970	$151,737	$227,707	$227,707	$0	0.0%	2.78	2.41
13	32C Firm Sales	$2,060,560	$2,060,560	$6,848,855	$8,909,415	$8,909,415	$0	0.0%	1.87	1.63
14	32I Firm Sales	$2,056,408	$2,056,408	$6,988,666	$9,045,074	$9,045,074	$0	0.0%	5.69	4.94
15	32 Firm Trans	$3,945,752	$3,945,752		$3,945,752	$3,945,752	$0	0.0%	7.34	6.38
16	32C Interr Sales	$1,749,021	$1,749,021	$10,336,141	$12,085,162	$12,085,162	$0	0.0%	7.19	6.24
17	32I Interr Sales	$2,647,371	$2,647,371	$16,475,613	$19,122,984	$19,122,984	$0	0.0%	6.45	5.60
18	32 Interr Trans	$6,846,817	$6,846,817		$6,846,817	$6,846,817	$0	0.0%	4.98	4.32

NW Natural
Oregon Jurisdictional Rate Case
Increase in Revenue Requirement
Proof of Revenue - Phase-in Year 1

	Rate Schedule	Number of Customers (A)	Test Year Sales Volumes (B)	Test Year Demand Volumes (C)	Customer Charge (D)	Current Rates Volumetric Rate (E)	MDDV Rate (F)	Customer Charge Revenue (G)	Proof of Current Sales Revenue (H)	Demand Revenue (I)	Total Distribution Revenue (J)
Oregon Sales	**Residential 2**	538,601	349,920,397		$6.00	$0.42899		$38,779,242	$150,112,351		$188,891,594
	Residential 1	3,764	706,257		$5.00	$0.49735		$225,868	$351,257		$577,125
	Commercial - 3	56,653	150,510,301		$8.00	$0.34721		$5,438,687	$52,258,682		$57,697,369
	Commercial - 1	169	109,077		$5.00	$0.47553		$10,140	$51,869		$62,009
	31 CFS Block 1		24,749,352			$0.18533			$4,586,797		
	31 CFS Block 2		35,860,719			$0.16909			$6,063,689		
	Commercial - 31	1,198	60,610,071		$325.00			$4,671,518	$10,650,486		$15,322,004
	32 CFS Block 1		5,059,321			$0.10066			$509,271		
	32 CFS Block 2		4,834,146			$0.08555			$413,561		
	32 CFS Block 3		1,397,725			$0.06040			$84,423		
	32 CFS Block 4		172,093			$0.03524			$6,065		
	32 CFS Block 5		0			$0.02015			$0		
	32 CFS Block 6		0			$0.01007			$0		
	Commercial - 32	53	11,463,285	1,708,764	$675.00		0.36163	$429,300	$1,013,320	$617,940	$2,060,560
	Industrial - 3	285	4,184,174		$8.00	$0.31903		$27,360	$1,334,877		$1,362,237
	31 IFS Block 1		4,447,875			$0.16890			$751,246		
	31 IFS Block 2		12,665,213			$0.15261			$1,932,838		
	Industrial - 31	225	17,113,089		$325.00			$877,500	$2,684,084		$3,561,584
	32 IFS Block 1		4,284,027			$0.10103			$432,815		
	32 IFS Block 2		5,123,215			$0.08587			$439,930		
	32 IFS Block 3		2,033,143			$0.06063			$123,269		
	32 IFS Block 4		365,005			$0.03536			$12,907		
	32 IFS Block 5		0			$0.02021			$0		
	32 IFS Block 6		0			$0.01014			$0		
	Industrial - 32	45	11,805,390	1,888,634	$675.00		0.36163	$364,500	$1,008,922	$682,987	$2,056,408
	31 IIS Block 1		58,763			$0.17099			$10,048		
	31 IIS Block 2		249,948			$0.15452			$38,622		
	Interruptible - 31	7	308,711		$325.00			$27,300	$48,670		$75,970
	31 CIS Block 1		228,881			$0.18731			$42,872		
	31 CIS Block 2		1,144,578			$0.17091			$195,620		
	Comm - 31	12	1,373,459		$325.00			$46,800	$238,492		$285,292
	32 IIS Block 1		6,799,312			$0.10049			$683,263		
	32 IIS Block 2		8,656,598			$0.08542			$739,447		
	32 IIS Block 3		4,763,986			$0.06030			$287,268		
	32 IIS Block 4		8,983,218			$0.03518			$316,030		
	32 IIS Block 5		4,316,607			$0.02010			$86,764		
	32 IIS Block 6		0			$0.01006			$0		
	Interruptible - 32	66	33,519,721		$675.00			$534,600	$2,112,771		$2,647,371
	32 CIS Block 1		4,180,367			$0.10088			$421,715		
	32 CIS Block 2		5,441,419			$0.08575			$466,602		
	32 CIS Block 3		3,043,549			$0.06053			$184,226		
	32 CIS Block 4		5,715,124			$0.03532			$201,858		
	32 CIS Block 5		2,648,468			$0.02017			$53,420		
	32 CIS Block 6		0			$0.01011			$0		
	Comm. - 32	52	21,028,927		$675.00			$421,200	$1,327,821		$1,749,021

NW Natural
Oregon Jurisdictional Rate Case
Increase in Revenue Requirement
Proof of Revenue - Phase-in Year 1

	Rate Schedule	Number of Customers	Test Year Sales Volumes	Test Year Demand Volumes	Customer Charge	Current Rates Volumetric Rate	MDDV Rate	Customer Charge Revenue	Proof of Current Sales Revenue	Proof of Current Demand Revenue	Total Distribution Revenue
Transp	**32 CFT Block 1**		0			$0.09991			$0		
	32 CFT Block 2		0			$0.08490			$0		
	32 CFT Block 3		0			$0.05996			$0		
	32 CFT Block 4		0			$0.03498			$0		
	32 CFT Block 5		0			$0.01999			$0		
	32 CFT Block 6		0			$0.01002			$0		
	Commercial - 32	0	0		$925.00		0.15748	$0	$0	$0	$0
	31 IFT Block 1		97,558			$0.16816			$16,405		
	31 IFT Block 2		730,157			$0.15196			$110,955		
	Industrial Firm - 31	8	827,715		$575.00			$55,200	$127,360		$182,560
	31 CFT Block 1		44,572			$0.18429			$8,214		
	31 CFT Block 2		188,242			$0.16816			$31,655		
	Comm. Firm - 31	6	232,814		$575.00			$41,400	$39,869		$81,269
	32 IFT Block 1		6,123,208			$0.09991			$611,770		
	32 IFT Block 2		9,627,749			$0.08490			$817,396		
	32 IFT Block 3		6,499,238			$0.05996			$389,694		
	32 IFT Block 4		13,339,852			$0.03498			$466,628		
	32 IFT Block 5		20,577,047			$0.01999			$411,335		
	32 IFT Block 6		3,129,647			$0.01002			$31,359		
	Industrial Firm - 32	65	59,296,740	3,150,048	$925.00		0.15748	$721,500	$2,728,182	$496,070	$3,945,752
	32 IIT Block 1		8,025,070			$0.10011			$803,390		
	32 IIT Block 2		13,347,959			$0.08509			$1,135,778		
	32 IIT Block 3		10,296,468			$0.06008			$618,612		
	32 IIT Block 4		32,663,184			$0.03505			$1,144,845		
	32 IIT Block 5		65,455,540			$0.02003			$1,311,074		
	32 IIT Block 6		84,185,134			$0.01004			$845,219		
	Interruptible - 32	89	213,973,355		$925.00			$987,900	$5,858,917		$6,846,817
	Special Contracts FIRM										
	Special Contracts INTERRUPTIBLE										
	Sales Total	601,130	662,652,859	3,597,398				$51,854,015	$223,193,602	$1,300,927	$276,348,544
	Transport Total	168	274,330,624	3,150,048				$1,806,000	$8,754,328	$496,070	$11,056,398
								$53,660,015	$231,947,930	$1,796,997	$287,404,942

NW Natural
Oregon Jurisdictional Rate Case
Increase in Revenue Requirement
Proof of Revenue - Phase-in Year 1

						Proposed Rates			Proof of Revenue				
	Rate Schedule	Number of Customers (A)	Test Year Sales Volumes (B)	Test Year Demand Volumes (C)	Customer Charge (L)	Volumetric Rate (M)	MDDV Rate (N)	Customer Charge Revenue (O)	Sales Revenue (P)	Demand Revenue (Q)	Total Distribution Revenue (R)	Revenue Increase (S)	Percentage Increase (T)
Oregon Sales	**Residential 2**	538,601	349,920,397		$13.70	$0.38228		$88,545,937	$133,767,570		$222,313,506	$33,421,912	17.69%
	Residential 1	3,764	706,257		$8.19	$0.44857		$369,971	$316,806		$686,777	$109,652	19.00%
	Commercial - 3	56,653	150,510,301		$15.00	$0.37386		$10,197,539	$56,269,781		$66,467,320	$8,769,951	15.20%
	Commercial - 1	169	109,077		$13.62	$0.39972		$27,621	$43,600		$71,222	$9,212	14.86%
	31 CFS Block 1		24,749,352			$0.22185			$5,490,644				
	31 CFS Block 2		35,860,719			$0.20241			$7,258,568				
	Commercial - 31	1,198	60,610,071		$260.00			$3,737,214	$12,749,212		$16,486,426	$1,164,422	7.60%
	32 CFS Block 1		5,059,321			$0.10066			$509,271				
	32 CFS Block 2		4,834,146			$0.08555			$413,561				
	32 CFS Block 3		1,397,725			$0.06040			$84,423				
	32 CFS Block 4		172,093			$0.03524			$6,065				
	32 CFS Block 5		0			$0.02015			$0				
	32 CFS Block 6		0			$0.01007			$0				
	Commercial - 32	53	11,463,285	1,708,764	$675.00		$0.36163	$429,300	$1,013,320	$617,940	$2,060,560	$0	0.00%
	Industrial - 3	285	4,184,174		$15.00	$0.36279		$51,300	$1,517,977		$1,569,277	$207,039	15.20%
	31 IFS Block 1		4,447,875			$0.17994			$800,351				
	31 IFS Block 2		12,665,213			$0.16259			$2,059,237				
	Industrial - 31	225	17,113,089		$260.00			$702,000	$2,859,588		$3,561,588	$3	0.00%
	32 IFS Block 1		4,284,027			$0.10103			$432,815				
	32 IFS Block 2		5,123,215			$0.08587			$439,930				
	32 IFS Block 3		2,033,143			$0.06063			$123,269				
	32 IFS Block 4		365,005			$0.03536			$12,907				
	32 IFS Block 5		0			$0.02021			$0				
	32 IFS Block 6		0			$0.01014			$0				
	Industrial - 32	45	11,805,390	1,888,634	$675.00		$0.36163	$364,500	$1,008,922	$682,987	$2,056,408	$0	0.00%
	31 IIS Block 1		58,763			$0.19017			$11,175				
	31 IIS Block 2		249,948			$0.17185			$42,954				
	Interruptible - 31	7	308,711		$260.00			$21,840	$54,129		$75,969	-$1	0.00%
	31 CIS Block 1		228,881			$0.19466			$44,554				
	31 CIS Block 2		1,144,578			$0.17762			$203,300				
	Comm - 31	12	1,373,459		$260.00			$37,440	$247,854		$285,294	$2	0.00%
	32 IIS Block 1		6,799,312			$0.10049			$683,263				
	32 IIS Block 2		8,656,598			$0.08542			$739,447				
	32 IIS Block 3		4,763,986			$0.06030			$287,268				
	32 IIS Block 4		8,983,218			$0.03518			$316,030				
	32 IIS Block 5		4,316,607			$0.02010			$86,764				
	32 IIS Block 6		0			$0.01006			$0				
	Interruptible - 32	66	33,519,721		$675.00			$534,600	$2,112,771		$2,647,371	$0	0.00%
	32 CIS Block 1		4,180,367			$0.10088			$421,715				
	32 CIS Block 2		5,441,419			$0.08575			$466,602				
	32 CIS Block 3		3,043,549			$0.06053			$184,226				
	32 CIS Block 4		5,715,124			$0.03532			$201,858				
	32 CIS Block 5		2,648,468			$0.02017			$53,420				
	32 CIS Block 6		0			$0.01011			$0				
	Comm. - 32	52	21,028,927		$675.00			$421,200	$1,327,821		$1,749,021	$0	0.00%

NW Natural
Oregon Jurisdictional Rate Case
Increase in Revenue Requirement
Proof of Revenue - Phase-in Year 1

	Rate Schedule	Number of Customers	Test Year Sales Volumes	Test Year Demand Volumes	Customer Charge	Proposed Rates Volumetric Rate	MDDV Rate	Customer Charge Revenue	Proof of Revenue Sales Revenue	Proof of Revenue Demand Revenue	Total Distribution Revenue	Revenue Increase	Percentage Increase
Transp	**32 CFT Block 1**		0			$0.09991			$0				
	32 CFT Block 2		0			$0.08490			$0				
	32 CFT Block 3		0			$0.05996			$0				
	32 CFT Block 4		0			$0.03498			$0				
	32 CFT Block 5		0			$0.01999			$0				
	32 CFT Block 6		0			$0.01002			$0				
	Commercial - 32	0	0					$0	$0		$0	$0	
	31 IFT Block 1		97,558			$0.16816			$16,405				
	31 IFT Block 2		730,157			$0.15196			$110,955				
	Industrial Firm - 31	8	827,715		$575.00			$55,200	$127,360		$182,560	$0	0.00%
	31 CFT Block 1		44,572			$0.20592			$9,178				
	31 CFT Block 2		188,242			$0.18790			$35,371				
	Comm. Firm - 31	6	232,814		$510.00			$36,720	$44,549		$81,269	$0	0.00%
	32 IFT Block 1		6,123,208			$0.09991			$611,770				
	32 IFT Block 2		9,627,749			$0.08490			$817,396				
	32 IFT Block 3		6,499,238			$0.05996			$389,694				
	32 IFT Block 4		13,339,852			$0.03498			$466,628				
	32 IFT Block 5		20,577,047			$0.01999			$411,335				
	32 IFT Block 6		3,129,647			$0.01002			$31,359				
	Industrial Firm - 32	65	59,296,740	3,150,048	$925.00		$0.15748	$721,500	$2,728,182	$496,070	$3,945,752	$0	0.00%
	32 IIT Block 1		8,025,070			$0.09181			$736,782				
	32 IIT Block 2		13,347,959			$0.07803			$1,041,541				
	32 IIT Block 3		10,296,468			$0.05510			$567,335				
	32 IIT Block 4		32,663,184			$0.03214			$1,049,795				
	32 IIT Block 5		65,455,540			$0.01837			$1,202,418				
	32 IIT Block 6		84,185,134			$0.00921			$775,345				
	Interruptible - 32	89	213,973,355		$1,380.00			$1,473,840	$5,373,216		$6,847,056	$239	0.00%
	Special Contracts FIRM												
	Special Contracts INTERRUPTIBLE												
	Sales Total	601,130	662,652,859	3,597,398				$105,440,462	$213,289,349	$1,300,927	$320,030,738	$43,682,194	
	Transport Total	168	274,330,624	3,150,048				$2,287,260	$8,273,307	$496,070	$11,056,637	$239	
								$107,727,722	$221,562,656	$1,796,997	$331,087,375	$43,682,433	

NW Natural
Oregon Jurisdictional Rate Case
Increase in Revenue Requirement
Proof of Revenue - Phase-in Year 2

						Current Rates			Proof of Current		
	Rate Schedule	Number of Customers	Test Year Sales Volumes	Test Year Demand Volumes	Customer Charge	Volumetric Rate	MDDV Rate	Customer Charge Revenue	Sales Revenue	Demand Revenue	Total Distribution Revenue
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Oregon **Sales**	**Residential 2**	538,601	349,920,397		$6.00	$0.42899		$38,779,242	$150,112,351		$188,891,594
	Residential 1	3,764	706,257		$5.00	$0.49735		$225,868	$351,257		$577,125
	Commercial - 1	169	109,077		$5.00	$0.47553		$10,140	$51,869		$62,009

NW Natural
Oregon Jurisdictional Rate Case
Increase in Revenue Requirement
Proof of Revenue - Phase-in Year 2

	Rate Schedule	Number of Customers	Test Year Sales Volumes	Test Year Demand Volumes	Proposed Rates Customer Charge	Proposed Rates Volumetric Rate	MDDV Rate	Customer Charge Revenue	Proof of Revenue Sales Revenue	Proof of Revenue Demand Revenue	Total Distribution Revenue	Revenue Increase	Percentage Increase
		(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)
Oregon Sales	**Residential 2**	538,601	349,920,397		$21.39	$0.24024		$138,247,999	$84,064,876		$222,312,875	$33,421,281	17.69%
	Residential 1	3,764	706,257		$11.38	$0.24453		$514,075	$172,701		$686,776	$109,651	19.00%
	Commercial - 1	169	109,077		$22.25	$0.23927		$45,123	$26,099		$71,222	$9,213	14.86%

NW Natural
Oregon Jurisdictional Rate Case
Increase in Revenue Requirement
Proof of Revenue - Phase-in Year 3

						Current Rates			Proof of Current		
	Rate Schedule	Number of Customers (A)	Test Year Sales Volumes (B)	Test Year Demand Volumes (C)	Customer Charge (D)	Volumetric Rate (E)	MDDV Rate (F)	Customer Charge Revenue (G)	Sales Revenue (H)	Demand Revenue (I)	Total Distribution Revenue (J)
Oregon Sales	**Residential 2**	538,601	349,920,397		$6.00	$0.42899		$38,779,242	$150,112,351		$188,891,594
	Residential 1	3,764	706,257		$5.00	$0.49735		$225,868	$351,257		$577,125
	Commercial - 1	169	109,077		$5.00	$0.47553		$10,140	$51,869		$62,009

NW Natural
Oregon Jurisdictional Rate Case
Increase in Revenue Requirement
Proof of Revenue - Phase-in Year 3

					Proposed Rates				Proof of Revenue					
	Rate Schedule	Number of Customers (A)	Test Year Sales Volumes (B)	Test Year Demand Volumes (C)	Customer Charge (L)	Volumetric Rate (M)	MDDV Rate (N)	Customer Charge Revenue (O)	Sales Revenue (P)	Demand Revenue (Q)	Total Distribution Revenue (R)	Revenue Increase (S)	Percentage Increase (T)
Oregon Sales	**Residential 2**	538,601	349,920,397		$29.09	$0.09802		$188,014,693	$34,299,197		$222,313,890	$33,422,297	17.69%
	Residential 1	3,764	706,257		$11.65	$0.22726		$526,272	$160,504		$686,776	$109,651	19.00%
	Commercial - 1	169	109,077		$24.70	$0.19372		$50,092	$21,130		$71,222	$9,213	14.86%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
With Phase-In by Year

Line No.	Month	Volume Therms	Cust	Therms	Revenues at Present Rates	Phase-In Yr 1: Revenues at Proposed Rates	Phase-In Yr 1: Difference $	Phase-In Yr 1: Difference %	Phase-In Yr 2: Revenues at Proposed Rates	Phase-In Yr 2: Difference $	Phase-In Yr 2: Difference %	Phase-In Yr 3: Revenues at Proposed Rates	Phase-In Yr 3: Difference $	Phase-In Yr 3: Difference %
				(A)	(B)	(C)	(D) (c-b)	(E) (d/b)	(F)	(G) (f-c)	(H) (g/c)	(I)	(J) (I-f)	(K) (j/f)
						Rate Schedule 1R			Rate Schedule 1R			Rate Schedule 1R		
1	November	80,700	3,764	21.44	$28.67	$30.82	$2.14	7.48%	$29.63	-$1.18	-3.84%	$29.53	-$0.10	-0.34%
2	December	107,057	3,764	28.44	$36.40	$38.20	$1.80	4.95%	$35.59	-$2.61	-6.84%	$35.37	-$0.22	-0.62%
3	January	102,161	3,764	27.14	$34.97	$36.83	$1.87	5.34%	$34.48	-$2.35	-6.37%	$34.29	-$0.20	-0.58%
4	February	82,151	3,764	21.82	$29.10	$31.22	$2.13	7.30%	$29.96	-$1.26	-4.04%	$29.85	-$0.11	-0.36%
5	March	73,957	3,764	19.65	$26.69	$28.92	$2.23	8.36%	$28.11	-$0.82	-2.83%	$28.04	-$0.07	-0.25%
6	April	53,303	3,764	14.16	$20.63	$23.13	$2.50	12.11%	$23.44	$0.30	1.30%	$23.46	$0.03	0.11%
7	May	34,325	3,764	9.12	$15.07	$17.81	$2.75	18.22%	$19.14	$1.33	7.46%	$19.26	$0.11	0.59%
8	June	24,849	3,764	6.60	$12.29	$15.16	$2.87	23.34%	$17.00	$1.84	12.16%	$17.16	$0.16	0.92%
9	July	28,421	3,764	7.55	$13.34	$16.16	$2.82	21.16%	$17.81	$1.65	10.21%	$17.95	$0.14	0.78%
10	August	28,752	3,764	7.64	$13.43	$16.25	$2.82	20.97%	$17.88	$1.63	10.04%	$18.02	$0.14	0.77%
11	September	33,642	3,764	8.94	$14.87	$17.62	$2.75	18.52%	$18.99	$1.37	7.75%	$19.10	$0.12	0.61%
12	October	56,938	3,764	15.13	$21.70	$24.15	$2.45	11.30%	$24.26	$0.10	0.43%	$24.27	$0.01	0.04%
13														
14	Total	706,257		187.61	$267.16	$296.29	$29.13	10.90%	$296.29	$0.00	0.00%	$296.29	$0.00	0.00%

*Note: Assumes an Average Costs of Gas of $0.60684 per Therm

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
With Phase-In by Year

Line No.	Month	Volume Therms	Cust	Therms	Revenues at Present Rates	Phase-In Yr 1: Revenues at Proposed Rates	Phase-In Yr 1: Difference $	Phase-In Yr 1: Difference %	Phase-In Yr 2: Revenues at Proposed Rates	Phase-In Yr 2: Difference $	Phase-In Yr 2: Difference %	Phase-In Yr 3: Revenues at Proposed Rates	Phase-In Yr 3: Difference $	Phase-In Yr 3: Difference %
				(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
							(c-b)	**(d/b)**		**(f-c)**	**(g/c)**		**(I-f)**	**(j/f)**
							Rate Schedule 1C			**Rate Schedule 1C**			**Rate Schedule 1C**	
15	November	15,871	169	93.91	$106.65	$108.15	$1.50	1.41%	$101.71	-$6.44	-5.95%	$99.88	-$1.83	-1.80%
16	December	20,426	169	120.86	$135.82	$135.28	-$0.54	-0.40%	$124.51	-$10.76	-7.96%	$121.46	-$3.06	-2.45%
17	January	17,252	169	102.08	$115.49	$116.37	$0.88	0.76%	$108.62	-$7.75	-6.66%	$106.42	-$2.20	-2.03%
18	February	13,210	169	78.17	$89.60	$92.30	$2.69	3.01%	$88.39	-$3.91	-4.24%	$87.28	-$1.11	-1.26%
19	March	11,251	169	66.57	$77.06	$80.63	$3.57	4.64%	$78.58	-$2.05	-2.54%	$77.99	-$0.58	-0.74%
20	April	6,994	169	41.38	$49.79	$55.28	$5.48	11.01%	$57.27	$1.99	3.60%	$57.83	$0.56	0.99%
21	May	4,338	169	25.67	$32.79	$39.46	$6.67	20.36%	$43.97	$4.51	11.43%	$45.25	$1.28	2.91%
22	June	3,450	169	20.42	$27.10	$34.17	$7.07	26.10%	$39.52	$5.35	15.67%	$41.04	$1.52	3.85%
23	July	3,990	169	23.61	$30.55	$37.38	$6.83	22.36%	$42.22	$4.84	12.95%	$43.60	$1.37	3.26%
24	August	4,230	169	25.03	$32.09	$38.82	$6.72	20.95%	$43.43	$4.61	11.89%	$44.74	$1.31	3.02%
25	September	4,738	169	28.04	$35.35	$41.84	$6.49	18.37%	$45.97	$4.13	9.87%	$47.14	$1.17	2.55%
26	October	3,326	169	19.68	$26.30	$33.43	$7.13	27.10%	$38.90	$5.47	16.37%	$40.46	$1.55	3.99%
27														
28	Total	109,077		645.42	$758.59	$813.10	$54.51	7.19%	$813.10	$0.00	0.00%	$813.10	$0.00	0.00%

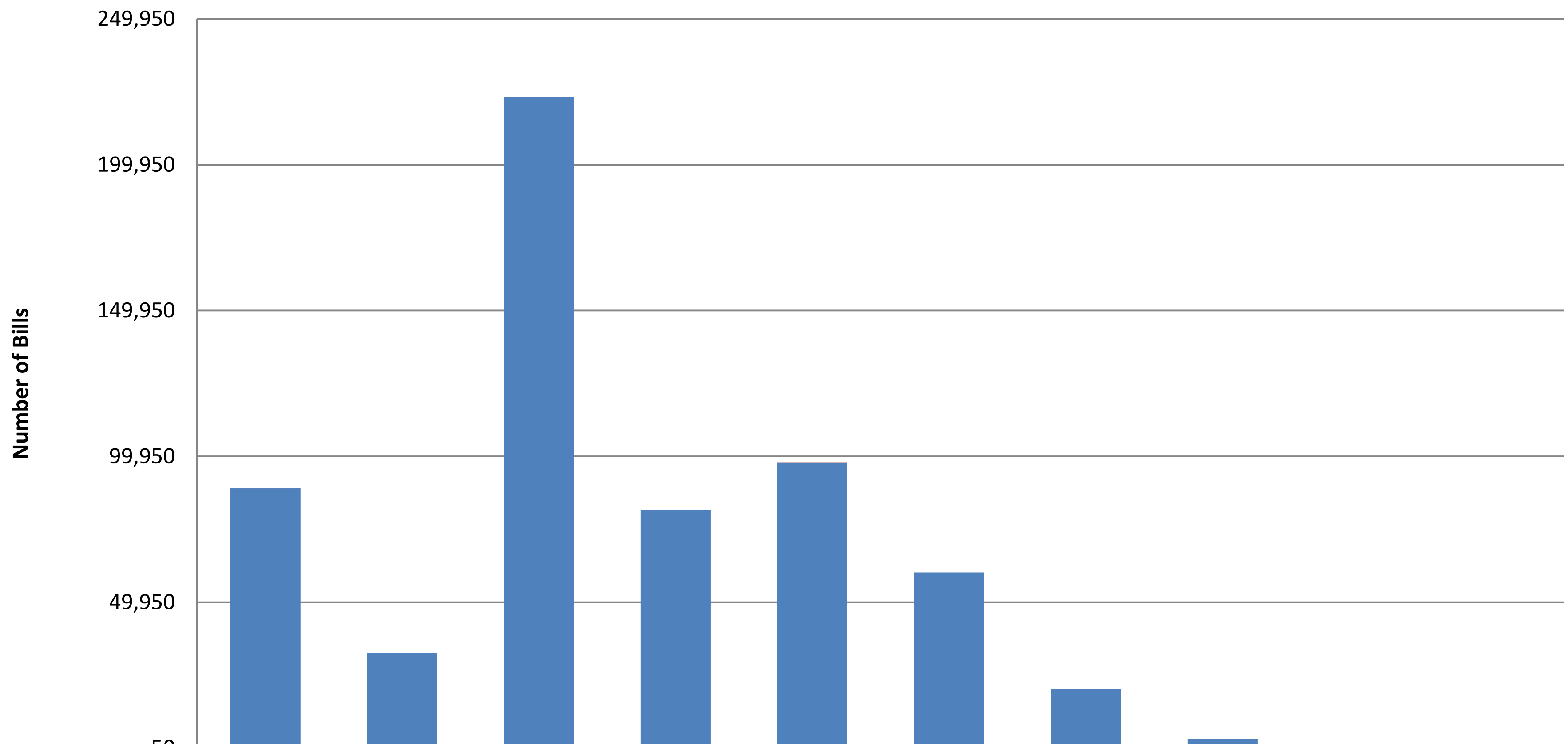
*Note: Assumes an Average Costs of Gas of $0.60684 per Therm

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
With Phase-In by Year

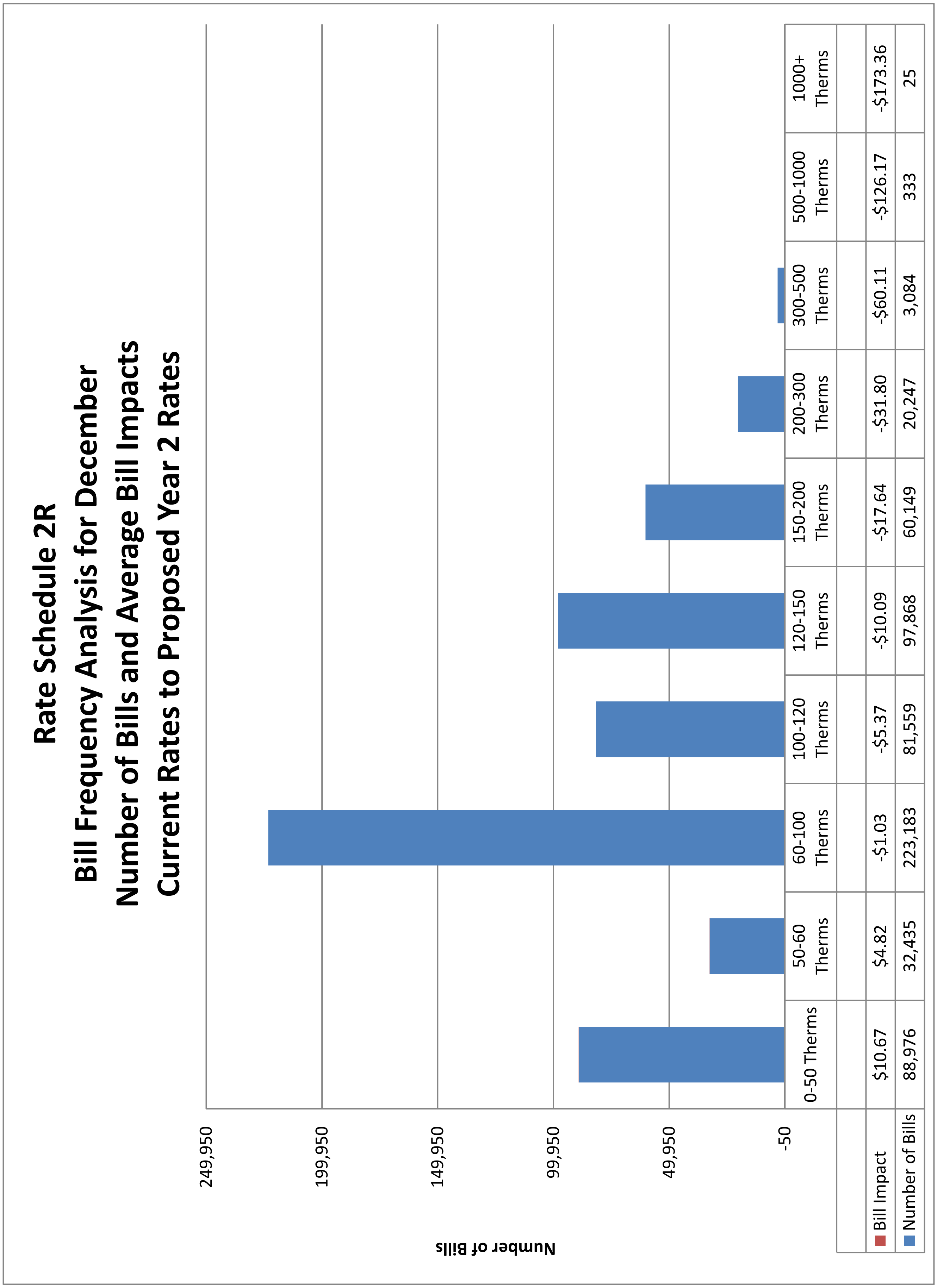
						Phase-In Yr 1			Phase-In Yr 2			Phase-In Yr 3		
Line No.	Month	Volume Therms	Cust	Therms	Revenues at Present Rates	Revenues at Proposed Rates	Difference $	Difference %	Revenues at Proposed Rates	Difference $	Difference %	Revenues at Proposed Rates	Difference $	Difference %
				(A)	(B)	(C)	(D) (c-b)	(E) (d/b)	(F)	(G) (f-c)	(H) (g/c)	(I)	(J) (I-f)	(K) (j/f)
						Rate Schedule 2R			Rate Schedule 2R			Rate Schedule 2R		
29	November	41,831,081	535,652	78.09	$86.89	$90.94	$4.05	4.66%	$87.54	-$3.40	-3.74%	$84.14	-$3.41	-3.89%
30	December	59,803,033	537,019	111.36	$121.35	$123.85	$2.50	2.06%	$115.72	-$8.13	-6.56%	$107.58	-$8.14	-7.03%
31	January	57,727,713	538,125	107.28	$117.12	$119.81	$2.69	2.30%	$112.26	-$7.55	-6.30%	$104.70	-$7.56	-6.73%
32	February	47,041,944	539,025	87.27	$96.40	$100.02	$3.62	3.76%	$95.32	-$4.71	-4.71%	$90.60	-$4.71	-4.94%
33	March	40,388,258	539,396	74.88	$83.56	$87.76	$4.20	5.03%	$84.82	-$2.95	-3.36%	$81.87	-$2.95	-3.48%
34	April	28,354,983	539,542	52.55	$60.44	$65.68	$5.25	8.68%	$65.91	$0.23	0.34%	$66.13	$0.23	0.34%
35	May	17,376,017	539,630	32.20	$39.35	$45.55	$6.20	15.74%	$48.67	$3.12	6.84%	$51.79	$3.12	6.41%
36	June	9,566,876	539,270	17.74	$24.38	$31.25	$6.87	28.19%	$36.42	$5.17	16.55%	$41.59	$5.18	14.22%
37	July	8,360,076	539,027	15.51	$22.07	$29.04	$6.98	31.61%	$34.53	$5.49	18.89%	$40.02	$5.49	15.91%
38	August	8,332,732	538,597	15.47	$22.03	$29.00	$6.98	31.68%	$34.50	$5.49	18.94%	$40.00	$5.50	15.94%
39	September	9,045,289	538,547	16.80	$23.40	$30.31	$6.92	29.56%	$35.62	$5.30	17.50%	$40.93	$5.31	14.91%
40	October	22,092,395	539,376	40.96	$48.43	$54.21	$5.79	11.95%	$56.09	$1.87	3.45%	$57.96	$1.87	3.34%
41														
42	Total	349,920,397		650.11	$745.40	$807.44	$62.03	8.32%	$807.37	-$0.06	-0.01%	$807.32	-$0.06	-0.01%

*Note: Assumes an Average Costs of Gas of $0.60684 per Therm

Rate Schedule 2R
Bill Frequency Analysis for December
Number of Bills and Average Bill Impacts
Current Rates to Proposed Year 1 Rates

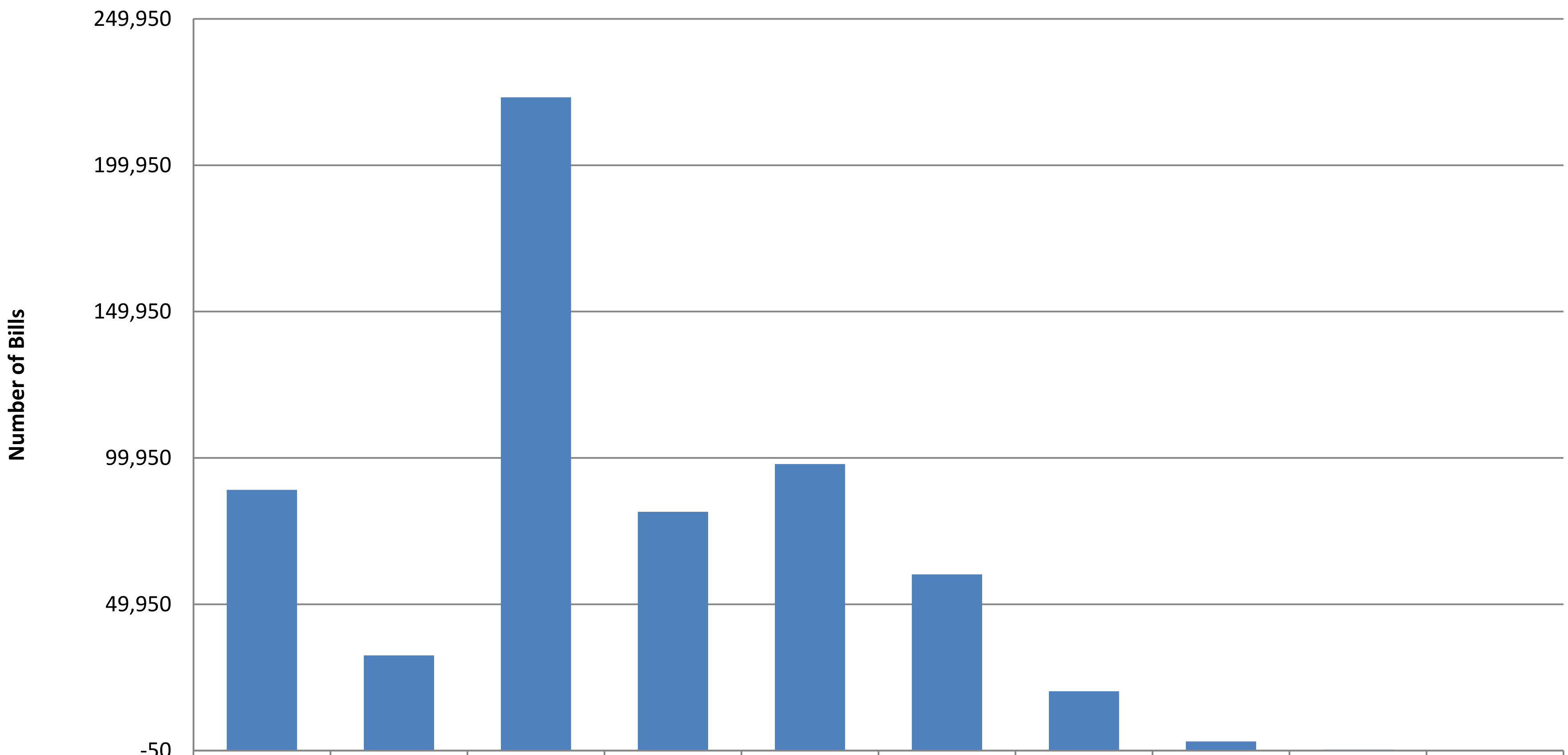


	0-50 Therms	50-60 Therms	60-100 Therms	100-120 Therms	120-150 Therms	150-200 Therms	200-300 Therms	300-500 Therms	500-1000 Therms	1000+ Therms
Bill Impact	$6.53	$5.08	$3.64	$2.56	$1.39	-$0.47	-$3.98	-$10.98	-$27.33	-$39.01
Number of Bills	88,976	32,435	223,183	81,559	97,868	60,149	20,247	3,084	333	25



	0-50 Therms	50-60 Therms	60-100 Therms	100-120 Therms	120-150 Therms	150-200 Therms	200-300 Therms	300-500 Therms	500-1000 Therms	1000+ Therms
Bill Impact	$10.67	$4.82	-$1.03	-$5.37	-$10.09	-$17.64	-$31.80	-$60.11	-$126.17	-$173.36
Number of Bills	88,976	32,435	223,183	81,559	97,868	60,149	20,247	3,084	333	25

Rate Schedule 2R
Bill Frequency Analysis for December
Number of Bills and Average Bill Impacts
Current Rates to Proposed Year 3 Rates



	0-50 Therms	50-60 Therms	60-100 Therms	100-120 Therms	120-150 Therms	150-200 Therms	200-300 Therms	300-500 Therms	500-1000 Therms	1000+ Therms
Bill Impact	$14.82	$4.56	-$5.70	-$13.32	-$21.59	-$34.83	-$59.65	-$109.30	-$225.14	-$307.88
Number of Bills	88,976	32,435	223,183	81,559	97,868	60,149	20,247	3,084	333	25

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 3C

Line No.		Therms (A)	Revenues at Present Rates (B)	Revenues at Proposed Rates (C)	Difference $ (D) (c-b)	Difference % (E) (d/b)
1	Number of Customers	56,653				
2	Annual Volumes	150,510,301				
3	MDDV					
4	50 Percent of Average Monthly Volume	111	$113.61	$123.56	$9.95	8.76%
5	Average Monthly Volume	221	$219.22	$232.12	$12.90	5.88%
6	150 Percent of Average Monthly Volume	332	$324.83	$340.68	$15.85	4.88%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 3I Firm Sales

Line No.		Therms	Revenues at Present Rates	Revenues at Proposed Rates	Difference $	Difference %
		(A)	(B)	(C)	(D) (c-b)	(E) (d/b)
1	Number of Customers	285				
2	Annual Volumes	4,184,174				
3	MDDV					
4	50 Percent of Average Monthly Volume	612	$574.37	$608.14	$33.77	5.88%
5	Average Monthly Volume	1,223	$1,140.75	$1,201.29	$60.54	5.31%
6	150 Percent of Average Monthly Volume	1,835	$1,707.12	$1,794.43	$87.31	5.11%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 31C Firm Sales

Line No.		Therms	Revenues at Present Rates	Revenues at Proposed Rates	Difference $	Difference %
		(A)	(B)	(C)	(D) (c-b)	(E) (d/b)
1	Number of Customers	1,198				
2	Annual Volumes	60,610,071				
3	MDDV					
4	50 Percent of Average Monthly Volume	2,108	$1,993.40	$2,005.05	$11.65	0.58%
5	Average Monthly Volume	4,217	$3,629.32	$3,711.22	$81.90	2.26%
6	150 Percent of Average Monthly Volume	6,325	$5,265.25	$5,417.40	$152.15	2.89%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 31C Firm Trans

Line No.		Therms	Revenues at Present Rates	Revenues at Proposed Rates	Difference $	Difference %
		(A)	(B)	(C)	(D) (c-b)	(E) (d/b)
1	Number of Customers	6				
2	Annual Volumes	232,814				
3	MDDV					
4	50 Percent of Average Monthly Volume	1,617	$872.95	$842.92	($30.03)	-3.44%
5	Average Monthly Volume	3,234	$1,151.01	$1,153.62	$2.61	0.23%
6	150 Percent of Average Monthly Volume	4,850	$1,422.89	$1,457.41	$34.52	2.43%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 31C Interruptible Sales

Line No.		Therms	Revenues at Present Rates	Revenues at Proposed Rates	Difference $	Difference %
		(A)	(B)	(C)	(D) (c-b)	(E) (d/b)
1	Number of Customers	12				
2	Annual Volumes	1,373,459				
3	MDDV					
4	50 Percent of Average Monthly Volume	4,769	$3,516.90	$3,485.18	($31.72)	-0.90%
5	Average Monthly Volume	9,538	$6,676.00	$6,676.28	$0.28	0.00%
6	150 Percent of Average Monthly Volume	14,307	$9,835.10	$9,867.38	$32.28	0.33%

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Bill Comparison with Gas Costs
Rate Schedule 31I Firm Sales

Line No.		Therms	Revenues at Present Rates	Revenues at Proposed Rates	Difference $	Difference %
		(A)	(B)	(C)	(D) (c-b)	(E) (d/b)
1	Number of Customers	225				
2	Annual Volumes	17,113,089				
3	MDDV					
4	50 Percent of Average Monthly Volume	3,169	$2,764.35	$2,733.09	($31.25)	-1.13%
5	Average Monthly Volume	6,338	$5,171.11	$5,171.49	$0.38	0.01%
6	150 Percent of Average Monthly Volume	9,507	$7,577.88	$7,609.88	$32.00	0.42%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 31I Firm Trans

Line No.		Therms (A)	Revenues at Present Rates (B)	Revenues at Proposed Rates (C)	Difference $ (D) (c-b)	Difference % (E) (d/b)
1	Number of Customers	8				
2	Annual Volumes	827,715				
3	MDDV					
4	50 Percent of Average Monthly Volume	4,311	$1,262.50	$1,262.50	$0.00	0.00%
5	Average Monthly Volume	8,622	$1,917.60	$1,917.60	$0.00	0.00%
6	150 Percent of Average Monthly Volume	12,933	$2,572.71	$2,572.71	$0.00	0.00%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 31I Interruptible Sales

Line No.		Therms (A)	Revenues at Present Rates (B)	Revenues at Proposed Rates (C)	Difference $ (D) (c-b)	Difference % (E) (d/b)
1	Number of Customers	7				
2	Annual Volumes	308,711				
3	MDDV					
4	50 Percent of Average Monthly Volume	1,838	$1,542.41	$1,512.65	($29.76)	-1.93%
5	Average Monthly Volume	3,675	$2,732.22	$2,734.61	$2.39	0.09%
6	150 Percent of Average Monthly Volume	5,513	$3,919.37	$3,953.60	$34.24	0.87%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 32 C Firm Sales

Line No.		Therms	Revenues at Present Rates	Revenues at Proposed Rates	Difference $	Difference %
		(A)	(B)	(C)	(D) (c-b)	(E) (d/b)
1	Number of Customers	53				
2	Annual Volumes	11,463,285				
3	MDDV	142,397				
4	50 Percent of Average Monthly Volume	9,012	$2,067.95	$2,067.95	$0.00	0.00%
5	Average Monthly Volume	18,024	$14,277.36	$14,277.36	$0.00	0.00%
6	150 Percent of Average Monthly Volume	27,036	$21,003.00	$21,003.00	$0.00	0.00%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 32I Firm Sales

Line No.		Therms	Revenues at Present Rates	Revenues at Proposed Rates	Difference $	Difference %
		(A)	(B)	(C)	(D) (c-b)	(E) (d/b)
1	Number of Customers	45				
2	Annual Volumes	11,805,390				
3	MDDV	157,386				
4	50 Percent of Average Monthly Volume	10,931	$9,030.95	$9,030.95	$0.00	0.00%
5	Average Monthly Volume	21,862	$17,235.30	$17,235.30	$0.00	0.00%
6	150 Percent of Average Monthly Volume	32,793	$25,369.16	$25,369.16	$0.00	0.00%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 32I Firm Trans

Line No.		Therms	Revenues at Present Rates	Revenues at Proposed Rates	Difference $	Difference %
		(A)	(B)	(C)	(D) (c-b)	(E) (d/b)
1	Number of Customers	65				
2	Annual Volumes	59,296,740				
3	MDDV	3,150,048				
4	50 Percent of Average Monthly Volume	456,129	$18,254.73	$18,254.73	$0.00	0.00%
5	Average Monthly Volume	912,258	$29,570.96	$29,570.96	$0.00	0.00%
6	150 Percent of Average Monthly Volume	1,368,386	$37,957.29	$37,957.29	$0.00	0.00%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 32C Interruptible Sales

Line No.		Therms (A)	Revenues at Present Rates (B)	Revenues at Proposed Rates (C)	Difference $ (D) (c-b)	Difference % (E) (d/b)
1	Number of Customers	52				
2	Annual Volumes	21,028,927				
3	MDDV					
4	50 Percent of Average Monthly Volume	202,201	$108,580.24	$108,580.24	$0.00	0.00%
5	Average Monthly Volume	404,402	$212,044.59	$212,044.59	$0.00	0.00%
6	150 Percent of Average Monthly Volume	606,604	$315,508.93	$315,508.93	$0.00	0.00%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 32I Interruptible Sales

Line No.		Therms	Revenues at Present Rates	Revenues at Proposed Rates	Difference $	Difference %
		(A)	(B)	(C)	(D) (c-b)	(E) (d/b)
1	Number of Customers	66				
2	Annual Volumes	33,519,721				
3	MDDV					
4	50 Percent of Average Monthly Volume	253,937	$135,016.69	$135,016.69	$0.00	0.00%
5	Average Monthly Volume	507,875	$264,936.09	$264,936.09	$0.00	0.00%
6	150 Percent of Average Monthly Volume	761,812	$394,736.89	$394,736.89	$0.00	0.00%

NW Natural
Oregon Jurisdictional Rate Case
Bill Comparison with Gas Costs
Rate Schedule 32 Interr Trans

Line No.		Therms	Revenues at Present Rates	Revenues at Proposed Rates	Difference $	Difference %
		(A)	(B)	(C)	(D) (c-b)	(E) (d/b)
1	Number of Customers	89				
2	Annual Volumes	213,973,355				
3	MDDV					
4	50 Percent of Average Monthly Volume	100,175	$6,588.13	$6,573.32	($14.81)	-0.22%
5	Average Monthly Volume	200,350	$9,343.00	$9,099.62	($243.38)	-2.60%
6	150 Percent of Average Monthly Volume	300,524	$11,349.50	$10,939.83	($409.67)	-3.61%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Natasha Siores

RATE ADJUSTMENT MECHANISMS
EXHIBIT 1200

December 2011

EXHIBIT 1200 – DIRECT TESTIMONY– RATE ADJUSTMENT MECHANISMS

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NW NATURAL
220 N.W. Second Avenue
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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 Natasha Siores. I am Revenue Requirements and Regulatory Consultant in the Rates and Regulatory Affairs department of NW Natural. I have worked at NW Natural since November 2003. My responsibilities include regulatory accounting, pricing, development of regulatory reports and rate filings, research relevant to gas rates and regulatory mechanisms, and analysis of revenue requirement, cost of service, and rate base issues.

Q. Please describe your education and employment background.

A. I earned my Bachelor of Science degree in Commerce (Accountancy, honors program) from DePaul University in Chicago in 1993 and am a Registered Certified Public Accountant in the state of Illinois. I have previously testified for the Company in a regulatory proceeding.

Prior to NW Natural, I spent ten years working for two subsidiaries of Nicor Inc., including accounting and forecasting positions at the local gas distribution company Nicor Gas in Naperville, Illinois, and the ocean transportation company Tropical Shipping in Riviera Beach, Florida.

Q. Please summarize your testimony.

A. In my testimony, I:

- Provide background on our Weather Adjusted Rate Mechanism (WARM) and decoupling mechanism;

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- Explain the impact of the Company's proposed rate design on WARM and decoupling for residential and commercial customers; and
- Propose modifications to the mechanisms.

II. DESCRIPTION OF WARM AND DECOUPLING MECHANISM

Q. Please describe the WARM mechanism.

A. WARM is a weather normalization mechanism that adjusts customers' bills in real time to mitigate increases and decreases that are caused by changes in usage attributable to colder- or warmer-than-normal weather. Only non-commodity costs are covered by WARM. Costs which are mostly fixed for the utility (that is, do not vary with usage), are recovered through a volumetric-based rate. WARM adjustments are made during the heating season, between December 1 and May 15. When weather is colder than normal during the billing period, billing rates are adjusted down and when weather is warmer than normal, billing rates are adjusted up. This means that customers' bills will not be as high for a colder-than-normal month, but also will not be as low for a warmer-than-normal month. While WARM is the default billing method for customers subject to WARM (Residential Rate Schedule 2 and Commercial Rate Schedule 3), participation is optional, and customers can elect to opt out of the method and not have WARM applied to their bills.

Q. Please explain the concept of decoupling.

A. The term decoupling, as it applies to utilities, is the concept of breaking the traditional link between a utility's commodity sales and its ability to recover fixed costs, thus removing the disincentive to promote conservation. When a portion of a utility's fixed

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costs are recovered through volumetric charges, lower consumption means that the utility does not recover its fixed costs. Decoupling provides a remedy for this dilemma by providing the utility the opportunity to recover its fixed costs even while encouraging customers to conserve and reduce their energy usage.

Q. Please describe the Company's decoupling mechanism.

A. The Company's decoupling mechanism employs a use-per-customer methodology, whereby adjustments are made that are intended to enable the Company to recover revenues from its customers sufficient to cover its fixed costs, based on an average therm use-per-customer established in the last rate case, Docket UG 152 ("2002 Rate Case"). This average use-per-customer is referred to as baseline usage.

The decoupling mechanism is made up of two adjustments: a monthly decoupling deferral and a price elasticity adjustment that is made whenever rates change. For the monthly decoupling deferral, the Company compares baseline usage volume and actual weather-normalized usage volume. The volume variance between baseline and actual weather-normalized usage is multiplied by the applicable margin rate per therm and is deferred for future refund or surcharge to customers in the next annual Purchased Gas Adjustment (PGA) filing. The price elasticity adjustment is made whenever rates change (usually during the PGA) in order to affect the baseline usage for the changes expected as a result of the change in price. When prices increase, baseline usage is expected to decline, and if prices decrease, baseline usage is expected to increase. In the elasticity adjustment, the Company adjusts the baseline usage upwards or downwards and takes the difference between the new baseline volumes and the old

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baseline volumes, multiplies by the applicable margin rate per therm, and adds or subtracts the result to or from base rates.

Q. How and when were NW Natural's WARM and decoupling mechanisms established?

A. The decoupling mechanism was first established in 2002, and was subsequently extended in 2005, and again in 2007. WARM was approved in 2003 and was extended with the decoupling mechanism in 2007. Both mechanisms will, under the terms of the stipulations that implemented them, expire on October 31, 2012.

When NW Natural's decoupling mechanism was adopted, NW Natural was among the first local gas distribution companies to have one. In comparison, today, decoupling tariffs have been approved for 47 gas utilities in 20 different states, covering 29 million residential gas customers.[1]

Under the original authorization of the Company's decoupling mechanism, the Company established public purpose charges to provide funding for low-income energy efficiency activities, low income bill payment assistance, and enhanced energy efficiency programs developed and administered by the Energy Trust of Oregon (ETO). In addition, the Company's conservation programs were turned over to the ETO.

Q. Have the WARM and decoupling mechanisms operated as intended?

[1] American Gas Association, "Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms" (July 2011) *available at* http://www.aga.org/our-issues/RatesRegulatoryIssues/ratesregpolicy/Documents/09-29-11%20Innovative%20Rates%20Current%20Status.pdf.

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A. Generally, the mechanisms have operated as expected and have provided the benefits expected to both customers and the Company. WARM was designed to mitigate the impact to customers of bill variability due to colder- and warmer-than-normal weather. Essentially WARM was designed to remove the "gamble" that actual weather would turn out to be the same as was assumed when designing rates. WARM has reduced bill variability for customers and the over- or under-collection of the Company's fixed costs that would otherwise have resulted due to variability in the weather.

Decoupling was designed to break the link between volumes (after being normalized for weather) and cost recovery in order to remove the disincentive to encouraging customers to conserve and reduce their use of natural gas. Decoupling has helped to recover the Company's fixed costs in a period of significant declines in use-per-customer and has benefitted customers through facilitating the funding of programs provided by the ETO. NW Natural believes that balancing the interests of customers and the Company in this way has been mutually beneficial.

Nonetheless, the Company believes that certain adjustments to the mechanisms, discussed below, would improve the mechanisms for both customers and the Company and provide a smooth transition period as we move to the proposed rate design for residential customers described in Russell Feingold's direct testimony.

Q. To date, how have WARM and decoupling affected the Company and customers?

A. Customers who remain in the WARM program have received overall bill refunds related to WARM in five of the nine heating seasons since WARM's inception, due to the way actual weather patterns have varied from normal weather. Table 1 below details the

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refunds or surcharges generated by WARM in each of the last nine calendar years. Over the long term, assuming no bias in the weather normalization adjustment used to set rates and no trend in weather patterns, we would expect the WARM refunds and surcharges to tend toward zero.

Table 1 – WARM refund/surcharge history

Calendar Year	WARM (Refund)/Surcharge ($ millions)
2003	1.8
2004	7.9
2005	(1.3)
2006	2.3
2007	(2.5)
2008	(15.3)
2009	(15.2)
2010	14.0
2011 (through June)	(10.6)
Total	(18.9)

Since the inception of the decoupling mechanism, the decoupling deferral recorded by the Company has increased, reflecting a significant decline in use-per-customer. During the 2003-2004 heating season, actual residential use-per-customer normalized for normal weather was 729 therms. During the 2010-2011 heating season, the annual actual normalized usage was 629 therms, a decrease of 13.7 percent from the 2003-2004 period. Commercial normalized usage has decreased eight percent,

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from 3,992 therms to 3,673 during that same time period. Historical weather normalized use per-customer is provided in Table 2.

Table 2 – History of weather normalized use-per-customer (in therms)

Heating Season	Residential	Commercial
2003-04	729.0	3,991.6
2004-05	686.1	3,808.1
2005-06	689.5	3,879.9
2006-07	670.9	3,863.3
2007-08	681.7	3,952.2
2008-09	630.7	3,698.1
2009-10	643.4	3,667.7
2010-11	629.1	3,672.9
Percent change	-13.7 percent	-8.0 percent

As a result of declining use-per-customer, customers have paid surcharges related to decoupling in seven of the nine heating seasons since the inception of the decoupling mechanism. Table 3 reflects the deferral amounts placed in rates during the PGA filings for each heating season.

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Table 3 – Decoupling refund/surcharge history

Deferral period	Recovery period	Decoupling (Refund)/Surcharge ($ millions)
2002-03	2003-04	3.6
2003-04	2004-05	2.2
2004-05	2005-06	6.2
2005-06	2006-07	(2.3)
2006-07	2007-08	0.9
2007-08	2008-09	(2.5)
2008-09	2009-10	12.1
2009-10	2010-11	16.8
2010-11	2011-12	19.7
Total		56.7

Public purpose charges to fund energy efficiency programs administered by the ETO have been charged to customers since the inception of the decoupling mechanism. Public purpose charges transferred to the ETO total $97.1 million from 2003 through August of 2011. These amounts are detailed in Table 4.

Table 4 – History of ETO-related public purpose charges

Calendar year	Transferred to the ETO ($ millions)
2003	4.5
2004	6.5
2005	7.8
2006	9.1
2007	9.5
2008	9.4
2009	14.0
2010	23.5
YTD Aug 2011	12.7
Total	97.1

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III. IMPACT OF PROPOSED RATE DESIGN ON WARM AND DECOUPLING MECHANISM

Q. What happens to WARM and the decoupling mechanism if the proposed rate design is adopted?

A. For residential customers, if the proposed rate design is adopted, both mechanisms would remain in place through the transition period with the modifications described below. Once transitioned, the proposed rate design takes the place of WARM and the decoupling mechanism for the residential customer class. For commercial customers on Rate Schedule 3 and Rate Schedule 31, WARM and the decoupling mechanism will remain in effect.

Q. What do you propose with respect to WARM and the decoupling mechanism if the proposed rate design is not adopted?

A. If the proposed rate design is not adopted, we would propose that both mechanisms remain in place, covering the same rate schedules they cover today. However, whether or not the proposed rate design is adopted, the modifications discussed below, which include changes to keep decoupling deferral balances from reaching high levels, should be made to the mechanisms.

Q. Does the proposed rate design change the Company's use of public purpose charges to provide funding to the ETO?

A. No. The Company will continue to employ public purpose charges to fund ETO programs as long as the final rate design adopted in this proceeding continues to

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remove the financial disincentive to the Company of encouraging increased energy efficiency for our customers.

IV. MODIFICATIONS TO WARM AND DECOUPLING MECHANISM

Q. What modifications to WARM and the decoupling mechanism is the Company proposing?

A. First, we propose that WARM incorporate certain updates that were developed in preparing this case. In particular, as part of the load forecast used to establish revenue requirement, we have updated normalized use-per-customer, normal heating degree days (HDDs) and statistical coefficients relating HDDs to therm usage. Please refer to the revenue requirement testimony that I co-sponsored with Kevin McVay for details regarding the load forecast development. These updates will be used by both mechanisms. The new normalized use-per-customer calculated for residential and commercial customers will become the new baselines for the decoupling mechanism. The WARM program will incorporate the new normal heating degree days by district. And both mechanisms will utilize the updated statistical coefficient that relates HDDs to therm usage.

Second, in addition to this update, the elasticity component of the decoupling mechanism should be removed. During the work performed to update the normal weather and HDDs used in this case, we determined that there was very little correlation between changes in price and resulting changes in usage. When prices went up, usage indeed went down, but when prices went down, usage still went down. Removal of the elasticity adjustment does not change the overall collection of costs from customers

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under the decoupling mechanism; it merely changes how much of the decoupling impact is recovered or refunded through the monthly deferral versus how much is recovered or refunded through the elasticity adjustment. Removing the elasticity component creates greater transparency, simplifies the decoupling calculation, and would be expected to reduce the size of the decoupling deferral.

Third, additional minor proposed changes to the mechanisms would be made, including the following:

1. Change the decoupling deferral period to November-October to coincide with the PGA tracker year. Currently the deferral period remains October-September, as established in the original mechanism. This change would simplify the accounting and deferral tracking and has no impact on the deferral calculations or deferral levels.
2. In the decoupling mechanism, for the month of May, usage will be normalized by the actual WARM effect attributable to May that is included in customer bills. This is consistent with the normalization calculation for November (the other shoulder month of the heating season), and also provides a simplified calculation and a better matching of weather observed in the WARM program with the weather assumed in the decoupling deferral calculation.

Fourth, we are proposing to remove the WARM opt-out provision. Removal of the opt-out provision would simplify WARM. The opt-out provision has been confusing for customers and added complexity for the Company in communicating with customers and assisting them with their opt-in status. WARM mitigates bill volatility for customers

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due to weather that is warmer- or colder-than-normal. Despite this benefit, over the past five years, an average of nine percent of WARM-eligible customers have elected to opt-out of the program, putting them at risk for bill volatility due to non-normal weather. Additionally, residential customers subject to WARM will ultimately transition to the new rate design. By transitioning all residential customers to the WARM program now, the long-term transition to the proposed rate design will be more gradual. Although commercial customers subject to WARM will not be moving to the new rate design in this proceeding, removal of the opt-out provision ensures that commercial Rate Schedule 3 customers will experience less bill volatility as a result of warmer- or colder-than-normal weather.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Robert Wyatt

ENVIRONMENTAL MITIGATION – PROGRAMS AND CURRENT STATUS EXHIBIT 1300

December 2011

EXHIBIT 1300 – DIRECT TESTIMONY – ENVIRONMENTAL MITIGATION – PROGRAMS AND CURRENT STATUS

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I. INTRODUCTION AND SUMMARY

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

A. My name is Robert J. Wyatt. I am Environmental Manager of NW Natural. I manage all aspects of environmental compliance at NW Natural's former manufactured gas plant (MGP) sites. I also serve as the Chairman of the Lower Willamette Group, which is described below.

Q. Please describe your educational and professional background.

A. I earned a Bachelor of Science degree in Geology in 1984 from Lafayette College in Easton, Pennsylvania. I studied hydrogeology at Temple University in Philadelphia, Pennsylvania from 1984 to 1986 and conducted additional graduate studies on coastal habitats at East Carolina University in North Carolina. I have been a Licensed and Registered Geologist in Oregon, North Carolina, Pennsylvania, Tennessee, Kentucky, and Georgia. In the mid-1980s, I began working as an environmental consultant focused primarily on Superfund and Resource Conservation and Recovery Act (RCRA) sites. I became Vice President of Front Royal Environmental Services, Inc. in 1989 and served as Senior Scientist and Principal in Charge for a number of large scale projects. I became Environmental Manager of NW Natural in 2000.

Q. Please summarize your testimony?

A. In my testimony, I:

- Provide background on the sites where the two MGPs operated by NW Natural's predecessor in interest were located and the contamination that resulted from their operation;

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- Describe the sites that are subject to environmental remediation, a.k.a. "clean-up," activities;
- Describe the statutory framework that governs environmental remediation and the specific state and federal agency actions taken at the sites pursuant to this statutory framework;
- Explain the process of environmental remediation;
- Describe the status of environmental remediation activities at the sites;
- Explain the costs incurred to date by NW Natural in its remediation efforts and discuss the uncertainties surrounding future costs; and
- Describe the actions NW Natural has taken to control the costs associated with environmental remediation.

Q. Are other witnesses providing testimony related to environmental remediation issues?

A. Yes. C. Alex Miller of NW Natural describes the Company's proposed regulatory treatment of the cleanup costs we have incurred and will continue to incur. Andrew Middleton, a national expert in MGP investigation and remediation, describes the history of MGPs in the United States, the normal and accepted practices related to the operation of those plants, and the prudence with which Portland Gas & Coke (PG&C), predecessor in interest to NW Natural, operated the MGP plants. Finally, Sandra K. Hart discusses the steps NW Natural has taken to recover the costs of environmental remediation from its insurance carriers.

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II. BACKGROUND

Q. Please describe the sources of contamination that led to the environmental remediation efforts you discuss in your testimony.

A. Natural gas did not come to Western Oregon until 1956. Before that, NW Natural's predecessor, PG&C, manufactured gas primarily at two MGPs.[1] The Portland Gas Manufacturing (PGM) facility, which was located in downtown Portland, operated from 1860 to 1913. The much larger Gasco facility was constructed downstream of PGM and operated from 1913 to 1956.

MGPs produced gas for commercial and residential use using different feedstocks. PGM used coal as a feedstock from 1860 to 1906 and then used oil as its principal feedstock from 1906 until 1913. The Gasco plant only used oil. The manufacturing process produced marketable products, recyclable materials and waste materials. The processes used to manufacture gas are described in detail in the direct testimony of Andrew Middleton. For the purpose of my testimony, it is important only to understand that the by-products and wastes from these processes resulted in contamination of the MGP sites and, in some cases, nearby areas.

Q. When were the environmental impacts of the MGPs first identified?

A. The Oregon Department of Environmental Quality (DEQ) first identified contamination at the site of the former Gasco facility (the "Gasco Site") in the late 1980s. The Environmental Protection Agency (EPA) placed the larger Portland Harbor Superfund Site on the National Priority List (NPL or "Superfund list") in 2000. Environmental

[1] A predecessor to PG&C, the East Portland Gas Light Company, also operated a small MGP on the east side of the Willamette River between 1882 and 1892. NW Natural is not aware of any environmental issues associated with that operation.

impacts near the PGM site were identified in 2007 during the investigation of the Portland Harbor Superfund Site.

III. REMEDIATION SITES

Q. Please describe the sites that are the subject of NW Natural's environmental remediation efforts.

A. There are four sites: the Portland Harbor Site, the PGM Site, the Gasco Site, and the Siltronic Site. The Company is managing six remediation projects at these sites, as described below.

- **The Portland Harbor Site**, which EPA has listed as a Superfund site, is a ten-mile stretch of the bed and banks of the Willamette River, from River Mile 1.9 to River Mile 11.8. Investigation of the site as a whole is being managed by a consortium of potentially responsible entities known as the Lower Willamette Group (LWG), under EPA's oversight. NW Natural is a participant in the LWG; this participation is our **Harborwide Project**. As I will explain later in my testimony, the Company is managing MGP-contaminated sediments adjacent to the Gasco Site as a separate project within the Portland Harbor Site, also under EPA oversight. This is our **Gasco Sediments Project.**
- **The PGM Site** covers approximately 3.7 upland acres and is located on the Willamette River near the Steel Bridge. The location of the former MGP is now a fully developed part of downtown Portland. NW Natural is managing this site as the **PGM Project** under DEQ's oversight.
- **The Gasco Site** covers approximately 45 acres and is located on the Willamette River between the St. Johns Bridge and the Railroad Bridge. The manufacturing

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facility is gone, and the site is currently occupied by the Company's Portland liquefied natural gas storage facility and two tenant facilities. Work at this site consists of two projects: the **Source Control Project** and the **Uplands Project**. These projects are subject to DEQ oversight. Both projects include work on the Siltronic Site, described below.

- **The Siltronic Site** is adjacent to the Gasco Site. The land is now owned by Siltronic Corporation ("Siltronic"), but approximately 38.5 acres of it was previously owned by PG&C. Some of the contamination at the site resulted from PG&C's use of approximately 400 feet of the property adjacent to the Gasco Site for storage and management of MGP residuals. Subsequent owners of the Siltronic Site placed a significant amount of fill on the property and redistributed MGP material across the property. Other contaminants from different sources, including Siltronic's own operations, also exist at the site. The Siltronic Site is managed by Siltronic and NW Natural under DEQ's oversight. Both the Gasco Source Control and Gasco Sediments projects involve work on the Siltronic property. The **Siltronic Project** is all of NW Natural's work on the Siltronic Site that is not covered by the other two Gasco Site projects.

IV. REGULATORY FRAMEWORK

Q. Please describe the general statutory framework that governs NW Natural's responsibilities related to remediation for past gas manufacturing operations.

A. Congress enacted the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) in 1980. The law empowers EPA to require the owner or operator of any facility from which a release of a hazardous substance has occurred to

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perform or pay for cleanup of property contaminated by the release. These owners and operators are known as Potentially Responsible Parties (PRPs). CERCLA initially created a cleanup fund (the "Superfund") with revenues from a tax on certain industries but the tax expired in the mid-1990s and has not been renewed. All cleanup activities, including agency and trustee oversight costs, are now funded by the PRPs. EPA can also require current PRPs to pay for the cleanup of contamination caused by entities that no longer exist—known as "orphan shares." Many of the entities that contributed to the contamination in Portland Harbor sediments over nearly 150 years of industrial activity are now out of business, leaving NW Natural and other current PRPs with potential liability for the orphan shares as well as the contamination attributable to their own properties or operations. Finally, under the "joint and several liability" provisions in CERCLA, EPA may be able to order one PRP, or a small number of PRPs, to bear all of the remediation costs associated with the Portland Harbor Site. Those PRPs would then have to seek reimbursement from other PRPs, likely through litigation.

Oregon's Environmental Cleanup Law provides similar authority to DEQ. Enforcement orders and agreements with EPA and DEQ ("the agencies") define the investigation and remediation activities that NW Natural must undertake.

Q. What actions have the agencies taken under these laws with respect to the Portland Harbor?

A. EPA has taken action on the Portland Harbor Site as a whole and also on the sediments immediately adjacent to the Gasco Site.

In approximately 1997, EPA began a Preliminary Assessment of sediment contamination in the Portland Harbor. In December 2000, EPA placed the Portland

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Harbor on the Superfund list and sent letters to 69 parties, including NW Natural, advising those parties that EPA considered them jointly and severally liable for completing a Remedial Investigation and Feasibility Study (RI/FS) for the Portland Harbor. In September 2001, EPA, NW Natural and eight other PRPs entered into an Administrative Settlement Agreement and Order on Consent for Remedial Investigation/Feasibility Studies for the Portland Harbor Superfund Site (the "RI/FS Consent Order"). One additional party signed the RI/FS Consent Order in 2002. These ten parties, together with four other parties who provide funding for the RI/FS, constitute the LWG. NW Natural's work as a part of the LWG is our current Harborwide Project.

In 2004, EPA issued an Administrative Order on Consent for Removal Action, which required NW Natural to remove a tar-like feature in the Willamette River adjacent to the Gasco Site. Except for long-term monitoring, that work was completed in 2005.

Shortly thereafter, EPA indicated that it would require the Company to perform a second, much more extensive, removal action. The Company resisted and instead proposed carving the sediments adjacent to the Gasco Site out of the larger Portland Harbor Site for an expedited final remedial design. EPA agreed, but required that Siltronic be involved in that work. Accordingly, in 2009, NW Natural and Siltronic entered into an Administrative Settlement Agreement and Order on Consent for Removal Action with EPA. That document requires the Company and Siltronic to design a final remedy for sediments adjacent to the Gasco Site. NW Natural's work on the Sediment Project is being performed pursuant to this order.

Q. What actions have the agencies taken with respect to the Gasco Site?

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A. In 1993, DEQ proposed the Gasco Site for the Oregon Confirmed Release List (the CRL). The CRL is the state law equivalent of EPA's Superfund list, and DEQ may require owners and operators of listed sites to clean them up. In 1994, NW Natural entered DEQ's voluntary cleanup program for the Gasco Site by signing a Voluntary Agreement with DEQ. It is important to note that such an agreement is "voluntary" in name only. Our failure to enter into the voluntary program would have resulted in immediate enforcement action. Further, in 2006, DEQ required an amendment to the Voluntary Agreement that added stipulated penalties and other provisions typical of consent orders. The Voluntary Agreement requires NW Natural to investigate contamination from the former Gasco MGP at both the Gasco Site and the adjacent Siltronic Site and, where necessary, to perform clean-up work or take measures to prevent contamination from spreading.

In 2000, DEQ issued an Order Requiring Remedial Investigation and Source Control Measures at the Siltronic Site. NW Natural and Siltronic are both subject to the Order. NW Natural's work on the Gasco Uplands Project and the Source Control Project are being performed pursuant to these orders.

Q. What action have the agencies taken with respect to the PGM site?

A. In 1987, EPA performed a Preliminary Assessment of the PGM site and concluded that no further federal action was warranted under CERCLA at that time. In approximately 1992, DEQ completed a preliminary assessment of the PGM site and concluded that it was a low priority for further environmental investigations. In 2007, the LWG collected sediment samples upstream of the Portland Harbor Site, in the vicinity of the PGM site. Laboratory analyses of those samples identified contaminants that may be related to

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MGP operations. Accordingly, on April 27, 2009, NW Natural entered into an Order on Consent with DEQ. The order requires NW Natural to define the nature, extent, and potential risks associated with gas plant-related chemicals in river sediments and to determine whether any contamination in shoreline soils or groundwater might be a continuing source of contamination to the river. This order is the source of our work on the PGM Project.

Q. Have the agencies taken any additional actions with respect to the Siltronic Site?

A. Siltronic is working under a separate agreement with DEQ to investigate and remediate contamination from TCE, a chlorinated solvent, that is attributable to its manufacturing operations. That work is being performed independently by Siltronic and is in addition to the work being done by NW Natural for DEQ on the Gasco projects. The Siltronic property is also impacted by groundwater contaminated by offsite sources; this contamination is being investigated by the current owners of the Rhone-Poulenc property, a nearby site from which chemical contamination is suspected to have originated.

Q. How have EPA and DEQ determined the Company's specific obligations for clean-up work?

A. The agreements and orders described above set forth the general scope of work NW Natural must perform at each site. The details of the work are generally resolved by technical consensus or negotiations with EPA and DEQ project staff. When the Company or the LWG cannot reach technical agreement with the relevant agency on some aspect of work, the agency staff will issue a directive that requires a particular approach. From time-to-time, NW Natural will dispute an agency directive because we disagree with agency staff on legal, technical or policy grounds. In these instances, the work is determined by upper management at DEQ or EPA.

V. ENVIRONMENTAL REMEDIATION PROCESS

Q. What is the process for remediation at the sites?

A. Each site proceeds through a sequence of activities required by the regulatory agencies. These stages are: Remedial Investigation; Risk Assessment; Feasibility Study; Remedy Design and Construction; Operation and Maintenance; and Monitoring.

Q. Please explain the Remedial Investigation stage.

A. During the Remedial Investigation (RI) stage, the parties determine the nature and extent of the contamination at the site. This stage includes extensive sampling of soil, groundwater, surface water, stormwater, air, sediment, porewater, Dense Non-Aqueous Phase Liquid (DNAPL), bioassays, and tissue. The samples are used to evaluate the physical, chemical, and biological factors at a site. Laboratory analysis of the samples determines the extent and magnitude of contamination.

The RI is an iterative process. After each round of data collection, the data must be analyzed and reported to the regulatory agency for review and approval. The process continues until the agency determines that it has the information it needs to understand the nature and extent of the contamination at the site. At that point the agency approves the RI Report.

Q. How does the RI stage of remediation transition to the Risk Assessment stage?

A. Information in the RI is used to conduct the Risk Assessment (RA). The RA determines whether the contamination at the site poses unacceptable risks to human and ecological "receptors." In the human health risk assessment, the universe of human receptors is

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refined into smaller population groups for focused evaluation of their exposure to chemicals from the site. In the ecological risk assessment, the receptors are organisms that may be exposed to chemicals from the site. Ecological receptors include fish, birds, mammals, amphibians, reptiles, insects, invertebrates and plants. The regulatory agency approves the RA when it is satisfied that all routes of exposure for each chemical to each receptor have been adequately evaluated.

Q. Please explain the Feasibility Study stage of remediation.

A. The Feasibility Study (FS) is written after the RA. The FS evaluates various technologies that can be used to remediate the chemical impacts that are causing unacceptable risk. The FS provides the agency with a range of clean-up alternatives. The FS evaluates each alternative in terms of its environmental benefit, its cost, and the feasibility of implementation. The agency considers the alternatives described in the FS and selects its proposed remedy. The agency solicits public comment on its proposal and then makes a final decision.

Q. Please explain the final stages of remediation—Design and Construction, Operation and Maintenance, and Monitoring.

A. Once the agency has selected a remedy, the PRP must develop a construction design for the remedy. Remedy design is also an iterative process, with revisions based on agency reviews and comments. After the agency approves a final design, the PRP begins construction. Depending on the scope and design of the remedy, the construction stage may be short or construction may be performed in phases that occur over multiple years. For example, dredging activities can only take place in the Willamette River during discrete periods of time (in total, about five months each year)

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when potential impacts to fish from dredging activities are lowest. A large dredging operation would therefore need to be phased over multiple years.

After construction, the agencies require operation and maintenance as well as performance monitoring and reporting. If the remedy does not perform as predicted, the agency has the authority to require additional remediation work.

Q. Do all remediation projects move through all of these stages?

A. No. In some cases governed by CERCLA, EPA has enough information early in the process to determine that some clean-up should occur before the agency has all of the information it will need to select a final remedy for the site. In such a case, CERCLA gives EPA the authority to order a "removal," also known as an "early action." Removal actions can include physical removal of material (such as excavation or dredging), or less intrusive means of preventing exposure to hazardous materials (such as capping, fencing, or installing signs). It is important to note that EPA does not issue a record of decision in such a case and the PRP performing the removal does not receive any of the legal protections (*e.g.* covenants not to sue and releases) that come with the performance of a final remedy pursuant to a record of decision.

VI. <u>STATUS OF REMEDIATION WORK AT THE SITES</u>

Q. What is the status of the LWG's remediation work at the Portland Harbor Site?

A. The LWG has completed most of the work required by the RI/FS Consent Order; the work is at the Feasibility Study stage. The LWG has submitted and received comments from EPA on drafts of the Remedial Investigation Report, the Human Health Risk Assessment, and the Ecological Risk Assessment. The LWG submitted revised drafts of each of those documents to EPA in 2011. The documents provide EPA with analyses of

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the nature and extent of the chemical impacts to Portland Harbor sediments, and the risks to human and ecological receptors. The LWG is currently developing the Portland Harbor Feasibility Study, which will provide an evaluation of remedial alternatives. The LWG will submit a Draft FS to EPA on or before March 30, 2012.

Q. Does the LWG's work on the Portland Harbor Site affect any of NW Natural's other remediation projects?

A. Yes. All of our work on the Gasco Sediment Project must be consistent with Portland Harbor data and regulatory requirements. Therefore, NW Natural will use the information developed for the Portland Harbor Site to design a remedy for the Gasco sediments. The Company will also use information from the Portland Harbor in the Source Control Project to ensure that the source control measures we construct will both satisfy DEQ requirements and prevent recontamination of the Portland Harbor Site.

Q. What is the status of NW Natural's work on the Gasco Sediments Project?

A. This project is at the Feasibility Study stage. As I mentioned earlier, in 2004, EPA required NW Natural to remove a tar-like feature from the sediments adjacent to Gasco under CERCLA's "removal" provisions. The Company completed the removal in 2005. Shortly after that project was completed, EPA indicated that it would require the Company to perform a second, more extensive removal action. The Company resisted the second action and instead proposed carving the sediments adjacent to the Gasco Site out of the larger Portland Harbor Site for an expedited final remedial design. EPA agreed. The Order with EPA for this project allows NW Natural to utilize information in the RI, RA, and FS documents for the Portland Harbor to conduct an Engineering Evaluation/Cost Analysis (EE/CA) for the Gasco sediments. EPA will select a remedy

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for the Gasco Sediments Project from this analysis, which will be consistent with the FS for the rest of the Portland Harbor Site. NW Natural will then produce a remedial construction design that can be included in the Portland Harbor Record of Decision (ROD). NW Natural will construct the remedy under a Consent Decree with EPA, after EPA issues the ROD for the Portland Harbor Site.

Q. What is the status of the remediation work at the PGM Site?

A. This site is in the Investigation stage. DEQ's Order for the PGM Site requires NW Natural to report on historical operations to determine the nature and extent of contamination in river sediments and porewater, evaluate upland groundwater and soil along the river bank, determine hydraulic conditions in the uplands, and investigate source control. To date, the Company has submitted a detailed history of the facility operations to DEQ and conducted extensive sediment and upland riverbank investigations. We are currently conducting supplemental sediment and riverbank groundwater studies required by DEQ.

Q. What is the status of the remediation work at the Gasco Site?

The projects at the Gasco Site are at different stages:

- Gasco Uplands Project: This project is in the Risk Assessment stage. Extensive soil sampling, groundwater monitoring, air quality analysis, stormwater study, DNAPL evaluation, and surface water sampling have provided a comprehensive understanding of the nature and extent of the contamination in the uplands. NW Natural anticipates collecting a limited amount of additional data to support risk assessment and source control activities. All of the data will be utilized to finalize the RA. After DEQ approves the RA, NW Natural will develop the FS.

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- Gasco Source Control Project: This project is in the Design stage. DEQ requested that NW Natural use information specific to groundwater and DNAPL contamination from the Gasco Uplands RI and RA to prepare a Focused Feasibility Study (FFS) for groundwater and DNAPL source control. The FFS was submitted in 2007. DEQ then requested a series of extensive data collection, analysis, and modeling efforts to supplement the FFS and assist its evaluation of alternatives. NW Natural disputed direction from DEQ in 2010 to construct only a partial groundwater source control system. The dispute was resolved in early 2011 when DEQ agreed to a complete hydraulic containment system for groundwater source control. The Company submitted a comprehensive design for that system in May 2011. We received comments from DEQ in September 2011. The final design is currently under development.

Q. What is the status of the remediation work at the Siltronic Site?

A. The Siltronic Project is in the Investigation stage. NW Natural is currently investigating the presence of MGP-related contaminants on the Siltronic property. The RI is nearing completion, and the risk assessment for those chemicals will be initiated when the RI is approved by DEQ. Siltronic is independently conducting a separate soil, groundwater, surface water, stormwater, and sediment investigation for TCE.

Q. Has EPA required any "early actions" in the Portland Harbor Site?

A. Yes. EPA's 2004 order requiring the Company to remove a tar-like feature in the sediments adjacent to the Gasco Site was issued pursuant to the agency's "early action" authority. This work was completed in 2005. EPA has also required two other members of the LWG to perform early actions at other locations within the Portland Harbor Site.

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VII. NW NATURAL'S COSTS OF REMEDIATION

Q. To date, how much has NW Natural spent in connection with the remediation work described in your testimony?

A. As of September 30, 2011, we had spent about $51.8 million, including legal, investigation, remediation, and monitoring costs. Approximately $10 million of that amount was spent on removal of the tar-like feature in 2005.

Q. What types of remedial actions will likely be required in the future?

A. The goal of clean-up work is to reduce the risks posed by chemicals to humans and the environment to acceptable levels. NW Natural does not have the authority to decide which measures will best achieve that goal on each site; EPA and DEQ will make those decisions. The feasibility studies will, however, present viable technical alternatives to the agencies for consideration. Technologies currently available for the upland components of the Gasco, Siltronic, and PGM sites include excavation with offsite disposal, excavation with onsite treatment, *in situ* treatment of soils, capping, subsurface barrier installation, groundwater pumping and water treatment plant operations with offsite discharge, surface water body removal, DNAPL recovery and offsite disposal, engineering controls on existing structures, capping, and institutional controls. Technologies currently available for cleanup of the sediments in the Portland Harbor and PGM sites include dredging with associated surface water containment (*e.g.* silt curtains or sheet pile walls), stabilization capping, *in situ* treatment, monitored natural recovery, enhanced monitored natural recovery, augmented and chemical isolation caps, sediment treatment and stabilization, offsite disposal at a hazardous waste landfill, offsite disposal at a solid waste landfill, bank excavation, and construction mitigation steps.

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Q. Has NW Natural projected the costs that may be incurred in the future?

A. We do not have an estimate of our total future costs due to the preliminary nature of our work at some of the sites and the many uncertainties surrounding the agencies' remediation decisions. In NW Natural's 10-Q for the quarter that ended September 30, 2011, we estimated a range of liability for the Source Control Project at the Gasco Site between $11 million and $30 million and we recorded an accrued liability of $11.8 million. We are not far enough along in the remediation process to estimate ranges for the rest of the projects, so we accrue the lowest estimable cost. Based on these low-end estimates, the 10-Q reported that we expect to pay $58 million in future remediation costs. Future filings will increase this amount as we gain more information.

Q. For how long will NW Natural incur remediation costs for the Harborwide and PGM Projects?

A. We do not know. The time frame for the Portland Harbor Site as a whole will be determined by EPA decisions that have not yet been made. EPA has estimated that the ROD for the Portland Harbor will be available, at the soonest, in late 2013. After that, the design and construction of remedies throughout the Harbor will likely take several years. O&M and monitoring costs will continue for an undetermined period of time after construction. If post-construction monitoring reveals that a remedy is not effective, EPA will likely require the design and construction of additional remedial measures, which would extend the timeframe over which the Company will incur remediation costs.

We cannot predict the timeframe for the PGM Site because it is still in the Investigation stage.

Q. Will the timeframe over which the Company anticipates incurring remediation costs relevant to the other Projects be different?

A. We anticipate a somewhat shorter timeframe for construction of the Source Control, Gasco Uplands, and Gasco Sediments Projects.

NW Natural will construct the source control system as soon as possible following DEQ's approval of a final design. We hope to construct the system in 2012. Operation and maintenance of the system is expected to continue for decades.

Remediation of the Gasco Uplands is scheduled to occur next and should be completed before the construction of remedial measures in the Portland Harbor Site.

The Gasco Sediments Project was originally governed solely by the RI/FS Consent Order but, as I described earlier in my testimony, NW Natural entered into a separate order for those sediments in 2009. Under this order, NW Natural will design the Gasco Sediments Project remedy prior to the issuance of EPA's ROD for the Portland Harbor Site and will be prepared to implement that remedy under a Consent Decree with EPA as soon after the ROD as practicable. This approach will minimize the amount of time it will take to resolve the majority of NW Natural's liability. There will, however, be ongoing O&M and monitoring costs as described above and the potential for additional remedial work if the remedies do not work as planned.

Q. In addition to the costs associated with remediation at the Portland Harbor Site, could NW Natural incur other costs associated with that site?

A. Yes. CERCLA and Oregon law also allow designated natural resource trustees to recover monetary damages for injuries to natural resources resulting from hazardous substance releases. Two federal trustees (the National Oceanic and Atmospheric

Administration and the U.S. Fish & Wildlife Service), six Tribal trustees, and the Oregon Department of Fish & Wildlife have notified NW Natural and other parties of their intent to seek damages for alleged injuries to natural resources in the Portland Harbor. NW Natural and 22 other parties are participating in a cooperative assessment with the Portland Harbor Trustee Council in an attempt to reach a settlement of the trustees' claims.

VIII. COST CONTAINMENT EFFORTS AND EFFORTS TO RECOVER FROM THIRD PARTIES

Q. Has NW Natural attempted to contain its environmental remediation costs?

A. Yes. Two of the Company's top priorities are to aggressively manage the costs arising from our environmental liability and to maximize recovery from our insurance companies and other PRPs. Our efforts in these areas reflect our commitment to minimize costs at the same that time we comply with applicable law, act as a responsible corporate citizen, meet our customers' expectations, and ensure solid working relationships with regulatory agencies and other stakeholders.

Q. What steps has NW Natural taken to control the costs associated with the remediation of past manufactured gas operations in its interactions with relevant agencies and parties?

A. The Company evaluates each task required by EPA and DEQ for cost effectiveness, environmental benefit and technical merit before we perform the work. We object to tasks that we believe are unnecessary, technically unsound, or beyond the scope of the agency's jurisdiction or legal authority. Those objections are usually resolved through collaborative negotiations with the agency in question. When we cannot resolve our concerns though negotiations, we invoke the formal dispute resolution mechanisms

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available under both the DEQ and EPA processes and advocate vigorously for the most cost-effective approach.

Q. **Please describe your formal disputes with the agencies.**

A. I described our successful source control dispute with DEQ earlier in my testimony. We also disputed two EPA staff directives associated with our removal of the tar-like feature adjacent to the Gasco Site. We were unable to convince EPA to allow disposal of the dredged material at a less expensive Subtitle D (non-hazardous waste) landfill but we argued successfully for a more cost-effective containment system than EPA's project staff had required.

Q. What, if any, role does the LWG play in NW Natural's efforts to control its remediation costs?

A. The LWG has negotiated rates with vendors that are below standard rates. The LWG has also conducted a market analysis to ensure that vendor costs are below market. In addition, the LWG monitors its consultants' work on a regular basis and constantly seeks ways to minimize costs.

Q. Does NW Natural take internal steps to control its remediation costs?

A. Yes. NW Natural has established a thorough internal process for managing approved tasks and associated costs. Because of the magnitude and complexity of our environmental liabilities, we must maintain a team of highly qualified technical consultants and lawyers. As a result, most of the costs we incur are for external resources.

The long-term nature of our remediation work and the iterative nature of the regulatory process require us to have long-term vendor contracts and purchase orders.

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When NW Natural's project team identifies a potential vendor, the vendor is directed to NW Natural's Purchasing Department. The Purchasing Department negotiates the terms of the contract, including the rate schedule. The Legal Department reviews the contract to ensure that it meets our standards and requirements. After the contract is executed, we request cost estimates for the work that needs to be done to comply with regulatory requirements. Using the rate schedules in its contract, the vendor provides estimates for the number of hours and materials necessary to perform project tasks. As the Project Manager, I evaluate these estimates for accuracy and appropriateness. I also review and update all project costs and tasks on a quarterly basis.

Q. Does NW Natural track the spending associated with environmental remediation?

A. Yes. All spending is tracked both by me as the Project Manager and by the Company's Accounting Department to verify that actual costs remain aligned with approved spending limits. Cost tracking includes both project-specific spending as well as spending against the amount the Board of Directors approves each year. NW Natural reports updated estimates of its environmental liabilities quarterly in the 10-Q and annually in the 10-K.

Q. Are the Company's environmental costs subject to outside audit?

A. Yes. The Company provides quarterly cost updates to PricewaterhouseCoopers LLP, which includes those costs in its integrated audit of the Company.

Q. Has NW Natural attempted to recover any of its remediation costs from third parties?

A. Yes. As I mentioned at the beginning of my testimony, Sandra K. Hart's testimony describes the steps NW Natural has taken to recover costs from insurance carriers.

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In 2007, the LWG successfully recovered some of its RI/FS costs from PRPs who are not in the LWG and reserved its rights to pursue additional cost recovery in later legal proceedings. NW Natural's share of that recovery was approximately $430,000.

More significantly, NW Natural and 91 other PRPs are participating in a confidential, non-judicial process intended to settle claims for past and future costs related to the Portland Harbor Site. The Company has entered into tolling agreements with approximately 100 additional parties pending the outcome of this settlement process. In April 2009, NW Natural and the other signatories to the RI/FS Consent Order filed litigation in the United States District Court for the District of Oregon against 69 parties who refused to participate in the settlement process or toll claims. Most of those parties have either joined the settlement process or signed tolling agreements. Those parties have been dismissed from the litigation. Thirteen defendants and one third-party defendant (the United States) remain in the litigation. The federal court has stayed the litigation pending completion of the settlement process.

Finally, NW Natural and Siltronic are working cooperatively to implement the EPA's 2009 Sediment Order under an interim cost sharing arrangement and have entered into tolling agreements in support of settlement discussions related to co-mingled contamination at and from the Gasco and Siltronic operations.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Sandra K. Hart

ENVIRONMENTAL MITIGATION – COST RECOVERY – INSURANCE EXHIBIT 1400

December 2011

EXHIBIT 1400 – DIRECT TESTIMONY – ENVIRONMENTAL MITIGATION – COST RECOVERY – INSURANCE

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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 Sandra K. Hart. I am the Director of Risk and Land at NW Natural. For the past 13 years, my responsibilities have included the management of the corporate insurance program and environmental insurance recovery.

Q. Please summarize your educational background and business experience.

A. I joined NW Natural in 1985 as an engineer. In 1994, I became Manager of Environmental Services and Occupational Safety, and in 1998 Manager of Risk Environment and Land. Then, in 2009, I became the Director of Risk and Land. I also have experience with environmental site investigation, clean-up and compliance. Prior to joining NW Natural, I worked as an engineer for CH2M Hill. I have a Bachelor of Science degree in Structural Engineering and a Master of Business Administration.

Q. Please summarize your testimony.

A. In my testimony, I:

- Describe the insurance coverage the Company may have to cover the costs of its environmental investigation and remediation of the contamination associated with its historical operations;
- Describe NW Natural's efforts to recover from its historical insurers the costs of the Company's environmental investigation and remediation activities related to past operations; and

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- Explain the efforts undertaken by NW Natural to ensure that it achieves the best outcome from its litigation against its insurers, and I explain the status of the insurance recovery litigation.

This testimony supplements the direct testimonies of Robert Wyatt, C. Alex Miller, and Andrew Middleton.

II. <u>INSURANCE COVERAGE</u>

Q. Please describe what, if any, insurance coverage the Company may have to cover the costs of its environmental investigation and remediation of the contamination associated with its historical MGP operations.

A. From 1938 through 1986, NW Natural carried Excess General Liability (XGL) insurance coverage with various insurance providers—each of which, in NW Natural's view, should be obligated to cover costs associated with its environmental remediation efforts subject to the monetary limits of coverage of their respective insurance policies.

Q. Why does the Company have coverage for environmental remediation only between 1938 and 1986?

A. Prior to 1938, XGL coverage for utilities was generally not available. After 1986, the insurance industry inserted very broad pollution exclusions in their liability policies that exclude coverage for damages associated with most incidents of environmental contamination.

Q. Please describe the levels of coverage provided by the XGL policies the Company maintained between 1938 and 1986.

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A. As was typical for utilities and other types of companies during that time period, the XGL policies that NW Natural had in place had varying limits and terms. The total amount of coverage purchased in a given policy year increased over time, from $500,000 in the early 1940s to $40 million in the mid-1980s. In addition, the policies in each of the years attach a self-insured retention (SIR), which acts like a deductible. The amount of the SIR layer also increased over time, from $5,000 in the early 1940s to $250,000 in the late 1970s and $500,000 in 1986. This type of increase in SIR was also typical for utilities and other kinds of companies during this time period. Some of the insurers that issued policies to NW Natural have become insolvent or gone out of business, and those policies are not generally available for recovery.

Q. What is the potential of obtaining coverage for NW Natural's environmental liabilities from the policies issued by still-solvent insurers?

A. Based on the language of its policies, controlling Oregon law and the underlying facts, NW Natural believes that each of its historical policies provide coverage for the costs related to the environmental damage that NW Natural is investigating and remediating. However, many of the insurers that issued the policies to NW Natural have refused to provide coverage for the environmental sites and have asserted various defenses to coverage. Nationally, coverage claims relating to remediation costs at environmental sites have been resolved in litigation with mixed results—in some instances the policyholder has prevailed in whole or part, and in other cases the insurer has prevailed in whole or part. Most cases settle prior to verdict because of the uncertainty for each side. In this case, NW Natural cannot predict the outcome of its coverage efforts with certainty.

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III. EFFORTS TO RECOVER FROM HISTORICAL INSURERS

Q. What actions has NW Natural taken to obtain payments from these insurance policies?

A. As NW Natural began to learn of its potential environmental liability, the Company undertook efforts to identify, search for, and assemble the historical liability policies that might provide coverage. After NW Natural identified the relevant insurers, the Company provided them notice of its claim for coverage and thereafter kept them informed of ongoing investigation and remediation efforts.

Q. Has the Company made efforts to resolve its claims?

A. Yes. In 2007, NW Natural issued settlement demands to most of the insurers. In 2008, NW Natural withdrew its original demands and then issued revised, higher demands because of U.S. Environmental Protection Agency (EPA) actions and positions on some sites that had the potential of driving NW Natural's costs higher. By late 2009, NW Natural had met with most of its historical insurers to discuss settlement and determined that they were not willing to engage in serious negotiations. Therefore, NW Natural decided to initiate litigation to enforce its right to coverage. In December of 2010, NW Natural filed litigation against its insurers in Multnomah County Circuit Court. The Company filed a First Amended Complaint on January 3, 2011. *See NWN/1401, Hart/1-18*.

Q. What remedy is NW Natural seeking from these insurance companies?

A. We are seeking insurance recovery of past investigation and remediation costs, and a declaratory judgment holding that the insurers responsible for covering the investigation and remediation costs incurred in the future.

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IV. EFFORTS UNDERTAKEN TO ENSURE BEST OUTCOME

Q. What efforts has NW Natural taken to ensure that it achieves the best outcome from its litigation against its insurers?

A. NW Natural conducted a national search for counsel to prosecute its claims. The Company invited eight law firms from across the country, with established and well-regarded insurance recovery practices, to submit proposals to NW Natural detailing their relevant experience and proposed approaches. After screening the proposals, the four firms with the strongest proposals were invited to make presentations to NW Natural's management. Based on the presentations, the written proposals and comments from references, K&L Gates LLP emerged as the strongest firm. K&L Gates is a large, international law firm, with offices throughout the country, including Portland. K&L Gates has a group of lawyers located in its Pittsburgh office that have specialized in litigating environmental coverage claims for over 20 years, with substantial experience handling these types of claims for utilities. For example, K&L Gates obtained a trial verdict on behalf of Washington Natural Gas Company requiring its historical insurers to pay all of that company's environmental investigation and remediation costs arising from a former manufactured gas plant in Tacoma.

Q. Are settlement discussions continuing with the insurance companies even during the litigation?

A. To some extent, although the level of engagement has varied by insurer.

Q. Have these discussions led to any settlements being reached?

A. Yes. To date, a settlement was reached this year with one insurer, Aegis.

Q. What is the current schedule for resolving the litigation?

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A. The Court Scheduling Order calls for the case to be tried in two phases. The first trial is scheduled to begin on November 19, 2012 and conclude by the end of November, 2012. The first trial will principally address the existence and terms of the insurance policies at issue. The second trial is scheduled to begin on June 3, 2013 and conclude by the end of the summer. This trial will cover all remaining issues. If the trial schedule slips or the losing party appeals the trial court decision, the resolution of the litigation will be delayed.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Exhibits of Sandra K. Hart

ENVIRONMENTAL MITIGATION – COST RECOVERY – INSURANCE EXHIBIT 1401

December 2011

EXHIBIT 1401 – DIRECT TESTIMONY – ENVIRONMENTAL MITIGATION – COST RECOVERY – INSURANCE

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COPY

IN THE CIRCUIT COURT OF THE STATE OF OREGON

FOR THE COUNTY OF MULTNOMAH

NORTHWEST NATURAL GAS COMPANY d/b/a NW NATURAL,

Plaintiff,

v.

ASSOCIATED ELECTRIC & GAS INSURANCE SERVICES LIMITED (f/k/a General Assurance Services Limited), ALLIANZ GLOBAL RISKS US INSURANCE COMPANY (f/k/a Allianz Insurance Company), ALLIANZ UNDERWRITERS INSURANCE COMPANY (f/k/a Allianz Underwriters, Inc.), CARDIF PROPERTY AND CASUALTY INSURANCE COMPANY (f/k/a Industrial Underwriters Insurance Company), CENTURY INDEMNITY COMPANY (for itself and as successor-in-interest to CIGNA Specialty Insurance Company, formerly known as California Union Insurance Company), CONTINENTAL CASUALTY COMPANY, THE CONTINENTAL INSURANCE COMPANY (as successor-in-interest to Harbor Insurance Company), GENERAL REINSURANCE CORPORATION, MUNICH REINSURANCE AMERICA, INC. (f/k/a American Re-Insurance Company), ST. PAUL FIRE AND MARINE INSURANCE COMPANY, SEATON INSURANCE COMPANY (f/k/a Unigard Security Insurance Company f/k/a Unigard Mutual Insurance Company), STONEWALL INSURANCE COMPANY, CERTAIN UNDERWRITERS AT LLOYD'S, LONDON, CERTAIN LONDON MARKET INSURANCE COMPANIES:

ACCIDENT & CASUALTY INSURANCE COMPANY, ADRIATIC INSURANCE COMPANY LTD., THE

No. 1012-17532

FIRST AMENDED COMPLAINT (Declaratory Relief and Breach of Contract)

DEMAND IN EXCESS OF $50,000

CLAIM IS NOT SUBJECT TO COURT ADMINISTERED ARBITRATION

DEMAND FOR JURY TRIAL

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ALBA GENERAL INSURANCE COMPANY LTD., ANGLO-FRENCH INSURANCE COMPANY LIMITED, BISHOPSGATE INSURANCE COMPANY LIMITED, BRITISH AVIATION INSURANCE COMPANY LTD., BRITISH NORTHWESTERN INSURANCE CO., LTD., BRITISH RESERVE INSURANCE COMPANY LIMITED, CHARTIS PROPERTY CASUALTY COMPANY (f/k/a Birmingham Fire Insurance Company), CIA AGRICOLA DE SEGUROS S.A., CONTINENTAL INSURANCE COMPANY, CX REINSURANCE COMPANY LIMITED, (f/k/a CNA Reinsurance of London), THE DOMINION INSURANCE COMPANY LIMITED, EDINBURGH ASSURANCE COMPANY LIMITED, ENNIA (UK), L'ETOILE, EXCESS INSURANCE COMPANY LIMITED, FIDELIDADE INSURANCE COMPANY OF LISBON, GENERALI-ASSICURAZIONI GENERALI S.P.A. (f/k/a Assicurazioni Generali di Trieste e Venezia), GENERALI FRANCE ASSURANCES, S.A. (f/k/a La Concorde), GENERAL INSURANCE CO. HELVETIA LIMITED, HELVETIA-ACCIDENT SWISS INSURANCE COMPANY LTD., HISCOX INSURANCE COMPANY LIMITED (f/k/a Economic Insurance Company Limited), INSCO LIMITED, INSURANCE COMPANY OF NORTH AMERICA, LLOYD ITALICO, THE LONDON & EDINBURGH INSURANCE COMPANY LIMITED, LONDON & HULL MARITIME INSURANCE COMPANY LIMITED, MARKEL INTERNATIONAL INSURANCE COMPANY LIMITED (f/k/a Terra Nova Insurance Company Limited), NATIONAL CASUALTY COMPANY OF AMERICA LTD., NATIONAL CASUALTY COMPANY, NATIONAL SECURITY, PRUDENTIAL CITY, RIVER THAMES INSURANCE COMPANY, ROAD TRANSPORT & GENERAL INSURANCE COMPANY LIMITED, LA ROYALE BELGE S.A. D'ASSURANCES, THE ROYAL

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SCOTTISH INSURANCE COMPANY LIMITED, THE SCOTTISH LION INSURANCE COMPANY LIMITED, SEGUROS LA REPUBLICA, SOMPO JAPAN INSURANCE INC. (f/k/a Yasuda Fire and Marine Insurance Company (U.K.) Limited), STRONGHOLD INSURANCE COMPANY LTD., THE SWISS NATIONAL INSURANCE COMPANY LTD., THREADNEEDLE INSURANCE COMPANY LTD., TIG INSURANCE COMPANY (as successor-in-interest to International Insurance Company), TRENT INSURANCE COMPANY LIMITED, TUREGUM INSURANCE COMPANY LTD., ULSTER MARINE INSURANCE COMPANY LIMITED, L'UNION DES ASSURANCE DE PARIS, UTILITY SERVICES INSURANCE COMPANY LTD., THE WORLD AUXILIARY INSURANCE CORPORATION LTD.,

and JOHN DOES 1-5,

Defendants.

Plaintiff Northwest Natural Gas Company, d/b/a NW Natural ("NW Natural"), hereby files this First Amended Complaint against various historical insurers of NW Natural identified below (collectively, the "Insurers"), and alleges as follows:

INTRODUCTION

1.

This is an insurance coverage action for declaratory relief pursuant to Oregon's Uniform Declaratory Judgments Act, OR. REV. STAT. ANN. § 28.010, *et seq.* (2010), and for breach of contract.

2.

NW Natural seeks a declaration that it is entitled to insurance coverage under the insurance policies issued by the Insurers to NW Natural identified on Exhibit 1 (hereinafter, the "Subject

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Policies"). More specifically, NW Natural seeks a declaration that the Insurers must indemnify and reimburse NW Natural for certain amounts arising from liabilities and losses incurred by NW Natural as a result of alleged environmental property damage existing at the sites identified below. A declaratory judgment is necessary to resolve disputes between NW Natural and the Insurers regarding their respective obligations under the Subject Policies to indemnify and reimburse NW Natural regarding such liabilities and losses.

3.

In addition, NW Natural seeks relief and damages based upon the Insurers' breach of their obligations under their respective Subject Policies by failing to provide insurance coverage to NW Natural for liabilities and losses it has incurred and will incur in the future as a result of alleged environmental property damage existing at the sites identified below.

PARTIES

A. Plaintiff

4.

NW Natural is a public utility corporation organized under the laws of the state of Oregon and having its principal place of business in Portland, Oregon.

5.

NW Natural's corporate history dates back to the founding of Portland Gas Light Company in 1859 and its incorporation in October 1862.

6.

In 1892, Portland Gas Company was formed. At or about that time, Portland Gas Company purchased and combined Portland Gas Light Company and East Portland Gas Light Company, which had been incorporated in September 1882.

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7.

In 1910, Portland Gas Company was sold to American Power and Light Company of New York City. The company was reorganized under the name Portland Gas and Coke Company ("PG&C") and incorporated under Oregon law.

8.

By 1951, American Power and Light Company sold its holdings in PG&C, which became a publicly traded company.

9.

In December 1957, PG&C changed its name to Northwest Natural Gas Company.

B. <u>The Insurers</u>

10.

The Insurers are insurance companies, persons or entities that, during all relevant time periods, engaged in the business of providing insurance coverage to customers, including NW Natural under, *inter alia*, the Subject Policies, and/or were authorized to conduct insurance business in Oregon.

11.

The Insurers that issued the Subject Policies to NW Natural listed on Exhibit 1 hereto, and the Insurers' respective places of incorporation and principal places of business, to the extent known or believed, are identified on Exhibit 2 hereto. True and correct copies of excerpts of each of the Subject Policies, to the extent that NW Natural has located such to date, are attached hereto as Exhibit 4 as substitutes for the actual policies, which are too voluminous to attach to this Complaint. Copies of such policies will be made available upon request.

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12.

Defendants, Certain Underwriters at Lloyd's, London, who have participated in, subscribed to, or have reinsured-to-close, directly or indirectly, the syndicate-years-of account identified on Exhibit 3 hereto ("Underwriters"), are those individuals residing in countries around the world, including in various states in the United States, who have subscribed to, or have reinsured-to-close, directly or indirectly, the Subject Policies issued to NW Natural by Underwriters including those identified on Exhibit 3 hereto.

13.

Defendants, John Does 1 through 5 are individuals or entities that have issued the Subject Policies and/or other policies to NW Natural during the relevant time period and whose identities are unknown at this time. These John Does may include individuals residing in countries around the world, including in various states in the United States who have subscribed to, or have reinsured-to-close, directly or indirectly, the Subject Policies issued to NW Natural by Underwriters, including those identified on Exhibits 1 and 3 hereto. Upon identification of those individuals or entities, NW Natural will amend this Complaint to identify them specifically.

C. <u>Jurisdiction and Venue</u>

14.

This Court has personal jurisdiction, pursuant to the Oregon Rules of Civil Procedure, Rule 4, over the Insurers named herein because, upon information and belief, such parties:

(a) are or were licensed or authorized to do business in Oregon;

(b) have, within the relevant time periods, transacted business in Oregon, including the selling of insurance in Oregon, the assumption of insurance policies covering risks in Oregon and/or handling of insurance claims involving risks located in Oregon;

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(c) have agreed in the policies that they have issued or subscribed to in favor of NW Natural to submit to the jurisdiction of any court of competent jurisdiction within the United States, to comply with all requirements necessary to give such court jurisdiction and to have all matters arising under their policies determined in accordance with the law and practice of such court;

(d) have realized, and sought to realize, pecuniary benefit from their business activities in Oregon;

(e) have made, and continue to make, business decisions which have a direct and substantial impact in Oregon; and/or

(f) have authorized agents to transact business in Oregon on their behalf.

15.

To the extent that any Insurer sued in this action is a foreign state or an instrumentality of a foreign state within the meaning of 28 U.S.C. § 1603 (1994), for purposes of this case, NW Natural releases and waives in their entirety any claims that it may have against any such Insurer for claims made in this action.

16.

Venue is proper in this Court because NW Natural and the Underlying Environmental Sites described herein as to which NW Natural seeks coverage are located in Multnomah County, Oregon.

NATURE OF THE CAUSES OF ACTION

17.

From approximately 1860 through 1956, NW Natural's predecessors-in-interest ("NW Natural's predecessors") operated various facilities that manufactured, stored and/or

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distributed gas and various by-products. As they relate to the causes of action brought herein, these facilities may be characterized as former manufactured gas plant ("MGP") sites and former remote gas holder stations associated with the MGPs. Various residuals from the operation of each of these facilities have allegedly caused environmental damage to the soil at, and the groundwater beneath, the sites of these facilities, as well as to the soil, groundwater, sediments, and/or natural resources at other sites, including the Portland Harbor Site. These sites, and other environmental sites identified herein, shall collectively be referred to herein as the "Underlying Environmental Sites."

18.

NW Natural is liable or allegedly liable under the laws of the State of Oregon and/or the United States to investigate and remediate alleged environmental contamination and property damage occurring at and around each of the Underlying Environmental Sites. NW Natural is currently investigating and remediating such contamination and property damage pursuant to orders and directives of, or agreements with, the Oregon Department of Environmental Quality ("ODEQ") under Oregon law and the United States Environmental Protection Agency ("USEPA") under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, 42 U.S.C. §§ 9601 *et seq.* (1995) ("CERCLA"), including natural resource damages ("NRD") pursuant to sections 107 (a)(4)(A) and (C) of CERCLA at certain of the Underlying Environmental Sites. Pursuant to these authorities, NW Natural has been required to pay, and will in the future be required to pay, monies to investigate and remediate the Underlying Environmental Sites.

19.

In breach of the Subject Policies, the Insurers have failed to reimburse and indemnify NW Natural's costs for its investigation and remediation of the Underlying Environmental Sites.

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A. **The MGP Sites and Related Gas Holder Stations**

20.

NW Natural's predecessors owned and operated the following MGPs (the "MGP Sites"):

(a) **Portland MGP Site** – This facility was located on an approximately 6 acre area in downtown Portland presently bounded by NW Flanders St. to the north, the Willamette River to the east, NW Everett St. to the south, and NW 2nd Avenue to the west. The gas plant began operations in 1860 and ceased operations in 1913. Related gas holder stations include the one located at NW 6th Avenue and NW Flanders Street in Portland and the one located at NW Couch Street and NW 14th Avenue in Portland.

(b) **East Portland MGP Site** – This site was located on an approximately 12,000-square foot area at the southwest corner of SE 3rd Avenue and SE Ankeny Street. The MGP operated at this site from approximately 1883 until 1892.

(c) **GASCO Site** – This site is located on NW St. Helens Road in Linnton, Oregon and occupies approximately 90 acres. PG&C purchased the property in 1910 and NW Natural still owns approximately 45 acres of the property today. The remainder of the property has been owned by Siltronic Corporation since 1978. The MGP manufactured gas at this site from 1913 to 1956. A third-party operated a tar distillation and refining plant on the site after 1956. Related gas holder stations included one located at N. Alberta and N. Kerby Avenue in Portland and three gas holders located at 2630 SE 9th Avenue in Portland, which is now the location of NW Natural's Central Service Center.

21.

The foregoing former MGP facilities used different processes to manufacture gas for distribution to individual customers, businesses and municipalities.

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22.

In manufacturing gas, these MGP facilities generated various residuals, including, but not limited to, tars and lampblack. At each of the Underlying Environmental Sites, these and other residuals relating to the gas manufacturing processes are alleged to be present in the soil, groundwater, surrounding sediments and/or natural resources. Under the authorities identified above, NW Natural is liable for the investigation and remediation of these Sites.

B. <u>Other Sites</u>

23.

At various times, residuals from NW Natural's predecessors' MGP Sites were allegedly discharged or released at, or migrated to, other sites as identified below (the "Other Sites") and those residuals are alleged to be present in the soil, groundwater, sediments, natural resources, and/or surrounding property. Under the authorities identified above, NW Natural is liable for the investigation and remediation of these sites.

24.

The Other Sites are as follows:

(a) **<u>The Portland Harbor Site</u>** – This site encompasses the Portland Harbor Study Area and is located along a 9.9-mile long reach of the lower Willamette River between downtown Portland and 2 miles upstream of the confluence with the Columbia River. The GASCO Site is located along the western bank of the lower Willamette River between mile 6 and 7.

(b) **<u>Oregon Steel Mills Site</u>** – This site is located at 14400 N. Rivergate Boulevard in Portland, Oregon. The property is approximately 145 acres and was used by the US Army Corps of Engineers and the Port of Portland to dispose of dredged material from the Willamette River from the 1940s to the 1960s. The site also involved a disposal facility operated

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by the Port of Portland and Shaver Transportation at which NW Natural is alleged to have disposed of MGP wastes. Oregon Steel Mills, Inc. sued the Port of Portland in 2002 for past remediation response costs, for contribution, and for declaratory relief for future costs. The Port of Portland filed claims against 11 third-party defendants, including NW Natural, based on the alleged disposal of wastes associated with the GASCO facility.

(c) **Central Service Center Site** – This site, originally the location of three gas holders related to the GASCO Site, was redeveloped in 1978 for NW Natural's Central Service Center. In addition to MGP-related residuals, other residuals from the operation of the Central Service Center are alleged to be present in the soil, groundwater, surrounding sediments and/or natural resources.

25.

On December 1, 2000, the Portland Harbor Site was designated a Superfund Site and in February 2001, the ODEQ, USEPA and other governmental parties signed a memorandum of agreement for the management of this site.

26.

NW Natural is named as a Potentially Responsible Party regarding the Portland Harbor Site as the GASCO Site is an alleged source of contamination to the harbor.

27.

The USEPA is also seeking to impose additional liability on NW Natural under federal law for response costs and/or NRD at the Portland Harbor Site pursuant to sections 107(a)(4)(A) and (C), respectively, of CERCLA, which NRD is "property damage" under the Subject Policies.

28.

The underlying environmental claims and liabilities relating to the Underlying

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Environmental Sites - MGP Sites and Other Sites - shall be collectively referred to herein as the "Underlying Environmental Claims."

29.

NW Natural has been legally obligated to expend in excess of $40 million in connection with investigation and remediation of the Underlying Environmental Claims. Further, based on the information currently available, NW Natural believes and avers that it will incur millions of dollars more in investigating and remediating the Underlying Environmental Claims in the future.

C. <u>The Subject Policies Issued to NW Natural</u>

30.

At various times during the period from at least 1938 through 1986, the Insurers, in consideration of premiums paid by or on behalf of NW Natural, sold policies of excess liability insurance to NW Natural. Attached hereto as Exhibit 1 is a list of the Subject Policies sold by each Insurer to NW Natural, along with the relevant policy numbers and policy periods.

31.

By issuing the Subject Policies, the Insurers undertook, among other things, to indemnify NW Natural in connection with liabilities, and related costs, arising from property damage, such as the Underlying Environmental Claims.

<u>COUNT ONE: DECLARATORY JUDGMENT</u>

32.

The averments in each of the preceding paragraphs are incorporated by reference as if fully set forth herein at length.

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33.

NW Natural's actual and potential liability arising out of the Underlying Environmental Claims, as well as NW Natural's costs of defending against such claims, is within the coverage provided by the Subject Policies.

34.

With respect to NW Natural's liability arising out of the Underlying Environmental Claims, an accident or occurrence, or personal injury, or property damage or other triggering event within the meaning of the Subject Policies has taken place at each of the Underlying Environmental Sites during the policy periods of the Subject Policies.

35.

All conditions precedent, if any, to recovery under the Subject Policies have been satisfied, waived or are otherwise inapplicable.

36.

To date, the Insurers have failed to provide coverage under the Subject Policies.

37.

An actual controversy currently exists among NW Natural and the Insurers regarding the Insurers' duties and obligations under the Subject Policies. Specifically, NW Natural contends, and, upon information and belief, Insurers apparently dispute, that:

(a) Each Insurer has a duty to indemnify and pay all sums that NW Natural is obligated to pay by reason of the Underlying Environmental Claims, subject to its policies' limits of liability, and each Insurer is jointly and severally liable for such sums up to the limit of its policies;

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(b) Through their policies, the Insurers have a duty to reimburse NW Natural for costs arising from NW Natural's defense of the Underlying Environmental Claims, and each Insurer is jointly and severally liable for such costs, subject to the limits of its policies; and

(c) NW Natural is entitled to select the insurance policy(ies) and policy years that it will access to provide coverage to NW Natural such defense and/or indemnity payments.

38.

A determination by this Court of the respective rights, duties, and obligations of NW Natural and the Insurers is necessary and proper to terminate some or all of these disputes and controversies and/or to avoid prejudicing NW Natural's rights with respect to the Insurers and to allow the parties the opportunity to assess their respective positions.

39.

Pursuant to Oregon's Uniform Declaratory Judgments Act, OR. REV. STAT. ANN. § 28.010, *et seq.* (2010), NW Natural is entitled to a declaration by this Court of its rights and the Insurers' duties, and a judicial declaration is necessary as to NW Natural's rights and the Insurers' duties, regarding the Underlying Environmental Claims.

WHEREFORE, NW Natural demands judgment in its favor against Insurers:

(a) declaring and adjudging the rights and obligations of the parties under the Subject Policies with respect to NW Natural's past and future liabilities and related expenses arising from the Underlying Environmental Claims;

(b) requiring each Insurer on a joint and several basis to indemnify NW Natural for, or pay on behalf of NW Natural, all liability, loss, and/or expense, including defense costs, caused by reason of the Underlying Environmental Claims;

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(c) enjoining the Insurers from failing and refusing to indemnify NW Natural for, or pay on behalf of NW Natural, all liabilities, losses and expenses that have been and will be incurred with respect to any such Underlying Environmental Claim;

(d) granting NW Natural specific performance of the contracts of insurance issued by the Insurers;

(e) for money damages in an amount to be determined at trial, together with prejudgment and post-judgment interest;

(f) for costs of suit;

(g) for all counsel fees, expert fees and other costs relating to the litigation of this matter; and

(h) for such other and further relief, including any appropriate equitable relief, as the Court may deem just and proper.

COUNT TWO: BREACH OF CONTRACT

40.

The averments in each of the preceding paragraphs are incorporated by reference as if fully set forth herein at length.

41.

The Insurers accepted premiums from NW Natural and issued the Subject Policies promising, among other things, to indemnify NW Natural for liabilities and related costs and expenses, such as those arising from the Underlying Environmental Claims.

42.

NW Natural has already incurred financial losses in excess of $40 million arising out of the Underlying Environmental Claims.

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43.

All conditions precedent, if any, to recovery under the Subject Policies have been satisfied or waived.

44.

With respect to such financial losses, the Insurers, in breach of their respective insurance policies, have failed to provide NW Natural with indemnification as required under the terms of the respective Subject Policies.

45.

By their actions, the Insurers have acted in a manner inconsistent with the terms and conditions of the Subject Policies such as to constitute a breach of those Policies.

46.

As a result of the Insurers' breach of their respective insurance policies by wrongfully failing to accept responsibility pursuant to the terms and conditions of the policies, the Insurers are liable to NW Natural for damages, in an amount yet to be ascertained, for all costs, both disbursed and incurred to date, and to be incurred in the future, in connection with the liabilities and the investigation and remedial work performed at the Underlying Environmental Sites, together with the costs and disbursements of this action, including, but not limited to, reasonable attorney's fees and pre-judgment and post-judgment interest.

WHEREFORE, NW Natural demands judgment in its favor against the Insurers:

(a) requiring each Insurer to indemnify NW Natural for, or pay on behalf of NW Natural, all liabilities and expenses caused by reason of the Underlying Environmental Claims;

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(b) enjoining the Insurers from failing and refusing to indemnify NW Natural for all liabilities and expenses that have been and will be incurred with respect to any such claim;

(c) granting NW Natural specific performance of the contracts of insurance issued by the Insurers;

(d) for money damages in an amount to be determined at trial, together with pre-judgment and post-judgment interest;

(e) for costs of suit;

(f) for all counsel fees, expert fees and other costs relating to the litigation of this matter; and

(g) for such other and further relief, including any appropriate equitable relief, as the Court may deem just and proper.

DEMAND FOR JURY TRIAL

Pursuant to Oregon Rules of Civil Procedure 50 and 51, NW Natural hereby demands a trial by jury as to all counts set forth in the above Complaint.

DATED this 3rd day of January 2011.

K&L GATES LLP

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of C. Alex Miller

ENVIRONMENTAL MITIGATION – COST RECOVERY / RATE ADJUSTMENT MECHANISM
EXHIBIT 1500

December 2011

EXHIBIT 1500 – DIRECT TESTIMONY - ENVIRONMENTAL MITIGATION – COST RECOVERY / RATE ADJUSTMENT MECHANISM

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Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
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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 C. Alex Miller. My current position is Vice President, Finance and Regulation and Assistant Treasurer for NW Natural. I am responsible for Rates & Regulatory Affairs, as well as budgets, financial planning, and financial analysis.

Q. Please summarize your educational background and business experience.

A. I received a Bachelor of Arts in Economics from the University of Oregon in 1980. I received a Master of Business Administration from Claremont Graduate School in 1984. From 1981 through 1997, I worked at Southern California Edison Company in various rate and finance positions, including Vice President and Treasurer. From 1997 to 2001, I worked at PacifiCorp in various positions, including Vice President of Business Development. I joined NW Natural in 2003. Since 2005, I have been a member of the environmental steering committee at NW Natural, a group of executives and managers that monitors and helps in decision-making regarding NW Natural's ongoing environmental remediation activities and cost recovery efforts.

Q. Please summarize your testimony.

A. In my testimony, I:

- Describe costs incurred and expected to be incurred by NW Natural associated with environmental remediation related to its historic operations;
- Explain why rate recovery of environmental remediation costs in rates is appropriate and consistent with other states' treatment of such costs;

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- Describes the Company's proposed mechanism for collection of environmental remediation costs in rates, under which the Company would collect an amount equal to one-fifth of the balance of the Company's prudently incurred environmental remediation expenses, net of any settlements or third-party payments received by the Company related to its efforts; and
- Describes the Company's proposed rate recovery of its investment in a pumping station required as part of its remediation activities, under which the costs would be added to rate base and amortized over a longer period to reflect the nature of the investment and its expected life.

II. NW NATURAL'S COSTS OF ENVIRONMENTAL REMEDIATION

Q. Please state the costs NW Natural has incurred related to environmental remediation for past operations.

A. As of September 30, 2011, NW Natural had deferred about $64.5 million in environmental remediation costs that have already been incurred. This amount includes $51.8 million of total expenditures to date plus accrued interest of $18.1 million, partially offset by $5.4 million of environmental costs expensed in prior years.

Q. What costs does NW Natural expect to incur in the future related to its remediation activities?

A. In addition to the costs the Company has already incurred, NW Natural estimates $58 million in future remediation costs—which, in accordance with standard accounting

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practices, is a low-end estimate.[1] In total, NW Natural has recorded on its books a regulatory asset related to environmental costs of $122.5 million.[2] All but about $1.1 million of these costs relate to NW Natural's remediation activities with respect to its historic manufactured gas plant (MGP) operations. The other costs include remediation of other sites, such as the cleanup and removal of gas holder containers.[3]

Q. Does NW Natural expect to recover any of its remediation costs from third parties?

A. Yes. Sandra K. Hart's direct testimony describes our efforts to recover remediation costs from our historic liability insurance carriers. As explained by Ms. Hart, aside from a settlement reached with one insurer this year, it is unclear whether NW Natural will recover some or all of those costs from insurance carriers with whom NW Natural has policies. We are also involved in a non-judicial allocation process with other entities responsible for contamination in the Portland Harbor Superfund Site. That process is in a very early stage, but we hope it will also result in the recovery from third parties of some of the costs we incur.

III. COLLECTION OF ENVIRONMENTAL REMEDIATION COSTS

Q. How is NW Natural requesting to begin collecting from customers the costs of its environmental remediation activities?

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[1] *See* Financial Accounting Standards Board Accounting Codification 450-20 and Security and Exchange Commission volume 4940.
[2] NW Natural's Form 10-Q for quarter ended Sept. 30, 2011 at 21.
[3] Exhibit 1501 is NW Natural's most recent application to defer environmental remediation costs. That exhibit shows the remediation sites to which the costs that NW Natural is seeking to collect through the Site Remediation Recovery Mechanism described in this testimony relate. *See NWN/1501, Miller/1-12.*

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A. NW Natural is requesting that the Commission establish a mechanism through which NW Natural will begin to collect the costs that it has incurred and will incur in fulfilling its remediation obligations. The mechanism that NW Natural proposes also recovers future costs when incurred, and would recognize the receipt of funds from third parties, such as insurance proceeds.

Q. Given the uncertainties around the future costs of remediation and future recovery from insurers and other parties, why does NW Natural propose that the Commission establish a mechanism to begin recovering these costs now?

A. There are several reasons why NW Natural believes it is appropriate for the Commission to establish a mechanism in this case to allow NW Natural to begin recovering environmental remediation costs. First, as I mentioned above, the environmental deferral account balance is now at around $64.5 million, and would be expected to continue to increase each year for several years to come as a result of continued MGP-related remediation costs and financing costs. And we are not the only ones concerned about the growing liability. Staff has also expressed concern about the size of NW Natural's environmental cost deferral, and the fact that it continues to grow.[4] Further delay will not make the problem go away, and especially with current relatively low gas prices, the Company believes that now is an appropriate time to begin collection of these costs.

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[4] *See, e.g., Re. Application for Deferred Accounting of Unrecovered Environmental Costs Associated with Gasco, Wacker, Portland Gas, Portland Harbor and Eugene Water and Electric Board*, Docket UM 1078, Order No. 10-117 Appendix A at 5 (Apr. 2, 2010) ("Staff remains concerned since this is the seventh year since [NW Natural] first requested authorization to defer unrecovered environmental expenses.").

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Second, timely recovery of its environmental remediation costs is important to the Company's financial health and stability. Up to now, the Company has financed all of the costs associated with environmental remediation, which has put pressure on the Company's cash flow. As described above, to date NW Natural has spent approximately $65 million. This represents about ten percent of the total equity of the Company. If a recovery mechanism is not adopted in this case, the pressure will only continue to build as new costs are incurred. If established, the rate mechanism proposed in my testimony will begin to mitigate this pressure beginning in 2012.

Third, establishing a mechanism now that allows for amortization of some of these costs furthers the regulatory goal of providing for intergenerational equity, which aims to match the payment of costs and the time period in which the costs are incurred. NW Natural has incurred significant costs of environmental remediation, and will likely continue to incur costs over the next several years. Waiting for the total expenditures to be known before beginning to amortize these costs would lead to a situation where future customers would pay for costs that were incurred in a much earlier period. Rather than simply continuing to defer these costs, NW Natural believes it appropriate to begin collecting these costs much more closely in time to when the expenditures are made.

Q. Given that the environmental harms associated with MGPs operated by NW Natural and its predecessors occurred many years ago, why does NW Natural believe it is appropriate to collect the costs of remediation through the rates of its current customers?

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A. As described in the direct testimony of Andrew Middleton, although the operations of MGPs many years ago were the source of the environmental impacts that require remediation, the requirements that actually mandate the remediation are much more recent. *See NWN/1600, Middleton/17-18.* The Company's actions related to the mitigation are imposed by current laws and current federal and state agency requirements and processes. It is therefore appropriate that current customers pay for the current costs being incurred by the utility in order to comply with current laws and administrative agency orders.

Q. Have other state regulatory bodies found that it is appropriate for current customers to pay for the costs of environmental remediation for MGP operations that occurred many years ago?

A. Yes. It appears that in nearly every instance of the many cases in which state public utility commissions have considered this question, they have determined that it is appropriate for current customers of a gas utility to bear remediation costs for past MGP operations.[5]

Q. What are some of the reasons that other commissions and reviewing courts have found that collection from customers of historic MGP remediation costs is appropriate?

[5] We are aware of only two instances (Indiana Gas Company in Indiana and Delmarva Power & Light Company in Maryland) in which recovery from customers of these costs have been denied, and the facts in those instances seem very different from NW Natural's circumstances. In those cases, the company had either acquired the property after knowing that the property was contaminated by prior MGP operations, or the MGP operations had no connection with the utility's provision of service to its customers.

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A. State commissions and reviewing courts cite many different reasons. Some of these reasons include: (1) the company operated in accordance with standards and practices of MGPs and other industries at the time, and the costs of remediation flow to the utility currently only because of changes in environmental laws; (2) costs incurred for cleaning up MGP sites are a reasonable and current cost of doing business for a gas utility; (3) the property being remediated had been used and useful in providing utility service at the time of the operations; (4) utilities are entitled to recovery of statutorily imposed costs that are assessed against utility property; and (5) remediation of MGP environmental contamination is a generally accepted social good, and it would be poor public policy to discourage environmental cleanup by disallowing prudent and reasonable costs of the process.

Q. Do these considerations apply in the case of the remediation costs NW Natural is proposing to recover from its customers?

A. Yes, all of these reasons are applicable. As the direct testimony of our expert Andrew Middleton shows, the operations of the MGP plants at issue were conducted prudently and consistent with the standards and practices of MGPs and other industries at the time. *See NWN/1600, Middleton/38.* In addition, the costs associated with the remediation are being imposed on NW Natural now because of laws that were adopted after the operation of the plants had ceased. Also, the properties being remediated were used and useful in providing utility service, and in fact the site of the former Gasco MGP continues to be used by the utility in providing service to its customers. Finally, the

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Company believes that appropriate cleanup of past environmental damage is an important result that should be encouraged.

IV. PROPOSED MECHANISM FOR COLLECTION OF REMEDIATION COSTS

Q. Has the Company developed a specific proposal for the method or mechanism through which remediation costs should be collected?

A. Yes.

Q. What criteria did the Company use to formulate its proposal?

A. The Company determined that the mechanism should satisfy four basic criteria. First, it should flow costs through rates in a manner that mitigates the burden on customers by spreading costs over time, while matching reasonably close in time the recovery of costs with the expenses themselves. Second, it should effectively control the size of deferrals associated with the costs. Third, it should accommodate uncertainty regarding future costs and accommodate the receipt of funds from third parties, such as insurers, and pass those benefits along to customers on a timely basis. Fourth, it should help preserve the financial integrity of the Company.

Q. What is the Company's proposed mechanism for collecting the costs of MGP site remediation?

A. The Company is requesting that the Commission adopt a rate adjustment mechanism, in which prudently incurred costs of environmental remediation will be passed through to customers on a rolling basis, adjusted for future costs and for receipt of insurance proceeds and other potential recoveries. Through this mechanism, which we propose calling the Site Remediation Recovery Mechanism (SRRM), the Company would begin

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to collect in late 2012 the costs of site investigation and remediation already spent and deferred, and the ongoing costs of investigation and remediation would continue to be collected until five years after the year in which the last remediation expenses were incurred.

Q. Please describe in more detail how the SRRM would work.

A. Deferral of environmental remediation expenses would continue as they are now. Any proceeds recovered from insurance companies or other third parties would be booked as an offset to these deferred expenses. Each year, one-fifth of those deferred expenses (offset by any proceeds received) would be put into an SRRM account for amortization during the November 1 through October 31 period, after the Commission has an opportunity to review those costs and ensure that they were prudently incurred. Any over- or under-collection of the balance in the SRRM account at the end of a 12-month amortization period will be retained in the SRRM account and used to adjust the amount amortized into rates in the subsequent amortization period.

The specific workings of the SRRM are set forth in Schedule 183 of the proposed Tariff. *See* Sheets 183-1 through 183-3 in *NWN/1701, King*.

Q. How would the SRRM work in the first year?

A. One-fifth of all amounts deferred through September 30, 2012, less any insurance proceeds or other third-party proceeds related to its remediation activities received by that date, would be placed in the SRRM account. This amount would be recovered through rates during the period between November 1, 2012 and October 31, 2013, assuming that, as the Company requests in this proceeding, the Commission finds costs

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deferred through that date to be prudently incurred. This period of time for collecting costs would match up with the Purchased Gas Adjustment (PGA) year, and would be after the effective date of the rates determined in this proceeding.

Q. How would the SRRM work on a going-forward basis?

A. On a going-forward basis, by each July 15, NW Natural would submit to the Commission a report detailing all of its recorded expenditures for environmental remediation activities since the last time expenses were placed into the SRRM account, up through the end of the second quarter (June 30). The Company would also report the receipt of any insurance or other third-party proceeds related to its remediation activities. Between July 15 and the PGA effective date, the parties, Commission Staff, and ultimately the Commissioners would have an opportunity to review these costs and receipts to determine that they were prudently incurred. Once they were determined to be appropriately recoverable in rates, one-fifth of the amount in the deferral account would be put in the SRRM account to be recovered in rates during the upcoming PGA period.

Q. Why is the Company proposing to use July 15 as the cutoff date for determining amounts to be recovered during the subsequent PGA year?

A. A July 15 date would allow Staff and other interested parties an opportunity to review the past year's remediation costs ahead of the review that is required for gas costs and other amortizations that occur under the PGA. Setting the cutoff date too close to the PGA could unduly limit Staff's and parties' time for review. In addition, by July 15, the Company will be able to report on all expenditures through the end of the second quarter of that year. Because the first year of the SRRM's operation would not begin until after

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this rate proceeding is concluded, the Company is requesting that the Commission make a prudence determination for costs deferred through September 30, 2012 in this proceeding. The direct testimony of Robert Wyatt demonstrates that NW Natural has been prudently managing these costs, and the direct testimony of Andrew Middleton supports a finding of prudence.

Q. How did the Company determine that one-fifth is an appropriate portion of costs in the SRRM account to collect each year?

A. This ratio falls within the range that seems to be used by most other jurisdictions. Also, that rate of amortization appears to strike a reasonable balance between collecting costs on a timely basis, while at the same time minimizing any resulting volatility in customers' rates. Exhibit NWN/1502 shows a simplified depiction of how the mechanism may operate under a hypothetical future cost and insurance recovery scenario.[6] *See NWN/1502, Miller/1-7.*

Q. From which customers would the remediation costs be collected under the proposed mechanism?

A. It would be collected from all customers by applying a percentage of the costs to each class that is equal to the percentage of margin that is paid by that class.

Q. Have other states adopted similar mechanisms?

[6] The amounts shown in the exhibit do not take into consideration an appropriate treatment of deferred taxes. NW Natural proposes to adjust amounts collected to address future deferred tax balances, which will vary based on ultimate expenditures, insurance recovery amounts, etc., but which have been credited to customers in NW Natural's revenue requirement as a diminishing component of rate base.

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A. Yes, other states have used similar mechanisms to recover the costs of environmental remediation. It is worth noting that there appear to be about as many variations as there are jurisdictions; for example, states use different periods over which to collect the costs as they are incurred, ranging generally from four to ten years. But the concept of using a mechanism that collects costs on a rolling basis appears to be the most common method for dealing with these costs.

Q. What will be the SRRM's impact on customers?

A. The amounts that will be recovered by the mechanism depend on future expenses, which are not known, and the receipt of insurance and other proceeds that are uncertain at this time. For this reason, it is not possible to quantify the amount that will be collected from customers. However, it could be that in the first year of its operation, it would result in an increase, through temporary rates, of one to three percent on top of the increase associated with the revenue requirement in this case.

Q. Are there other aspects of the mechanism that are set out in NW Natural's proposed tariff on which you would like to comment?

A. Yes. First, under the Company's proposal, the Company would be allowed to recover the costs of financing remediation expenses until they are collected from customers. The Company expects that it would continue to finance these costs with a mix of debt and equity, as it has in the past, and therefore proposes that its authorized rate of return be used to establish those financing costs for amounts remaining in the deferral account. However, for the costs that are transferred to the SRRM account and amortized under the mechanism, the Company would collect the Modified Blended Treasury Rate

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(MBTR) that was established in Order No. 08-263 as financing costs on the amounts being amortized that year, in accordance with the Company's understanding of the Commission's policies discussed in further detail below.

Second, Schedule 183 specifies what would happen if the Company receives amounts from insurers that result in a negative SRRM balance. *See* Schedule 183, Sheet 183-2 in *NWN/1701, King.* In those instances, customers would receive a refund of one-fifth of the negative amount in the SRRM account in the PGA year following the establishment of the account at a negative value. However, under the proposed tariff, the Commission has the option of conducting a hearing or taking other action as necessary to determine whether it would be appropriate to forego providing refunds if it appeared that the negative balance was due simply to the timing of the receipt of insurance proceeds or other potential recoveries. In other words, the Commission could determine in certain instances that it would make more sense to suspend the refunds that would otherwise be paid, and apply the negative balance to offset expenses that were expected in the near future. The Commission could also continue payment at a specific level to mitigate upcoming expenses. For example, if a sizeable insurance settlement were received, such that the balance became slightly negative in one year, but it was expected that significant costs would be incurred in the next year, the Commission may find that it would be in customers' interests to forego the refunds to mitigate the increase that would be expected the next year, and perhaps to continue the prior year's recovery level. In any instance where this occurred, the Company's rate of return would be applied to the negative balance to reflect that the Company did not have

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financing costs, and that the customers' payments retained by the Company should accrue financing costs until applied to the future expenses.

Q. Is the Company's proposal that deferral balances that are not yet being amortized accrue interest at the Company's authorized rate of return consistent with Commission policy?

A. Yes. The Commission determined in Order No. 05-1070 that deferred balances prior to amortization will accrue interest at the utility's authorized rate of return.[7] During amortization, deferred balances accrue interest at the MBTR. The MBTR changes each year, but is currently 2.01 percent. Consistent with Commission policy, NW Natural has been accruing interest on deferred environmental remediation costs at the Company's authorized rate of return.

Q. Apart from the fact that doing so is consistent with Commission policy, why does the Company believe that it is appropriate to accrue interest at a rate equal to the utility's regulated rate of return?

A. The Company will continue to finance remediation costs with a mix of debt and equity, and will be financing costs over a long period of time. The Company has financed environmental remediation costs since 2003 and will be financing the unamortized portions of remediation costs until five years after the year in which the final expenditures are made. Because the proposed mechanism is expected to maintain deferred amounts at a reasonable level, it will serve to substantially mitigate the

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[7] *Re. Pub. Util. Comm'n of Or. Staff Request to Open an Investigation Related to Deferred Accounting*, Docket UM 1147, Order No. 05-1070 at 14 (Oct. 5, 2005).

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additional costs to customers that would otherwise accrue if the deferral balance were allowed to continue to grow and accrue interest as it has in the past.

Additionally, as described in the direct testimony of Andrew Middleton, the Gasco plant was one of the larger gas manufacturing plants in the U.S. *See NWN/1600, Middleton/28*. Thus, NW Natural's exposure is higher than many utilities that have liabilities for smaller MGPs, and would be higher than the exposure of larger companies that have similar or smaller liabilities. This means that NW Natural's shareholders would be relatively more exposed to financial harm than would be the case for other utilities if it were allowed a carrying charge that is less than its cost of capital.

Q. Is NW Natural proposing to collect its environmental remediation costs only from its Oregon customers?

A. No. The Company expects to collect an appropriate percentage of these costs from its Washington customers as well. The Company has learned that beginning around 1913, it served Washington customers with gas that was manufactured at its Gasco MGP facilities. Thus, the Company is proposing to collect from Washington customers some of the costs of remediation of environmental harms associated with historic Gasco operations.

Q. What portion of costs is the Company proposing to collect from Washington customers?

A. The Company believes that around 3.32 percent of its costs of remediation related to Gasco should be allocated to Washington customers. This percentage is the Company's best estimate of the percentage of gas from the Gasco facility that was sold

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to Washington customers during the period from 1913 through 1956, when the plant ceased operations. Exhibit NWN/1503 provides the calculations that support the 3.32 percent figure. *See NWN/1503, Miller/1*.

The Company is seeking to work jointly with the Washington Utilities and Transportation Commission and the Commission to determine the allocation. The Company will work with the parties and staff in both states during the pendency of this proceeding to determine if they can support a joint solution.

Q. Earlier you described several criteria that guided the Company in developing its proposal. Can you please explain how the SRRM meets those criteria?

A. The first criterion is that the mechanism should flow through costs to ratepayers in a manner that mitigates the burden by spreading the costs over time, while still providing for recovery over a reasonable period of time. The SRRM meets this criterion by spreading out the recovery of costs, over a period from November 2012 to five years after the year in which the costs of remediation are all incurred. Moreover, the SRRM levelizes the impact of any large costs or receipts that may occur in any given year, and thus normalizes the recovery of costs and is designed to mitigate drastic rate changes.

The second criterion is that the mechanism should effectively control the size of deferrals associated with remediation costs. The SRRM controls the size of deferred amounts by providing for recovery of an appropriate portion during each year of the mechanism's operation. It also controls the size of the deferrals by allowing recovery to begin now and thereby reducing the amount of interest that will accrue on the deferrals.

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The third criterion is that the mechanism should accommodate uncertainty regarding future costs and the receipt of funds from third parties and insurance. The SRRM accomplishes this goal by adjusting the amount of recoveries in the future to reflect costs as they are incurred, and by collecting from customers only the amounts that are ultimately required to perform the remediation. The SRRM also allows for recovery to be based on actual costs, avoiding the over- or under-recovery that would result from basing collections strictly on a forecast of costs or receipts.

The fourth criterion is that the mechanism should act to preserve the financial integrity of the Company. The SRRM achieves this goal by giving assurance of recovery of prudently incurred costs, and by easing the cash flow requirements associated with financing ongoing environmental remediation costs.

Q. Does the SRRM provide for a splitting of environmental remediation costs between shareholders and ratepayers?

A. No, it does not. Under NW Natural's proposal, shareholders would not be required to bear the costs of prudently incurred utility expenses.

Q. Why does the mechanism not require shareholders to bear the costs of the remediation?

A. Shareholders are not required to bear the costs of prudently incurred expenses of providing utility service. Rather, they invest in the Company and put their money at risk in the hopes that the utility will manage its costs and business well, so that they can earn a reasonable return on that investment. Designing a mechanism that requires shareholders to bear the costs of prudently incurred utility expenses would undercut

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investors' reasonable expectations, and would undermine the regulatory compact, which gives a utility an opportunity to earn its regulated rate of return if it manages well.

Additionally, it would be highly unusual for the Commission to disallow recovery of expenses that are imposed on the utility by law. Normally, costs imposed on the Company over which the Company has no control are passed through to customers at one hundred percent. Examples of these types of costs include pipeline charges established by the Federal Energy Regulatory Commission, and the imposition of federal, state, and local taxes. Like these costs, the costs being incurred by NW Natural for environmental remediation are imposed by state and federal laws, and enforced in great detail by regulatory agencies, including the Oregon Department of Environmental Quality (DEQ) and the U.S. Environmental Protection Agency. It is therefore appropriate to allow these costs to be passed on to customers, absent a finding of imprudence by the Commission related to the Company's actions.

V. <u>RECOVERY OF COSTS OF PUMPING STATION AT GASCO SITE</u>

Q. Is the Company proposing that all of the costs associated with remediation for historic MGP operations be dealt with in the same way through the SRRM?

A. The Company is proposing that the costs of one specific remediation project be treated as an addition to rate base once the project is put into service to allow amortization over a longer period of time matching more closely the expected life of the facilities. That treatment is described in Schedule 184 of the proposed Tariff at Sheet 184-1 in *NWN/1701, King*.

Q. What project is that?

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A. NW Natural is currently seeking final sign-off from DEQ on plans to construct a hydraulic containment system for groundwater source control at the Gasco Site. *See NWN/1300, Wyatt/15*. The project, which is required by DEQ, involves the design and construction of an expensive series of wells, pumps, and water treatment facilities. The general purpose of the project is to prevent the further movement of contaminated groundwater from the Gasco Uplands into the Willamette River.

Q. Why is the Company proposing to treat the costs of the pumping station differently than its other remediation costs?

A. Unlike most other required actions NW Natural expects to take in fulfilling its remediation obligations, the pumping station involves the construction of utility plant that will be operated over a long period of time. Such plant is normally added to rate base, and amortized over the life of the plant. This treatment would lessen the near-term impact of the SRRM on customers, and would match the payment of the costs of the plant more closely to its useful life. This treatment would be helpful in the case of the pumping station because it is expected to cost between $11 million and $30 million to construct.

The specific treatment of the costs of the source control system is detailed in proposed Schedule 184. *See* Schedule 184 at Sheet 184-1 in *NWN/1701, King*. If the Commission were to find that the costs of the system should not be added to rate base, then the Company would propose that the costs be treated as other remediation expenses under the SRRM.

Q. Does the Company know of any other specific remediation projects for which it proposes unique treatment under the SRRM?

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A. Not at this time. If other projects are required in the future that appear to be most appropriately handled through rate base treatment, the Company would expect to discuss such projects with the Commission and the parties, in order to determine whether the costs should be treated differently than the standard process outlined in the SRRM.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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NW Natural

Exhibits of C. Alex Miller

ENVIRONMENTAL MITIGATION – COST RECOVERY / RATE ADJUSTMENT MECHANISMS
EXHIBITS 1501 - 1503

December 2011

**EXHIBITS 1501-1503 – ENVIRONMENTAL MITIGATION –
COST RECOVERY – RATE ADJUSTMENT MECHANISMS**

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January 21, 2010

VIA ELECTRONIC FILING

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ATTN: Filing Center

Re: **OPUC Docket UM 1078:** Application for Reauthorization of Deferred Accounting of Certain Expenses or Revenues – Unrecovered Environmental Costs

In accordance with ORS 757.125, ORS 757.259(2)(e), and OAR 860-027-0300, Northwest Natural Gas Company, dba NW Natural ("NW Natural" or "Company"), files herewith the above-referenced Application for Reauthorization of Deferred Accounting of Unrecovered Environmental Costs Associated with Gasco, Wacker (now known as Siltronic), Portland Gas, Portland Harbor, Eugene Water and Electric Board, Central Gas Hold, Oregon Steel Mills, and the French American International School.

A notice concerning this application will be sent to all parties who participated in Docket UM 1078 and in the Company's most recent general rate case, UG 152. A copy of the notice is part of the enclosed application.

Please call Jennifer Gross at (503) 226-4211, extension 3590, if you have any questions or require any further information.

Sincerely,

/s/ Mark R. Thompson

Mark R. Thompson
Manager, Rates and Regulatory Affairs

enclosures

BEFORE THE PUBLIC UTILITY COMMISSION

OF

OREGON

UM 1078

In the Matter of the Application	)
by NORTHWEST NATURAL GAS COMPANY,	)
dba NW NATURAL, for Reauthorization	)
to Defer Certain Expenses or Revenues	)
Pursuant to ORS 757.259	)

APPLICATION FOR REAUTHORIZATION
TO DEFER CERTAIN EXPENSES OR REVENUES

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company), hereby files with the Public Utility Commission of Oregon (Commission) this application for reauthorization (Application) to use deferred accounting pursuant to ORS 757.210 and 757.259, and OAR 860-027-0300, for the 12-month period beginning January 26, 2011, through January 25, 2012.

In compliance with the requirements of OAR 860-027-0300(3) and (4), NW Natural hereby submits the following information:

1. A description of the utility expenses or revenues for which deferred accounting is requested. [OAR 860-027-0300 (3)(a)]:

NW Natural seeks authorization to record all environmental costs, which shall include, but are not necessarily limited to, all costs related to investigation, study, monitoring, oversight, legal and remediation costs, and all costs associated with pursuing insurance recoveries (hereafter "Environmental Costs") that are associated

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with the nine projects: eight were described in more detail in the Company's initial Application for Authorization to Defer Accounting, filed April 7, 2003; the ninth project designated as the French American International School (FAIS), was described in the Company's Application for Reauthorization to Defer Accounting, filed on January 25, 2008.

In addition, the Company has recently received notice from the US Army Corp of Engineers that it believes that Gasco operations contributed to the contamination at its US Moorings facility, which is adjacent to Gasco. If responsibility is assigned to NW Natural during the deferral period, the Company may file a supplemental request to begin deferring Environmental Costs associated with this site as well.

NW Natural is also currently attempting to determine what portion of the Environmental Costs are attributable to the provision of service in Washington, and NW Natural advises the Commission that it may soon be filing in Washington an application for deferred accounting similar to the one in this docket.

2. Justification for the deferred accounting requested with reference to the sections of ORS 757.259 under which deferral can be authorized. [OAR 860-027-0300 (3)(b)]:

Authorization to defer Environmental Costs and amounts from insurance recoveries can be authorized pursuant to ORS 757.259(2)(d) because they are "utility expenses or revenues, the recovery or refund of which the commission finds should be deferred in order to minimize the frequency of rate changes … or to match appropriately the costs borne by and benefits received by ratepayers."

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3. The accounts proposed for recording the amounts to be deferred and the accounts that would be used for recording the amounts in the absence of approval of deferred accounting are as follows. [OAR 860-027-0300 (3)(c)]:

NW Natural proposes to accrue estimates of the Environmental Costs to a separate liability account for each site with the charge recorded in an operation and maintenance expense account. The proposed balance sheet accounts to be used are:

262140	Injuries & Damage Reserve ------Gasco
262143	Injuries & Damage Reserve-------Wacker (*aka* Siltronic)
262144	Injuries & Damage Reserve-------Portland Harbor
262145	Injuries & Damage Reserve-------Oregon Steel Mills
262146	Injuries & Damage Reserve-------Tar Body (a subset of Portland Harbor)
262147	Injuries & Damage Reserve-------Central Gas Hold
262149	Injuries & Damage Reserve-------French American International School (FAIS)

As environmental liabilities are paid, or as they are accrued and if insurance recovery is not likely or is uncertain, the costs will be deferred in the following deferred regulatory asset accounts on the balance sheet:

186145	Environmental Inv.-------Gasco
186146	Environmental Inv.-------EWEB (*aka* Eugene)
186147	Environmental Inv.-------Wacker (*nka* Siltronic)
186148	Environmental Inv.-------Portland Harbor
186149	Environmental Inv.-------Portland Gas (*aka* Front Street)
186151	Environmental Inv.-------Tar Body (a subset of Portland Harbor)

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186152 Environmental Inv.-------Oregon Steel Mills

186153 Environmental Inv--------Central Gas Hold

186154 Environmental Inv--------French American International School (FAIS)

NW Natural has recorded amounts estimated as insurance receivables, Account 143008----Insurance Recovery for Gasco and Portland Harbor and Account 186260----Deferred Regulatory Receivable-Environmental. The total balance in the receivable accounts is currently $703,608. The estimated insurance receivable reduced the amount charged to the O&M expense. Any recoveries from insurance would be recorded in the 143008 or 186260 accounts.

NW Natural contemplates recording of authorized deferred expenses and insurance recoveries until the net Environmental Costs can be addressed in a future general rate case filing, in compliance with the Commission's Order No. 06-211, dated April 27, 2006. As the nine sites are at different study and remediation stages, NW Natural may present to the Commission a proposed ratemaking treatment for deferred costs associated with a particular site, should costs and remediation at the particular site become known and certain. At the time of consideration for incorporation into rates, NW Natural will propose an appropriate amortization period for the Environmental Costs for the Commission's consideration. NW Natural does not request a determination of ratemaking treatment of the Environmental Costs at this time.

4. An estimate of the amount to be recorded in the deferred accounts for the 12-month period subsequent to the Application. [OAR 860-027-0300 (3)(d)]:

The Company will incur additional site study, clean-up, potential natural resource damages, DEQ/Environment Protection Agency, tribe and natural resource damage

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trustee oversight, and legal costs as well as administrative expenses related to feasibility studies and remediation activities associated with these sites. Environmental Costs will be charged to deferred regulatory asset accounts. Insurance recoveries will be used as offsets to deferred Environmental Costs. These anticipated expenses and recoveries from insurance are the cause of this filing. At this time, information is insufficient to more accurately estimate the total potential liability for investigation and remediation costs associated with the nine sites, or to accurately estimate the corresponding total insurance recovery amounts.

5. A description and explanation of the entries in the deferred accounts. [OAR 860-027-0300 (4)(a)]:

Below is a list of all liabilities, costs and interest that has been recorded as of December 31, 2010:

Account	Site Name	Recorded Liability	Recorded Expense*	Accrued Interest
186145	Gasco	72,847,178	25,271,052	4,659,744
186146	EWEB	0	145,738	50,085
186147	Wacker (*nka* Siltronic)	2,907,753	2,637,729	529,056
186148	Portland Harbor	16,745,170	13,915,799	3,543,724
186149	Portland Gas (Front Street)	1,937,539	932,647	82,162
185151	Tar Body (a subset of Portland Harbor)	9,888,017	15,582,720	5,060,916
186152	Oregon Steel Mills	200,000	31,878	10,956
186153	Central Gas Hold	549,815	37,798	7,743
186154	French American International School (FAIS)	138,482	174,278	26,475
	TOTAL	105,213,954	58,729,639	13,970,861

*Recorded expense includes accrued interest

Recorded costs are for investigation and remediation, including consultants' fees and ODEQ oversight reimbursement and legal fees.

6. Interest on Deferred Balances. [OAR 860-027-0300(4)(b)]:

As part of this reauthorization, the Company requests continued permission to accrue interest to the deferred actual cash expenses. The Commission has allowed the Company to collect interest on deferred balances as stated in Commission Order Nos.

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06-211, 07-147, 08-247, 09-172, and 10-117. As of 2010, the Company has spent over $59 million on projects. As those amounts continue to be outstanding in anticipation of insurance offsets or recovery from ratepayers, financing the spent amounts is an ongoing burden. As insurance proceeds are attained, they will be used to draw down the amounts outstanding, until final ratemaking is determined for the deferred accounts and interest on the balance would be affected accordingly. Please note that the Company does not accrue interest on the recorded liability.

7. Reason for the continued request for deferred accounting. [OAR 860-027-0300(4)(b)]:

Since early 2006, NW Natural has been pursuing recovery of insurance for its environmental liabilities. It has identified and analyzed all of the liability insurance policies issued between the late 1930s and 1986 which may provide coverage. All of the insurers have been contacted. Most have signed confidentiality agreements and have been provided detailed information about the environmental liabilities. Because the coverage issues involve complex legal and factual issues, the insurers have not agreed that coverage exists. However, most insurers agreed to enter into negotiations in an effort to resolve the claims. In late 2010, NW Natural determined it would not be able to reach settlements within a reasonable period of time, so the Company filed a lawsuit against the insurers seeking a recovery of funds.

8. Requirements per Commission Order No. 09-263

Below is the information required per Commission Order No. 09-263, issued in Docket UM-1286, Staff's Investigation into Purchased Gas Adjustment Mechanisms:

a. A completed Summary Sheet, the location in the PGA filing, and an account map that highlights the transfer of dollars from one account to another

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NW Natural does not currently intend to request that costs deferred under UM 1078 be amortized in the 2011 PGA filing.

b. The effective date of the deferral

This application is for the 12-month period beginning January 26, 2011 through January 25, 2012.

c. Prior year Order Number approving the deferral

Approval to defer Environmental Costs was last granted under Commission Order No. 10-117.

d. The amount deferred last year

$ 12,642,266 was deferred in the last deferral year of January 26, 2009, through January 26, 2010. This amount includes $4,443,792 in interest.

e. The amount amortized last year

No costs deferred under UM 1078 were amortized for collection in 2010.

f. The interest rate that will apply to the accounts

The interest rate for deferral accounts is 8.618%.

g. An estimate of the upcoming PGA-period deferral and / or amortization

For the reasons described in Section 4 above, the Company is unable to estimate the costs it will incur for its environmental remediation efforts in 2011.

8. A notice of this Application has been served on the UM 1078 service list and on all parties who participated in the Company's most recent general rate case, UG 152, and is attached to this Application.

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9. Communications regarding this Application should be addressed to:

Jennifer Gross
Rates & Regulatory Affairs
NW Natural
220 NW Second Avenue
Portland, OR 97209-3991
Telephone: (503) 226-4211, ext. 3590
Facsimile: (503) 721-2516
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and

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E-mail: efiling@nwnatural.com

DATED this 21st day of January 2011.

Respectfully submitted,

NW NATURAL

/s/ Mark R. Thompson

Mark R. Thompson
Manager, Rates & Regulatory Affairs

NW Natural

January 21, 2011

NOTICE OF APPLICATION FOR REAUTHORIZATION TO DEFER ACCOUNTING OF UNRECOVERED ENVIRONMENTAL COSTS

To All Parties Who Participated in UG 152:

Please be advised that today Northwest Natural Gas Company, dba NW Natural ("NW Natural" or "Company"), applied for reauthorization to defer certain expenses and revenues relative to unrecovered environmental costs associated with Gasco, Wacker (now known as Siltronic), Portland Gas, Portland Harbor, Eugene Water and Electric Board, Central Gas Hold, the French American School, and Oregon Steel Mills, pursuant to the provisions of ORS 757.259(2)(e). Copies of the Company's application are available for inspection at its main office.

This is not a rate case. The purpose of this Notice is to inform parties that participated in Docket UM 1078, and in the Company's most recent general rate case, UG 152, that the Application was 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 Public Utility Commission of Oregon as follows:

NW Natural
Attn: Jennifer Gross
220 NW Second Avenue
Portland, Oregon 97209-3991
Telephone: (503) 226-4211 ext 3590

Public Utility Commission of Oregon
Attn: Judy Johnson
550 Capitol St., NE, Ste 215
PO Box 2148
Salem, Oregon 97308-2148
Telephone: (503) 378-6636

Any person may submit to the Commission written comments on this matter no sooner than 25 days from the date of this Application. The granting of this Application will not authorize a change in rates, but will permit the Company to defer amounts in rates to a subsequent proceeding.

* * * * *

UM 1078-Application for Reauthorization to Defer Certain Revenues and Expenses

CERTIFICATE OF SERVICE

I hereby certify that on the 21st day of January 2011, I served the foregoing NOTICE OF APPLICATION FOR REAUTHORIZATION TO DEFER CERTAIN EXPENSES OR REVENUES in dockets UM 1078 and UG 152 upon each party listed below by U.S. mail, postage prepaid, or where paper service is waived, by electronic mail.

UM 1078

CARLA BIRD
PUBLIC UTILITY COMMISSION OF OREGON
PO BOX 2148
SALEM OR 97308-2148

UG 152

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DATED at Portland, Oregon, this 21st day of January 2011

/s/ Jennifer Gross
Jennifer Gross
Rates & Regulatory Affairs
NW NATURAL
220 NW Second Avenue
Portland, Oregon 97209-3991
1.503.226.4211, extension 3590
jgg@nwnatural.com

Environmental Cost Recovery Hypothetical Scenario

($ in thousands)

NOTE: The purpose of this model is to present a hypothetical cost scenario for purposes of illustrating how the proposed Site Remediation Recovery Mechanism would operate in that scenario. The costs contained in this table do not represent actual or forecast costs or NW Natural's actual expectations of what insurance recoveries it will receive.

General assumptions:

- Annual expenditures are made during the first 10 years with payments evenly spread
- Clean-up is completed and final expenditures are made by 10/31/2021
- Expenditures are collected on a 5-year rolling basis

Inputs:

WACC (proposed)	8.28%
Modified blended rate (proposed)	2.01%
Expenditures and interest - 10/31/11	65,000
Future expenditures	100,000
	165,000
Less insurance recoveries	
2012	(35,000)
2014	(25,000)
2017	(25,000)
	(85,000)
Net expenditures	80,000

SUMMARY						
PGA Year	Current Expenditures	Insurance Recovery	Collected	Interest	End Balance 10/31	1/5th of Balance
2010	-	-	-	-	65,000	13,000
2011	10,000	(35,000)	-	5,894	45,894	9,179
2012	10,000	-	(9,179)	1,604	48,320	9,664
2013	10,000	-	(12,170)	1,362	47,511	9,502
2014	10,000	(25,000)	(14,290)	(550)	17,670	3,534
2015	10,000	-	(10,978)	550	17,242	3,448
2016	10,000	-	(12,467)	725	15,500	3,100
2017	10,000	(25,000)	(5,364)	(1,109)	(5,974)	(1,195)
2018	10,000	-	26	181	4,233	847
2019	10,000	-	448	591	15,272	3,054
2020	10,000	-	(5,138)	760	20,895	4,179
2021	-	-	(5,345)	370	15,919	4,179
2022	-	-	(3,357)	289	12,851	4,179
2023	-	-	(6,550)	194	6,496	4,179
2024	-	-	(4,029)	83	2,550	4,179
2025	-	-	(2,554)	4	-	-
TOTAL	**100,000**	**(85,000)**	**(90,948)**	**10,948**		

Year	Gas Volumes Sold Washington	Gas Volumes Sold System	Washington % Gas Volumes Sold	
1922	36,292	3,166,707	1.15%	
1923	31,508	3,329,937	0.95%	
1924	30,167	3,887,222	0.78%	
1925	49,060	4,130,818	1.19%	
1926	52,150	3,998,203	1.30%	
1927	59,070	4,362,441	1.35%	
1928	64,710	4,335,864	1.49%	
1929	78,102	4,435,926	1.76%	
1930	82,788	4,341,878	1.91%	
1931	80,833	3,996,857	2.02%	
1932	73,077	3,721,513	1.96%	
1933	60,020	3,329,499	1.80%	
1934	58,294	2,967,388	1.96%	
1935	60,388	3,367,475	1.79%	
1936	66,167	3,598,131	1.84%	
1937	76,592	3,890,948	1.97%	
1938	80,418	3,926,566	2.05%	
1939	84,615	3,978,949	2.13%	
1940	101,524	4,183,852	2.43%	
1941	128,591	4,065,870	3.16%	
1942	179,752	5,160,805	3.48%	
1943	218,537	5,925,699	3.69%	
1944	225,971	6,248,702	3.62%	
1945	260,899	7,050,560	3.70%	
1946	282,474	5,984,619	4.72%	
1947	301,472	6,078,065	4.96%	
1948	313,922	6,203,992	5.06%	
1949	303,749	6,038,748	5.03%	
1950	413,877	8,997,327	4.60%	
1951	391,543	8,511,795	4.60%	
1952	394,493	8,575,939	4.60%	
1953	376,454	8,183,793	4.60%	
1954	276,767	6,644,537	4.17%	
1955	288,932	8,834,971	3.27%	
1956	292,045	8,930,158	3.27%	
			2.98%	**average of WA %**
	5,777,286	174,001,886	**3.32%**	**sum of volumes**
	180,540	5,437,559	3.320%	average of volumes

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Andrew Middleton

ENVIRONMENTAL MITIGATION - HISTORY
EXHIBIT 1600

December 2011

EXHIBIT 1600 – DIRECT TESTIMONY - ENVIRONMENTAL MITIGATION - HISTORY

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position.

A. My name is Andrew C. Middleton. I am President of Corporate Environmental Solutions LLC.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Northwest Natural Gas Company ("NW Natural" or the "Company").

Q. Please describe your educational and professional background.

A**.** I hold a Bachelor of Science degree in Civil Engineering from Virginia Polytechnic Institute and State University (awarded 1971), a Master of Science degree in Sanitary Engineering from Virginia Polytechnic Institute and State University (awarded 1972), and a Ph.D. in Environmental Engineering from Cornell University (awarded 1975). Since 1975, I have taught environmental engineering at universities, worked for industry on environmental matters, and worked as an environmental consultant.

My industrial experience included a large number of environmental projects on facilities involving the production, processing, and handling of tar and tar chemicals, including ones on industrial wastewater treatment and industrial site investigation and remediation. As an environmental consultant, I have worked on at least 300 manufactured gas plant (MGP) sites, including visits to at least 145 sites. My scope of work on the vast majority of the 300 sites included a review of historical information about them. In the course of my research concerning these 300 MGPs and the manufactured gas industry in general, I have also seen and reviewed information concerning numerous other plants. I have testified on six occasions before public utility commissions regarding manufactured gas plants. I have also testified about MGPs in a number of lawsuits across the United States in depositions and affidavits, as well as twice in court where the courts recognized me as an expert on manufactured gas plants.

At *NWN/1604, Middleton, 1-16* is my curriculum vitae describing my background in more detail.

Q. Please summarize your testimony.

A. In my testimony, I:

- Review the history and evolution of the manufactured gas industry—how and why it developed, its general characteristics, and why it declined;
- Identify the major gas manufacturing processes and the residual streams generated in gas manufacture;
- Describe the demolition and dismantling practices of gas plant equipment and vessels; and,
- Describe the state of gas industry knowledge regarding the potential environmental consequences, as understood today, of
  - the operation of manufactured gas plants;
  - the disposition of residuals from gas manufacture; and,
  - the demolition and dismantling of manufactured gas plants.

Second, my purpose is to:

- Review the history of gas manufacture in Portland at MGP sites now connected with NW Natural ("Portland MGP Sites");
- Identify the residual streams generated by this gas manufacture and the disposition of those streams;

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- Describe the demolition and dismantling of the gas manufacturing and storage facilities in Portland; and,
- Compare these to the practices of the gas industry during the comparable time frames.

II. HISTORY OF THE MANUFACTURED GAS INDUSTRY

Q Please provide an overview of the history of gas manufacture in the United States.

A. Although "gas" was first named in 1609, the first gas company was not founded until over 200 years later in London in 1812. The first U.S. gas company was founded in Baltimore in 1816. A century later, by 1920, the U.S. had over 1,000 manufactured gas companies. However, by 1970, utility-owned or operated manufactured gas plants were almost non-existent, with manufactured gas having been replaced by natural gas across the U.S. The 150-year period from 1816 until the mid-1960s defines the era of manufactured gas ("MGP Era").

During the MGP Era, the U.S. manufactured gas industry began, matured, and ended. Various gas-making processes, gas storage vessels, and gas purification equipment were developed and modified throughout much of the MGP Era.

Q. How was gas manufactured?

A. Three types of gas-making processes generally dominated the manufacture of gas in the United States during the MGP Era: coal gas, carburetted water gas (also known as just "water gas") and oil gas. Coal gas manufacture, which began in 1816, had two primary process configurations: retorts and byproduct coke ovens. In either case, bituminous coal was heated to a high temperature in a closed vessel in the absence of air. This resulted in the volatile portion of the coal being driven off as gas which was cooled and

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purified through various processes. Retorts were smaller vessels more widely used by the gas industry than the larger coke ovens. The purified gas was stored in gas holders prior to its distribution. The remaining part of the coal was coke, which was a high carbon material used as fuel, in metallurgical processes, or as feedstock to the carburetted water gas process. Coal gas was manufactured in retorts at two of the Portland MGP Sites.

Carburetted water gas manufacture, which began in the 1870s, made gas from coal or coke and oil in three cylindrical vessels. The process was cyclical alternating in vessel heating and in making gas. By the early 1900s, the carburetted water gas process was widely used in the gas industry. As with coal gas, the carburetted water gas was cooled and purified before storage. Carburetted water gas was manufactured at one of the Portland MGP Sites.

Oil gas manufacture had three general process configurations: small-scale oil gas, West Coast oil gas and high-Btu oil gas.[1] These processes made gas from oil or a fraction of oil often in conjunction with the use of steam. There were many equipment configurations for the small scale oil gas process, which was used predominantly in the 1800s, but not at the Portland MGP Sites. The West Coast oil gas ("Oil Gas") process was used in major installations beginning around 1900 on the West Coast and continuing throughout the MGP Era. This process relied on one or two vessels operated in alternate heating and gas making cycles. The hot gas was cooled and purified before

[1] It should be noted that in this document "Btu" stands for British thermal unit, which is a measure of heat content. As used here, "Btu" generally means the heat content of the gas per cubic foot of gas. For example, a reference to "530 Btu gas" means that the heat content of the gas was 530 British thermal units per cubic foot of gas, which was generally the approximate Btu value of manufactured gas. Natural gas has a Btu value of around 1000. High-Btu oil gas had a Btu value around 1000 to be compatible with natural gas.

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storage. The other major oil gas process was the high Btu oil gas process used later in the MGP Era. This process relied on Oil Gas equipment or modified carburetted water gas equipment. It operated similarly to the Oil Gas process, but the feedstocks were manipulated to produce a heat content of around 1000 Btu so that it could be mixed with natural gas in contrast to the other major processes, which produced gas with a heat content in the range of 500-600 Btu. Oil Gas was manufactured at two of the Portland MGP Sites and high Btu oil gas at one site.

More detailed descriptions of retort coal gas, carburetted water gas, and Oil Gas are provided below in regard to the types of processes that were used at the Portland MGP Sites.

In addition, there were at times other gas-making processes used less frequently than those discussed above (*e.g.*, refinery gas reforming, small-scale oil gas manufacture, petroleum coking, or rosin gas manufacture). Petroleum coking was used at one of the Portland MGP Sites and is described below in regard to that site.

Q. What was generated by gas manufacture in addition to the gas itself?

A. In addition to gas, the gas-making processes also generated solid and liquid residuals. Depending on the particular gas-making process, these residuals included tar, lampblack, light oil, ammonia, ash, clinker, residuals from sulfur removal, and/or wastewater.

Q. How was manufactured gas purified?

A. After its manufacture by one of the above processes, gas was purified to recover byproducts and to remove residuals not suitable to be distributed with the gas. *NWN/1601, Middleton/1* is a general overview of a typical gas manufacture process

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diagram showing purification steps. As described above, the first step in purification of the hot gas was its quenching (*e.g.*, hydraulic main for coal gas and wash box for carburetted water gas and Oil Gas). Further removal of tar not removed in the quench step was accomplished generally by the use of condensers and scrubbers. Additional equipment, such as tar extractors or Cottrell precipitators, was used at some plants as it became commercially available. At coal gas plants, ammonia removal, typically through water absorption, was the next step. At some coal gas plants, absorption of ammonia into sulfuric acid was used. Depending on the process and scale of operation, light oil and naphthalene may have also been removed typically by oil scrubbing.

The most common last step before gas storage was hydrogen sulfide removal. Prior to the 1880s, lime absorption was the typical process. In the 1880s and afterwards, iron-oxide beds became the dominant process. Around 1920 and afterwards, some larger plants used liquid sulfur removal. In the case of coal gas and Oil Gas plants using crude oil, hydrogen sulfide removal also accomplished cyanide removal from the gas.

After hydrogen sulfide removal, the gas went into storage prior to its distribution.

Q. How was gas stored?

A. There were three general types of gas holders used to store gas: 1) low-pressure, water-seal; 2) waterless, low-pressure; and, 3) high-pressure.

The low-pressure, water-seal gas holder consisted of a water tank, the holder itself, which could have had multiple telescoping lifts, and structural components and piping equipment. *NWN/1602, Middleton/1* is a picture of a low-pressure, water-seal holder with an above-ground steel water tank. The water tank was filled with water

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which sealed the gas within the holder. The holder itself moved up and down within its superstructure as gas was added or removed from it.

The waterless, low-pressure holder consisted of a very large, vertical tank with a disk floating on the gas inside. The purpose of the disk was to contain and pressurize the gas. The disk moved up and down in the interior of the tank as gas was added and removed, respectively. The seal between the perimeter of the disk and the inside of the holder was typically wetted with recirculating tar.

High pressure holders were either spherical (*e.g.*, the Hortonsphere), horizontal cylinders (a.k.a. "bullet tanks" like current propane storage cylinders) or vertical cylinders. These tanks received gas from compressors and stored the gas at higher pressures (*e.g.*, 30-60 pounds per square inch) than the low-pressure holders. These were mechanically sealed, pressurized tanks in contrast to the low pressure, water-seal holders.

Gas holders ranged in size from small (*e.g.*, 25,000 cubic feet in an early low-pressure water seal) up to very large (*e.g.*, 20 million cubic feet for waterless holders of the 1920s and afterwards).

Q. What was the general disposition of residuals from gas manufacture?

A. The gas-making processes produced various residuals in addition to manufactured gas. Residuals included both byproducts and wastes. Byproducts were materials that could be sold or beneficially used at the MGP. Wastes were the converse—materials that could not be sold or used beneficially. There were three general methods for disposition of these residuals:

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- <u>Sale or Use as Byproducts:</u> Various markets existed at different times for byproducts. These markets changed according to external factors. Byproducts could also be used by a gas company directly or as feedstocks to other manufacturing processes to create more valuable byproducts.
- <u>Use as Fuel</u>: If residuals had sufficient energy content and had physical and chemical characteristics that could reasonably facilitate use as fuel, they could be burned to generate heat for the gas manufacturing process or in the boiler house to generate steam.
- <u>Disposal:</u> If residuals could not be sold or used as byproducts or fuel, they became wastes for disposal.

The viability of byproduct recovery was dependent on several factors, including: economical technologies had to be available to recover byproducts that would meet market specifications; sufficient quantities of material had to be produced to warrant recovery; and there had to be a market for the byproducts. The principal motivation for byproduct recovery was to generate added revenue, reducing the cost of gas to the consumer, thereby making manufactured gas less costly. As part of their oversight role on behalf of the gas consumer, public service commissions often received reports on the recovery and sale or use of byproducts from manufactured gas companies within their respective jurisdictions.

Q. What was the typical disposition of coke?

A. Coke from coal carbonization was a high-carbon content byproduct sold for use as fuel or in metallurgical processes or used as fuel at the MGP or at the MGP as feedstock to

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the carburetted water gas process. Petroleum coke was a high-carbon, low-ash coke that was sold, for example to be used in the manufacture of aluminum.

Q. What was the typical disposition of tar?

A. Tar from any of the processes was a byproduct sold for use in making commercial products (*e.g.*, road tar and tar chemicals), used as fuel at the MGP, or used as a feedstock for producing commercial products at the MGP (*e.g.*, road tar and tar chemicals). As necessary, tar was dehydrated where practical, with the resulting tar sold or burned as fuel. Various dehydration processes were available to generate lower water content tar, including heating and centrifugation methods. None, however, proved to be completely practical on every high water content tar. If a high water content tar could not be reasonably treated or the tar could not be sold or burned, it was typically stored in tanks, gas holders, or onsite ponds, or was disposed of as a waste.

Q. What were commercial uses of tar?

A. Tar is a complex mixture of hundreds of organic chemical compounds, including many polycyclic aromatic hydrocarbons. It had and still has many beneficial uses. Various companies outside of the gas industry purchased tar during the MGP Era to refine it into commercial products. The primary refining process for tar was distillation into different fractions. The commercial products included creosote as a preservative for railroad ties and utility poles, road tar, bitumen used for tar roofs, tar coatings, and tar pitch used in the manufacture of aluminum. Some gas companies refined the tar at the MGP and sold the resulting commercial products directly to end users such as state or county road departments.

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Substantial volumes of tar were put on the ground in paving roads and streets or for dust suppression on roads and streets, including at locations in Oregon. For example, application rates were up to two gallons of tar binder per square yard of road. On a 20-foot wide road, this would be 23,000 gallons of tar per mile of road. In 1913, the Barrett Company stated that its product, Tarvia, had been used successfully on over 50 million yards of roadways and pavements in this country. For a 20-ft wide road, this quantity in square yards equates to over 4,000 miles of roads and streets. At an application rate of two gallons per square yard, this would equate to 100 million gallons of tar placed on roads and streets.

Currently, coal tar (there is no current production of carburetted water gas or Oil Gas tar) remains a commercial product used for a variety of purposes, including production of creosote, roofing bitumen, tar pitch for the aluminum industry, and driveway sealer. In addition, certain shampoos (*e.g.*, Westwood-Squibb Sebutone® tar shampoo) contain a USP-grade of coal tar.

Q. What was the typical disposition of lampblack?

A. Lampblack was very fine carbon particles with low ash content. Lampblack from the Oil Gas process was typically used at the MGP as fuel or sold as fuel or a feedstock in certain manufacturing processes. As discussed in further detail below, the Portland Oil Gas MGPs used lampblack to make briquettes which they then sold as fuel. If neither of these uses were practical, lampblack could have been disposed on onsite at the MGP or offsite at a waste disposal site.

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Q. What was the typical disposition of ammonia?

A. Ammonia from a coal gas process was typically recovered and sold as a chemical source of ammonia or sold or given away as fertilizer. As an example of a commercial use, in the early days of refrigeration, ammonia was the gas used in the compressor equipment.

Q. What was the typical disposition of light oil?

A. In the manufactured gas industry, “light oil” was a liquid recovered from the gas-making process that was made up primarily of volatile aromatic hydrocarbons (*e.g.*, benzene and toluene). Light oil was less dense than, and therefore floated on, water. Without being refined, light oil could be used as fuel or sold as commercial product for use as a feedstock in chemical manufacture. It could be refined into motor fuel for mixing with gasoline or for use by itself. It could also be distilled into its different fractions, thereby serving as a source for commercial chemicals such as benzene. Light oil recovered from the gas of any of the processes was typically sold as a commercial product, used at the MGP as fuel or processed at the MGP into other commercial products (*e.g.*, motor fuel).

Q. What was the typical disposition of materials from sulfur removal?

A. There were two general types of material mixtures resulting from sulfur removal: spent lime primarily in the 1800s and spent iron oxides from the 1880s until the end of the MGP Era. In addition, there was elemental sulfur recovered from certain liquid sulfur removal processes from the 1920s until the end of the MGP Era. This typical disposition of these materials was as follows:

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Spent Lime

Spent lime was a mixture of wet lime that had reacted with hydrogen sulfide (and in the case of coal gas, hydrogen cyanide) to form chemical compounds of sulfide (and cyanide in the case of coal gas). Its use was predominantly before the 1880s when iron oxide sulfur removal was developed; however, its use afterwards continued at some MGPs. It was sold or given away as a soil conditioner or disposed of as a waste.

Spent Iron Oxides

Spent iron oxide was a mixture of iron compounds, sulfur compounds, and elemental sulfur, and the medium on which the iron oxide had originally been fixed. This medium was often wood chips or wood shavings, but it could have been other materials (*e.g.*, corn cobs) depending on the materials available to the MGP. The purpose of the medium was to provide porosity together with a surface for the iron oxide so that the hydrogen sulfide containing gas could flow through a bed of the material and have the sulfide react with the iron. In the case of coal gas and of Oil Gas using crude oil, the spent iron oxide also contained iron cyanides, as the iron would react with the hydrogen cyanide present in these manufactured gases. Iron cyanides typically converted to Prussian blue or ferric ferrocyanide (FFC), which is a stable compound. Commercially, Prussian blue is used as a blue pigment.

The sulfide removal capacity of the iron oxide could be regenerated several times (known as revivification in the gas industry). Revivification was accomplished by removing the iron oxides and placing them on the MGP site for exposure to air or by adding air to the gas entering the purification process. However, at some point no further revivification could be attained and they became “spent.”

The spent oxides were typically used as fill materials, disposed of as a waste, or sold or used as sources of chemicals. An example of this market is the appearance in the 1910s in Brown's Directory of advertisements seeking to purchase spent oxide.

Elemental Sulfur

Liquid sulfur purifiers were developed in the 1920s for use at larger scale MGPs. The purification process was to scrub the gas with a solution that would absorb the hydrogen sulfide and then treat the scrubber solution to remove the sulfide so the solution could be recycled to the scrubber. In certain of these processes, elemental sulfur was recovered.

Elemental sulfur from liquid sulfur purifiers was typically sold as a commercial product or disposed of as a waste if it was not saleable.

Q What was the typical disposition of ash and clinker?

A. Ash resulted from heating the retort coal gas process by burning coke or the burning of coal or coke in the boiler house to generate steam. It consisted of the chemical compounds in coal which did not combust. Clinker was a residual of the carburetted water gas process, being the remnants of the coal or coke that did not burn or react with steam in the cyclical process in the generator vessel. It consisted of the non-combustible compounds in coal or coke along with unreacted carbon. Clinker had a slag-like appearance.

Ash and clinker were not generally marketable in the U.S. Sometimes, ash was used in building materials and clinker was used in sports running tracks. The majority of ash and clinker was used as fill, or disposed of as a waste.

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Q What was the typical disposition of wastewater?

A. Wastewater was the excess water from the gas-making and purifying processes not recycled to the process. Substantial amounts of water were recirculated for hot gas quenching, gas scrubbing, and gas cooling. Typically, the excess water (*i.e.*, wastewater) became an effluent discharged to surface waters, to local municipal sewerage systems or to the MGP site itself, where its fate depended on the local site hydrologic conditions.

Q. What happened if residuals from an MGP had no market or economic use during some time period in which the MGP operated?

A. If there was no market or economic use for any of the residuals produced, they became wastes for disposition by the means contemporary to the situation at the time.

Q. What general waste disposal practices did the manufactured gas industry employ?

A. In the manufactured gas industry, as in other industries during the MGP Era, when residuals could not be recovered and sold or used as fuel or byproducts, they became wastes for disposal. Wastewaters were typically discharged as effluents to surface waters, municipal sewerage systems, or the MGP site itself. Solids were generally disposed of on land. For example, unusable tar was disposed of in ponds or low-lying areas onsite or offsite. These disposal methods were widely practiced during the MGP Era by MGPs, other types of industry, and municipalities, and were considered to be acceptable and proper. Indeed, due to the state of the technology at that time, there were no other feasible means of disposal.

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Q. How were MGP residuals released at MGP sites?

A. In addition to waste disposal practices, there were several activities related to the storage and transfer of liquids at an MGP that sometimes resulted in releases of residuals to an MGP site. As liquid byproducts, such as tar, were produced, they were pumped around the plant through piping networks to above and below-grade processing and storage vessels. Accidental leaks and spills from pipes, pump seals and valves occurred. These incidents resulted in releases of liquids to the site. In addition, leaks and spills of liquids from above- and below-ground tanks, pits, and other vessels, such as gas holders, sometimes also occurred, causing liquids to reach the surface or enter the subsurface of the site.

The revivification process for iron oxides from gas purification was also a means through which residuals or their chemical constituents could have reached the surface of the site. One means to revivify oxide was by spreading it in thin layers on the ground so that air could oxidize the iron sulfide to iron oxide, its reactive state, and sulfur (*i.e.*, *ex situ* revivification). When the oxides could no longer be revivified, they were often removed from the purifier boxes and placed on the ground. Depending on the circumstances, the oxide might be stored on the ground at the MGP for extended periods of time. Eventually, if the oxides could not be sold or used as the source of saleable chemicals, they might be used as fill or disposed of on other parts of the site or in offsite landfills.

Related to iron oxide handling, in the late 1800s and into the 1900s, there were newspaper articles about people bringing their children to gas plants when the purifying boxes were being opened to change out the media. According to these articles,

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breathing the vapors from the spent oxide boxes brought relief to those suffering from croup, colds, and whooping cough.

Q. How were MGPs demolished and dismantled?

A. MGPs were taken out of service throughout the MGP Era for various reasons. Some plants reached the end of their useful lives and were not replaced. Some were closed when gas could be more economically provided by other larger plants on a regional basis. Many were closed when the introduction of natural gas made them obsolete. Some carburetted water gas plants were converted to high-Btu oil gas plants for peak shaving during the 1940s and thereafter before being closed permanently. Peak-shaving equipment operated intermittently for short periods of time to provide gas during a period of high demand (*e.g.*, very cold winter days).

Once taken out of service, the plants were dismantled in whole or in part for various reasons. One purpose was to reduce their assessed value for tax purposes. Another was to allow for reuse or redevelopment of the land.

The procedures for taking a plant out of service generally entailed dismantling and demolishing all of the above-ground structures and leveling the site, except where certain buildings were left for future use. Below-ground tanks were filled with building debris or other material to bring them to ground level. Bulk liquids removed from tanks were disposed of either onsite or offsite and sludge layers were often left behind in tanks that were not completely removed (*e.g.*, below grade water tanks of gas holders of below grade tar separators). Below-grade pipes were left in place along with the liquids they might contain. Salvageable materials, such as steel from tanks, were recovered. Solid

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wastes from above-ground vessels, such as iron oxides, were used as fill or disposed of either onsite or offsite.

Q. How did current environmental impacts result from historic MGP activities and practices?

A. Typical operating, disposal, and demolition-dismantling practices during the MGP Era at former MGP sites resulted in environmental contamination of soil, groundwater, or stream sediments as it is defined today (*i.e.*, in 2011), which may require remediation under current state or federal laws and regulations. Additionally, post-MGP activities sometimes also resulted in releases of chemicals or spreading of chemicals left behind at the cessation of MGP activities.

Beginning around the 1970s, analytical technologies became commercially available to measure relatively low concentrations of chemical constituents in water, soil, and sediments which provided a basis to begin assessing impacts. A number of organic or inorganic chemicals may possibly be present in now measurable concentrations in soils, groundwater and sediments at or near a former MGP site as a result of historic gas plant activities. Organic chemical compounds include the following groups: volatile aromatics (*e.g.*, BTEX), phenolics, and polycyclic aromatic hydrocarbons (*i.e.*, PAHs). It should be noted that these groups of compounds generally represent the chemicals possibly present at MGP sites, but they may not represent what actually will be discovered at any specific location. Current testing at a specific MGP site may or may not find any or all of these chemical compounds.

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Q. How did consideration of the environment change after the end of the MGP Era?

A. The MGP Era had ended by the first Earth Day in 1970, the year that began the modern era of environmentalism ("Environmental Era"). From 1970 onward, the U.S. Congress enacted a series of laws revolutionizing the U.S. approach to environmental regulation and management of air quality, water quality, solid waste, industrial sites, and historic disposal facilities. A national understanding of the impact of historic industrial operating and disposal activities on soil and groundwater quality evolved in the 1970s, resulting in the passage of the "Superfund" Act in December 1980. Laws, regulations and guidance issued under Superfund and state counterparts formed the foundations of the then new environmental field of site remediation. Application of the site remediation process to MGP sites generally began in the 1980s and continues through the present as a significant post-MGP Era effort by those held responsible for MGP sites.

Q. During the MGP Era, what was the gas industry's knowledge of environmental impacts as they are understood currently (2011)?

A. Manufactured gas plants' operating, waste disposal, and demolition-dismantling practices were consistent with the practices of other industries, governments, and individuals throughout the U.S. During the MGP Era and prior to the Environmental Era, these practices throughout industry and society as a whole were generally regulated by the principle of nuisance control (*e.g.*, controlling offenses to the senses, such as smoke and odors in the air, objectionable tastes in the water, or soot deposition). Nuisances were considered temporary problems and were dealt with as discrete and separate situations in a manner so as to eliminate the immediate offensive condition.

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From 1816 until the present, surface water has been accepted as the proper receptor of wastewaters. Discharge of wastewater to surface waters (*e.g.*, rivers) was common for industries and municipalities during the MGP Era and continues to be so today. The required degree of treatment of wastewaters throughout this time period has changed significantly, especially during the Environmental Era after passage of the amendments to the Clean Water Act in 1972. In 1972, regulations promulgated under the Clean Water Act mandated controls on wastewater discharges across the U.S. based on best practical treatment and subsequently best available treatment. Since 1972, there has been increasing limitations placed on wastewater discharges based on current understandings of impacts to rivers with respect to present water quality standards. These Environmental Era requirements have also extended to stormwater discharges and runoff from agricultural lands. Present-day regulation of wastewater discharges contrasts greatly to the situation during the MGP Era.

From 1816 until the 1970s, land was accepted as the final receptor for many kinds of wastes. Solid and liquid wastes from industries and municipalities were disposed of in open dumps either onsite or offsite, and/or in low-lying areas onsite. In the 1970s, the requirements for land disposal of waste began to change significantly.

There are several significant examples of industries, other than the manufactured gas industry, that also followed these disposal practices prior to the 1980s. In the iron and steel industry, solid wastes from byproduct coke plants were disposed of on land, either onsite or offsite. These wastes consisted primarily of ash, sludges from cleaning of process tanks and vessels, and spent oxides or other gas cleaning solids (*e.g.*, off-specification sulfur). Additionally, in the petroleum refining industry, oily sludges were

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disposed of on land. In the wood-treating industry, waste liquids were disposed of in onsite ponds. Additionally, sludges from cleaning of tanks and vessels were disposed of in onsite dump areas. All these practices continued until the 1980s, when regulations promulgated under the 1976 Resource Conservation and Recovery Act (RCRA) mandated controls on land disposal of wastes across the U.S. These Environmental Era regulations have also required for treatment of certain wastes prior to land disposal and for incineration of certain wastes.

Municipal garbage, trash, and sludges from sewage treatment plants were disposed of in open dumps. These practices remained in effect in the U.S. until the 1970s and 1980s, when regulations began to systematically phase them out, in favor of sanitary landfills or controlled land application, in the case of sewage sludges.

Q. What do you consider to be the definition of a reasonable industry practice with respect to the operation of an industrial facility like an MGP and to the disposition of residuals from such a facility?

A. I consider an activity to be a reasonable practice if the activity was one which a reasonable business person, given the context of the legal standards and state of knowledge at the time of the activity, would have engaged in.

III. GAS MANUFACTURE AT THE PORTLAND MGP SITES

Q. Please describe the history of gas manufacture at the Portland MGP Sites?

A. As an overview, gas manufacture began in 1860 and continued until the fall of 1956. Three gas manufacturing processes were used at the Portland MGP Sites: coal gas, carburetted water gas, and Oil Gas. During the fall of 1956, Portland Gas & Coke Company (PGCC) converted to natural gas distribution. Afterwards, the Oil Gas

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equipment was converted to high Btu oil gas and maintained for standby and peak shaving until 1958.

The beginning was in 1859 when the Oregon territorial legislature granted a franchise for gas manufacture in Portland. A coal gas plant was constructed in downtown Portland on the east bank of the Willamette River and it began operation in 1860 as an unincorporated enterprise that provided gas for gas lighting. In 1862, the newly incorporated Portland Gas Light Company (PGLC) took over the franchise and plant. PGLC operated until 1892 when it was purchased by the newly formed Portland Gas Company (PGC).

In 1892, PGC also purchased the East Portland Gas Light Company (EPGLC) which had been formed in 1882. EPGLC had constructed a relatively small gas plant in East Portland at that time which, according to Brown's Directory editions at the time, produced coal gas. PGC ceased gas manufacture at this plant around 1892 with the construction of a pipeline across the Willamette River to supply gas to East Portland. This plant was subsequently demolished and dismantled to make way for new developments on its site. There are no surface remnants of the original plant left on the site.

The PGC gas plant in downtown Portland continued to manufacture coal gas until 1897, when carburetted water gas apparatus was added to the plant. Both coal gas and carburetted water gas manufacture continued until 1906 when the carburetted water gas apparatus was converted to Oil Gas manufacture. PGC eventually recovered the lampblack from the Oil Gas manufacture for fuel and for production of lampblack briquettes. This plant ceased operation in 1913. It was subsequently demolished and

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dismantled to make way for new developments on its site. There are no surface remnants of the original plant left on the site.

In 1910, the American Power & Light Company formed PGCC, acquiring the gas business from PGC. In 1912-13, PGCC constructed a new Oil Gas plant at Linnton on the west bank of the Willamette River, several miles northwest of downtown Portland. In 1913, operations began at this new plant, negating the need to operate the downtown plant.

E.L. Hall of PGCC, in a 1916 paper, described the rationale for building a new gas plant as follows:

> Due to the phenomenal growth since the Lewis and Clark Exposition in 1905, the old site of the gas works at Front and Everett Streets, consisting of a few city blocks on the water front, became inadequate to take care of the continuous additions to plant and machinery, while the business center drawing its cordon tighter around the manufacturing activities, brought about increased complaints against the smoke and odor in connection with manufacturing operations. Growing inefficiency and inadequacy of the old machinery, most of which had been in use for many years, called for a reconstruction of the plant. It was, therefore, decided in 1910 that the time had come to move the manufacturing plant to the outskirts of the city.

In the citation above, Hall's mention of complaints against smoke and odor provide an example of nuisance issues related to manufactured gas operations. Hall closed this paper with a conclusion about "Operating Efficiencies:"

> The new plant effects a saving over the old plant approximating $45,000.00 per annum, or practically 15 per cent, accounted for principally in fuel and labor.

The new plant also manufactured lampblack briquettes on a significant scale for sale as fuel in the Portland area. This planned briquette manufacture was a significant aspect of the economics of the new plant. The plant also stored tar recovered from the

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oil gas process, which it then either sold or used as fuel at the plant. In the 1920s, the plant installed equipment to recover light oil and process it into motor fuel and to process tar into a variety of products. These tar products included road tar used across Oregon, including in Multnomah County. In 1941, PGCC installed petroleum coke ovens to generate gas and petroleum coke. Petroleum coke was in demand by aluminum smelting plants, particularly those located in Vancouver, Washington. Aluminum manufacture was a primary industry in support of the war effort of World War II. Production of gas, petroleum coke, and also of pitch from tar at this plant provided significant support of the war effort.

PGCC operated this facility producing gas and commercial byproducts until 1956, when natural gas pipelines reached Portland. At that time, the Oil Gas plant at Linnton was placed on standby for a few years to be available for peak shaving.

In the 1960s, demolition and dismantling of the gas plant began in order to make way for the installation of the liquefied natural gas (LNG) tank, which began operation in 1969. Renovation of the surface of the MGP site at Linnton continued into at least the 1970s to bring it more or less to its present general topographical condition. The only remnants of the original MGP are the office building, now vacant, and the tar processing facility, which was first leased to a third party in 1965. Third party leasing of this part of the site has continued to the present (2011).

In addition to the two primary MGPs (the one in downtown Portland and the one at Linnton), there were gas holders located in other parts of Portland, the small MGP in East Portland, which remained a gas holder site, and several motor fuel filling stations operated by the gas companies. As the gas holders and filling stations became

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obsolete, these facilities ceased operation. Afterwards, they were demolished and dismantled and then sold or redeveloped. For example, the Central Service Center of NW Natural is the site of three former gas holders.

Finally, beginning in the 1910s, PGCC began supplying Vancouver, Washington with manufactured gas, acquiring the Vancouver gas business in the 1920s and continuing to supply gas to Vancouver to the present (2011).

NWN/1602, Middleton/2-7 are 1879 and 1890 panoramic maps from the Library of Congress collection on which enlargements of the earlier gas plants and holders have been superimposed showing the map artists' rendition of these facilities. *NWN/1602, Middleton/8-14* are pictures from a 1916 paper of the new gas plant at Linnton. *NWN/1603, Middlton/1* is a drawing from a 1916 paper showing the layout of the new gas plant at Linnton.

Q. When and where was the coal gas process used?

A. The downtown Portland MHP, starting in 1860, made coal gas in retorts. It was a relatively small plant with six retorts and a daily capacity of 40,000 cubic feet. As a reference point, this capacity would have required the processing of around four tons of coal per day. Coal was brought in from Vancouver Island, British Columbia, and from across the Pacific Ocean. Coal gas continued to be listed as a process through the 1904 edition of Brown's Directory.

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Q. Please describe retort coal gas manufacture.

A. In the U.S., retort coal carbonization began around 1816 and was used in various parts of the country into the 1950s.[2] This was the original coal gas process producing gas and coke from coal in heated vessels called retorts. Coke is the remnant of coal remaining after the volatile materials in the coal have been driven off by heating. Coke is predominantly carbon with only the substances making up the ash of coal present other than carbon. Coal gas manufacture in retorts occurred at the downtown Portland MGP from 1860 until probably around 1904, but no longer than until 1906. In addition, the East Portland MGP used coal gas from around 1882 until 1892.

In the coal gas process, coal was carbonized at high temperature in the absence of oxygen, driving off around 30 percent of the weight of the coal as gas and residuals. *NWN/1603, Middleton/2* is a schematic diagram of the coal gas process. Bituminous coal was added to a closed vessel (retort) and heated. The gas emanating from the closed vessel was immediately quenched with water, which cooled it and condensed coal tar. Quenching occurred in a hydraulic main, which was a pipe continuously flowing with water and also receiving the hot gas from the retorts. The resulting coal tar and water mixture flowed to quiescent basins for separation, with substantial recycle of the water phase and recovery of the tar phase. Following quenching, the coal gas went through further purification steps to remove remaining tar, ammonia, sulfur, and cyanide, and then into the storage and distribution system.

[2] In the 1890s, byproduct coke ovens were first installed in the U.S. These ovens were a much larger scale version of retorts for large capacity coal gas and coke manufacture. Byproduct coke ovens are still used in the U.S. to manufacture coke for metallurgical processes. From the 1970s to the present, I have worked at a number of operating byproduct coke plants regarding treatment of their wastewaters.

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The residuals generally produced from retort coal gas manufacture were coke, coal tar, ammonia, ash, wastewater, and materials from sulfur removal. In some retort operations, additional residuals may have also been recovered from the gas, such as light oil.

Q. When and where was the carburetted water gas process used?

A. Around 1897, carburetted water gas equipment was added to the downtown Portland MGP. This equipment was likely the Lowe carburetted water gas process because it was provided by the United Gas Improvement Company (UGI) of Philadelphia. This equipment was added in response to the flood of 1894, which had flooded the plant and completely disrupted service. The new carburetted water gas equipment was placed at a higher elevation to be out of the flood prone area of the plant. By 1905, the daily gas manufacture had increased to around 960,000 cubic feet, substantially up from the rate in 1860. Carburetted water gas equipment continued in service until 1906.

Q. Please describe carburetted water gas manufacture.

A. In the 1870s, T.S.C. Lowe invented the carburetted water gas process, and it rapidly became the dominant process in the U.S., surpassing coal carbonization. In many locations, coal gas and carburetted water gas were both used at the same time. Carburetted water gas manufacture occurred at the downtown Portland MGP from around 1897 until 1906.

Carburetted water gas manufacture required coal or coke plus a petroleum oil to generate a suitable gas. *NWN/1603, Middleton/3* is a schematic diagram of the carburetted water gas process. True water gas (also referred to as blue gas) was first made by reacting red-hot coal or coke with steam in a generator, the first of three

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vessels used in the process. To generate sufficient heating or illuminating capacity to be distributed to the public, true water had to be carburetted. This was accomplished by passing the true water gas into a second vessel, the carburetter, where it was sprayed with petroleum or a petroleum fraction. The petroleum or petroleum fraction vaporized and was then permanently converted to gas in the third vessel, the superheater.

As with coal carbonization, the gas was immediately quenched upon exiting the gas generation equipment in a wash box to cool it and condense carburetted water gas tar. The resulting tar and water mixture flowed to quiescent basins for separation, with substantial recycle of the water phase and recovery of the tar phase. Following the wash box, carburetted water gas went through further purification steps to remove remaining tar and sulfur and then flowed into the storage and distribution system.

Carburetted water gas manufacture was more flexible in operation than coal gas manufacture, and it also converted most of the coal or coke to gas. By around 1900, carburetted water gas facilities were very popular and became dominant in many communities.

The carburetted water gas process produced the residuals carburetted water gas tar, clinker, materials from sulfur removal and wastewater. At some carburetted water gas plants, additional residuals (*e.g.*, light oil) may also have been recovered.

Carburetted water gas tar was similar, but not identical, to coal tar produced by the coal gas process. The principal difference resulted from the use of petroleum in the gas manufacturing process.

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Q. When and where was the Oil Gas process used?

A. In 1906, carburetted water gas manufacture at the downtown Portland MGP was discontinued due to the price of coal used in the generator. The carburetted water gas equipment was modified to produce Oil Gas from crude oil. Oil Gas was made from 1906 until the downtown Portland MGP ceased operations with the startup of the new oil gas plant at Linnton.

On October 27, 1913, the new Oil Gas plant at Linnton began operation. This plant used a single shell Oil Gas process with five gas machines installed at that time. Each Oil Gas set (*i.e.*, single Oil Gas machine) had a gas production capacity of two million cubic feet per day. Subsequently, additional Oil Gas machines were added to further increase the capacity of the plant. The operation of the Oil Gas machines was modified at times as necessary to respond to changing conditions. For example, in 1935, the single-shell generators were cross-connected in pairs to enable the plant to use a high-carbon fuel oil available at lower cost, as described by William Q. Hull and W.A. Kohlhoff in a 1952 paper in Industrial and Engineering Chemistry. In the fall of 1956, PGCC converted to natural gas, thereby ending base load manufacture of gas. Afterwards, the Oil Gas equipment was converted to high Btu oil gas and maintained for standby and peak shaving until 1958. In 1958, the MGP at Linnton was mothballed for future emergency use.

The Linnton plant was one of the larger gas manufacturing plants in the U.S. *NWN/1603, Middleton/4* is a graph of the annual production at the Linnton plant from 1914 through 1953. Annual gas production during this time period ranged from a low of 1.5 billion cubic feet in 1915 up to a high of 10.5 billion cubic feet in 1948. The 1949-50

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edition of Brown's Directory of American Gas Companies listed manufactured gas production for calendar year 1948 from which examples can be taken. The listed 1948 annual production amounts of the western cities of Seattle and Honolulu, which were producing Oil Gas at the time, were 3.6 and 2.4 billion cubic feet, respectively. There was also 0.8 billion cubic feet of carburetted water gas production listed for Seattle in that year bringing the total to 4.4 billion cubic feet. Contrastingly, the listed 1948 annual production for a smaller eastern city, Holyoke, Massachusetts, was 0.4 billion cubic feet of carburetted water gas. The 1948 Linnton production of 10.5 billion cubic feet was multiples of these example cities.

Q. Please describe Oil Gas manufacture.

A. Oil gas manufacture was with the large scale oil gas process (*i.e.*, Oil Gas) and the high-Btu oil gas process.

The Oil Gas processes, also known as Pacific Coast oil gas, were first developed in the 1890s with the first major oil gas plant beginning operation in 1902 in Oakland, California. Oil Gas manufacture was economically beneficial in situations where crude oil was more readily available and less costly than coal, such as on the West Coast of the U.S. in the 1900s. Oil Gas manufacture occurred at the downtown Portland MGP from 1906 until 1913, using modified carburetted water gas equipment. Oil Gas manufacture occurred at the Linnton MGP from 1913 until 1956 using single shell oil gas equipment modified at times during this period to accommodate change feedstocks and situations.

NWN/1603, Middleton/5 is a schematic diagram of the Oil Gas process. The process was cyclical and it relied on one (single-shell Oil Gas) or two vessels (two-shell

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Oil Gas) filled with firebrick in a manner to create gas-passageways. In the first cycle, oil was burned in the vessels to heat the firebrick to a high temperature. In the second cycle, manufacture of Oil Gas occurred by injection of steam and additional oil into the hot vessels which caused a reaction to form gas.

As with the carburetted water gas process, the hot gas exited the vessel into a wash box, in which it was quenched with water. This quenching caused, depending on the process, lampblack and/or Oil Gas tar to separate from the gas. The relative proportions of lampblack and tar in the hot gas depended on the operational conditions of the Oil Gas process. For example, the Oil Gas process could be configured and operated to produce more lampblack and less tar. Also, depending on the configuration and operation of the wash box, the degree of separation of lampblack and tar could be affected. For example, primary removal of lampblack from the gas could be accomplished in the wash box with tar removal in subsequent purification steps by the design and operation of the wash box. The resulting lampblack and water mixture or Oil Gas tar and-water mixture flowed to quiescent basins or other processes for separation of the water and recovery of the lampblack and tar.

Following the wash box, gas was further purified to remove remaining tar and sulfur. In the case of Oil Gas plants using crude oil as a feedstock, purification downstream of the wash box would also have removed some cyanide.

The Oil Gas process generally produced the residuals oil gas tar, clinker, materials from sulfur removal, and wastewater. At some Oil Gas plants, additional residuals (*e.g.*, light oil) were recovered.

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After conversion to natural gas in 1956, PGCC used the high Btu oil gas process until 1958 for peak shaving. The high-Btu oil gas process was generally developed for application when gas companies were switching from manufactured gas to natural gas. High Btu oil gas was a modification of Oil Gas manufacture that resulted in the manufactured gas having a heat content of around 1000 Btu per cubic foot, thus allowing it to be compatibly mixed with natural gas. Typically, the role of this process was to be on standby such that during periods of peak demands (*e.g.*, colder winter times), it could be activated to supplement natural gas supplies. This process was often used just a few days a year. The high Btu oil gas process could be developed either by modifying a carburetted water gas process or a regular Oil Gas process. Its operation was similar to that of the Oil Gas process, as were the residuals it produced.

Q. When and where was the petroleum coking process used?

A. In 1941, four petroleum coke ovens (Knowles Coke Ovens) were added at the Linnton facility to produce gas and petroleum coke. The high Btu content (around 1000 Btu) of the gas from these ovens was reformed downward to meet required Btu content of 570 Btu. These ovens operated until 1953, after which they were dismantled.

Q. What was petroleum coking?

A. The process of petroleum coking is analogous to that of coking coal (*i.e.*, coal gas manufacture), except that petroleum or petroleum fractions were subjected to high temperature heating in the absence of air. This resulted in the production of gas and residuals. The coking apparatus was constructed to facilitate the treatment of liquids rather than solids as in the case of coal gas manufacture. Petroleum coking gas manufacture occurred at the Linnton MGP from 1941 until 1953 using Knowles Coke

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Ovens. The gas was purified for removal of tar and sulfur. The general residuals from petroleum coking were tar and petroleum coke. At some oil gas plants, additional residuals (*e.g.*, light oil) may also have been recovered.

Q. What residuals were generated by gas manufacture at the Portland MGP Sites and what was the disposition of those residuals?

A. I will first discuss the residuals generated by the respective gas manufacturing processes used at the Portland MGP Sites. The next topic will be the fate of any of the residuals not usable or saleable. Finally, since wastewater was a residual common to all of the processes, its consideration will be made separately at the end.

- **Coal Gas:** As discussed above, typically, the primary residuals of coal gas manufacture were coke, coal tar, ammonia, spent purifier materials, and ash. As often happens for MGPs of this time frame, company records of the disposition of residuals have not been found to date (2011) with respect to coal gas manufacture in Portland. The disposition of these likely included:
    - Coke: use as fuel at the MGP or sale as a commercial byproduct (*e.g.*, fuel);
    - Coal Tar: use as fuel at the MGP, sale as a commercial byproduct, or use as a paint at the MGP;
    - Ammonia: sale as a commercial byproduct;
    - Spent purifier materials:
        - Spent lime (prior to the 1880s): sale or giveaway as a byproduct or disposal on land;
        - Spent iron oxides (1880s and afterwards): sale or giveaway as a byproduct, or use as fill material; and

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- o Ash: sale or giveaway as a byproduct.
- **Carburetted Water Gas:** As discussed above, typically, the primary residuals of carburetted water gas manufacture were carburetted water gas tar, spent purifier materials, and clinker. Company records on the disposition of these residuals have not been found to date (2011). The disposition of these likely included:
  - o Carburetted Water Gas Tar: use as fuel at the MGP or sale as a commercial byproduct;
  - o Spent purifier materials: likely spent iron oxides (since 1880s and afterwards), for sale or giveaway as a byproduct or use as fill material; and
  - o Clinker: sale or giveaway as a byproduct.
- **Oil Gas (Downtown Portland MGP):** As discussed above, typically, the primary residuals of oil gas manufacture were lampblack, oil gas tar, and spent purifier materials. Some records on lampblack disposition at the plant have been found. The disposition of these likely included:
  - o Lampblack: first mixed with sawdust and burned as boiler fuel and subsequently briquetted for sale as fuel;
  - o Oil Gas Tar: to the extent it was not recovered with the lampblack, use as fuel at the MGP or sale as a commercial byproduct;
  - o Spent Purifier Materials: likely spent iron oxides (since after 1880s), for sale or giveaway as a byproduct or use as fill material; and
  - o Clinker: sale or giveaway as a byproduct.
- **Oil Gas (Linnton MGP):** As discussed above, typically, the primary residuals of oil gas manufacture were lampblack, oil gas tar, and spent purifier materials. In

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addition, this MGP recovered light oil from the gas. Records regarding the disposition of these residuals have been found. Based on these records, the disposition of these residuals was as follows:

- o <u>Lampblack</u>: predominantly pressed into briquettes for sale as fuel, but some sales occurred in bulk for use as a chemical feedstock; lampblack not pressed into briquettes was stored on site and eventually sold in the late 1940s and early 1950s in bulk to local industry as well as elsewhere;
- o <u>Oil Gas Tar</u>: separately recovered from the lampblack and initially used as fuel in the boiler with some sold; and subsequently processed into commercial products at the MGP (*e.g.*, road tar, pitch) which were sold;
- o <u>Light Oil</u>: processed into commercial products at the MGP (*e.g.*, motor fuel, chemicals) which were sold, including some sales of motor fuel at company-owned filling stations for a period of time; and
- o <u>Spent Purifier Materials</u>: spent iron oxides placed on the MGP site until its demolition and dismantling in the 1960s and 1970s; some recovery of yellow prussiate of soda was done during World War I; some sulfur recovery was done in the time frame of the late 1930s.

- **<u>Petroleum Coking (Linnton MGP)</u>:** As discussed above, typically, the primary residuals of petroleum coking were petroleum coke, tar, light oil, and spent purifier materials. Records regarding the disposition of these residuals have been found. Based on these records, the disposition of these residuals was as follows:
  - o <u>Petroleum Coke</u>: sold to aluminum smelters for electrode manufacture;

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- Tar: processed into commercial products at the MGP (*e.g.*, road tar, pitch) which were sold;
- Light Oil: processed into commercial products at the MGP (*e.g.*, motor fuel, chemicals) which were sold including some sales of motor fuel at company-owned filling stations for a period of time; and
- Spent Purifier Materials: the gas from petroleum coking was purified of sulfur after consolidation with oil gas; see the discussion above for the disposition of the spent purifier materials.

- **Unusable, Unsalable Residuals:** If, because of market conditions, any of the residuals discussed above, which were typically commercial byproducts or beneficially used, could not be sold or used, they became waste for disposal by the means contemporary to the situation at the time. In addition, if there were other residuals such as sludge from tanks or from residuals processing, which were unusable and unsalable, these were waste for disposal by the means contemporary to the situation at the time. These means contemporary to the operation of the Portland MGP Sites included disposal on land onsite at the MGP or offsite.
- **Wastewater:** Manufactured gas plants used water for quenching, condensing, and scrubbing of the gas in the purification process, quenching of hot coke, cooling, and for boiler water. Such water use, in part, resulted in tar-water and lampblack-water mixtures. A plant would typically attempt to separate tar and lampblack from these mixtures using quiescent basins or filters. A substantive amount of the water recovered by such separation was typically recycled to the quenching and scrubbing processes. Any excess water became a wastewater effluent for disposition.

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Generally, disposition of the effluent was directly to surface waters, to municipal sewers, or to drainage ditches, channels, or areas of the plant which, in turn, could have led to surface waters. In the case of the downtown Portland MGP and the Linnton MGP, effluent was discharged to plant sewers that went to the Willamette River or to drainage channels connected to the Willamette River. At the Linnton MGP, in its later years, effluent passed through settling lagoons prior to discharge to the Willamette River. At the Linnton MGP, some wastewater was discharged to areas of the plant which may have been connected to the drainage channels on the site.

Q. What are examples of technical efforts made by PGCC to improve gas manufacture or residuals processing?

A. Examples of technical efforts made by PGCC to improve gas manufacture or residuals processing include the following:

- In 1916, E. L. Hall of PGCC described the rationale for the oil gas plant at Linnton as one that produced substantial amounts of byproducts. He presented general ways to accomplish the goal of producing “the greatest number of B.t.u.’s per dollar.” First was by “elimination of all by-products, *i.e.*, by conversion of all the raw material into gas.” The second was “by production simultaneously with the gas of the largest amount of merchantable by-products on the theory that weight for weight the latter are worth more than the raw material.” He went on to say that the first method had been developed by E. C. Jones in San Francisco, but it had not yet been able to completely eliminate lampblack generation. He characterized the second method as more universal and exemplified in Los Angeles, San Diego,

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Oakland, and, notably, Portland, in so far as byproducts are marketed. He went on to say, "Nearly all other oil gas plants produce lampblack, but have not sufficient volume to briquette. . . . Where there is a good fuel market and oil is cheap, it will unquestionably pay to produce by-products." The technical effort by PGCC in planning the new MGP at Linnton resulted in the specific configuration of the overall plant including the intentional production of lampblack as the dominant byproduct with its disposition to be sale of briquettes as fuel in the Portland market in pursuit of the goal of producing "the greatest number of B.t.u.'s per dollar."

- In 1924, Russell Ripley and Sigmund Schwarz applied for a patent entitled "Process for the Recovery of Gas Tars from Their Emulsions with Water," and this patent was granted in 1929. Their invention was the means to recover salable tar from the "heavy viscous hydrocarbon emulsions with water which are byproducts in the manufacture of city gas from crude petroleum. . . ." Generally, the process involved addition of sodium hydroxide to the emulsion, followed by heating under pressure. This process prepared oil gas tar made at Linnton for further processing into higher value commercial byproducts such as road tar, thereby decreasing the cost of gas generation. Prior to this, the higher water content tar had been burned in the boiler as a primary means of disposition.
- In 1925, Professor S.H. Graf of Oregon Agricultural College ("OAC", the predecessor to Oregon State University) investigated the use of 620 BTU gas tar primarily for use as a road binder and issued a report on this date. He concluded that the tar was suitable for this use and described its preparation to attain ASTM standards on road tar. He also concluded that this tar appeared "wonderfully

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adapted to painting concrete for damp proofing." Subsequent to this, Professor Graf followed up with reports on the treatment of macadam road surfaces with tar from the Linnton MGP. One of the road surfaces was at the MGP itself. The basis of his reports included interviews with municipal staff.

Q. How did the environmental conditions presently under investigation and remediation at these MGP sites result from past manufacture of gas?

A. The environmental conditions that at present (2011) require investigation include the presence in soil, groundwater, surface water, and river sediments of certain chemicals (*e.g.*, benzene, naphthalene, polycyclic aromatic hydrocarbons, cyanide) or materials (*e.g.*, oil, tar, lampblack). Where concentrations exist that pose unacceptable risks by present standards, remediation of soil, groundwater, and river sediments will likely be required. The means by which these chemicals reached their present locations at the MGP sites include leaks or spills of MGP residuals, placement of MGP residuals directly onto the sites, migration of these chemicals from where they first reached the site, and the reworking of site soils in redevelopment activities. In the case of river sediments, the means included discharges or spills to the river, transport of the chemicals from the uplands to the river or through reworking of river sediments by natural water flow, or by dredging activities. It is also important to understand that other parties are likely possible sources of some of these same chemicals, especially in the river sediments as numerous industrial and municipal wastewaters were discharged to the Willamette River throughout the time period that gas was manufactured in Portland.

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Q. How would you characterize the residuals handling and disposition practices of the MGPs in Portland?

A. Based on my review of the history of gas manufacture in Portland, I believe the practices at the Portland MGP Site for handling and disposition of residuals from gas manufacture were fully consistent with those of other MGPs, other industries, and municipalities in the Portland area and across the country during the MGP Era, and were reasonable and prudent in view of the circumstances and information available at the time.

Q. How would you characterize the demolition and dismantling practices of the MGPs in Portland?

A. Based on my review of the history of the Portland MGP Sites, I believe the Portland MGP practices for demolition and dismantling practices were fully consistent with those of other MGPs and other industries in the Portland area and across the country during the MGP Era, and were reasonable and prudent in view of the circumstances and information available at the time.

Q. On what did you rely to answer the questions about gas manufacture in Portland?

A. I relied on my training as a civil, sanitary, and environmental engineer; experience with manufactured gas, byproduct coke oven and tar distillation plants, sites or projects; and my more than 35 years of experience as a consulting engineer, an industrial environmental engineer, an industrial environmental manager and executive, and a university professor and researcher, in addition to historical documents that provide information on manufactured gas in Portland.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

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Exhibits of Andrew Middleton

ENVIRONMENTAL MITIGATION - HISTORY
EXHIBITS 1601 - 1604

December 2011

EXHIBITS 1601-1604 – ENVIRONMENTAL MITIGATION - HISTORY

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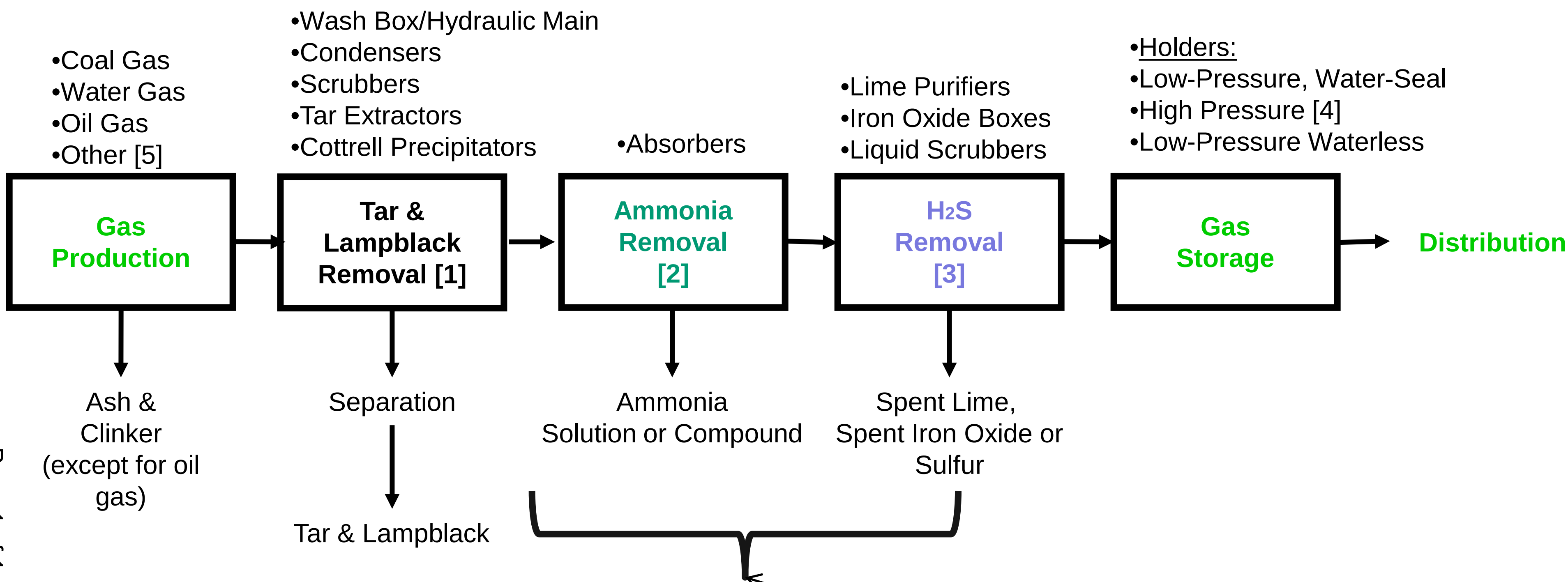


Notes:

[1] Not all of these processes were necessarily at an MGP; water gas included a relief holder in this step to equalize gas flow from cyclical production; lampblack removal was for oil gas manufacture

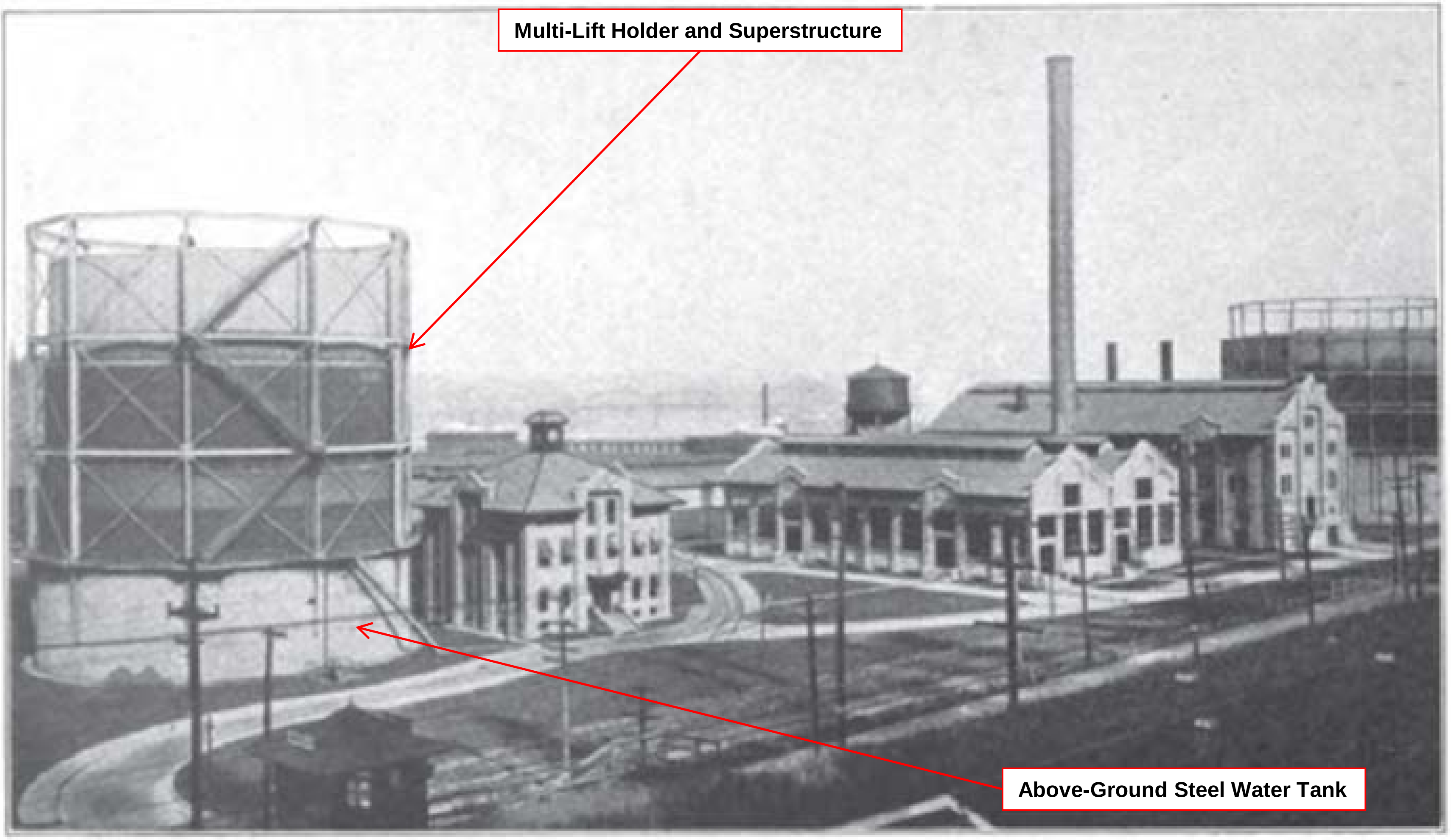
[2] In coal gas processes only; water gas and oil gas did not typically contain significant ammonia

[3] For coal gas and oil gas using crude oil, cyanide would also be removed here; water gas did not typically contain significant cyanide

[4] Pressurization of manufactured gas generated condensate

[5] Depending on which other process, the gas purification steps may have varied from this diagram

Exhibit 2: Schematic Diagram of the Overall General Gas Manufacturing, Purification and Storage Processes



BUILDINGS AND GROUNDS.

Exhibit 3: Picture of Portland Gas & Coke Low Pressure, Water-Sealed Gas Holder at Gasco Plant (From Hall 1916)

Exhibit 4: 1879 Panoramic Map Showing Downtown Portland MGP and Location of Remote Holder at NW Flanders and 6th

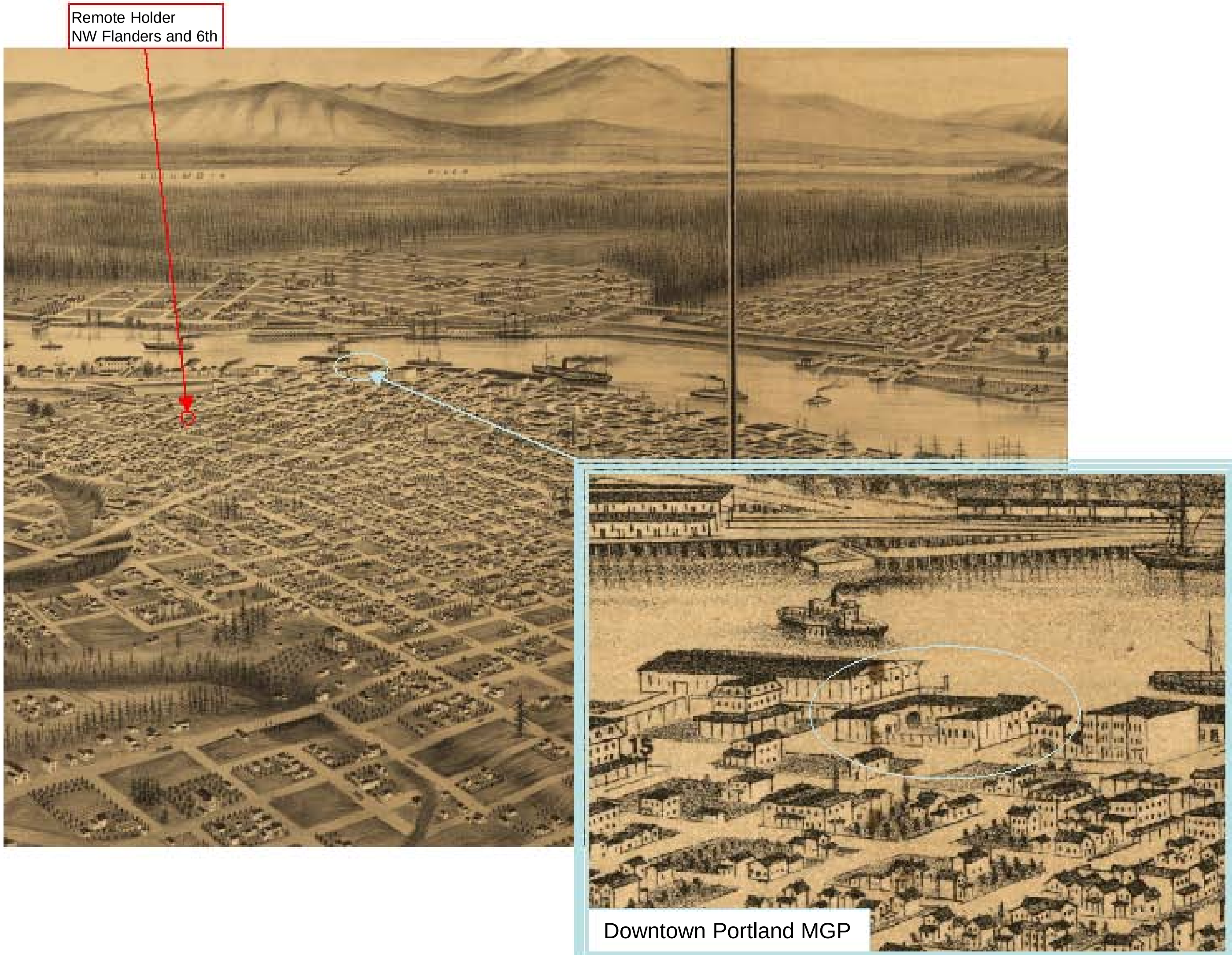


Exhibit 5: 1879 Panoramic Map Showing Downtown Portland MGP and Location of Remote Holder at NW Flanders and 6th

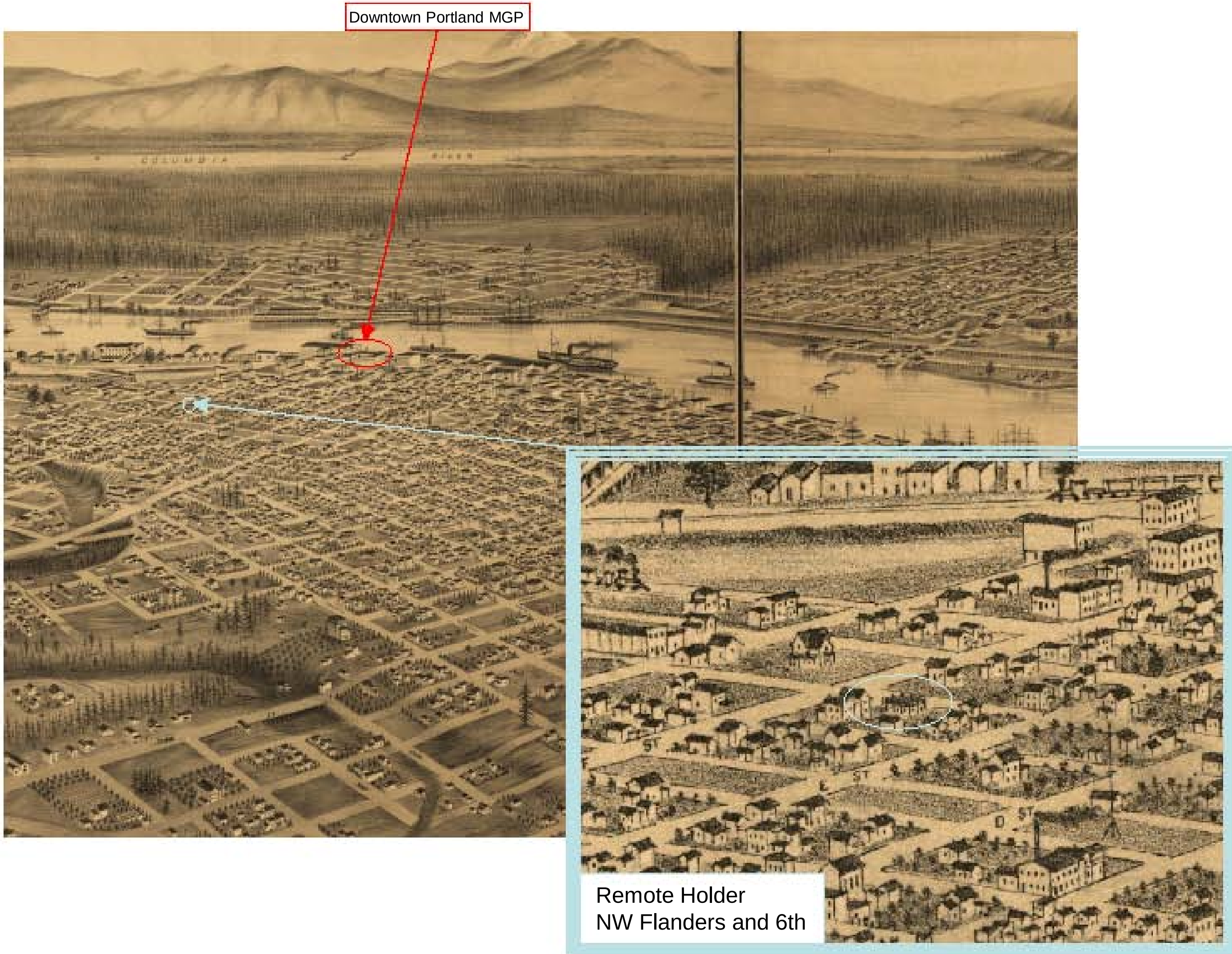


Exhibit 6: 1890 Panoramic Map Showing MGPs and Remote Holders with an Enlargement of the Downtown Portland MGP

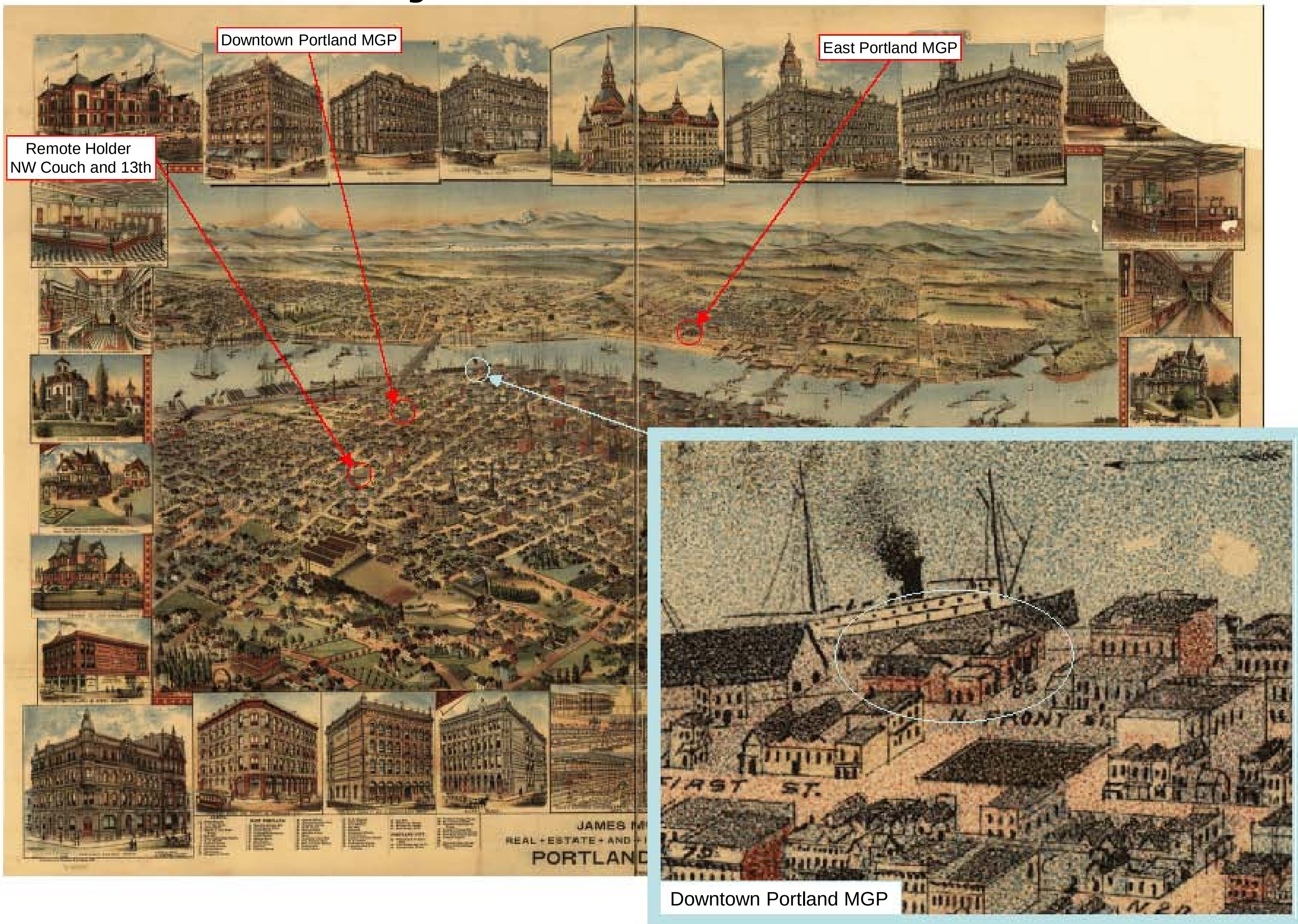


Exhibit 7: 1890 Panoramic Map Showing MGPs and Remote Holders with an Enlargement of the East Portland MGP

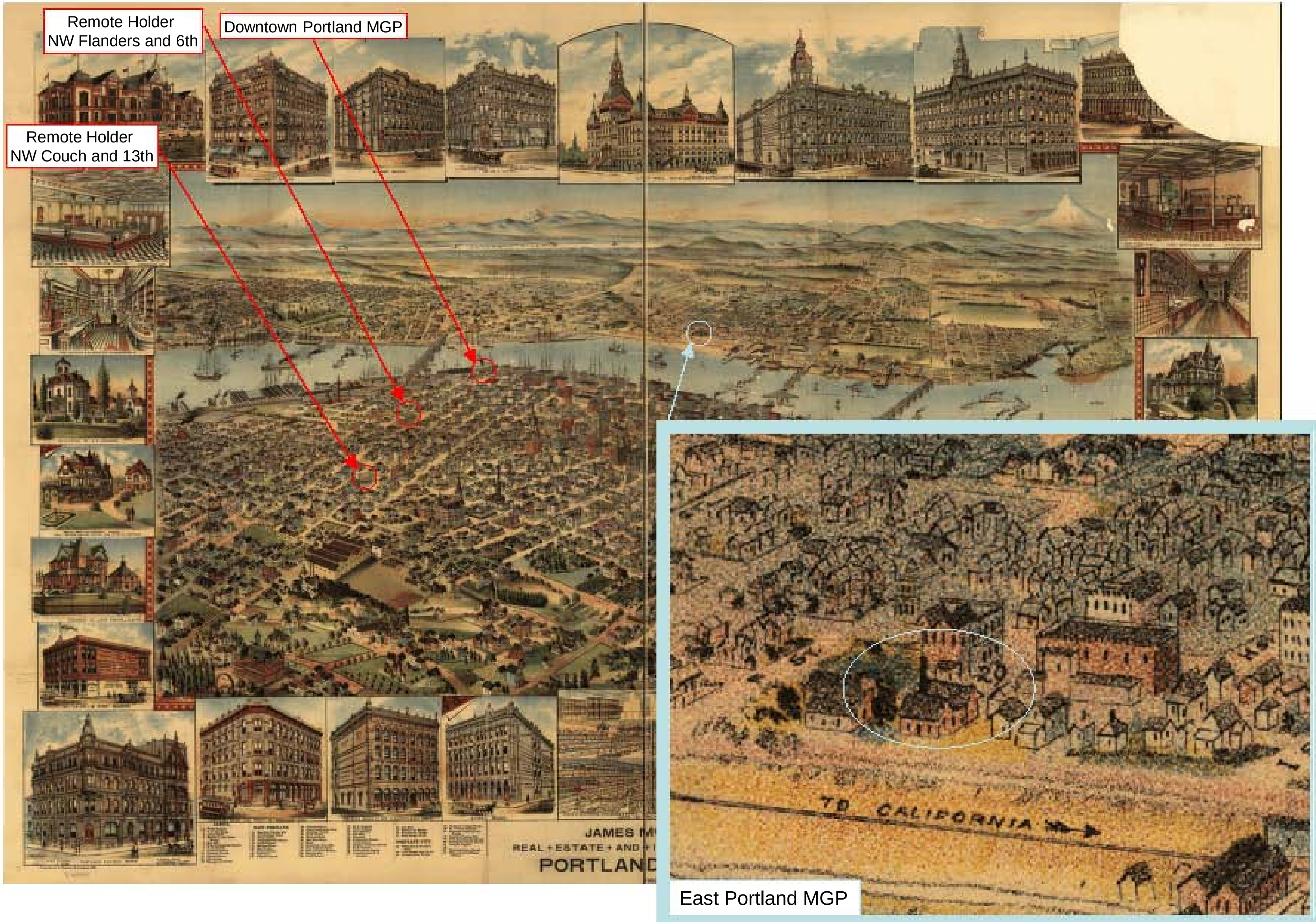


Exhibit 8: 1890 Panoramic Map Showing MGPs and Remote Holders with an Enlargement of the Remote Holder NW Flanders and 6th

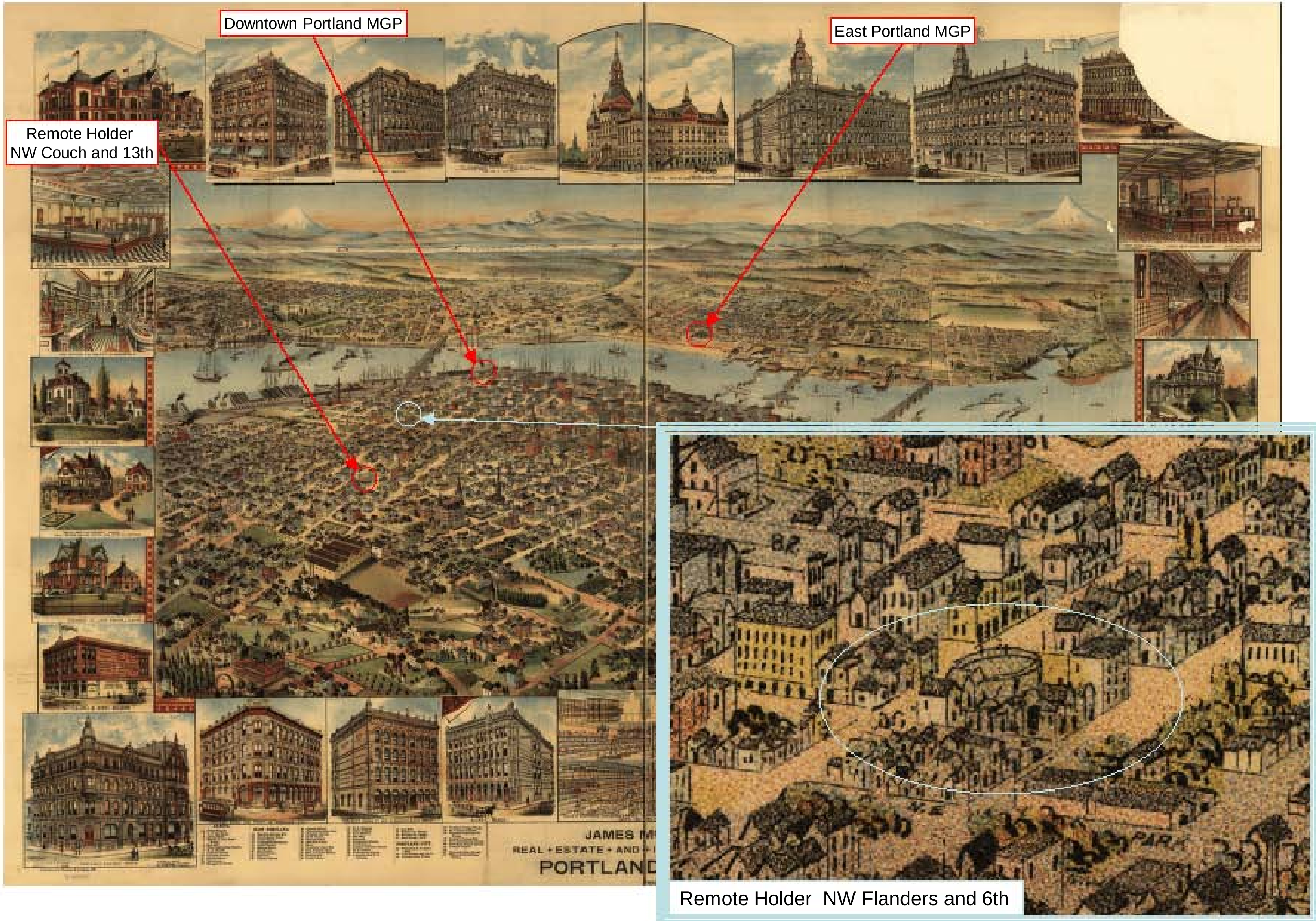
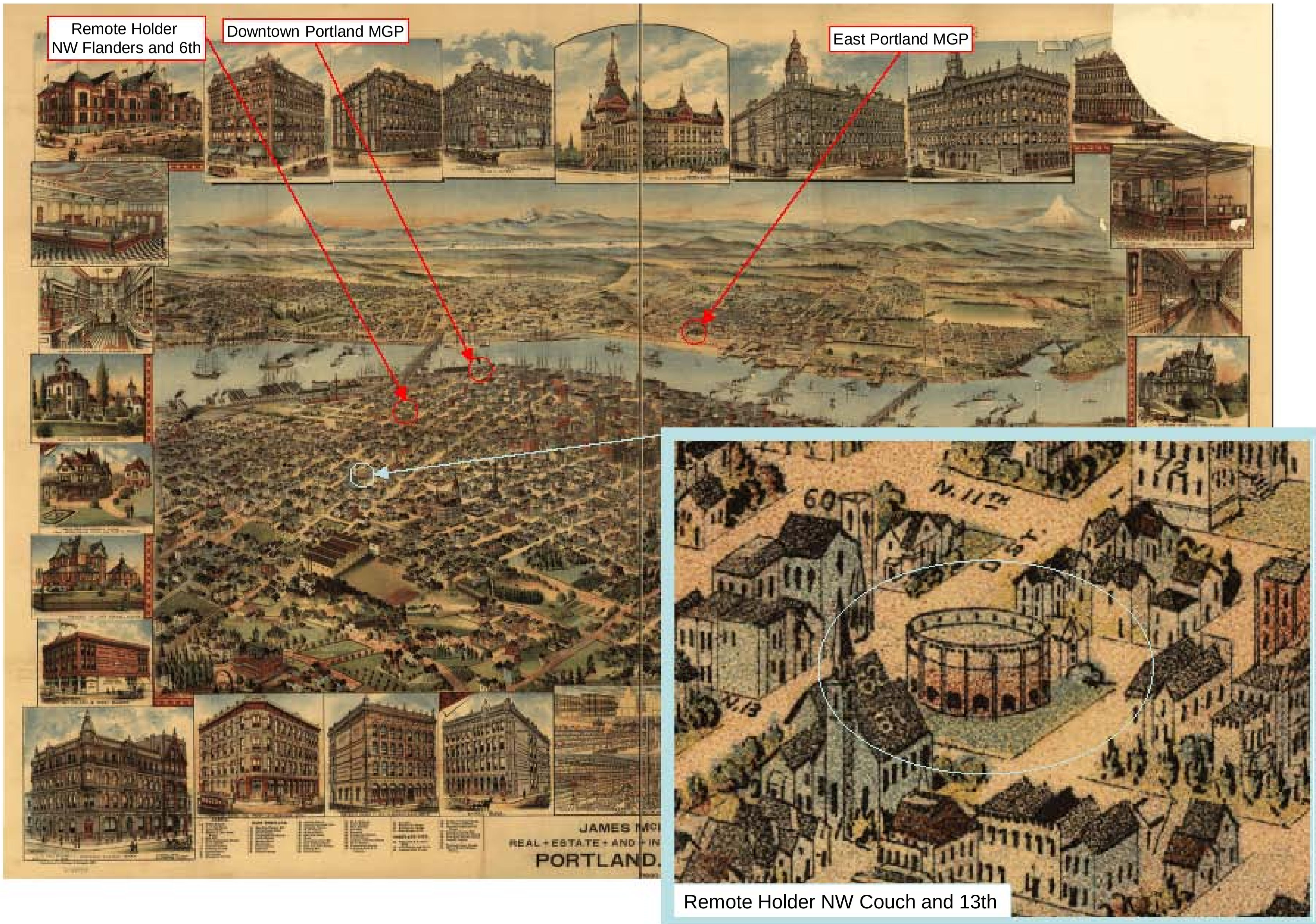
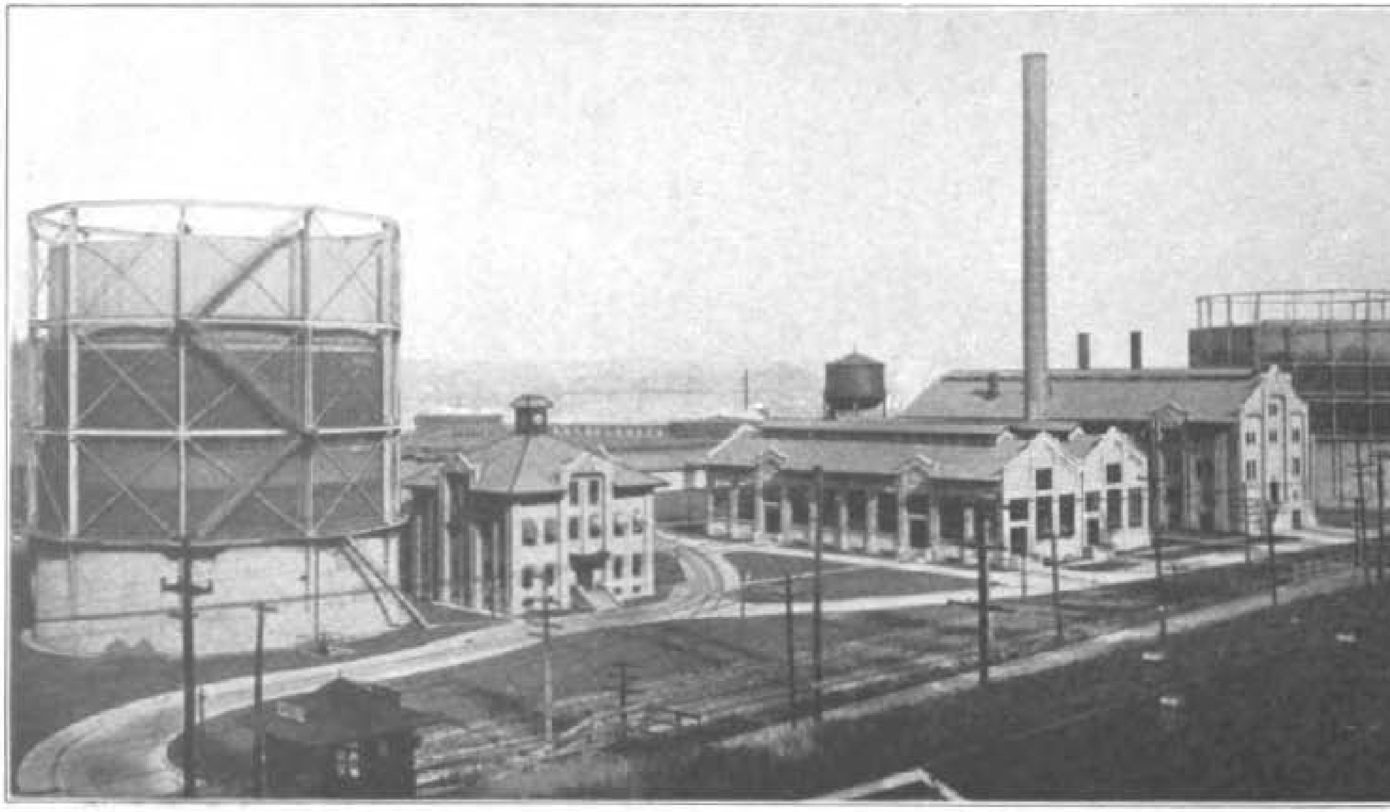


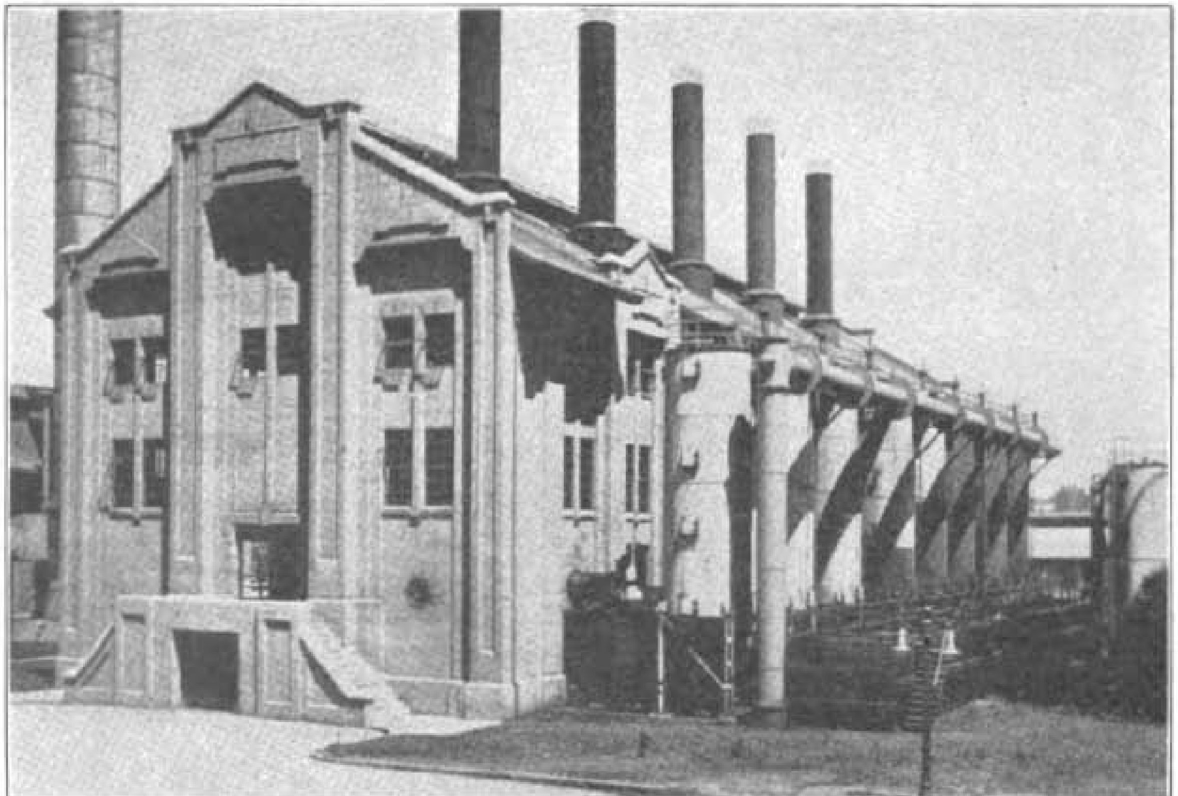
Exhibit 9: 1890 Panoramic Map Showing MGPs and Remote Holders with an Enlargement of the Remote Holder NW Couch and 13th





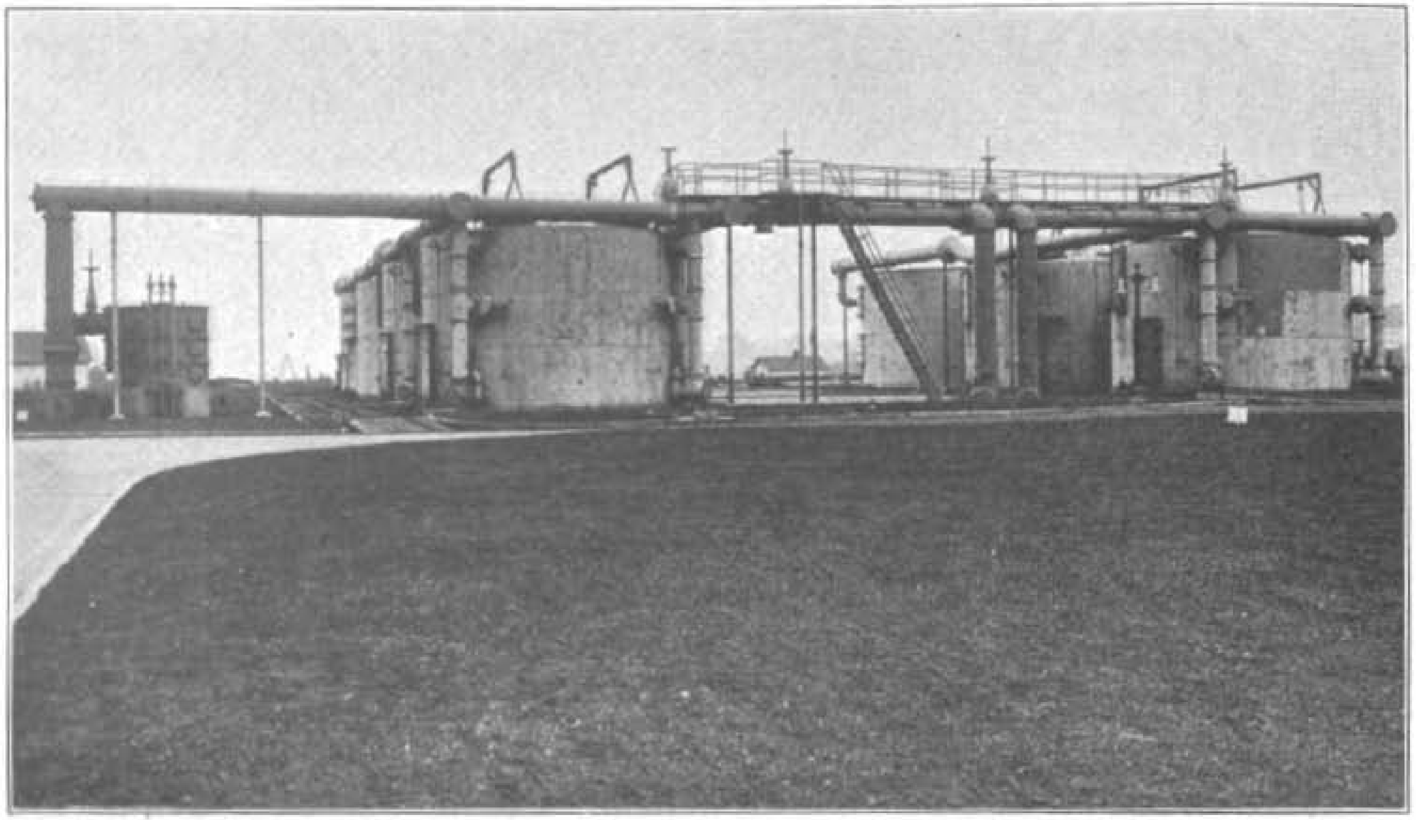
BUILDINGS AND GROUNDS.

Exhibit 10: Picture of Entrance to New Gas Plant at Linnton from 1916 Paper



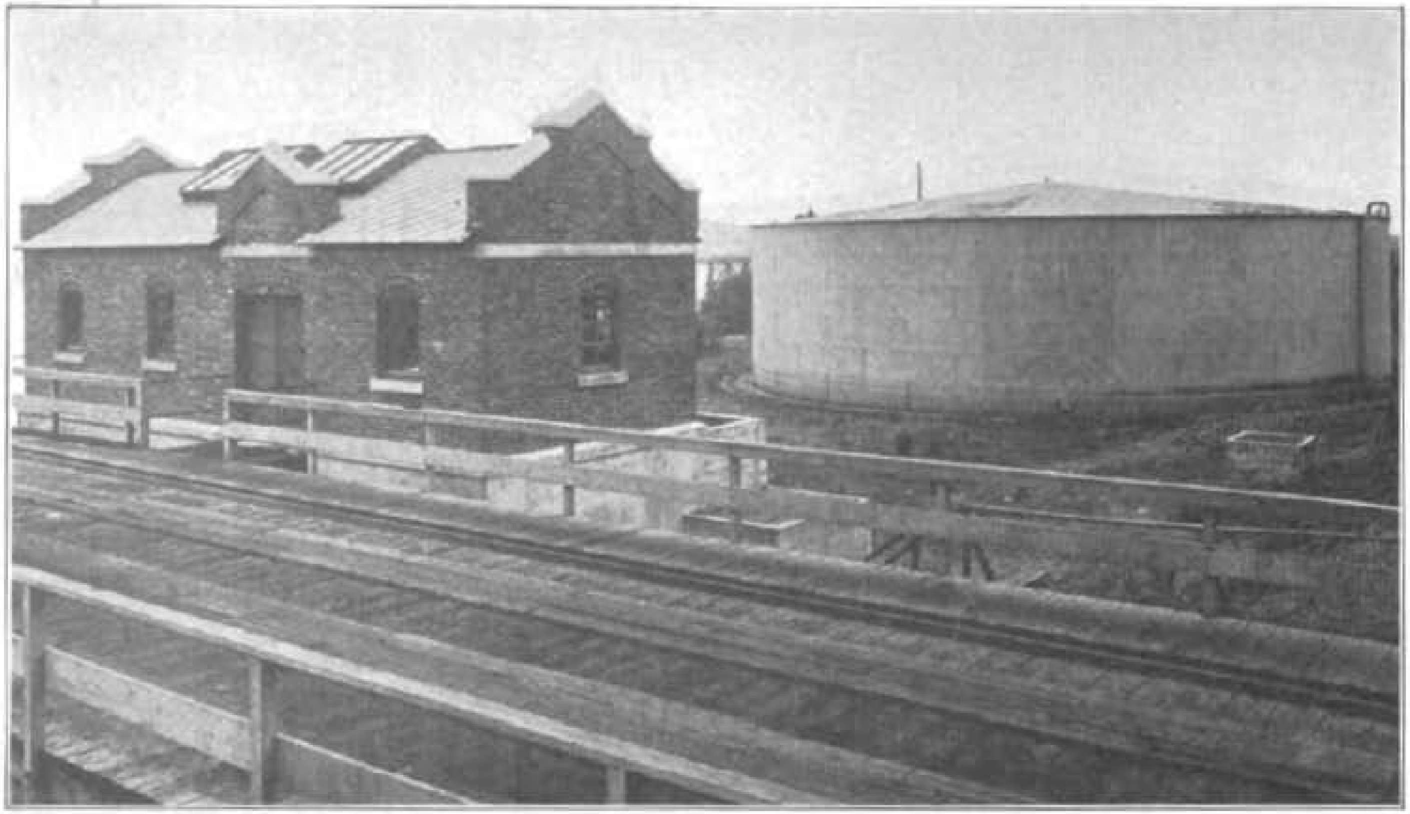
GENERATOR BUILDING.

Exhibit 11: Picture of Generator Building at New Gas Plant at Linnton from 1916 Paper



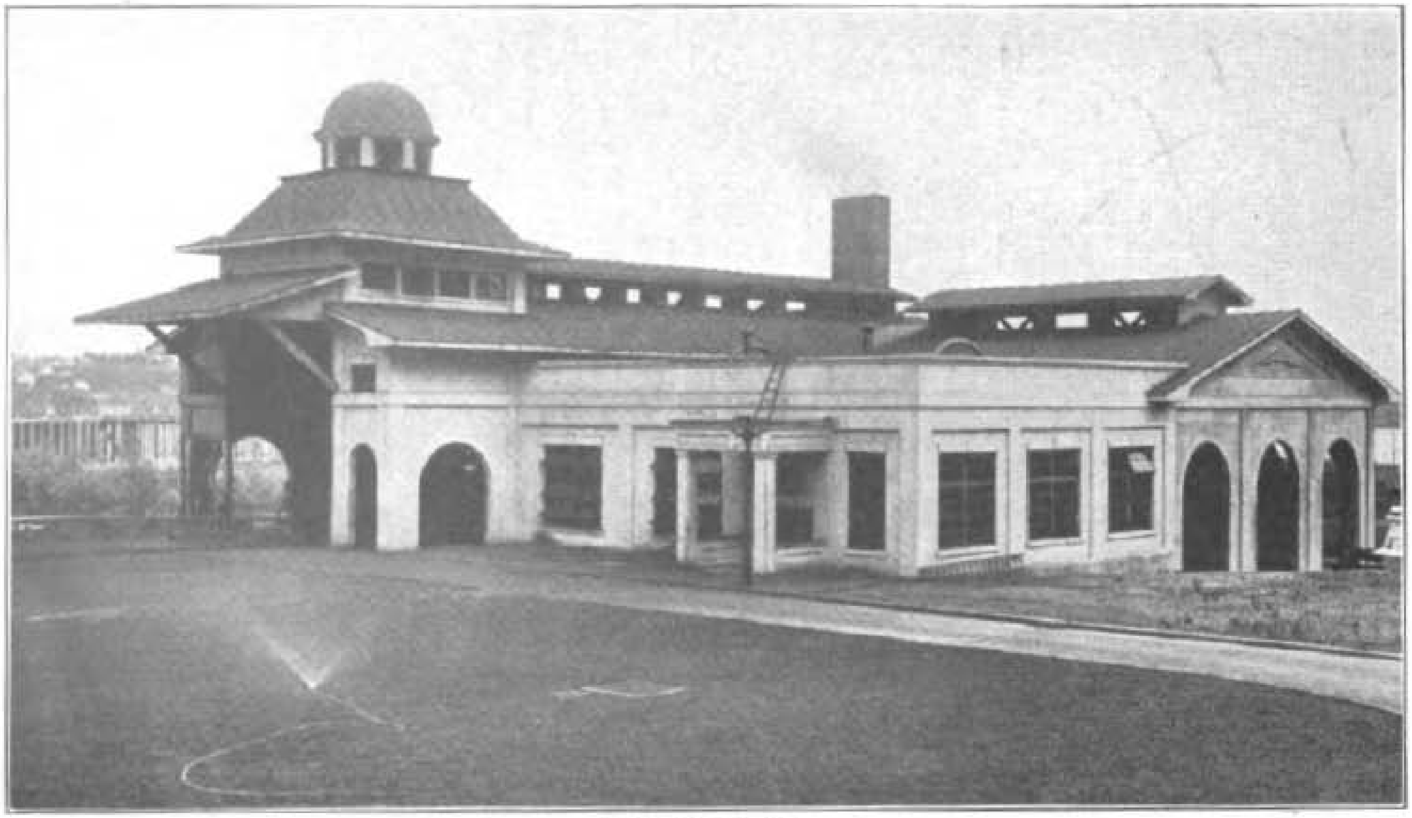
PURIFYING PLANT.

Exhibit 12: Picture of Purifiers at New Gas Plant at Linnton from 1916 Paper



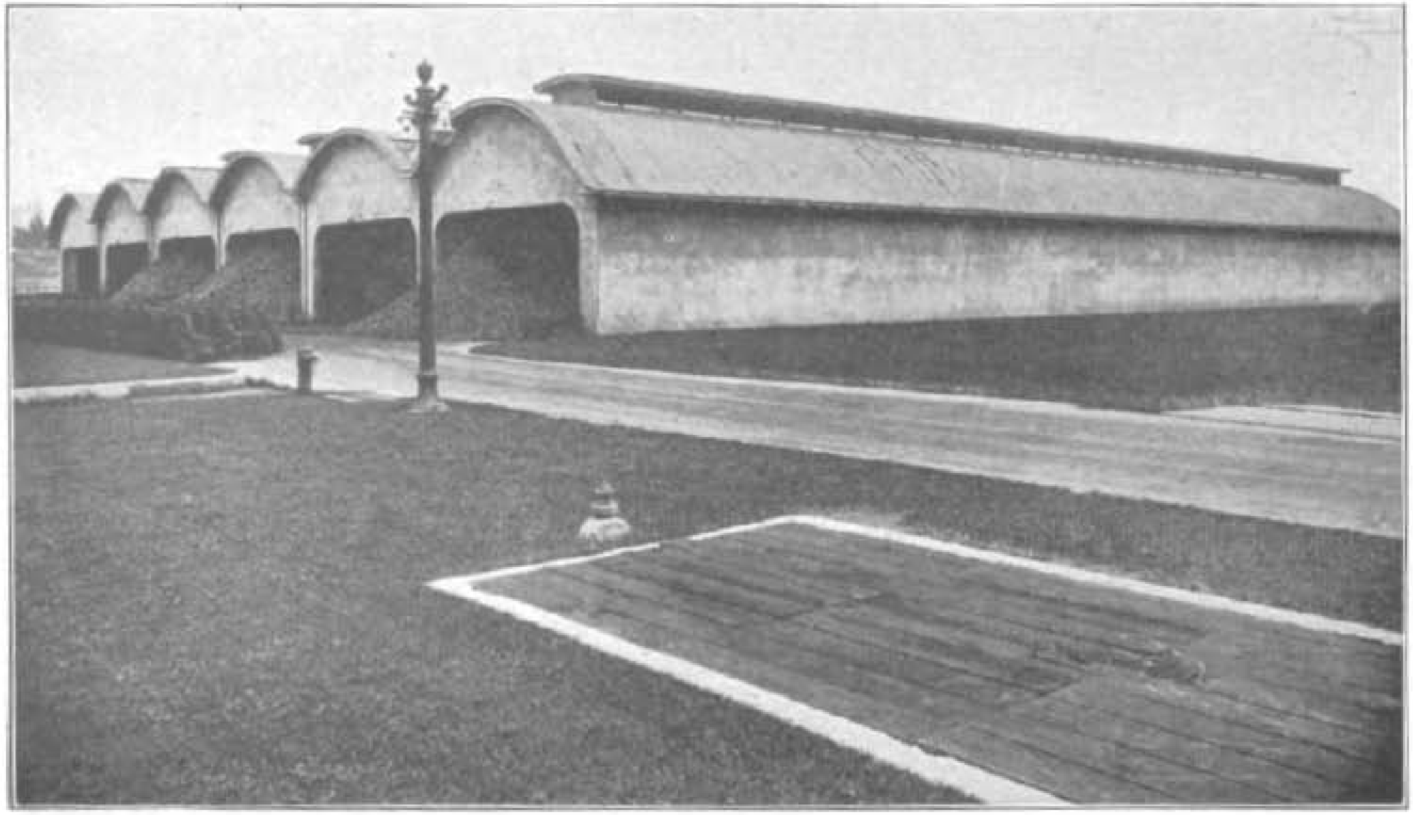
PUMPING STATION AND OIL TANK.

Exhibit 13: Picture of Oil Tank at New Gas Plant at Linnton from 1916 Paper



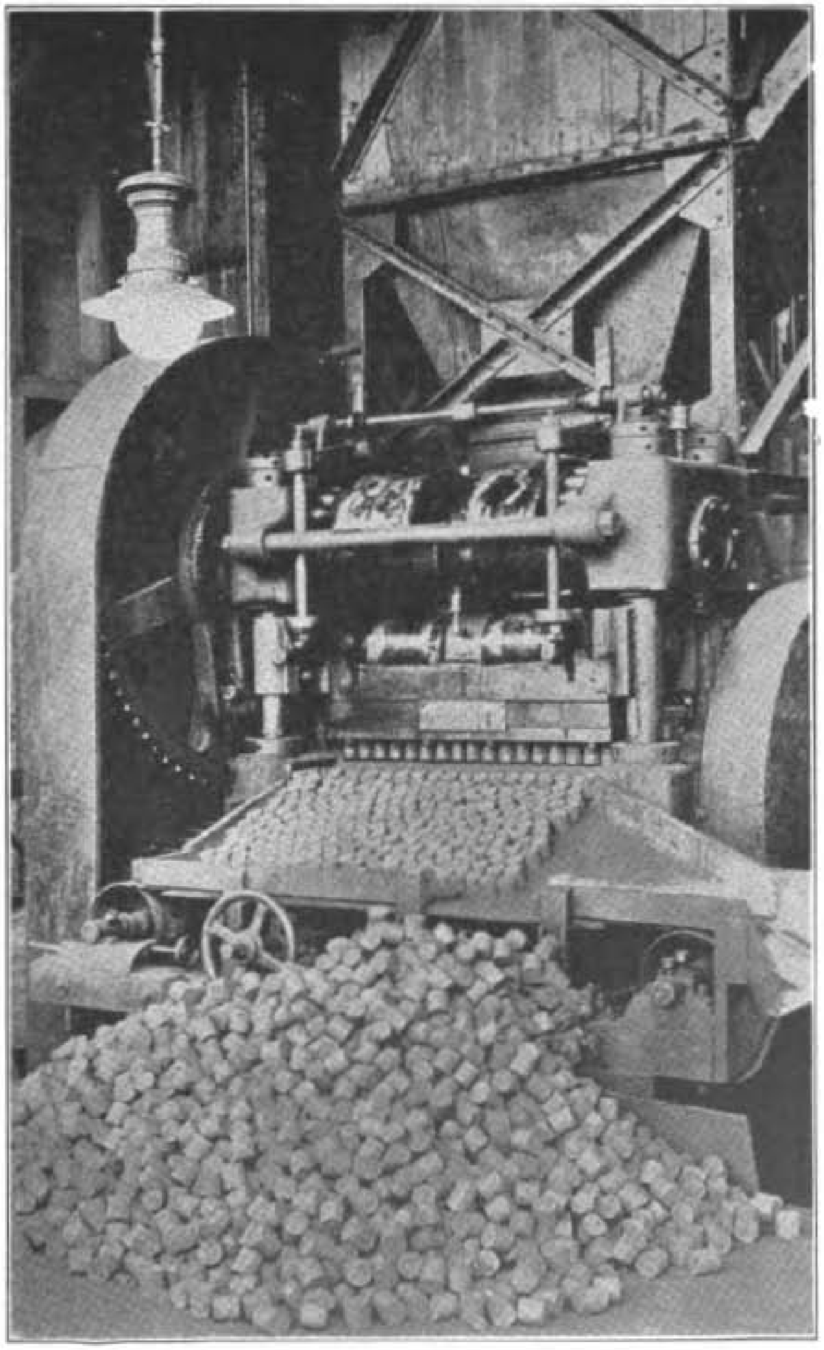
BRIQUETTE PLANT.

Exhibit 14: Picture of the Briquette Plant at New Gas Plant at Linnton from 1916 Paper



BRIQUETTE STORAGE SHEDS.

Exhibit 15: Picture of the Briquette Storage Sheds at New Gas Plant at Linnton from 1916 Paper



BRIQUETTE PRESS.

Exhibit 16: Picture of a Briquette Press at New Gas Plant at Linnton from 1916 Paper

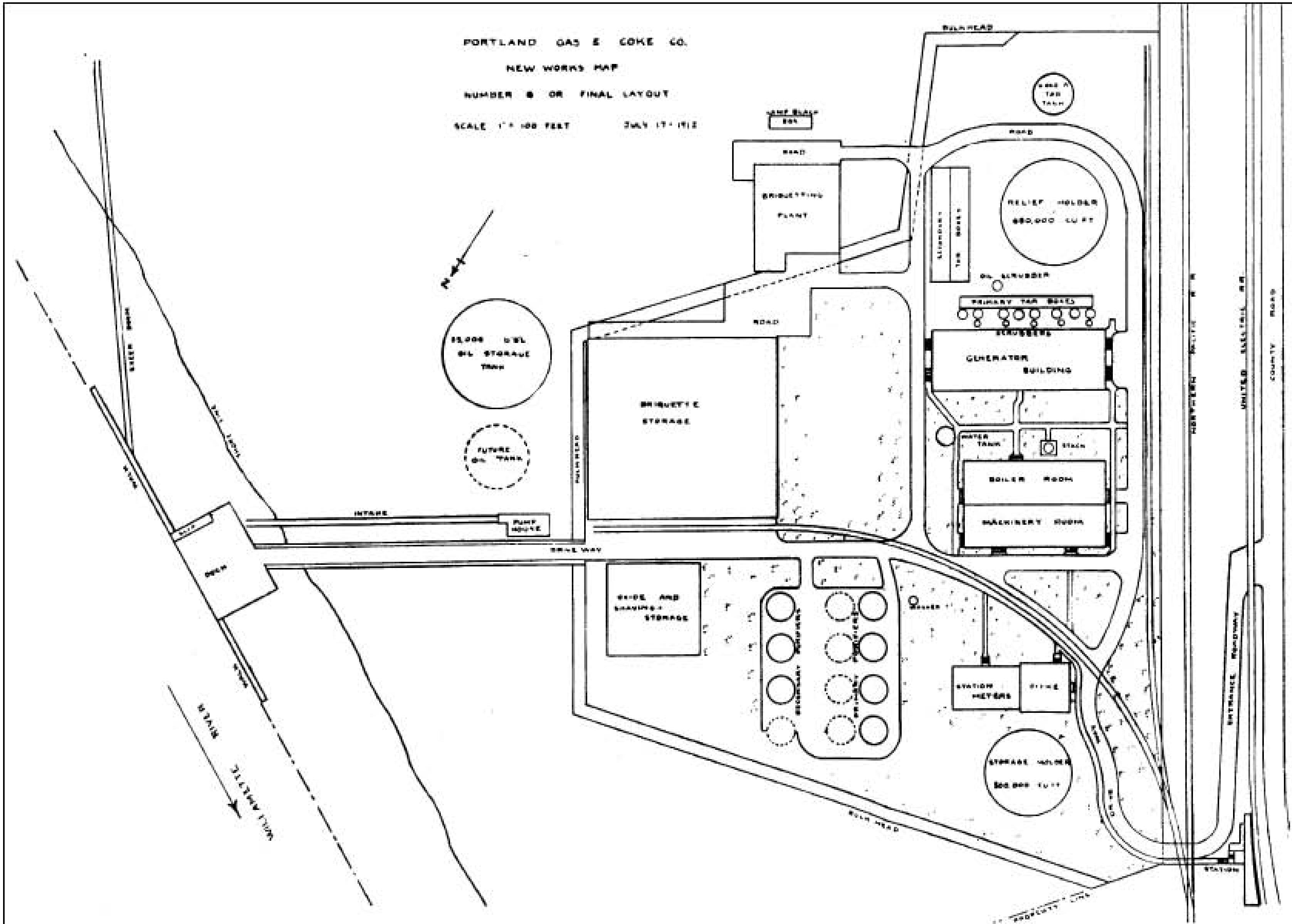


FIG. 2.

Exhibit 17: Site Layout Plan of the New Gas Plant at Linnton from 1916 Paper

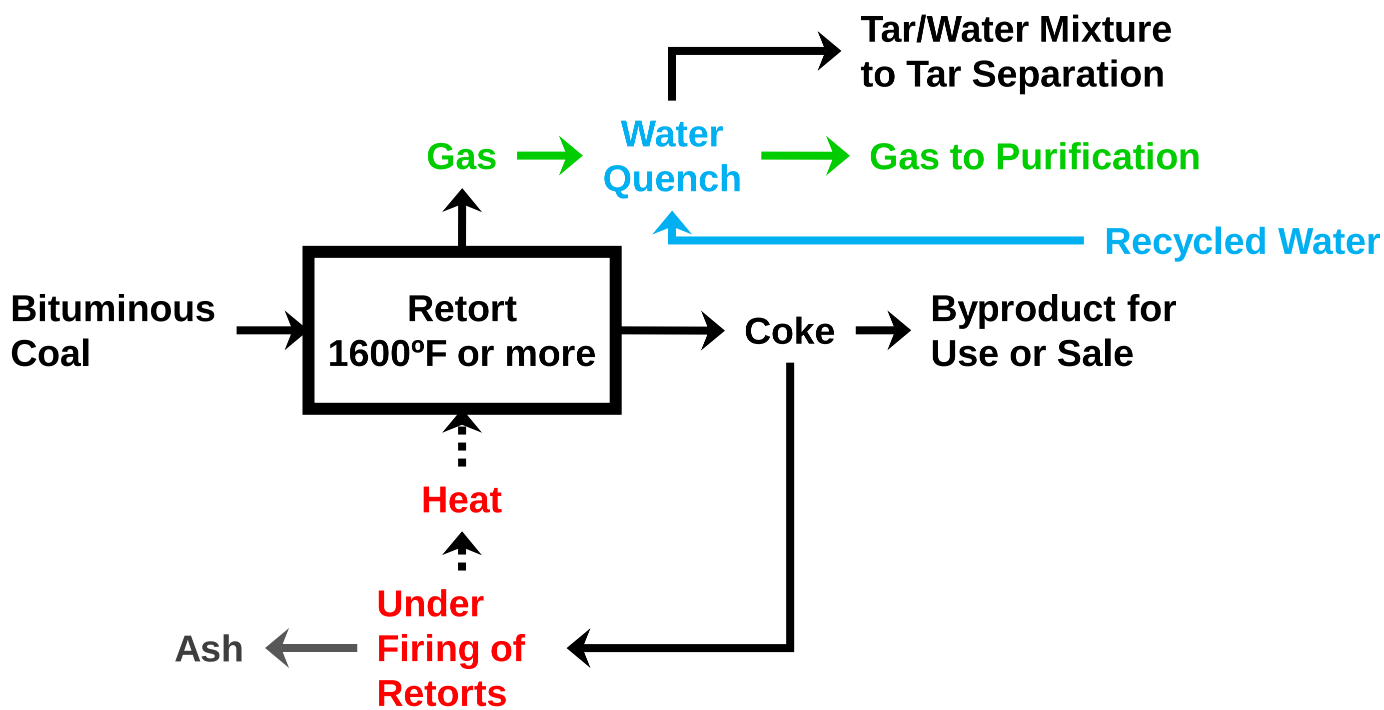


Exhibit 18: Schematic Diagram of Coal Gas Manufacture in Retorts

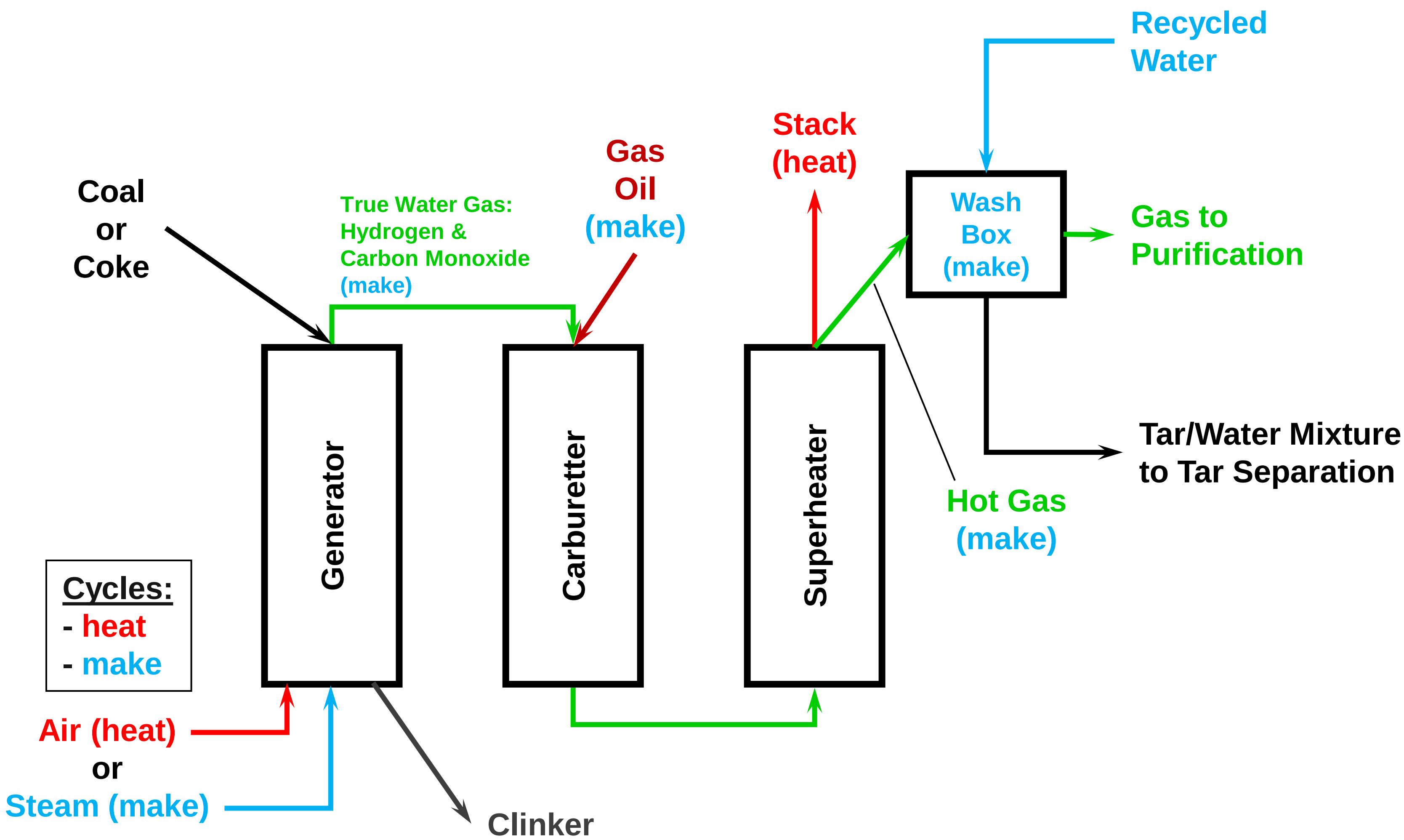


Exhibit 19: Schematic Diagram of Carburetted Water Gas ("Water Gas") Manufacture

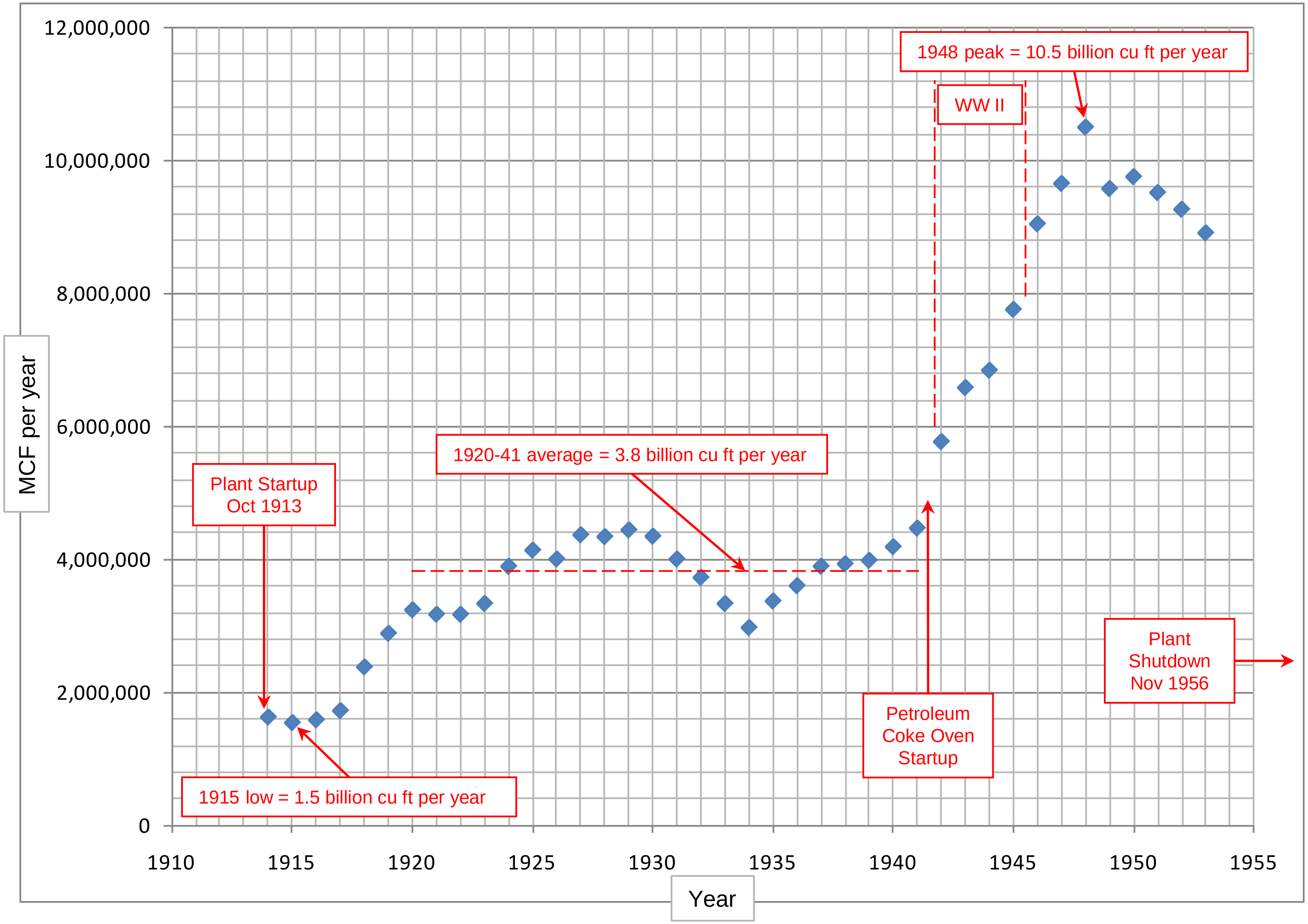


Exhibit 20: Graph of Annual Gas Production at the Linnton Plant 1914-53

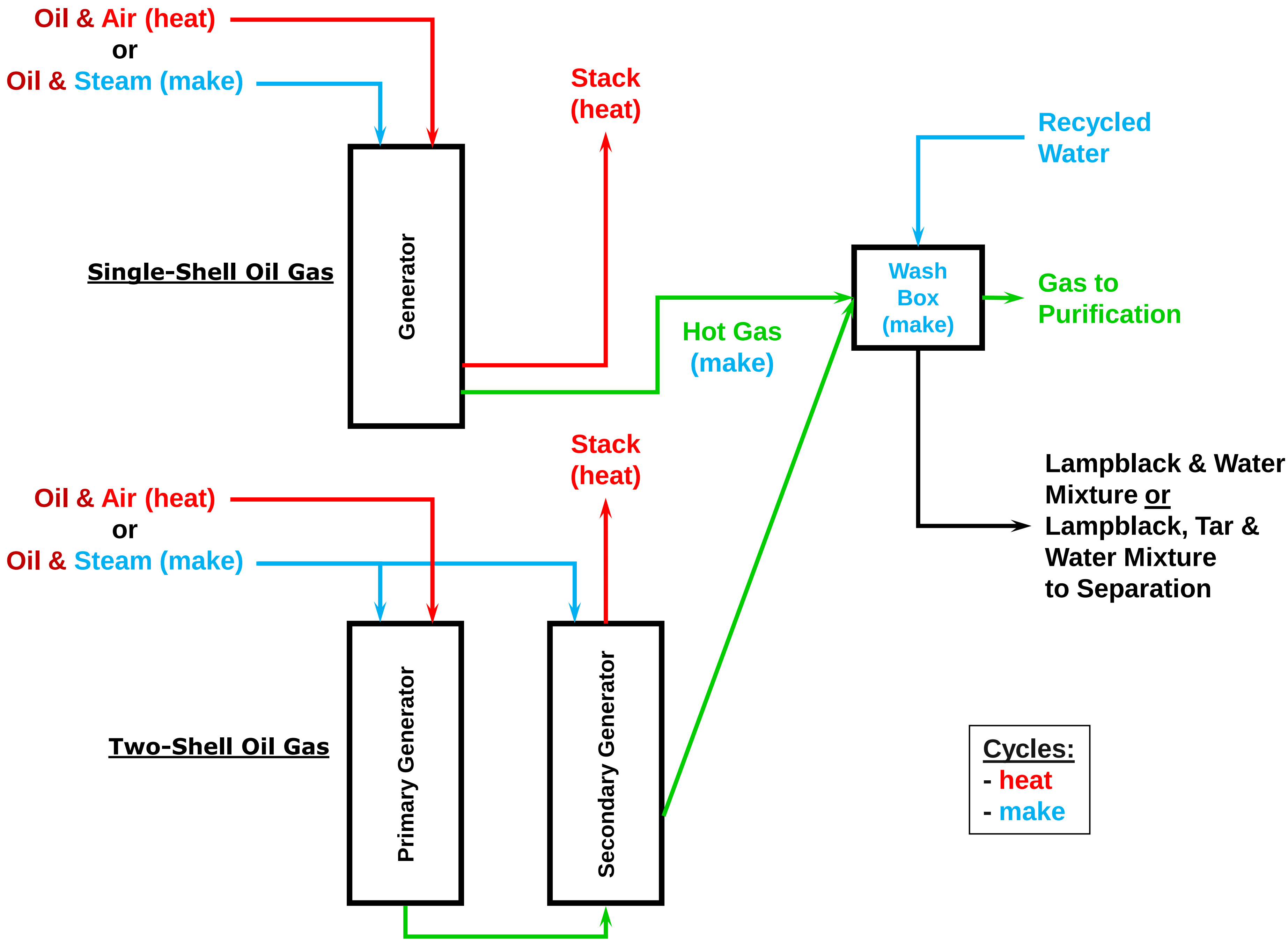


Exhibit 21: Schematic Diagram of Oil Gas Manufacture

CURRICULUM VITAE

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EDUCATION

Rockingham County Public School System, Rockingham County, Virginia, 1954-1966.
Virginia Polytechnic Institute & State University, Blacksburg, Virginia, 1966-1971.
Awarded B.S. with distinction in Civil Engineering with Cooperative Education Option (1971).
Awarded M.S. in Sanitary Engineering (1972).
Cornell University, Ithaca, New York, 1971-74
Awarded Ph.D. in Environmental Engineering (1975).

PROFESSIONAL REGISTRATION

Registered Professional Engineer of Province of Ontario (No. 31596018) since 1975.

PROFESSIONAL SOCIETIES

American Society of Civil Engineers
American Society for Testing and Materials
Water Environment Federation

BOARD CERTIFCATION

American Academy of Environmental Engineers (board certified by eminence in the specialty area of hazardous waste management), BCEE

AWARDS

Recipient of 1995 New York Water Environment Association Linn H. Enslow Memorial Award for outstanding paper, "Treatment of Organically Contaminated Groundwater in Municipal Activated Sludge System."

Recipient of the 1999 PECO Energy (Philadelphia, PA) High Energy Excellence Award for work as a member of PECO's Environmental Insurance Recovery Team.

MEMBERSHIP/COMMITTEE ACTIVITIES

November 1995 – Present: *National Trainer for ASTM* for its risk-based corrective action (RBCA) standard (E1739). In this capacity, Dr. Middleton instructs at the two-day ASTM RBCA course being held nationally. He has instructed hundreds of students in numerous of these courses across the U.S.

2000 – 2006: *Member of the External Advisory Panel, Environmental Engineering Department, SUNY/Buffalo, Buffalo, NY.* As a member he advised the Environmental Engineering Department on the educational needs of the environmental engineering practice on matters related to environmental remediation, waste treatment and management and management of environmental affairs. This panel periodically met with the faculty of the Department regarding the undergraduate environmental engineering program.

1999 – 2004: *Member of the Environmental Technical Advisory Board, Alcoa, Pittsburgh, PA.* As a member he advised the Alcoa Corporation on technical topics related to environmental remediation, waste treatment and management and management of environmental affairs, including topics for research and development. This board met several times annually with Alcoa's environmental management and remediation teams.

1999 – 2002: *Chair, Water Environment Research Foundation (WERF) Project Subcommittee on "Enhancing Biodegradability of Refractory Aromatics in Wastewater: Pretreatment with Elemental Iron, 99-CTS-3."* WERF awarded this grant to the University of Delaware for research on the capabilities of elemental iron to pretreat recalcitrant organic compounds in wastewater to improve their treatability in biological systems. The subcommittee then provided oversight on the progress of the research including review of the interim and final reports.

1998 – 2004: *Chair, Water Environment Research Foundation (WERF) Project Subcommittee on "Evaluating and Optimizing Source Treatment Technologies to Improve the Biodegradability of Organic Compounds, 99-WWF-5."* This subcommittee solicited and awarded a WERF grant to San Diego State University for research on the capabilities of advanced oxidative technologies to pretreat recalcitrant organic compounds in wastewater to improve their treatability in biological systems. The subcommittee then provided oversight on the progress of the research including review of the interim and final reports.

EMPLOYMENT RECORD

November 2001 – Present: *President, Corporate Environmental Solutions LLC.* Dr. Middleton founded this company in 2001 to provide environmental services. He is responsible for technical, operational and business affairs. He personally provides senior consulting services in the areas of corporate environmental management, environmental risk characterization and management, environmental dispute resolution, site assessment and remediation, and treatment of industrial wastewaters.

September 1981 – 2001: *Civil Engineering Department, Carnegie-Mellon University, Pittsburgh, Pennsylvania*: Intermittent teaching of graduate courses in contaminated water treatment. He developed an innovative approach for the water and wastewater treatment course by unifying the subject matter into a course on "Treatment of Contaminated Water." This course focused on selection and design of a treatment system based on the nature and concentrations of contaminants and the intended means of disposition using a matrix of individual unit processes. The approach is applicable regardless of whether the contaminated water is municipal or industrial wastewater, groundwater or storm runoff. This approach contrasts to separate courses for water, wastewater or groundwater treatment.

January 2001 – November 2001: *Senior Vice President, The RETEC Group, Inc.* In this capacity he was responsible for executive oversight of engineering, science and technology efforts across the company as well as his technical consulting client program management practices. Additionally, he managed the O&M Group and provided consulting and engineering services, project and program management and business development in environmental management; contaminated water treatment; and, in site assessment and remediation.

April 1999 – December 2000: *General Manager of ThermoRetec's Site Management and Closure Division.* Responsible for the division technical and business affairs including division P&L. This division had a Construction Group and an Operations and Maintenance (O&M) Group. The construction group carried out large civil remediation construction projects (e.g., excavation, sheet piling, slurry walls, landfill covers, contaminated water treatment plant construction) for industrial and utility clients. The O&M Group operated remediation systems (e.g., groundwater extraction and treatment, land treatment units for bioremediation of soil, soil venting, NAPL recovery, landfill leachate treatment) across the U.S. also for industrial and utility clients. Additionally, he provided consulting and engineering services in environmental management, contaminated water treatment, laboratory and field treatability projects on site assessment and remediation.

January 1990 – April 1999: *Principal of ThermoRetec Consulting Corporation*. Responsible for technical and business affairs of company. ThermoRetec (formerly RETEC) is an engineering and remedial services company specializing in on-site treatment of organic wastes. Day-to-day duties included project management of RI/FS's on Superfund sites, site remediation, environmental audits of industrial facilities, design and operation of treatment facilities for contaminated groundwater, soils, industrial and municipal wastewaters, permitting of industrial facilities, and remedial technology development. He also was the principal investigator on field research studies for site remediation. He served as a member of ThermoRetec's Board of Directors from 1990 until 1995.

June 1991 – December 1996: *Member of the Board of Directors of EnSys Environmental Products, Inc.:* EnSys was a biotechnology start up company developing and selling immunoassay test kits for the analysis of soil and water. During his tenure on the Board, EnSys went public in an IPO in 1993 and merged with Strategic Diagnostics, Inc. (symbol: SDIX) in 1996. Dr. Middleton provided advice on commercialization opportunities for new test kits, served on the Audit Committee and chaired the Compensation Committee of this publicly traded company.

May 1990 – December 1995: *Member of the Board of Directors of Remediation Technologies, Inc (RETEC):* RETEC was a privately held company during his tenure on the Board. It tripled in size in this five-year period and became an acquisition of the publicly traded Thermo Remediation, Inc. (later renamed ThermoRetec) in December 1995. Dr. Middleton provided advice on strategic direction for the company as well as on technology commercialization.

July 1988 – December 1989: *President of Haniel Environmental Services, Inc. (HES).* Responsible for operations, technical matters and business affairs. HES was the U.S. branch of a German company specializing in site remediation. While in this position, his technical activities included managing soil gas surveys and *in situ* clean up of volatile organic compounds with soil venting and groundwater aeration systems, as well as general site decommissioning and remediation, project management of RI/FS's, and technical support of litigation. He served on the boards of directors of HES and its subsidiary companies during this his tenure as President.

June 1986 – June 1988: *President of Keystone Environmental Resources, Inc.* (also founder of Keystone). Responsible for management and leadership that grew the company from 90 employees to over 250 with ten offices in the United States and Canada offering environmental consulting, analytical, and remediation services. Keystone was a wholly owned subsidiary of Koppers. Keystone specialized in the investigation and remediation of wood treating, tar-contaminated and chemical sites and in the design and operation of wastewater and groundwater treatment systems. He was also the principal investigator for Keystone's research project funded by the Gas Research Institute on assessment and remediation of manufactured gas plant sites and the director of the company's research and development efforts on new environmental technologies. He served on the board of directors of Keystone and continued as Vice President of Koppers Environmental Resources.

August 1984 – June 1986: *Vice President and General Manager of Pioneering Technologies (in addition to Environmental Resources):* Overall responsibilities for a program made up of a Materials Science Department, a Manufacturing Technologies Department, a Technical Information Department, and a Project Management Group; activities included research on polymer science and wood treating chemicals, computer-assisted drafting; instrumentation and control, systems design and installation, and computer and library facility management. Project management activities included facilitating use of a computer-based project management system throughout Koppers Science and Technology activities, especially on interdisciplinary teams. Additionally, Dr. Middleton directed this department's interactions with Koppers' venture investments in biotechnology and materials science.

June 1981 – June 1988: *Vice President and General Manager of Environmental Resources Department, Koppers Company, Inc., Monroeville, Pennsylvania*: Overall responsibility for management of Koppers environmental affairs. Included in Koppers operations were over 50 Chemical & Allied Products plants including 17 wood preserving plants, as well as other facilities producing metal products and road materials. In addition to the operating facilities, his overall responsibility included management of over 50 previously operated plants (wood treating and chemical plants) and disposal sites, a number of which are Superfund sites. His duties also included management of the environmental reserves for remediation of previously operated properties as well as developing an annual budget for activities on these sites. He built a multi-disciplinary staff of environmental engineers and scientists from 1981-1986, which was of such quality and capability that it was converted to a P&L subsidiary in 1986 (Keystone Environmental Resources, Inc.) to provide services outside of Koppers on a commercial basis.

February 1979 – May 1981: *Manager of Water Quality Engineering Section of Environmental Resources and Occupational Health Department, Koppers Company, Inc., Monroeville, Pennsylvania*: The objective of this section was to provide in-house water quality engineering services to Koppers Company. Projects included activated sludge treatability studies (bench-scale and pilot plant) at tar distillation plants; wastewater characterization studies at tar distillation and chemical plants; treatability studies for oil removal (bench-scale and pilot plant) at tar distillation and chemical plants; activated sludge plant startup at coke plants; preparation of activated sludge control programs at coke, chemical, and tar distillation plants; hydrogeologic surveys at tar distillation, wood preserving, and coke plants; fish toxicity studies on chemical and tar distillation plant wastewaters; priority pollutant surveys at chemical, coke, and tar distillation plants; development of wastewater treatment processes to achieve BAT for coke, tar distillation, and synthetic fuels plants. In this position, he also established a treatability laboratory program for wastewater, groundwater, sludge and soil.

June 1978 – January 1979: *Senior Research Engineer, Research Department, Koppers Company, Inc., Monroeville, Pennsylvania*: Responsible for water pollution control projects with Koppers Company, Inc., including activated sludge pilot plant study with continuous fish bioassays of effluent at a chemical plant; preparation of operational control programs at chemical sludge plants for coke and tar distillation plants.

July 1976 – May 1978: *Assistant Professor of Civil Engineering, SUNY at Buffalo, Buffalo, New York:* Teaching graduate and undergraduate courses in water and wastewater treatment and environmental engineering; acquiring and directing funded programs of research in water pollution control engineering, supervised graduate students and development of water pollution control laboratories; two students received Ph.D. degrees and nine received M.S. degrees in environmental engineering under his direction.

September 1974 – June 1976: *Assistant Professor of Civil Engineering, University of Ottawa, Ottawa, Ontario*: Teaching graduate and undergraduate course in water and wastewater treatment and environmental engineering; acquiring and directing funded programs of research in water pollution control engineering; supervising graduate students and development of water pollution control laboratories; seven students received M.S. degrees in environmental engineering under his direction.

September 1971 – August 1974: *EPA Post Masters Trainee, Cornell University, Ithaca, New York*: Study in the Environmental Engineering Ph.D. Program under Dr. A. W. Lawrence in Civil and Environmental Engineering School. In addition to his experimental research on the kinetics of microbial sulfate reduction, he also developed an approach for least cost design of wastewater treatment systems. He received a Ph.D. in environmental engineering.

September 1970 – August 1971: *Public Health Fellow, VPI&SU, Blacksburg, Virginia*: Study in Sanitary Engineering Program under Dr. E. M. Jennelle, Civil Engineering Department. He conducted experimental research on the water quality of a large, pumped storage reservoir near VPI for his Master's thesis. He received an MS in sanitary engineering.

March-June, September-December 1968; March-June, September-December, 1969: *Co-op student in Civil Engineering, Wiley & Wilson Consulting Engineers & Architects, Lynchburg, Virginia*: Worked as Engineering Design Assistant on municipal water and wastewater projects and as a land and route survey party member. The Co-op Program was part of his undergraduate work at Virginia Tech, from which he received a BS in civil engineering with distinction.

PUBLICATIONS (JOURNALS)

1. Middleton, A.C. and Lawrence, A.W., 1973. Discussion of "Optimal Design of Wastewater Treatment Systems by Enumeration," by G.F. Parkin and R.R. Dague, Journal Environmental Engineering Division, ASCE, 99, 960.

2. Middleton, A.C. and Lawrence, A.W., 1974. "Cost Optimization of Activated Sludge Systems," Biotechnology and Bioengineering, XVI, 807.

3. Middleton, A.C. and Lawrence, A.W., 1976. "Least Cost Design of Activated Sludge Systems," Journal Water Pollution Control Federation. 48, 395.

4. Middleton, A.C. and Lawrence, A.W., 1977. "Kinetics of Microbial Sulfate Reduction, "Journal Water Pollution Control Federation. 49,1659.

5. Middleton, A.C. and Rovers, F.A., 1976. "Average pH," Communications, Journal Water Pollution Control Federation, 48, 395.

6. Adamowski, K and Middleton, A.C., 1977. "Steady-State Dissolved Oxygen Model for the Rideau River," Canadian Journal of Civil Engineering. 4, 471.

7. Craig, E.W., Meredith, D.D., and Middleton, A.C., 1977. Discussion of "Simplified Optimization of Activated Sludge Process," by C.P.L. Grady, Jr., Journal Environmental Engineering Division, ASCE, 103, 1158.

8. MacInnes, C.D., Middleton, A.C., and Adamowski, K, 1978. "Stochastic Design of Flow Equalization Basins," Journal Environmental Engineering Division, ASCE, 104, 1277.

9. Craig, E.W., Meredith, D.D. and Middleton, A.C., 1978. "Cost Optimization of the Activated Sludge Process Using the Box-Complex Algorithm," Journal Environmental Engineering Division, ASCE. 104, 1101.

10. Westerndorf, J.R. and Middleton, A.C., 1979. "Chemical Aspects of the Relationship Between Drinking Water Quality and Long-Term Health Effects: An Overview," Journal American Water Works Association. 71, 417.

11. Fritz, J.J., Middleton, A.C., and Meredith, D.D., 1979. "Dynamic Process Modeling of Wastewater Stabilization Ponds," Journal Water Pollution Control Federation, 51, 2724.

12. Fritz, J.J., Meredith, D.D., and Middleton, A.C., 1980. "Non-Steady State Bulk Temperature Determination for Simple Aquatic Ecosystems: Stabilization Ponds," Water Research (U.K), 14, 413.

13. Habicht, M.H., Adamowski, K., and Middleton, A.C., 1981. "Potential Eutrophication of the Rideau River by an Urban Drainage Waterway," Canadian Journal of Civil Engineering, 8, 165.

14. Hughey, P.W., Meredith, D.D., and Middleton, A.C., 1982. "Optimal Operation of an Activated Sludge Plant," Journal Environmental Engineering Division, ASCE, 108, 349.

15. Smith, J.R., Luthy, R.G., and Middleton, A.C., 1988. "Microbial Ferrous Iron Oxidation in Acidic Solution," Journal Water Pollution Control Federation, 60, 518.

16. Meredith, D.D., Middleton, A.C., and Smith, J.R., 1990. "Design of Detention Basins for Industrial Sites," Journal Water Resources Planning and Management, ASCE, 116, 586.

17. Middleton, A.C., Nakles, D.V., and Linz, D.G., 1991. "The Influence of Soil Composition on Bioremediation of PAH-Contaminated Soils," Remediation, 1, 391.

18. Smith, J.R., Neuhauser, E.F., Middleton, A.C., Weightman, R.L, Linz, D.G., 1993. "Treatment of Organically Contaminated Groundwaters in Municipal Activated Sludge Systems," Water Environment Research, 65.

PUBLICATIONS (BOOKS)

1. Craun, J.C. and Middleton, A.C. (co-editors/authors), 1984. Handbook on Manufactured Gas Plant Sites, Washington, D.C.: Edison Electric Institute.

2. Unites, D., Nakles, D., Menzie, C., Middleton, A., and Helsel, R. (co-editors/authors), 1987. Management of Manufactured Gas Plant Sites, Vol. I-IV, Chicago, Illinois: Gas Research Institute.

PUBLICATIONS (CONFERENCE PROCEEDINGS)

1. Weyland, H.J. and Middleton, A.C., 1977. "Metals Recovery from Metallic Hydroxide Sludges Through Microbial Sulfate Reduction," Proceedings 9th Mid-Atlantic Industrial Waste Conference, Bucknell University, Lewisburg, Pennsylvania.

2. Lee, G.C., Meredith, D.D., and Middleton, A.C., Eds., 1979. "Proceedings of Hazardous Waste Management and Disposal Seminar," WREE Report No. 79-2, Civil Engineering SUNY/Buffalo, Buffalo, New York.

3. Bhattacharyya, A. and Middleton, A.C., 1979. "Development of Biological Treatment System Achieving BATEA for Coke Plant Wastewaters," Proceedings 11th Mid-Atlantic Industrial Waste Conference, Pennsylvania State University, State College, Pennsylvania.

4. Bhattacharyya, A. and Middleton, A.C., 1980. "Solids Retention Time: A Controlling Factor in the Successful Biological Nitrification of Coke Plant Wastes," Proceedings 12th Mid-Atlantic Industrial Waste Conference, Bucknell University, Lewisburg, Pennsylvania.

5. Bhattacharyya, A. and Middleton, A.C., 1980. "Enhanced Biological Treatment System for Coke Plant Wastewater Achieving Complete Nitrification," Proceedings 35th Industrial Waste Conference, Purdue University, Lafayette, Indiana.

6. Middleton, A.C., 1981. "Process Control for Activated Sludge Treatment of Coke Plant Wastewater," Proceedings: Symposium on Iron and Steel Pollution Abatement Technology for 1980, EPA-600/9-81-017, Philadelphia, Pennsylvania.

7. Middleton, A.C., Smith, J.R., Urbassik, M.R., Keffer, R.E., Sawchuck, P.W., and Edwards, G.E., 1984. "Industrial Wastewater Treatability Study Achieving BCT/BAT Treatment," Proceedings 16th Mid-Atlantic Industrial Waste Conference, Pennsylvania State University, State College, Pennsylvania.

8. Middleton, A.C., 1995. "Historical Overview of Manufactured Gas Processes Used in the United States," presented at International Symposium and Trade Fair on the Clean-up of Manufactured Gas Plants, Prague, Czech Republic; published in Land Contamination & Reclamation, Vol. 3, No. 4, pp.5-17 – 5-19.

PRESENTATIONS

1. Middleton, A.C. and Jenelle, E.M., "The Influence of an Impoundment on the Priority of Effluent Treatment in the Upstream Watershed," presented at 26th Annual Meeting, Virginia Water Poll. Control Assn., Roanoke, Virginia, April 30, 1970.

2. Middleton, A.C. and Jenelle, E.M., "Processes Influencing Water Quality in a Pumped Storage Reservoir," presented at 8th Annual Meeting, Am. Water Resources Assn., St. Louis, Missouri, October 31, 1972.

3. Middleton, A.C. and Lawrence, A.W., "Cost Optimization of Activated Sludge Wastewater Treatment Systems," presented at 166th National Meeting, Am. Chem. Soc., Chicago, Illinois, August 30, 1973.

4. Middleton, A.C. and Lawrence, A.W., "Least Cost Design of Activated Sludge Systems," presented at 46th Annual Meeting, Water Pollution Control Federation, Cleveland, Ohio, October 22, 1973.

5. Adamowski, K and Middleton, A.C., "Water Quality of the Rideau River," invited seminar at 2nd Annual Science Education Day Conf., Kanata, Ontario, April 12, 1975.

6. Middleton, A.C. and Lawrence, A.W., "Kinetics and Engineering Significant of Microbial Sulfate Reduction," presented at 47th Annual Meeting, Water Pollution Control Federation, Miami Beach, Florida, October 8, 1975.

7. Middleton, A.C., "The Science of Environmental Impact Statement," invited seminar for Buffalo Section of ASCE Workshop on "The Preparation of Environmental Impact Statements," Buffalo, New York, February 8, 1977.

8. Middleton, A.C., "Design of the Activated Sludge Process," invited seminar for Buffalo Section ASCE Workshop on "Design and Operation of the Activated Sludge Process," Buffalo, New York, March 14, 1978.

9. Middleton, A.C. and Lawrence, A.W., "The Effect of Recycle Sludge Pumping Rates on the Activated Sludge Process," invited seminar for Buffalo Section ASCE Workshop on "Design and Operation of the Activated Sludge Process," Buffalo, New York, March 14, 1978.

10. Westendorf, J.R., Middleton, A.C., and Kasprzak, P.J., "Co-Disposal of a Combined Municipal/Industrial Wastewater Treatment Plant Sludge with Municipal Refuse in a Sanitary Landfill," presented at 52nd Annual Conference Water Pollution Control Federation, Houston, Texas, October, May 14, 1980.

11. Middleton, A.C., "Wastewater Treatment for Coke and Coal-Tar Distillation Plants," presented at the Spring Meeting American Coke and Coal Chemicals Institute, Hilton Head, South Carolina, May 19, 1981.

12. Middleton, A.C., "Hazardous Wastes," presented at Disaster Emphasis Day, Annual Conference, Church of the Brethren, Indianapolis, Indiana, June 23, 1981.

13. Hughey, P.W., Meredith, D.D., and Middleton, A.C., "Optimal Operation of an Activated Sludge Wastewater Treatment Plant," presented at The International Symposium on Real Time Operation of Hydrosystems, Waterloo, Ontario, Canada, June 25, 1981.

14. Middleton, A.C., "Removal of Priority Pollutants From Coal-Tar Condensate Water," invited speaker at The Fate of Wastewater-Borne Priority Pollutants Subjected to Biological Treatment, U.S. EPA Seminar, Washington, D.C., May 4, 1982.

15. Malik, D.P., Middleton, A.C., Bryant, D.L., Sgro, G.A., Fillo, J.P., Charna, R.B., and Maruhnich, E.D., "Water Usage and Treatment, Tennessee Synfuels Project," presented at ASCE Conference on Water & Energy: Technical & Policy Issues, Pittsburgh, Pennsylvania, May 1982.

16. Middleton, A.C., "BAT Regulations for Coke Plants," invited speaker at Fall Meeting, Manufacturing and Environmental Committee, American Coke and Coal Chemicals Institute, Indianapolis, Indiana, September 14, 1982.

17. Middleton, A.C., “Priority Pollutant Removal From Coke and Coal-Tar Distillation Plant Wastewaters By Biological Treatment,” invited speaker at Biological Treatment, Priority Pollutants and BATEA Seminar, Philadelphia, Pennsylvania, December 10, 1982.

18. Middleton, A.C., “Wastewater Treatment For Coke Plants: Regulations and Capabilities,” invited speaker at Eastern States Coke Conference, Pittsburgh, Pennsylvania, February 1983.

19. Middleton, A.C., “Land Disposal and Spill Site Environments,” invited speaker at Genetic Control of Environmental Pollutants, University of Washington, Seattle, August 1, 1983.

20. Middleton, A.C. and Oster, L.A., “Projected Environmental Costs to Permit and Operate the PMA Methanol Plant,” presented at the AIChE 1984 Summer National Meeting, Philadelphia, Pennsylvania, August 19, 1984.

21. Spencer, J.D., Middleton, A.C., Smith, J.R., Campbell, J.R., and Zeff, J.D., “Evaluation of Treatment Technologies for Contaminated Groundwater,” presented at the Water Pollution Control Federation 59th Annual Conference/Exposition, Los Angeles, California, October 6-9, 1986.

22. Middleton, A.C., “Opportunities for Chemical Engineers in Hazardous Waste Management,” presented to the Pittsburgh Section of AIChE, Pittsburgh, Pennsylvania, January 13, 1987.

23. Middleton, A.C., “Environmental Management,” invited speaker at the annual meeting of the National Wood Window and Door Association, Maui, Hawaii, February 1987.

24. Hegnauer, A. and Middleton, A.C., “Environmental Considerations at Manufactured Gas Plant Sites,” presented at the American Gas Association Distribution/Transmission Conference, Las Vegas, Nevada, May 1987.

25. McShea, L.J., Smith, J.R., Middleton, A.C., and Zeff, J.D., “Chemical Oxidation of Aqueous Pentachlorophenol and Phenolics by UV-Ozonation,” presented at the American Institute of Chemical Engineers 1986 Summer National Meeting, Boston, Massachusetts, August 24-27, 1986.

26. Middleton, A.C., Presentation on bioremediation of wood treating wastes to Committee on Small Business, Subcommittee on Energy and Agriculture, U.S. House of Representatives, Washington, D.C., September 1987.

27. Hiller, D.H. and Middleton, A.C., “Die Abwicklung von Schadensfallen in den USA,” presented at Harress Geotechnik-Umweltseminar, Kloster Banz, Germany, October, 21-22, 1988.

28. Smith, J.R., Fu, J.K, and Middleton, A.C., “Field Work Evaluating Engineered Biodegradation System Treatment of Soil Contaminated with Wood Preserving Chemicals,” presented at Conference on Genetically Engineered or Adapted Microorganisms in Hazardous Waste Treatment, Washington, D.C., December 1988.

29. Middleton, A.C., “Co-Treatment of Groundwater in POTWs,” presented at Management of Manufactured Gas Plant Sites Technology Transfer Seminar sponsored by EEI, EPRI, and GRI, Pittsburgh, Pennsylvania, April 19-20, 1989.

30. Middleton, A.C. and Hiller, D.H., "*In Situ* Aeration of Groundwater, a Technology Overview," presented at Conference on Prevention and Treatment of Soil and Groundwater Contamination in the Petroleum Refining and Distribution Industry, Montreal, Quebec, October 16-17, 1990.

31. Linz, D.G., Neuhauser, E.F. and Middleton, A.C., "Perspectives on Bioremediation in Gas Industry," presented at Environmental Biotechnology Symposium, Knoxville, TN, October 17-19, 1990.

32. Middleton, A.C., "A Historical Perspective of Manufactured Gas Plant Operations," presented at 1990 Manufactured Gas Plant Site Workshop sponsored by AGA, Boston, MA, October 31-November 1, 1990.

33. Middleton, A.C., "Past Operations and Present-Day Site Management," presented at MGP Technology Transfer Seminar sponsored by EPRI and GRI, Atlanta, GA, April 2-3, 1991.

34. Middleton, A.C., "Remediation Options and Technologies," presented at Manufactured Gas Plant Site Workshop sponsored by NEGA, Sutton, MA, October 9, 1991.

35. Saber, D.L., Smith, J.R., Lawrence, A.W. and Middleton, A.C., "Optimization of an Oil Recovery/Groundwater Treatment System Based upon Treatability Study/Engineering Evaluations of Superfund Site Clean-Up," presented at the AIChE 1992 Summer National Meeting, August 9-12, 1992.

36. Smith, J.R., Lawrence, A.W. and Middleton, A.C., "Sequencing Batch Reactor Treatment of Superfund Site Groundwater," presented at the 65th Annual Water Environment Federation Conference, New Orleans, LA, September 20-24, 1992.

37. Middleton, A.C., Lawrence, A.W., Morgan, D.J., Lees, M.G. and Hayes, T.D., Biosparging Strategies for Containment and Remediation of Organic Contaminant Groundwater Plumes at E&P Sites Using Either Vertical or Horizontal Sparge Wells," presented at The Eighth International IGT Symposium on Gas, Oil and Environmental Biotechnology, Colorado Springs, Colorado, December 11-13, 1995.

38. Middleton, A.C., Draybuck, B.M., Grizzle, P.L. and Hayes, T.D., "Pilot Test of Biosparging at a Natural Gas Plant and Pipeline Facility," presented at the Ninth International IGT Symposium on Gas, Oil, and Environmental Biotechnology, Colorado Springs, Colorado, December 9-11, 1996

39. Middleton, A.C., Lawrence, A.W., Draybuck, B.M., Grizzle, P.L. and Hayes, T.D., "The Role of Preliminary Testing in the Design of a Biosparge System at a Natural Gas Plant and Pipeline Facility," presented at the 1997 SPE/EPA Exploration & Production Environmental Conference, Dallas, Texas, March 3-5, 1997.

40. Middleton, A.C., "Historical Operations at MGP Sites," presented at the Illinois Manufactured Gas Plant (MGP) Forum, Bloomington, Illinois, May 20, 1999 and at the Midwest Energy Association Meeting, Colorado Springs, CO, October 15, 1999.

41. Middleton, A.C., "Future Needs to be Addressed by Environmental Engineers and Scientists," presented at the University at Buffalo, Buffalo, NY, October 22, 1999.

42. Middleton, A.C., “Future Corporate Needs to be addressed by Environmental Engineers and Scientists,” presented at Carnegie Mellon University, Pittsburgh, PA, February 18, 2000, and the University of Texas Austin, Austin, TX, February 23, 2000.

43. Middleton, A.C., “Future Trends in Corporate Environmental Management,” presented at the University of Pittsburgh, Pittsburgh, PA, March 22, 2000.

44. Hasel, M.J., Shamory, C. and Middleton, A.C., “Thermal Desorption of Heavily Impacted MGP Soils under New TCLP Exemption,” presented at the GTI 14th International Conference on Site Remediation Technologies, Orlando, FL, December 2-6, 2001.

45. Middleton, A.C., “The Effect of Historical Issues on Risk,” presented at the AGA MGP Workshop, Washington, DC, August 6, 2004.

46. Morgan, D., Mahfood, J., Malle, J., Middleton, A. and McGraw, D., “The Effect of Site Remediation Risk Level on Potential Incidence of Cancer within the United States,” poster displayed at the Midwestern Risk Assessment Meeting, Indianapolis, IN, August 26, 2004.

47. Middleton, A.C. and Flaherty, J.M., “PAH Sources: Sources and Their Identification,” presented at the MEA Environmental Management Conference, Chicago, IL, September 23, 2004.

48. Bhattacharyya, A., Blayden, J.M., and Middleton, A.C. “Estimating Historic Tar Production at Manufactured Gas Plants,” presented at the poster session of National Gas Technologies 2005 Conference, Orlando Fl, January 30-February 2, 2005.

49. Blayden, J.M., Gould, J.E., Middleton, A.C., Morgan, D.J., Sladky, B.R. and McCauley, P.B., “Integration of State Risk-Based Closure Endpoints into Probabilistic Remediation Cost Estimates for MGP Sites,” presented at the National Gas Technologies 2005 Conference, Orlando Fl, January 30-February 2, 2005.

50. Sladky, B.R., Fernandes, A.C., Middleton and Morgan, D.J. “Long-Term Management Issues Resulting from Risk-Based Closure of MGP Sites,” presented at the National Gas Technologies 2005 Conference, Orlando FL, January 30-February 2, 2005.

51. Middleton, A. C. **“**Financial Strategies for Environmental Projects,” presented at the MEA Environmental Management Conference, Colorado Springs, CO, September 28, 2005.

52. Middleton, A. C. and Gould, J. E. **“**Data Management,” presented at the MEA Environmental Management Conference, Colorado Springs, CO, September 28, 2005.

53. Fernandes, A. F. and Middleton, A.C., "A Unified Multi-State Utility MGP Management Program," presented at MGP 2006 Conference, Reading, UK, April 4-6, 2006.

54. Middleton, A.C., Weightman, R.L. and Blayden, J.M. "Forensic Observation during MGP Site Remediation," poster displayed at MGP 2006 Conference, Reading, UK, April 4-6, 2006.

55. Lynch, M.J., Sylvester, J.M., Hart-Lovelace, J., Jones, D.R., and Middleton, A.C. “Insurance Recovery for MGP Site Clean-Up Costs," presented at MGP 2006 Conference, Reading, UK, April 4-6, 2006.

56. Morgan, D.J., Middleton, A.C. and Blayden, J.M. "Business Management Considerations in the Selection of Institutional and Engineering Controls for MGP Site Remediation," presented at MGP 2006 Conference, Reading, UK, April 4-6, 2006.

57. Middleton, A.C. "Influence of History of MGPs – Lecture 1," presented at EPRI MGP 101 Course, Philadelphia, PA, June 18, 2008.

TECHNICAL AND RESEARCH REPORTS

1. Middleton, A.C. and Lawrence, A.W., 1973. "Cost Optimization of Activated Sludge Wastewater Treatment Systems," EPM Technical Report No. 73-1, Department of Environmental Engineering, Cornell University, Ithaca, New York.

2. Middleton, A.C. and Lawrence, A.W., 1974. "Least Cost Design of Activated Sludge Wastewater Treatment Systems," EPM Technical Report 74-1, Department of Environmental Engineering, Cornell University, Ithaca, New York.

3. Adamowski, K and Middleton, A.C., 1976. "Comprehensive Water Quality Study of the Rideau River from Long Island to Hog's Back Falls, June-July, 1975," Final Report to the Ontario Ministry of Environment, Kingston, Ontario.

4. Middleton, A.C. and McDougall, W.J., 1977. "Technological Alternatives for Industrial Wastewater Treatment," Seminar Notes, Civil Engineering, SUNY/Buffalo, Buffalo, New York.

5. Uchida, A. and Middleton, A.C., 1978. "Water Quality Modeling of Mine Acid Drainage II: Laboratory Evaluation of Preliminary Model," WREE Report No. 78-3, Civil Engineering, SUNY/Buffalo, Buffalo, New York.

6. Fritz, J.J., Meredith, D.D., and Middleton, A.C., 1978. "Modeling and Design of Wastewater Stabilization Ponds," WREE Report No. 78-4, Civil Engineering, SUNY/Buffalo, Buffalo, New York.

7. Middleton, A.C., Narbaitz, R.M., and Uchida, A., 1980. "Phosphorus Solubilization during Anaerobic Decomposition of Algae," WREE Report No. 80-1, Civil Engineering, SUNY, Buffalo, Buffalo, New York.

8. Fritz, J.J., Middleton, A.C., and Meredith, D.D., 1981. "Application of a Rational Process Model in Design of Waste Stabilization Ponds," WREE Report, Civil Engineering, SUNY/Buffalo, Buffalo, New York.

9. Kasprzak, P.J., Meredith, D.D., and Middleton, A.C., 1982. "Effect of Primary Settling Tank Efficiency on Cost Optimization of the Activated Sludge Process," WREE Report, Civil Engineering, SUNY/Buffalo, Buffalo, New York.

10. Numerous other technical, research and expert reports have been prepared during employment outside universities.

FUNDED RESEARCH PROJECTS

1. "Design of Aerated Lagoons for Low Temperature Operation," funded by Research Office, School of Graduate Studies, University of Ottawa, for the amount of $4,500, during the period March 20,1975 to December 31,1975 (Principal Investigator).

2. "Assessment and Control of Storm Water Pollution," funded by National Research Council of Canada, for the amount of $16,500 during the period of April 1, 1975 to March 31, 1978 (Principal Investigator).

3. "Development of a Water Quality Model for the Rideau River," funded by Ontario Ministry of the Environment for the amount of $12,065 during the period of May 20, 1975 to August 8, 1975 (Co-Principal Investigator).

4. "Microbial Production of Limestone from Gypsum," funded by the SUNY Research Foundation for the amount of $2,100 during the period of January 1, 1977-December 31, 1980 (Principal Investigator).

5. "Phosphorus Solubilization during Anaerobic Decomposition of Algae," funded by National Science Foundation for the amount of $52,887 during the period of October 15, 1977-March 31, 1980 (Principal Investigator).

6. "Co-Disposal of Wastewater Treatment Sludge and Municipal Refuse – City of Niagara Falls, New York," funded by City of Niagara Falls, New York for the amount of $1,500 during the period of June 1,1978 to September 30,1978 (Co-Principal Investigator).

7. "Metals Recovery from Waste Metallic Hydroxide Sludges through Microbial Sulfate Reduction," funded by Environment Canada for the amount of $30,000 during the period of January 1980 to May 1980 (Co-Principal Investigator).

8. "Development of MGP Site Remediation Methodologies," funded by Gas Research Institute for the amount of $250,000 during the period of June 1986-June 1988 (Principal Investigator).

9. "Co-Treatment of MGP Groundwater in a POTW," funded by Gas Research Institute for the amount of $250,000 during the period of June 1987-June 1988 (Principal Investigator).

10. "Pilot Scale Biosparging Project," funded by Gas Research Institute for the amount of $226,000 during the period January 1994-April 1995.

PAST PROFESSIONAL ACTIVITIES

1. Lecturer, Short Course on Engineering Control of Industrial Wastewaters, Cornell University, June 1975.

2. Technical Advisor, Environmental Conservation Task Force, Greater Buffalo Development Foundation, December 1976-May 1978.

3. Organizer and Chairperson, Hazardous Waste Management and Disposal Seminar, SUNY/Buffalo, February 1979.

4. Associate Engineer, Conestoga-Rovers, Ltd., Waterloo, Ontario, 1976-78. Consultant to government and industry on water and wastewater treatment and waste disposal on land.

5. Member, Chemical Manufacturers Association (CMA) Five-Plant Study Work Group on Priority Pollutant Removal by Biological Treatment Plants.

6. Member, U.S. EPA TSCA Panel on Genetic Engineering of Microorganisms for Bioremediation, Washington, D.C., 1987.

7. Member, Environmental Advisory Committee, Fox Chapel Borough, PA, 1988-91.

8. Member, Industrial Advisory Committee, Gulf States Hazardous Research Center, Lamar University, Beaumont, TX, 1990-91.

9. Member, Technical Advisory Committee, New York State Hazardous Waste Management Center, SUNY/Buffalo, Buffalo, NY, 1988-95.

10. Organizer of Gas Research Institute Seminar on Risk-Based Corrective Action for Gas Industry Applications, Chicago, IL, 1996-97.

11. Developer and Lecturer in Courses on Operation of a Refinery Activated Sludge Wastewater Treatment Plant, Ergon Refining, Newell, WV, 1997-99.

HEALTH AND SAFETY

Current on 8-hour OSHA Hazardous Waste Operations Refresher
40-hour OSHA Hazardous Waste Operations Training, 1991
8-hour Hazardous Waste Supervisor Training, 1992
10-hour OSHA Construction Outreach Training, 2000
8-hour Competent Person Training (Trenching), 2000
Confined-Space Entry Training, 2005

TESTIMONY

YEAR	TESTIMONY	STATE	CASE
1988-89	Deposition and trial testimony (expert witness) in Broderick Investment Co. vs. Ponderosa Timber regarding wood treating plants (Broderick Investment Co.)	CO	---
1989	Deposition and trial testimony (expert witness) in USF&G Co. vs. Colorado National Bank, et al. regarding wood treating plants (Broderick Investment Co.)	CO	Civil Action No. 86-Z-1033
1989-90	Pre-filed direct and rebuttal and cross-examination testimony (expert witness) before Massachusetts Department of Public Utilities regarding manufactured gas plants (Bay State Gas, et. al.).	MA	DPU 89-161

1991	Deposition testimony (expert witness) in Burlington Northern vs. Washington Natural Gas, et. al. regarding manufactured gas plants (Electric Utilities Group)	WA	No. C89-155TB
1991	Pre-filed direct and cross-examination testimony (expert witness) before Illinois Commerce Commission regarding manufactured gas plants (Peoples Gas Light & Coke, et al.)	IL	ICC: Docket Nos. 91-0080 through 91-0095
1991	Trial testimony (expert witness) in Escambia vs. Soule regarding wood treating plants (Escambia)	FL	---
1992	Rebuttal and cross-examination testimony (expert witness) before the New Jersey Bureau of Regulatory Commissioners regarding manufactured gas plants (South Jersey Gas)	NJ	BRC Docket No. GR91071243J
1992	Direct and cross examination testimony (expert witness) before the New Jersey Bureau of Regulated Utilities regarding manufactured gas plants (New Jersey Natural Gas)	NJ	BRC Docket No. GR91081393J
1992	Deposition testimony (expert witness) in Chemical Lehman Tank Lines vs. Aetna regarding wastewater management (Chemical Lehman)	NJ	Case No. 89-1543
1993	Pre-filed direct and cross-examination testimony (expert witness) before Indiana Utilities Regulatory Commission regarding manufactured gas plants (Indiana Gas)	IN	Cause No. 39353 Phase II
1993	Deposition and trial testimony (expert witness) in Broderick vs. Hartford regarding wood treating plants (Broderick Investment Co.)	CO	Civil Action No. 86-Z-1033 CA No. 90-1112
1993	Deposition and trial testimony (expert witness) in Washington Natural Gas vs. Aetna regarding manufactured gas plants (Washington Natural Gas)	WA	Civil Action No. 91-2-13506-1
1994	Deposition testimony (fact witness) in Koppers Company vs. Aetna regarding the Koppers Company, Inc. (1978-1988)	PA	Civil Action No. 85-2136
1994-95	Pre-filed direct and cross-examination testimony (expert witness) before the Michigan Public Service Commission regarding manufactured gas plants (Consumers Power Company)	MI	Case No. 4-10755
1995	Testimony (expert witness) before the Oklahoma Corporation Commission regarding groundwater remediation (Oryx, ANR and Conoco, Inc.)	OK	Cause PD No. 920024760
1996	Deposition testimony in Indiana Gas vs. Aetna regarding manufactured gas plants (Indiana Gas)	IN	Civil Action 1:95CV101
1996	Deposition testimony (expert witness) in Hickmon vs. Oryx Energy Co. regarding groundwater remediation (Oryx, ANR and Conoco, Inc.)	OK	Case No. CIV94-1524-T
1997	Deposition testimony (expert witness) in EnergyNorth Natural Gas vs. UGI Utilities, Inc. regarding manufactured gas plants (EnergyNorth Natural Gas)	NH	C-95-438-B
1997	Deposition testimony (fact witness) in Penn Fuel Gas vs. Pennsylvania Electric Co. regarding manufactured gas plant site investigations and remediation (1996-1997)	PA	---

1999	Deposition testimony (fact witness) in Penn Fuel Gas vs. Aetna, et al. regarding manufactured gas plant site investigations and remediation (1996-1999)	PA	Chester Co., PA, Court of Common Pleas Civil Division No. 94-07744
2001	Deposition testimony (fact witness) in PSI Energy, Inc vs. Aetna, et al. regarding manufactured gas plant site investigations and remediation (1996-1999)	IN	Hendricks Co., IN, Hendricks Superior Court Cause No. 32DO1 9807 CP 230
2002-03	Deposition testimony (expert witness) in PECO Energy vs. INA, et al. regarding manufactured gas plants (PECO Energy)	PA	Chester Co., PA, Court of Common Pleas Civil Division No. 99-07386
2004	Deposition testimony (expert witness) in Bangor vs. Citizens Communications vs. Barrett et al. regarding manufactured gas plants (Citizens Communications)	ME	USDC, Maine, Civil Docket No. 02-cv-183-B-S
2004	Deposition testimony (30(b)6 witness, rebuttal expert witness) in PECO Energy vs. INA, et al. regarding manufactured gas plants (PECO Energy)	PA	Chester Co., PA, Court of Common Pleas Civil Division No. 99-07386
2005	Deposition testimony (expert witness, rebuttal expert witness) in Puget Sound Energy v. Alba General Insurance Co. et al. regarding manufactured gas plants (Puget Sound Energy)	WA	Superior Court of State of Washington No. 97-2-29050-3 SEA
2005	Trial testimony (expert witness) in Bangor vs. Citizens Communications vs. Barrett et al. regarding manufactured gas plants (Citizens Communications)	ME	USDC, Maine, Civil Docket No. 02-cv-183-B-S
2006	Deposition testimony (30(b)6 witness) in CGCU vs. Aetna Casualty & Surety Co., et al. regarding manufactured gas plants (CGCU)	IN	Marion Co., IN, Superior Court Cause No. 49F12-0407-PL-01986
2007	Deposition testimony (expert witness, 30(b)6 witness) in CGCU vs. Aetna Casualty & Surety Co., et al. regarding manufactured gas plants (CGCU)	IN	Marion Co., IN, Superior Court Cause No. 49F12-0407-PL-01986
2010	Deposition testimony (expert witness) in SIGECO vs. Admiral Ins. Co., et al. regarding manufactured gas plants (SIGECO [Vectren])	IN	Marion Co., IN, Superior Court Cause No. 49D05-0411-PL-2265
2011	Deposition testimony (rebuttal expert witness) in SIGECO vs. Admiral Ins. Co., et al. regarding manufactured gas plants (SIGECO [Vectren])	IN	Marion Co., IN, Superior Court Cause No. 49D05-0411-PL-2265

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Direct Testimony of Onita R. King

TARIFFS
EXHIBIT 1700

December 2011

EXHIBIT 1700 – DIRECT TESTIMONY - TARIFFS

Table of Contents

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NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
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I. INTRODUCTION AND SUMMARY

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

A. My name is Onita R. King. I am the Tariffs and Regulatory Consultant in the Rates & Regulatory Affairs Department at NW Natural. My responsibilities include providing guidance and advice to Company employees and management on various regulatory issues as needed and managing the administration of the Company's Oregon and Washington tariffs. In this role, I prepare the various schedules and rules and regulations that comprise the tariffs, oversee the filing of proposed changes with the respective utility commissions, and monitor and enforce overall corporate compliance with the Company's tariffs.

Q. Please describe your educational and professional background.

A. I came to the Company in August 1983. I held positions in the Accounting and Engineering Departments before joining the Rates & Regulatory Affairs Department in 1986. I have a Bachelor of Sciences Degree from Concordia University, where I majored in Business Management and Communications. I have previously filed testimony before the Oregon Public Utility Commission ("Commission") and the Washington Utilities and Transportation Commission.

Q. Please summarize your testimony.

A. In my testimony, I present the Company's new Tariff, P.U.C. Or. 25, which will replace, in its entirety, the Company's current Tariff P.U.C. Or. 24 ("Tariff"), upon affirmative approval of this general rate case filing by the Commission. Specifically, I:

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- Describe changes and additions to the Tariff that relate directly to issues proposed in this general rate case filing through the testimony of other witnesses, specifically:
    - Direct Testimony of Grant Yoshihara, NWN/600: System Integrity Program (SIP) – Schedule 177;
    - Direct Testimony of Russell Feingold, NWN/1100: Rate Design – Rate Schedules 1 and 2;
    - Direct Testimony of Natasha Siores, NWN/1200: Rate Adjustment Mechanisms – Schedule 190 and Schedule 195; and
    - Direct Testimony of C. Alex Miller, NWN/1500: Environmental Mitigation Cost Recovery – Schedule 183 and Schedule 184.
- Describe changes and additions to the Tariff that complement a specific case issue but that are not specifically discussed in the testimony of others. The schedules in this category include:
    - Schedule B – Bill Payment Options;
    - Schedule C – Miscellaneous Charges;
    - Schedule X – Distribution Facilities Extensions for Applicant Requested Services and Main Extensions;
    - Schedule 27 – Residential Heating Dry-Out Service; and
    - Schedule 301 – Public Purpose Funding Surcharge; and
- Describe housekeeping and other general changes and additions included in the new Tariff. The revisions addressed in this section are primarily for the purpose of clarifying conditions of service or improving the form and content of the

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respective general rules and schedules that are a part of the Tariff. The schedules and rules in this category include:

- o General Rules and Regulations – multiple rules;
- o Rate Schedule 19 – Gas Light Service – Frozen;
- o Rate Schedule 31 – Non-Residential Sales and Transportation Service;
- o Rate Schedule 32 – Large Volume Non-Residential Sales and Transportation Service;
- o Schedule 100 – Summary of Adjustments; and
- o Schedule P – Purchased Gas Cost Adjustments.

II. TARIFF CHANGES RELATING TO RATE CASE TESTIMONY

Q. Please describe the changes to Schedule 177 "System Integrity Program Rate Adjustment."

A. As described in the direct testimony of Grant Yoshihara, the Company does not propose to change the current regulatory treatment for the System Integrity Program (SIP), except for a change to the soft cap for capital expenditures in 2012. *See NWN/600, Yoshihara/12.* Therefore, the changes to Schedule 177 are intended solely to clarify the specific provisions of the regulatory treatment that were adopted in the Docket UM 1406 Stipulation in Order No. 11-337.[1] As Mr. Yoshihara explains, the Company may seek changes to this program, and tariff revisions associated with it, once there is further clarity about the types of regulations that are likely to be imposed upon NW Natural in the future.

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1 *Re. NW Natural Application for an Accounting Order*, Docket UM 1406, Order No. 11-337 (Aug. 30, 2011).

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Q. Please describe the changes to Rate Schedule 1 "General Sales Service" and Rate Schedule 2 "Residential Sales Service."

A. These schedules are revised to reflect the new rate structure and associated proposed billing rates, as well as the proposed phased-in rate changes. The proposed rate design for these schedules is discussed in detail in the testimony of Russell Feingold.

Rate Schedule 1 as proposed is "frozen" to new customers. New language has been added to describe the new restrictions of service. Specifically, the "frozen" status will serve to restrict new customers from taking service under Rate Schedule 1 after November 1, 2012. Customers that take service under Rate Schedule 1 as of November 1, 2012 will be allowed to continue service until the customer account is closed. When an account closes and a new customer applies for service at the same location, the new customer will be served under Rate Schedule 2.

The special provision pertaining to temporary disconnection of service under Rate Schedule 1 and Rate Schedule 2 has been revised. This provision states that before service will be reconnected following a temporary disconnection of service, the customer must pay the monthly customer charge for each of the billing months that the customer is temporarily disconnected, in addition to the reconnection charge set forth in Schedule C, and any past-due amounts owing to the Company. This change is necessary to minimize the occurrence of customer-requested disconnections of service for the sole purpose of avoiding payment of the monthly customer charge.

Q. Please describe the changes to Schedule 190 "Partial Decoupling Mechanism" and Schedule 195 "Weather-Adjusted Rate Mechanism (WARM Program)."

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A. These schedules are revised to reflect the changes to the mechanisms that are discussed in the direct testimony of Natasha Siores.

The changes proposed to Schedule 190 also result in the elimination of Schedule 163 "Special Adjustment to Rates – Price Elasticity."

Q. Please describe Schedule 183 "Site Remediation Recovery Mechanism (SRRM)."

A. Schedule 183 is a new schedule that is not a part of the Company's current Tariff. Schedule 183 reflects the terms and conditions associated with the proposed regulatory treatment for environmental mitigation cost recovery discussed in detail in the direct testimony of C. Alex Miller.

Q. Please describe Schedule 184 "Special Rate Adjustment - Gasco Upland Pumping Station."

A. Schedule 184 is also a new schedule that is not a part of the Company's current Tariff. Schedule 184 reflects the terms and conditions associated with the proposed regulatory treatment for cost recovery of the Company's investment in the pumping station at the Company's facilities located in Linnton, Oregon, referred to as the "Gasco Upland" site. *See NWN/1500, Miller/18-19.* The proposed tariff revisions would result in an adjustment to permanent rates to reflect the addition to rate base of the Company's investment in the pumping station once it is placed into service, as well as the associated operations and maintenance costs of the facility.

III. <u>TARIFF CHANGES COMPLEMENTARY TO RATE CASE TESTIMONY</u>

Q. Please describe the changes to Schedule B.

A. Schedule B "Bills and Bill Payment Options" has been revised for consistency with the proposed elimination of the user fee for credit and debit card payments, discussed in the

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direct testimony of David Williams. Specifically, the section pertaining to credit or debit card payments on Sheet B-2 has been revised, and language regarding payment by credit and debit card has been added under the standard billing and bill payment section at Sheet B-1.

Q. Please describe the changes to Schedule C "Miscellaneous Charges."

A. The primary changes to Schedule C are: (1) changes to the reconnection charge structure and charge amounts; (2) an increase in the field visit charge; (3) removal of the $20 and $30 occurrence charges for meter interference; (4) elimination of charges for paper copies of tariff schedules and for duplicate checks; (5) clarification of Customer Service Representative (CSR)-assisted automated payment charge; and (6) the removal of charges related to Company-provided utility pathway for new construction (Schedule X), along with the addition of the priority installation charge that was previously a part of Schedule X.

Q. Please describe the changes to the reconnection charges, including seasonal reconnections, and to the field visit charge.

A. The service reconnection charges are changed from a two-tiered charge structure of $25 and $75 to a three-tiered charge structure of $40 for standard scheduled reconnection of service during business hours Monday-Friday, $80 for after-hours scheduled reconnection of service Monday-Friday, and $185 for reconnection on the same-day after-hours or on Saturdays or holidays. The proposed three-tiered structure is consistent with Commission rules regarding reconnection of service, *See OAR 860-021-0328*. The last time that the Company revised its service reconnection charges was in May 1995.

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The change to the field visit charge is intended to bring the charge more in line with current costs, and is increased from $15 to $20.

Q. Please explain why the Company is proposing to eliminate the occurrence charges for meter interference, the charge for paper copies of tariff schedules, and the charge for duplicate checks.

A. The meter interference occurrence charges are eliminated because these charges are not a useful deterrent to acts of interference. Customers that are found to have interfered with the Company's meter or other facilities will continue to be subject to payment of actual costs associated with any required repairs, theft prevention devices, and unbilled gas associated with an act of interference.

The charge for paper copies of tariff schedules is eliminated because the Company's Tariff is available on its website, largely negating the need for printed copies. In the event a request for a printed copy of a tariff schedule is received, the Company will provide such printed copy at no charge.

The charge for duplicate checks is eliminated because the service is no longer necessary with the increased adoption of electronic banking options. The Company has not received any requests for duplicate checks in several years.

Q. Please explain the elimination of the charges for Company-provided Utility Pathway for New Construction under Schedule X.

A. The Company will continue to offer a Company-provided utility pathway when requested based on the Company's cost of such construction. The costs associated with the utility pathway construction will be established by the Company and updated periodically along

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with all construction costs under Schedule X. Removing these amounts from Schedule C will allow the Company to respond more quickly to cost changes.

Q. Please describe the changes to Schedule C that relate to the Automated Special Payment Charge.

A. Schedule C has been clarified to reflect that this charge applies only when the customer requests assistance from a CSR. The charge does not apply when the customer self-initiates an electronic check through the on-line and telephone options. This change is also discussed in the direct testimony of David Williams.

Q. Please describe the changes to Schedule X.

A. Schedule X "Distribution Facilities Extensions for Applicant-Requested Services and Mains" reflects the Company's policy for new service line and main extension installations as required by OAR 860-021-0050 and OAR 860-021-0051. The fundamental change to Schedule X in the proposed Tariff is that the construction allowance for residential customer applicants is modified from a 5.0 times margin calculation to a fixed amount based on the life cycle for specific gas-fired appliances and the margin revenue to be derived from the customer under the proposed Schedule 2 rate design, discussed in the direct testimony of Mr. Feingold. In concert with this change, the refund provisions of Schedule X are revised to eliminate the refund of a construction contribution paid when additional qualifying appliances are installed within three years of the service installation. Except for some clarifying changes to the language, there are no changes to the refund provisions for contributions paid for main extension installations.

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In all other respects, the provisions of Schedule X remain the same, except that the content has been rewritten and reorganized for the purpose of improved clarity with no change in intent or substance.

Q. Please describe Schedule 27.

A. Schedule 27 “Residential Heating Dry-Out Service” is a new rate schedule that is designed to serve residential new construction builders and developers for dry-out purposes during the construction phase. The maximum term of service under this new rate schedule is twelve consecutive billing months. Historically, service to builders and developers was provided under the Company’s residential Rate Schedule 2. The rate design changes proposed to Rate Schedule 2 necessitate the implementation of a different rate schedule to serve residential builders and developers in light of the temporary nature of their service needs.

Q. Please describe the changes to Schedule 301.

A. Schedule 301 “Oregon Low-Income Gas Assistance (OLGA) Program” is a customer-funded program that supports low-income bill payment assistance. The change proposed in the new Tariff is to increase the funding level for low-income bill payment assistance from 0.58 percent to 0.75 percent. This change is estimated to increase annual program funding from approximately $2.6 million to approximately $3.4 million. The increase in bill payment assistance funding will help to partially offset recent funding reductions in Oregon’s Low-Income Heating Energy Assistance Program (LIHEAP).

IV. GENERAL TARIFF CHANGES

Q. Please describe the changes to the General Rules and Regulations.

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A. The General Rules and Regulations have been reviewed and revised as needed for consistency with changes proposed to certain schedules and rate schedules as discussed elsewhere in my testimony. I have also reviewed the rules and regulations for clarity and content, and have made some minor editorial changes throughout this section of the Tariff.

Q. Please explain why Rate Schedule 19 is not included in the new Tariff.

A. Rate Schedule 19 “Gas Light Service – FROZEN” has been frozen to new customers since August 10, 1973. Gas lights are not metered, but are billed based on the number of mantles installed in the light itself. The Company’s billing records show that there are 50 currently active Oregon accounts that are billed under Rate Schedule 19. All but two of these accounts use other gas equipment served from an existing service line at the premise. It is preferable that all gas usage be metered, so the Company proposes to eliminate the billing of unmetered gas lights altogether. Customers that have an existing gas line will have the option to run a houseline from the gas light to the existing meter and combine its usage with their primary gas usage, disconnect the gas light altogether, or convert the gas light to electric. The two customers that do not have an existing service line will have the option of installing a service line under the terms and conditions of Schedule X, removing the light, or converting the gas light to electric. In the event a customer desires to abandon the gas light, the Company will assist the customer in its removal.

Q. Please describe the changes to Rate Schedule 31.

A. Rate Schedule 31 “Non-Residential Sales and Transportation Service” is modified to eliminate interruptible sales and interruptible transportation service from this rate

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schedule. The Company will assist existing Rate Schedule 31 interruptible service customers in transferring to Rate Schedule 32 interruptible service, or to another service type that will meet the customer's service requirements. There are currently 18 customers taking interruptible service under Rate Schedule 31.

Also, the terms and conditions for the annual election of the Winter Sales WACOG commodity component have been revised so that customers that wish to continue with this service option from year-to-year may do so without submitting an annual election form, and are only required to submit an annual service election if they do not want to continue with service under this option.

In addition, the capacity release provision applicable to customers that transfer from firm sales service to transportation service is eliminated. There have not been any requests for this capacity release option since this provision was implemented.

Finally, new terms and conditions around a new commodity component "Interim WACOG" is added to the annual service election provisions of this schedule. The terms and conditions of the Interim WACOG will apply whenever a customer is approved to transfer from transportation service to sales service, and will remain in effect until the customer has completed two consecutive subsequent PGA years on sales service, or until the customer transfers back to transportation service, whichever first occurs. Upon fulfillment of two consecutive PGA years on sales service under the terms and conditions of Interim WACOG, the customer will be eligible to receive sales service at Annual Sales WACOG or Winter Sales WACOG.

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In all other respects, the provisions of Rate Schedule 31 remain the same, except that the content has been rewritten and reorganized for the purpose of improved clarity with no change in intent or substance.

Q. Please describe the changes to Rate Schedule 32.

A. The rate structure for Rate Schedule 32 “Large Volume Non-Residential Sales and Transportation Service” remains the same. Except for the elimination of interruptible service options, the revisions discussed above with regard to Rate Schedule 31 are also applied to Rate Schedule 32.

In addition, the conditions upon which a customer request for interruptible service under Rate Schedule 32 will be approved are more directly identified in the rate schedule. The effect of this change is to restrict the availability of interruptible service only to customers that are located in areas where the Company has determined that there is a need to have interruptible customers that can be curtailed due to system capacity or supply reasons.

Customers that are approved for interruptible service as of November 1, 2012, or such other date as Tariff P.U.C. Or. 25 may be approved, will be grandfathered into that service option for a period of five consecutive PGA Years, at which time the Company will determine if continued service under an interruptible service option is warranted. All interruptible service elections approved after November 1, 2012 will be subject to review and approval after five consecutive PGA Years.

Q. Please describe the changes to Schedule 100.

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A. Schedule 100 has been updated to reflect the addition of new adjustment schedules and the elimination of outdated adjustment schedules. The deleted schedules are identified later in my testimony.

Q. Please describe the changes to Schedule P.

A. Schedule P "Purchased Gas Adjustment" has been revised to add the new Interim WACOG which is applicable to Rate Schedule 31 and Rate Schedule 32, as discussed earlier in my testimony.

Q. Are there other changes to the Tariff that you have not specifically addressed here?

A. Yes. There are a number of minor changes that are too numerous to detail in this testimony. A redline version of the proposed Tariff is submitted separately in supporting work papers. The redline version clearly shows all of the changes that have been made, and should prove useful in conducting a thorough comparison of Tariff P.U.C. Or. 24 to the proposed Tariff P.U.C. Or. 25.

In addition, there are a number of schedules that are a part of Tariff P.U.C. Or. 24 but are not included in Tariff P.U.C. Or. 25 as proposed because these schedules are either no longer active or no longer needed. These schedules are:

Schedule D "Residential Meter Reading Estimating program;"

Schedule 161 "Automatic Adjustment for Utility Income Tax;"

Schedule 161A "Revision of Charges for Multnomah County Income Tax;"

Schedule 166 "Adjustments to Rates (UM 1335);"

Schedule 169 "Special Adjustments to Rates for Storage Inventories;"

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Schedule 176 “Adjustments to Rates for Costs Relating to South Mist Pipeline Extension Project;”

Schedule 179 “Automated Meter Reading (AMR) Rate Adjustment;”

Schedule 199 “Special Rate Adjustment (UM 1148/UP 205);” and

Schedule 305 “Special Adjustment to Rates for Smart Energy Program Costs.”

Q. Does this conclude your direct testimony?

A. Yes, it does.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural

Exhibits of Onita R. King

TARIFFS
EXHIBIT 1701

December 2011

RATES, RULES AND REGULATIONS
FOR
NATURAL GAS SERVICE
IN
OREGON

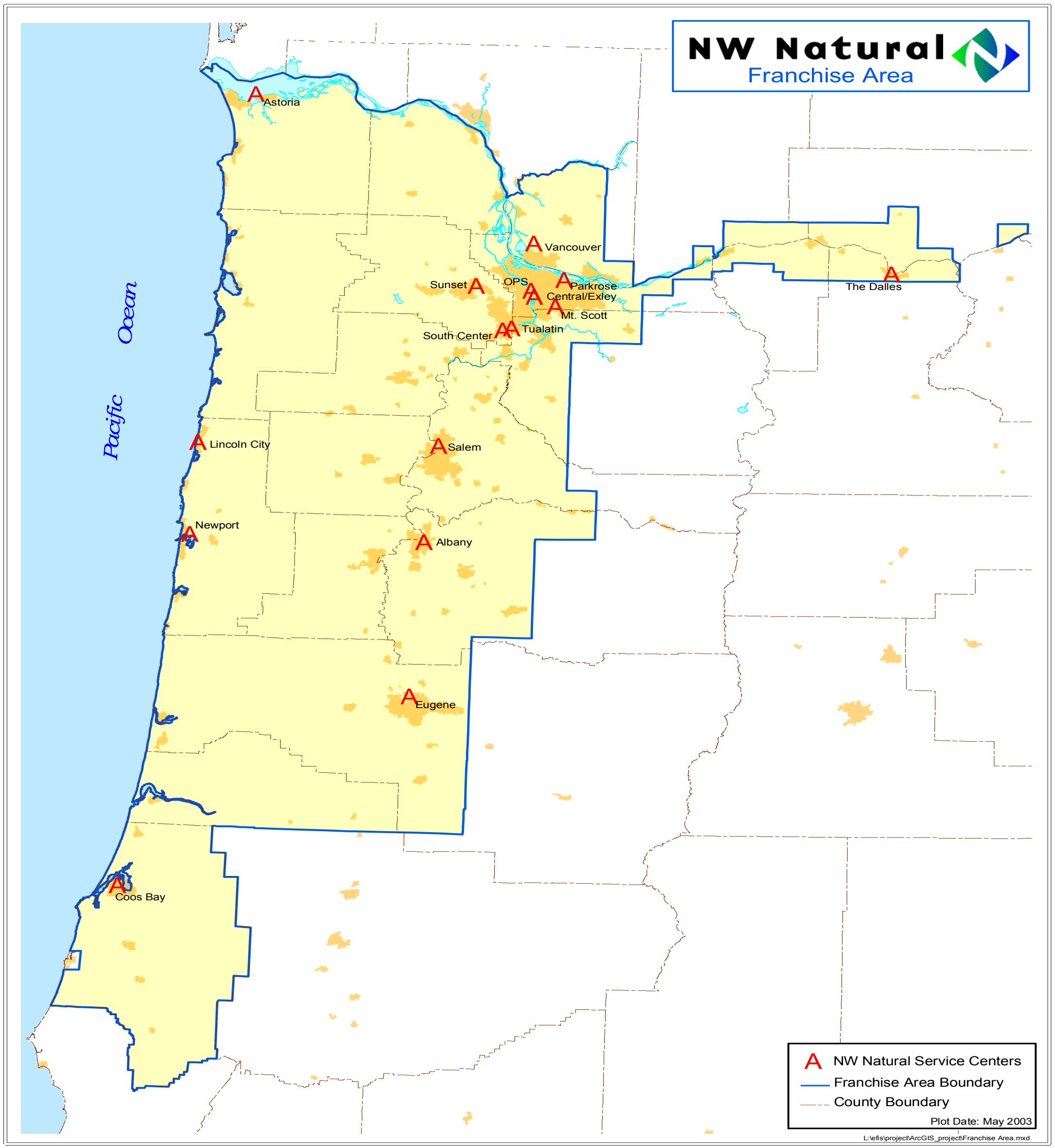
INCLUDING SERVICE TO THE INCORPORATED COMMUNITIES OF:

ADAIR VILLAGE, ALBANY, AMITY, ASTORIA, AUMSVILLE, AURORA;
BANKS, BARLOW, BEAVERTON, BROWNSVILLE;
CANBY, CANNON BEACH, CLATSKANIE, COBURG, COLUMBIA CITY, COOS BAY, COQUILLE, CORNELIUS, CORVALLIS, COTTAGE GROVE, CRESWELL;
DALLAS, DAMASCUS, DEPOE BAY, DONALD, DUNDEE, DURHAM;
EUGENE;
FAIRVIEW, FOREST GROVE;
GEARHART, GERVAIS, GLADSTONE, GRESHAM;
HALSEY, HAPPY VALLEY, HARRISBURG, HILLSBORO, HOOD RIVER, HUBBARD;
INDEPENDENCE;
JEFFERSON, JOHNSON CITY, JUNCTION CITY;
KEIZER, KING CITY;
LAFAYETTE, LAKE OSWEGO, LEBANON, LINCOLN CITY, LYONS;
MAYWOOD PARK, McMINNVILLE, MILL CITY, MILLERSBURG, MILWAUKIE, MOLALLA, MONMOUTH, MT. ANGEL, MYRTLE POINT;
NEWBERG, NEWPORT, NORTH BEND, NORTH PLAINS;
OREGON CITY;
PHILOMATH, PORTLAND;
RAINIER, RIVERGROVE;
ST. HELENS, SALEM, SANDY, SCAPPOOSE, SCIO, SEASIDE, SHERIDAN, SHERWOOD,
SILETZ, SILVERTON, SODAVILLE, SPRINGFIELD, STAYTON, SUBLIMITY, SWEET HOME;
TANGENT, THE DALLES, TIGARD, TOLEDO, TROUTDALE, TUALATIN, TURNER;
VERNONIA;
WARRENTON, WATERLOO, WEST LINN, WILLAMINA, WILSONVILLE, WOODBURN, WOOD VILLAGE;

AND IN TERRITORY SERVED BY THE COMPANY IN OREGON, ADJACENT TO THE ABOVE COMMUNITIES.

(continue to Sheet ii)

MAP OF SERVICE AREA



(continue to Sheet iii)

TARIFF INDEX

(continue to sheet iv)

TARIFF INDEX
(continued)

SHEET

GENERAL SCHEDULES

RATE SCHEDULES

(continue to Sheet v)

TARIFF INDEX
(continued)

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GENERAL RULES AND REGULATIONS

Definitions:
The following terms shall have the meanings listed herein unless defined otherwise within a specific Rule or Schedule.

Allowance. See Construction Allowance.

AMR. Automated meter reading, or automated meter reading device.

Annual Sales WACOG. The Company's annual weighted average commodity cost of gas, as determined in the Company's most recent Purchased Gas Cost Adjustment (PGA) Filing, and set forth in **Schedule P** and **Schedule 164** of this Tariff. Sometimes referred to as the Commodity Component.

Annual Service Election Date. The date by which a Non-Residential Customer may request to change all or a portion of their current service type for the next PGA Year. The Annual Service Election Date is July 31.

Applicant. A person, business, or agency who applies for utility service with the Company, or who reapplies for utility service at the same or a different location more than 20 days after a voluntary termination of service, or who applies for service any time after service has been disconnected under **General Rule 11** of this Tariff P.U.C. Or. 25. An Applicant may also be an existing Customer who requests that the Company make changes to or install additional Distribution Facilities.

Authorized Supplier/Agent. A third party agent authorized by an end-use Transportation Customer to nominate and transport Natural Gas to the Company's system on a Customer's behalf.

Base Rate Adjustments. The net amount by which the Base Rates under a given Rate Schedule are to be adjusted on a permanent basis outside of a general rate case proceeding. Base Rate Adjustments include amounts set forth in **Schedule 177**, **Schedule 183, Schedule 184**, and such other **Schedules** as may be approved by the Commission from time to time.

Btu. See British Thermal Unit.

Balancing. The process of equalizing receipts and deliveries of gas for a Transportation Customer.

Balancing Period. A period of time in which a Transportation Customer must eliminate or bring into allowed tolerance levels an Imbalance situation.

Billing Month. The period of time between, and including, the date of the current meter read and the date of the prior meter read, which is the period upon which Customer's monthly bill is based. A Billing Month may be contained within a single calendar month, or may encompass a portion of two separate calendar months.

British Thermal Unit (Btu). The standard unit for measuring a quantity of thermal energy. One Btu equals the amount of thermal energy required to raise the temperature of one pound of water one degree Fahrenheit and is exactly defined as equal to 1,055.05585262 joules. 100,000 Btus is equivalent to one Therm.

Business Day. A business day is Monday through Friday between the hours of 8:00 a.m. and 5:00 p.m. Pacific Standard Time (PST) except where such day falls on a holiday.

(continue to Sheet 00.2)

GENERAL RULES AND REGULATIONS
(continued)

Definitions (continued):

Change in Responsible Party. Any merger, consolidation, sale of assets or other similar transaction or series of transactions involving Customer, other than any such transaction or transactions following which the Customer or its shareholder(s), member(s) or owner(s) continue to own a majority of the combined voting power of the outstanding securities of the corporation or other entity surviving or succeeding to the business of the Customer.

Commercial Customer Class. Customers that use natural gas for space or water heating in an office or retail space, or where natural gas is used in equipment that primarily supports a commercial trade or other commercial purpose. For example, providing services, wholesale or retail trade, restaurants, agriculture, forestry, fisheries, transportation, communications, utilities, finance, insurance, real estate, clubs and hotels. Customers not included directly in other definitions will be classified in this category.

Commission. The Public Utility Commission of Oregon also referred to as OPUC, or any successor entity holding responsibility for the regulation of utility service in the state of Oregon.

Commission Rules. The Oregon Administrative Rules (OAR) of the OPUC, Chapter 860.

Commodity Component. The component of the billing rate that a Sales Service Customer pays for the physical natural gas supply procured by the Company under any of the Rate Schedules that provide for Sales Service. The Commodity Component is either Annual Sales WACOG, Winter Sales WACOG, or Interim Sales WACOG, adjusted for Revenue Sensitive Effects, (see **Schedule P** and **Schedule 164)**, or, where applicable, Monthly Incremental Cost of Gas (**see Schedule 150**).

Company. Northwest Natural Gas Company d.b.a. NW Natural, also referred to as NWN, acting through its duly authorized officers, employees or representatives within the scope of their respective duties.

Confirmed Nominations. The final physical quantity of customer-owned gas confirmed by the Pipeline as delivered to a specific Company Receipt Point(s) for a specific Transportation Service Customer on a specific Gas Day. Only the Pipeline's Confirmed Nominations will be used for balancing and billing purposes.

Construction Allowance. The dollar credit that may be available to an Applicant or Customer to offset the cost of construction of Distribution Facilities. The Construction Allowance will vary by Customer and type of equipment installed.

Construction Contribution. The amount that an Applicant or Customer must pay toward the cost of construction of Distribution Facilities.

(continue to Sheet 00.3)

GENERAL RULES AND REGULATIONS
(continued)

Definitions (continued):

Curtailment. A condition where the Company must interrupt service to Customers in accordance with the General Rules and Regulations of this Tariff (**Rule 12**, **Rule 13**, and **Rule 14**). A Curtailment event may affect any level of service depending on the severity and geographical scope of the event. Gas taken by a Customer due to failure to comply with a Curtailment Order will be considered unauthorized and subject to charges as set forth in **Schedule C**.

Curtailment Discount. A billing credit offered to Firm Non-Residential Sales Service Customers whose gas service is curtailed for reasons other than Force Majeure.

Curtailment Order. The term used to refer to the Company's notification to Customers of a Curtailment condition. Only one Curtailment Order can be in effect at any one time.

***Custody Transfer Point*.** The primary meter located at the Delivery Point; generally the meter at the interconnection between the Company's Distribution Facilities and Customer's House Line. Title and risk of loss to the gas shall pass from the Company to Customer at this point.

Customer. A person(s), business, or agency in whose name service is rendered, as evidenced by the signature on an application, Special Contract, Service Agreement or Service Election Form on file with the Company. In the absence of a signed instrument, a Customer shall be identified by the receipt and payment of bills regularly issued in that name.

Customer Charge. A monthly charge designed to recover a portion of the fixed costs associated with serving Customers that is not directly related to gas usage or otherwise collected.

Customer-Owned Gas. Natural Gas procured by the Customer that is transported by the Company for Customer's own use. Title to Customer-Owned gas is held by the Customer at all times, and Customer-Owned Gas is not a part of the Company's system supplies.

Dekatherm (Dth). A unit of heating value equivalent to 1,000,000 Btus. One (1) dekatherm or ten (10) Therms equals 1,000,000 Btus.

Delivery Point. The point at which gas leaves the Company's Distribution System and passes through the Custody Transfer Point at Customer's facility.

Disconnection of Service. The cessation of gas service to a Customer where action is taken by Company to physically shut-off service at the meter, cut service at the curb, or other action that causes the Distribution Facilities that serve a Customer to become inactive.

(continue to Sheet 00.4)

GENERAL RULES AND REGULATIONS
(continued)

Definitions (continued):

Distribution Capacity Charge. A charge applicable to Firm Service Customers under **Rate Schedule 32** and **Rate Schedule 33** that relates to the cost of providing Firm service on the Company's Distribution System.

Distribution Facilities. Facilities required to provide natural gas service to end-users, and include any combination of meters, regulators, compression, valves, service piping, main piping, piping required to accommodate metering of individual units within multi-unit buildings, and associated equipment.

Distribution System. The compilation of all of the Company's Distribution Facilities upon which Company and Customer-procured gas supplies are transported from the Receipt Point to the Delivery Point.

Domestic. Of or relating to the residential household.

Dth. See dekatherm.

Entitlement. A condition where a Transportation Service Customer is required to control gas usage to be within a specified threshold percentage as detailed in Schedule T of this Tariff. Failure to comply with an Entitlement Order will be subject to the charges set forth in Schedule T. Entitlement may be declared by the Company upon receiving notice of Entitlement from the Pipeline, or due to operational difficulties on the Company's system. See also Overrun Entitlement and Underrun Entitlement.

Essential Human Needs Customers. Customers whose use of natural gas is required to provide primary space heat to areas where residents sleep or receive life-essential medical care, or to fuel essential functions related to providing life-essential medical care, including back-up electric generation required for the purpose of operating equipment necessary to support or sustain human life, and that absent the availability of natural gas, an immediate danger to the lives of persons that rely upon such Customer would exist.

Excess Flow Valve (EFV). A device installed in a Natural Gas service line pursuant to DOT 49 – CFR Part 192, designed to limit the flow of gas in the event that the flow in the service line exceeds a pre-determined level.

Extraordinary Conditions. Conditions at the Applicant or Customer site, or leading to the Applicant or Customer site, which have the potential to increase the Company's costs to construct Distribution Facilities, and include but are not necessarily limited to the conditions described in **Schedule X** of this Tariff.

(continue to Sheet 00.5)

GENERAL RULES AND REGULATIONS
(continued)

Definitions (continued):

Firm Sales Service. Sales Service which the Company provides on a firm basis. The Company will exercise reasonable diligence and care to supply and deliver continuous service; provided, however, Company does not guarantee such continuity of service or sufficiency of quantity. See Interruptible Sales Service.

Firm Transportation Service. Transportation Service which the Company provides on a firm basis. Customer must secure firm or interruptible pipeline delivery service to the Receipt Point. The Company will exercise reasonable diligence and care to ensure continuous delivery of Customer-procured gas supply from the Receipt Point to the Delivery Point, but the Company does not guarantee such continuity of service. See Interruptible Transportation Service.

Force Majeure. Unavoidable accident or casualty, extraordinary action of the elements, strikes, interruptions caused by government action or authority, litigation, or any cause beyond the reasonable control of the party claiming Force Majeure which could not have been prevented by the exercise of due diligence, or which could not otherwise reasonably be foreseen and guarded against. Force Majeure usually does not include required maintenance of Customer's facilities, plant closures, economic conditions, or variations in agricultural crop production.

Gas Day. A twenty-four (24) hour period beginning daily at 7:00 a.m. Pacific Clock Time (PCT). The Company's Gas Day coincides with the Gas Day established by the Pipeline, and may change from time to time, upon approval of the Federal Energy Regulatory Commission ("FERC").

House Line. The piping which extends from the Custody Transfer Point to a Customer's gas-fired equipment, and which shall be owned and maintained by Customer.

Imbalance. The difference between Confirmed Nominations and the volume of gas actually used by or delivered to a Transportation Customer within a Balancing Period. A positive imbalance exists when the volume of Transportation gas confirmed for Customer's account is greater than the volume of gas used. A negative imbalance exists when the volume of Transportation gas confirmed for Customer's account is less than the volume of gas used.

Industrial Customer Class. Customers that use Natural Gas in equipment that is used primarily in a process that creates or changes raw or unfinished materials into another form or product.

Interim WACOG. The Company's weighted average commodity cost of gas, excluding the cost of Gas Reserves as defined in **Schedule P** of this Tariff.

Interruptible Sales Service. Sales Service which the Company provides on an interruptible basis. Interruptible Sales Service is subject to Curtailment or Entitlement, or both.

(continue to Sheet 00.6)

GENERAL RULES AND REGULATIONS
(continued)

Definitions (continued):

Interruptible Transportation Service. Transportation Service which the Company provides on an interruptible basis. Customer must secure firm or interruptible pipeline delivery service to the Receipt Point. Interruptible Transportation Service is subject to Curtailment or Entitlement, or both.

Main. Piping and associated fittings that serves, or is expected to serve, as a common source of supply for more than one Service Line.

Main Extension. Piping and associated facilities required to extend service from the Company's existing Main facilities into an area not previously supplied to serve an Applicant.

Maximum Daily Delivery Volume (MDDV). Company's maximum daily responsibility to Customer. MDDV will be based on the known actual use, or estimated use, of Customer's equipment to be served, as mutually agreed between Company and Customer.

Maximum Hourly Delivery Volume (MHDV). Company's maximum hourly responsibility to Customer. MHDV will be based on the capacity of Customer's equipment to be served, as mutually agreed between Company and Customer.

Monthly Incremental Cost of Gas. The Commodity Component that shall be paid by a Customer that makes a Service Type Selection change from Firm Transportation Service or Interruptible Transportation Service to Firm Sales Service or Interruptible Sales Service at times where the Company's Annual Sales WACOG or Winter Sales WACOG choices are not available.

Natural Gas (also referred to as ***gas***)***.*** A naturally occurring non-toxic mixture of hydrocarbon and non-hydrocarbon gases found in porous geologic formations beneath the earth's surface, which consists essentially of methane, and is the fuel source for the operation of equipment served by the Company.

Nomination. A request by a specific Transportation Service Customer or that Customer's Authorized Supplier/Agent to have a physical quantity of customer-owned gas delivered to a specific Company Receipt Point(s) for a specific Gas Day or period. Nominations are not considered final until confirmed by the Pipeline. See Confirmed Nominations.

Non-Residential Customer. Any Commercial or Industrial Customer.

NSF. The acronym used to refer to the refusal of a financial institution to honor a payment by check, bank card, or other similar type of payment.

(continue to Sheet 00.7)

GENERAL RULES AND REGULATIONS
(continued)

Definitions (continued):

OPUC. The Public Utility Commission of Oregon, also referred to as the Commission.

Overrun Entitlement. A condition whereby a Transportation Service customer is restricted to use no more than a percentage of such Customer's Confirmed Nominations on a specified Gas Day.

PGA Year. The period November 1 through October 31.

Pipeline. Northwest Pipeline Corporation.

Pipeline Capacity Charge. A charge applicable to Sales Service Customers served under **Rate Schedule 31** and **Rate Schedule 32** that is designed to recover the cost of the delivery of natural gas from an interstate pipeline to the Company's Receipt Point.

Pre-emption. A condition wherein Transportation Customers are required to make their gas available to the Company for a price, to the extent the Company determines that it is necessary to maintain service to Customers with higher service priorities.

Premise. All of the real property and apparatus in use by a single Customer on an integral parcel of land undivided by a dedicated street, highway or other public thoroughfare or railway which comprises the site upon which Customer facilities are located and to which Natural Gas service is provided.

Purchased Gas Adjustment (PGA) Filing. The regulatory document filed with the Commission that supports the Company's request for rate changes under **Schedule P**, and for other changes to rates as the Commission may allow.

Qualifying Valid State or Federal Identification. Includes but is not necessarily limited to: (a) Passport; (b) U.S. Visa; (c) Military identification; (d) Immigration and Naturalization Service (INS) identification; (e) Oregon Tribal Identification; (f) Oregon Driver's License; (g) Oregon Department of Motor Vehicles (DMV) Identification. Any identification having an expired date will not be considered valid. Other forms of state or federal identification may be allowed in accordance with Company policy and procedures.

Receipt Point. The point at which gas enters Company's system from the Pipeline's interconnect.

Residential Customer Class. Single-family dwellings, separately metered apartments, condominiums or townhouses, and centrally metered multiple dwellings or apartments.

Sales Service. Gas service to Customers that use Company procured gas supplies. This term does not include service to Customers that purchase Company procured gas supplies upstream of the Company's distribution system.

(continue to Sheet 00.8)

GENERAL RULES AND REGULATIONS
(continued)

Definitions (continued):

Schedule 1C or 01C. Refers to Rate Schedule 1, Commercial Service.

Schedule 1R or 01R. Refers to Rate Schedule 1, Residential Service.

Schedule 3 CSF or 03CSF. Refers to Rate Schedule 3, Commercial Firm Sales Service.

Schedule 3 ISF or 03ISF. Refers to Rate Schedule 3, Industrial Firm Sales Service.

Schedule 31 CSF or 31CSF. Refers to Rate Schedule 31, Commercial Firm Sales Service.

Schedule 31 CTF or 31CTF. Refers to Rate Schedule 31, Commercial Firm Transportation Service.

Schedule 31 ISF or 31ISF. Refers to Rate Schedule 31, Industrial Firm Sales Service.

Schedule 31 ITF or 31ITF. Refers to Rate Schedule 31 Industrial Firm Transportation Service.

Schedule 32 CSF or 32CSF. Refers to Rate Schedule 32 Commercial Firm Sales Service.

Schedule 32 ISF or 32ISF. Refers to Rate Schedule 32 Industrial Firm Sales Service.

Schedule 32 CTF or 32CTF. Refers to Rate Schedule 32 Commercial Firm Transportation Service.

Schedule 32 ITF or 32ITF. Refers to Rate Schedule 32 Industrial Firm Transportation Service.

Schedule 32 CSI or 32CSI. Refers to Rate Schedule 32 Commercial Interruptible Sales Service.

Schedule 32 ISI or 32ISI. Refers to Rate Schedule 32 Industrial Interruptible Sales Service.

Schedule 32 CTI or 32CTI. Refers to Rate Schedule 32 Commercial Interruptible Transportation Service.

Schedule 32 ITI or 32ITI. Refers to Rate Schedule 32 Industrial Interruptible Transportation Service.

Schedule 33 TF or 33TF. Refers to Rate Schedule 33 Firm Transportation Service.

Rate Schedule 33 TI or 33TI. Refers to Rate Schedule 33 Interruptible Transportation Service.

Seasonal Customer. A Non-Residential Customer that by the nature of the Customer's business sixty percent (60%) or more of the Customer's annual gas usage occurs in any period of four (4) months or less.

Service Agreement. The oral or written agreement between Company and Customer for gas service.

Service Election. The term used to describe a Non-Residential Customer's choice of service options.

Service Line. The piping that runs from the Main to the Delivery Point at Customer's service site.

(continue to Sheet 00.9)

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GENERAL RULES AND REGULATIONS
(continued)

Definitions (continued):

Special Contract. A negotiated contract with unique rates and terms and conditions that must be approved by the Commission and must meet the criteria established by ORS 757.210 and OPUC Order No. 87-402.

Standby Service. Service to equipment that is available in lieu of or as a supplement to the usual source of supply; or service to equipment that is used for the protection of equipment or commodity during cold weather.

Storage Charge. A charge applicable to Firm Sales Service Customers served under **Rate Schedule 32** designed to recover the cost of storage facilities used to support Firm Sales Service on the Company's Distribution System.

Tariff. The published volume of Schedules, Rate Schedules, and General Rules and Regulations under which the Company's Natural Gas service will be provided.

Temporary Adjustment. The net amount by which the rates under a given Rate Schedule are to be adjusted on a temporary basis. Temporary adjustments include amounts set forth in **Schedule 162**, and any other **Schedules** as may be approved by the Commission.

Temporary Disconnection. A period of more than one Billing Month but less than twelve (12) consecutive Billing Months following the date of a Disconnection of Service. At the Company's discretion, the maximum period that a disconnection can be deemed temporary may be extended for reasonable cause.

Termination of Service. The ending of the service relationship between a Customer and the Company effectuated by closing the Customer's service account at a specific Premise, by the Disconnection of Service at a Customer's Premise, or both.

Therm. A unit of heating value equivalent to 100,000 Btus. The amount of heat energy in approximately 100 cubic feet of Natural Gas. One Therm equals 29.3 kilowatt hours of electricity at 100% conversion efficiency.

Time Payment Agreement. A monthly payment plan available to Customers as a means to bring delinquent account balances current within a specified period, usually not more than twelve (12) months.

Transportation. The movement of Customer-Owned Natural Gas from the Pipeline Receipt Point(s) through the Company's Distribution Facilities to a Customer's Delivery Point(s).

Transportation Service. Service to Customers that use Customer procured gas supplies.

Underrun Entitlement. A condition whereby a Transportation Service Customer is required to use the gas previously nominated and received on such Customer's behalf on a specified Gas Day.

Weighted Average Cost of Gas (WACOG). See Annual Sales WACOG and Winter Sales WACOG. Sometimes referred to as the Commodity Component.

Winter Sales WACOG. The Company's weighted average commodity cost of gas for the winter period (November through March), as determined in the Company's most recent Purchased Gas Cost Adjustment (PGA) filing, and set forth in **Schedule P** and **Schedule 164** of this Tariff. Sometimes referred to as the Commodity Component.

Year. A period of twelve (12) consecutive Billing Months.

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

GENERAL RULES AND REGULATIONS
(continued)

Rule 1. General Terms Of Service.

Service will be furnished by Company provided adequate capacity exists in the Company's system.

Service provided to Customers under this Tariff is Firm Sales or Firm Transportation Service, except where the Company has authorized Interruptible Sales or Interruptible Transportation Service in accordance with **Rate Schedule 32** or **Rate Schedule 33**. The Company, in its sole discretion, will determine the availability of Interruptible Service. A Customer request for Interruptible Service will be considered on a case-by-case basis.

All Applicants must establish credit as set forth in **Rule 2** and any other requirements of these Rules**.** Where an application for service requires the installation of Distribution Facilities, Applicant shall first pay any amounts required under **Rule 20** or **Schedule X**.

A Service Agreement will be deemed to be in effect upon the Company's acceptance of an application. The Service Agreement created by the Company's acceptance of an application for gas service under a specific Rate Schedule or Special Contract shall continue in full force and effect until terminated by the Customer or by the Company as provided in the respective Rate Schedule or Special Contract, and by all applicable Rules of this Tariff.

A Rate Schedule election shall be made at the time of initial application. Customer shall elect the Rate Schedule for which customer fully qualifies, and which is best suited to meet Customer's service requirements. The Company will assist Customer in electing the appropriate Rate Schedule based on the representations of the Customer at the time of application. The Company shall classify a Non-Residential Customer as Commercial or Industrial based on the Customer-provided description of the business and applied natural gas use at the service address.

Any person(s), business, or other entity that uses gas service prior to applying for and being accepted by the Company shall pay for such service in accordance with the applicable Rate Schedule, provided that no other party is known by Company to have responsibility.

Any person(s) that at any time is found to have provided false identification to establish service, continue service, or verify identity will be considered an Applicant and will be required to immediately provide valid proof of identification in order to receive new or continued service. Failure to provide valid identification will be cause for disconnection as set forth in **Rule 11** of this Tariff.

(continue to Sheet RR-1.1)

GENERAL RULES AND REGULATIONS
(continued)

Rule 1. General Terms of Service (continued).

Customer is responsible to notify the Company of any changes in installed equipment or service conditions that may warrant a change in Rate Schedule, a change in Customer class, or that necessitate construction, relocation, removal, or replacement of Distribution Facilities. The Company may examine Customer's gas-fired equipment at any time, and Company shall have the right to disconnect, discontinue, or refuse service under a Rate Schedule if the Customer's equipment and gas usage do not meet the Conditions set forth in this Tariff, or in a specific Rate Schedule.

Unless specifically allowed in a Rate Schedule, written Service Agreement, or Special Contract, or as otherwise permitted by the Company, Customer may not transfer from one Rate Schedule to another or change a Service Agreement or Special Contract for the purpose of obtaining more favorable rates, priority of service, or avoiding minimum charges, unless the minimum term of service has been met and appropriate notices have been received by the Company.

The Company reserves the right to refuse to provide service for reasons set forth in the Commission Rules.

(continue to Sheet RR-2)

Issued December 30, 2011
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220 N.W. Second Avenue
Portland, Oregon 97209-3991

GENERAL RULES AND REGULATIONS
(continued)

Rule 2. Service Application, Establishment and Re-establishment of Credit.

SERVICE APPLICATION
An application for service shall be made by Applicant(s) orally or in writing. Applicants with multiple service sites must submit separate applications for each site. Where two or more responsible individuals reside at the same address, a joint application or separate applications for each individual, is required. Where two or more individuals join in one application, such individuals shall be jointly responsible for the account.

All Residential Applicants shall provide all of the following information for each responsible individual named on the account:

(a) The service address;
(b) The name of the person(s) responsible for payment on the account;
(c) The name to be used to identify the account, if different than the actual name;
(d) The birth date of the person(s) responsible for payment on the account;
(e) Proof of identification by one of the options identified below;
(f) The billing address, if different than the service address; and
(g) Any available telephone numbers where the Applicant can be reached night and day.

All Residential Applicants must provide proof of identification through any one of the following options:

1. The social security number of the person(s) responsible for payment on the account and a current valid Oregon driver's license number of the person(s) responsible for payment on the account; or
2. The social security number of the person(s) responsible for payment on the account and the identification number of a Qualifying Valid State or Federal Identification containing name and photograph of the person(s) responsible for payment on the account; or
3. Current valid Oregon driver's license number of the person(s) responsible for payment on the account and the identification number from another Qualifying Valid State or Federal Identification containing name and photograph of the person(s) responsible for payment on the account; or
4. All of the following submitted by facsimile or U.S. mail:

    i. An original or certified true copy of the Applicant's birth certificate;
    ii. A photocopy of a current identification from school or employer containing a photograph, notarized by a notary public commissioned by any of the 50 United States or the District of Columbia; and
    iii. The name, address, and telephone number of a person who can verify the Applicant's identity, such as a teacher, employer, or caseworker.

(continue to Sheet RR-2.1)

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GENERAL RULES AND REGULATIONS
(continued)

Rule 2. Service Application, Establishment and Re-establishment of Credit (continued).

SERVICE APPLICATION (continued)
All Non-Residential Applicants shall provide the following information for the responsible entity and each responsible individual named on the account:

(a) The service address;
(b) The business name, and the name of the parent company, if applicable;
(c) A description of the business activity and the applied use of natural gas at the service address for purposes of determining rate and customer classification
(d) The name of the business owner or representative of the business that is responsible for payment on the account;
(e) The name to be used to identify the account, if different than (b);
(f) The federal tax identification number, or the social security number of the person(s) responsible for payment on the account, whichever applies;
(g) The billing address, if different than the service address; and
(h) Any available telephone numbers where a representative of the business can be reached night and day.

A Non-Residential Customer is responsible to notify the Company of any Change in Responsible Party. Where practicable, such notice should be made within ten (10) Business Days of the change. If a sale or transfer of majority ownership constitutes a Change in Responsible Party, the new owner will be considered an Applicant, and in such case will have twenty (20) Business Days from the date of ownership to apply for service. If the business activity materially differs from the previous owner, a change in Rate Schedule or service type may be warranted and a new Service Election form may be required.

The Company may refuse any application for service until it receives payment in full for any past due amount or other obligation on a prior Oregon account, or as also set forth in OAR 860-021-0335. See **Rule 8** of this Tariff. If an Applicant is denied service for failure to provide an acceptable form of identification, the applicant may pursue conflict resolution under the Commission's rules.

The Company will not approve an application for service until the Applicant(s) has established satisfactory credit as set forth in this **Rule 2**, or otherwise provided sufficient security, as described in **Rules 6, 6A, 6B and 6C** of this Tariff.

ESTABLISHMENT OF CREDIT
The establishment of credit or the Company's acceptance of other security shall not relieve an Applicant or Customer from complying with the Rules and Regulations established by the Commission, including but not limited to, the prompt payment of bills and the Disconnection of Service for nonpayment.

(continue to Sheet 2.2)

GENERAL RULES AND REGULATIONS
(continued)

Rule 2. Service Application, Establishment and Re-establishment of Credit (continued).

ESTABLISHMENT OF CREDIT (continued)
If an Applicant has other active or inactive gas service accounts with the Company for the same class of service, then the account history of all such accounts may be considered in the establishment of credit for any new application. If the estimated monthly bill for service under any new Non-Residential Applicant is higher by 50% or more than the average monthly bill of the Applicant's other accounts for the same class of service, then a deposit may be required, irrespective of the credit standing on such Applicant's other gas service accounts.

In the event that there are multiple active accounts but no single account has been active for a consecutive 12-month period, then the requirement for 12-months of continuous service may be met by combining the non-duplicative active months across all accounts (i.e. account #1 was active January-May; Account #2 was active April through December). If the consecutive 12-month period cannot be met (i.e. the accounts were all activated less than 12 months and for the same calendar months), then a deposit may be required.

If the principals of a corporation, partnership or other Non-Residential enterprise are substantially the same as those of another corporation, partnership or Non-Residential enterprise that either is or has at one time received Natural Gas service from the Company, then they will be deemed to be the same corporation, partnership or Non-Residential enterprise for the purposes of establishing or re-establishing credit standing under this **Rule 2**.

In order to be considered substantially the same as those of another corporation, partnership or Non-Residential enterprise, seventy-five percent (75%) of the business ownership must be the same. Where there are only two principals, both principals must be the same in order to be considered substantially the same corporation, partnership, or Non-Residential enterprise.

For purposes of establishing credit, a builder, contractor, property developer, or property manager shall be considered a Non-Residential Applicant on any application made for gas service to real property for which they are responsible through their business activities, whether the property to which the application for service applies is classified as Residential or Non-Residential.

A Residential Applicant that is required to pay a deposit, or that provides a surety agreement in lieu of a deposit, will be deemed to have established credit when they have maintained an active account with the Company for one Year, and during such Year: (a) Customer did not receive more than two final notices of disconnection (also known as a 5-day notice), and (b) Customer was not disconnected for non-payment, theft, diversion of service, or for tampering with utility facilities. If there are multiple active accounts for the same Customer, all such accounts must meet the above requirements.

(continue to Sheet RR-2.3)

GENERAL RULES AND REGULATIONS
(continued)

Rule 2. Service Application, Establishment and Re-establishment of Credit (continued).

ESTABLISHMENT OF CREDIT (continued)
A Non-Residential Applicant or Customer that is required to pay a deposit will be deemed to have established or re-established credit when they have maintained an active account with the Company for one Year and during such Year: (a) Customer did not receive more than two final notices of disconnection (also known as a 5-day notice), and (b) Customer was not disconnected for non-payment, theft, diversion of service, or for tampering with utility facilities. If there are multiple active accounts for the same Customer, all such accounts must meet the above requirements.

Residential Service

An Applicant who received Residential gas service from the Company within the prior 24- months, whether such account(s) is currently active or inactive, will be deemed to have established credit if all of the below listed conditions are met for all current and prior accounts.

a. Applicant was a responsible person on a gas service account and received twelve (12) consecutive months of service from the Company within the Company's Oregon or Washington service territory during the prior 24-months; and

b. During the prior 24-months, Applicant did not have service disconnected for non-payment, for theft or diversion of service, or for tampering with utility facilities; and

c. Applicant does not owe an account balance to the Company that was not paid in full when service was terminated.

If one or more of the above conditions cannot be met, the Applicant must pay a deposit. In the alternative, an Applicant may secure the account by providing the Company a written surety agreement. See the conditions set forth in **Rule 6A**.

An Applicant that has no prior account history with the Company within the prior 24- months may establish credit through one of the two methods described below.

1. Applicant represents that they had a prior energy utility service account with another energy utility within the Company's Oregon or Washington service territory where the Applicant was named as a responsible person on the utility service account within the prior 24 months; and meets all of the following:

(continue to Sheet 2-4)

GENERAL RULES AND REGULATIONS
(continued)

Rule 2. Service Application, Establishment and Re-establishment of Credit (continued).

<u>ESTABLISHMENT OF CREDIT (continued)</u>

<u>Residential Service (continued)</u>

a. The Company can verify prior utility service either by contact with the former utility or through an authorized letter provided by the former utility on the utility letterhead that states the dates service was provided to Applicant;
b. The prior energy utility service account was active for a minimum of twelve (12) consecutive months;
c. Applicant did not have service disconnected for non-payment, for theft or diversion of service, or for tampering with utility facilities;
d. Applicant voluntarily terminated service and timely paid for all services rendered; and
e. Applicant does not owe an account balance to the Company or another Oregon energy utility that was not paid in full when service was terminated.

2. Applicant provides proof of ability to pay by providing one of the following:

a. Proof of employment during the 12 consecutive months prior to the date of application with not more than two different employers, along with a telephone number(s) to verify employment; or
b. If not employed, a statement or other documentation from an income provider or an authorized representative that the Company can verify, stating that the Applicant receives a regular source of income. For purposes of this provision, a regular source of income shall mean income that is recurring at fixed intervals with no predetermined termination date, from a legal trust, pension, or other similar fund, and that at least averages on a monthly basis not less than three (3) times the estimated average monthly bill at the service address; and
c. Applicant does not have any unpaid balance owing to the Company.

If the Applicant cannot establish credit by one of the above methods, the Applicant must pay a deposit. In the alternative, the Applicant may secure the account by providing the Company a written surety agreement. See the conditions set forth in **Rule 6A**.

The Company must receive any required documentation within five (5) Business Days from the date of application. If such documentation is not received by such date, a deposit may be assessed on the first regular monthly bill.

(continue to Sheet RR-2.5)

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GENERAL RULES AND REGULATIONS
(continued)

Rule 2. Service Application, Establishment and Re-establishment of Credit (continued).

Non-Residential Service

A Non-Residential Applicant, or a Customer that is required to re-establish credit, must meet all of the following conditions:

a. Applicant is licensed to do business in the state of Oregon and has kept current over the past twelve (12) consecutive months on all real estate mortgages or lease agreements, commercial loans, utility bills and trade accounts; and
b. Applicant has not been involved in a solvency proceeding, including but not limited to bankruptcy, receivership, liquidation, bulk sale, or financial reorganization, naming the Applicant or any principals of the corporation, partnership, or Non-Residential entity as a debtor party to the filing at any time during the prior thirty-six (36) consecutive months; and
c. Applicant received twelve (12) consecutive months of service with the Company or another energy utility immediately prior to the date of application and:
    i. Received no more than two final disconnection notices during such 12-month period; and
    ii. Did not have service disconnected for non-payment, theft, diversion of service, or for tampering with utility facilities during such 12-month period; and
    iii. Does not owe a past due amount.

If any one of the above conditions cannot be met, the Non-Residential Applicant or Customer must pay a deposit, and the Company may require the Applicant to provide other security, as set forth in **Rule 6B**.

The Company may also require additional credit or financial information deemed necessary in its judgment to determine credit worthiness. Customer will have five (5) Business Days from the date of the Company's request to provide the Company with such information.

Re-establishment of Credit – Non-Residential Service

Any Non-Residential Customer may be required to re-establish credit under this **Rule 2** when the conditions of service or the basis upon which credit was originally established has changed, including:

(a) A change in the type of business in use at the service address;
(b) A business name change;
(c) A change in responsible party(ies);
(d) A change in ownership;
(e) The expiration or termination of Customer's Oregon business license;
(f) Customer was found to have established credit standing based on false or incomplete information;

(continue to Sheet 2.6)

GENERAL RULES AND REGULATIONS
(continued)

Rule 2. Service Application, Establishment and Re-establishment of Credit (continued).

Re-establishment of Credit – Non-Residential Service (continued)

(g) Customer has been approved by the Company to select a different Service Type that results in an expected change to the average monthly bill for such Customer of 50% or more; or

(h) Other circumstances which the Company can be reasonably certain may result in Customer's inability to regularly and timely pay for services rendered by the Company or that otherwise may have the potential to adversely affect rates for other ratepayers of the Company.

When a Non-Residential Customer is required to re-establish credit, the Customer must then meet all of the conditions set forth in this **Rule 2** based on the most recent 12 months of service with the Company. If any one of these conditions cannot be met, Customer may be required to pay a deposit, pay an additional deposit, and/or provide other security as set forth in **Rule 6B.** The Company may also require additional credit or financial information deemed necessary by the Company to determine credit worthiness. Customer will have five (5) Business Days from the date of the Company's request to provide the Company with such information.

GENERAL RULES AND REGULATIONS
(continued)

Rule 3. Written Service Agreements.

The Company reserves the right to require any Customer to enter into a written Service Agreement as a condition of service. In all cases, a written Service Agreement will be required as a condition precedent to service when any Rate Schedule or Rule contained in this Tariff specifies that a written Service Agreement is required.

All Service Agreements will incorporate the General Rules and Regulations of this Tariff, other applicable Schedules, and the terms and conditions of Customer's Rate Schedule. In the event of a conflict, the terms and conditions of the Rate Schedule shall prevail.

The term of a written Service Agreement shall be no less than the term stated in the applicable Rate Schedule or Rule, or a minimum of one Year, if not stated.

Termination of a written Service Agreement by a Customer must comply with the provisions of **Rule 16**, or otherwise comply with the notice provisions stated in the Service Agreement.

The interpretation and performance of any Service Agreement shall be in accordance with the laws of the state of Oregon, excluding principles of conflict of law, and the valid laws, orders, rules, and regulations of the authorities having jurisdiction (or the successors of those authorities).

Except as required by law, Commission Order, or rule or regulation a written Service Agreement may only be amended or modified in writing. Any amendment or modification must be signed by Customer and by the Company. No Service Agreement, or any related rights or obligations, may be assigned by Customer without the prior written consent of the Company, which shall not be unreasonably withheld.

If during the term of a written Service Agreement, the Rate Schedule or Rule to which the written Service Agreement applies is cancelled or replaced by order of the Commission, the written Service Agreement shall (a) automatically terminate or (b) if specified in the Commission's order, transfer to successor Rate Schedule or Rule and continue in effect.

If the Company waives any one or more defaults by a Customer in the performance of a Service Agreement, the waiver(s) shall not operate or be construed as a waiver of any other future default(s).

(continue to Sheet RR-4)

GENERAL RULES AND REGULATIONS
(continued)

Rule 4. Special Contracts.

The Company, at its sole discretion, may negotiate Special Contracts with Customers to provide rates and services that are not part of the Company's core Rate Schedule offerings on a case-by-case basis.

Special Contract rates shall only be available to Customers with viable economic alternatives to the Company's service, including but not limited to, price competition from alternate fuels or a service alternative, such as direct physical connection to an interstate Pipeline.

All Special Contracts shall be subject to Commission approval, pursuant to the criteria established by ORS 757.230, Commission Order No. 87-402, and Commission Rule OAR 860-022-0035.

A description of each Special Contract approved by the Commission will be published in **Rate Schedule 60.**

(continue to Sheet RR-5)

GENERAL RULES AND REGULATIONS
(continued)

Rule 5. Notices and Communications.

Unless otherwise directed by the Company, notices and communications to the Company shall be in writing.

When written notice is made by U.S. mail, the notice shall be sent postage prepaid, to the Company at the following address:

NW Natural
One Pacific Square
220 NW Second Avenue
Portland, Oregon 97209

Electronic communications may be sent to one of the following email addresses:

Large Commercial and Industrial Customer Accounts:	mast@nwnatural.com
Residential and Small Commercial Customer Accounts:	caswebmail@nwnatural.com
Rates & Regulatory:	eFiling@nwnatural.com

For additional electronic communication options, visit the Company's website at nwnatural.com

(continue to Sheet RR-6)

GENERAL RULES AND REGULATIONS
(continued)

Rule 6. Deposits and other Security: General.

The Company may require a deposit or other security from a Customer or Applicant for reasons set forth in **Rule 2** and for other reasons as set forth in this **Rule 6, Rule 6A, Rule 6B,** or **Rule 6C.** The requirements for a Residential Customer or Applicant are set forth in **Rule 6A.** The requirements for a Non-Residential Customer or Applicant are set forth in **Rule 6B** and **Rule 6C.** For builders, contractors, property developers, and property managers, when a deposit or other security is required the provisions applicable to Non-Residential service shall apply.

Where a deposit or deposit installment amount is billed and due and payable along with a Customer's bill for regular monthly gas usage, the amount paid by Customer shall first be applied toward payment of the amount due for the deposit, as set forth in **Rule 7**.

In the event an Applicant pays a deposit, in full or in part, as a condition of service activation and the check or draft for payment is returned or not honored by the respective financial institution, the deposit will be deemed unpaid and Customer status is not met for such Applicant. The Company will attempt telephone notice to the Applicant of the failed payment, and the Applicant will have one business day in which to make a valid payment. If a valid payment is not received and the gas service is active, service may be disconnected without further notice.

In the event a Customer pays a deposit or additional deposit amount, with a check or draft for payment that is returned or not honored by the respective financial institution, the Company may disconnect service for nonpayment of the deposit as set forth in **Rule 11**.

In the event a Customer concurrently terminates service at a current address and applies for service at a new address within the Company's service area, any deposit held by the Company for service at the current service address, plus accrued interest, will be applied to the new service address. Nothing precludes the Company from requiring an additional deposit under the terms set forth in **Rule 6A, Rule 6B,** or **Rule 6C**. If such Customer notified the Company of the change of address subsequent to the issuance of the closing bill for service at the terminated service address, then the Customer may be required to pay a new deposit as required by these rules.

Deposits will accrue interest at a rate prescribed by order of the Commission. Interest shall be computed from the date the deposit is paid (if paid in installments, from the date of the first payment) to the date of refund or application of the entire deposit amount to the Customer's account, or if applicable, to the end of any one Year period. Interest will be prorated on deposits held by the Company for less than a full Year.

(continue to Sheet RR-6.1)

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GENERAL RULES AND REGULATIONS
(continued)

Rule 6. Deposits and other Security: General (continued).

Except where provided otherwise in this or any other applicable Schedule of this Tariff P.U.C. Or. 25, deposits will be held by the Company for one Year. At the end of one Year, the Company will review the account to determine if Customer has met the conditions for establishing satisfactory credit, which are described in **Rule 2**. If a Customer has not established satisfactory credit, the deposit may be held on the account for a subsequent Year, with interest. Any interest accrued for the prior Year will be applied as a bill credit on the Customer's next regular monthly bill.

If Customer has met the conditions for establishing satisfactory credit, the deposit plus accrued interest will be refunded or credited to Customer. If there are any other current or prior accounts for such Customer, the Company may review such accounts to determine if there is any unpaid past-due balance owing to the Company. Prior to refunding or crediting a deposit amount, the Company may first apply the refundable deposit and accrued interest, to such past due amounts. Any remaining balance shall be refunded or credited to the account for which the deposit was held.

Upon voluntary termination of service, any deposit amount held on account of a Customer shall be refunded or credited to the Customer in the manner set forth in **Rule 16.**

The Company's acceptance of a deposit or other security shall not relieve an Applicant or Customer from complying with the Rules and Regulations established by the Commission, including but not limited to the prompt payment of bills and the Disconnection of Service for non-payment.

(continue to Sheet RR-6A)

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220 N.W. Second Avenue
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GENERAL RULES AND REGULATIONS
(continued)

Rule 6A. Deposits and Surety Agreements: Residential.

Deposits.

A deposit may be required from a Residential Applicant as a condition of new or continued service as set forth in **Rule 2**.

The total deposit for any one Residential Customer account will not exceed one-sixth of the estimated annual billing at the service address.

Deposits will be refunded or credited to Customers as set forth in **Rule 6**. Except as provided otherwise in this or any other applicable Schedule of this Tariff P.U.C. Or. 25, deposits are typically due prior to or at the time that service is activated, or reactivated. At the Company's discretion, a deposit or additional deposit amount may be billed with the first monthly bill following the date of notice that a deposit is required.

A deposit or additional deposit may be required from a Residential Customer following the Company's receipt of notification that such Customer is named as a debtor party to a bankruptcy filing. Such a deposit shall be separate and apart from any additional surety amount ordered by the bankruptcy court.

The Company may also require an additional deposit amount when there is a change in rate schedule, a change in billing rates, or a change in usage at the same or a different service address. An adjustment for usage may occur when (i) historical usage was based on a different occupant at the premise and is not reflective of the current Customer's usage; (ii) Customer adds or removes gas-fired equipment at the premise; or (iii) the average monthly usage at a new service address is different from the prior premise upon which the deposit was based. The Company will provide written notice to the Customer of such action at the time that the additional deposit amount is billed.

A Residential Customer that is required to pay an additional deposit amount must pay the deposit in full, or make deposit payment arrangements, within five (5) Business Days from the date of notice that the additional deposit is required. If a deposit installment arrangement is already in place, the existing installment payments will be adjusted for the additional deposit amount. In no event will two installment payments be required for the same account within a single bill period.

Any Applicant or Customer may pay a deposit or additional deposit amount in three (3) consecutive installments. If a deposit is paid in installments, the first payment equal to the greater of $30.00 or one-third of the total deposit amount shall be immediately due. The remaining payments shall be due and payable with each of the Customer's next two regular monthly bills following the initial payment date. Except for the last payment, installment payments will not be less than $30.00.

(continue to Sheet RR-6A.1)

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GENERAL RULES AND REGULATIONS
(continued)

Rule 6A. Deposits and Surety Agreements: Residential (continued).

Deposits (continued).

When a Residential Applicant or Customer agrees to a deposit installment plan, the Company will provide the Customer with documentation showing the total deposit amount and the date that each installment payment is due. The notice will include a statement that the deposit will accrue interest at the rate prescribed by the Commission, an explanation of the conditions under which the deposit will be refunded, information on how to obtain financial assistance, and a statement that service will be disconnected if the payments are not received by the Company when due.

Failure to pay a deposit or to abide by the terms of a deposit installment plan is cause for Disconnection of Service. Service may be disconnected after written notice is issued not less than five (5) calendar days prior to the date of the scheduled disconnection, except that if the deposit is deemed unpaid because the payment was returned or not honored by the respective financial institution, notice of disconnection will be made as set forth in **Rule 6**. Before service will be restored, the full deposit amount, plus one-half of any past due amount for gas service, plus the applicable reconnection fee and late payment fee, shall first be paid. The balance of the past due amount shall be paid within thirty (30) days of the date service is restored. An existing Time Payment Plan may continue upon payment of all past-due installments, along with the full deposit and other applicable fees.

Surety Agreements.

In lieu of paying a deposit, a Residential Applicant or Customer may obtain a written surety agreement from a qualifying third person (“the Surety”). The Surety must be a current Customer of the Company who meets all of the conditions of provision (A) as set forth in **Rule 2**. The Surety will have the right to receive and discuss with the Company the account of the benefiting Customer, and will be sent a duplicate of any notices of disconnection (5-day notice) issued on the benefiting Customer’s account.

The surety agreement must secure payment in an amount equal to two months’ average usage at the benefiting Customer’s service address. Nothing precludes the Surety from voluntarily paying more than this amount if the surety agreement is invoked.

The Company must receive a signed surety agreement before service will be activated or reactivated. If the gas service is active, the Applicant or Customer will have five (5) Business Days in which to submit the signed surety agreement, Gas Service will be disconnected without further notice if the signed surety agreement or other acceptable security is not received.

In the event a Customer for whom a surety agreement is in effect is disconnected for nonpayment, the Company may collect from the Surety the amount of the two months’ average usage at the benefiting Customer’s service address. The payment made by the Surety will be applied to the benefiting Customer’s balance due.

(continue to Sheet RR-6A.2)

GENERAL RULES AND REGULATIONS
(continued)

Rule 6A. Deposits and Surety Agreements: Residential (continued).

Surety Agreements (continued).

The same surety agreement may be used to secure the Customer's account for reconnection of service following a disconnection, provided the Surety fulfilled any obligations under the surety agreement if it was invoked, and provided the Surety has not given prior notice to the Company of termination of the surety agreement.

A surety agreement may be terminated by the Surety at any time upon five (5) Business Days advance written notice to the Company.

A surety agreement may be terminated by the Company at any time upon five (5) Business Days notice to the Customer and to the Surety if the Company finds that the Surety no longer meets the qualifications described in this General Rule.

A surety agreement will automatically terminate when the benefiting Customer has established satisfactory credit as described in **Rule 2**. If the benefiting Customer has not established satisfactory credit by the end of one Year, the surety agreement will continue to be held as security on the benefiting Customer's account provided the surety agreement is not otherwise terminated as provided in this General Rule.

In the event a surety agreement is terminated for any reason other than establishment of credit, the Customer will have five (5) Business Days in which to either pay the required deposit or make deposit payment arrangements, or obtain a written surety agreement from another qualifying Customer. Failure to provide sufficient replacement security is cause for Disconnection of Service without further notice.

(continue to Sheet RR-6B)

GENERAL RULES AND REGULATIONS
(continued)

Rule 6B. Deposits and other Security: Non-Residential.

A deposit may be required from a Non-Residential Applicant or Customer as a condition of new or continued service as set forth in **Rule 2**.

A Non-Residential Customer may also be required to pay a deposit, or to pay an additional deposit, in the following circumstances:

a) Upon the filing of an insolvency proceeding, including but not limited to bankruptcy, receivership, liquidation, bulk sale, or financial reorganization, naming the Customer or any principals of the corporation, partnership, or Non-Residential entity, as a debtor party to the filing;
b) When Customer's bill has or is expected to increase by 50% or more due to a change in billing rates, a change in rate schedule, or a change in gas usage at the service address;
c) When Customer is issued two or more final disconnection notices (also known as a 5-day notice) within a consecutive 12-month period; or
d) When Customer was found by the Company to have committed theft, diversion of service, or tampering with utility facilities.

Any deposit or additional deposit collected by the Company under order of the bankruptcy court pursuant to Title 11 of the Bankruptcy Code and, in particular, 11 USC § 366, will be held separate from any deposit collected under this **Rule 6B**, and will be refunded following the final ruling of the bankruptcy court.

The Company may also require the receipt of other security, which may include, but is not limited to an irrevocable letter of credit, surety bond (performance bond) or some other form of guarantee acceptable to the Company.

Except for seasonal Applicants or Customers, the amount of the deposit for any one Non-Residential account will not exceed one-sixth of the estimated annual billing at the service address. The deposit for a seasonal Applicant or Customer for any one account will not exceed the estimated ensuing season's billing for services provided by the Company.

Deposits will be refunded or credited to Customers as set forth in **Rule 6**.

Deposits are typically due in full prior to or at the time that service is activated or reactivated. However, at Company's discretion, a deposit may be billed with the first monthly bill following the service activation date.

(continue to Sheet RR-6B.1)

GENERAL RULES AND REGULATIONS
(continued)

Rule 6B. Deposits and other Security: Non-Residential (continued).

A Non-Residential Customer that is required to pay a deposit to re-establish credit or to pay an additional deposit amount as set forth in this **Rule 6B** must pay the deposit or request deposit payment arrangements within ten (10) Business Days from the date of the notice that a deposit is required. Such notice may also serve as the notice of disconnection required under OAR 860-021-0505. At the Company's discretion, the deposit may be billed with the Customer's next regular monthly bill.

At the Company's discretion, a Non-Residential Applicant or Customer that cannot pay the deposit in full may be allowed to pay the deposit in three (3) consecutive installments. If paid in installments, the first payment is immediately due. The remaining amount will be billed and will be due and payable with each of the next two regular monthly bills. Failure to abide by the terms of a deposit installment plan is cause for Disconnection of Service. Service may be disconnected after written notice is issued not less than five (5) calendar days prior to the date of the scheduled disconnection, except that if a deposit is deemed unpaid because the check or draft for payment was not honored by the respective financial institution, notice of disconnection will be made as set forth in **Rule 6**.

Failure to pay a deposit or deposit payment, or to provide any other required security, is cause for Disconnection of Service. If service is disconnected, the entire deposit, plus the past due account balance, plus the applicable reconnection fee and late payment fee must be paid before service will be restored.

(continue to Sheet RR-6C)

GENERAL RULES AND REGULATIONS
(continued)

Rule 6C. Special Deposits and other Security: Non-Residential Anticipatory Breach or Other Circumstances.

This Rule is applicable only to Service Agreements or Special Contracts executed after July 1, 1991.

Irrespective of a Customer's credit standing, the Company may require one or any combination of a deposit, pre-payment, bond, letter of credit, or other security may be required, in the amount of the charges for one-sixth of the estimated annual usage at the Customer's service address, plus any fixed charges due upon Termination of Service where:

(a) There is an anticipatory breach by a Customer of a Service Agreement or Special Contract, in the form of an overt communication of intention or an action which renders performance impossible or demonstrates a clear determination not to continue with performance; or

(b) It is reasonably certain that a Customer will discontinue, disconnect, or terminate service entirely prior to fulfilling existing contractual obligations. Facts sufficient to establish such a reasonable certainty would include, but would not be limited to, the construction of a service connection to an alternative energy source; the installation of alternate fuel facilities, or other explicit acts, statements, or correspondence indicating an intent to discontinue service under existing contracts or otherwise to decline to comply with existing contractual obligations.

The Company shall give written notice to any Non-Residential Customer from whom a deposit or other security is required. Customers shall have ten (10) calendar days from the date of the notice to comply with such requirement. Such notice shall also serve as the notice of disconnection required under OAR 860-021-0505. Failure to comply with such requirement is cause for Disconnection of Service. If service is disconnected for non-compliance with a deposit or other security under this rule, the entire deposit, plus any past due account balance, plus the applicable reconnection fee and late payment fee must be paid before service will be restored.

The notice shall include a statement that the Customer may dispute the requirement by appealing to the Commission as provided in the Commission Rules. Pending resolution of the appeal, the Commission may require the Company to continue service upon such terms and conditions as the Commission finds reasonable. However, the Company may disconnect service thirty (30) days after the date of its request for a deposit unless the Customer has provided the deposit, or the Commission has concluded its proceedings on appeal with an order that the deposit shall not be required.

(continue to Sheet RR-7)

GENERAL RULES AND REGULATIONS
(continued)

Rule 7. Bills and Bill Payments.

Any service rendered by the Company obligates the Customer, co-customer or other responsible person to pay for such service in accordance with the applicable Rule or Rate Schedule of this Tariff.

Bill Payments.
Monthly payments received from Customers will be credited in the following priority:

1. Any required deposits
2. Past due gas service account balances, if any,
3. Current gas service account balances,
4. Any non-gas service account balances or charges, if any.

Payments for non-gas service account balances will be credited first to past-due account balances if any, then to current account balances. Where more than one non-gas service account exists for a single customer, payments will be credited first to the account with the earliest account activation date. In the event a payment is received that is greater than the amount needed to bring all balances current, the remaining credit balance will be applied to the Customer's active gas service account unless Customer requests a refund.

Non-payment of a regular monthly bill is cause for Disconnection of Service under **Rule 11**.

In the event that any payment is not honored by the respective financial institution, the bill will be deemed unpaid. In such event, if valid payment is not received within one Business Day following notice to Customer, the account may be subject to Disconnection of Service under **Rule 11**. A fee will be assessed for each payment not honored as set forth in **Schedule C**. The Company may require payment by cash, certified check, or money order if two or more payments are not honored in any consecutive twelve (12) month period.

Billing Period and Payment Due Date.
Except as otherwise provided in this **Rule 7**, or in **Rate Schedule 31** or **Rate Schedule 32**, Customers will be billed for service on a meter read cycle determined by the Company in its sole discretion. A typical monthly bill will be based on a meter read cycle of approximately thirty (30) calendar days. The meter read cycle may be changed from time to time when such change is determined necessary for the Company's business practices. Typically, bills will be issued the next Business Day following the last read date.

In the event that a change to the Customer's meter read cycle creates a short or long bill that results in the issuance to Customer of more than one bill in a single revenue month or less than one bill in a single revenue month, the Company may refund or surcharge any applicable additional Monthly Fixed Charge amounts, as defined below in this **Rule 7**, on the same or a subsequent monthly bill.

(continue to Sheet RR-7.1)

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GENERAL RULES AND REGULATIONS
(continued)

Rule 7. Bills and Bill Payments (continued).

Billing Period and Payment Due Date (continued).
A Non-Residential Customer may request that a bill be rendered based on a calendar month cycle. The Company will accommodate such requests, but Customer may be required to provide, at Customer's expense, any utility, telephone, cellular, or other services or devices that the Company deems necessary to support AMR technology for the transmission of metered data to the Company. Customers must ensure that any service or devices installed by the Customer to support AMR are continuously active at all times. Charges set forth in **Schedule 15** may apply.

Regular monthly gas bills are due when rendered, and become delinquent if not paid by the due date printed on the bill. Customer may select a payment due date different than the date normally designated for that customer's regular billing cycle, except that the Company may deny a customer's preferred due date if the requested date is later than the bill issue date in any billing month within the next 12-month period, or if such date would otherwise violate standard billing practices or Commission Rules. The Company may restrict a Customer from changing their bill due date more than once in a 12-month period. The Company may terminate a preferred due date billing arrangement with a Non-Residential Customer, if more than two late payment charges are assessed on the Customer's account within a 6-month period.

Prorated Bills.
A bill may be prorated when: (1) there is a change in billing rates within a meter read cycle; (2) there is an opening bill with an initial meter read cycle that is less than 26 days or more than 35 days; (3) there is a closing bill with a final meter read cycle that is less than 26 days or more than 35 days; or (4) there is a need to re-bill more than one billing period on a single bill statement. Except where a change in billing rates occurs, a long or short bill that results from a change in meter read cycle will not be prorated.

Any bill proration will be computed as follows:

(1) A change in billing rates:
Old Rate:
a. Monthly Fixed Charge(s) x # of days at old rate / # of days in Billing Month
b. Metered service x # of days at old rate / # of days in Billing Month

New Rate:
a. Monthly Fixed Charge(s) x # of days at new rate / # of days in Billing Month
b. Metered service x # of days at new rate / # of days in Billing Month

(2) Opening and closing bills or re-bills *:
a. Monthly Fixed Charge(s) x # of days / 30 days
b. Metered service for the amount metered during the bill period
c. For blocked rates: blocked volume x # of days at billed rate / 30 days

* Month-end bills will be prorated based on the number of days in the Billing Month / # of days in the calendar month

(continue to Sheet 7.2)

GENERAL RULES AND REGULATIONS
(continued)

Rule 7. Bills and Bill Payments (continued).

Prorated Bills. (continued)
For purposes of this General Rule, Monthly Fixed Charges include, but are not necessarily limited to: (a) Customer Charge; (b) Standby Charge; (c) MDDV-based Charges; or (d)Transportation Charge. Monthly Fixed Charges do not include charges under **Schedule C** or **Schedule 15**.

Opening and closing bills will be prepared from actual meter reads obtained through the normal meter read cycle. Upon a Customer request, or when otherwise deemed necessary, the Company will obtain an out-of-cycle meter read for purposes of preparing an opening or closing bill.

Estimated Bills.
The Company may issue bills based on an estimated read when (a) the Company is unable to gain access to read the meter, (b) weather conditions or other conditions beyond the Company's control interfere with the Company's ability to complete meter reading routes, (c) the Company determines that a theft of service or meter interference has occurred; (d) the meter or appurtenances thereto fail to operate for any reason; or (e) at such other times as may be warranted. Any estimated reading will be clearly noted on the bill. Except in extraordinary circumstances, the Company will not issue an estimated bill for more than two consecutive months.

Any bill estimation will be computed as follows:

- Space and/or water heating load. For accounts with known space and/or water heating equipment, the estimate will be based upon historical base load and degree day use of the account premise, if available. Otherwise, the estimate will be calculated from a recent historical use profile, adjusted for actual weather, if appropriate.

- All other load. For all other accounts, the estimate will be based on the actual use at the account premise from the same month of the prior year, or if not available, from the most recently billed months.

- Insufficient historical use. If there is insufficient historical usage from which to derive an estimate based on the above criteria, a default estimate may be used based on the most recent average use of other customers on the same rate schedule.

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GENERAL RULES AND REGULATIONS
(continued)

Rule 8. Prior Account Balances.

If at the time an application for service is made, the Company identifies an outstanding balance owed to the Company by such Applicant for a prior Oregon account or for service at a prior Oregon address, or from amounts owing under **Rule 21** or **Schedule X**, the full amount shall be paid to Company before service will be provided.

If the Company's records indicate that reasonable payments were made on the past due amounts owed during the lapse in service, at least one-half of any remaining overdue amount must be paid before service will be provided. If no payments were made on such past due amount, the Company may refuse to provide service until the entire past due amount is paid in full.

If any of the past due amount is associated with an unpaid deposit, the deposit amount must be paid in full. The remaining balance shall be due within thirty (30) days of service initiation. The Company may require payment in full under other circumstances as set forth in the Commission Rules.

If after the date service is initiated, the Company identifies an outstanding balance owed to the Company by a Customer or co-customer from a prior Oregon account or prior address for Oregon service or from amounts owing under **Rule 21** or **Schedule X**, the Company may transfer the amount to the Customer's current account, or may choose other collection means if deemed appropriate, after giving the Customer notice of the action to be taken. The notice shall include the amount due under the prior account, the period of time during which the balance was incurred, and the service address under which the bill was incurred.

If there is an existing Time Payment Agreement for service at the current service address with at least six (6) months remaining, the Time Payment Agreement will be adjusted to include the outstanding balance from the prior account, and the installment payment will be recalculated so as to bring the account into balance within the time period specified in the original plan. If there are less than six (6) months remaining, the Time Payment Agreement will be recalculated to bring the account into balance within twelve (12) months. Any past due installments must be paid prior to any adjustment to a Time Payment Agreement.

In applying this Rule, the Applicant, Customer, or co-customer is someone that was a responsible person on such prior Oregon account or at the prior address in Oregon during the time the overdue balance was incurred.

(continue to Sheet RR-9)

GENERAL RULES AND REGULATIONS
(continued)

Rule 9A. Time Payment Agreements – Non-Residential Customers.

The Company may offer a Time Payment Agreement to Non-Residential customers when, in the Company's sole judgment, circumstances are such that a Time Payment Agreement is deemed to be in the best interest of both the Company and the Customer.

The terms and conditions of any Time Payment Agreement will be set forth in writing by the Company, and must be acknowledged by signature of an authorized representative of the Customer before the Time Payment Agreement shall become effective.

Any modifications to a Time Payment Agreement must be in writing and signed by an authorized Company and Customer representative.

A carrying charge in an amount not to exceed the equivalent annual percentage rate associated with the late payment charge set forth in **Schedule C** may be assessed on any unpaid past-due balances that are included in a Time Payment Agreement, unless otherwise specified in the terms and conditions of the Time Payment Agreement.

The Company's decision to enter into a Time Payment Agreement does not preclude the Company from requiring a deposit, pre-payment, or other security as provided under **Rule 6A and Rule 6B**.

Failure to abide by the terms of a Time Payment Agreement may be cause for Disconnection of Service as provided in **Rule 11** of this Tariff.

(continue to Sheet RR-10)

GENERAL RULES AND REGULATIONS
(continued)

Rule 9. Time Payment Agreements – Residential Customers.

Residential Customers with accounts that become delinquent may be eligible to enter into a Time Payment Agreement to bring the account current. The Customer may choose a Levelized Payment Plan or a Current Bill-Plus-Past Due Installment Plan.

The Levelized Payment Plan ("LPP") requires an initial payment equal to the Customer's average annual bill, including the account balance, divided by twelve (12). A like payment will be due each month over the next eleven (11) months. Billings in month twelve (12) of the LPP will reflect any over- or under-payments.

The Current Bill-Plus-Past Due Installment Plan ("CBP") requires an initial payment equal to one-twelfth of the total amount owed by Customer for gas service, including (a) the amount overdue, (b) any current bill amount, and (c) any bill under preparation but not yet presented to the Customer. A like amount will be added to and payable with the Customer's current charges each month over the next eleven (11) months.

If a Customer changes their service address during the term of an active and current Time Payment Agreement, the monthly installment will be adjusted to reflect the balance of the account at the previous address and the average annual bill at the new address so as to bring the account into balance within the time period specified in the original Time Payment Agreement. Customer shall pay any other charges associated with the change in address. When installment payments on a Time Payment Agreement have not been kept current, Customer shall be required to pay all past-due installments, together with any other applicable charges, before service is provided at the new address.

The Company may periodically review and adjust the monthly installment of a Customer's Time Payment Agreement to reflect changes in billing rates, to more accurately reflect usage, or to reflect a change in service address.

Failure to abide by a Payment Agreement may be cause for Disconnection of Service as provided under **Rule 11**.

(continue to Sheet RR-9A)

GENERAL RULES AND REGULATIONS
(continued)

Rule 10. Emergency Medical Certificates – Residential Customers.

Customer must notify Company if a medical emergency exists. A medical emergency does not excuse a Customer from paying delinquent and ongoing charges.

The Company will not disconnect Residential Service for nonpayment if the Customer submits an emergency medical certificate from a qualified medical professional stating that disconnection would significantly endanger the physical health of the Customer or a member of the Customer's household.

A qualified medical professional is defined as a licensed physician, nurse practitioner, or a physician's assistant authorized to diagnose and treat the medical condition described without direct supervision by a physician.

Customer shall enter into a Time Payment Agreement as described in **Rule 9** of this Tariff, or on such other terms as the Company deems reasonable, within twenty (20) days of filing the medical certificate with the Company. If the Customer fails to enter into a Time Payment Agreement, or if the Customer fails to abide by the terms of a Time Payment Agreement, service may be disconnected in accordance with **Rule 11**, following notice to the Commission’s Consumer Services Section.

An emergency medical certificate will be valid only for the length of time the health endangerment is certified to exist, but no longer than six (6) months for non-chronic illnesses and no longer than twelve (12) months for chronic illnesses, without renewal.

A medical certification given to Company verbally must be confirmed in writing within fourteen (14) calendar days by the qualified medical professional prescribing medical care.

The Company may verify the accuracy of any emergency medical certificate submitted under this Rule.

The Company will provide written notice to Customer of the upcoming expiration of a medical certificate at least fifteen (15) days prior to the expiration date, unless the medical certificate is renewed with the Company before that day arrives.

(continue to Sheet RR-11)

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GENERAL RULES AND REGULATIONS
(continued)

Rule 11. Disconnection and Reconnection of Service – By Company.

The following shall be cause for a Disconnection of Service by the Company:
(a) Failure to pay Tariff or price-listed charges for services rendered;
(b) Meter tampering, diverting service, or other theft of service;
(c) When a Customer is found to have provided false identification to establish service, continue service, or verify identity;
(d) Failure to pay a deposit under the terms of **Rule 6**;
(e) Failure to abide by the terms of a Time Payment Agreement;
(f) For a delinquent collect balance on an Equal Pay Plan;
(g) The existence of hazardous or unsafe conditions; or
(h) Failure to provide access to the Company's meter or other Distribution Facilities; or
(i) Other applicable reasons set forth in the Commission Rules.

The Company will not disconnect service for non-payment on Friday, Saturday, Sunday, on a holiday, or the day preceding a state- or utility-recognized holiday.

A Customer that receives a Disconnection of Service notice for non-payment may be eligible to enter into a Time Payment Agreement designed to bring their account current. The Time Payment Agreements available to Customers are described in **Rules 9 and 9A.**

<u>Notice of Disconnection of Service</u>

<u>Non-payment</u>
The Company will issue no fewer than two notices to a Residential Customer before a Disconnection of Service is initiated by the Company for non-payment. The first notice will give the Customer at least fifteen (15) calendar days following the day the notice was mailed to make payment or payment arrangements. The second notice will give the Customer at least five (5) Business Days following the date of mailing before service will be disconnected.

If the notice is for non-payment of a deposit, Customer will have no fewer than five (5) Business Days after mailing or delivery of the notice to make payment before service is disconnected.

A Residential Customer with a bona fide medical condition will be given an additional five (5) Business Days to submit an emergency medical certificate before service will be disconnected. The emergency medical certificate must comply with the terms and conditions set forth in **Rule 10** of this Tariff.

The Company will attempt to contact the Customer on the day the service is scheduled to be disconnected. If service is disconnected, a notice stating the requirements for service reconnection will be left in a conspicuous place at the residence.

Service to Non-Residential Customers may be disconnected for non-payment on not less than five (5) Business Days written notice.

(continue to Sheet RR-11.1)

GENERAL RULES AND REGULATIONS
(continued)

Rule 11. Disconnection and Reconnection of Service – By Company (continued).

<u>False Identification</u>
When the Company determines that an account was established with false identification within sixty (60) calendar days from the date the false identification was given to the Company, the Company will notify the Customer that valid identification must be submitted within five (5) Business Days from the date the notice was mailed.

When more than sixty (60) calendar days have passed from the date the false identification was given to the Company, the notice will require that valid identification be submitted within fifteen (15) Business Days following the date the notice was mailed.

If the Customer fails to provide valid identification in the form required by **Rule 2** within the time indicated on the notice, the Company may disconnect service without further notice.

<u>Other</u>
For any other cause for a Disconnection of Service, the Company will issue one notice to a Customer before service is disconnected. The notice will give the Customer at least five (5) Business Days prior to the date service is scheduled to be disconnected to take appropriate actions to prevent the Disconnection of Service.

Advance notice is not required when the Disconnection of Service is for emergencies where life or property is in danger or for additional reasons as set forth in this Rule.

<u>Reconnection of Service</u>

Customer must first satisfy the requirements for reconnection of service as set forth in this provision before the Company will reconnect service following a Disconnection of Service performed under this Rule.

Except as otherwise provided in **Schedule C** of this Tariff, the Company will reconnect service by the end of the next Business Day.

If the Disconnection of Service was the result of a Company action, such as maintenance or repair of Company facilities, then service will be reconnected as soon as reasonably possible and the requirements for reconnection of service set forth in this provision do not apply.

(continue to Sheet RR-11.2)

GENERAL RULES AND REGULATIONS
(continued)

Rule 11. Disconnection and Reconnection of Service – By Company (continued).

Residential Requirements - Reconnect within 20 days of Disconnection.
Where the Disconnection of Service was for non-payment, Customer/Applicant must first pay at least one-half of all past due amounts, except any past due deposit payments must be paid in full, plus any new deposit amount due, plus the applicable service reconnection charge set forth in **Schedule C**.

If Disconnection of Service was for theft, Customer/Applicant must pay in full all amounts owed by Customer/Applicant, including amounts owed for gas used but not billed, and any amounts due for damage to the Company's meter or other Distribution Facilities, as set forth in **Schedule C**.

Non-Residential Requirements – Reconnect within 20 days of Disconnection
Where Disconnection of Service was for non-payment, Customer/Applicant must first pay all past due amounts, plus any deposit amounts, plus the service reconnection charge set forth in **Schedule C**.

If Disconnection of Service was for theft, Customer/Applicant must pay in full all amounts owed by Customer/Applicant, including amounts owed for gas used but not billed, and any amounts due for damage to the Company's meter or other Distribution Facilities, as set forth in **Schedule C**.

Residential and Non-Residential Requirements- Reconnect more than 20 days of Disconnection
When more than twenty (20) days, but less than one Billing Month, have passed before a reconnection of service is requested following a Disconnection of Service under this Rule, a new service application, as set forth in General **Rule 2** of this Tariff, will be required before service will be reconnected. Applicant must pay in full all amounts owed from the date of Disconnection of Service, plus any deposit amount, plus the service reconnection charge set forth in **Schedule C**.

When reconnection of service is requested after one Billing Month, but within twelve consecutive Billing Months, the request for reconnection will be treated as a Temporary Disconnection of Service and Applicant must pay in full all amounts owed from the date of Disconnection of Service, plus any deposit amount, plus the monthly Customer Charge for the number of months that service was disconnected, plus the service reconnection charge set forth in **Schedule C**.

If more than twelve (12) consecutive Billing Months have passed since the date of Disconnection of Service, then the Company will treat the request as a new application for service subject to the **Rule 2** and the provisions of this **Rule 11** do not apply.

(continue to Sheet RR-12)

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GENERAL RULES AND REGULATIONS
(continued)

Rule 12. Service Interruptions.

Interruption Initiated by Company.
The Company may temporarily interrupt service to Customer(s) when it is necessary, as determined by the Company in the exercise of its reasonable judgment, to repair or make changes to the Company's Distribution Facilities, or for reasons of Force Majeure.

The Company will give reasonable notice to Customer(s) as circumstances permit, prior to interrupting service, unless prevented by reasons of Force Majeure, and will make reasonable efforts to restore service as soon as practicable under the circumstance.

The Company shall be exempt from all liability or damage caused by temporary Interruptions of service.

Interruption Initiated by a Non-Residential Customer.
Customer must provide advance notice to the Company if the Customer must temporarily discontinue its operations for repairs, changes in equipment, or for reasons of Force Majeure.

Except as may be otherwise agreed between the Company and the Customer, during the period that service is suspended under this Rule Customer shall continue to be responsible to pay the Monthly Customer Charge and other fixed monthly charges, as well as all Gas used during the suspension. The duration of any suspension of service under this Rule shall be as determined between the Customer and the Company on a Customer-specific basis.

A suspension of service under this Rule shall not void the Service Agreement between Company and Customer. The Company, at its sole option, may extend the term of a Customer's Service Agreement for a period of time equal to the period of time the Customer's Service Agreement was deemed suspended.

(continue to Sheet RR-13)

GENERAL RULES AND REGULATIONS
(continued)

Rule 13. Curtailment of Service.

The Company will curtail Sales or Transportation Services to Customers in the order set forth in **Rule 14** if the Company determines that Curtailment is required to meet all Firm Service Customer requirements; to balance available gas supply; to sustain operational control and/or to maintain the integrity of the Company's distribution system or when Curtailment is deemed necessary due to Force Majeure conditions.

Following each Annual Service Election Date, the Company will require that all Interruptible Service Customers update the Customer Emergency Contact List Form. The Company will use this information to notice Customers of Curtailment as provided in this General Rule. At all other times, Customer must report any emergency contact changes to the Company within five (5) Business Days. The Company will ensure that the Customer Emergency Contact List Form is readily accessible for this purpose.

Company shall give as much notice as possible with respect to each instance of Curtailment, but in no event less than two (2) hours, unless prevented by Force Majeure conditions. Each Curtailment Order will specify the reason for the Curtailment, the service address to which the Curtailment Order applies, and the quantities of each particular service to be curtailed. If no quantity is specified, Customer shall curtail its gas use to zero therms. Each restoration notice will specify the time restoration is to be instituted. Curtailment and restoration notices need not be in writing, but will be given to the authorized representative(s) designated by the Customer.

In the event that the Company is unable to provide notice of Curtailment either because a Customer's authorized emergency contact information on record with the Company is not current or because the Company is unable to reach any of the named authorized emergency contacts on record, all gas usage by the Customer within the Curtailment Period will be considered unauthorized and the Company will bill, and the Customer will be responsible to pay the charges as set forth in **Schedule C** on such unauthorized gas usage.

Customers shall be obligated to limit gas use to the quantities permitted under Curtailment Orders and shall be responsible to take whatever steps are necessary to reduce or discontinue their gas usage to the level required in the Curtailment Order. Except as otherwise provided in this Rule, the Company will not physically valve off or disconnect a Customer's gas service to reduce or stop Customer's gas use.

Any gas taken in excess of the quantity permitted by the Curtailment Order shall be deemed to be unauthorized. Customers shall pay for unauthorized quantities at the rate specified in **Schedule C**, in addition to all other charges otherwise applicable for the period in which the unauthorized quantity was used. In no event shall a Customer's payment for unauthorized quantities and the Company's acceptance of the payment, be construed as giving the Customer the right to take the gas, or preclude the Company from pursuing any other available remedies

At the Company's sole discretion, any Customer that fails to comply with a Curtailment Order may be immediately physically disconnected or valved-off. In such instance, the Customer shall pay a reconnection charge as set forth in **Schedule C**, in addition to any unauthorized overrun charges, before service will be restored. In exercising this provision, the Company will make reasonable effort to ensure that such action, if applicable to a Customer defined as an Essential Human Needs Customer, will not impose an immediate danger to persons whose lives depend upon the use of natural gas by such Customer.

(continue to Sheet RR-13.1)

GENERAL RULES AND REGULATIONS
(continued)

Rule 13. Curtailment of Service (continued).

Following a Curtailment Period, the Company may refuse to serve all or a portion of Customer's gas usage under Interruptible Service for a minimum one Year period if such Customer is found to have violated a Curtailment Order. An exception to this provision may be made for an Essential Human Needs Customer that violated a Curtailment Order in order to preserve human life.

In the event of a refusal of Interruptible Service, the Company will transfer such Customer to Firm Service effective with the first day of the next Billing Month. The Company will notify Customer of such transfer not less than five (5) Business Days in advance of the effective date of the transfer. The portion to be transferred to Firm Service will be determined as the highest daily volume overrun in the Curtailment Period. Thereafter, a Customer may request to return to Interruptible Service subject to all of the terms, conditions and restrictions of the applicable Rate Schedule.

Two Curtailment Order violations by a single Customer within a 12-month period may be cause for the Company to refuse to serve the Customer under Interruptible Service for an indefinite period of time.

A Curtailment Discount will be given on bills for any Firm Service Customer who is curtailed during the twelve (12) billing months ending June. The Curtailment Discount shall be applied in accordance with **Rule 15**.

The Company shall not be liable to Customers for any claim, costs, loss, or damage of any kind, including but not limited to, damages to equipment or property arising out of, in connection with, or incident to the Company's Curtailment of gas, as provided in ORS 757.730; provided that Company shall have the continuing obligation to use reasonable diligence to purchase gas supplies in sufficient quantities to satisfy present and future requirements of Firm Sales Service Customers.

In the event Company determines that conditions so warrant, during any Curtailment period Customer-Owned Gas may be Pre-empted in the manner set forth in **Schedule T**.

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GENERAL RULES AND REGULATIONS
(continued)

Rule 14. Curtailment Priority.

If a Curtailment Order is issued, as described in **Rule 13**, service to Customers shall be curtailed according to the curtailment priorities listed below, with Priority 4 Customers being curtailed first and Priority 1 Customers being curtailed last:

Priority 4.
All Interruptible Sales Service and Interruptible Transportation Service usage under **Rate Schedule 32**, **Rate Schedule 33**, and Special Contracts.

Customers with a Combination Service Type having a Firm base block will be allowed to take Firm Service up to the Customer's Firm MDDV. Amounts in excess of the Firm MDDV may be considered unauthorized and subject to charges under **Schedule C**.

Priority 3.
All Firm Sales Service and Firm Transportation Service usage under **Rate Schedule 31**, **Rate Schedule 32**, **Rate Schedule 33**, and Special Contracts. Firm Service to Essential Human Needs Customers will not be included in Priority 3 provided such Customers can reasonably be identified by the Company and the Curtailment condition allows the Company the ability to maintain continued service to such Customers.

Firm Service usage under a Combination Service Type may be prorated on an hourly basis.

Priority 2.
All Firm Non-Residential usage under **Rate Schedule 1** and **Rate Schedule 3**. Firm service to Essential Human Needs Customers will not be included in Priority 2 provided such Customers can reasonably be identified by the Company and the Curtailment condition allows the Company the ability to maintain continued service to such Customers.

Priority 1.
All Firm Residential usage and requirements of Firm Service Essential Human Needs Customers.

Service to Customers in each priority classification shall be curtailed in full or in part on a pro-rata or on a Customer-by-Customer basis, until sufficient volumes have been curtailed, in the Company's sole judgment, to balance available gas supply, sustain operational control, and/or maintain the integrity of all of portions of the Company's Distribution Facilities.

For purposes of Priority 3, unless a Customer has specified a maximum hourly delivery volume in the Customer's Service Election form, the hourly proration will equal 1/24 of the Customer's Firm MDDV.

(continue to Sheet RR-15)

GENERAL RULES AND REGULATIONS
(continued)

Rule 15. Curtailment Discount: Non-Residential Firm Service Curtailment.

If any Non-Residential Firm Service Customer is curtailed under the Rules of this Tariff, Customer shall receive a Curtailment Discount on bills for gas taken during the twelve (12) Billing Months ending June (the Annual Period) within which a Curtailment occurs.

The Curtailment Discount shall be calculated as the difference between the sum of the bills actually rendered in the Annual Period and the sum of bills which would have been rendered in the Annual Period had Customer been served under the Interruptible Service option under **Rate Schedule 32**, and received identical monthly quantities, multiplied by the ratio of the number of "100% Equivalent Days" of Curtailment experienced by Customer in the Annual Period to the average number of "100% Equivalent Days" of Curtailment experienced by the applicable Interruptible Service Customers in the same period.

A 100% Equivalent Day of Curtailment is defined as a twenty-four (24) hour period during which Customer's supply under the applicable Rate Schedule is curtailed in its entirety.

In the event of partial day Curtailment, where Customer's entire supply is curtailed for part of a full day, the partial Curtailment will equal the fractional part of a 100% Equivalent Day as the number of hours of Curtailment bears to twenty-four (24) hours.

In the event of partial supply Curtailment, where part of Customer's supply is curtailed for a full day, the partial Curtailment will equal the fractional part of a 100% Equivalent Day as the volume of gas remaining available to the Customer during such day bears to Customer's MDDV.

The Curtailment Discount shall be applied as a credit, until extinguished, on Customer's bills commencing with the terminal month of the Annual Period.

The Curtailment Discount will not be granted when Curtailment is due to Force Majeure conditions.

(continue to Sheet RR-16)

GENERAL RULES AND REGULATIONS
(continued)

Rule 16. Termination of Gas Service Account – By Customer.

Customers that receive service under **Rate Schedule 1**, **Rate Schedule 2**, or **Rate Schedule 3** may terminate their gas service account by giving no fewer than five (5) calendar days notice prior to the desired date of Termination of Service. Notice may be oral or in writing. Customer shall be liable for all gas supplied to the Premise named in the application until the stated termination date.

Customers taking service under **Rate Schedule 31**, **Rate Schedule 32**, **Rate Schedule 33**, or under a Special Contract may terminate their gas service account by giving written notice in accordance with the terms of the Rate Schedule or Special Contract. Where no notice period is stated, or where Customer is electing to change Rate Schedules, the notice period will be one (1) Billing Month in advance of the desired termination date. A termination on less than the required notice may be cause for the Company to bill, and for the Customer to pay, the total of all fixed charges due for each Billing Month within the required notice period, and the closing bill proration of Monthly Fixed Charges as described in **Rule 7** will not apply.

All Customer notices for Termination of Service must specify the date service is to terminate.

Any amounts held by Company on account of a Customer for deposits, including accrued interest, or for Construction Contribution refunds payable to Customer at the time an account is terminated may be first applied to any deposit on a new account, or to any unpaid past due balance owing by Customer to Company on any other account for which the Customer is responsible, with any remaining amount applied as a credit on the closing bill of the terminating account.

Any amounts owed to Company by Customer at the time the account is terminated will be reflected in the total balance due. If the closing bill reflects a credit balance, the credit amount will be refunded to Customer by check following the issuance of the closing bill. If the Customer has made a new service arrangement with the Company, such as applied for service under a new Rate Schedule, or applied for service at a new service address, any credit balance or balance due will be transferred to the account for the new service arrangement.

Closing bills will be issued as set forth in **Rule 7** of this Tariff.

The Company, in its sole discretion, may choose to leave the gas meter active following a voluntary termination of service by a Customer.

(continue to Sheet RR-17)

GENERAL RULES AND REGULATIONS
(continued)

Rule 17. Gas Delivery and Measurement.

The Company shall provide service under the Rate Schedules contained in this Tariff provided that, in the Company's sole judgment, adequate gas volumes are available, adequate capacity exists on the Company's Distribution System to accommodate such service, and that where applicable, the terms and conditions set forth in **Schedule X**, or any successor Schedule, are first met.

The delivery of Natural Gas under this Tariff, contemplates service to a single consumer unit, on a single Premise, through a single Delivery Point, and Customer's House Line must be brought to this point. The installation and use of sub-meters beyond the Delivery Point will not modify the Custody Transfer Point between the Company and Customer, and will not modify the respective liabilities in connection with custody transfer at the Delivery Point.

For the purpose of measuring the amount of gas supplied to and used by a Customer, the Company will select the meter or meter configuration that best fits the Customer's load and service requirements. The Company will install the meter(s) at the Customer's Premise, at a point to be determined by and most convenient for the Company. Said meter(s) shall be the sole medium of measurement of all gas supplied to Customer. Metering equipment and gas measurement practices will conform to currently applicable standard industry practices.

In the event any meter fails to register the actual amount of gas supplied to a Customer, a bill will be rendered based on an estimated consumption level determined in a manner that best represents Customer's actual consumption, including but not limited to, a reading from other meter(s) on the Premise, Customer's previous consumption history, or consumption based on predicted equipment usage. Customer's account will be adjusted to reflect actual consumption data as soon as the information is available. If actual information cannot be obtained, then the estimated bill shall be deemed and considered a stated account.

No gas shall be re-metered or sub-metered by a Customer for resale to others at any price which is not an applicable Tariffed rate, except for gas purchased and delivered solely and explicitly for direct resale for vehicular fuel. Additionally, the use of sub-meters for purposes of billing a Customer on more than one different Rate Schedule is not allowed. However, any sub-meters installed and used for billing purposes for Customers that were in place prior to September 1, 2003 may be grandfathered and allowed to continue at the Company's discretion until such time as the Customer further changes or terminates its service agreement or such agreement expires on its own terms, after which time, no new sub-metering arrangements for billing purposes will be allowed with respect to such Customer.

The Company may require, at Customer's expense, that the Customer provide any utility, telephone, cellular, or other services or devices that the Company deems necessary to support Automated Meter Reading (AMR) technology for the transmission of metered data to the Company for billing purposes. The charges set forth in **Schedule 15** may apply. Where the volume or type of use warrants, the Company may install telemetry equipment at Customer's Premise, and Customer shall pay the telemetry charge set forth in **Schedule 15**.

(continue to Sheet RR-18)

GENERAL RULES AND REGULATIONS
(continued)

Rule 18. House Piping and Gas Appliance Standards.

Customer shall have sole responsibility for the cost of installation, use, safety, repair, and maintenance of all House Line and other Customer-owned equipment beyond Company meter(s), including all accessories thereto; and for the cost of installation, use, safety, repair, maintenance and replacement of retrofitted excess flow valves installed on the Service Line at the request of a Customer, where applicable. Any loss or damage from leaks beyond the meter is at the risk and expense of the Customer.

All installations of Gas appliances, including vents and connections, safety devices and other Customer-owned or Customer-installed equipment shall conform to the applicable specifications of regulatory authorities and industry standards, including the Company's Standard Practices. The Company reserves the right to refuse or disconnect service in the event such standards are not met.

The Company will not connect meters to House Line or appliances known to be defective. When, in the course of normal business activities, the Company finds the House Line or appliances on a Customers' Premise to be defective or in an unsafe condition, the Company may immediately disconnect service under **Rule 11.** The charges set forth in **Schedule C** may apply at the time of reconnection of service following a disconnection under this Rule.

The Company shall not be responsible for any injury to persons or property arising out of, in connection with, or incident to the use, safety, repairs, maintenance or replacement of retrofitted excess flow valves installed on the Service Line at the request of a Customer, or for the use, safety, repairs, maintenance, or replacement of Customer's House Line, appliances or related equipment, whether performed by Customer or any of Customer's employees, contractors, subcontractors, or agents.

(continue to Sheet RR-19)

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GENERAL RULES AND REGULATIONS
(continued)

Rule 19. Appliance Inspection and Adjustment Services: Residential.

Upon reasonable Customer request, the Company will inspect and adjust Customer-owned appliances and facilities for safe and efficient operation.

The Company's basic gas service includes certain inspection and adjustment services, offered at no direct charge to the Customer. Such services include, but are not necessarily limited to: inspection of gas-fired appliances (*e.g.*, furnace, water heater, range, dryer, etc.) and facilities generally; gas input and primary air adjustments to pilot and main burner flames; repair of leaks in appliance parts and connections; minor cleaning operations to burners; cleaning of pilots, pilot orifices, pilot tubings, and B-valves; greasing valve cores; adjustment of appliance control mechanisms as needed; and the re-lighting of pilots.

The Company will replace defective thermocouples for a charge, and will, in the course of providing meter installation or equipment inspection or adjustment services, perform other repairs, parts replacements, or services, for a charge, in portions of its service territory where in the Company's judgment such services are not readily available.

Where conditions or repairs are beyond the scope of these services, the Company will refer the Customer to a service repair agency.

(continue to Sheet RR-19A)

GENERAL RULES AND REGULATIONS
(continued)

Rule 19A. Equipment Inspection and Adjustment Services: Non-Residential.

Upon reasonable Customer request, the Company will inspect and adjust Customer-owned equipment and facilities for safe and efficient operation.

The Company's basic gas service includes certain inspection and adjustment services, offered at no direct charge to the Customer. Such services include, but are not necessarily limited to: inspection of gas-fired equipment and facilities generally; gas input and primary air adjustments to pilot and main burner flames; repair of minor leaks in equipment parts and connections; minor cleaning operations to burners; cleaning of pilots, pilot orifices, pilot tubing, and B-valves; greasing valve cores; adjustment of equipment control mechanisms as needed; and the re-lighting of pilots.

The Company may, in the course of providing meter installation or equipment inspection or adjustment services, perform other repairs, parts replacements, or services, for a charge, in portions of its service territory where in the Company's judgment such services are not readily available.

Where conditions or repairs are beyond the scope of these services, the Company will refer the Customer to a service repair agency.

(continue to Sheet RR-20)

GENERAL RULES AND REGULATIONS
(continued)

Rule 20. Distribution Facilities Standards.

The Company shall be responsible for planning, designing, engineering, and installing Distribution Facilities using the Company's standards for material, design, and construction. All Distribution Facilities are owned, operated, and maintained by the Company.

Customer shall grant any necessary written easement(s) to install, operate, maintain, and expand the Distribution Facilities on Customer's Premise to serve Customer. The Company will seek any necessary easements from third parties. Company is not obligated to serve Customer where appropriate easement(s) cannot be obtained.

Not more than one Service Line, meter, and associated facilities will be installed by the Company to supply a single Premise, unless it is for Company convenience. When an Applicant or Customer requests special or additional facilities, they may be provided at Company's option at Customer or Applicant's expense.

Where multiple meters are installed to measure gas supplied to multi-family dwellings or to separate tenants in Commercial buildings, the property owner is responsible to clearly identify the respective unit number and/or service address associated with each House Line connection, and the Company will connect each meter and establish the premise account according to such markings. The Company is not responsible for any billing issues that may arise from the failure of the property owner, or their designated representative, to properly identify the House Line and associated service address. Should a billing issue arise, the Company will adjust such bills in accordance with the rules of this Tariff and the Oregon Administrative Rules of the Commission.

Any relocation, rearrangement, removal, or replacement of existing Distribution Facilities, or the installation of new or additional Distribution Facilities, including metering equipment, determined by Company to be necessary for system maintenance, service quality, or operating convenience, will be performed at no charge. Customer shall provide Company unobstructed access to complete such work.

Applicant or Customer will be required to pay the entire cost of any relocation, rearrangement, removal, or replacement of existing Distribution Facilities, or the installation of new or additional Distribution Facilities, performed by the Company for the convenience of the Applicant or Customer, or performed to correct conditions caused by the actions of Applicant or Customer which create hazards or make a meter or other Distribution Facilities inaccessible. Where additional gas-fired appliances are being installed by Customer at the time of a relocation or other similar action, Customer may receive a Construction Allowance to offset the cost.

The Company will install excess flow valves on existing Service Lines upon Customer request, and at Customer's expense. The installation costs will be based on site-specific construction conditions, and will include actual material, equipment, and labor costs. Such retrofitted installations are subject to the provisions and conditions set forth in **Rule 18**.

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GENERAL RULES AND REGULATIONS
(continued)

Rule 20. Distribution Facilities Standards (continued).

In all cases, the Company will abandon or remove its existing facilities at Company's sole option.

Where an idle Service Line is found to exist at the Applicant or Customer site and the Service Line is determined by the Company to be safe to activate without repair or upgrade, the Service Line will be activated and there may be no charge to the Applicant or Customer. If repair or upgrade is required, the request will be considered the same as a new Service Line installation under **Schedule X**, and an appropriate Construction Allowance will be calculated.

The construction and installation of Customer requested Distribution Facilities will be performed in accordance with **Schedule X**.

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d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

GENERAL RULES AND REGULATIONS
(continued)

Rule 21. Distribution Facilities: Access and Protection.

Unobstructed access to meters and other property of the Company located on the Customer's Premises must be given to the Company, its employees, its contractors, subcontractors, and agents, at all reasonable times, for installation, inspection, adjustment, repair, maintenance, removal and other purposes. Failure to permit access at reasonable times and after reasonable notice is grounds for Disconnection of Service.

Any meters supplied by the Company shall at all times remain the property of the Company.

If for any reason the Company's employees cannot gain access to read a meter, an estimated bill will be rendered as set forth in **Rule 7**. Any estimated reading shall be clearly noted on the bill.

If the Company cannot gain access to a meter to complete a Disconnection of Service because actions of the Customer or conditions at the Premise cause the meter to be inaccessible, the Company may elect to install a shut-off valve at the curb. Customer shall pay a charge for such installation as set forth in **Schedule C**.

In cases where access to a meter is restricted, the Company may ask Customer to obtain monthly readings by completing and returning the meter reading form to the Company. Any Customer reading is subject to actual verification by the Company not less than once every four (4) months.

Customer shall protect meters and other property supplied by the Company from damage or theft. Interference by anyone, except employees of the Company, with the meter or its connections, services, mains, or other property of the Company shall be unlawful and subject to charges set forth in **Schedule C**.

The Company will install guard posts around meters in Company-approved locations when, in Company's judgment, such measures are necessary for safety. If Customer requests a different meter location that requires the installation of guard posts, Company will install the guard posts at Customer's expense.

If, in the Company's judgment, Company meters or other property are not accessible or safe because of Customer improvements at the Premise, or because of hazardous or potentially hazardous conditions or other actions of Customer, the Company may move or relocate the meter or other property at Customer's expense.

(continue to Sheet RR-22)

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GENERAL RULES AND REGULATIONS
(continued)

Rule 22. Distribution Facilities: Temporary Service.

Temporary Distribution Facilities may be installed at Company's sole discretion, upon Applicant or Customer request, provided that existing Customers are not disadvantaged, and provided that the Applicant or Customer has met the credit criteria set forth in **RULE 2**.

Applicant or Customer shall pay all costs associated with the installation of temporary Distribution Facilities in advance of the installation, or otherwise as allowed by the Company. The amount charged by the Company shall take into account the estimated cost of the installation plus the estimated cost of the Disconnection or removal of the Distribution Facilities, less the estimated salvage value, if any.

A written Service Agreement will be required in all cases. The Service Agreement shall specify the type of equipment and facilities to be installed, the expected duration of the temporary operation, payment provisions, the Rate Schedule under which service will be provided, and any special terms and conditions that may apply.

Permanent status will be given to any temporary Distribution Facilities where a Gas service account has been active on a continuous basis for a period of thirty-six (36) consecutive calendar months from the date the facilities are first ready for use, or from the date specified in Customer's written Service Agreement, if applicable. Permanent status may also be given at any time if the Company determines, in its sole judgment that the character of the Customer's operations has changed.

In the event that a change from temporary to permanent status is granted, the Company will refund an amount equal to the Construction Allowance set forth in **Schedule X** that would have applied to the installation if it were not initially installed under a temporary service agreement.

(continue to Sheet RR-23)

GENERAL RULES AND REGULATIONS
(continued)

Rule 23. Hazardous Substances.

The Company may evaluate the job site of any new service request, or of any site where maintenance or repairs of existing Distribution Facilities are required, for the purpose of identifying any hazardous wastes, substances, or contaminants ("hazards"), as such hazards are defined under state or federal law.

The circumstances that would cause an evaluation include, but are not limited to, the following: (a) the job site is within an area designated or listed as a hazardous site by a state or federal environmental agency; or (b) an employee or agent of the Company or site owner reports unusual odor, unusual materials in, or unusual skin reaction to, soil, equipment, tanks, or any substance found in any form at the site.

The Company shall specify mandatory conditions for the protection of its employees or agents, which may include indemnification of the Company by the Customer, when the Company receives information that hazards may exist at a job site, and such hazards may, in the Company's determination, cause a risk to the health or safety of its employees or agents in performance of the installation, maintenance, or repair of the service. The cost of complying with any such conditions, including the cost of handling contaminated soil moved during the installation process, if applicable, shall be borne by the Customer.

If conditions cannot be prescribed which, in the Company's judgment, will adequately protect its employees or agents against hazards, the Company may require the Customer to have its own Company-approved agents perform the installation and subsequent maintenance or repair within the hazardous area. The Company will retain responsibility for normal permits, and will retain ownership of Distribution Facilities to the Delivery Point.

If the area cannot be made safe, in the Company's judgment, the Company may move or relocate meters or other Company property at Customer's expense, as provided in **Rule 21**.

This rule does not apply to hazards in the public right-of-way, either for the purpose of recovering extraordinary costs associated with installation or maintenance, or for indemnification against future costs, except where the Customer's property is the source of the hazards in the right-of-way.

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GENERAL RULES AND REGULATIONS
(continued)

Rule 24. Determination of Thermal Units.

The quality of Natural Gas procured and delivered by the Company, or by Customers under **Schedule T**, shall conform to standard purity requirements of the Commission; shall have an energy content of 1050 Btu per standard cubic foot ± 10 percent (945 to 1155); and shall permit satisfactory operation of appliances.

Customer usage is calculated in energy units, normally in Therms. Determination of thermal units shall consider metered volume, metering pressure, temperature, compressibility ratio, and the energy content of the gas. Therms are computed to a standard base pressure of 14.73 PSIA and a standard temperature of 60 degrees Fahrenheit. Equipment and methods used for billing factor calculations may vary.

The billing factor calculation is: Therms = Metered Volume (hundreds of cubic feet, ccf)
x Pressure Factor (PF)
x Temperature Factor (TF)
x Compressibility Ratio (CR)
x BTU Multiplier

Metered Volume is measured at the Customer Premises. The meter index volume readings are typically in hundreds of cubic feet (ccf). An index multiplier of one (1) is used for most Residential and Commercial Customers. Larger volume Customers may have index multipliers of 10, 100, or 1000.

Metered Volume = Index Volume x Index Multiplier

The Pressure Factor times compressibility ratio (PF x CR) for Residential and small Commercial Customer billings is approximately 1.0091 when metering pressure is 6.5 inches water column, and approximately 1.1293 for 2.0 psig metering pressure. The pressure factor will be calculated on a Customer-specific basis for metering pressures above 2.0 psig. Some meters may use a pressure-compensating device for automatic calculation of the pressure factor at the meter site.

$$\text{Pressure Factor (PF)} = \frac{\text{Metering Pressure (PSIG)} + \text{Atmospheric Pressure (PSIA)}}{14.73\ \text{PSIA}}$$

Atmospheric Pressure (PSIA) is calculated in accordance with American Gas Association (AGA) recommendations (AGA 3, as revised from time to time), and is determined from plat map average elevation and an average determined from the daily barometric pressure during the billing period.

$$\text{Atmospheric Pressure (PSIA)} = 14.73 \times \text{Barometric Factor} \times \text{Elevation Factor}$$

$$\text{Barometric Factor} = \frac{\text{PDX Barometer Reading (inHg)} + 0.025}{29.99}$$

$$\text{Elevation Factor} = 0.9871 \times \frac{(55457 - \text{Elevation})}{(54735 + \text{Elevation})}$$

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GENERAL RULES AND REGULATIONS
(continued)

Rule 24. Determination of Thermal Units (continued).

Temperature Factor (TF) is an average determined from representative samples of metering temperatures for the billing period. Temperature information for most accounts will be obtained from daily temperature data for the weather stations specified in this **Rule 24,** as published daily by third party sources. The temperature factor might alternatively be applied through on-site temperature compensating devices or other temperature recording equipment.

$$\text{Temperature Factor} = \frac{520}{(\text{Metering Temperature }^\circ\text{F} + 460)}$$

Temperature data will be based on the daily temperatures reported for the weather stations listed in the table below. Each weather station corresponds to one of eight weather zone assignments within the Company's Oregon service territory. Each account is assigned a weather zone based upon where the Customer's premise is located on a geographical plat map. In most cases, the weather zone assigned to a plat will correspond with its assigned service district. NW Natural uses data received from County Assessors Offices in the process of establishing weather zone assignments.

Weather Station	NWN Weather Zone
Astoria (350328)	Astoria
Coos Bay (356073)	Coos Bay
Newport (356032)	Lincoln City
Corvallis (351862)	Albany
Hood River Exp Station (354003)	The Dalles
Portland (356751)	Portland
Eugene (352709)	Eugene
Salem (357500)	Salem

If at any time the daily temperature data is not available for any of the listed weather stations, the Company will use data from a substitute station within the respective weather zone, and will adjust the data for the high and low temperature differential between the two stations. In the event that temperature data for any weather station is continually unavailable or unreliable, the Company will select a replacement weather station within the respective weather zone. When a replacement weather station is established, the normal weather heating degree days for the replacement station will be adjusted so that the data used for the replacement weather station remains aligned with the data used to determine normal weather in the Company's last general rate case.

(continue to Sheet RR-24.2)

GENERAL RULES AND REGULATIONS
(continued)

Rule 24. Determination of Thermal Units (continued).

Compressibility Ratio (CR) is calculated in accordance with AGA recommendations. The CR is dependent on pressure, temperature and gas composition. At very high metering pressures, the value becomes significant (about 1.100 at 500 PSIG). For larger volume Customers, the CR may be applied through on-site equipment. At low metering pressures, it has a value close to about 1.000, and an approximation is used.

Compressibility Ratio (CR) = 1 + Metering Pressure / 6000

The Btu Multiplier, Btu per standard cubic foot (Btu/scf), is Gross Heating Value measured at 60 degrees at 14.73 PSIA and without water vapor, in accordance with AGA methods. The energy content of gas shall be measured at the Company's Receipt and storage points. The Btu multiplier for a billing period is based on the appropriate gas source during the billing period.

(continue to Sheet RR-25)

GENERAL RULES AND REGULATIONS
(continued)

Rule 25. General Company Liability.

THE COMPANY, ITS SHAREHOLDERS, DIRECTORS, OFFICERS, AND EMPLOYEES, SHALL NOT BE LIABLE FOR ANY PUNITIVE, SPECIAL, EXEMPLARY, INDIRECT, INCIDENTAL, CONSEQUENTIAL, LOST PROFITS, OR OTHER SIMILAR DAMAGES TO PERSONS OR PROPERTY, WHETHER SUCH DAMAGES ARE CLAIMED UNDER ANY LEGAL OR EQUITABLE THEORY, INCLUDING BUT NOT LIMITED TO LOSS, DAMAGE, OR EXPENSE TO PERSONS OR PROPERTY, DIRECTLY OR INDIRECTLY, ARISING OUT OF THE ACTIONS OF THE COMPANY THAT ARE IN ACCORDANCE WITH THE SERVICES, TERMS, AND CONDITIONS COVERED IN THIS TARIFF, UNLESS SUCH DAMAGES ARE A RESULT OF COMPANY'S WILLFUL MISCONDUCT. IN ADDITION, THE COMPANY SHALL NOT BE LIABLE FOR DAMAGES TO PERSONS OR PROPERTY RESULTING FROM A CURTAILMENT OF SERVICE IN ACCORDANCE WITH A PLAN APPROVED BY THE COMMISSION.

SCHEDULE A
BILLING FOR CITY AND COUNTY EXACTIONS

APPLICABLE:
To all Customers served by the Company under the Tariff of which this Schedule is a part.

PURPOSE:
To specify the method for billing of business or occupation taxes, license, franchise or operating permit fees, or similar exactions, hereinafter referred to in the entirety as "Exactions", imposed upon the Company by any city or county for engaging in business therein or for use and occupancy of streets and public ways.

CITY EXACTIONS:
The aggregate of the Exactions imposed on the Company, up to 3% of the Company's gross revenues, will be applied to rates in accordance with OAR 860-022-040 (1), except that the actual amount of Exactions applicable to Customers taking service under Special Contracts set forth in **Schedule 60** will be added to the total of all charges due.

When the aggregate of the Exactions imposed on the Company by any city exceeds 3%, the excess shall be billed pro rata to Customers served within that city, and the excess amount will be separately stated on the Customer's regular billings. This shall not apply to franchises existing as of November 6, 1967.

Any other Exactions unilaterally imposed or increased by any city during the unexpired term of an existing franchise that contains a provision for compensation, shall be billed pro rata to Customers served within that city in the manner stated above.

COUNTY EXACTIONS:
The full amount of all new or increased taxes, license, franchise or operating permit fees imposed on the Company by any county, other than a city/county, shall be billed pro rata to Customers served within that county. If the taxes or fees cover the Company's operations in only a portion of the county, the amount shall be billed pro rata to Customers served within that portion of the county. The amount associated with these taxes or fees shall be separately stated on Customer's regular billings.

Multnomah County Business Income Tax (MCBIT):

Applicable: All customers that receive Natural Gas service within Multnomah County

Rate: 0.13% of the total rate schedule revenue billed amount.

A MCBIT Balancing Account will be maintained to accrue any difference between the Company's actual MCBIT expense and the amount collected from Customers. The Balancing Account will accrue interest at the rate approved by the Commission.

The rate will be reviewed annually and updated as necessary based on the following calculation:

Forecast MCBIT expense / Forecast Multnomah County Gas Revenues

SCHEDULE B
BILLS AND BILL PAYMENT OPTIONS

AVAILABLE:
In all territory served by the Company under the Tariff of which this Schedule is a part.

DESCRIPTION:
This Schedule describes the various billing and bill payment options available to the Company's Customers. Customers may use any one of the automated options in conjunction with an Equal Pay Plan. Once elected, the billing and payment option(s) will remain in effect until terminated by Customer, or until terminated by the Company should Customer fail to comply with its terms.

STANDARD BILLING AND BILL PAYMENT:
Unless a paperless billing option is elected, Customers will receive a printed bill via U.S. Mail. Bills may be paid by any one of the following methods: Online bill payment, electronic check payment, credit card, debit card, check, money order, or in cash. Payments made by means other than cash shall be considered valid only when honored by the financial institution.

PAPERLESS BILLING:
Paperless billing is an online bill presentment option available to most Customers directly through NW Natural. Under this billing option, a monthly bill notification e-mail is sent to the Customer fifteen (15) days prior to the stated due date. The bill notification e-mail includes the amount due, the due date, and a link back to a secure area in the Company's website where, upon valid sign-in, the Customer can view their bill statement. No paper bill will be issued. Customers that select this billing option may choose to pay their bill through any of the available bill payment options, including online checking account payments or signing up for Auto Pay. Customers can enroll in the bill presentment option via the Company's website. To enroll, Customers must register at the company's web site using a valid gas account number, and e-mail address.

Paperless billing is available to most Customers from the Company's website. Customers on Interruptible Service or Transportation Service schedules or special contracts are not eligible to use this option.

AUTO PAY PLAN:
The Auto Pay Plan is an electronic bill payment option available to Residential and small Commercial Customers. Auto Pay allows for automatic bill payments to be made to the Company directly from Customer's checking or savings account or from a valid bank card (credit card or debit card). To participate, Customers must provide valid account information to Company. Customers that sign up over the telephone will be required to provide the account or card number, and if from a checking account, a voided blank check or deposit slip from the account that payments are to be deducted. Customers that sign up through the Company's website will be required to provide an electronic signature. Payments will be automatically deducted from Customer's bank account or bank card and credited to Customer's gas service account on the payment due date stated on Customer's regular monthly gas bill. In the event that sufficient monies are not available in Customer's bank account or credit card on the payment due date, the Company will make one additional attempt to obtain payment. If the second attempt is not successful, the Company will issue a letter to the Customer

(continue to Sheet B-2)

SCHEDULE B
BILLS AND BILL PAYMENT OPTIONS
(continued)

AUTO PAY PLAN (continued):
advising them of the payment failure, and requiring that payment be made in cash, or by a cashier's check or money order. In the event that a payment failure occurs because the account is reported closed, the Company will not make any additional attempts to obtain payment. When any payment failure occurs, an NSF charge will be assessed to Customer's account at that time, and the account will be considered delinquent. Failure to pay such account will be cause for Disconnection of Service. Two (2) payment failures in a twelve-month period will be cause for the Company to automatically terminate Customer's Auto Pay Plan.

CREDIT OR DEBIT CARD PAYMENT:
Customers can make bill payments with a credit card or debit card at any time. The Company may limit the number of transactions that can be made in any given time period. Payment by credit or debit card can be done online on the Company's website, through the Company's Interactive Voice Recognition (IVR) system, or through the Company's Auto Pay Plan. When any payment failure occurs, an NSF charge will be assessed to Customer's account at that time, and the account will be considered delinquent. Failure to pay such account will be cause for Disconnection of Service. Two (2) payment failures in a twelve-month period will be cause for the Company to automatically terminate Customer's Auto Pay Plan.

ONLINE CHECKING ACCOUNT PAYMENTS:
Customers can make a secure online checking account payment each month at the Company's web site. To use this payment option, Customers must provide NW Natural valid checking account information for the account from which payments are to be deducted. When making an online checking account payment, payments will be automatically deducted from Customer's bank account and credited to Customer's gas service account on the date specified by the Customer, or the following business day if the date specified is a weekend or Holiday. In the event that the payment is returned to NW Natural by the Customer's bank, the Company will issue a letter to the Customer advising them of the payment failure, and requiring that payment be made in cash, or by a cashier's check or money order. When any payment failure occurs, an NSF charge will be assessed to Customer's account at that time, and the account will be considered delinquent. Failure to pay will be cause for Disconnection of Service.

RESIDENTIAL EQUAL PAY PLAN:
Residential Customers whose gas service accounts are current may sign up for the Equal Pay Plan at any time during the calendar year.

The Residential Equal Pay Plan is a bill payment option designed to levelize Customer's monthly payments for gas service over an eleven-month period. Levelized monthly payments are based on (a) the rates stated in Customer's respective Rate Schedule and (b) an estimate of Customer's projected annual usage requirements, determined from prior usage history at the service address, or from a calculated usage adjusted for Customer's current requirements.

(continue to Sheet B-3)

SCHEDULE B
BILLS AND BILL PAYMENT OPTIONS
(continued)

RESIDENTIAL EQUAL PAY PLAN (continued):
The monthly payment will equal one-eleventh of Customer's estimated annual obligation, and will be payable each month for the succeeding eleven (11) months. Billings in the 12th month will reflect over or under payments. Overpayments of more than $75.00 shall be refunded. Unless Customer requests otherwise, lesser amounts will be credited to Customer's account and reflected in the level payments for the following Plan year. Underpayments will be due in full on or before the 12th month's billing due date.

The Company will re-estimate the amount of Customer's level payments each succeeding Year that Customer remains on the Plan. During the Plan Year, monthly payments will be periodically reviewed and may be adjusted to reflect rate changes, to more accurately reflect usage, or to reflect a change in service address.

Level payments under the Equal Pay Plan shall not be construed as a guarantee or assurance that the annual cost of gas service will not exceed the estimate upon which they are based.

Customers that become delinquent will be notified in writing that they may be removed from the Plan if the Plan is not brought current. A Customer with a delinquent collect balance on the Plan's account receivable will be subject to Disconnection of Service pursuant to **Rule 11**. A Disconnection of Service will not occur on Plans that have a credit balance on the Plan's accounts receivable.

A Customer that is unable to make regular payments under the Plan or is unable to pay the accounts receivable balance at the end of the Plan term may be eligible for a Time Payment Agreement as described in **Rule 9**. A Customer whose service is disconnected under **Rule 11** may establish a new Equal Pay Plan upon bringing the accounts receivable balance to zero.

NON-RESIDENTIAL EQUAL PAY PLAN:
Qualifying Non-Residential Customers may sign up for the Equal Pay Plan at any time during the calendar year. To qualify for the Equal Pay Plan, Non-Residential Customers must:

- (a) Take service under **Rate Schedule 1** or **Rate Schedule 3** of this Tariff;
- (b) Have a good credit status with the Company;
- (c) Be current on their gas service account;
- (d) Have had an active gas service account for at least twelve (12) consecutive months previous to the date the Customer requests to participate in the Equal Pay Plan; and
- (e) Take service at a premise for which the Company has at least twelve (12) consecutive months of gas usage history.

The Company, in its sole discretion, may refuse to allow a Customer whose annual gas usage exceeds 25,000 therms per year to participate in the Equal Pay Plan.

The Non-residential Equal Pay Plan is a bill payment option designed to levelize Customer's monthly payments for gas service. The Customer's monthly payment will be calculated as set forth below. Monthly payments will be levelized over the eleven-month period May through March, with the balance of the plan being adjusted to zero in the month of April.

(continue to Sheet B-4)

SCHEDULE B
BILLS AND BILL PAYMENT OPTIONS
(continued)

NON-RESIDENTIAL EQUAL PAY PLAN (continued):
The levelized monthly payment for a Customer whose Equal Pay Plan is effective in any month other than the month of May will be based on the number of months between the sign up month and the month of April. Thereafter, the monthly payments will be levelized over the eleven-month period May through March.

Billings in the month of April will reflect over or under payments. Overpayments of more than $75.00 shall be refunded. Unless Customer requests otherwise, lesser amounts will be credited to Customer's account and reflected in the level payments for the following Plan year. Underpayments will be due in full on or before the April billing due date.

Levelized monthly payments are determined from (a) the rates stated in Customer's respective rate schedule and (b) an estimate of Customer's projected annual usage requirements, based upon prior usage history at the service address.

The Company will re-estimate the amount of Customer's level payments each succeeding year that Customer remains on the Plan. During the Plan year, monthly payment requirements will be periodically reviewed and may be adjusted to reflect rate changes, to more accurately reflect usage, or to reflect a change in service address.

Level payments under the Equal Pay Plan shall not be construed as a guarantee or assurance that the annual cost of gas service will not exceed the estimate upon which they are based.

Customers may terminate their Equal Pay Plan at any time. The Company may terminate a Customer's Equal Pay Plan at any time the Company determines that the Customer no longer meets all of the conditions of qualification. Upon termination of an Equal Pay Plan, the entire balance on the account will be due and payable. If a Customer's Equal Pay Plan is terminated for any reason, that Customer may not be allowed to sign up for the Equal Pay Plan again until the following May.

A Customer with a delinquent collect balance on the Plan's account receivable will be subject to Disconnection of Service pursuant to **Rule 11**. A Disconnection of Service will not occur on Plans that have a credit balance on the Plan's accounts receivable. A Customer that is unable to make regular payments under the Plan or is unable to pay the accounts receivable balance at the end of the Plan term may be eligible for a Time Payment Agreement as described in **Rule 9A**.

GENERAL TERMS:
Service under 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.

SCHEDULE C
MISCELLANEOUS CHARGES AND CREDITS

APPLICABLE:
To all Customers served by the Company under the Tariff of which this Schedule is a part.

PURPOSE:
To describe and summarize the charges and credits that may apply to Customers in addition to the rates established in the Rate Schedule or Service Agreement under which Customer receives service. See the DESCRIPTION OF CHARGES provision of this Schedule for specific terms and conditions.

SUMMARY OF CHARGES and CREDITS:

Late Payment Charge	1.7% of unpaid balance per payment period, but no less than $3.00
Charge for Payment Not Honored (per incident)	$ 15.00
Service Reconnection Charges	
Scheduled 8:00 a.m. – 5:00 p.m. Mon.-Fri. (except Holidays)	$ 40.00
Scheduled after 5:00 p.m., Mon.-Fri.	$ 80.00
Same Day after 5:00 p.m. Mon-Fri, or on Saturday or on a Holiday	$185.00
Service Reconnection Charges – Curtailment Order	
8:00 a.m. - 5:00 p.m. Mon.-Fri. (except Holidays)	$ 150.00
After 5:00 p.m. Mon.-Fri. and on weekends or Holidays	$ 600.00
Inaccessible Meter Charge – Installation of Shut-off Valve	$ 250.00
Field Visit Charge	$ 20.00
Meter Interference	Actual costs of damages, repairs and any additional or unusual costs or services directly related to the meter interference, plus the amount of unbilled gas determined to have been lost, plus applicable Service Reconnection Charges.
Unauthorized Use – failure to comply with Curtailment Order	$ 10.00 per therm
CSR Assisted Automated Payment Charge	$ 2.50 per check
Summary Billing Charge	
One-time time set up fee, per account	$ 5.00
Per account billed per month	$ 1.00

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(continue to Sheet C-1.1)

SCHEDULE C
MISCELLANEOUS CHARGES AND CREDITS
(continued)

SUMMARY OF CHARGES and CREDITS (continued):

Priority Installation Schedule (Schedule X)	$ 200.00
Service Guarantee credit on Company Provided Utility Pathway for New Construction (Schedule X)	$100.00
Wasted Trip charge on Applicant Provided Utility Pathway for New Construction (Schedule X)	
Main Trench (all classes)	$290.00 each additional trip
Service Trench (Commercial)	$290.00 each additional trip
Service Trench (Residential)	$155.00 each additional trip

(continue to Sheet C-2)

SCHEDULE C
MISCELLANEOUS CHARGES AND CREDITS
(continued)

DESCRIPTION OF CHARGES and CREDITS:

Late Payment Charge. Customer accounts not paid in full each month are subject to a late payment charge. For Residential Customers, the late payment charge will be applied to overdue account balances at the time of preparing the subsequent month's bill. For Non-Residential Customers, the late payment charge will be assessed the day after the due date stated on the bill. The late payment charge will not apply to accounts if the balance is less than $50.00, or to Equal Pay Plan or Time Payment Plan accounts that are current.

Charge For Payment Not Honored. A charge will be applied each time a Customer makes a payment on account that is not honored, for any reason, by a bank or other financial institution.

Service Reconnection Charges. A charge will be assessed to restore service to a Customer following a Disconnection of Service under **Rule 11**, or any other applicable Rule or Schedule of this Tariff, or where service is disconnected for more than one Billing Month and Customer subsequently requests service be restored at the same address within twelve (12) Billing Months of the date of Disconnection of Service, ("Temporary Disconnection").

Customers that are reconnected following a Temporary Disconnection are also subject to additional charges as set forth in the terms and conditions of the applicable Rate Schedule.

Before service will be restored, all amounts then due and payable, including the service reconnection charge, and any Customer Charges associated with a Temporary Disconnection must be paid to Company at the Company's offices prior to 6:00 p.m. Monday through Friday, or, upon prior arrangement between Company and Customer, shall be paid to the Company's representative at the time of visit. The service reconnection options are as follows:

Customer Contact with Company	Service Reconnection Options *	Charge
Monday-Thursday 7:00 a.m. to 6:00 p.m.	By 5:00 p.m. of the next day After 5:00 p.m. the next day Same Day after 5:00 p.m.	$40 $80 $185
Monday-Thursday after 6:00 p.m.	Applicant must call on the next Business Day	
Friday before 3:00 p.m.	By 5:00 p.m. of the next day (Saturday) After 5:00 p.m. the next day (Saturday) Same Day after 5:00 p.m.	$40 $185 $185
Friday 3:00 p.m. to 6:00 p.m.	By 5:00 p.m. of the next Business Day (Monday) After 5:00 p.m. of the next Business Day (Monday) Friday after 6:00 p.m. Saturday	$40 $80 $185 $185
Friday after 6:00 p.m.	Applicant must call on next Business Day	

* The time frame for all service reconnection options is subject to change for any cause not reasonably within the Company's control. If the next day is a state-recognized holiday, then reconnection is scheduled for the next Business Day, or Customer can pay the Reconnection Charge applicable to same day and Saturday and Holiday reconnections..

(continue to Sheet C-3)

SCHEDULE C
MISCELLANEOUS CHARGES AND CREDITS
(continued)

DESCRIPTION OF CHARGES and CREDITS (continued):

Service Reconnection Charges – Curtailment Order. A charge will be assessed to restore service to an Interruptible Customer where the Customer is requesting that service be restored following disconnection due to Customer's failure to comply with a Curtailment Order. Before service will be restored, all amounts then due and payable, including the service reconnection charge, must be paid to Company at the Company's offices prior to 6:00 p.m., or, upon prior arrangement between Company and Customer, shall be paid to the Company's representative at the time of visit.

Inaccessible Meter Charge – Installation of Shut-off Valve. A charge will be assessed when the Company must install a shut-off valve at the curb because the Company cannot gain access to the meter to complete a Disconnection of Service under **Rule 11**. Before service will be restored, all amounts then due and payable, including this installation charge and the service reconnection charge, must be paid to the Company at the Company's offices prior to 6:00 p.m., or, upon prior arrangement between the Company and Customer, shall be paid to the Company's representative at the time of visit.

Field Visit Charges. A charge will be assessed to Customer when the Company goes to the Premise to (a) disconnect service for non-payment and service is left active; or (b) to restore service after a disconnection and the Company representative is unable to restore service due to Customer actions or inactions.

Charge For Meter Interference. When the Company discovers that there has been interference with the meter or its connections at the Customer's service address, Customer will be required to pay the cost of any repairs, replacement, or prevention devices required to be installed by the Company as a result of the interference, plus the amount of any unbilled gas determined to have been lost as a result of such interference. For this purpose, unbilled gas will be calculated as the difference between the usage shown on the meter register at the time interference was discovered and the amount of gas the Company estimates the Customer would have used based on previous usage history at the Premise for the time period in question. Unbilled gas will be billed at the rates specified in the Rate Schedule under which Customer took service at the time of the incident.

Charge For Unauthorized Use. A charge will be assessed on any gas taken by a Customer in excess of that allowed under a Curtailment Order. The Charge shall be in addition to all applicable Rate Schedule charges on the gas volumes taken.

CSR Assisted Automated Payment Charge. A charge will be assessed for each Customer Service Representative (CSR) assisted check processed by the Company. The payment of this charge does not relieve Customer of any charges resulting from the check being not honored, or from any other charges that may apply. A Customer may self-initiate an automated check over the telephone through the Company's Interactive Voice Recognition (IVR) system or online at the Company's website at no charge.

(continue to Sheet C-4)

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SCHEDULE C
MISCELLANEOUS CHARGES AND CREDITS
(continued)

DESCRIPTION OF CHARGES and CREDITS (continued):

Summary Billing Charge. This option is not available to Transportation Service Customers or Interruptible Service Customers. The Company will provide Customers, upon request, with a summary billing for two or more accounts. A one-time set up charge, and a monthly service charge will apply.

Charge for a Priority Installation Schedule (Schedule X).
The Priority Installation Schedule charge will apply to Residential and Commercial Applicants that request expedited service under **Schedule X.** An expedited request for service means that the installation of Distribution Facilities will be completed within five (5) working days from the date that the application for service is approved by the Company.

The priority installation option is available between September 1 and January 31, except that the Company may refuse to accommodate a priority installation if doing so would adversely affect the quality or timing of installations of other Applicants or Customers. The Priority Installation Schedule charge must be paid prior to the installation of Distribution Facilities. The charge will be refunded if the Company fails to meet the priority installation date.

Service Guarantee Credit for Company Provided Utility Pathway for New Construction (Schedule X). The Service Guarantee Credit will apply when the Company agrees to provide the utility pathway for a project and the Company does not meet the scheduled construction date.

Wasted Trip Charge on Applicant Provided Utility Pathway for New Construction (Schedule X).
The wasted trip charge will apply when the Company goes to the site of a new construction project following notice by Applicant that the site is ready, and the site is not ready when the Company arrives, thereby requiring the Company to schedule a return trip.

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.

SCHEDULE M
METER TESTING PROCEDURES

The Company shall test new meters and meters that are removed from service and intended for reuse in the manner set forth in this Schedule, as more completely described in the Company's Meter Testing Standards and Procedures.

Meter test equipment and methods used by the Company shall conform to the applicable standards of the American National Standards Institute (ANSI) and American Gas Association (AGA).

The minimum acceptable accuracy for all new and rebuilt meters is 100% ± 1% at specified flow rates. New meter shipments may be sample-tested in accordance with the applicable standards of ANSI and the American Society for Quality Control, and the entire batch accepted or rejected on the basis of the sample test results.

The Company's performance control program allows diaphragm meters with a rated capacity of up to and including 1,000 cf per hour to remain in service outside of the periodic testing requirements of OAR 860-23-015, provided that the meters satisfy the program's performance requirements.

Each meter in the performance control program is initially assigned to a meter family according to manufacturer, size, type, and set year. At Company's option, meters in any family may be further subdivided according to location, age, or other factors which may be disclosed by test data to have an effect on the performance of the meters. Subsequently, meter families may be modified or combined as justified by the performance records.

Each meter family in the meter sampling program is subject to an annual statistical performance evaluation using a random sample of the family. A meter family is considered to be acceptable if the family sample indicates (a) a minimum proportion of .80 of the family measures between 98.0% and 102.0% accurate (an "accuracy" requirement), and (b) a minimum proportion of .90 of the family measures no more than 102.0% accurate (a "not fast" requirement). Based on the annual performance evaluation, each meter family determined to be acceptable is allowed to remain in service, subject to sample testing and review in succeeding years.

Meters in families determined to require change-out are changed by December 31st of the Year following determination of the need for change-out (*i.e.*, by December of the second year following the year of sampling). However, if in any given Year, the number of meters required for change-out exceeds five (5) percent of the total number of meters in the Meter Sampling Program, the Company may, at its option, extend the change-out schedule so that the meter family is changed within a maximum of four (4) years from determination that change-out is required (*i.e.*, by December of the fourth year following the year of sampling).

SCHEDULE O
ON-THE-BILL REPAYMENT SERVICES – PILOT PROGRAM

AVAILABLE:
To Clean Energy Works Oregon or its assigned representative, either or both of which are referred to hereafter as "CEWO."

DESCRIPTION:
On-the-Bill Repayment services provided to CEWO is offered in compliance with Commission Order No. 11-075 issued in Docket UM 1519. This order extended the pilot programs offered in accordance with the Energy Efficiency And Sustainable Technology ("EEAST") legislation codified as ORS 470.500 through ORS 470.715.

Under this pilot, NW Natural Customers with gas heated homes as qualified by CEWO or its assigned representative, will be given access to financing to be used for energy efficient improvement to the customer's residence. The Company's role in this program is solely to provide billing services for the CEWO authorized loans granted to NW Natural Customers. The Company's bill for natural gas service will display the loan payment amount determined by CEWO to be collected from the NW Natural Customer. The Company will then remit to CEWO amounts paid toward loan balances less any uncollectibles.

SPECIAL PROVISIONS:

1. CEWO will reimburse the Company for all costs related to system upgrades, including billing system changes, required for the implementation or ongoing delivery of services under this pilot program. The Company will directly bill CEWO for ongoing administrative costs, including costs associated with loan setup, loan termination and other incremental activities related to accounting and processing of bill payments. The Company will not seek to pass any associated costs on to Customers at this time.

2. All services exchanged between CEWO and the Company shall be in accordance with the operating agreement that has been signed and executed on September 30, 2011, by CEWO and NW Natural. This agreement is by reference part of this Tariff Schedule.

3. The provision of On-the-Bill Repayment Services to CEWO will not affect the Company's compliance with all Division 21, Utility Regulation, Oregon Administrative Rules (OARs).

4. A Customer's decision to enter into a loan agreement with CEWO will not affect his/her ability to establish credit with the Company; it will have no impact on the amount that a Customer may be required to pay on deposit for Natural Gas utility service; and it will have no effect on a Customer's ability to receive reliable natural gas service. The Company will communicate this in writing to Customers who participate in CEWO's loan program.

(continue to Sheet O-2)

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SCHEDULE O
ON-THE-BILL REPAYMENT SERVICES – PILOT PROGRAM
(continued)

SPECIAL PROVISIONS (continued):

4. By entering into a loan agreement with CEWO, the Customer will be responsible to remit such amount to NW Natural with his/her monthly bill payment. NW Natural is not a party to CEWO's loan agreements and has no financial interest in the loans or CEWO.

5. Monthly payments received from Customers participating in this program will be allocated to the Customers' account in accordance with **Rule 7** of this Tariff.

6. The Company will not disconnect gas service to a Customer for non-payment of a CEWO loan amount. The provisions of **Rule 11** shall apply for non-payment of amounts related to gas utility service.

7. NW Natural is nothing more than the billing agent for the bank. Participating Customers must acknowledge that the Company shall be held harmless for any liability resulting from contractors actions with regard to installation of energy efficiency upgrades resulting from this pilot project.

8. NW Natural is not responsible for any financial assurances given or guarantees as to the net financial benefit of the dollars spent on energy efficiency upgrades versus the dollars saved on energy consumption that are given to participants of this pilot project by contractors or other parties to this pilot.

9. Recovery of loaned dollars is the sole responsibility of CEWO.

10. CEWO is responsible to tell the Company how much to bill per month for each loan and how many months each customer should be billed. The Company is not responsible for any misinformation provided by CEWO.

11. The Company will not a) accept loan pay-offs, b) issue refunds on loan payments, c) offer payment arrangements on loan amounts due, or d) allow energy assistance to be applied to loan balances.

12. CEWO is responsible to obtain a signed consent form from participating Customer's that states that the Customer agrees to allow the Company to provide CEWO with Customer specific bill payment information.

13. CEWO must obtain signed documentation from the Customer that certifies that the Customer has been made aware of the Company's limited role in the loan repayment process.

14. CEWO must provide the Company with a toll-free customer service phone number to which the Company will refer Customers who have questions or concerns about their loan. The Company is not responsible for Customer questions and disputes related to the CEWO loan or the Customer's perceived or real experience with CEWO.

(continue to Sheet O-3)

SCHEDULE O
ON-THE-BILL REPAYMENT SERVICES – PILOT PROGRAM
(continued)

SPECIAL PROVISIONS (continued):

15. CEWO must provide evidence to the Company's satisfaction of its compliance with the Federal Trade Commission FACTA Red Flag Identity Theft Prevention Program (16 C.F. R. § 681).

16. Approval of this Schedule shall constitute verification that the Commission also grants the Company a waiver from applicable Customer Service or Billing Service Quality Measures (SQMs) regarding issues that may arise specifically attributed to this Portland Pilot Project.

GENERAL TERMS:
Service under 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.

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS

APPLICABILITY:
This schedule applies to all schedules for natural gas Sales Service within the entire territory served by the Company in the State of Oregon. The definitions and provisions described herein shall establish the natural gas costs for Purchased Gas Adjustment (PGA) deferral purposes on a monthly basis.

PURPOSE:
The purpose of this schedule is to allow the Company, on established Adjustment Dates, to adjust rate schedules for changes in the cost of gas purchased in accordance with the rate adjustment provisions described herein.

This Schedule is an "automatic adjustment clause" as defined in ORS 757.210, and is subject to the customer notification requirements as described in OAR 860-022-0017.

DEFINITIONS:
1. Actual Commodity Cost: The natural gas supply costs for commodity actually paid for the month, including Financial Transactions, fuel use, and distribution system lost and unaccounted for natural gas (LUFG) plus Gas Storage Facilities withdrawals, plus or minus the cost of natural gas associated with pipeline imbalances, plus propane costs, plus odorization charges, if applicable, less Net Commodity Off-System Sales Revenues for the month, plus actual Variable Transportation Costs, plus commodity-related reservation charges, plus the costs of Gas Reserves,[1] less all transportation demand charges embedded in commodity costs.
2. Net Commodity Off-System Sales Revenues: Revenues from the sale of natural gas to a party other than the Company's Oregon Sales Service Customers less costs associated with the sales transactions.
3. Variable Transportation Costs: Variable transportation costs, including Pipeline volumetric charges, and other variable costs related to volumes of commodity delivered to Sales Service Customers.
4. Actual Non-Commodity Cost: Actual Non-Commodity gas costs shall be equal to actual Demand Costs, less actual Capacity Release Benefits, plus or minus actual Pipeline refunds or surcharges.
5. Demand Costs: Fixed monthly Pipeline costs and other demand-related natural gas costs such as capacity reservation charges, plus any transportation demand charges embedded in commodity costs.
6. Capacity Release Benefits: This component includes revenues associated with pipeline capacity releases. The benefits to Customers, through the monthly PGA deferrals, shall be 100% of the capacity release revenues up to the full Pipeline rate, and 80% of the capacity release revenues exceeding amounts reflecting full Pipeline rates. Capacity release revenues shall be quantified on a transaction-by-transaction basis.

(continue to Sheet P-2)

[1] Per the terms of the Stipulation in Docket UM 1520/UG 204.

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

7. Estimated Annual Sales Weighted Average Cost of Gas (Annual Sales WACOG):
The estimated Annual Sales WACOG is the default Commodity Component for billing purposes, and is used for purposes of calculating the monthly gas cost deferral costs for entry into the Account 191 sub-accounts calculated by the following formula: (Forecasted Purchases at Adjusted Contract Prices) divided by forecasted sales volumes.
   a. "Forecasted Purchases" means November 1 – October 31 forecasted sales volumes, "weather-normalized", plus a percentage for distribution system LUFG.
   b. "Distribution system embedded LUFG" means the 5-year average of actual distribution system LUFG, not to exceed 2%.
   c. "Adjusted contract prices" means actual and projected contract prices that are adjusted by each associated Canadian pipeline's published (closest to August 1) fuel use and line loss amount provided for by tariff, and by each associated U.S. pipeline's tariffed rate.

   Effective November 1, 2011:
   Estimated Annual Sales WACOG per therm (w/ revenue sensitive): **$0.48994**
   Estimated Annual Sales WACOG per therm (w/o revenue sensitive): **$0.47596**

8. Estimated Winter Sales WACOG: The Company's weighted average Commodity Cost of Gas for the five-month period November through March.
   Effective November 1, 2011:
   Estimated Winter Sales WACOG per therm (w/ revenue sensitive): **$0.48977**
   Estimated Winter Sales WACOG per therm (w/o revenue sensitive): **$0.47580**

9. Estimated Interim WACOG: The Company's weighted average Commodity Cost of Gas without the costs of Gas Reserves.
   Effective November 1, 2012:
   Estimated Interim WACOG per therm (w/revenue sensitive): **$0.48764**
   Estimated Interim WACOG per therm (w/o revenue sensitive): **$0.47373**

10. Estimated Non-Commodity Cost: Estimated annual Non-Commodity gas costs shall be equal to estimated annual Demand Costs, less estimated annual Capacity Release Benefits, plus or minus estimated annual pipeline refunds or surcharges

11. Estimated Non-Commodity Cost per Therm – Firm Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Firm Sales Service divided by November 1 – October 31 forecasted Firm Sales Service volumes.
   Effective November 1, 2010:
   Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive): **$0.13472**
   Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive: **$0.13088**

(continue to Sheet P-3)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

12. Estimated Non-Commodity Cost per Therm – Interruptible Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Interruptible Sales Service divided by November 1 – October 31 forecasted Interruptible Sales Service volumes.
    Effective November 1, 2011:
    Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive): **$0.01602**
    Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive): **$0.01556**

13. Estimated Non-Commodity Cost per Therm – MDDV Based Sales: The portion of the Estimated annual Non-Commodity Cost applicable to MDDV Based Sales Service.
    Effective November 1, 2011:
    Estimated Non-Commodity Cost per therm - MDDV Based Sales (w/revenue sensitive): **$2.01**
    Estimated Non-Commodity Cost per therm- MDDV Based Sales (w/o revenue sensitive): **$1.95**

14. Actual Monthly Firm Sales Service Volumes: The total actual monthly billed Firm Sales Service therms, excluding MDDV based volumes, adjusted for estimated unbilled Firm Sales Service therms.

15. Actual Monthly Interruptible Sales Service Volumes: The total actual monthly billed Interruptible Sales Service therms, adjusted for estimated unbilled Interruptible Sales Service therms.

16. Actual Monthly MDDV Based Firm Sales Service Volumes: The total actual monthly billed Firm Sales Service Volumes for Rate Schedule 31 and Rate Schedule 32 customers billed under the Firm Pipeline Capacity Charge - Peak Demand option, adjusted for estimated unbilled MDDV Firm Sales Service Volumes.

17. Embedded Commodity Cost: The Estimated Annual Sales WACOG, updated for October 31 storage inventory prices, multiplied by the Total of the Actual Monthly Firm and Interruptible Sales Service Volumes.

18. Embedded Non-Commodity Cost per Therm – Firm Sales Service: The Estimated Non-Commodity Cost per Therm - Firm Sales Service multiplied by the Actual Monthly Firm Sales Service Volumes.

19. Embedded Non-Commodity Cost per Therm – Interruptible Sales Service: The Estimated Non-Commodity Cost per Therm – Interruptible Sales Service multiplied by the Actual Monthly Interruptible Sales Service Volumes.

(continue to Sheet P-4)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

20. Embedded Non-Commodity Cost – MDDV Based Sales Service: The Estimated Non-Commodity Cost per Therm – MDDV Based Firm Sales Service multiplied by the Actual Monthly MDDV Sales Service Volumes.

21. Financial Transactions: Cost of Financial Transactions related to gas supply, including but not limited to, hedges, swaps, puts, calls, options and collars that are exercised to provide price stability/control or supply reliability for sales service customers.

22. Gas Storage Facilities: The cost of natural gas for injections shall be the actual cost of purchasing gas for storage and the cost of injection of the gas into the storage facility. Withdrawals of natural gas shall be valued at the weighted average cost of gas in the facility plus any variable withdrawal costs. For purposes of annual rate filings, the cost of inventory in storage shall be an overall average cost including existing inventory volumes and costs and refill inventory volumes and costs. Refill volumes will be priced at the expected pricing used in each filing. Only the cost of natural gas withdrawn from Gas Storage Facilities will be included in the Actual Commodity Cost, as defined herein.

23. Seasonalized Fixed Charges: The projected monthly non-Commodity costs of gas recovery, calculated by multiplying the Embedded Non-Commodity Costs by Oregon forecasted sales.

24. Gas Reserves: The volumes of natural gas actually received by the Company through its acquisition of gas reserves through joint venture agreements as authorized by the Commission.[1] For purposes of annual rate filings, the cost of Gas Reserves includes all carrying costs on the rate base investment, amortization, operating expenses, gathering and processing costs, and ad Valorem and severance taxes. The cost of Gas Reserves will be included in Actual Commodity Costs.

CALCULATION OF MONTHLY GAS COSTS FOR DEFERRAL PURPOSES:
The Company shall maintain sub-accounts of Account 191. Monthly entries into these sub-accounts shall be made to reflect: 1) the difference between the monthly Actual Commodity Cost and the monthly Embedded Commodity Cost, 2) the difference between Actual Non-Commodity Cost and the monthly portion of Estimated Non-Commodity Cost and, 3) the difference between Embedded Non-Commodity Cost and monthly Seasonalized Fixed Charges. The entries shall be calculated each month as follows:

1. A debit or credit entry shall be made equal to 100% of the difference between the monthly Actual Non-Commodity Cost and the Monthly Embedded Non-Commodity Cost, net of revenue sensitive effects.

(continue to Sheet P-5)

[1] See Commission order 11-140 in UM 1520/UG 204.

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

CALCULATION OF MONTHLY GAS COSTS FOR DEFERRAL PURPOSES (continued):

2. A debit or credit entry shall be made equal to 100% of any monthly difference between Embedded Non-Commodity Costs and Monthly Seasonalized Fixed Charges. The monthly Seasonalized Fixed Charges for the period November 1, 2011 through November 30, 2012 are:

November 2010	$9,197,282
December 2010	$9,408,909
January 2011	$13,091,551
February	$12,686,039
March	$10,589,655
April	$9,097,670
May	$6,636,600
June	$4,315,225
July	$2,844,289
August	$2,576,878
September	$2,571,836
October	$2,703,508
November	$5,510,293
ANNUAL TOTAL	$82,032,453

3. A debit or credit entry shall be made equal to 90% of the difference between the Actual Commodity Cost and the Embedded Commodity Cost. A debit or credit entry will also be made equal to 100% of the difference between storage withdrawals priced at the actual book inventory rate as of October 31 prior to the PGA year and storage withdrawals priced at the inventory rate used in the PGA filing. For any given tracker year, if the total activity subject to debit or credit entries that is related to the Gas Reserves transaction exceeds $10 million, amounts beyond $10 million will be recorded at 100%.

4. Monthly differentials shall be deemed to be positive if actual costs exceed embedded costs and to be negative if actual costs fall below embedded costs.

5. The cost differential entries shall be debited to the sub-accounts of Account 191 if positive, and credited to the sub-accounts of Account 191 if negative.

6. Interest – Beginning November 1, 2007, the Company shall compute interest on existing deferred balances on a monthly basis using the interest rate(s) approved by the Commission.

(continue to Sheet P-6)

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SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

AMORTIZATION OF PGA ACCOUNT DEFERRALS:
The balances in the sub-accounts of Account 191 shall be amortized over the twelve (12) month period commencing with the November 1 adjustment date or such other time period acceptable to the Company and the Commission. The amount of amortization for the PGA Accounts shall consist of an amount necessary to recover or return the amount accumulated in the sub-accounts and other deferral accounts.

ADJUSTMENT DATES:
The Adjustment Date shall be November 1 of each year for changes in annual gas costs. The Company may file out-of-cycle PGA adjustments to be effective at times other than November 1 of each year, if the sum of the Company's annual Actual Commodity Cost and Actual Non-Commodity Costs differs from the sum of the annual Embedded Commodity Cost and Embedded Non-Commodity Costs, by ten percent (10%) or more, or for such other reasons and on such terms as the Commission may approve.

TIME AND MANNER OF FILING:
Applications will be made to the Commission not less than sixty (60) days in advance of the requested effective date, or upon such other date as the Commission may authorize.

AMOUNT OF ADJUSTMENT:
The amount of adjustment to be made to customers' rates effective on each November 1 adjustment date shall consist of the sum of the changes in the Embedded Commodity Cost and Non-Commodity Cost and the change in amortization rates of the PGA Accounts, as well as other deferral accounts as the Commission may approve.

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 Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE S
SERVICE SOLUTIONS DEALER APPOINTMENT SERVICE PROGRAM

AVAILABLE:
To Residential Customers in all territory served by the Company under the Tariff of which this Schedule is a part.

DESCRIPTION:
The Company will notify Customers that inquire about this service that the Company will perform inspection and adjustment of Customer-owned appliances and facilities for safe and efficient operation as a part of the Company's normally scheduled services. The Service Solutions program enables the Company to provide Customer assistance beyond the inspection and adjustment service described in **Rule 19** by referring a Qualified Dealer, as defined in this **Schedule S**. upon request to set up a service call. Service Solutions is available to Customers twenty-four hours (24) per day, seven (7) days per week.

The service offered under this Schedule is not tied to normal gas utility service and applies to the repair, replacement, and/or tune-up of equipment, including but not limited to all heating equipment, gas line and appliances. All program costs and revenues will be accounted for as a non-utility activity.

Customer Responsibility. For the purposes of this **Schedule S**, Customer is any person that receives service under this Schedule. The Customer must indicate an interest in participating in the program, through a Company initiated contact, by being transferred from a Company Customer Service Representative or by directly calling the Service Solutions contact telephone number to request the service. The Customer is under no obligation to enlist the services of the Qualified Dealer. However, should the Customer retain the Qualified Dealer to perform the necessary service, Customer shall be responsible to pay such Qualified Dealer directly for their services.

Company Responsibility. Upon Customer request, the Company shall contact a Qualified Dealer to arrange for the dealer to directly contact the Customer regarding the requested service. The Company will select the Qualified Dealer to be contacted, unless Customer requests a specific Qualified Dealer. The Company will use a rotation system to ensure that Customer referrals are fairly distributed among Qualified Dealers.

Dealer Responsibility. The Qualified Dealer shall be responsible to contact the referred Customer within one hour of receipt of the Company's referral to schedule the service call. The Qualified Dealer will schedule the service call within one week of the date of the referral, or at such other time as is agreed to between the Qualified Dealer and the Customer. If the Customer determines their situation needs urgent attention and the equipment repairs are on a furnaces or water heating equipment, the

(continue to Sheet S-2)

SCHEDULE S
SERVICE SOLUTIONS DEALER APPOINTMENT SERVICE PROGRAM
(continued)

DESCRIPTION (continued):
Qualified Dealer will schedule the service call within twenty-four (24) hours of the time of the referral. Where a Customer requests an after-hours appointment (before 8:00 a.m. or after 5:00 p.m. Monday through Friday, or on a holiday or a weekend) the Dealer may charge the Customer a premium trip charge and/or bill the Customer for service performed at the Dealer's overtime hourly rate.

CUSTOMER NOTIFICATION:
The Company will publish information about this program on its website and, from time to time, in Customer newsletters and/or bill messages. The Company will also have available a printed brochure that describes the details of the program available to hand out to Customers.

The Company will maintain a current list of participating Qualified Dealers on the Company's website. Customers are not obligated to use the Company's service to schedule a service call appointment, but may directly contact any Qualified Dealer on the list. However, Customers that choose to directly contact a Qualified Dealer may not receive the same service call price or service response turnaround that they would receive if they used this service through the Company.

QUALIFIED DEALER:
The Company will have discretion as to the number of dealers that will be allowed to participate as a Qualified Dealer under this program at any given time. The Company will have discretion to disqualify or refuse participation to any dealer that does not meet the Company's established criteria for a Qualified Dealer. In order to qualify as a Qualified Dealer under this program, the dealer must:

(a) Be a licensed contractor in business in their specialty in Oregon or Washington for a minimum of five (5) years;

(b) Provide proof of an active Construction Contractors Board (CCB) license and bond as required by the state, with no unresolved Customer complaints;

(c) Operate in a commercially zoned storefront with branded signage where office/sales staff are available throughout normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday (applies to HVAC dealers only);

(continue to Sheet S-3)

SCHEDULE S
SERVICE SOLUTIONS DEALER APPOINTMENT SERVICE PROGRAM
(continued)

QUALIFIED DEALER (continued):

(d) Have a minimum percentage, as defined in the annual service agreement, of service technicians and equipment installers certified under North American Technical Excellence (NATE) – applies to HVAC dealers only;
(e) Have a minimum percentage, as defined in the annual service agreement, of their technicians certified by National Fireplace Institute – applies to Hearth product dealers only;
(f) Have a local telephone exchange (or a toll-free telephone number) with 24-hour service manned by a live receptionist or answering service that is able to contact a dealer representative who can call a Customer within one hour any time of the day or night. HVAC and Water Heaters dealers only;
(g) Have working business systems, i.e. fax, computer, website and e-mail, to communicate with the Company and its Customers;
(h) Have a dedicated service department;
(i) Have branded vehicles driven by their service technicians on all Customer jobs;
(j) Agree to comply with the terms and conditions of this **Schedule S,** and;
(k) Agree to comply with all other terms and conditions set forth in the Certified Dealer Agreement entered into between the Company and the dealer.

In order to retain status as a Qualified Dealer under this **Schedule S**, the dealer must:

(a) Meet all of the qualifying criteria stated above and in the annual service agreement on an ongoing basis;
(b) Maintain good Customer satisfaction ratings based on a Company initiated survey of participating Customers, and have no Customer issues that remain unresolved for longer than one month; and
(c) Attend training as required in the annual service agreement.

DEALER REFERRAL FEE:
Each year all participating Qualified Dealers agree to pay an annual participation fee, billed quarterly. The amount charged is determined by equitably dividing the cost of the Program by the historic opportunities for receiving service referrals throughout the service territory.

GENERAL TERMS:
Service under 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.

SCHEDULE T
CUSTOMER-OWNED
NATURAL GAS TRANSPORTATION SERVICE

SERVICE AVAILABILITY:
Service under this Schedule is available on the Company's Distribution System to Non-Residential Customers in all territory served by the Company under the Tariff of which this Schedule is a part, provided that Customer has an approved Service Election for Transportation Service under one of the following Rate Schedules:

Rate Schedule 31	Rate Schedule 33
Rate Schedule 32	Rate Schedule 60

TERM OF SERVICE:
The minimum term for the Transportation of Customer-Owned Gas supplies is as set forth in the applicable Rate Schedule under which the Customer shall pay for Transportation Service. Upon termination of Transportation Service, any Imbalances in gas receipts and deliveries will be cleared in accordance with the Imbalance buy-out provisions of this Schedule.

PREREQUISITES TO SERVICE:

1. A Customer must have an approved Service Election Form for service under the Rate Schedule under which Customer shall pay for Transportation Service.

2. A Customer must have the capability to receive notices via automatic electronic means acceptable by the Company. Customer must provide any utility, telephone, cellular, or other services or devices that the Company deems necessary to support Automated Meter Metering (AMR) technology for the transmission of metered data to the Company for billing purposes. All installations must comply with the Company's specifications, must be in place and activated not less than five (5) Business Days prior to the effective date of service, and must remain continuously active at all times. The Company may require the installation of telemetry equipment at the Customer's Premise, subject to charges set forth in **Schedule 15**.

3. Customer must have secured the purchase and delivery of gas supplies, which may include supplies secured from an Authorized Supplier/Agent) of their choosing. Customer must complete the Company's Transportation Service: Supplier/Agent Authorization Form and name such Authorized Supplier/Agent not less than five (5) Business Days prior to the effective date of service.

4. The Company must receive the completed Transportation Service: Supplier/Agent Authorization Form before the Company will accept any nominations on behalf of the Customer.

(continue to Sheet T-2)

SCHEDULE T
CUSTOMER-OWNED
NATURAL GAS TRANSPORTATION SERVICE
(continued)

SERVICE DESCRIPTION:
Service under this Schedule applies to the Transportation of Customer-Owned Gas supplies under applicable Rate Schedules or Special Contracts. Service under this Schedule does not include the use of Company's gas supplies, and does not apply to gas produced or stored within Company's service territory and/or transported by an intrastate pipeline or gathering system connected to Company's system. Customer-Owned Gas supplies must meet the gas quality specifications set forth in **Rule 24** of this Tariff.

The delivery sequence that will apply to combinations of Firm and Interruptible Sales and Transportation Service through a single Delivery Point is specified in the applicable Rate Schedule.

The Transportation of Customer-Owned Gas is governed by the terms of this **Schedule T**, the applicable Rate Schedule, the Company's Nomination, Balancing and other operating procedures, as modified from time to time, the Customer's Service Type as approved by the Company, 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. Any modifications to these documents will made available to Customers as soon as practicable as they occur.

The Receipt Point for Customer-Owned Gas supplies shall be designated by the Company. If reasonably feasible, Company will accommodate a Customer's request to use a Receipt Point other than that designated by the Company. Transportation Customers shall hold the Company harmless from any damage caused by failure of Customer-Owned gas supplies to arrive at the Company's Receipt Point.

Customer-Owned Gas transported under this **Schedule T** is subject to Entitlement, Curtailment and Pre-emption.

(continue to Sheet T-3)

SCHEDULE T
CUSTOMER-OWNED
NATURAL GAS TRANSPORTATION SERVICE
(continued)

SUPPLY NOMINATIONS AND DELIVERIES:
Customer must submit the Company's Transportation Service: Supplier/Agent Authorization Form, naming the Authorized Supplier/Agent(s) that will have authority to Nominate Natural Gas supplies on Company's distribution system for delivery on Customer's behalf.

Nominations of Customer-Owned Gas will be made in accordance with the Company's Nominations procedures. Confirmed Nominations, as received by the Company from the Pipeline, determines the volume of gas to be credited to Customer's account.

Company shall have the right to adjust a Customer's daily Nominations when, in Company's judgment, such action is necessary to bring into balance its system Nominations as a receiving party on the Pipeline system, or otherwise to maintain operational control or maintain the integrity of the Company's Distribution System.

Customer shall be deemed to be in control and possession of gas purchased by Customer until it has been accepted by the Company at the Receipt Point. Company shall be deemed to be in control or possession of gas purchased by Customer until the equivalent therms are delivered to Customer at the Delivery Point.

The Company accepts gas purchased by Customer at the Receipt Point subject to Customer's warranty that at the time of the Company's receipt, Customer has good title to all gas received, free and clear from all liens, encumbrances and claims. Customer shall indemnify and hold Company harmless should a third party make any claims regarding Customer's title to gas transported under this Schedule.

When combinations of Sales and Transportation Services through a single Delivery Point are applicable, the following delivery sequence will apply during the Gas Day.

(1) Firm Sales gas up to Customer's Firm Sales MDDV will be first through the meter, then;
(2) Firm Transportation gas up to Customer's Firm Transportation MDDV, or Confirmed Nomination level, whichever is less, then;
(3) Interruptible Sales gas up to Customer's Interruptible Sales MDDV, then;
(4) Interruptible Transportation gas up to Customer's Interruptible Transportation MDDV, or Confirmed Nomination level, whichever is less.

(continue to Sheet T-4)

SCHEDULE T
CUSTOMER-OWNED
NATURAL GAS TRANSPORTATION SERVICE
(continued)

BALANCING OF RECEIPTS AND DELIVERIES:
Balancing of receipts and deliveries shall be accomplished on a daily basis to the extent possible. Cumulative Imbalances in receipts and deliveries will be carried over to the next Billing Month. If a Customer's cumulative Imbalance in any Billing Month is more than five percent (5%) above or below total Confirmed Nominations for that Billing Month, such Customer will be notified by the fifteenth (15^{th}) day of the following Billing Month that the Imbalance exceeds the allowed tolerance, and such Customer will receive a minimum of forty-five (45) non-restricted days (“Balancing Period”), which may or may not be consecutive, from the date of notification by the Company to eliminate the Imbalance. A non-restricted day is any day where there is no Entitlement, Curtailment, or Pre-emption Order in effect.

If a Customer's cumulative Imbalance comes within the five percent (5%) tolerance, or if the balance is less than ten (10) therms, or the Imbalance has moved from negative to positive, or from positive to negative at the end of a Billing Month within a Balancing Period, that Balancing Period will end.

If by the end of the Balancing Period an Imbalance is not eliminated in a manner described above, Customer will be required to choose one of two options to clear the Imbalance:

Option 1. Pay a Balancing charge of $1.00 per Therm on all Imbalance Therms and the Imbalance volumes will carry to the next Balancing Period. The Imbalance charge will be billed on the Customer’s next monthly bill and will be due and payable in addition to Customer's normal charges.

Option 2. Buy out the Imbalance. If the Imbalance is negative, Customer may buy out the entire negative Imbalance volume by paying the Company a price per Therm that is the greater of: (a) the highest Monthly Incremental Cost of Gas calculated in accordance with **Schedule 150** over the previous three (3) month period, or (b) 150% of the Company’s current Annual Sales WACOG. If the Imbalance is positive, the Company will pay the Customer on all positive Imbalance volumes a price per Therm that is the lesser of: (a) the lowest Monthly Incremental Cost of Gas calculated in accordance with **Schedule 150** over the previous three (3) month period, or (b) 50% of the Company’s current Annual Sales WACOG. Following a buyout, Customer's cumulative Imbalance will be eliminated and that Balancing Period will end.

Customer must notify the Company in writing of its intent to exercise Option 2 not later than the fifteenth (15^{th}) day of the Billing Month in which imbalance charges would be assessed. If a Customer exercises Option 2 in the month following the end of a Balancing Period, such Customer's cumulative Imbalance will be eliminated, but such Customer will be responsible for the payment of any Balancing charge assessed for the prior period.

Balancing gas is not available when Entitlement, Curtailment or Pre-emption has been ordered, except, during an Entitlement, to the extent of the Threshold Percentage tolerance levels.

Imbalances incurred as a direct result of a meter error or malfunction shall be resolved on a case-by-case basis between the Company and the Customer. In such an event, Customer shall notify the Company prior to purchasing Imbalance volumes from third party suppliers. The Company shall not be responsible to Customer for any costs incurred should Customer fail to make such appropriate notification.

(continue to Sheet T-5)

SCHEDULE T
CUSTOMER-OWNED
NATURAL GAS TRANSPORTATION SERVICE
(continued)

CURTAILMENT AND ENTITLEMENT:
Any restrictions of service to Customer when Curtailment or Entitlement conditions exist will be made in accordance with the Rules of this Tariff, and in accordance with currently effective Company policies and procedures, as circumstances dictate. Entitlement, Curtailment and Pre-emption of service may exist concurrently during any one episode. However, not more than one Entitlement, Curtailment, or Pre-emption condition will exist at any one time.

Restrictions of service under Curtailment conditions will be made in accordance with **Rule 13** and **Rule 14**. Curtailment of Customer-Owned Gas due to Force Majeure conditions or due to capacity limitation on the Company's system shall not be considered a Pre-emption of Customer-Owned Gas. Gas taken by a Customer due to a failure to comply with a Curtailment order will be considered unauthorized, and subject to charges set forth in **Schedule C**.

Restrictions of service under Entitlement conditions will be made as follows:

Overrun Entitlement. In an Overrun Entitlement condition the following threshold percentage levels will be effective:

Stage 1: Three percent (3%) of Confirmed Nominations; or
if ordered within two (2) hours of the start of the Gas Day;
five percent (5%) of Confirmed Nominations

Stage 2: Eight percent (8%) of Confirmed Nominations

Stage 3: Thirteen percent (13%) of Confirmed Nominations

The Company will specify the applicable threshold percentage in its Entitlement notice.

The following overrun charges will apply during any Overrun Entitlement episode:

- $0.50 per Therm for any overrun that is greater than the threshold percentage but less than the threshold percentage plus two percent (2%) of a Customer's Confirmed Nomination on that day;

- $1.00 per Therm for any overrun that is equal to or greater than the threshold percentage plus two percent (2%) of a Customer's Confirmed Nominations for that day.

(continue to Sheet T-6)

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

SCHEDULE T
CUSTOMER-OWNED
NATURAL GAS TRANSPORTATION SERVICE
(continued)

CURTAILMENT AND ENTITLEMENT (continued):

Underrun Entitlement. During an Underrun Entitlement condition, a Customer that is in an underrun situation will be notified and given seventy-two (72) hours to clear the system of the underrun Imbalance to avoid underrun charges. Customer will be subject to underrun charges for each instance of underrun Imbalance that occurs during any Underrun Entitlement period. The following charges will apply during any Underrun Entitlement episode:

- $0.50 per Therm for any underrun between five percent (5%) and ten percent (10%) of a Customer's Entitlement on that day;
- $1.00 per Therm for any underrun in excess of ten percent (10%) of a Customer's Entitlement on that day, and;
- An additional $1.00 per Therm for any underrun Imbalances not taken within the seventy-two (72) hour period.

PRE-EMPTION:
Customer-Owned Gas may be Pre-empted in the event that the Company's Firm gas supply and Company's peaking facilities are insufficient at any time to meet the requirements of Firm Sales Service Customers.

The Company will use reasonable efforts to obtain voluntary Pre-emption of gas by negotiation with individual Customers. If the Company cannot obtain sufficient volumes of Gas from volunteers, then the Company shall select and pay individual Customers for involuntary Pre-emption of gas at a rate of $10.00 per Therm. The selection of individual Customers for involuntary Pre-emption will be based on system needs and Company's ability to maintain operational control or system integrity. The Company will use its best efforts to avoid Pre-empting an individual Customers gas on a repeated basis.

A Customer who fails to comply with a Pre-emption Order shall pay $10.00 per Therm for any gas taken, and the Company shall not be obligated to pay such Customer for Pre-emption gas.

The priorities of service for Pre-emption purposes due to limited gas supply are, as follows:

(1) Firm Service (pre-empted last).
(2) Interruptible Service (pre-empted first).

A Customer's priority of service within each of the above categories shall be based on economic considerations and/or other contract considerations.

GENERAL TERMS:
Service under 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.

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SCHEDULE X
DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS

AVAILABLE:
In all territory served by the Company under the Tariff of which this Schedule is a part.

APPLICABLE:
The terms and provisions of this Schedule apply to the installation of Distribution Facilities required to provide utility service to a bona fide Applicant, or to a builder or developer ("Builder/Developer") of real property where gas-fired equipment is committed to be installed and used in a residential dwelling(s), commercial building(s), or industrial plant(s) that is located or to be constructed on such property. Except where specifically stated otherwise, the use of the term Applicant shall be construed to include a Builder/Developer. This Schedule does not apply to Company initiated system improvements or expansions of its Distribution System.

GENERAL CONDITIONS OF SERVICE:
The installation of Distribution Facilities under this Schedule will be completed as soon as reasonably possible following the receipt and approval of a service application. Requests for service to Non-Residential Applicants and to any new construction planned development will require sufficient advance notice to allow for design, permits, and any other special requirements necessary to provide the requested utility service.

The Company may accept requests for service received through an equipment installer or other third party on behalf of an Applicant provided that the Applicant information is included with the service request. Any Construction Contribution paid to the Company by an equipment installer or other third party on behalf of an Applicant will be considered paid by Applicant, and any subsequent refunds of such Construction Contribution shall go to the Applicant.

Prior to the installation of any Distribution Facilities, the Company may require that an Applicant sign a Service Agreement as described in the "SERVICE AGREEMENT" provision of this Schedule.

A request for utility service on a temporary basis is subject to the terms and conditions set forth in **Rule 22.**

During the period September 1 through January 31, Residential and Commercial Applicants may request a priority installation schedule, subject to the priority installation schedule charge set forth in **Schedule C**. When the Company agrees to a priority installation schedule, the Company will expedite the service installation date for completion within five (5) working days from the date that the application of service is approved by the Company. The Company may deny a request for a priority installation if the quality or timing of the installation of other Applicants or Customers would be adversely affected.

(continue to Sheet X-2)

SCHEDULE X
DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

GENERAL CONDITIONS OF SERVICE (continued):
All Applicants must meet the credit criteria set forth in **Rule 2** before construction and activation of any Distribution Facilities, and Applicant must agree to take and pay for service in accordance with all applicable Schedules, General Rules and Regulations of this Tariff, and in accordance with the provisions and conditions of the Rate Schedule under which service will be provided by the Company.

Each Applicant is responsible for the installation and maintenance of all gas-fired appliances and House Line. All installations must conform with applicable laws, codes, and ordinances of all governmental authorities having jurisdiction. See **Rule 18** for additional information. Each Builder/Developer must also comply with the terms and conditions set forth in the “REQUIREMENTS FOR NEW CONSTRUCTION AND PLANNED DEVELOPMENTS” provision of this Schedule.

An Applicant must install and use the equipment associated with the Construction Allowance afforded to the Applicant within ninety (90) days from the date that the meter is installed at the site, or by such other date specifically agreed to by the Company. Failure to comply with this provision shall be cause for the Company to demand payment from the initial Applicant in the amount of the actual construction costs, less any Construction Contribution paid. If the actual equipment installed warrants a different Construction Allowance then the Construction Contribution will be recalculated. Any overpayment of $75 or less will be credited to the Customer’s gas utility account. A refund check will be issued for any overpayment in excess of $75. If the recalculation results in a shortfall, the amount of the shortfall shall be immediately due and payable to the Company. Failure to pay such amount is cause for Disconnection of Service or for refusal of service under **Rule 1** and **Rule 11** of this Tariff.

LOCATION OF FACILITIES:
The Company reserves the right to designate the location of all Distribution Facilities required to serve an Applicant. In this designation, the Company will consider the distance along the shortest most practical, available and acceptable route that is clear of obstructions from the Main to the meter location.

All installations shall be made in accordance with **Rule 20** of this Tariff, and with the Company’s Standard Practices and Procedures.

(continue to Sheet X-3)

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SCHEDULE X
DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

CONSTRUCTION COSTS:
Construction costs include all costs associated with the extension of the Company's Distribution Facilities. All costs applicable to this Schedule will be reviewed annually and updated as needed.

Construction costs for Service Line installations are based upon the Company's historical system average costs, except the Company may use a site-specific cost estimate if extraordinary construction conditions exist at the site. For purposes of this provision, extraordinary construction conditions include, but are not necessarily limited to:

a) Extreme rocky conditions along the main or Service Line route.
b) The connection must be made from a high pressure main.
c) The Service Line is more than 700 feet in length.
d) The installation requires a railroad, bridge, or other non-standard crossing permit.

In all cases, Main Extension costs will be based upon a site-specific cost estimate.

Where there is more than one Applicant for an installation that includes a Main Extension, the costs will be distributed equally among each of the Applicants, or in such other manner determined by the Applicants.

REQUIREMENTS FOR NEW CONSTRUCTION AND PLANNED DEVELOPMENT INSTALLATIONS:
This provision is applicable to any new construction installation or planned development project where the installation of Class B (less than or equal to 60 psig) Main is required, and where there are no existing buildings, roads, or other hard surfaces along the construction route.

For purposes of this provision, planned developments include but are not limited to, residential single-family subdivisions, residential multi-family developments, mixed-use developments, commercial and industrial parks, and any other similar project.

Except as otherwise provided in this provision, the Applicant must provide a utility pathway for all Main and Service Line installations within the permitted area. The pathway must be a Company-approved trench constructed in accordance with all applicable Company procedures, standards, and practices.

The Company will provide:
(a) Any necessary Main installations in existing public rights-of-way and outside of the permitted project area;
(b) Conduit for crossings; and
(c) If there are no other proposed utility crossings, tie-in installation for gas-only road crossings in existing public rights-of-way outside of the permitted area.

(continue to Sheet X-4)

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SCHEDULE X
DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

REQUIREMENTS FOR NEW CONSTRUCTION AND PLANNED DEVELOPMENT INSTALLATIONS (continued):

The following installation schedule guidelines will apply:

	MAIN*	SERVICE(S)
Applicant Notification to Company	No less than 7 Business Days prior to start of pathway excavation	No less than 3 Business Days prior to date pathway will be ready
Company Installs Pipe	No more than 7 Business Days after confirmation that pathway is ready	No more than 4 Business Days after notice of date that pathway will be ready
Estimated time from Notice to Installation	No less than 14 Business Days from Notice to Company	No more than 7 Business Days from notice to Company

* Within the permitted area

Exceptions may be accommodated where extenuating circumstances arise. In such event, the Company and the Applicant will develop a mutually acceptable modified installation schedule.

An Applicant must promptly notify the Company of any known delays in the scheduled installation date. If the Company does not receive notice of a construction delay prior to dispatching a crew to the site, the wasted trip fee specified in **Schedule C** will apply.

In the event the Company fails to meet a scheduled installation date through no fault of the Applicant, the Applicant is not obligated to hold the utility pathway open, and the Company will be responsible for all costs associated with re-opening the utility pathway or constructing a new utility pathway (whichever shall apply).

The Company will construct the utility pathway for an Applicant, at the Applicant's expense, under the following circumstances:

1. When the Company determines that an Applicant-provided pathway is not required.
2. When, prior to commencement of construction, the Applicant requests that the Company provide the pathway. All costs associated with construction of the pathway must be received by the Company prior to commencement of construction.
3. When, after commencement of construction, for whatever reason, the Applicant is unable to provide the pathway and Applicant requests that the Company perform the work.

The Company will charge an Applicant to construct the utility pathway under conditions 2 and 3 above. The costs associated with the Company's construction of the utility pathway under this provision are incremental and separate from any other construction costs applicable to the installation, and must be paid in full to the Company prior to construction.

(continue to Sheet X-5)

SCHEDULE X
DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

REQUIREMENTS FOR NEW CONSTRUCTION AND PLANNED DEVELOPMENT INSTALLATIONS (continued):
The installation schedule for a Company provided utility pathway will be determined between the Company and the Applicant. If the Company fails to meet the agreed installation schedule, the Company will pay to the Applicant the service guarantee credit specified in **Schedule C.**

CONSTRUCTION ALLOWANCE:
The Construction Allowance is based upon the Customer classification. The customer classifications are:

(1) Residential (Single-Family or Multi-Family Dwellings), and
(2) Non-Residential (Commercial and Industrial) and Planned Developments.

An Applicant is subject to the conditions set forth in the “GENERAL CONDITIONS OF SERVICE” provision of this Schedule if the Applicant fails to install the equipment associated with the Construction Allowance afforded to the Applicant under this Schedule.

The Construction Allowances for each Customer classification follow:

Residential
The Construction Allowance per residential dwelling is based upon the gas-fired appliances to be installed, as set forth in the table below:

Category	Description	Notes	Construction Allowance (per Premise)
A	Primary Natural Gas space heating (does not apply to centralized space heating that serves multiple units)	1	$2,900
B	Primary Natural Gas water heat (does not apply to centralized water heating that serves multiple units) Natural Gas heating fireplace Natural Gas wall heat	2	$2,100
C	Range, Cook top, Clothes dryer	3	$ 900
D	Gas barbecue, log lighter, gas log, tiki torch, Bunsen burner, pool, spa, or hot tub water heaters, non-primary space or water heat installed in a detached garage , shop, or outbuilding	4	$0

[1] Alone or in combination with any additional Category A-D gas-fired appliances.
[2] Alone or in combination with any additional Category B-D gas-fired appliances.
[3] Alone or in combination with any additional Category C-D gas-fired appliances.
[4] Alone or in combination with any additional Category D gas-fired appliances.

(continue to Sheet X-6)

SCHEDULE X
DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

CONSTRUCTION ALLOWANCE (continued):

The Construction Allowances shown above will apply to individually metered multi-family units. When a multi-family installation includes centralized gas-fired space or water heating equipment, or where the use of gas-fired equipment will be in place for laundry facilities, swimming pools, spas, or common building spaces, then the Non-Residential Construction Allowance will apply. In certain circumstances, both the Residential and Non-Residential Construction Allowances may apply to multi-a family Applicant.

Non-Residential and Planned Developments

The Company will perform an investment analysis for each installation to determine the amount of any Construction Allowance. At a minimum, the Construction Allowance will equal 5.0 times the annual margin revenue that is estimated to be generated from the operation of natural gas-fired equipment to be installed at the service address.

The Company will estimate therm usage associated with the operation of gas-fired equipment based on structure characteristics, the type and frequency of use of the gas-fired equipment, and the nameplate rating of the gas-fired equipment to be installed.

CONSTRUCTION CONTRIBUTION:

If the Construction Allowance applicable to an Applicant is less than the construction cost, then a Construction Contribution will be required.

The Company will not schedule any installation until the required Construction Contribution is paid. Each Construction Contribution payment will be adjusted for the applicable tax amount then in effect. The tax amount may change from time to time without prior notice.

Where a site-specific cost estimate was used to determine an Applicant's Construction Contribution, actual construction costs for such installation will be reviewed by the Company as soon as all costs have been accounted for. If actual construction costs are less than the site-specific cost estimate, then a refund of the cost difference will be issued to the Applicant. Any such refund is subject to the terms and conditions set forth in **Rule 11** and **Rule 16**.

(continue to Sheet X-7)

SCHEDULE X
DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

SERVICE AGREEMENTS:
A Service Agreement may be required, at the sole discretion of the Company, in the following circumstances:

1. Whenever a Main Extension is required.
2. For service to Planned Developments.
3. When the cost of construction is greater than $50,000.
4. When the Company's investment analysis requires a guarantee of margin revenue as a condition of the investment.

REFUNDS OF CONSTRUCTION CONTRIBUTIONS:
When the installation requires a Main Extension, any Construction Contribution paid may be subject to refund. A refund opportunity exists only when a new Service Line installation is added along the Main Extension within thirty-six (36) months from the date that the Main Extension was installed.

The Company will review Main Extension activity at the end of the thirty-six (36) month period to determine whether a refund of a Construction Contribution is due. The Company will perform a refund calculation prior to the end of the refund period upon specific request from the original contributor.

To determine the amount available for refund, the construction cost and the Construction Allowance will be updated. The construction cost will equal the actual construction cost of the original installation plus the cost of the subsequent connection. The Construction Allowance will equal the original Construction Allowance plus the Construction Allowance afforded the subsequent Applicant. If the resulting Construction Contribution is less than the Construction Contribution paid by the original contributor, then a refund equal to such difference will be issued to the original contributor. Example Calculation for a single original contributor:

Cost	Allowance	Contribution	Description
$ 6,900			Cost of original Main Extension with 1 Service Line
	$ 2,900		Less Original Construction Allowance
		$ 4,900	Original Construction Contribution Paid
$ 2,042			Add cost of new connection to Main Extension
$ 8,942			Updated cost of Main Extension and 2 Service Lines
	$ 5,800		Less Construction Allowance on 2 Service Lines
	$ 3,142		Revised Construction Allowance (updated cost less updated Construction Allowance)
		$ 1,758	Refund to Original Contributor (original contribution less updated Construction Allowance

In no event will a refund exceed the amount of the original Construction Contribution.

(continue to Sheet X-8)

SCHEDULE X
DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

REFUNDS OF CONSTRUCTION CONTRIBUTIONS (continued):

All refunds are calculated on the Construction Contribution amount before the income tax effects are applied.

Any Construction Contribution amounts not refunded by the end of the 36-month period will be retained by the Company.

SPECIAL CONDITIONS FOR INSTALLATIONS COMPLETED PRIOR TO NOVEMBER 1, 2012
For Service Line installations completed on or before November 1, 2012, the terms and conditions for refunds of Construction Contributions under Schedule X of P.U.C. Or. 24 shall continue to apply until the end of the 3rd Year following the Service Line installation date.

GENERAL TERMS:
Service under 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.

Issued by: NORTHWEST NATURAL GAS COMPANY
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220 N.W. Second Avenue
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FROZEN
RATE SCHEDULE 1
GENERAL SALES SERVICE

AVAILABLE:
To all Residential and Commercial Customer classes in all territory served by the Company under the Tariff of which this Rate Schedule is a part, and to which Distribution Facilities were committed or installed prior to November 1, 2012, except that Temporary Disconnection of Service is allowed subject to Special Provision 1 of this Rate Schedule.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment installed prior to November 1, 2012, including but not limited to one or any multiple or combination of the following:

(a) Non-ducted space heating equipment that does not qualify as primary heating systems under **Rate Schedule 2**, including but not limited to fireplace inserts, free standing gas stoves, and room heaters;
(b) Standby space heating equipment used in residential applications, including but not limited to Natural Gas back-up to electric heat pumps;
(c) Water heating equipment used to serve single-family residential swimming pools, spas, and hot tubs;
(d) Other equipment including, but not limited to, log lighter, gas log, gas barbecue, tiki torch, Bunsen burner, Domestic cooking equipment, hobby kilns, refrigeration or Domestic clothes drying;
(e) Equipment installed for use in detached garages, shops, or outbuildings.

Service under this Rate Schedule is not available for Standby Service to Commercial Customers.

MONTHLY RATE: Effective: February 1, 2012

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160**.

	Base Rate	Base Rate Adjustment	Pipeline Capacity	Commodity Component	Temporary Adjustment	Total Billing
RESIDENTIAL:						
Customer Charge:	$8.19					**$8.19**
Volumetric Charges:	$0.44857	$0.00000	$0.13472	$0.48994	$0.03965	**$1.11288**
COMMERCIAL:						
Customer Charge:	$13.62					**$13.62**
Volumetric Charges:	$0.39972	$0.00000	$0.13472	$0.48994	$(0.00302)	**$1.02136**

Minimum Monthly Bill: Customer Charge plus charges under **Schedule C** and **Schedule 15** (if applicable).

(continue to Sheet 1-2)

FROZEN
RATE SCHEDULE 1
GENERAL SALES SERVICE
(continued)

SPECIAL PROVISIONS:

1. A Customer that requests reconnection of service at the same address following a Temporary Disconnection of Service shall pay the minimum bill due under this Rate Schedule for each month of the Temporary Disconnection, in addition to the reconnection charge set forth in **Schedule C** and any past-due amounts owing to the Company, before service will be restored.

2. Service under this Rate Schedule will automatically terminate upon (a) voluntary closure of the account by a Customer, except where the closure is associated with a Temporary Disconnection of Service; (b) when the Company has determined that the equipment or Company's facilities are unsafe; or (c) when the Company determines that additional investment in Distribution Facilities are required in order to provide continued service.

3. In the event that the Company is requested or required to make additional investment in Distribution Facilities in order to provide service to a Customer served under this Rate Schedule, such investment shall be subject to the terms and conditions set forth in **Rule 20** and **Schedule X,** and at the Company's discretion, the Customer may be transferred to a different Rate Schedule as a condition of continued service.

4. The Customer Charge and Base Rate charges under this Rate Schedule shall be revised over the next two-year period as follows:

RESIDENTIAL:

Adjustment Date	New Customer Charge	New Base Rate Volumetric Charge (per therm)
November 1, 2013	$11.38	$0.24453
November 1, 2014	$11.65	$0.22726

COMMERCIAL:

Adjustment Date	New Customer Charge	New Base Rate Volumetric Charge (per therm)
November 1, 2013	$22.25	$0.23927
November 1, 2014	$24.70	$0.19372

The Base Rate charges above may be further adjusted for any additional Base Rate Adjustments then in effect.

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 Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

RATE SCHEDULE 2
RESIDENTIAL SALES SERVICE

AVAILABLE:
To Residential Customers in all territory served by the Company under the Tariff of which this Rate Schedule is a part. Temporary Disconnection of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, is subject to the provisions of **Schedule X**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment used in Residential dwellings that provide complete family living facilities in which the occupant normally cooks, eats, sleeps, and carries on the household operations incident to Domestic life.

MONTHLY RATE: Effective: February 1, 2012

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160.**

		Base Adjustment	Pipeline Capacity	Commodity	Temporary Adjustment	Total Billing
Customer Charge:	$13.70	---	---	---	---	**$13.70**
Volumetric Charge (per therm):	$0.38228	$0.00000	$0.13472	$0.48994	$0.03421	**$1.04115**

Minimum Monthly Bill: Customer Charge plus charges under **Schedule C** or **Schedule 15** (if applicable)

(continue to Sheet 2-2)

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RATE SCHEDULE 2
RESIDENTIAL SALES SERVICE
(continued)

SPECIAL PROVISIONS:

1. A Customer that requests reconnection of service at the same address following a Temporary Disconnection of Service shall pay the minimum bill due under this Rate Schedule for each month of the Temporary Disconnection, in addition to the reconnection charge set forth in **Schedule C** and any past-due amounts owing to the Company, before service will be restored.

2. Customers may be required to pay the Company, in advance, for costs related to the Company's installation of any Distribution Facilities necessary to provide service to Customers under this Schedule. This amount may be subject to refund under certain circumstances. See **Schedule X**.

3. The Customer Charge and Base Rate charges under this Rate Schedule shall be revised over the next two-year period as follows:

Adjustment Date	New Customer Charge	New Base Rate Volumetric Charge (per therm)
November 1, 2013	$21.39	$0.24024
November 1, 2014	$29.09	$0.09802

The Base Rate charges above may be further adjusted for any additional Base Rate Adjustments then effect.

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 Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

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RATE SCHEDULE 3
BASIC FIRM SALES SERVICE - NON-RESIDENTIAL

SERVICE AVAILABLITY:
Service under this Rate Schedule is available on the Company's Distribution System to Non-Residential Customers in all territory served by the Company under the Tariff of which this Rate Schedule is a part,-provided that the Company determines, in its sole judgment, that adequate supply and capacity exists to accommodate a Customer's service requirements.

Service under this Rate Schedule is not available to single-family Residential dwellings or separately metered apartments, condominiums or townhouses. Temporary Disconnection of Service is allowed subject to Special Provision 2 of this Rate Schedule.

Service under this Rate Schedule cannot be combined with service under any other Rate Schedule.

APPLICATION FOR SERVICE:
An application for service must be made in accordance with the provisions of **Rule 2** of this Tariff, including the requirements to establish or re-establish credit.

SELECTION OF RATE SCHEDULE AND TYPE OF SERVICE:
It is the responsibility of the Customer to select the Rate Schedule and Service Type that best meets the Customer's individual service requirements. A Customer's selection of service under this Rate Schedule is subject to the Company's approval as described in Special Provision 1 of this Rate Schedule, and in the Company's applicable policies and procedures.

PRE-REQUISITES TO SERVICE:

1. A Customer may be required to pay the Company, in advance, for costs related to the Company's installation of any new or additional Distribution Facilities necessary to provide service to Customer under this Schedule. See **Schedule X**;
2. When the installation of new or additional Distribution Facilities is necessary to provide service to Customer, the Company may require Customer enter into a written service agreement.
3. A New Customer must specify the Customer's selection for service under this Rate Schedule at the time the Customer initially applies for service with the Company.

GENERAL OBLIGATIONS APPLICABLE TO EACH SERVICE TYPE:
The Company will bill a Customer and the Customer must pay the Company the rates according to: the Customer's designated class of service as shown under the Monthly Rates section at the end of this Rate Schedule.

Customers that select Sales Service under this Rate Schedule will be billed on a monthly cycle basis as determined by the Company.

A Customer that requests AMR capability for Customer's own use is subject to the charges under **Rate Schedule 15** of this Tariff.

(continue to Sheet 3-2)

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RATE SCHEDULE 3
BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to approved gas-fired equipment. A Customer with gas equipment installed for Standby Service shall be subject to a minimum monthly bill obligation equal to the Standby Charge set forth in this Rate Schedule on all Therms of Maximum Hourly Delivery Volume (MHDV) of that equipment. A Customer subject to the Standby Charge will be required to specify the MHDV of such standby equipment on their Service Election Form.

RATE SCHEDULE TRANSFERS:
A transfer between Rate Schedules will be allowed upon one Billing Month advance written notice to the Company in accordance with **Rule 5** of this Tariff. Only one Rate Schedule transfer is allowed in any consecutive 12-month period. Any requests to also change the Service Type Selection with a Rate Schedule transfer must comply with the Provisions of “OUT-OF-CYCLE TRANSFERS FOR CERTAIN SERVICE TYPES as set forth in the requested Rate Schedule. Customer eligibility for a Rate Schedule transfer is as follows:

New Customer. To be considered a new Customer under this provision, the gas service account in the name of such Customer must have been activated at the service address within the most recent twelve (12) calendar months.
Existing Customer. To be considered an existing Customer under this provision, the gas service account in the name of such Customer must have been active and uninterrupted at the service address and served under this Rate Schedule for a minimum of 12 consecutive months prior to the requested effective date of the transfer.
Company Required Rate Schedule Transfer. A Customer that was reassigned by the Company to this Rate Schedule for reasons related to the installation of an AMR device will be allowed to transfer back to the Rate Schedule from which they were transferred if within three (3) Billing Months of the effective date of the transfer, Customer can show to the Company’s satisfaction that the Customer has met the requirements for qualifications of that Rate Schedule. Unless otherwise agreed between the Customer and the Company, if no such showing is made, the Customer must fulfill twelve (12) months of continuous service under this Rate Schedule to qualify to transfer as an existing Customer. See also Special Provision 3 of this Rate Schedule. A Company required transfer due to a Customer’s failure to comply with a Curtailment Order is subject to the provisions set forth in **Rule 13** of this Tariff.

SPECIAL PROVISIONS:
1. Company Approval of Service. The Company’s approval for service under this Rate Schedule will be based upon the Company’s determination, in its sole judgment, that: (a) adequate supply and capacity is available to accommodate service to the Customer, and (b) Customer has satisfactorily established or has satisfactorily re-established credit under the terms and conditions of **Rule 2** of this Tariff. For purposes of this Special Provision 1, any change in a Customer’s Rate Schedule or Service Type will be deemed a change in condition of service.

2. Temporary Disconnection of Service. A Customer that requests reconnection of service at the same address following a Temporary Disconnection of Service shall pay the minimum bill due under this Rate Schedule for each month of the Temporary Disconnection, in addition to the reconnection charge set forth in **Schedule C** and any past-due amounts owing to the Company, before service will be restored.

RATE SCHEDULE 3
BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

SPECIAL PROVISIONS (conintued):

3. Out-of-Cycle Transfer Requests from an Existing Customers. An Out-of-Cycle Transfer is a change in Rate Schedule that is effective prior to November 1 of the current PGA Year. Any request to transfer to this **Rate Schedule 3** from **Rate Schedule 31, Rate Schedule 32** or **Rate Schedule 33** or to transfer from this Rate Schedule to **Rate Schedule 31**, **Rate Schedule 32**, or **Rate Schedule 33**, must be made in writing on the Company's Service Election Form. The terms and conditions for submission of a Service Election Form and for a transfer to one of the other available Rate Schedules are as set forth in the respective Rate Schedule.

   A Customer that transfers to this Rate Schedule from Sales Service on another Rate Schedule will be billed at Annual Sales WACOG for the Commodity Component.

   A Customer that transfers to this Rate Schedule from Transportation Service will be billed according to the price set forth in **Schedule 150** "Monthly Incremental Cost of Gas" for the remainder of the current PGA Year. If prior to the date of the transfer such Customer had been on Transportation Service for the two prior PGA Years, then continued service under this Rate Schedule will be subject to Interim WACOG set forth in **Schedule P** commencing with the start of the PGA Year following the out-of-cycle transfer.

   The Interim WACOG shall apply to such Customer's Sales Service Type in any PGA Year when the price effect of Gas Reserves, as defined in **Schedule P**, causes Annual Sales WACOG to be lower than Interim WACOG. Upon fulfillment of two uninterrupted and consecutive PGA Years under this Rate Schedule, the Commodity Component will automatically revert to Annual Sales WACOG.

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 Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(continue to Sheet 3-4)

RATE SCHEDULE 3
BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

MONTHLY RATE: Effective: February 1, 2012

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160**.

FIRM SALES SERVICE CHARGES: (03CSF and 03ISF)						**Billing Rates [1]**
Customer Charge (per month):						**$15.00**
Volumetric Charges (per therm):		Base Adjustment	Pipeline Capacity	Commodity Component [2]	Temporary Adjustment	
Commercial	$0.37386	$ $0.00000	$0.13472	$0.48994	$(0.00659)	**$0.99193**
	$0.36279	$0.00000	$0.13472	$0.48994	$(0.00124)	**$0.98621**
Standby Charge (per therm of MHDV) [3]:						**$10.00**

[1] **Schedule C** and **Schedule 15** Charges shall apply, if applicable.
[2] The Commodity Component shown is the Annual Sales WACOG. The actual Commodity Component billed could be different for certain customers as described in the special provisions of this Rate Schedule

Minimum Monthly Bill. The Minimum Monthly Bill shall be the Customer Charge plus any **Schedule C** and **Schedule 15** Charges.

RATE SCHEDULE 15
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS AND METERING SERVICES

AVAILABLE:
In all territory served by the Company under the Tariff of which this Rate Schedule is a part.

TERM OF SERVICE:
The Term of Service for monthly meter rentals and metering services provided under this Schedule is twelve (12) consecutive billing months. At the end of a full Term of Service, service under this Rate Schedule will continue on a billing month basis until terminated by either the Customer or the Company upon one (1) billing month advance notice.

I. TELEMETRY EQUIPMENT CHARGE:

Telemetry is required and installed when the Company determines that a Customer's load consumption characteristics are such that monitoring is necessary to maintain stability in the distribution system.

Monthly Charge per affected service meter: $127.00

SPECIAL PROVISION FOR TELEMETRY:

1. Telemetry may be required prior to receiving gas service.
2. The decision to install telemetry equipment shall be made by the Company, at the Company's discretion, based on the load consumption characteristics of the Customer's operations.

II. MONTHLY METER RENTAL RATES AND SPECIAL METERING EQUPMENT (OPTIONAL):

Any Customer may rent supplementary displacement type meters from the Company at the following rates:

Diaphragm Meters

New Service Offers

Meter Size (Cubic Feet/hour)	Monthly Charge
250	$1.00
630	$3.00
1000	$5.16

(continue to Sheet 15-2)

RATE SCHEDULE 15
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS, AND METERING SERVICES
(continued)

Diaphragm Meters (continued)

No New Service after September 24, 2008. These charges are for service agreements initiated prior to September 24, 2008.

175	$0.81
310	$1.00
425	$1.70
800	$4.07
1400	$9.29
2300	$14.68
5000	$23.33

Rotary Meters

Meter Size	Meter Capacity (Cubic Feet/hour)	**Monthly Charge**
8C175	800	$ 13.00
1.5M175/15C175	1500	$ 15.00
3M175	3000	$ 16.00
5M175	5000	$ 18.00
7M175	7000	$ 22.00
11M175	11000	$ 25.00
16M175	16000	$ 32.00
23M175	23000	$ 48.00
38M175	38000	$ 56.00

Metering Services and Charges	**One Time Charge**	**Installation Charge**	**Monthly Charge**
Rental Read	---	---	$0.76
Automated Meter Reading (AMR) Device	---	$200.00	$18.00
Remote Index	---	$50.00	$4.00
Pulse Output	---	$100.00	$8.00
Administrative Set-Up/Consultation Fee (all meters)	$100.00	---	---
Technical Assistance (Rotary meters only)	$100.00	---	---
Company provided Telephone service to AMR	---	---	$127.00

(continue to Sheet 15-3)

RATE SCHEDULE 15
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS, AND METERING SERVICES
(continued)

SPECIAL PROVISIONS FOR RENTAL METERS AND SPECIAL METERING EQUIPMENT:

1. Prior to receiving service under this section of the Schedule, the Customer must sign a rental agreement that requires a 12-month term. Customers who terminate service after less than 12 months will be required to pay all charges otherwise due to fulfill the 12-month obligation under the service agreement. This requirement protects non-participating Customers from absorbing costs associated with this service.
2. Service under this section of this Schedule is voluntary and separate from billing for or delivery of natural gas to a Customer's premise.
3. Since the Company does not maintain an inventory of all meter types offered under this Schedule, a delay may occur from the time a Customer requests service under this Schedule until the Company can provide it.
4. The Customer will be responsible for the meter pick-up and return of diaphragm meters.
5. The Customer will incur the Administrative Set-Up/Consultation Fee for each rental meter.
6. Upon delivery of a rotary meter, the Customer will incur the Technical Assistance charge listed above for each rental rotary meter. A Customer may not waive this provision or the associated fee. Technical assistance helps the Company ensure proper handling of rotary meters.
7. The Company will install AMR Devices for the charge listed above. AMR devices will only be installed on Company owned meters and the Company will require that the Customer provide phone service enabling meter communications. If a shared phone line does not prove reliable for meter communications, the Company may require the Customer install a dedicated phone line.
8. Upon request, the Company will provide one differential test per calendar year on rotary meters. The testing will be scheduled at the Company's convenience.
9. The Customer is responsible to protect all rental equipment from damage including but not limited to installing parking bollards to protect the rental equipment from vehicular or other damage.
10. Unless manufacturer error can be established, a Customer will be charged for damaged rental equipment. The charge will be the replacement cost less depreciation determined from the initiation date of the rental agreement to the present.
11. A new rental agreement is required each time rental equipment is replaced.
12. An Administrative Set-Up/Consultation Fee will be incurred each time a new rental agreement is initiated, except when the rental meter is being replaced because of manufacturer error.
13. Meter reads are available for the charge established above only when the Customer's service meter is remotely read with the Company's drive-by technology and that technology can easily receive transmitted reads from the rental meter. The Company may determine that meter reads are not available where these conditions are not met. Also, only the Company may choose the billing cycle on which the meter is read.

(continue to Sheet 15-4)

RATE SCHEDULE 15
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS, AND METERING SERVICES
(continued)

SPECIAL PROVISIONS FOR RENTAL METERS AND SPECIAL METERING EQUIPMENT (continued):

14. The Company may periodically offer rental equipment that is not listed in this rate schedule. Temporary rental equipment will be offered at a billing rate based on approved prices for near equivalent equipment. The use of temporary rental equipment will be for a limited duration not to exceed one year at which time the rental equipment will either be removed or the Company will file with the Commission to add the equipment to this rate schedule.
15. The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable adjustments.

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 Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

RATE SCHEDULE 27
RESIDENTIAL HEATING DRY-OUT SERVICE

AVAILABLE:
To Residential home builders, developers, and contractors during the period that a Residential dwelling is under construction, in all territory served by the Company under the Tariff of which this Rate Schedule is a part.

SERVICE DESCRIPTION:
Service under this Rate Schedule is restricted to the use of gas in approved permanently-installed gas heating equipment in place during the period the dwelling is under construction. Upon occupancy of the dwelling, service under this Rate Schedule shall terminate automatically. In no event will service under this Rate Schedule continue for more a period of time greater than twelve (12) months from the date the gas meter is set at the dwelling. Upon termination of service under this Rate Schedule, gas service shall transfer to **Schedule 1** or **Schedule 2**, whichever is applicable.

MONTHLY RATE: Effective: February 1, 2012

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160**.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate
Customer Charge:	$10.28				**$10.28**
Volumetric Charge (per therm)					
All therms	$0.28671	$0.13472	$0.48994	$0.00000	**$0.91137**

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 15** (if applicable)

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 Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE

SERVICE AVAILABILITY:
Service under this Rate Schedule is available on the Company's Distribution System to Non-Residential Customers in all territory served by the Company under the Tariff of which this Rate Schedule is a part, provided that the Company determines, in its sole judgment, that adequate supply and/or capacity exists to accommodate a Customer's service requirements. Service under this Rate Schedule cannot be combined with service under any other Rate Schedule.

APPLICATION FOR SERVICE AND SELECTION OF RATE SCHEDULE AND SERVICE TYPES:
An application for service must be made in accordance with the provisions of **Rule 2** of this Tariff, including the requirements to establish or re-establish credit.

It is the responsibility of the Customer to select the Rate Schedule and Service Type that best meets the Customer's individual service requirements. A Customer's Service Type selection must be stated on the Service Election Form, subject to the Company's approval as described in "SERVICE SELECTIONS – PROCESS AND PROCEDURE" of this Rate Schedule and in the Company's applicable policies and procedures.

PRE-REQUISITES TO SERVICE:

1. A Customer may be required to pay the Company, in advance, for costs related to the Company's installation of any new or additional Distribution Facilities necessary to provide service to Customer under this Rate Schedule. See **Schedule X**.
2. When the installation of new or additional Distribution Facilities is necessary to provide service to Customer, the Company may require Customer enter into a written service agreement.
3. The Company may require that Company-owned telemetry equipment be installed at Customer's Premise, subject to charges set forth in **Schedule 15**.
4. Customers that request or are required to use Automated Meter Reading (AMR) technology must, at Customer's expense provide any utility, telephone, cellular, or other services or devices that the Company deems necessary to support AMR technology for the transmission of metered data to the Company. All installations must comply with the Company's specifications, must be in place and activated not less than five (5) Business Days prior to the requested effective date of service, and must remain continuously active at all times.
5. Customers approved for Transportation Service, alone or in combination with Firm Sales Service must be able to access and receive notices via automatic electronic means acceptable to the Company.

GENERAL CONDITIONS OF SERVICE:
The Company will bill a Customer and the Customer must pay the Company the rates according to: (a) the Customer's designated class of service, (b) the Customer's Service Type, and (c) other billing options selected by Customer as shown in the Monthly Rates section at the end of this Rate Schedule.

(continue to Sheet 31-2)

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

GENERAL CONDITIONS OF SERVICE (continued):
Customers that select Sales Service under this Rate Schedule will be billed on a monthly cycle basis as determined by the Company. Customers that select Transportation Service or a Combination Service Type will be billed on a calendar month billing cycle and bills will be issued as soon as reasonably possible following the end of each calendar month. A Customer that requests AMR capability for Customer's own use is subject to the charges under **Rate Schedule 15** of this Tariff.

Except as provided in **Rule 12** of this Tariff, or as otherwise approved by the Company, Temporary Disconnection of Service is not permitted for any Service Type under this Rate Schedule. Should a Customer experience a Temporary Disconnection of Service more than twice within a 24-month period, the Company may deny service to such Customer under this Rate Schedule for a period of one Year.

Customers must comply with the provisions of **Rule 2** in the event of a change in business name or a change in ownership.

Customers must ensure that any services or devices installed by the Customer to support AMR are continuously active at all times. Any outage or failure must be promptly remedied, no matter the cause. In the event an outage or failure continues for more than thirty (30) calendar days, or if there are continuous problems with outage or failure, the Company may in its sole discretion, replace, repair, or take other corrective action, at Customer's expense. If the Company determines that such replacement, repair or other corrective action is not feasible, the Company may reassign Customer to another Rate Schedule or another Service Type that does not require AMR.

DESCRIPTION OF SERVICE TYPES AND REQUIREMENTS FOR SERVICE:
Service under this Rate Schedule requires one Service Type per billing meter set assembly. All Service Types are subject to approval by the Company. The following Service Types are available under this Rate Schedule:

1. Firm Sales Service
2. Firm Transportation Service
3. Combination Firm Sales and Firm Transportation Service

The respective requirements of each Service Type are described below and elsewhere in this Rate Schedule, including, without limitation," PRE-REQUISITES TO SERVICE":

Firm Sales Service Type:

This is Firm Service on the Company's Distribution System. The availability of this service is dependent upon the Company's determination that adequate supply and capacity exists to provide Firm Service to the Customer. The Commodity Component applicable to gas usage is as set forth in the "ANNUAL SERVICE ELECTION DATE" provision of this Rate Schedule. Customer must select one of two Pipeline Capacity Charge options:

(continue to Sheet 31-3)

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

DESCRIPTION OF SERVICE TYPES AND REQUIREMENTS FOR SERVICE (continued):

Firm Sales Servcie Type (continued):

(a) **Volumetric**. For the volumetric choice, the rate stated for the Firm Pipeline Capacity Charge – Volumetric option in the Monthly Rates provision of this Rate Schedule is multiplied by all therms used by Customer each Billing Month.

(b) **Maximum Daily Delivery Volume (MDDV)**. For the MDDV choice, each therm of Customer's MDDV is multiplied by the Firm Pipeline Capacity Charge-Peak Demand option each Billing Month. The provisions for determination of a Customer's MDDV are described under "DETERMINATION OF MDDV" in this Rate Schedule.

Firm Transportation Service Type:

This is Firm Transportation Service on the Company's Distribution System. The availability of this service is dependent upon the Company's determination that adequate capacity exists to provide Firm Service to the Customer.

Customer must secure the purchase and delivery of gas supplies to be transported on the Company's Distribution System from an Authorized Supplier/Agent of Customer's choosing. Customer must complete the Company's Transportation Service: Supplier/Agent Authorization Form and name such Authorized Supplier/Agent not less than five (5) Business Days prior to the effective date of service. The Transportation of Customer-Owned Gas supplies is governed by the Terms and Conditions set forth in **Schedule T** of this Tariff, and the Company's Gas Transportation Operating Policies and Procedures.

Combination Firm Sales and Firm Transportation Service.

Customer must specify the exact daily delivery volume that is to be billed as Sales Service. Customer may choose to specify an hourly delivery volume on the Service Election Form. An hourly delivery volume that exceeds 1/24 of the MDDV does not supersede the specified MDDV.

The Firm Pipeline Capacity Charge – Peak Demand Option (per therm of MDDV) for payment of Pipeline Capacity Charges will apply for all Firm Sales Service volumes.

Firm Sales Service volume will be billed at the rates specified in this Rate Schedule for Firm Sales Service, and will always bill first. When all Sales Service volume has billed, all additional volumes will be billed at the rates specified for the Transportation Service Type. One Customer Charge and one Transportation Charge will apply for this Service Type.

Customer must secure the purchase and delivery of gas supplies to be transported on the Company's Distribution System from an Authorized Supplier/Agent of Customer's choosing. Customer must complete the Company's Transportation Service: Supplier/Agent Authorization Form and name such Authorized Supplier/Agent not less than five (5) Business Days prior to the effective date of service. The Transportation of Customer-Owned Gas is governed by the Terms and Conditions set forth in **Schedule T** of this Tariff, and the Company's Gas Transportation Operating Policies and Procedures.

(continue to Sheet 31-4)

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

SERVICE TYPE SELECTION – PROCESS AND PROCEDURE:
Customer must complete and submit a Service Election Form following an application for service, and subsequently at any time that a change in Service Type is requested under the "ANNUAL SERVICE ELECTION DATE" provision or under the "OUT-OF-CYCLE TRANSFERS" provision of this Rate Schedule.

The Company will personally deliver, mail, fax, or e-mail a Service Election Form to a Customer, upon request. Customers with multiple active Natural Gas service accounts and/or multiple billing meter set assemblies within a single service account must submit a separate Service Election Form for each billing meter set assembly. Any change in a Customer's Rate Schedule or Service Type will be deemed a change in condition of service and the Company may require that the Customer re-establish credit as set forth in **Rule 2** of this Tariff.

When an out-of-cycle change in Service Type is requested, the Service Election Form must be completed and signed by an authorized representative of the Customer, and delivered to Company in person, by fax, by email, or by U.S. mail not less than one Billing Month prior to the requested effective date of the Service Type change. For changes requested under the Annual Service Election provision of this Rate Schedule, the Service Election Form must be received by 5:00 p.m. on July 31. If July 31 falls on a weekend or holiday, the Service Election Form must be received by 5:00 p.m. of the first business day following July 31.

The Company will notify a Customer of the Company's approval or denial of Customer's Service Type selection request within ten (10) Business Days from the date that the Service Election Form is received by Company. The Company will include an explanation for any denial of a Customer's Service Type request at the time of the notification.

When considering each Service Type request under this Rate Schedule, approval will be based upon the Company's determination, in its sole judgment, that: (a) adequate supply and capacity is available to accommodate Firm Service, and (b) Customer has satisfactorily established or has satisfactorily re-established credit under the terms and conditions of **Rule 2** of this Tariff.

ANNUAL SERVICE ELECTION DATE – July 31 Election for November 1 Service:
The Annual Service Election Date is the date by which a Customer may request to change all or a portion of their current Service Type to be effective the following November 1 through October 31 period (PGA Year). Except for a change in Rate Schedule, or an election of Winter Sales WACOG, any out-of-cycle transfer approved to be effective after the Annual Service Election Date but prior to the start of the new PGA Year will automatically terminate on October 31.

To request a change in Service Type under this provision, Customer must complete and submit the Service Election Form in accordance with the terms and conditions of the "SERVICE TYPE SELECTION – PROCESS AND PRODCEDURE" provision of this Rate Schedule. A Customer need not submit a Service Election Form for the next PGA Year if the Customer desires to retain the Service Type that is in effect on July 31.

(continue to Sheet 31-5)

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

ANNUAL SERVICE ELECTION DATE – July 31 Election for November 1 Service (continued):
The following changes may be requested under this provision:

(1) Change in Sales Service Type (with a Rate Schedule change)
(2) Change in Transportation Service Type (with a Rate Schedule change)
(3) Transfer to a Sales Service Type;
(4) Transfer to a Transportation Service Type;
(5) Selection of a Combination Service Type
(6) Selection of Winter Sales WACOG (Sales Service Types only);
(7) Change in Pipeline Capacity Charge billing option (Firm Sales Service Type only);
(8) Change to Firm Sales Service Maximum Daily Delivery Volume (MDDV) (Combination Service Type only);
(9) Change in Rate Schedule

Requests to transfer to a Sales Service Type or to change a Sales Service Type with a Rate Schedule change are subject to the Company's determination that such service is available at the requested location based on the conditions set forth in the "SERVICE AVAILABILITY" provision of this Rate Schedule.

Transfers between Sales Service and Transportation Service are further subject to the "APPLICATION OF TEMPORARY ADJUSTMENTS TO RATES (Account 191 Adjustments)" provision of this Rate Schedule.

Commodity Component for Sales Service
The default Commodity Component is Annual Sales WACOG, and will be used to bill Sales Service Customers effective November 1, except as otherwise set forth in this provision.

If a Customer's Commodity Component for Sales Service is Winter Sales WACOG during the current PGA Year, then the Commodity Component for Sales Service for the next PGA Year will default to Winter Sales WACOG, unless Customer elects a different Commodity Component or otherwise elects a different Service Type by the Annual Service Election Date.

Customers that were served under a Sales Service Type at Annual Sales WACOG during the prior PGA Year will have until September 15 to select the Winter Sales WACOG option (for a term of November 1 through March 31). If September 15 falls on a weekend or holiday, the selection must be received by 5:00 p.m. of the first Business Day following September 15. If no selection is made, the Commodity Component option will default to Annual Sales WACOG (November 1 through October 31).

A Customer that selects Winter Sales WACOG will be billed at Monthly Incremental Cost of Gas as set forth in **Schedule 150** effective with service on and after April 1 unless Customer makes an Out-of-Cycle Transfer to Transportation Service.

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Issued December 30, 2011 Effective with service on
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RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

ANNUAL SERVICE ELECTION DATE – July 31 Election for November 1 Service (continued):

Commodity Component for Sales Service (continued)
A Customer that was served on a Transportation Service Type at any time during the two most recent PGA Years and that elects a Sales Service Type under this provision will be subject to the Interim WACOG set forth in **Schedule P** for the Commodity Component for Sales Service for the earlier of two uninterrupted consecutive PGA Years, or the effective date of a transfer to a Transportation Service type.

The Interim WACOG shall apply to such Customer's Sales Service Type in any PGA Year when the price effect of Gas Reserves, as defined in **Schedule P**, causes Annual Sales WACOG to be lower than Interim WACOG. Upon fulfillment of two uninterrupted and consecutive PGA Years, the Customer will be eligible to elect Annual Sales WACOG or Winter Sales WACOG as the Commodity Component for Sales Service.

OUT-OF-CYCLE TRANSFERS:
Unless otherwise specified in this provision, the out-of-cycle transfers described herein may be requested at any time during the calendar year. An out-of-cycle transfer request must comply with the terms and conditions of this provision, and the "SERVICE TYPE SELECTIONS – PROCESS AND PROCEDURE" provision of this Rate Schedule. All out-of-cycle requests are subject to approval by the Company under the terms and conditions of this provision, as set forth elsewhere in this Rate Schedule.

The following out-of-cycle changes may be requested:

1. Rate Schedule Transfer
2. Transfer to Sales Service from Transportation Service
3. Transfer to Transportation Service from Sales Service

Rate Schedule Transfers.
A Customer is eligible to transfer to any other Rate Schedule for which they qualify if they are a New Customer or an Existing Customer, as defined below:

New Customer. To be considered a new Customer under this provision, the gas service account in the name of such Customer must have been activated at the service address within the most recent twelve (12) calendar months.

Existing Customer. To be considered an existing Customer under this provision, the gas service account in the name of such Customer must have been active and uninterrupted at the service address and served under this Rate Schedule for a minimum of twelve (12) consecutive months prior to the requested effective date of the transfer.

Only one Rate Schedule transfer is allowed in any consecutive 12-month period.

(continue to Sheet 31-7)

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

OUT-OF-CYCLE TRANSFERS FOR CERTAIN SERVICE TYPES (continued):

Transfer to Sales Service from Transportation Service.
The applicable Commodity Component for all out-of-cycle transfers to Sales Service for the remainder of the PGA Year in which the transfer is made is the Monthly Incremental Cost of Gas, as determined in accordance with **Schedule 150** of this Tariff. Thereafter, the Commodity Component shall be established as set forth in the "ANNUAL SERVICE ELECTION DATE" provision of this Rate Schedule.

Except where a Customer was served under a Sales Service Type in the prior PGA Year, a Customer that transfers to Sales Service from Transportation Service will not be subject to the Account 191 adjustments in effect for the Sales Service selection. If the transfer is made under the "OUT-OF-CYCLE TRANSFERS" provision, the Account 191 adjustments will not be billed for the remainder of the current PGA Year. If the transfer is made under the "ANNUAL SERVICE ELECTION DATE" provision, the Account 191 adjustments will not be billed for one complete PGA Year.

Out-of-cycle transfers to Firm Sales Service are subject to the applicable monthly Firm Pipeline Capacity Charges commencing with the effective date of the Firm Sales Service and continuing through the remainder of the current PGA Year. The monthly Firm Pipeline Capacity Charges will continue to apply even if the Customer makes a subsequent out-of-cycle transfer to return to Transportation Service within the same PGA Year.

Transfer to Transportation Service from Sales Service.
A transfer to Transportation Service from Sales Service is allowed only if the Commodity Component for Sales Service is Monthly Incremental Cost of Gas under **Schedule 150**.

Customer will continue to be billed and will pay any Account 191 adjustments that applied to Customer's Sales Service.

Transfers from Firm Sales Service will continue to be subject to the applicable monthly Firm Pipeline Capacity charges associated with the Firm Sales Service

APPLICATION OF TEMPORARY ADJUSTMENTS TO RATES (ACCOUNT 191 ADJUSTMENTS):
Account 191 Adjustments are the portion of the Temporary Adjustment in rates that relates to the deferral of commodity and pipeline capacity charges, specifically, the Account 191 Commodity Adjustment and Account 191 Pipeline Capacity Adjustment, as set forth in **Schedule 162**.

Within a PGA Year, a Customer is subject to the Account 191 portion of the Temporary Adjustment if:

(1) The Customer is on Sales Service in the current PGA Year and was on Sales Service in the prior PGA Year; or
(2) The Customer is on Transportation Service in the current PGA Year and was on Sales Service in the prior PGA Year.

(continue to Sheet 31-8)

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

DETERMINATION OF MDDV:
The MDDV is used to calculate the Firm Pipeline Capacity Charge – Peak Demand option applicable to Firm Sales Service under this Rate Schedule. Following establishment of a Customer's Initial MDDV, as set forth in Sections A and B, the Customer's MDDV will be adjusted each year as set forth in Section C below:

A. For a New Customer, the Initial MDDV to be used for billing purposes will equal the "name plate" hourly rating of the equipment to be served, times twelve (12), or an estimated volume acceptable to the Company that is based upon the best information about Customer's planned operations that is known at that time.

B. For an Existing Customer, the Initial MDDV for billing purposes will be:

   (i) The highest actual MDDV of record for the most recent months January, February, November and December, as determined from AMR data, if available; or, if not available,
   (ii) The highest calculated MDDV for each of the most recent months January, February, November and December, calculated by taking the Customer's actual metered usage during the month, divided by the number of days in the Billing Month, the result divided by 0.7.

C. The Initial MDDV will be used for billing purposes in each Billing Month, up to the first Peak Period month that follows the date that the Initial MDDV was first effective for billing purposes. During the first Peak Period, and for each Peak Period thereafter, the MDDV for billing purposes will be determined as follows:

   (i) For each month of the Peak Period, the MDDV for billing purposes will equal the higher of (a) the Customer's current MDDV or (b) the Customer's actual MDDV of record for that Billing Month, as determined from AMR data, or from the calculated method described in (B)(ii) above, whichever applies. AMR data will always be used where an AMR device is installed and operational.
   (ii) Effective with the first Billing Month following the end of the Peak Period, the MDDV to be used for billing purposes in each month of the following non-Peak Period (March through October) will be the highest MDDV of record during the last Peak Period.

Peak Period is defined as (a) the most recent consecutive Billing Months November through February for customers billed at month-end; or (b) the most recent consecutive Billing Months November through March for customers billed on any other monthly interval.

(continue to Sheet 31-9)

Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

DETERMINATION OF MDDV (continued):

Out-of-Cycle Adjustments to MDDV. Upon a Customer's request, and upon a showing to Company's satisfaction that a change in Customer's operations warrants a change to the Customer's MDDV, the Company may adjust Customer's MDDV at any time. Any MDDV change will be effective with the first monthly bill issued following the date that the need for the change is identified. The Company will not be required to adjust any previously issued bills.

Existing AMR. If AMR is installed and operational at the time a Customer initiates service under this Rate Schedule, the Company may use the AMR data to calculate a Customer’s MDDV for purposes of billing the Pipeline Capacity Charge, even if the AMR data is not used for other billing purposes.

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 Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(continue to Sheet 31-10)

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR COMMERCIAL CUSTOMER CLASS:

Effective: February 1, 2012

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160**.

FIRM SALES SERVICE CHARGES (31 CSF) [1]:					**Billing Rates**
Customer Charge (per month):					**$260.00**
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]	
Block 1: 1st 2,000 therms	$0.22185	$0.00000	$0.48994	$(0.01163)	**$0.70016**
Block 2: All additional therms	$0.20241	$0.00000	$0.48994	$(0.01258)	**$0.67977**
Pipeline Capacity Charge Options (select one):					
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.13472**
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$2.01**
FIRM TRANSPORTATION SERVICE CHARGES (31 CTF):					
Customer Charge (per month):					**$260.00**
Transportation Charge (per month):					**$250.00**
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [4]	
Block 1: 1st 2,000 therms	$0.20592	$0.00000		$0.01555	**$0.22147**
Block 2: All additional therms	$0.18790	$0.00000		$0.01516	**$0.20306**

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from **Schedule C** or **Schedule 15**.
[2] The Commodity Component shown is the Annual Sales WACOG. The actual Commodity Component billed could be different for certain customers as described elsewhere in this Rate Schedule.
[3] Where applicable, as set forth in this Rate Schedule, the Account 191 portion of the Temporary Adjustments as set forth in **Schedule 162** may not apply.
[4] Where applicable, as set forth in this Rate Schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in **Schedule 162** may also apply.

(continue to Sheet 31-11)

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR INDUSTRIAL CUSTOMER CLASS: **Effective: February 1, 2012**

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160**.

FIRM SALES SERVICE CHARGES (31 ISF) [1]:					**Billing Rates**
Customer Charge (per month):					**$260.00**
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]	
Block 1: 1st 2,000 therms	$0.17994	$0.00000	$0.48994	$(0.00582)	**$0.66406**
Block 2: All additional therms	$0.16259	$0.00000	$0.48994	$(0.00687)	**$0.64566**
Pipeline Capacity Charge Options (select one):					
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.13472**
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$2.01**
FIRM TRANSPORTATION SERVICE CHARGES (31 ITF):					
Customer Charge (per month):					**$325.00**
Transportation Charge (per month):					**$250.00**
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [4]	
Block 1: 1st 2,000 therms	$0.16816	$0.00000		$0.00422	**$0.17238**
Block 2: All additional therms	$0.15196	$0.00000		$0.00382	**$0.15578**

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from **Schedule C** and **Schedule 15**.
[2] The Commodity Component shown is the Annual Sales WACOG. The actual Commodity Component billed could be different for certain customers as described elsewhere in this Rate Schedule.
[3] Where applicable, as set forth in this Rate Schedule, the Account 191 portion of the Temporary Adjustments as set forth in **Schedule 162** may not apply.
[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in **SCHEDULE 162** may also apply.

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE

SERVICE AVAILABILITY:
Service under this Rate Schedule is available on the Company's Distribution System to Non-Residential Customers in all territory served by the Company under the Tariff of which this Rate Schedule is a part. Firm Service under this Rate Schedule is available provided that the Company determines, in its sole judgment, that adequate supply and capacity exists to accommodate a Customer's service requirements. The Company, in its sole discretion, will determine the availability of Interruptible Service under this Rate Schedule in cases where supply and capacity are adequate to provide Firm Service. A Customer request for an Interruptible Service Type will be considered on a case-by-case basis. Service under this Rate Schedule cannot be combined with service under any other Rate Schedule.

SPECIAL CONDITIONS FOR INTERRUPTIBLE SERVICE:
Any Customer served under an Interruptible Service Type as of November 1, 2012 will be allowed to continue service on such Interruptible Service Type after November 1, 2012 for a period of five (5) consecutive PGA Years. Thereafter, the eligibility for Interruptible Service shall be determined in accordance with the "SERVICE AVAILABILITY" and "DESCRIPTION OF SERVICE TYPES AND REQUIREMENTS FOR SERVICE" provisions of this Rate Schedule. If a Customer to which this special condition applies transfers to a Firm Service Type in accordance with the "OUT-OF-CYCLE TRANSFERS" or "ANNUAL SERVICE ELECTION DATE" provisions of this Rate Schedule before the end of five (5) PGA Years, then any subsequent request for Interruptible Service will be subject to the conditions for approval as set forth above under 'SERVICE AVAILABILITY".

This special condition will carry to any subsequent Customer at the same service address following a change in business name or a change of ownership. In all other situations, a subsequent Customer must submit a Service Election Form to request Interruptible Service, subject to approval as set forth above under 'SERVICE AVAILABILITY".

APPLICATION FOR SERVICE AND SELECTION OF RATE SCHEDULE AND SERVICE TYPES:
An application for service must be made in accordance with the provisions of **Rule 2** of this Tariff, including the requirements to establish or re-establish credit.

It is the responsibility of the Customer to select the Rate Schedule and Service Type that best meets the Customer's individual service requirements. A Customer's Service Type must be stated on the Service Election Form, and is subject to the Company's approval as described in "SERVICE SELECTIONS – PROCESS AND PROCEDURE" of this Rate Schedule and in the Company's applicable policies and procedures.

PRE-REQUISITES TO SERVICE:

1. A Customer may be required to pay the Company, in advance, for costs related to the Company's installation of any new or additional Distribution Facilities necessary to provide service to Customer under this Rate Schedule. See **Schedule X**.
2. When the installation of new or additional Distribution Facilities is necessary to provide service to Customer, the Company may require Customer enter into a written service agreement.

(continue to Sheet 32-2)

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

PRE-REQUISITES TO SERVICE (continued):

3. The Company may require that Company-owned telemetry equipment be installed at Customer's Premise, subject to charges set forth in **Schedule 15**.
4. Customer, at Customer's expense, must provide any utility, telephone, cellular, or other services or devices that the Company deems necessary to support Automated Meter Reading (AMR) technology for the transmission of metered data to the Company for billing purposes. All installations must comply with the Company's specifications, must be in place and activated not less than five (5) Business Days prior to the requested effective date of service, and must remain continuously active at all times.
5. Customers approved for Interruptible Service or Transportation Service, alone or in combination with another Service Type must be able to access and receive notices via automatic electronic means acceptable to the Company.
6. Customers approved for an Interruptible Service Type must complete the Company's Customer Emergency Contact List Form. Customer may name multiple authorized emergency contacts. At least one authorized emergency contact must be accessible for notification 24-hours per day, 7-days per week. Customer must notify the Company of any change in emergency contacts or of any change in the contact information as provided in this Rate Schedule, or at least annually upon Company request;

GENERAL CONDITIONS OF SERVICE:

The Company will bill a Customer and the Customer must pay the Company the rates according to: (a) the Customer's designated class of service, (b) the Customer's Service Type, and (c) other billing options selected by Customer as shown in the Monthly Rates section at the end of this Rate Schedule.

All Customers served under this Rate Schedule will be billed on a calendar month billing cycle. Bills will be issued as soon as reasonably possible following the end of each calendar month.

Except as provided in **Rule 12** of this Tariff, or as otherwise approved by the Company, Temporary Disconnection of Service is not permitted for any Service Type under this Rate Schedule. Should a Customer experience a Temporary Disconnection of Service more than twice within a 24-month period the Company may deny service to such Customer under this Rate Schedule for a period one year.

Customers must comply with the provisions of **Rule 2** in the event of a change in business name or a change in ownership.

Customers must ensure that any services or devices that the Company requires Customer install to support AMR are continuously active at all times. Any outage or failure must be promptly remedied, no matter the cause. In the event an outage or failure continues for more than thirty (30) calendar days, or if there are continuous problems with outage or failure, the Company may in its sole discretion, replace, repair, or take other corrective action, at Customer's expense. If the Company determines that such replacement, repair or other corrective action is not feasible, the Company may reassign Customer to another Rate Schedule or another Service Type that does not require AMR.

(continue to Sheet 32-3)

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

DESCRIPTION OF SERVICE TYPES AND REQUIREMENTS FOR SERVICE:

Service under this Rate Schedule requires one Service Type Selection per billing meter set assembly. All Service Types are subject to approval by the Company. The following Service Types are available under this Rate Schedule:

1. Firm Sales Service
2. Interruptible Sales Service
3. Firm Transportation Service
4. Interruptible Transportation Service
5. Combination Sales Service
6. Combination Transportation Service
7. Combination Sales and Transportation Service

The respective requirements of each Service Type are described below and elsewhere in this Rate Schedule, including, without limitation," PRE-REQUISITES TO SERVICE":

Sales Service Types:

Firm Sales Service. This is Firm Service on the Company's Distribution System. The availability of this service is dependent upon the Company's determination that adequate supply and capacity exists to provide Firm Service to the Customer. The Commodity Component applicable to gas usage is as set forth in the "ANNUAL SERVICE ELECTION DATE" provision of this Rate Schedule. Customer must select one of two Pipeline Capacity Charge options:

(a) **Volumetric**. For the volumetric choice, the rate stated for the Firm Pipeline Capacity Charge – Volumetric option in the Monthly Rates provision of this Rate Schedule is multiplied by all therms used by Customer each Billing Month.
(b) **Maximum Daily Delivery Volume (MDDV)**. For the MDDV choice, each therm of Customer's MDDV is multiplied by the Firm Pipeline Capacity Charge- Peak Demand option each Billing Month. The provisions for determination of a Customer's MDDV are described under "DETERMINATION OF MDDV" in this Rate Schedule.

Interruptible Sales Service. This is Interruptible Service on the Company's Distribution System and is subject to Curtailment of Service, as set forth in **Rule 13** and **Rule 14** of this Tariff. The Commodity Component applicable to gas usage is as set forth in the "ANNUAL SERVICE ELECTION" provision of this Rate Schedule. The initial term for an Interruptible Sales Service option is five (5) consecutive PGA Years. Thereafter, Interruptible Sales Service may continue on a year-to-year basis, subject to approval by the Company under the "SERVICE AVAILABILITY" provisions of this Rate Schedule. The determination for continued service shall be made coincident with the "ANNUAL SERVICE ELECTION DATE" to be effective November 1. Should a Customer transfer to a Firm Service Type before the end of the initial term and subsequently request Interruptible Sales Service, then the request will be subject to approval by the Company and if approved, a new initial term will begin.

(continue to Sheet 32-4)

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

DESCRIPTION OF SERVICE TYPES AND REQUIREMENTS FOR SERVICE (continued):

Transportation Service Types:

Firm Transportation Service. This is Firm Service on the Company's Distribution System. The availability of this service is dependent upon the Company's determination that adequate capacity exists to provide Firm Service to the Customer.

Interruptible Transportation Service. This is Interruptible Service on the Company's Distribution System and is subject to Curtailment of Service, as set forth in **Rule 13** and **Rule 14** of this Tariff. The initial term for an Interruptible Transportation Service option is five (5) PGA Years. Thereafter, Interruptible Transportation Service may continue on a year-to-year basis, subject to approval by the Company under the "SERVICE AVAILABILITY" provisions of this Rate Schedule. The determination for continued service shall be made coincident with the "ANNUAL SERVICE ELECTION DATE" to be effective November 1. Should a Customer transfer to a Firm Service Type before the end of the initial term and subsequently request Interruptible Sales Service, then the request will be subject to approval by the Company and if approved, a new initial term will begin.

Customer must secure the purchase and delivery of gas supplies to be transported on the Company's Distribution System from an Authorized Supplier/Agent of Customer's choosing. Customer must complete the Company's Transportation Service: Supplier/Agent Authorization Form and name such Authorized Supplier/Agent not less than five (5) Business Days prior to the effective date of service. The Transportation of Customer-owned gas supplies is governed by the Terms and Conditions set forth in **Schedule T** of this Tariff, and the Company's Gas Transportation Operating Policies and Procedures.

Combination Service Types:
For all Combination Service Types, Customer must specify the exact daily delivery volume to be billed for the Service Type that is billed first through the meter. Customer may choose to specify an hourly delivery volume on the Service Election Form. An hourly delivery volume that exceeds 1/24 of the MDDV does not supersede the specified MDDV.

The initial term for a Combination Service Type that included Interruptible Sales or Interruptible Transportation Service is five (5) PGA Years. Thereafter, the Interruptible Service portion of the Combination Service Type may continue on a year-to-year basis, subject to approval by the Company under the "SERVICE AVAILABILITY" provisions of this Rate Schedule. The determination for continued service shall be made coincident with the "ANNUAL SERVICE ELECTION DATE" to be effective November 1. Should a Customer transfer to a Firm Service Type before the end of the initial term and subsequently request Interruptible Sales Service, then the request will be subject to approval by the Company and if approved, a new initial term will begin.

(continue to Sheet 32-5)

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

DESCRIPTION OF SERVICE TYPES AND REQUIREMENTS FOR SERVICE (continued):

Combination Service Types (continued):

Combination Sales Service. This is a combination of Firm Sales Service and Interruptible Sales Service. Firm Sales Service volumes are first through the meter for billing purposes. Customer must specify the exact daily delivery volumes that are to be billed as Firm Sales Service. Firm Sales Service volumes will be billed at the rates specified in this Rate Schedule for Firm Sales Service. When all Firm Sales Service volumes have billed, all additional volumes will be billed at the rates specified for Interruptible Sales Service. All Firm Sales Service volumes will be subject to the Firm Pipeline Capacity Charge – Peak Demand Option (per therm of MDDV). One Customer Charge will apply for this Service Type. All Interruptible Sales Service volumes are subject to Curtailment as set forth in **Rule 13** and **Rule 14** of this Tariff.

Under a Priority 4 Curtailment Order, Customer will be allowed to take their Firm Sales Service up to the Firm Sales MDDV. Amounts in excess of the Firm MDDV may be considered unauthorized and subject to charges under **Schedule C**. Under a Priority 3 Curtailment Order, the Company may require that the Firm Sales MDDV be prorated on an hourly basis, and amounts used in excess of the hourly basis volume are subject to charges under **Schedule C**.

Combination Transportation Service. This is a combination of Firm Transportation Service and Interruptible Transportation Service. Firm Transportation Service volumes are first through the meter for billing purposes. Customer must specify the exact daily delivery volume that is to be billed as Firm Transportation Service. Firm Transportation Service volumes will be billed at the rates specified in this Rate Schedule for Firm Transportation Service. When all Firm Transportation Service volume has billed, all additional volumes will be billed at the rates specified for Interruptible Transportation Service. One Customer Charge and one Transportation Charge will apply for this service type. All Interruptible Transportation Service volumes are subject to Curtailment as set forth in **Rule 13** and **Rule 14** of this Tariff.

Customer must secure the purchase and delivery of gas supplies for all Transportation Service volume from an Authorized Supplier/Agent of Customer's choosing. Customer must complete the Company's Transportation Service: Supplier/Agent Authorization Form and name such Authorized Supplier/Agent not less than five (5) Business Days prior to the effective date of service. The Transportation of Customer-Owned Gas is governed by the Terms and Conditions set forth in **Schedule T** of this Tariff, and the Company's Gas Transportation Operating Policies and Procedures.

Combination Sales and Transportation Service. This is a combination of a Sales Service Type and a Transportation Service Type. The Sales Service Type may be Firm or Interruptible Service, except that Interruptible Sales Service cannot be combined with Firm Transportation Service. Interruptible Sales and Interruptible Transportation Service may be further restricted as set forth later in this provision.

Customer must specify the exact daily delivery volume that is to be billed as Sales Service. For Firm Sales Service, the Firm Pipeline Capacity Charge – Peak Demand Option (per therm of MDDV) for payment of Pipeline Capacity Charges will apply for all Firm Sales Service volumes. Firm Sales Service volume will be billed at the rates specified in this Rate Schedule for Firm Sales Service and will always bill first. When all Sales Service volume has billed, all additional volumes will be billed at the rates specified for the elected Transportation Service Type. One Customer Charge and one Transportation Charge will apply for this Service Type.

(continue to Sheet 32-6)

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

RATE SCHEDULE 33
HIGH VOLUME NON-RESIDENTIAL
FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICE
(continued)

OUT-OF-CYCLE TRANSFERS (continued):

The following out-of-cycle changes may be requested:

1. Rate Schedule Transfer
2. Rate Schedule Transfer with a Change in Service Type
3. Transfer to Firm Transportation Service from Interruptible Transportation Service

Rate Schedule Transfers.
A Customer is eligible to transfer to any other Rate Schedule for which they qualify if they are a New Customer or an Existing Customer, as defined below:

New Customer. To be considered a new Customer under this provision, the gas service account in the name of such Customer must have been activated at the service address within the most recent 12 calendar months.

Existing Customer. To be considered an existing Customer under this provision, the gas service account in the name of such Customer must have been active and uninterrupted at the service address and served under this Rate Schedule for a minimum of twelve (12) consecutive months prior to the requested effective date of the transfer.

Only one Rate Schedule transfer is allowed in any consecutive 12-month period.

Rate Schedule Transfer with a Change in Service Type.
This transfer is subject to the terms and conditions for a transfer to Sales Service from Transportation Service, as set forth in the Rate Schedule to which Customer will transfer.

Transfer to Firm Transportation Service from Interruptible Transportation Service
An out-of-cycle transfer to Firm Transportation Service from Interruptible Transportation Service may be allowed provided the Company has determined that adequate capacity exists to accommodate Firm Service at that location. An out-of-cycle transfer to Interruptible Transportation Service from Firm Transportation Service is not allowed except where Company pre-approved the transfer as part of a Customer's initial service application.

(continue to Sheet 33-7)

Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

RATE SCHEDULE 33
HIGH VOLUME NON-RESIDENTIAL
FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICE
(continued)

APPLICATION OF TEMPORARY ADJUSTMENTS TO RATES (ACCOUNT 191 ADJUSTMENTS):
Account 191 Adjustments are the portion of the Temporary Adjustment in rates that relates to the deferral of commodity and pipeline capacity charges, specifically, the Account 191 Commodity Adjustment and Account 191 Pipeline Capacity Adjustment, as set forth in **Schedule 162**.

Within a PGA Year, a Customer is subject to the Account 191 portion of the Temporary Adjustment if:

(1) The Customer is on Sales Service in the current PGA Year and was on Sales Service in the prior PGA Year; or
(2) The Customer is on Transportation Service in the current PGA Year and was on Sales Service in the prior PGA Year.

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 Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(continue to Sheet 33-8)

Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

RATE SCHEDULE 33
HIGH VOLUME NON-RESIDENTIAL
FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICE
(continued)

MONTHLY RATE: Effective: February 1, 2012

The rates shown below may not always reflect actual billing rates. See **Schedule 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM TRANSPORTATION SERVICE CHARGES (33 TF)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:		Base Rate	Base Rate Adjustments	Total Temporary Adjustment [1]	
Per therm, all therms:		$0.00541	$0.00000	$0.00015	**$0.00556**
Firm Service Distribution Capacity Charge: Per therm of MDDV per month					**$0.15748**
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus Firm Service Distribution Capacity Charge, plus any other charges that may apply from **Schedule C** and **Schedule 15**.					

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (33 TI)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:		Base Rate	Base Rate Adjustments	Total Temporary Adjustment [1]	
Per therm, all therms:		$0.00541	$0.00000	$0.00015	**$0.00556**
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus any other charges that may apply from **SCHEDULE C** and **SCHEDULE 15**.					

[1] Where applicable, as set forth in this Rate Schedule, the Account 191 portion of the Temporary Adjustments as set forth in **Schedule 162** shall apply.

SCHEDULE 60
SPECIAL CONTRACTS

PORTLAND GENERAL ELECTRIC COMPANY

Natural Gas Transportation and Service Agreement for Electric Generation.

ELIGIBILITY CRITERIA:
Customer is a user of upstream capacity for electric generation that: (a) has the recognized ability to immediately acquire upstream firm capacity; (b) has Standby facilities and can accept the recall of both capacity and gas supply for system needs with minimal notice; and (c) can provide the Company with assurances of the reliability of their gas supply.

TERM:
The Firm Transportation Service provisions are effective November 1, 1995, and will continue through November 1, 2011, and thereafter until either party terminates in accordance with the terms and conditions established in the Agreement.

Firm Transportation Service: Monthly Charge: $115,000 per month

State taxes and any local franchise fees are added to the total of all charges.

SPECIAL PROVISIONS:

1. Company will make available to Customer 30,000 MMBtu/day of Firm Transportation contract demand on the Company's distribution system beginning November 1, 1995. By October 31, 1995, Customer paid the Company $3 million as a contribution in aid of system construction, along with actual additional costs for any specific facilities Company is required to construct to deliver firm Transportation volumes to certain generation sites.

2. Other special conditions as specified in the Agreement.

(continue to Sheet 60-2)

SCHEDULE 60
SPECIAL CONTRACTS
(continued)

INTERNATIONAL PAPER COMPANY (Springfield, Oregon Plant)

Weyerhaeuser Paper Company transferred assignment of this Special Contract to International Paper Company, the purchaser of Weyerhaeuser's Springfield, Oregon Plant, through an Integrated Services Agreement, executed August 4, 2008.

Part 4 of the Integrated Services Agreement terminated July 1, 2009. Parts 2 and 3 terminated November 1, 2010.

ELIGIBILITY CRITERIA:
Customer is economically and physically capable of bypassing the Company's system.

High-Volume Firm Transportation Agreement:
Effective July 1, 1996, and for five (5) years from the date of initial deliveries of gas, and thereafter until terminated on the giving of not less than twelve (12) months' notice. Customer shall operate in accordance with the provisions of **Schedule T.**

RATES:

Transportation Service Charge:	$ 1,000.00 per month
Transportation Capacity Charge:	$36,000.00 per month
Transportation Commodity Charge:	$0.0005 per therm

State taxes and any local franchise fees are added to the total of all charges. At any time after the first five (5) years of this Agreement, the Company, its sole discretion, may annually adjust the Transportation Service Charge and the Transportation Commodity Charge based upon the percentage change experienced in the Consumer Price Index (CPI).

(continue to Sheet 60-3)

SCHEDULE 60
SPECIAL CONTRACTS
(continued)

CASCADE KELLY HOLDINGS, LLC (Clatskanie, Oregon) (*formerly known as* Cascade Grain Products, LLC)
Special Firm Transportation Service Agreement.

ELIGIBILITY CRITERIA:
Customer (a) has met the criteria established by the Commission in Order No. 87-402; (b) agrees not to receive direct Sales or Transportation Service by direct ("bypass") connection with the Pipeline; (c) can demonstrate an ability to construct, own and operate a bypass pipeline having the ability to take delivery of Natural Gas from the Pipeline to serve the respective Natural Gas requirements of the Customer.

BASIC TERM:
Effective the seventh (7th) calendar day following receipt of approval of the Agreement from the OPUC, for fifteen (15) years, with an optional second primary term extension of ten (10) years; and year-to-year thereafter until terminated on the giving of not less than twelve (12) months' written notice.

MONTHLY RATES:

Capacity Service Charge:	$20,000.00 per month
Volumetric Charge:	$0.0025 per therm transported

At each anniversary of the service commencement date under the agreement after the first year of service, the volumetric charge will be increased in the amount of the Consumer Price Index change for All Urban Consumers – U.S. City Average for the preceding November through October period not to exceed three percent (3%).

Charges are subject to late payment charges as provided for in NW Natural's General Rules and Regulations, and to charges associated with gas management telemetry, or any additional services requested by Customer and provided by Company, such as telemetering or submetering.

Company will add to the total of all charges, the actual amounts payable by Company, if any, as city exactions or franchise taxes on account of revenues received by Company under this Agreement.

SPECIAL PROVISIONS:

1. Customer will operate in accordance with **Schedule T** and with the General Rules and Regulations contained in this Tariff.

2. Other special conditions are as specified in the Agreement.

(continue to Sheet 60-4)

SCHEDULE 60
SPECIAL CONTRACTS
(continued)

Georgia-Pacific West, Inc. (Halsey Mill) (*formerly known as* James River Paper Co.)
Special Transportation Service Agreement.

ELIGIBILITY CRITERIA:
Customer (a) is located such that it is economically physically capable of bypassing the Company's system; (b) has the capability of economically substituting an alternate fuel for current Natural Gas requirements; (c) holds firm capacity rights on the Pipeline, and agrees to provide Company with recall provisions during the winter heating season; and (d) agrees to a specified minimum monthly payment.

BASIC TERM: Effective July 1, 1993 for two (2) Years from the date of initial deliveries of gas, and thereafter until terminated on the giving of not less than twelve (12) months' notice.

RATES:

Customer Charge:	$1,873/$2,000 per month, without/with telemetry
Transportation Capacity Charge:	$18,200 per month
Transportation Commodity Charge:	$0.004 per therm

Minimum Monthly Bill: The Customer Charge plus the Transportation Capacity Charge, plus applicable taxes and fees.

State taxes and any local franchise fees are added to the total of all charges.

SPECIAL PROVISIONS:

1. This Agreement may be terminated and superseded at any time upon negotiation of a new agreement governing additional cogeneration load at Customer's plant.
2. Customer agrees to deliver to Company up to 10,000 Therms per day for up to fifteen (15) days per winter heating season (November through March). No single delivery shall exceed five (5) days. Subsequent deliveries in the same heating season shall begin no earlier than the 7th day following the date of the last delivery. Company will only request gas volumes from Customer when needed, in Company's sole judgement, to serve Firm Sales Customers.
3. Company will credit Customer's monthly gas bill in the month following a Company recall of a gas delivery in an amount equal to Customer's cost of replacing the Natural Gas delivered to Company with an alternate fuel, transported F.O.B. Halsey Mill.
4. Customer will operate in accordance with **Schedule T**.
5. Other special conditions specified in the Agreement.

(continue to Sheet 60-5)

SCHEDULE 60
SPECIAL CONTRACTS
(continued)

MICROCHIP TECHNOLOGY, INC. (Gresham, Oregon Plant)

Special Firm Transportation Service Agreement.

ELIGIBILITY CRITERIA:

(1) Customer took assignment of the Fujitsu Special Contract approved by the Oregon Public Utility Commission on January 22, 1997, but has given notice to NW Natural of its desire to terminate that contract;
(2) Customer is economically and physically capable of bypassing NW Natural's system;
(3) Customer has demonstrated the ability to construct, own and operate a bypass pipeline having the ability to take delivery of natural gas from Northwest Pipeline to serve the natural gas requirements of the facility;
(4) Customer agrees not to receive Sales or Transportation Service via a bypass of Company's system during the effective term of this agreement;

BASIC TERM:
Effective on the first Gas Day following receipt of approval from the Oregon Public Utility Commission for fifteen (15) years, and thereafter extend year-to-year until terminated on the giving of not less than twelve (12) months' written notice.

RATES:

Capacity Service Charge:	$5,000.00 per month
Volumetric Charges:	
1st 200,000 therms/month	$0.005 per therm transported
All additional therms/month	$0.001 per therm transported
Minimum Monthly Charge:	$5,000.00

Adjustment to Rates:

(1) The Company will add to the total of all charges, the actual amount of taxes payable by NW Natural, if any, as city exactions or franchise taxes on account of revenues received by NW Natural under this Agreement.
(2) Charges are subject to periodic adjustments for costs incurred by the Company that are directly attributable to the Transportation of gas on account of Customer.

SPECIAL PROVISIONS:

1. Customer will operate in accordance with **Schedule T**.
2. Other special conditions are as specified in the Agreement.

(continue to Sheet 60-6)

SCHEDULE 60
SPECIAL CONTRACTS
(continued)

UNIVERSITY OF OREGON (EUGENE, OREGON)

Special Firm Transportation Service Agreement.

ELIGIBILITY CRITERIA:
Customer (a) has met the criteria established by the Commission in Order No. 87-402; (b) agrees not to receive direct Sales or Transportation service by direct (“bypass”) connection with the Pipeline; (c) is a public agency in the state of Oregon holding tax exempt status; and (d) can demonstrate an ability to jointly construct, own and operate a bypass pipeline with another party or parties, having the ability to take delivery of Natural Gas from the Pipeline to serve the respective Natural Gas requirements of all parties.

BASIC TERM:
Effective March 18, 1997 for ten (10) years from the date approved by the Commission, and year-to-year thereafter until terminated on the giving of not less than twelve (12) months’ written notice.

RATES:

Capacity Service Charge:	$5,312.50 per month
Volumetric Charge:	$0.00475 per therm transported
Minimum Monthly Charge:	$5,312.50

SPECIAL PROVISIONS:

1. The Agreement is contingent upon continuous service to the Customer and the Eugene Water & Electric Board (EWEB) under a Special Firm Transportation Service Agreement. In the event of termination by the EWEB, Customer will have the option to assume the obligations of that special agreement.

2. Customer will operate in accordance with **Schedule T**.

3. Other special conditions are as specified in the Agreement.

(continue to Sheet 60-7)

SCHEDULE 60
SPECIAL CONTRACTS
(continued)

OREGON STEEL MILLS, HEAT TREAT FACILITY (Portland, Oregon)
Special Firm Transportation Service Agreement.

ELIGIBILITY CRITERIA:
Customer (a) has met the criteria established by the Commission in Order 87-402; (b) agrees not to receive direct Sales or Transportation Service by direct (“bypass”) connection with the Pipeline; and (c) can demonstrate an ability to jointly construct, own and operate a bypass pipeline with another party or parties, having the ability to take delivery of Natural Gas from the Pipeline to serve the respective Natural Gas requirements of all parties.

BASIC TERM:
Effective April 1, 1997 for an initial primary term of five (5) years from the date approved by the Commission, with an optional second primary term extension of five (5) years; and year-to-year thereafter until terminated on the giving of not less than twelve (12) months’ written notice.

RATES:

Capacity Service Charge:	$8,750.00 per month
Volumetric Charge:	$0.00350 per therm transported
Minimum Monthly Charge:	$8,750.00

At any time after the first year of the primary term, the Company, in its sole discretion, may annually adjust the Volumetric Charge based upon the percentage change experienced in the Consumer Price Index for All Urban Consumers – U.S. City Average for the preceding November through October period.

Charges under this schedule are subject periodic adjustments for costs incurred by the Company that are directly attributable to the Transportation of gas on account of Customer.

SPECIAL PROVISIONS:

1. Customer will operate in accordance with **Schedule T**.

2. Other special conditions are as specified in the Agreement.

(continue to Sheet 60-8)

Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

SCHEDULE 60
SPECIAL CONTRACTS
(continued)

COLUMBIA STEEL CASTING COMPANY, INC. (Portland, Oregon)
Special Firm Transportation Service Agreement.

ELIGIBLITY CRITERIA:
Customer (a) has met the criteria established by the Commission in Order No. 87-402; (b) agrees not to receive direct Sales or Transportation Service by direct (“bypass”) connection with the Pipeline; and (c) can demonstrate an ability to jointly construct, own and operate a bypass pipeline with another party or parties, having the ability to take delivery of Natural Gas from the Pipeline to serve the respective Natural Gas requirements of all parties.

BASIC TERM:
Effective April 1, 1997 for an initial primary term of five (5) years from the date approved by the Commission, with an optional second primary term extension of five (5) years; and year-to-year thereafter until terminated on the giving of not less than twelve (12) months’ written notice.

RATES:

Capacity Service Charge:	$8,750.00 per month
Volumetric Charge:	$0.00350 per therm transported
Minimum Monthly Charge:	$8,750.00

At any time after the first year of the primary term, the Company, in its sole discretion, may annually adjust the Volumetric Charge based upon the percentage change experienced in the Consumer Price Index for All Urban Consumers – U.S. City Average for the preceding November through October period.

Charges are subject periodic adjustments for costs incurred by the Company that are directly attributable to the Transportation of gas on account of Customer.

SPECIAL PROVISIONS:

1. Customer will operate in accordance with **Schedule T**.

2. Other special conditions are as specified in the Agreement.

(continue to Sheet 60-9)

SCHEDULE 60
SPECIAL CONTRACTS
(continued)

DYNO NOBEL, INC. (St. Helens, Oregon) (*formerly known as* Coastal St. Helens Chemical (St. Helens, Oregon)
Special Firm Transportation Service Agreement.

ELIGIBILITY CRITERIA:
Customer (a) has met the criteria established by the Commission in Order No. 87-402; (b) Customer agrees not to receive direct Sales or Transportation Service by direct ("bypass") connection with the Pipeline; and (c) can demonstrate an ability to construct, own and operate a bypass pipeline having the ability to take delivery of Natural Gas from the Pipeline to serve the respective Natural Gas requirements of the Customer.

BASIC TERM:
Effective June 1, 1997 for ten (10) years, and year-to-year thereafter until terminated on the giving of not less than twelve (12) months' written notice.

ASSIGNMENT: Special Contract was assigned on January 21, 2004, by Coastal St. Helens Chemical to Dyno Nobel, Inc., effective December 3, 2003.

MONTHLY RATES:

Capacity Charge:	$13,333.00 per month
Volumetric Charge:	$0.00500 per therm

Company will add to the total of all charges, the actual amounts payable by Company, if any, as city exactions or franchise taxes on account of revenues received by Company under this Agreement.

Charges are subject periodic adjustments for costs incurred by the Company that are directly attributable to the Transportation of gas on account of Customer.

SPECIAL PROVISIONS:

1. Customer will operate in accordance with **Schedule T**.
2. Other special conditions are as specified in the Agreement.

Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

SCHEDULE 60A
SPECIAL CONTRACTS
INDEX

PURPOSE:
The purpose of this Rate Schedule is to describe generally the terms and conditions of service provided by the Company pursuant to Special Contracts approved by the Commission under *OAR 860-22-0035*. In each case, the rights and obligations of the parties are as specified in detail in the respective Special Contracts. In the event of any ambiguity or conflict between the summaries in this Schedule and the substantive provisions of the Special Contracts, the terms of the Special Contracts shall be controlling. The Company will maintain copies of the Special Contracts for public inspection, in the Company's main and district offices in Oregon, except where noted below by an asterisk (*) because such denoted Special Contracts contain proprietary, customer-specific information.

Description of Contract	Company	Sheet Number
Natural Gas Transportation and Service Agreement for Electric Generation	Portland General Electric Company	60-1
Integrated Services Agreement	International Paper Company	60-2
Special Firm Transportation Service Agreement	Cascade Kelly Holdings, LLC Clatskanie, Oregon	60-3
Transportation Service Agreement	Georgia-Pacific West, Inc. (Halsey Mill)	60-4
Firm Transportation Service Agreement	Microchip Technology, Inc.	60-5
Special Firm Transportation Service Agreement	University of Oregon	60-6
Special Firm Transportation Service Agreement	Oregon Steel Mills, Heat Treat Facility, Portland, OR	60-7
Special Firm Transportation Service Agreement	Columbia Steel Casting Co., Inc. Portland, OR	60-8
Special Firm Transportation Service Agreement	Dyno Nobel, Inc. St. Helens, Oregon	60-9

Issued December 30, 2011
NWN Advice No. OPUC 11-19

Effective with service on
and after February 1, 2012

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)

AVAILABLE:
To eligible Non-Residential Customers taking Firm Transportation Service of Customer-Owned Gas under **Rate Schedule 31**, **Rate Schedule 32**, **Rate Schedule 33**, or **Rate Schedule 60** (Special Contract) of this Tariff, or to eligible Natural Gas commodity suppliers of such Non-Residential Customers, provided that firm storage capacity designated for this service exists and the applicable Customer has met all of the applicable prerequisites to service described herein.

The Firm Storage Service offered under this Rate Schedule will be provided by the Company using storage capacity at Mist that is developed in advance of core Customer needs and the same firm capacity is also being simultaneously made available to the Company's firm interstate storage customers on a non-discriminatory basis. On an annual basis, the amount of storage capacity that is not under existing firm storage service agreements that is made available under this Rate Schedule is subject to change as the non-contracted for capacity may be subject to recall by the Company for core Customer use. Accordingly, the Company reserves its right not to offer or commence the Storage Service hereunder, or to limit the total amount of capacity that is available under this Rate Schedule when, in Company's sole discretion: (i) any impairment of its firm services to core Customers, including its ability to use storage to support such firm services and gas purchases for firm services, would or may result; and/or (ii) there is not sufficient available firm natural gas storage capacity at Mist that is designated for service under this Rate Schedule or an expansion is required, including, the lack of available firm injection and/or withdrawal capacity, and the lack of adequate capacity on the Company's system; and/or (iii) the Customer does not meet the prerequisites to service. All references to "Storage Service" or "Firm Storage Service" refer to the storage and related transportation on NW Natural's distribution system from the Receipt Point(s) to Mist and from Mist to the Storage Delivery Point(s) under this Rate Schedule.

All gas stored under this Rate Schedule must be consumed by a Customer capable of receiving the service from Mist within the Company's service territory in Oregon.

SERVICE DESCRIPTION:
The Firm Storage Service to be provided under this Rate Schedule consists of a bundled storage and transportation service of Customer-Owned Gas from the designated Receipt Point to Mist and from Mist to the designated Storage Delivery Point subject to excused interruption by the Company due to force majeure. The subsequent firm or interruptible transportation of the gas from the Storage Delivery Point to the Delivery Point at a Customer's facility shall take place according to the terms of the Transportation Rate Schedule that is applicable to a Customer's service account where the gas will be consumed as well as the terms of **Schedule T** and other provisions of the Company's Tariff.

(continue to Sheet 80-2)

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

SERVICE DESCRIPTION (continued):
From time to time, subject to the Company having available capacity for the Storage Service as described above, the Company will offer Firm Storage Service for Customer-Owned Gas to Requesting Parties and/or Customers meeting the prerequisites to service on a non-discriminatory basis. An Agreement for Firm Storage Service shall be for a term as set forth in the applicable Service Agreement. Firm Storage Service, Working Gas, Maximum Daily Injection Quantity (MDIQ), and Maximum Daily Withdrawal Quantity (MDWQ) will not be subject to curtailment, interruption, or discontinuance except as provided herein or in the Service Agreement. The Firm Storage Service offered under this Rate Schedule shall have an equal priority with the firm interstate storage service that is provided by the Company and the treatment of service requests and the scheduling priority for these firm storage customers will be on a non-discriminatory basis.

Subject to the other applicable provisions herein, once a Service Agreement has been entered into, a Storage Service Customer may nominate to withdraw amounts up to the specified MDWQ and the Company will schedule such amounts on a firm basis until such Customer's Working Gas inventory falls below fifty percent (50%) of its Maximum Storage Capacity. In such an event, the level of firm withdrawals that a Customer can request will be less than the full MDWQ, and will be limited to the amount specified in the withdrawal table attached to Customer's Service Agreement. The scheduling of Authorized Overrun Quantities in excess of a Customer's applicable MDIQ and MDWQ, may be allowed, but will have the lowest scheduling priority as described further herein.

PREREQUISITES TO SERVICE:
The availability of the Storage Service is subject to the following prerequisites:

1. (a) For a Non-Residential Customer requesting Storage Service under this Rate Schedule, it will be required to have firm Transportation Service volumes on the Company's system that on average equal to or exceed 5,000 Dth/day for a service single account, a storage withdrawal MDWQ of at least 5,000 Dth/day, and the Company must determine that the Delivery Point for the applicable service account is capable of receiving the gas from Mist from the Storage Delivery Point through subsequent transportation on the Company's distribution system.
   (b) If a Natural Gas commodity supplier is requesting Storage Service under this Rate Schedule, it will be required to have a storage withdrawal MDWQ of at least 5,000 Dth/d and either have its own firm Transportation Service Agreement in place to transport the stored gas following redelivery at the Storage Delivery Point, or it must provide information to the Company regarding the Oregon Firm Transportation Service Customer service account(s) and the associated Delivery Point(s) on the Company's system that will likely be receiving the gas by sale from the commodity supplier at the Storage Delivery Point so that the Company can verify that the stored gas will be ultimately consumed in Oregon by a Non-Residential Customer of the Company capable of receiving the gas from Mist as required under this Rate Schedule;

(continue to Sheet 80-3)

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220 N.W. Second Avenue
Portland, Oregon 97209-3991

RATE SCHEDULE 80
FIRST STORAGE SERVICE (EXPERIMENTAL)
(continued)

PREREQUISITES TO SERVICE (continued):

2. The Storage Service request is deemed to be valid by the Company (See the Requests for Service section below);
3. The Company has determined that adequate firm storage capacity designated for the service exists at Mist (no expansions are required), including for firm injection and withdrawals as well as capacity on its distribution system at levels sufficient to accommodate the Storage Service request;
4. The Requesting Party has met the Company's creditworthiness standards;
5. Unless a Storage Account transfer or title transfer takes place as provided for herein, the gas to be stored under this Rate Schedule will be redelivered and consumed within the Company's service territory in Oregon; and
6. The Requesting Party has executed a Service Agreement with the Company.

DEFINITIONS:
Except as otherwise provided for below, the terms used in this Rate Schedule are defined in the Definitions section of the Tariff.

Agreement. Means the terms of this Rate Schedule, as may be amended and supplemented from time to time, together with the applicable Service Agreement (including all Exhibits). All references to "Storage Services" refer to storage and related transportation on NW Natural's distribution system under this Rate Schedule.

Authorized Overrun or Authorized Overrun Quantities. Shall mean a quantity of Gas in excess of Customer's Maximum Daily Injection or Withdrawal Quantity, which the Company agrees, in its sole discretion, to inject or withdraw for Customer on any Gas Day.

Maximum Daily Injection Quantity (MDIQ). Means the maximum quantity of Gas, specified in the Service Agreement, which Customer is entitled to inject into Mist on any Day. Unless otherwise agreed by the Company, the MDIQ will be 40% of the MDWQ contracted for.

Maximum Daily Withdrawal Quantity (MDWQ). Means the maximum quantity of Gas, specified in the Service Agreement, which Customer is entitled to withdraw from Mist on any Day.

Maximum Storage Capacity (MSC). Means the maximum quantity of Gas which Customer is entitled to store at Mist at any given time.

(continue to Sheet 80-4)

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

DEFINITIONS (continued):

Mist. Means the underground natural gas storage facilities constructed and operated by the Company located in Columbia County, Oregon, near the town of Mist.

NAESB. Means North American Energy Standards Board.

Requesting Party. Means any person, including existing Customers or Natural Gas commodity suppliers, that makes a request to the Company for new or additional Storage Service under this Rate Schedule.

Storage Account. Shall mean, for accounting purposes, the account maintained by the Company into which Customer nominates Gas for injection or from which Customer nominates Gas for withdrawal under a Service Agreement. The Storage Account may not have a negative gas inventory balance.

Storage Delivery Point. Means the redelivery point for the stored gas on the Company's system in Oregon that is deemed acceptable for the redelivery by the Company and such point shall be specified in the Customer's Service Agreement.

Storage Service. As used herein means intrastate Natural Gas Firm storage and related Transportation Service from the Receipt Point to Mist and from Mist to the Storage Delivery Point on the Company's local distribution system in Oregon. Specifically, the injection, storage and withdrawal of gas from Mist, related Transportation, and any ancillary activities as may be provided to Customer by the Company pursuant to the terms of this Rate Schedule, and an applicable Service Agreement with such Customer.

Transporter. Means any upstream third party which provides transportation services required to effectuate delivery of the gas to be stored under this Rate Schedule to the Company's system.

Working Gas. Means the actual quantity of working gas in storage for Customer's Storage Account at the beginning of any given Gas Day.

(continue to Sheet 80-5)

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

REQUESTS FOR SERVICE:
A Requesting Party desiring Storage Service under this Rate Schedule may make an oral or written request to the Company. The request shall include, at a minimum:

1. The exact legal name of the Requesting Party;
2. The proposed MDIQ and MDWQ;
3. The proposed term of service;
4. The proposed Storage Delivery Point and the subsequent Firm Transportation contract and Delivery Point on the Company's system in Oregon; and
5. Other necessary information, if any.

A Storage Service request shall not be valid and the Company shall not be required to grant any Storage Service request if: (i) the Company determines, based on its credit analysis, that the Requesting Party does not meet the Company's creditworthiness standards; (ii) the Requesting Party does not meet the prerequisites to service set forth in this Rate Schedule; (iii) the service requested would require the construction, modification, expansion or acquisition of any storage or distribution system facilities; (iv) the service requested would not comply with this Rate Schedule; or (v) the Company lacks adequate injection/withdrawal or transportation capacity to provide the requested service; or (vi) the service requested is at less than the applicable maximum rate; provided, however, that the Company may agree to provide the service at less than the applicable maximum rate.

The Company shall consider a valid request, and will contact the Requesting Party regarding whether it can provide the requested Storage Service. If the Company is able to accommodate the request, the Company will provide the details according to which Company is willing to provide such service. If the Company can provide some, but not all of the requested Firm Storage Service, the Company will advise the Requesting Party of the maximum quantities that Company would be able to accommodate. If more than one request for Firm Storage Service is received, then the Company shall tender Service Agreements in order of the highest net present value proposed to be paid by such Requesting Parties. If the Company is unable to accept, in full, simultaneous requests for Firm Storage Service from Requesting Parties when they have proposed to pay the same rate, then the Company shall tender Service Agreements reflecting each Requesting Party's *pro rata* share of the capacity requested.

The Company shall tender a Service Agreement to the Requesting Party upon Company's acceptance of such party's request for Firm Storage Service. The Service Agreement shall be invalid unless signed by the Requesting Party and returned to the Company within thirty (30) days after the Company tenders such Service Agreement for execution.

(continue to Sheet 80-6)

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

RATES AND CHARGES:

***Monthly Deliverability Reservation Charge*.**
A monthly charge, as set forth in the Service Agreement, shall apply for each Dekatherm (Dth) of Customer's MDWQ. The maximum Monthly Deliverability Reservation Charge is $5.500/month and the minimum charge is $0.

Monthly Capacity Charge.
A monthly charge, as set forth in the Service Agreement, shall apply for each Dth of Customer's MSC. The maximum Monthly Capacity Charge is $.0600/month and the minimum charge is $0.

***Authorized Overrun Charge*.**
A charge, as set forth in the Service Agreement, may apply for each Dth of Gas withdrawn in excess of Customer's MDWQ or injected in excess of Customer's MDIQ (Authorized Overrun Quantities) on each Gas Day of a given Month. The maximum charge is $0.1850 and the minimum charge is $0.0000.

Fuel Charge.
Customers shall be assessed a 2% fuel-in-kind charge for each Dth of gas injected.

***Other Applicable Charges*.**
Any other applicable charges as provided for in the Tariff may be set forth on the Service Agreement or monthly invoice, as appropriate.

***Service Charge Credit*.**
If the Company fails to deliver to the designated Storage Delivery Point or receive at the Receipt Point hereunder, other than as may be excused by Force Majeure, ninety-five percent (95%) or more of the aggregate Confirmed Daily Nominations (as hereinafter defined) of all firm intrastate Storage Service Customers for more than twenty-eight (28) Days in any given Contract Year, then for each Gas Day during that Contract Year in excess of twenty-eight (28) Days that the Company so fails to deliver or receive (a "Credit Day"), Customer, as its sole remedy, shall be entitled to a Service Charge Credit calculated as set forth below.

(continue to Sheet 80-7)

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

RATES AND CHARGES (continued):

***Service Charge Credit (continued)*.**
For the purpose of this provision, Confirmed Daily Nomination shall mean for any Gas Day, the lesser of (1) Customer's Maximum Daily Withdrawal Quantity (MDWQ)(as may be reduced by the provisions of Customer's Service Agreement) or Maximum Daily Injection Quantity (MDIQ), as applicable; (2) the quantity of Gas that the connecting upstream interstate pipeline(s), local distribution company pipeline(s) or end-user(s) is/are capable of accepting for Customer's account at the designated Receipt Point or Storage Delivery Point; or (3) Customer's nomination to the Company. Additionally, for purposes of this subsection, Contract Year shall mean the 12-month period beginning with the commencement of Storage Service under a firm Service Agreement hereunder and ending one day prior to the anniversary date of service commencement, and each subsequent 12-month period thereafter during the term of the Agreement.

The Service Charge Credit for each Credit Day for a particular Customer shall be computed as follows:

$$\text{Service Charge Credit for Each Credit Day} = \frac{A + B}{(30.41)} \times \frac{C - D}{(C)}$$

where A = Customer's Monthly Reservation Charge (product of Reservation Charge per Dth and MDWQ)
B = Customer's Monthly Capacity Charge (product of Capacity Charge per Dth and MSC)
C = Customer's Confirmed Daily Nomination for the Credit Day
D = Actual quantity of gas delivered or received by Owner for Customer's account at the Storage Delivery Point for the Credit Day

At the anniversary date of a Customer's Contract Year, Owner will determine the applicable number of Days that performance fell below 95%, if any, and then determine if any Credit Days apply. If Credit Days are applicable to such Customer, Owner will calculate the Service Charge Credit and it will appear as a credit to the charges listed on such Customer's next regular monthly invoice for Storage Service. Additionally, if Customer's failure to receive gas at a downstream Delivery Point hereunder on any Gas Day is due to an interruption of interruptible transportation of the gas from the Storage Delivery Point to the Delivery Point at Customer's facility, then such an event shall not be considered in terms of calculating the Service Charge Credit provided for in this provision so long as the Confirmed Daily Nomination for the Firm Storage Service was otherwise available to the Customer for redelivery at the Storage Delivery Point on such day.

(continue to Sheet 80-8)

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

INJECTIONS AND WITHDRAWALS:

Maximum Storage Capacity. Customer's MSC shall be set forth in the Service Agreement.

Injections. Subject to Force Majeure, or as otherwise provided for herein, Customer will be allowed to nominate to inject Customer-Owned Gas into Mist on each Gas Day on a firm basis in an amount that is confirmed by the Company up to Customer's MDIQ, as set forth in the Service Agreement, so long as injection of such quantities does not cause Customer to exceed its MSC. On any Gas Day, Company is not obligated to receive more than the MDIQ in the Service Agreement.

Withdrawals. Subject to Force Majeure, or as otherwise provided for herein, Customer will be allowed to nominate to withdraw Customer-Owned Gas from Mist on each Gas Day on a firm basis in an amount that is confirmed by the Company up to Customer's MDWQ, as set forth in the Service Agreement, so long as the withdrawal of such quantities does not cause Customer to incur a negative Working Gas balance; provided, however, that once a Firm Storage Service Customer's Working Gas inventory falls below fifty percent (50%), then firm withdrawals shall be limited to the amount specified in the withdrawal table attached to Customer's Service Agreement.

The withdrawal of any amounts above the firm amount in the withdrawal table up to the MDWQ may be requested by Customer and will be accommodated by the Company on an as-available basis, and such quantities will be scheduled ahead of interruptible interstate Storage Services or Authorized Overrun Quantity nominations. On any Gas Day, the Company is not obligated to deliver more than the lesser of the MDWQ or the firm amount specified in the withdrawal table attached to the Service Agreement.

STORAGE ACCOUNT VOLUME TRANSFERS TO AN INTERSTATE STORAGE ACCOUNT:
Customer will be allowed to transfer Working Gas amounts between its Storage Account under this Rate Schedule and a storage account that such same Customer may have with the Company for interstate storage service upon prior written notice to the Company, but such transfer shall not impact any amounts due and owing under each applicable service agreement prior to the date of the transfer and invoice account balances may not be transferred under this provision. A Customer's ability to make such account transfers will not modify the MSC, MDIQ, or MDWQ amounts specified in the Service Agreement applicable to this Rate Schedule nor will it modify the MSC, MDIQ, or MDWQ amounts specified in the interstate storage service agreement. Additionally, Customers will not be allowed to increase the MDIQ, MDWQ, or MSC amounts set forth in the Service Agreement under this Rate Schedule by requesting to combine some or all of such amounts with those in an interstate storage service agreement for purposes of modifying the specified injection, withdrawal, or storage capacity amounts set forth under such separate storage service agreements.

(continue to Sheet 80-9)

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

TITLE TRANSFERS:
A Customer ("Transferor") may request that the Company transfer title to Working Gas quantities in Transferor's Storage Account to the intra or interstate Storage Account of another Customer or to the Company ("Transferee"). Subject to the provisions herein, the Company will document the change in Storage Account balances for the respective parties, but Transferor and Transferee will be responsible for any other Gas sale documentation that may be necessary to complete the title transfer transaction. The provisions in this section, however, do not apply to any permanent assignment of all or any portion of a Customer's Service Agreement and in such an event, the assignment provisions would apply.

Transferor shall nominate a title transfer no later than the nomination deadline provided for herein. The nomination request shall specify: (1) Transferor's Service Agreement number or type; (2) Transferee's name and Service Agreement number or type; (3) quantity of gas subject to the transfer; (4) Gas Day on which the transfer is requested to occur; and (5) Mist as the Title Transfer Point. No later than the deadline specified herein, the Company shall notify Transferor and Transferee if the title transfer request is authorized.

If Transferee is a Customer, the Transferee must meet the Company's credit and prerequisite to service requirements and must have an executed Service Agreement in place with the Company. The Company may reject a title transfer request if: (a) it would cause either Transferor or Transferee to violate any contract quantity limitations set forth in its Service Agreement; (b) Transferor or Transferee is not a Customer or the Company; or (c) the Company's credit and prerequisites to service requirements are not satisfied.

A title transfer shall be deemed to occur at the Title Transfer Point. There shall be no charge for each title transfer authorized by the Company. However, Transferor and Transferee shall each be responsible for all applicable charges payable to the Company under their respective service agreements.

STORAGE BALANCE AT SERVICE AGREEMENT EXPIRATION OR TERMINATION:
Customer shall be responsible for the withdrawal of all of its positive Firm Storage Service balance in its Storage Account: (i) on or before sixty (60) days after the date upon which any applicable Service Agreement expires by its own terms; or (ii) on or before thirty (30) days after the date of termination; provided that during such grace periods following expiration or termination, Customer shall pay Company the maximum rates specified herein for the additional Storage Service that is provided notwithstanding any previously negotiated discount applicable to the service prior to the Agreement expiration or termination. Such withdrawals shall be made at withdrawal rates that are mutually

(continue to Sheet 80-10)

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

STORAGE BALANCE AT SERVICE AGREEMENT EXPIRATION OR TERMINATION (continued):
agreed upon between Company and Customer subject to operating conditions at Mist. If Customer fails to remove its positive storage balance by the end of such grace period and Customer does not enter into a new Firm Storage Service Agreement, then Company shall purchase from Customer the Gas in Customer's Storage Account, free and clear of any adverse claims, at a price equal to fifty percent (50%) of the price set forth in the Canadian Gas Price Reporter, Natural Gas Market Report – Natural Gas Price Summary under the heading "The One-month spot price average" "For AECO/NIT transactions," in USD/MMBtu, that is applicable for the month in which the gas purchase takes place; provided, however, that if Customer's failure to remove the Gas during such grace period is due to the Company's inability to confirm the nomination (up to the applicable firm MDWQ), then Customer shall be entitled to additional time at no additional charge to complete the withdrawal equal to the number of days Customer was prevented from withdrawing.

NOMINATIONS, SCHEDULING AND SERVICE PRIORITY:

Daily Nomination Procedure. All nominations must be submitted to the Company's Gas Supply Department by email (preferred) or by facsimile using a format that is approved by the Company. The contact information for the Company is set forth in the Company's Storage Service Operating Policies and Procedures document, which contains further details regarding nomination and scheduling of Storage Service not inconsistent with this Rate Schedule and which document will be provided to each Customer, and such document may be updated from time to time. Oral nominations may be accepted, however, they must be emailed to Company within a reasonable amount of time. The Company will acknowledge receipt of the nomination request by email reply.

Required Information. Each nomination request shall specify: (1) the Gas Day Customer desires to inject or withdraw; (2) the applicable Customer upstream or downstream transportation agreement number; (3) Receipt Point; or in the case of delivery, both the Storage Delivery Point and the Delivery Point at Customer's facility where they gas will be consumed must be provided; (4) net Dth requested at the receipt or delivery points; (5) contact name and phone number; and (6) any other data required by upstream transporters or the Company to complete the nomination process.

Deadline. All nomination requests must be received by the Company one (1) hour prior to the applicable NAESB nomination cycle deadlines for timely noms, evening, intraday 1 (ID1), and intraday 2 (ID2). Additionally, post ID2 nominations are available to Customers to the extent the Company and any applicable upstream transporter is able to accommodate such changes. If confirmed, any actual Gas flows on the Company's system for injections or withdrawals will not begin until the time specified for gas flow under the NAESB guidelines for the next available processing cycle depending on when the nomination is received. The Company may, but is not required to, waive the one (1) hour requirement if, in its sole judgment, operating conditions permit such waiver.

(continue to Sheet 80-11)

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

NOMINATIONS, SCHEDULING AND SERVICE PRIORITY (continued):

Confirmation. The Company will notify Customer to confirm the nomination in advance of the applicable nomination deadline specified in the Company's Storage Operating Policies and Procedures based on when Customer's nomination is received by the Company. The Company's ability to confirm nominations will be determined based on its system operating ability for the Gas Day consistent with the service priorities set forth herein as well as the availability of the designated take away transportation capacity. Unless otherwise agreed or as limited by system operating constraints, all confirmed volumes will be delivered by Customer, or redelivered by the Company, at a uniform hourly rate of confirmed daily quantity divided by twenty-four (24). Variance from the uniform hourly rate will be allowed by the Company if the Company determines that it would not be detrimental to the operation of the Company's storage and related transportation facilities or adversely affect the Company's other Customers. The Company must receive confirmation from Customer's upstream transporter prior to commencing any receipts for Customer, and for redelivery, the Company must confirm the account under which the gas will be transported on after redelivery at the Storage Delivery Point.

Receipt Point(s) and Storage Delivery Point(s). The Company and Customer shall designate in the Service Agreement a list of the currently available Receipt Point(s) and Storage Delivery Point(s). The Receipt Point(s) shall be at mutually agreeable point(s) of interconnection between an interstate pipeline and the Company's facilities. The Storage Delivery Point(s) shall be at the Company's side of the metering facilities located at the Deer Island or Molalla gate interconnections between the Company's system and the facilities of Northwest Pipeline Corporation, or another point that is acceptable to the Company in its sole discretion. The subsequent transportation of the gas from the Storage Delivery Point to a Delivery Point in Oregon on the Company's distribution system will be subject to the provisions of the Rate Schedule or Special Contract terms for the Transportation of Customer-Owned Gas on the Company's system that are in place with respect to such Customer (or as designated by a Customer's commodity supplier), including any service limitations, service priority, and rates applicable to such transportation.

Customer Scheduling of Transportation.
The Customer hereunder shall be solely responsible for making all arrangements and paying for the Transportation of the gas to the Receipt Point(s) for injection into Mist, and for specifying and/or making all arrangements for the Transportation of the gas after withdrawal and redelivery by the Company at the Storage Delivery Point(s).

Other Transporter Charges.
Customer shall be responsible for all penalties and charges assessed by an upstream or downstream Transporter which solely arise from Customer's failure to provide delivery or receive redelivery of the Gas quantities provided pursuant to the nomination process in this Section.

(continue to Sheet 80-12)

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

NOMINATIONS, SCHEDULING AND SERVICE PRIORITY (continued):

Service Priorities.

(a) The Firm Storage Service provided under this Rate Schedule will have equal priority with the firm storage service provided to the Company's interstate storage customers as well as the storage service provided to the Company's local distribution customers. The scheduling of Firm Storage Service hereunder will have a superior priority over the scheduling of as-available firm withdrawal quantities for intrastate and interstate storage customers, interruptible interstate storage services, as well as any intrastate or interstate Authorized Overrun Quantities related to the storage services provided by the Company. Once confirmed, firm nominations will not be reduced ("bumped") in full or in part by Company due to a subsequent intraday firm nomination, unless Customer is changing its own prior nomination through an intraday nomination request. Firm Storage Service under this Rate Schedule will have scheduling priority (or "bumping rights") over previously scheduled as-available firm withdrawals for intrastate or interstate storage customers, interruptible interstate storage customers, and Authorized Overrun Quantities for both intrastate and interstate storage customers, except that firm nominations will not bump previously scheduled lower classes of service after the ID2 nomination cycle. Firm service nominations received outside of the timely or evening nomination cycles may be prorated based on prior confirmation of other firm Customer's as-available MDWQ requests.

(b) In the event that the Company must restrict initial Firm intrastate and interstate storage injection requests or previously scheduled and confirmed firm injection amounts for reasons allowed in this Rate Schedule, they will be restricted on a *pro rata* basis based on each customer's applicable MDIQ using the NAESB "elapsed pro-rata" methodology. In the event that the Company must restrict initial firm intrastate and interstate storage withdrawal requests or previously scheduled and confirmed firm withdrawal amounts for reasons allowed in this Rate Schedule, they will be restricted on a *pro rata* basis based on each Customer's applicable MDWQ using the NAESB "elapsed pro rata" methodology. In the event that such action must be taken, the Company will notify Customers via phone, facsimile, or electronic mail.

(c) If Firm intrastate and interstate storage customers must be pro-rated and any Customer has not made a timely nomination to schedule its pro rata share on any such Gas Day, then the Customers that made timely nomination requests shall, to the extent practicable, be given the ability to inject or withdraw in amounts greater than their allocated pro-rata share, not to exceed such Customer's MDIQ and MDWQ amounts set forth in their Service Agreements. These additional amounts will be identified by the Company and will be subject to bumping in later cycles except post ID2 by firm intrastate or interstate Customers then electing to receive their portion of the pro-rata share determined for them for that Gas Day. If there is available space in the post ID2 cycle, if requested by a Customer, the Company would schedule requests for firm Customers at that time.

(continue to Sheet 80-13)

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

NOMINATIONS, SCHEDULING AND SERVICE PRIORITY (continued):

Authorized Overrun. Authorized Overrun Quantities may be curtailed by all higher priority levels of service, including interruptible.

Interruption Notices. In the event that an interruption or restrictions are required, the Company will notify Customers of their revised confirmed amounts via email, facsimile, or phone call.

Nomination Changes. In the absence of a nomination, no changes or action will be taken by the Company with regard to a Customer's Storage Account.

Routine Maintenance. The Company shall have the right to interrupt, or discontinue Firm Storage Service in whole or in part from time to time to perform routine repair and maintenance on Company's system as necessary to maintain the operational capability of Company's facilities or to comply with applicable regulatory requirements. The Company shall exercise due diligence to schedule routine repair and maintenance so as to minimize disruptions of service to Customers and shall provide reasonable advance notice of the same to Customers by facsimile or email at least thirty (30) days in advance of the scheduled routine repair and maintenance. Upon request, Customers shall provide the Company with any information on their plans to utilize Mist during the scheduled routine repair and maintenance period and shall cooperate with the Company to minimize service disruptions. In any such disruption, quantities of gas deliverable under firm Service Agreements shall take priority over quantities of gas deliverable by the Company to intrastate and interstate storage customers at lower priorities. Notice of such interruptions or discontinuances shall be issued by Company to Customer via facsimile or email. Such interruptions or discontinuances shall in no way serve to alter the obligation(s) of a Customer under any applicable Service Agreement.

GAS PRESSURE, QUALITY AND MEASUREMENT:

Gas Pressure. Customer shall deliver or cause to be delivered to Company all Gas at the Receipt Point(s) at such pressures sufficient to enter Company's system. The Company shall redeliver Gas to Customer at the current operating pressures on Company's system at the Storage Delivery Point.

Quality. Gas delivered by or on behalf of the Customer to the Company at the Receipt Point(s) shall conform to the third party Transporter's Gas quality standards. Gas redelivered by Company to Customer at the Storage Delivery Point(s) shall conform to the Company's quality standards in Rule 24, or its successor rule.

Measurement. Measurement of Gas quantities hereunder shall be performed by Company in accordance with standard gas industry practices as set forth in the Tariff.

(continue to Sheet 80-14)

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

BILLING AND PAYMENT:

Monthly Statements. The bill payment provisions in Rule 7 of the Tariff, to the extent applicable, shall apply to this Rate Schedule. Regarding Storage Service, the statement will include: (a) the applicable rate(s); (b) the quantities being billed at each rate; and (c) documentation sufficient to support the billed quantities.

Payment. Payment shall be due as set forth on the invoice. Unless otherwise agreed, Customer shall pay by wire transfer or other electronic means acceptable to the Company in immediately available funds to the Company the full amount due. If the day for payment should fall upon a Saturday, Sunday or U.S. banking holiday, then such payment shall be made on the next Business Day. If Customer fails to pay such amounts when due, a late payment charge will be assessed as prescribed under **Schedule C** of this Tariff.

Billing Adjustments. If an error is discovered by either the Company or Customer, in the amount billed in any statement rendered by Company, the Company shall use its best efforts to correct any such billing error within sixty (60) Days of the discovery of such error by the Company, if the Company discovers the error, or the Company's receipt of notification of such error from Customer, if the error is discovered by the Customer. If Customer, in good faith, disputes the amount of any such statement or any part thereof, Customer shall pay the Company such amount as it concedes to be correct pending resolution of the dispute; provided, however, if Customer disputes the amount due, Customer must provide supporting documentation acceptable in industry practice to support the amount disputed. If the disputed amount is subsequently found to correct, then Customer shall pay the Company such amount, together with any late payment charge provided for above that accrued from the original charge due date. All statements shall be considered final, and any and all objections thereto shall be deemed waived**,** unless made in writing within three (3) years of Customer's receipt thereof. Nothing in this section shall prevent the Company from terminating Storage Service to a Customer for non-payment of the undisputed amounts per statements rendered pursuant to **Rule 11** of this Tariff. Customer is responsible for the payment of any applicable taxes assessed by taxing authorities that may be associated with the Storage Service provided under this Rate Schedule. Further, nothing in this provision shall be construed to relieve Customer of its obligation to pay any required taxes not included in the Company’s rates assessed by a taxing authority on Customer, including any taxes that may later be determined by a taxing authority to have been applicable to the Storage Service.

(continue to Sheet 80-15)

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

FORCE MAJEURE:

Except in regard to a Customer's obligation to make a payment that is due, neither shall be liable in damages to the other if rendered unable, by reason of an event of *force majeure*, to perform, in whole or in part, any firm obligation set forth in any Agreement. For purposes of this provision, the term *Force Majeure* as used in this Rate Schedule shall mean: any causes or circumstances not due to the fault of the Party claiming *force majeure* beyond such party's reasonable control, including, but not limited to, acts of God, strikes, lockouts, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or pipelines, freeze-offs, water encroachment, unscheduled downhole repairs, loss of well control, interruptions or failures of any upstream or downstream pipelines relied upon to effectuate any service under this Rate Schedule, the binding order of any court or governmental authority having jurisdiction, and any other cause, whether of the kind herein enumerated or otherwise, not reasonably within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome. Failure to prevent or settle any strike or strikes shall not be considered to be a matter within the control of the party claiming suspension and shall be entirely within the discretion of the party affected, and the requirement that any event of *force majeure* be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of those directly or indirectly involved in such strikes or lockouts when such course is inadvisable in the discretion of the party having such difficulty. The term *Force Majeure* shall not include: (i) instances where the party claiming excuse failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch; or (ii) economic hardship.

Upon the occurrence of an event of *Force Majeure*, the party affected shall give notice to the other party including the particulars of the event as soon as practicable, by telephone following by written confirmation. After the occurrence, the obligations of both parties, except for unpaid financial obligations arising prior to such event, shall be suspended to the extent and for the period of such *Force Majeure* condition.

(continue to Sheet 80-16)

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

RATE SCHEDULE 80
FIRM STORAGE SERVICE (EXPERIMENTAL)
(continued)

DEFAULT:

Termination for Default. The Company may terminate any Agreement if Customer fails to comply with, observe, perform, or shall default in any material respect with respect to any obligation under the Agreement, including, but not limited to, the failure to pay any undisputed invoices when due, except when such failure is excused by *Force Majeure* or attributable to Company's wrongful act or failure to act. If the Company exercises its right to terminate, the Company shall give Customer written notice of the default and, Customer shall be given a period of thirty (30) calendar days from the date of such notice in which to cure the default. If such default cannot be reasonably cured within such thirty (30) day period, Customer may request and the Company, in its sole discretion, may grant Customer additional time to cure the default, provided that Customer demonstrates to the Company's satisfaction that it is making or has made substantial efforts to effect such cure and is proceeding diligently to complete such cure. Effective as of the date of termination of the Agreement, all outstanding amounts for any Storage Services rendered by the Company prior to such date shall become immediately due and payable.

Withdrawal of Storage Account Balance upon Termination for Default. Customer shall be responsible for the withdrawal of all of its positive Storage Account balance on or before thirty (30) days after the termination date of any Service Agreement under this default provision. Such withdrawals shall be made at withdrawal rates that are mutually agreed upon between Company and Customer subject to operating conditions at Mist. If Customer fails to do so, the Company shall take title to any of Customer's positive Storage Account balance remaining at Mist as of the termination date, free and clear of all liens, encumbrances, and adverse claims.

Other Rights Preserved. The availability or exercise of the right to terminate an Agreement pursuant to the above provisions shall not limit the right of the Company to seek any other remedy available to it at law or in equity in the event of a Customer's default.

NOTICE:

All notices and communications to the Company shall be made pursuant to Tariff Rule 5. Customer's notice information shall be set forth in the Service Agreement.

GENERAL TERMS:

The terms of this Rate Schedule will apply in addition to the terms and conditions in the Company's Storage Service Operating Policies and Procedures document as well as the designated Transportation Rate Schedule or Special Contract applicable upon redelivery. Service under this Rate Schedule is also governed by the terms and conditions of NW Natural's Oregon Tariff, including the General Rules and Regulations and other relevant General Schedules, as amended from time to time.

SCHEDULE 100
SUMMARY OF ADJUSTMENTS

PURPOSE:

The purpose of this Schedule is to list and summarize the adjustment Schedules applicable to each of the Company's Rate Schedules.

SCHEDULE	A		160		162		164		167		172	
1R	ADD		ADD		INC		INC		INC		INC	
1C	ADD		ADD		INC		INC		INC			
2	ADD		ADD		INC		INC		INC		INC	
3 (CSF)	ADD		ADD		INC		INC		INC			
3 (ISF)	ADD		ADD		INC		INC		INC		INC	
15	ADD								INC			
27	ADD		ADD		INC		INC		INC			
31 (CSF)	ADD		ADD		INC		INC		INC			
31 (CTF)	ADD				INC				INC			
31 (ISF)	ADD		ADD		INC		INC		INC		INC	
31 (ITF)	ADD				INC				INC		INC	
32 (CSF/ISF)	ADD		ADD		INC		INC		INC		INC	
32 (CSI/ISI)	ADD		ADD		INC		INC		INC		INC	
32 (CTF/ITF)	ADD				INC				INC		INC	
32 (CTI/ITI)	ADD				INC				INC		INC	
33 (CTI/ITI)	ADD				INC				INC			
33 (CTF/ITF)	ADD				INC				INC			
60	ADD											

Table Code Key:

ADD This adjustment is added to the billing rates at the time the bill is issued.
INC This adjustment is included in the billing rates shown on the Rate Schedule.

(continue to Sheet 100-2)

SCHEDULE 100
SUMMARY OF ADJUSTMENTS
(continued)

<u>PURPOSE</u> (continued):

SCHEDULE	177	178	183	184	185	186	187	188	190	195	301
1R	INC	INC	INC	INC	ADD	ADD	INC		INC		ADD
1C	INC	INC	INC	INC	ADD	ADD	INC		INC		ADD
2	INC	INC	INC	INC	ADD	ADD	INC		INC	ADD	ADD
3 (CSF)	INC	INC	INC	INC	ADD	ADD	INC		INC	ADD	ADD
3 (ISF)	INC	INC	INC	INC	ADD	ADD	INC	INC			
15											
27	INC	INC	INC	INC			INC				ADD
31 (CSF)	INC	INC	INC	INC	ADD	ADD	INC		INC		ADD
31 (CTF)	INC	INC	INC	INC					INC		
31 (ISF)	INC	INC	INC	INC	ADD	ADD	INC	INC			
31 (ITF)	INC	INC	INC	INC							
32 (CSF/ISF)	INC	INC	INC	INC	ADD	ADD	INC	INC			
32 (CSI/ISI)	INC	INC	INC	INC		ADD	INC	INC			
32 (CTF/ITF)	INC	INC	INC	INC							
32 (CTI/ITI)	INC	INC	INC	INC							
33 (CTI/ITI)	INC	INC	INC	INC							
33 (CTF/ITF)	INC	INC	INC	INC							
60											

Table Code Key:

ADD This adjustment is added to the billing rates at the time the bill is issued.
INC This adjustment is included in the billing rates shown on the Rate Schedule.

(continue to Sheet 100-3)

SCHEDULE 100
SUMMARY OF ADJUSTMENTS
(continued)

The following is a brief description of the applicable Schedules:

Schedule A "Billing for City and County Exactions."
This is an adjustment to customer bills for the pass through collection of city and county exactions.

Schedule 160 "Revision of Charges for Coos County Customers."
This is an ongoing volumetric adjustment (per therm) that is applied to Coos County Customer bills.

Schedule 162 "Temporary (Technical) Adjustments to Rates."
These are Temporary Adjustments to volumetric rates (per therm) for the amortization of gas costs (Account 191) and non-gas cost (Account 186) deferral amounts.

Schedule 164 "Purchased Gas Cost Adjustments to Rates."
This schedule reflects the Pipeline Capacity and Commodity charges applicable to current billing rates.

Schedule 167 "General Adjustments to Rates."
These are Base Adjustments to volumetric rates (per therm) and to Customer Charges that apply the effect of general rate adjustments approved in a general rate case docket.

Schedule 172 "Special Adjustment to Rates for Intervenor Funding."
These are Temporary Adjustments to volumetric rates (per therm) for the recovery of costs associated with payments made to Citizens Utility Board and Northwest Industrial Gas Users for their participation in various Commission activities.

Schedule 177 "System Integrity Program Rate Adjustment."
These are Base Adjustments to volumetric rates (per therm) for the recovery of costs associated with the ongoing system integrity activities.

(continue to Sheet 100-4)

SCHEDULE 100
SUMMARY OF ADJUSTMENTS
(continued)

Schedule 178 “Regulatory Adjustment Rate.”
These are Temporary Adjustments to volumetric rates (per therm) associated with the amortization of one-time deferral or residual amounts from deferral accounts that have ended.

Schedule 183 "Site Remediation Recovery Mechanism"
These are Base Adjustments to volumetric rates (per therm) for the recovery of environmental remediation costs.

Schedule 184 "Special Rate Adjustment - Gasco Upland Pumping Station"
These are Base Adjustments to volumetric rates (per therm) for the recovery of costs associated with the pumping station installed at the Gasco Upland Site located in Linnton, Oregon.

Schedule 185 “Special Annual Interstate Storage and Transportation Credit.”
This is an annual lump sum adjustments to June bills for the sharing of revenues from non-utility storage and transportation activities that do not affect Rate Schedule billing rates.

Schedule 186 “Special Annual Core Pipeline Capacity Optimization Credit.”
This is an annual lump sum adjustment to June bills for the sharing of revenues from pipeline capacity optimization activities that do not affect Rate Schedule billing rates.

Schedule 187 “Special Adjustment for Storage Recall.”
These are Base Adjustments to volumetric rates (per therm) for the recovery of Mist storage facilities recalled from Interstate Storage activities to serve core utility customers.

Schedule 188 “Industrial Demand Side Management (DSM) Program Cost Recovery.”
These are Temporary Adjustments to volumetric rates (per therm) for the recovery of costs associated with demand side management programs available to Industrial Customers.

Schedule 190 “Partial Decoupling Mechanism.”
These are Base Adjustments to volumetric rates (per therm) to apply the effects of usage variances calculated in accordance with this Schedule.

Schedule 195 “Weather Adjusted Rate Mechanism (WARM).”
These are winter heating season adjustments to volumetric rates (per therm) applied to Residential and Commercial customer bills for the effect of any deviation from normal weather within a billing month.

Schedule 301 “Public Purposes Funding Surcharge.”
These are monthly adjustments applied as a percentage of the total billed amount that does not affect Rate Schedule billing rates.

SCHEDULE 150
MONTHLY INCREMENTAL COST OF GAS

APPLICABILITY:
This Schedule applies to Customers that have requested and been approved by the Company to change Rate Schedules and/or Service Types under the following situations:

1. Customer has requested and been approved to make a Service Type change from Transportation Service to Sales Service in accordance with the 'OUT-OF-CYCLE TRANSFERS" section of the applicable Rate Schedule.
2. Customer has requested and been approved to make a Service Type change from Transportation Service to Sales Service in accordance with the "ANNUAL SERVICE ELECTION DATE– JULY 31 ELECTION FOR NOVEMBER 1 SERVICE" section of the applicable Rate Schedule with an effective date for Sales Service that is prior to November 1,
3. Customer in on Sales Service at Winter Sales WACOG and Customer will pay for Sales Service at Monthly Incremental Cost of Gas effective April 1.
4. Customer has requested and been approved to make a Rate Schedule and Service Type change from Transportation Service under **Rate Schedule 31**, **Rate Schedule 32** or **Rate Schedule 33** or under a special contract to Sales Service under **Rate Schedule 3** outside of the Annual Service Election.

APPLICATION TO RATE SCHEDULES:
For each of the applicable Billing Months, the Commodity Component of the volumetric charges shall be billed at Monthly Incremental Cost of Gas.

CALCULATION OF MONTHLY INCREMENTAL COST OF GAS:
Monthly Incremental Cost of Gas will be calculated as follows:

For each Billing Month:

A. The "One-month spot price average" for AECO/NIT transactions published in the Canadian Gas Price Reporter Natural Gas Market Report, as listed in US dollars per million Btu (the AECO Index) at the start of the Billing Month will be added to:
B. Pipeline fuel-in-kind and line loss charges and pipeline variable transportation charges in effect on the pipeline systems of TransCanada Alberta (NOVA), TransCanada BC System (TCPL BC), Transmission Northwest Corporation (GTN), and Northwest Pipeline (NPC) to derive a city gate price.
C. The city gate price is then adjusted for the Company's revenue-sensitive effects and is converted from million Btus to Therms to derive the Monthly Incremental Cost of Gas.
D. The Company will post the Monthly Incremental Cost of Gas on its website as soon as it is available each month.

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 Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 160
REVISION OF CHARGES FOR COOS COUNTY CUSTOMERS

PURPOSE:
The adjustment under this Schedule, herein referred to as "Coos County Charge," is for the recovery of: (a) the cost of pipeline transportation service on the Coos County pipeline (County pipeline); and (b) the Coos County customer's share of costs associated with the construction of the initial distribution system investment required to deliver natural gas to serve the Coos County service territory, herein referred to as "Coos County share."

APPLICABLE:
To Coos County Sales Service Customers served under the following Rate Schedules of this Tariff:

Rate Schedule 1	Rate Schedule 31
Rate Schedule 2	Rate Schedule 32
Rate Schedule 3	
Rate Schedule 27	

APPLICATION TO RATE SCHEDULES: Effective: March 17, 2004
The Billing Rate in the above-listed Rate Schedules will be adjusted (increased) by $0.02000 per therm.

SPECIAL CONDITIONS:

1. Revenues collected from the Coos County Charge shall be applied first to pay the costs of transportation services on the County pipeline, and second to repay the Coos County share of costs associated with the initial investment required to bring natural gas service into the Coos County service territory.
2. Any shortfall between amounts collected from the Coos County Charge and the total transportation charges paid to the County pipeline will be included in total Oregon demand charges in accordance with the provisions of **Schedule P** of this Tariff.
3. The Coos County Charge shall be in effect for the initial term of the Transportation Agreement between NW Natural and the Coos County pipeline. The initial term will end December 31, 2024.
4. If at the end of the initial term, the Coos County share has not been fully repaid, the Company will calculate the balance of the Coos County share remaining to be repaid and will recalculate the Coos County Charge to repay such balance (including carrying charges) within a reasonable time. Any recalculation of the Coos County Charge is subject to approval by the Commission.
5. This Schedule is subject to other terms and conditions as set forth in a Stipulation and Agreement adopted by the Commission in Docket UG 152, Order No. 03-236.

GENERAL RULES AND REGULATIONS:
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 Rate Schedule apply to this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued by: ***NORTHWEST NATURAL GAS COMPANY***
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

SCHEDULE 162
TEMPORARY (TECHNICAL) ADJUSTMENTS TO RATES

PURPOSE:
To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of balances in all of the Company's conventional deferred revenue and gas cost accounts, Accounts 186 and 191, respectively.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 1 Rate Schedule 3 Rate Schedule 31 Rate Schedule 33
Rate Schedule 2 Rate Schedule 27 Rate Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: February 1, 2011

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Account 191 Commodity Adjustment	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments [1]	Total Temporary Adjustment
1R		$(0.02633)	$0.00051	$0.06547	**$0.03965**
1C		$(0.02633)	$0.00051	$0.02280	**$(0.00302)**
2		$(0.02633)	$0.00051	$0.06003	**$0.03421**
3 CSF		$(0.02633)	$0.00051	$0.01923	**$(0.00659)**
3 ISF		$(0.02633)	$0.00051	$0.02458	**$(0.00124)**
27					
31 CSF	Block 1	$(0.02633)	$0.00051	$0.01419	**$(0.01163)**
	Block 2	$(0.02633)	$0.00051	$0.01324	**$(0.01258)**
31 CTF	Block 1	N/A	N/A	$0.01555	**$0.01555**
	Block 2	N/A	N/A	$0.01516	**$0.01516**
31 ISF	Block 1	$(0.02633)	$0.00051	$0.02000	**$(0.00582)**
	Block 2	$(0.02633)	$0.00051	$0.01895	**$(0.00687)**
31 ITF	Block 1	N/A	N/A	$0.00422	**$0.00422**
	Block 2	N/A	N/A	$0.00382	**$0.00382**

[1] The sum of the adjustments identified in Schedules 172, 178, 183, 188, & 190.

(continue to Sheet 162-2)

SCHEDULE 162
TEMPORARY (TECHNICAL) ADJUSTMENTS TO RATES
(continued)

APPLICATION TO RATE SCHEDULES (continued): Effective: February 1, 2011

Schedule	Block	Account 191 Commodity Adjustment	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments [1]	Total Temporary Adjustment
32 CSF	Block 1	$(0.02633)	$0.00051	$0.02064	$(0.00518)
	Block 2	$(0.02633)	$0.00051	$0.02020	$(0.00562)
	Block 3	$(0.02633)	$0.00051	$0.01944	$(0.00638)
	Block 4	$(0.02633)	$0.00051	$0.01869	$(0.00713)
	Block 5	$(0.02633)	$0.00051	$0.01823	$(0.00759)
	Block 6	$(0.02633)	$0.00051	$0.01793	$(0.00789)
32 ISF	Block 1	$(0.02633)	$0.00051	$0.02054	$(0.00528)
	Block 2	$(0.02633)	$0.00051	$0.02011	$(0.00571)
	Block 3	$(0.02633)	$0.00051	$0.01941	$(0.00641)
	Block 4	$(0.02633)	$0.00051	$0.01869	$(0.00713)
	Block 5	$(0.02633)	$0.00051	$0.01826	$(0.00756)
	Block 6	$(0.02633)	$0.00051	$0.01797	$(0.00785)
32 CTF/ITF	Block 1	N/A	N/A	$0.00257	$0.00257
	Block 2	N/A	N/A	$0.00219	$0.00219
	Block 3	N/A	N/A	$0.00157	$0.00157
	Block 4	N/A	N/A	$0.00094	$0.00094
	Block 5	N/A	N/A	$0.00056	$0.00056
	Block 6	N/A	N/A	$0.00031	$0.00031
32 CSI	Block 1	$(0.02633)	$0.00006	$0.02031	$(0.00596)
	Block 2	$(0.02633)	$0.00006	$0.01990	$(0.00637)
	Block 3	$(0.02633)	$0.00006	$0.01924	$(0.00703)
	Block 4	$(0.02633)	$0.00006	$0.01857	$(0.00770)
	Block 5	$(0.02633)	$0.00006	$0.01816	$(0.00811)
	Block 6	$(0.02633)	$0.00006	$0.01790	$(0.00837)
32 ISI	Block 1	$(0.02633)	$0.00006	$0.02036	$(0.00591)
	Block 2	$(0.02633)	$0.00006	$0.01996	$(0.00631)
	Block 3	$(0.02633)	$0.00006	$0.01929	$(0.00698)
	Block 4	$(0.02633)	$0.00006	$0.01862	$(0.00765)
	Block 5	$(0.02633)	$0.00006	$0.01822	$(0.00805)
	Block 6	$(0.02633)	$0.00006	$0.01796	$(0.00831)
32 CT/ITI	Block 1	N/A	N/A	$0.00245	$0.00245
	Block 2	N/A	N/A	$0.00209	$0.00209
	Block 3	N/A	N/A	$0.00150	$0.00150
	Block 4	N/A	N/A	$0.00089	$0.00089
	Block 5	N/A	N/A	$0.00054	$0.00054
	Block 6	N/A	N/A	$0.00030	$0.00030
33 TI		N/A	N/A	$0.00015	$0.00015
33 TF		N/A	N/A	$0.00015	$0.00015

[1] The sum of the adjustments identified in Schedules 172, 178, 183, 188, & 190.

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.

SCHEDULE 164
PURCHASED GAS COST ADJUSTMENT TO RATES

PURPOSE:
To identify the Commodity and Pipeline Capacity Components applicable to the Rate Schedules listed below.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 1	Rate Schedule 3	Rate Schedule 31
Rate Schedule 2	Rate Schedule 27	Rate Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: February 1, 2012

Annual Sales WACOG [1]	$0.48994
Winter Sales WACOG [2]	$0.48977
Interim Sales WACOG [3]	$0.48764
Firm Sales Service Pipeline Capacity Component [4]	$0.13472
Firm Sales Service Pipeline Capacity Component [5]	$2.01
Interruptible Sales Service Pipeline Capacity Component [6]	$0.01602

[1] Applies to all Sales Service Rate Schedules (per therm) except where Winter Sales WACOG or Monthly Incremental Cost of Gas applies.
[2[Applies to Sales Customers that request Winter Sales WACOG at the September 15 Annual Service Election.
[3] Applies to Sales Service Customers following a transfer from Transportation Service when Sales Service is elected at the July 31 Annual Service Election. The maximum term on Interim WACOG is two (2) uninterrupted and consecutive PGA Years.
[4] Applies to Rate Schedules 1, 2, 3, and Schedule 31 and Schedule 32 Firm Sales Service Volumetric Pipeline Capacity option (per therm).
[5] Applies to Schedules 31 and 32 Firm Sales Service Peak Demand Pipeline Capacity option (per therm of MDDV per month).
[6] Applies to Schedule 32 Interruptible Sales Service (per therm).

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 Rate Schedule apply to service under the Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 167
GENERAL ADJUSTMENTS TO RATES

PURPOSE:
To identify the effects of general rate changes approved by the Commission with the Company's most recent general rate case proceeding, Docket UG-___.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 1 Rate Schedule 27
Rate Schedule 2 Rate Schedule 31 Rate Schedule 33
Rate Schedule 3 Rate Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: February 1, 2012
The Base Rates in the listed Rate Schedules include the adjustment shown below. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Rate Schedule/Class	Block	Customer Charge	Volumetric Charge		Rate Schedule/ Class	Block	Customer Charge	Volumetric Charge
1R		$3.19	($0.04878)		31 CSF	Block 1	($65.00)	$0.03652
1C		$8.62	($0.07581)			Block 2		$0.03332
2		$7.70	($0.04671)		31CTF	Block 1	($65.00)	$0.02163
03 CSF		$7.00	$0.02665			Block 2		$0.01974
03 ISF		$7.00	$0.04376		31ISF	Block 1	($65.00)	$0.01104
27		N/A	N/A			Block 2		$0.00998
					31 ITF	Block 1	$0.0	$0.00000
						Block 2		$0.00000

32 CSF	Block 1	N/A	N/A		32 CSI	Block 1	N/A	N/A
	Block 2	N/A	N/A			Block 2	N/A	N/A
	Block 3	N/A	N/A			Block 3	N/A	N/A
	Block 4	N/A	N/A			Block 4	N/A	N/A
	Block 5	N/A	N/A			Block 5	N/A	N/A
	Block 6	N/A	N/A			Block 6	N/A	N/A
32 ISF	Block 1	N/A	N/A		32 ISI	Block 1	N/A	N/A
	Block 2	N/A	N/A			Block 2	N/A	N/A
	Block 3	N/A	N/A			Block 3	N/A	N/A
	Block 4	N/A	N/A			Block 4	N/A	N/A
	Block 5	N/A	N/A			Block 5	N/A	N/A
	Block 6	N/A	N/A			Block 6	N/A	N/A
32 ITF/CTF	Block 1	N/A	N/A		32 CTI / ITI	Block 1	$455.00	($0.00830)
	Block 2	N/A	N/A			Block 2		($0.00706)
	Block 3	N/A	N/A			Block 3		($0.00498)
	Block 4	N/A	N/A			Block 4		($0.00291)
	Block 5	N/A	N/A			Block 5		($0.00166)
	Block 6	N/A	N/A			Block 6		($0.00083)
					33 (all)		N/A	N/A

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.

SCHEDULE 172
SPECIAL ADJUSTMENT TO RATES FOR INTERVENOR FUNDING

PURPOSE:
To identify adjustments to rates in the Rate Schedules listed below for the amortization of deferred balances related to Intervenor Funding. The rate adjustments under this Schedule are made pursuant to the Intervenor Funding Agreement in Docket UM 1357 adopted by Commission in Order No. 07-564.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 1R	Rate Schedule 3 ISF
Rate Schedule 2	Rate Schedule 31 (all Industrial Classes)
	Rate Schedule 32 (all Industrial Classes)

APPLICATION TO RATE SCHEDULES: Effective: February 1, 2012

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Residential Customer Adjustment:	$0.00034
Industrial Customer Adjustment:	$0.00006

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 the Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

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d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

SCHEDULE 177
SYSTEM INTEGRITY PROGRAM (SIP) RECOVERY MECHANISM

PURPOSE:
The purpose of this Schedule is to identify adjustments to rates in the Rate Schedules listed below for the recovery of costs associated with the Company's System Integrity Program (SIP) in accordance with Commission Order _____ in the Company's general rate case filing, Docket UG 221.

APPLICABLE:
The rate adjustments in this Schedule apply to all Sales and Transportation Service Customers served under the following Rate Schedules of this Tariff:

Rate Schedule 1	Rate Schedule 3	Rate Schedule 31	Rate Schedule 33
Rate Schedule 2	Rate Schedule 27	Rate Schedule 32	

ADJUSTMENT TO RATES:
All rate adjustments under this Schedule shall be made coincident with the Company's annual Purchased Gas Cost and Technical Rate Adjustment filing.

SYSTEM INTEGRITY PROGRAM (SIP):
The SIP consists of three parts:

Part A – Bare Steel Replacement Program – This program was first initiated in 2001 with an estimated completion date of 2021. See OPUC Order No. 01-843 in Docket UM 1030.

Part B –Transmission Integrity Management Program (TIMP) – This program was initiated in response to the Pipeline Safety Improvement Act of 2002 ("2002 Improvement Act") and PHMSA Natural Gas Integrity Management Rule. Initial Accounting Order approved in Docket UM 1156, OPUC Order No. 04-390.

Part C - Distribution Integrity Management Program (DIMP) – This program was initiated from the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (2006 PIPES Act), which expanded requirements for the 2002 Improvement Act to require PHMSA to prescribe minimum standards for DIMP with a focus on damage prevention. The PHMSA rules for DIMP were initiated in 2008.

The three parts described above are integrated to comprise the SIP as adopted by the Commission in Docket UM 1406, OPUC Order No. 09-067.

(continue to Sheet 177-2)

SCHEDULE 177
SYSTEM INTEGRITY PROGRAM (SIP) RECOVERY MECHANISM

SIP COST RECOVERY:
For purposes of this Schedule, SIP costs are all SIP costs in excess of (a) Operations and Maintenance (O&M) costs embedded in rates with the Company's most recent general rate case; (b) Leakage and bare steel capital costs of $3.25 million as established in OPUC Order No. 01-843; and (c) $250,000 in capital costs as established in OPUC Order No. 01-843.

A cost recovery soft cap of $26.3 million will apply to the 2012 PGA Year, November 1, 2012 through October 31, 2013. Thereafter, a soft cap of $12 million per PGA Year shall apply.

All SIP costs are classified as capital expenditures, and SIP costs will be tracked on a project basis into the respective capital account. The balances in such capital accounts will be used to calculate the SIP cost of service for the relevant year. The SIP cost of service shall be used to calculate permanent adjustments to Base Rates for the respective rate schedules, as follows:

> **Part A – Bare Steel Replacement Program** –Seventy percent (70%) of the cumulative investment is allocated to Residential and Commercial Firm Sales and Firm Transportation Customers on an equal cent per therm basis. The remaining thirty percent (30%) is allocated on an equal percent of margin basis to all customer classes.
>
> **Part B –Transmission Integrity Management Program (TIMP)** –Costs are allocated across all customer classes based on equal percent of margin.
>
> **Part C - Distribution Integrity Management Program (DIMP)** –Costs are allocated across all customer classes based on equal percent of margin.

The cost of service for the SIP investment will include incremental depreciation expense, property tax, return on investment, income taxes, and other costs customarily relating to utility investment. The capital structure and the cost of long-term debt and preferred stock to be used in the calculation of return on rate base will be that adopted by the Commission in the Company's most recent general rate case.

ANNUAL REPORTS:
The Company will file a report with the Commission on or before October 31 of each calendar year detailing (1) SIP costs incurred in the prior PGA Year; and (2) a forecast of SIP costs for the coming twelve (12) month period.

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.

(continue to Sheet 177-3)

SCHEDULE 177
SYSTEM INTEGRITY PROGRAM RATE ADJUSTMENT
(continued)

APPLICATION TO RATE SCHEDULES: **Effective: February 1, 2012**
The Adjustments shown below are included in the Base Adjustments in the listed Rate Schedules:

Schedule	Block	Part A		Part B	Part C	Total Adjustment
		70%	30%			
1R		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
1C		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
2		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
3 (CSF)		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
3 (ISF)		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
27		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
31 (CSF)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
31(CTF)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
31 (ISF)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
31 (IFT)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
32 (CSF)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000

(continue to Sheet 177-4)

SCHEDULE 177
SYSTEM INTEGRITY PROGRAM RATE ADJUSTMENT
(continued)

APPLICATION TO RATE SCHEDULES: **Effective: February 1, 2012**
The Adjustments shown below are included in the Base Adjustments in the listed Rate Schedules:

Schedule	Block	Part A		Part B	Part C	Total Adjustment
		70%	30%			
32 (ISF)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
32 (TF)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
32 (CSI)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
32 (ISI)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
32 (TI)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
33 (all)		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000

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SCHEDULE 178
REGULATORY RATE ADJUSTMENT

PURPOSE:
To reflect the effects of various regulatory adjustments including costs associated with Commission fee and other miscellaneous non-reoccurring costs or credits.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 1	Rate Schedule 3	Rate Schedule 31	Rate Schedule 33
Rate Schedule 2	Rate Schedule 27	Rate Schedule 32	

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.

DESCRIPTION:
The Total Adjustment is the net adjustment for the following:

Earnings Sharing – The application of the 2010 earnings sharing calculation pursuant to Docket UM 903.
Residual Balances - Residual balances associated with the Commission Fee (Docket UM 1218) and 2010 Billing Service Quality Measure (UM 1218)

TERM:
This adjustment rate shall be in effect through October 31, 2012, or such other date as the Commission may approve.

APPLICATION TO RATE SCHEDULES: **Effective: February 1, 2011**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Total Adjustment
1R		$(0.00053)
1C		$(0.00036)
2		$(0.00035)
3 CSF		$(0.00025)
3 ISF		$(0.00021)
27		
31 CSF	Block 1	$(0.00018)
	Block 2	$(0.00016)
31 CTF	Block 1	$(0.00013)
	Block 2	$(0.00012)

(continue to Sheet 178-2)

SCHEDULE 178
REGULATORY RATE ADJUSTMENT
(continued)

<u>APPLICATION TO RATE SCHEDULES</u>: **Effective: February 1, 2012**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Total Adjustment
31 ISF	Block 1	$(0.00014)
	Block 2	$(0.00013)
31 ITF	Block 1	$(0.00014)
	Block 2	$(0.00012)
32 CSF	Block 1	$(0.00010)
	Block 2	$(0.00008)
	Block 3	$(0.00006)
	Block 4	$(0.00003)
	Block 5	$(0.00002)
	Block 6	$(0.00001)
32 ISF	Block 1	$(0.00009)
	Block 2	$(0.00008)
	Block 3	$(0.00005)
	Block 4	$(0.00003)
	Block 5	$(0.00002)
	Block 6	$(0.00001)
32 CTF/ITF	Block 1	$(0.00008)
	Block 2	$(0.00007)
	Block 3	$(0.00005)
	Block 4	$(0.00003)
	Block 5	$(0.00002)
	Block 6	$(0.00001)
32 CSI	Block 1	$(0.00009)
	Block 2	$(0.00008)
	Block 3	$(0.00005)
	Block 4	$(0.00003)
	Block 5	$(0.00002)
	Block 6	$(0.00001)
32 ISI	Block 1	$(0.00008)
	Block 2	$(0.00007)
	Block 3	$(0.00005)
	Block 4	$(0.00003)
	Block 5	$(0.00002)
	Block 6	$(0.00001)
32 CTI/ITI	Block 1	$(0.00007)
	Block 2	$(0.00006)
	Block 3	$(0.00004)
	Block 4	$(0.00003)
	Block 5	$(0.00001)
	Block 6	$(0.00001)
33 (all)		$0.00000

SCHEDULE 183
SITE REMEDIATION RECOVERY MECHANISM (SRRM)

PURPOSE:
The purpose of this Schedule is to identify adjustments to rates in the Rate Schedules listed below for the amortization of balances in the Site Remediation Recovery Mechanism account ("SRRM Account") related to Environmental Site Remediation Costs, including past manufactured gas plant (MGP) operations pursuant to Commission Order ______, in Docket UG 221.

TERM:
Adjustments under this Schedule shall first be effective with service on and after November 1, 2012, and shall continue thereafter for a period of five (5) years following the date that the last remediation expenses are incurred, or such other date as the Commission may approve.

APPLICABLE:
To Sales and Transportation Service Customers served under the following Rate Schedules of this Tariff:

Rate Schedule 1	Rate Schedule 3	Rate Schedule 31	Rate Schedule 33
Rate Schedule 2	Rate Schedule 27	Rate Schedule 32	

DEFINITIONS:
The following definitions apply to this Schedule:

Collection Period is the 12-month period November 1 through October 31 coincident with the Purchased Gas Adjustment (PGA) Year in which amounts in the SRRM Account will be amortized. Any future change in the PGA Year will automatically carry to the Collection Period under this Schedule.

Environmental Site Remediation Costs are all costs that relate to environmental remediation, including for past manufactured gas plant (MGP) operations. Environmental Site Remediation Costs include investigation, testing, sampling, monitoring, removal, disposal, storage, remediation or other treatment of residues, land acquisition if appropriate, litigation costs/expenses or other liabilities excluding personal injury claims relating to MGP sites, disposal sites, sites that otherwise contain contamination that requires remediation for which the Company is responsible, or sites to which material may have migrated.

SPECIAL CONDITIONS – SRRM ADJUSTMENTS:

1. All Environmental Site Remediation Costs, including all amounts deferred under UM 1078 through September 30, 2012, and any proceeds from insurance companies or other third-parties, will be held in a deferral account. The balance in the deferral account shall accrue interest at the authorized rate of return approved in the Company's most recent general rate case.

(continue to Sheet 183-2)

SCHEDULE 183
SITE REMEDIATION RECOVERY MECHANISM (SRRM)
(continued)

SPECIAL CONDITIONS – SRRM ADJUSTMENTS: (continued)

2. One-fifth of the Oregon Customer's share of the deferral account balance as of June 30 will be transferred to an SRRM Account for amortization in each Collection Period. The first Collection Period is November 1, 2012 through October 31, 2013.

3. In the event that the amount in the SRRM Account in any Collection Period is negative (a refund), the Company, subject to approval by the Commission, will determine if the refund should be applied to Customer bills, or if the credit balance should carry to the next Collection Period. A credit balance may be carried to the next Collection Period if it is determined by the Commission that the credit balance is best used to offset future expected Environmental Site Remediation Costs not yet recorded in the deferral account, or for such other reasons as the Commission may approve.

4. The amounts in the SRRM Account will be amortized and applied to Customer bills based on equal percent of margin by Rate Schedule and Customer class.

5. The SRRM account balance shall accrue interest at the rate prescribed by the Commission in OPUC Order No. 08-263.

6. Any over- or under- collection of the balance in the SRRM Account at the end of a 12-month Collection Period will be retained in the SRRM account and used to adjust the amount amortized into rates for the subsequent Collection Period.

7. By July 15, 2013, and each year thereafter, the Company will submit a report to the Commission detailing all activity associated with Environmental Site Remediation Costs, including insurance or other third-party proceeds related to remediation activities recorded in the deferral account through June 30 of the report year.

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.

(continue to Sheet 183-3)

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

SCHEDULE 183
SITE REMEDIATION RECOVERY MECHANISM (SRRM)
(continued)

APPLICATION TO RATE SCHEDULES: **Effective: February 1, 2012**

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Rate Schedule/Class	Block	SRRM Adjustment		Schedule	Block	SRRM Adjustment
1R		$		31 CSF	Block 1	$
1C		$			Block 2	$
2		$		31 ISF	Block 1	$
03 CSF		$			Block 2	$
03 ISF		$		31 CTF	Block 1	$
27		$			Block 2	$
				31 ITF	Block 1	**$**
					Block 2	**$**

						$
						$
32 CSF	Block 1	**$**		32 CSI	Block 1	**$**
	Block 2	**$**			Block 2	**$**
	Block 3	**$**			Block 3	**$**
	Block 4	**$**			Block 4	**$**
	Block 5	**$**			Block 5	**$**
	Block 6	**$**			Block 6	**$**
32 ISF	Block 1	**$**		32 ISI	Block 1	**$**
	Block 2	**$**			Block 2	**$**
	Block 3	**$**			Block 3	**$**
	Block 4	**$**			Block 4	**$**
	Block 5	**$**			Block 5	**$**
	Block 6	**$**			Block 6	**$**
32 ITF/CTF	Block 1	**$**		32 CTI / ITI	Block 1	**$**
	Block 2	**$**			Block 2	**$**
	Block 3	**$**			Block 3	**$**
	Block 4	**$**			Block 4	**$**
	Block 5	**$**			Block 5	**$**
	Block 6	**$**			Block 6	**$**
				33 (all)		

SCHEDULE 184
SPECIAL RATE ADJUSTMENT
GASCO UPLAND PUMPING STATION

PURPOSE:
The purpose of this Schedule is to identify adjustments to Base Rates in the Rate Schedules listed below to reflect the rate treatment for the Oregon portion of the cost of service for the construction of a pumping station on the Company's property located in Linnton, Oregon ("Gasco Upland Site"). For purposes of this Schedule, the pumping station is the series of wells, pumps, and water treatment facilities installed at the Gasco Upland Site.

APPLICABLE:
To Sales and Transportation Service Customers served under the following Rate Schedules of this Tariff:

Rate Schedule 1	Rate Schedule 3	Rate Schedule 31	Rate Schedule 33
Rate Schedule 2	Rate Schedule 27	Rate Schedule 32	

SPECIAL CONDITIONS:

1. The pumping station shall be considered in service for rate recovery purposes on the date that the Company submits an attestation to the Commission that the Pumping Station is completed and operational.

2. The pumping station cost of service includes operating and maintenance (O&M) expense, incremental depreciation, expense, property tax, return-on-rate-base, income taxes, and other costs customarily relating to utility investment. The capital structure and the cost of long term debt and common equity to be used in the calculation of the return-on-rate-base will be that which is established in the Company's most recent general rate case.

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.

(continue to Sheet 182-2)

SCHEDULE 184
SPECIAL RATE ADJUSTMENT
GASCO UPLAND PUMPING STATION
(continued)

APPLICATION TO RATE SCHEDULES: **Effective: February 1, 2012**

The Total Adjustment amount shown below is included in the Base Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Rate Schedule/Class	Block	Base Adjustment		Schedule	Block	Base Adjustment
1R		$		31 CSF	Block 1	$
1C		$			Block 2	$
2		$		31 ISF	Block 1	$
03 CSF		$			Block 2	$
03 ISF		$		31 CTF	Block 1	$
27		$			Block 2	$
				31 ITF	Block 1	**$**
					Block 2	**$**

						$
						$
32 CSF	Block 1	**$**		32 CSI	Block 1	**$**
	Block 2	**$**			Block 2	**$**
	Block 3	**$**			Block 3	**$**
	Block 4	**$**			Block 4	**$**
	Block 5	**$**			Block 5	**$**
	Block 6	**$**			Block 6	**$**
32 ISF	Block 1	**$**		32 ISI	Block 1	**$**
	Block 2	**$**			Block 2	**$**
	Block 3	**$**			Block 3	**$**
	Block 4	**$**			Block 4	**$**
	Block 5	**$**			Block 5	**$**
	Block 6	**$**			Block 6	**$**
32 ITF/CTF	Block 1	**$**		32 CTI / ITI	Block 1	**$**
	Block 2	**$**			Block 2	**$**
	Block 3	**$**			Block 3	**$**
	Block 4	**$**			Block 4	**$**
	Block 5	**$**			Block 5	**$**
	Block 6	**$**			Block 6	**$**
				33 (all)		

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SCHEDULE 185
SPECIAL ANNUAL INTERSTATE AND INTRASTATE STORAGE AND TRANSPORTATION CREDIT

PURPOSE:
To credit customers served under the below-listed Rate Schedules for the Oregon share of revenues received by NW Natural for (a) interstate storage and related transportation service provided under a Limited-Jurisdiction Blanket Certificate from FERC granted under FERC Regulations, 18 C.F.R. § 284.224 (hereafter referred to as § 284.224 service), (b) core storage optimization activities; and (c) intrastate storage activities under **Rate Schedule 80**.

APPLICABLE:
The credit under this Schedule shall apply to customer bills issued during the June billing cycle of each calendar year, or such other time period as the Commission may approve. The credit shall apply to the following Sales Service Rate Schedules of this Tariff: **Schedule 1**; **Schedule 2**; **Schedule 3**, and; **Schedules 31** and **32** – Firm Sales only.

CREDIT: **Effective Billing Cycle: June 2011**
The bill credit to be applied to Customer bills during the effective billing cycle will be calculated by multiplying the following per therm credit by the customer's actual gas usage billed during the period January 1, 2010 through December 31, 2010:

Rate Schedule 1	($0.00584) per therm	Rate Schedule 31 CSF	($0.00390) per therm
Rate Schedule 2	($0.00897) per therm	Rate Schedule 31 ISF	($0.00390) per therm
Rate Schedule 3	($0.00946) per therm	Rate Schedule 32 CSF	($0.00391) per therm
		Rate Schedule 32 ISF	($0.00391) per therm

SPECIAL CONDITIONS:
1. NW Natural will share with customers served under the Rate Schedules listed above, the net margin received from interstate and intrastate storage service on an 80/20 basis; 80% will be retained by NW Natural, and 20% will be shared with customers through the credit provided for in this schedule. For this purpose, net margin is defined as revenues less incremental operating and maintenance (O&M) expense, less incremental capital-related costs, on a before income tax basis. Incremental capital-related costs include depreciation, interest, property taxes, and any other costs customarily relating to a utility investment other than return on equity. The imputed capital structure for this purpose shall be 50% debt and 50% equity, with the cost of debt defined as the average long-term cost of debt authorized by the OPUC in Docket UG 132.
2. The interstate and intrastate annual service credit shall be based on the net margin as described in paragraph 1 above, and as filed with the Commission. This credit shall be applied to customers' bills, or placed in an interest bearing deferred account, on June 1 of each year, or at a date other than June 1 for reasons and on terms as the Commission may approve.
3. If the net margin for the year is negative (a loss) then the credit will be zero.
4. In addition to the interstate and intrastate storage service sharing, NW Natural will share with customers served under the Rate Schedules listed above, net margin revenue that is attributable to optimization of core customer storage and related transportation services on a 67/33 basis; 33% will be retained by NW Natural, and 67% will be shared with customers through the credit provided for in this schedule. For this purpose, net margin is defined as revenues less incremental operating and maintenance (O&M) expense.
5. As provided under "OUT-OF-CYCLE TRANSFERS" provision set forth in Rate Schedules 31 and 32, a Customer that exercises the Capacity Release Option may only be eligible to receive one-half of the above-listed credit.

PRIOR YEAR BALANCES:
The Company will include any remaining balance from the prior year's credit in the calculation of the current year's credit.

(continue to Sheet 185-2)

SCHEDULE 185
SPECIAL ANNUAL INTERSTATE AND INTRASTATE STORAGE AND TRANSPORTATION CREDIT
(continued)

TERM OF SCHEDULE:
Application of the § 284.224 service credit under this Schedule is contingent upon continued FERC approval of NW Natural's § 284.224 Limited Jurisdiction Blanket Certificate.

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.

SCHEDULE 186
SPECIAL ANNUAL CORE PIPELINE CAPACITY OPTIMIZATION CREDIT

PURPOSE:
To credit Sales Service Customers served under the below-listed Rate Schedules for the Oregon share of revenues received by NW Natural for the optimization of core customer Pipeline and Storage capacity.

APPLICABLE:
This credit shall apply to customer bills issued during the June billing cycle of each calendar year, or such other time period as the Commission may approve. The credit shall apply to the following Sales Service Rate Schedules of this Tariff:

Rate Schedule 1	Rate Schedule 31 ISF	Rate Schedule 32 ISF
Rate Schedule 2	Rate Schedule 31 CSF	Rate Schedule 32 CSI
Rate Schedule 3	Rate Schedule 32 CSF	Rate Schedule 32 ISI

CREDIT: **Effective Billing Cycle: June 2011**

The bill credit to be applied to Customer bills during the effective billing cycle will be calculated by multiplying the following per therm credit by the customer's actual gas usage billed during the period January 1, 2010 through December 31, 2010:

($0.01371)

SPECIAL CONDITIONS:

1. NW Natural will share with customers served under the Rate Schedules listed above, the amount of net margin revenue that is attributable to optimization of core customer Pipeline and Storage capacity on an 67/33 basis; 33% will be retained by NW Natural, and 67% will be shared with customers through the credit provided for in this Schedule. For this purpose, net margin is defined as revenues less incremental operating and maintenance (O&M) expense.
2. The annual credit shall be based on the net margin as described in paragraph 1 above, and as filed with the Commission. This credit shall be applied to customers' bills, or placed in an interest bearing deferred account, on June 1 of each year, or at a date other than June 1 for reasons and on terms as the Commission may approve.
3. If the net margin for the year is negative (a loss) then the credit will be zero.

PRIOR YEAR BALANCES:
The Company will include any remaining balance from the prior year's credit in the calculation of the current year's credit.

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.

SCHEDULE 187
SPECIAL RATE ADJUSTMENT FOR MIST CAPACITY RECALL

PURPOSE:
The purpose of this Schedule is to reflect the rate effects of the Company's recall of Mist storage capacity for use by the Company's core Sales Service Customers.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 1	Rate Schedule 3	Rate Schedule 31
Rate Schedule 2	Rate Schedule 27	Rate Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: February 1, 2012

The Total Adjustment amounts shown below are included in the Base Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Rate Schedule/Class	Block	Mist Recall Base Adjustment		Schedule	Block	Mist Recall Base Adjustment
1R		$		31 CSF	Block 1	$
1C		$			Block 2	$
2		$		31 ISF	Block 1	$
03 CSF		$			Block 2	$
03 ISF		$				
27		$				
32 CSF	Block 1	$		32 CSI	Block 1	$
	Block 2	$			Block 2	$
	Block 3	$			Block 3	$
	Block 4	$			Block 4	$
	Block 5	$			Block 5	$
	Block 6	$			Block 6	$
32 ISF	Block 1	$		32 ISI	Block 1	$
	Block 2	$			Block 2	$
	Block 3	$			Block 3	$
	Block 4	$			Block 4	$
	Block 5	$			Block 5	$
	Block 6	$			Block 6	$

GENERAL TERMS:
Service under this Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this, 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.

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SCHEDULE 188
INDUSTRIAL DEMAND SIDE MANAGEMENT (DSM) PROGRAM
COST RECOVERY

PURPOSE:
This Schedule recovers the costs of the Company's Industrial Energy Efficiency Program offered under **Schedule 360** "Industrial Demand side Management (DSM) Programs."

APPLICABILITY:
This Schedule applies to Industrial Sales Service Customers taking service under **Rate Schedule 3, Rate Schedule 32**, or **Rate Schedule 32**, and to Commercial Sales Service Customers taking service under **Rate Schedule 32**.

APPLICATION TO RATES: Effective: February 1, 2012

The Temporary Adjustments in the applicable Rate Schedules include the adjustment shown below. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

$0.01763 per therm

GENERAL TERMS:
Service under this Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this, 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.

SCHEDULE 190
PARTIAL DECOUPLING MECHANISM

PURPOSE:
To (a) describe the partial decoupling mechanism established in accordance with Commission Order in Docket UG -221; and (b) identify the adjustment applicable to rates under the Rate Schedules listed below.

APPLICABLE:
To Residential and Commercial Customers served on the following Rate Schedules of this Tariff:

Residential	Commercial
Rate Schedule 1	Rate Schedule 1
Rate Schedule 2	Rate Schedule 3 CSF
	Rate Schedule 31 CSF
	Rate Schedule 31 CTF

The applicability of this Schedule to Residential Customers served under **Rate Schedule 1** and **Rate Schedule 2**, and to Commercial Customers served under **Rate Schedule 1** shall terminate effective on and after November 1, 2014, or such other date as the Commission may approve.

ADJUSTMENT TO RATE SCHEDULES: **Effective: February 1, 2012**
The Temporary Adjustments for Residential and Commercial Customers taking service on the above-listed Rate Schedules includes the following adjustment:

Residential Rate Schedules: **$0.04768** per therm
Commercial Rate Schedules: **$0.01048** per therm

PARTIAL DECOUPLING DEFERRAL ACCOUNT:

1. Each month, the Company will calculate the difference between weather-normalized usage and the calculated baseline usage for each Residential and Commercial Customer group. The resulting usage differential shall be multiplied by the per therm distribution margin for the applicable customer group.

   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.

(continue to Sheet 190-2)

SCHEDULE 190
PARTIAL DECOUPLING MECHANISM
(continued)

PARTIAL DECOUPLING DEFERRAL ACCOUNT (continued):

2. The baseline use-per-customer is:

   Residential: 636
   Commercial: 3,845

3. Weather-normalized usage is calculated using the approach to weather normalization adopted in the Company's last general rate case, Docket UG 221. The weather data is taken from the stations identified in **Rule 24**.

   Step One. For the heating season months October through May, usage is normalized by taking the difference between normal and actual heating degree days for each district using a base of 59 degrees for Residential and 58 degrees for Commercial.

   Step Two. This step derives the per-therm customer variance by multiplying the heating degree-day difference by the usage coefficient of .16394 for Residential variances, and .84888 for Commercial variances.

   Step Three. The per-therm customer variance is multiplied by the appropriate customer count, by district, with the sum of the district results representing the normalized therm amount.

4. Baseline usage will be adjusted to reflect actual customers billed each month.

5. The per therm distribution margins to be used in the deferral calculation effective November 1, 2012 is $0.38241per therm for Residential customers and $0.32696 per therm for Commercial customers.

6. Coincident with the Company's annual Purchased Gas Cost and Technical Rate Adjustment filing, the Company shall apply an adjustment to Residential and Commercial rates to amortize over the following 12 months, the balance in the balancing account as of June 30.

7. 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 (2) years.

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.

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)

PURPOSE:
To describe the Weather Adjusted Rate Mechanism (WARM) adopted by the Public Utility Commission of Oregon in Docket UG ____, Order No. _____ entered ____________.

APPLICABLE:
To Residential and Commercial Customers served on the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 3

The applicability of this Schedule to **Rate Schedule 2** shall terminate effective on and after November 1, 2014, or such other date as the Commission may approve.

APPLICATION TO RATE SCHEDULES:
The WARM Adjustment will be applied as an adjustment to the per therm Billing Rate on applicable Residential and Commercial Customer bills issued during the WARM Period. The WARM Period covers bills that are generated based on meters read on or after December 1st and on or before May 15th.

SPECIAL CONDITIONS:

1. The WARM Adjustment will apply to Customer bills that are based on applicable Residential Rate Schedule 2 or Commercial Rate Schedule 3 meters read on or after December 1st and on or before May 15th.

2. Residential bills --The maximum WARM Adjustment increase that will be added to any regular monthly bill during the WARM Period will be twelve dollars ($12.00), or twenty-five percent (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 billed in accordance with Special Condition 5.

3. Commercial bills--The maximum WARM Adjustment increase that will be added to any regular monthly bill during the WARM Period will be thirty-five dollars ($35.00), or twenty-five percent (25%) of the usage portion of that bill, whichever is less. For any billing period in which the total monthly WARM adjustment exceeds either thirty-five dollars or 25% of the usage, the balance of the WARM adjustment will be billed in accordance with Special Condition 5.

4. The cent per therm rate applied to any customer bill during the WARM Period will never be less than the currently effective Annual Sales WACOG rate, as shown in **Schedule 164** of this Tariff.

5. Any amounts not applied to a Customer's bill during the WARM Period due to the caps and floor described in Special Conditions 2, 3 and 4 will be applied to the Customer's first bill issued following the end of the WARM Period, except that these amounts will be applied earlier in the following situations: (a) at the time the Company issues a closing bill on a Customer account; and (b) at the time a Customer changes their status in the WARM program.

(continue to Sheet 195-2)

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

SPECIAL CONDITIONS (continued):

6. WARM is the Company's default billing method for the Rate Schedules to which this Schedule applies.

7. Upon request, the Company will provide Customer with historical billing information that reflects bills with and without the WARM adjustment for any month during the WARM Period.

8. Should a change to the margin rate 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. 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 6 days at the prior margin rate and 24 days at the new margin rate. The calculations performed under the provisions of Special Conditions 2, 3, and 4 will apply to each prorated period separately, except that the total WARM adjustment for each bill will not exceed the maximum WARM adjustment specified in Special Conditions 2 and 3.

WARM FORMULA:

1. The Formula 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 average of heating degree-days for each day (1986-2010) determined using a 25-year average temperature published by the National Oceanic and Atmospheric Administration (NOAA).
   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.

2. For purposes of calculating the WARM Adjustment, the following shall apply:

   a. A Heating Degree Day (HDD) is defined as the extent by which the daily mean temperature falls below a specified set point on a specified day. The HDD calculation uses a set point temperature of 59 degrees Fahrenheit for the **Rate Schedule 2** calculation, and 58 degrees Fahrenheit for the **Rate Schedule 3** calculation;

(continue to Sheet 195-3)

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

WARM FORMULA (continued):

b. The statistical coefficients to be used in the calculation of the WARM Adjustment Factor effective with the WARM Period commencing November 1, 2012 are:

Rate Schedule 2: 0.16394	Rate Schedule 3: 0.84888

c. The applicable margins to be used in the calculation of the WARM Adjustment Factor effective with the WARM Period commencing November 1, 2012 are:

Rate Schedule 2: $0.38241	Rate Schedule 3: $0.32696

Weather data used in the calculation of 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 **Rule 24.**

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	0.1639	$0.06		.8489	$0.32
5	0.8197	$0.31		4.2444	$1.59
10	1.6394	$0.63		8.4888	$3.17
15	2.4591	$0.94		12.7332	$4.76
20	3.2788	$1.25		16.9776	$6.35
25	4.0985	$1.57		21.2220	$7.93
30	4.9182	$1.88		25.4664	$9.52
35	5.7379	$2.19		29.7108	$11.11
40	6.5576	$2.51		33.9552	$12.69
45	7.3773	$2.82		38.1996	$14.28
50	8.1970	$3.13		42.4440	$15.87

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.

(continue to Sheet 195-4)

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

WARM BILL EFFECTS (continued):

Example Bill Calculation:

Here is the how the WARM adjustment is calculated for a residential **Rate Schedule 2** customer where the billing rate is $1.04115 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:	0.16394
	Equivalent therms:	-50 x 0.16394 = -8.197 therms
Total Warm Adjustment:	Equivalent therms:	-8.197 therms
	Margin Rate:	$0.38241
	Total WARM Adj.:	-8.197 x $0.38241 = -$3.1346
Total WARM Adjustment converted to cents per therm:	Total WARM Adj.	-$3.1346
	Monthly usage:	129 therms
	Cent/therm Adj.:	-$3.1346 ÷ 129 = -$0.02430
Billing Rate per therm:	Current Rate/therm:	$1.04115
	WARM cent/therm Adj.	-$0.02430
	WARM Billing Rate:	$1.04115 + -$0.02430 = $1.01685
Total WARM Bill:	Customer Charge:	$13.70
	Usage Charge:	$1.01685
	Total	(129 x $1.01685) + $13.70 = $144.87

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.

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220 N.W. Second Avenue
Portland, Oregon 97209-3991

SCHEDULE 200
PROMOTIONAL CONCESSIONS

PURPOSE:
The purpose of this Schedule is to list and summarize the major features of promotional concessions, the terms and conditions of which are specified in greater detail in the sheets following this index sheet.

(continue to Sheet 200-2)

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SCHEDULE 200
PROMOTIONAL CONCESSIONS
(continued)

General Merchandise Sales Program (Appliance Center)

PURPOSE:
To promote the purchase and installation of Natural Gas-fired equipment and appliances.

AVAILABLE:
Throughout the Company's service territory to customers and the general public.

DESCRIPTION:
The Company may offer various promotions directed toward the purchase and installation of gas and electric equipment. This program does not include space heating and air conditioning equipment.

Program activities may include, but are not necessarily limited to, the following:

- Appliance Discounts;
- Gift Certificates;
- Free installation with purchase;
- Contests or drawings for prizes;
- Giveaways;
- Rebates.

(continue to Sheet 200-3)

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SCHEDULE 200
PROMOTIONAL CONCESSIONS
(continued)

Equipment Sales Promotions

PURPOSE:
To promote the purchase, sale, and installation of Natural Gas-fired equipment and appliances.

AVAILABLE:
Within the Company's service territory to any or all of the following:

a. Distributors, manufacturers, retailers or dealers of Natural Gas equipment and appliances;
b. Retailers of pre-fabricated, modular, and manufactured homes;
c. Property Managers;
d. Homeowner Associations;
e. Customers; and
f. The public in general.

DESCRIPTION:
The Company may offer from time to time promotional activities, which include, but are not necessarily limited to the following:

- Contests or drawings for prizes;
- Rebates;
- Gift Certificates;
- Discounts;
- Giveaways;
- Cash payments.

SPECIAL PROVISIONS:
Specific promotions and offers made under this concession may have certain restrictions and limitations to service areas, market segments, type of equipment and appliances, and/or duration of the offer.

(continue to Sheet 200-4)

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SCHEDULE 200
PROMOTIONAL CONCESSIONS
(continued)

Cooperative Advertising Program

PURPOSE:
To promote the use of Natural Gas-fired equipment and appliances through advertising.

AVAILABLE:
To qualifying wholesale or retail dealers, manufacturers, associations, or other persons (advertisers), who's advertising appears in paid media in cities or communities in which the Company distributes Natural Gas.

DESCRIPTION:
The Company will furnish consideration to qualifying wholesale or retail dealers, manufacturers, associations, or other persons (advertisers) for a percentage of the direct media cost to the advertiser for selected advertising of Natural Gas-fired equipment.

Advertising must reasonably intend that the equipment or appliances will be installed at locations within the Company's service territory.

SPECIAL PROVISIONS:
The following qualifications and requirements will apply to this program:

a. Advertisers must receive advance written commitment and approval of advertising for the particular program.

b. For purposes of this program, "media" will include radio, television, newspapers, paid circulation publications, outdoor billboards, or direct marketing activities.

c. Commitments of funds under this program will be honored by the Company once made, but the new commitment of funds may be suspended or terminated at any time for budgetary or other reasons.

(continue to Sheet 200-5)

SCHEDULE 200
PROMOTIONAL CONCESSIONS
(continued)

Showcase Developments

PURPOSE:
To promote the use of Natural Gas-fired equipment in Residential and Commercial developments.

AVAILABLE:
To qualifying builders, developers, or architects involved in showcase developments within the cities or communities in which the Company distributes Natural Gas.

DESCRIPTION:
The Company may sponsor developments, or provide free, or at less than cost or value to qualifying builders, developers, or architects, consideration which includes, but is not necessarily limited to:

- Efficient gas equipment;
- Extended maintenance or warranty coverage on gas equipment;
- Cash payments for advertising or publicity.

(continue to Sheet 200-6)

SCHEDULE 200
PROMOTIONAL CONCESSIONS
(continued)

Natural Gas Vehicle Program

PURPOSE:
To encourage the use of Natural Gas as a motor vehicle fuel.

AVAILABLE:
To qualifying wholesale or retail dealers, manufacturers, and associations of Natural Gas vehicles, and Natural Gas Customers within the Company's service territory, where it is economically feasible to provide gas service for motor vehicle use.

DESCRIPTION:
The Company may offer various promotional activities within the Company's service territory in Oregon directed toward the purchase and use of bi-fuel or dedicated Natural Gas vehicles for residential, commercial, or industrial uses.

Program activities may include, but are not limited to, the following:

- Live demonstrations of Natural Gas vehicles;
- Cooperation in the development and distribution of communication materials related to the use of Natural Gas as a vehicular fuel;
- Assistance in displays at trade fairs and shows;
- Rebate offers as an incentive to use Natural Gas as a vehicular fuel;
- Promotion contests with an established drawing date for prizes to be awarded to the contest winner;
- Cooperative advertising with qualifying wholesale or retail dealers, manufacturers, associations, or other persons (advertisers).

SPECIAL PROVISIONS:
Specific promotions and offers made under this concession may have certain restrictions and limitations to service area, type of equipment, and/or duration of the offer.

(continue to Sheet 200-7)

SCHEDULE 200
PROMOTIONAL CONCESSIONS
(continued)

Equipment Financing Program

PURPOSE:
To promote the purchase, sale, and installation of Natural Gas-fired equipment and appliances.

AVAILABLE:
Within the Company's service territory to qualifying Customers and Applicants for Natural Gas service.

DESCRIPTION:
The Company may provide or arrange for the financing of the purchase and installation of selected appliances, products, and services.

SPECIAL PROVISIONS:

1. Specific financing offers may have certain restrictions and limitations to service areas, market segments, type of products, services, equipment and appliances that may be financed, maximum financing amount, and/or duration of the offer.

2. All financing offers are contingent upon the Customer or Applicant qualifying under applicable credit approval criteria.

3. On-the-bill payment options may be available for specific offers.

4. Interest rates and payment terms may vary by offer.

5. In association with a financing offer, the company may, from time to time, offer one or more promotional concessions which include, but are not necessarily limited to the following:

   - Contests or drawing of prize(s);
   - Rebates;
   - Gift certificates;
   - Giveaways;
   - Cash payments.

6. Offers made under this schedule may be discontinued at any time at the Company's sole discretion, however all outstanding offers at the time of any discontinuance will continue to be honored by the Company.

(continue to Sheet 200-8)

SCHEDULE 200
PROMOTIONAL CONCESSIONS
(continued)

Promotions for Company-Offered Products and Services

PURPOSE:
To promote the purchase, sale, and, or installation of Company-offered products and services.

AVAILABLE:
Within the Company's service territory to qualifying Customers and Applicants for Natural Gas service.

DESCRIPTION:
The Company may periodically offer promotional activities, which include, but are not limited to the following:

- Contest or drawings for prizes;
- Rebates;
- Gift Certificates;
- Discounts;
- Giveaways;
- Cash payments.

SPECIAL PROVISIONS:
Specific promotions and offers may have certain restrictions and limitations to service areas, market segments, and/or duration of the offer.

SCHEDULE 301
PUBLIC PURPOSES FUNDING SURCHARGE

PURPOSE:
To specify the method of billing of a Public Purposes surcharge that is to fund public purposes activities to be administered through one or more independent entities. Public purposes activities include, but may not necessarily be limited to, energy efficiency programs, market transformation programs, residential low-income energy efficiency programs, and residential low-income bill payment assistance programs designed to benefit Residential and Commercial Customers within NW Natural's service territory in Oregon.

APPLICABLE:
To Residential and Commercial Customers served on the following Rate Schedules of this Tariff:

Residential	Commercial
Rate Schedule 1	Rate Schedule 1
Rate Schedule 2	Rate Schedule 3 (03CSF)
	Rate Schedule 27
	Rate Schedule 31 (31CSF)

ADJUSTMENT TO RATES: Effective: February 1, 2012
A Public Purposes surcharge will be assessed on the total energy use billed (the total of the Customer Charge plus the per therm usage charges) and shown as a line item on each customer's monthly bill as follows:

Residential: 3.86% of the total energy use billed
Commercial: 3.01% of the total energy use billed

The funds collected from such Public Purposes surcharge shall be allocated to specific separate accounts to fund the specified public purposes program(s) as follows:

RESIDENTIAL:

2.86% will support public purpose funding for **Schedule 350** energy efficiency programs delivered and administered by the Energy Trust of Oregon (Energy Trust).

0.75% will support public purpose funding for **Schedule 310** low-income bill payment assistance activities.

0.25% will support public purpose funding for **Schedule 320** low-income energy efficiency activities.

COMMERCIAL:

2.86% will support public purpose funding for **Schedule 350** energy efficiency programs delivered and administered by the Energy Trust.

0.25% will support public purpose funding for **Schedule 320** low-income energy efficiency activities.

(continue to Sheet 301-2)

SCHEDULE 301
PUBLIC PURPOSES FUNDING SURCHARGE
(continued)

DETERMINATION OF RATE:
At least annually, effective November 1, or such other date as the Commission may approve, the Company will determine if the Public Purpose Funding Surcharge for the **Schedule 350** energy efficiency programs needs to be adjusted so that forecasted collections, plus unspent collections held by the Energy Trust are sufficient for acquiring cost-effective demand side management based upon resource portfolio and conservation supply curve methodologies consistent with the Company's last acknowledged Integrated Resource Plan or Integrated Resource Plan update, plus a spending reserve appropriately sized for economic conditions and forecasted growth.

SPECIAL CONDITIONS:

1. Each month, the Company will bill the Public Purposes surcharge on all Residential and Commercial Customer bills. By the 20th of the month following the billing month, the Company will forward the amount of funds expected to be collected from billings issued for the prior calendar month, less a reserve for uncollectibles in an amount equal to NW Natural's average percentage of net write-offs, to the respective fund administrator or program account. Funds retained in the accounts after the 20th of the month will earn interest at the Company's currently authorized rate of return until distributed, unless otherwise specified in an approved program or other agreement,

2. The Company will retain an amount not to exceed $50,000 per year from the monies collected to fund **Schedule 320** low-income energy efficiency programs to be used for the purpose of an independent program performance evaluation.

3. The monies collected for **Schedule 350** programs will be transferred to the Energy Trust. The Energy Trust is the entity approved by the Oregon Public Utility Commission (OPUC) to receive such public purposes funds, and to use such funds to design, promote and administer Natural Gas energy efficiency programs in accordance with agreements executed between the Company and the Energy Trust.

4. The monies collected for **Schedule 310** and **Schedule 320** programs will be transferred to the appropriate internal program accounts (OLGA and OLIEE, respectively) based on the allocation set forth in this **Schedule 301**.

5. Each year, to be effective October 1, or such other date as the Commission may approve, the Company will determine the amount of residential low-income public purposes funds that will be allocated between **Schedule 310** and **Schedule 320** programs. In making this determination, the Company will consult with at least one representative from: (a) the staff of the Public Utility Commission, (b) Citizens' Utility Board, and (c) Community Action Partnership of Oregon. The minimum public purposes fund allocation for **Schedule 310** programs shall be 0.75% of monthly residential customer bills.

(continue to Sheet 301-3)

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

SCHEDULE 301
PUBLIC PURPOSES FUNDING SURCHARGE
(continued)

6. The Company, and any independent entity selected to administer public purposes programs under this Tariff, will report program results as directed by the Commission. Copies of all reports provided by the fund administrators to the Commission shall also be submitted to the Company for review.

7. All funds collected from NW Natural Customers will be allocated only to programs that are available within the Company's service territory in Oregon.

GENERAL TERMS:
This 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.

SCHEDULE 310
OREGON LOW-INCOME GAS ASSISTANCE (OLGA)

PURPOSE:
To describe the program within which that portion of the funds collected and designated for use for low-income bill payment assistance activities under **Schedule 301** “Public Purposes Funding Surcharge” will be administered and delivered to eligible customers. This program is filed pursuant to ORS 757.315.

APPLICABLE:
To Residential Customers taking service under **Rate Schedule 1** and **Rate Schedule 2** of this Tariff.

SPECIAL CONDITIONS:

1. Funds collected under **Schedule 301** will be disbursed from the OLGA Account directly to individual customer utility accounts based on electronic vouchers received from each participating Community Action Agency (“Agency”).

2. All funds collected under this program will be distributed only to income-eligible Residential Customers of NW Natural. Funds distribution will be accomplished using a cashless voucher system. The cashless voucher system will allow the transfer of authorized payments to an individual customer’s utility account from the OLGA program account based on an electronic voucher list submitted to the company by each participating Agency. The Company will process vouchers as soon as possible following receipt. In the event the Company receives a voucher authorization for a single customer from two or more agencies, the Company will process only one voucher authorization.

3. In order to participate in the OLGA program, an Agency must be a legal entity, contracting or subcontracting with the State of Oregon, Department of Housing and Community Services (OHCS), which is eligible to administer funding under the Federal Low Income Energy Assistance Program (LIEAP).

4. Each participating Agency will have sole responsibility to screen and approve bill payment assistance applicants for eligibility. Except where funds are specifically authorized by the Company for customized bill payment assistance plans, which may be available from time to time, each Agency shall follow the established protocols for the qualification of and disbursement to eligible participants in accordance with the guidelines promulgated by OHCS and the Low-Income Energy Assistance Act of 1981 and subsequent amendments, as outlined in the OHCS Omnibus Contract. The amount of assistance from LIEAP and OLGA for eligible participants shall be based on the LIEAP/OEA Poverty Guidelines and Payment Matrix from the OHCS Operations Manual for these programs. Except where different allocations may be allowed under any special program that may be offered during a program year, any voucher authorizations received by the Company that exceed these guidelines will be appropriately adjusted.

(continue to Sheet 310-2)

SCHEDULE 310
OREGON LOW-INCOME GAS ASSISTANCE (OLGA)
(continued)

SPECIAL CONDITIONS (continued):

5. The Company will determine the allocation of OLGA funds to participating agencies at the beginning of each program year based on the same allocation used to allocate funds during the previous program year. Except that, in the Company's sole discretion, funds may be re-allocated to other Agencies at any time during the program year whenever the Company determines that such a re-allocation is the most effective and efficient use of the available funds.

6. Each Agency will be reimbursed from the OLGA Account for certain administrative costs and direct program costs incurred by them in the administration and delivery of the OLGA program to NW Natural customers. At the beginning of each program year, the Company will negotiate with each participating Agency to determine the specific reimbursements that will be allowed in that program year. Agency reimbursements will be determined by the following guidelines: Up to five percent (5%) for Administrative Costs; and up to fiftenn percent (15%) for Direct Program Costs. Any Agency requesting an amount greater than that provided for in these guidelines will be required first to support such request to the Company's satisfaction. In no event will the combination of Administration and Direct Program costs for any one Agency exceed 30 percent of the total OLGA funds actually disbursed by such Agency.

7. The Company will reimburse each Agency for their administrative and direct program costs on the 20th business day of the month following the month for which reimbursement is requested. Reimbursement will be based on the amount of OLGA funds actually disbursed by the agency in that month, as determined by the electronic voucher lists submitted by the Agency. The Company must receive all reports by the 5th business day of each month.

8. Any amounts not disbursed in the program year will carry over to the next program year.

9. The OLGA program year will extend from October 1 through September 30. The Company will provide an annual summary evaluation report on the progress of the OLGA program for review by the Commission by December 31 following the end of each program year.

GENERAL TERMS:
This 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.

SCHEDULE 320
OREGON LOW-INCOME ENERGY EFFICIENCY (OLIEE) PROGRAMS

PURPOSE:
To describe the Oregon Low-Income Energy Efficiency (OLIEE) program which is funded through a designated portion of the Schedule 301 "Public Purposes Funding Surcharge." The OLIEE program includes two parts: 1) the Community Action Program (CAP) and 2) the Open Solicitation Program (OSP).

AVAILABLE:
This program is available to income-eligible Residential Customer Class dwellings located within NW Natural's Oregon service territory where (1) a gas Service Line is installed at the Premise; (2) the primary space heating equipment is fueled by Natural Gas, and (3) and the occupant has an active account with the Company, or will have an active account upon completion of work performed under this **Schedule 320**. Any residential dwelling that received assistance for the installation of the same or similar measures under any other energy efficiency program may not be eligible for assistance under this program.

PROGRAM YEAR and REPORTING:
The OLIEE program year will extend from October 1 through September 30 (Program Year). The Company will submit an Annual Report of the OLIEE Programs to the Commission by December 31 following the end of each Program Year.

The Annual Report will consistently include the same Program Year results from year to year. The Annual Report will include the number of homes targeted for completion in the next Program Year, and the average pre-installation usage and average post-installation usage for each agency.

PROGRAM FUNDING:
Each month, the Company will bill and collect Public Purposes funds in accordance with **Schedule 301** of this Tariff. By the 20th of the month following the billing month, the amount collected, net of an allowance for uncollectibles, will be deposited into a market-based interest bearing bank account dedicated to the OLIEE program (OLIEE Account). The reserve for uncollectibles shall be in an amount equal to NW Natural's average percentage of residential net write-offs.

PROGRAM ADMINISTRATION, EVALUATION AND VERIFICATION:
All OLIEE programs are to be administered by the Company in accordance with this **Schedule 320**. The Company will be reimbursed from the OLIEE Account each month for actual program administration costs incurred, except that such reimbursement will not exceed the lesser of $90,000 or six percent (6%) of the total funds available during each Program Year.

In addition, the Company will be reimbursed from the OLIEE Account each month for actual project verification costs incurred for the OSP, except that such reimbursement will not exceed five percent (5%) of the total available funds collected during each Program Year.

(continue to Sheet 320-2)

SCHEDULE 320
OREGON LOW-INCOME ENERGY EFFICIENCY (OLIEE) PROGRAMS
(continued)

PROGRAM ADMINISTRATION, EVALUATION AND VERIFICATION (continued):
Following the end of each Program Year, the Company and the OLIEE Advisory Committee (OAC) will evaluate the need for an independent organization to conduct a process and/or impact evaluation for the OLIEE programs. Such evaluation shall be paid from the OLIEE account in an amount not to exceed $50,000.

PROGRAM ADVISORY COMMITTEE:
The OLIEE Advisory Committee (OAC) will assist in advising the Company on OLIEE program implementation, and evaluation. The OAC will be comprised of at least one member each from the Company, the Commission staff, the Community Action Partnership of Oregon (CAPO), plus two or more representatives from the CAP, and when appropriate, one or more representatives from the OSP. The OAC will have no decision-making authority. The OAC will meet at least twice each program year.

ALLOCATION OF FUNDS:
The amount of funds available to support each OLIEE program will be determined by NW Natural as follows:

1. At the beginning of each Program Year, the Company will determine the allocation of funds between the CAP and the OSP based on an estimate of the amount of funds available for that Program Year. Funds will be allocated first to the CAP and second to the OSP.

2. Any amounts not disbursed in the Program Year will carry over to the next Program Year.

I. COMMUNITY ACTION PROGRAM ("CAP") DESCRIPTION

The CAP is designed to leverage other funding sources with OLIEE funds to increase the overall energy efficiency in low-income households within NW Natural's service territory by providing rebates for the installation of certain energy efficiency measures in qualifying residential dwellings following the completion of a home energy evaluation performed by qualifying Agencies that contract with NW Natural, and when authorized by the Company, by providing funding for energy education programs.

(continue to Sheet 320-3)

SCHEDULE 320
OREGON LOW-INCOME ENERGY EFFICIENCY (OLIEE) PROGRAMS
(continued)

Agency Qualifications and Responsibilities for CAP Funds:

1. In order to qualify to participate in the OLIEE program, an Agency must be a legal entity that has been in the business of providing energy efficiency services to low-income customers for at least one year. Any Agency that is contracting or subcontracting with the State of Oregon, Department of Housing and Community Services (OHCS), which is eligible to administer funding under the Federal Low Income Energy Assistance Program (LIEAP) is automatically authorized to participate. All other Agencies must first apply to the Company for authorization to participate. The conditions upon which the Company will approve an application will include, but are not necessarily limited to (a) availability of funds, (b) Agency location, and (c) number of Residential Customer Class dwellings served by NW Natural.
2. All Agencies must enter into a written contract with the Company in order to participate in the administration and delivery of funds under this program.
3. Each participating Agency will have sole responsibility to screen and approve applicants for eligibility. Each Agency shall follow the established protocols for the qualification of and disbursement to eligible participants in accordance with the guidelines of this program and the guidelines promulgated by OHCS and the Low-Income Energy Assistance Act of 1981 and subsequent amendments, as outlined in the OHCS Omnibus Contract.
4. Each participating Agency shall be responsible to complete and return to the Company, all required paperwork and other documentation as may be necessary for the Company to process the rebate request in a form prescribed by the Company.
5. Each participating Agency must agree to abide by the program parameters established in this Schedule including using the Department of Energy (DOE) approved, residential, energy analysis software tool (“Energy Analyzer Software”) in its determination of all measures that qualify for a rebate under CAP.
6. An Agency that fails to abide by the terms and conditions set forth in this tariff schedule may be removed from participating in the CAP Program.
7. To improve the accuracy of the program’s realization rates (i.e. the ratio between verified savings and deemed savings) each participating Agency must attend a training workshop offered in collaboration with the Company, OHCS and CAPO. The workshop will be designed to ensure agencies are consistently and accurately entering data into the Energy Analyzer Software. The Company shall inform Staff of the selected workshop trainer and provide a summary report on the workshop’s accomplishments.

Customer Qualifications for CAP Funds
All CAP funds collected under this program will be used to weatherize homes inhabited by qualifying income-eligible residential customers of NW Natural. In the event the Company receives a rebate request for a single customer from two or more Agencies, the Company will process only one request.

(continue to Sheet 320-4)

SCHEDULE 320
OREGON LOW-INCOME ENERGY EFFICIENCY (OLIEE) PROGRAMS
(continued)

CAP Administration and Delivery Costs
Each Agency will be reimbursed from the OLIEE Account for administrative costs and direct program costs incurred by them in their administration and delivery of the OLIEE program in the amount of $225.00 per household. The Agency fee will be paid to each Agency along with the measure rebate payments. The Company will process measure rebate payments and Agency payments within thirty (30) days from the date the Company receives all completed documentation in support of such rebate request(s).

Annual Program Year Targets (households)
At the beginning of each Program Year, each participating Agency will be assigned a home completion target that supports the achievement of an annual program target. Agency targets may be adjusted from time to time throughout a Program Year, as necessary. Nothing precludes Agencies from serving more than the annual target of homes in any program year provided sufficient funds are available. The Company will include the expected targets for the following year, by Agency, in the Annual Report.

Energy Efficiency Measures and Rebates
Qualifying energy efficiency measures shall be those recommended by the Energy Analyzer Software. To qualify for a rebate under the CAP Program, the total group of measures prescribed by the Energy Analyzer Software for the whole house must meet or exceed a Savings to Investment Ratio (SIR) of 1.0 or better, and except for certain approved exceptions, measures must be chosen in the ranked order of the Energy Analyzer Software's prescriptions.

Rebates under the CAP Program will be paid based on the cost of the total group of qualifying measures for the whole house, as recommended by the Energy Analyzer Software and installed by the Agency. At the beginning of each program year, the maximum rebate amount per home shall be reset to an amount equal to ninety percent (90%) of the average total installed cost of measures as reported by the Agencies for the prior program year. To accommodate timing differences between measure installations, the rebate may be disbursed through one or more reimbursement requests provided all of the work is based on the same audit. Only one energy efficiency audit per home will be eligible for rebates under the OLIEE Program. Under no circumstances will the rebate exceed the actual installed cost of the measure(s).

(continue to Sheet 320-5)

SCHEDULE 320
OREGON LOW-INCOME ENERGY EFFICIENCY (OLIEE) PROGRAMS
(continued)

Health, Safety and Repair (HSR) Allowance and Reimbursement
In addition to the rebate for qualifying energy efficiency measures, a rebate will be available for the costs of health, safety and repair (HSR) measures. HSR measures are those items that if not completed would adversely impact the safety and health of the occupants or the effectiveness of the energy efficiency measures. Standard efficiency furnace replacements may qualify for HSR funds if the existing furnace is broken, is found to produce an unsafe level of CO emissions, is back-drafting, or has a cracked heat exchanger and a high-efficiency furnace is not cost-effective or if it is physically impossible to install a high-efficiency furnace. When a furnace is replaced with a standard efficiency furnace, the Agency must specify the reasons for the replacement in the reimbursement request.

The maximum annual HSR disbursement available to each Agency will be $440 times the actual number of households treated by the Agency in the Program Year (HSR Allowance).

Each Agency will have discretion in the use of their individual HSR Allowance such that they may use more or less than the $440 on any one home. Each Agency must manage their HSR funds to ensure that the average HSR amount per home is not more than $440.

Agency Reporting Requirements
For each home treated under the OLIEE Program, each Agency will be required to report to the Company, the following information:

- Customer Name (as shown on NW Natural Account)
- NWN Account Number
- Service Address
- Phone Number
- Owner or Property Manager Name
- Owner or Property Manager Phone Number
- Audit Date
- Installation Completion Date
- Reimbursement Request Date
- Agency and Agency Representative
- Size of home in square feet and Year Built
- Measure description
- Installed cost per measure
- Estimated therm savings per measure
- Energy Analyzer Software SIR per measure
- Total Energy Analyzer Software SIR for Measure Group
- Total Cost of all energy efficiency measures installed (EEMC)
- Total Energy Analyzer Software estimated savings for each household (Total therms)
- Total job cost to Agency (OLIEE and non-OLIEE measure costs)
- Cost per therm saved for each household (Cost/Savings)
- Requested reimbursement (90% of EEMC up to annual limit)
- Total HSR measure cost
- HSR Related Savings (i.e. – furnace replacements)
- Total Reimbursement Request: (90% of energy efficiency measure costs up to annual limit + Admin)
- Prior 12 months of gas usage
- Projected savings as a percentage of the last 12 months gas usage

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SCHEDULE 320
OREGON LOW-INCOME ENERGY EFFICIENCY (OLIEE) PROGRAMS
(continued)

II. OPEN SOLICITATION PROGRAM (OSP) DESCRIPTION

The overall goal of the OSP is to cost-effectively provide energy efficiency assistance to a greater number of low-income households in NW Natural's Oregon service territory through a broad and diverse network of delivery channels. The Company will invite proposals that include projects for new affordable housing, existing retrofit opportunities, and owner-occupied or rental dwellings, and will encourage proposals that include a component for energy education, environmentally sustainable practices, and collaboration with other entities or programs.

The Company will make the final determination as to which proposals will be awarded contracts under the OSP.

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.

SCHEDULE 350
ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

APPLICABLE:
This program is intended to provide an economical and effective means of conserving Natural Gas through the reduction of heat loss in Residential dwellings and Commercial buildings and in the improvement of the efficiency of space heating, water heating, and energy utilization of the dwellings. This Tariff is in compliance with ORS 469.631 et seq. and with Orders No. 81-778, No. 85-619, No. 85-639, No. 85-891, No. 85-896, No. 91-822, and No. 02-624 of the Commission.

AVAILABLE:
In all territory served by the Company under the Tariff of which this program is a part.

ENERGY EFFICIENCY SERVICES:
The Company will provide to its Residential and Commercial Customers, general and technical information about energy efficiency services offered by the Company, and about energy efficiency programs available through the Energy Trust of Oregon (Energy Trust), that will improve the efficiency of space heating and energy utilization of Residential dwellings and Commercial buildings. This information may be provided through the use of bill inserts, displays (all offices), booklets, handouts, advertisements, and industry and public agency literature.

Advice concerning the advantages or disadvantages of various methods of saving energy will be available through trained Company personnel upon request of Residential and Commercial Customers. Thermal insulation standards of the American National Standards Institute, the International Conference of Building Officials, and American Society of Heating, Refrigeration and Air Conditioning Engineers will be the basis for any technical advice. The Company will provide qualified speakers on energy efficiency subjects for any group desiring this assistance.

ENERGY EFFICIENCY PROGRAMS:
Energy efficiency programs will be available to customers directly through a designated third-party provider(s) or from the Company, as approved by the Commission. The Energy Trust of Oregon is an approved provider of energy efficiency program under this Schedule, and is authorized to deliver and administer certain energy efficiency programs to NW Natural's Customers. To participate in Energy Trust programs, Customers may contact the Energy Trust directly, or a NW Natural representative will connect the Customer upon request.

CUSTOMER NOTIFICATION:
Residential and Commercial Customers will be notified annually by "bill insert" that (1) information on energy efficiency is available from the Company; (2) that certain energy efficiency programs are available through the Energy Trust; (3) how to obtain energy efficiency information from the Company; and (4) how to contact the Energy Trust.

Notification to rental unit owners will be made by mail when a tenant who is a Customer: (a) requests that the material be mailed to the owner; and (b) furnishes the owner's name and address with the request.

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.

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SCHEDULE 360
INDUSTRIAL DEMAND SIDE MANAGEMENT (DSM) PROGRAMS

AVAILABLE:
In all territory served by the Company under the Tariff of which this program is a part.

APPLICABLE:
Service under this Schedule is applicable to Industrial Sales Service Customers taking service under **Rate Schedule 3**, **Rate Schedule 31** or **Rate Schedule 32** and to Commercial Sales Service Customers taking service under **Rate Schedule 32**. Service under this Schedule is not available to Transportation Service Customers. Customers that transfer from Sales Service to Transportation Service are subject to the special provisions contained in this **Schedule 360**.

PURPOSE:
This 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.

INFORMATION TO CUSTOMERS:
The Company will provide to its Industrial Customers, general and technical information about energy efficiency services offered by the Company, and about energy efficiency programs available through the Energy Trust of Oregon (Energy Trust), that will improve the efficiency of natural gas usage. This information may be provided through various channels such as electronic newsletters, letters, direct communications, etc.

ENERGY EFFICIENCY PROGRAMS:
The Energy Trust of Oregon has been approved to deliver and administer energy efficiency programs to NW Natural's Large Commercial and Industrial Customers. Customers may participate in such programs by contacting the Energy Trust directly, or a NW Natural representative will connect the Customer upon request.

PROGRAM COSTS:
Program costs will be deferred annually and amortized for recovery coincident with the Company's PGA Year (November 1 through October 31) through **Schedule 188** of this Tariff.

SPECIAL PROVISIONS:
If a Customer receives service under this Schedule and subsequently transfers to a Transportation Service Type or a Combination Service Type that includes Transportation Service within two Years from the date the most recent incentive was issued to the Customer under this Schedule, such Customer may incur a one-time charge equal to the two-year proration of the total incentive amounts received. The charge will be calculated as follows:

Charge= A x B

A= the total amount of Energy Trust incentives paid to Customer
B= 24 minus the number of months that have elapsed since the last incentive was issued, divided by 24

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SCHEDULE 360
INDUSTRIAL DEMAND SIDE MANAGEMENT (DSM) PROGRAMS
(continued)

SPECIAL PROVISIONS (continued):
A charge will not be assessed if the total incentive amounts received by such customer are $25,000 or less. This provision will not apply to Customers who committed to participating in Energy Trust programs prior to September 8, 2010.

Amounts collected from Customers under this special provision will be credited to the deferral account and will offset program costs amortized under **Schedule 188**.

When applicable, the charge must be paid in full as a condition of the Company's approval to change Service Type. The Customer must meet all other conditions for the change in Service Type as set forth in the respective Rate Schedule.

GENERAL TERMS:
Service under this Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this, 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.

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SCHEDULE 400
SMART ENERGY™ PROGRAM

PURPOSE:
To set forth the terms and conditions for billing, payment and disbursement of funds collected under the Smart Energy™ Program (Program).

AVAILABLE:
This Program is available to all Customers receiving service within the State of Oregon. Customers may enroll in the Program at any time. The rates for participation in this Program will be reflected on the Customer's next regular monthly bill following the date of enrollment.

PROGRAM DESCRIPTION:
Smart Energy™ is a voluntary program that enables all Customers to offset greenhouse gas emissions associated with their natural gas use by purchasing high quality project-based emission reductions from offset projects developed by The Climate Trust. Priority will be given to projects that help bring biogas to the region.

CANCELLATION OF PROGRAM PARTICIPATION:
Customers may terminate participation in the Program at any time by notifying NW Natural in writing, by telephone or by Internet. The termination will be reflected with the Customer's next regular monthly bill following the date of termination.

MONTHLY RATES:
Smart Energy™ charges are in addition to all other charges due for gas service to the Customer, and shall be subject to late charges as set forth in **Schedule C** of this Tariff.

Residential Customer Class Options.
Residential Customers may choose one of two rate options: (1) Fixed Rate, or (2) Volumetric Rate to offset their greenhouse gas emissions.

Fixed Rate:	$6.00 per bill
Volumetric Rate:	$0.10486 per therm

The Fixed Rate option is based on the cost, as of June 29, 2007, of offsetting emissions associated with natural gas from an average residential home that uses 686 therms per year. Customers that select this option will never pay more than the stated Fixed Rate per bill. The total offsets purchased from The Climate Trust may vary based on the cost of those offsets.

The Volumetric Rate provides the option to offset emissions associated with natural gas usage on the basis of the Customer's actual monthly usage. Customers that select this option will tend to pay more during the winter heating months. The Volumetric Rate is based on the cost of offsets as of June 29, 2007. The total offsets purchased from The Climate Trust may vary based on the cost of those offsets.

(continue to Sheet 400-2)

SCHEDULE 400
SMART ENERGY™ PROGRAM
(continued)

MONTHLY RATES (continued):

Commercial Customer Class Option.
Commercial Customers may choose a Fixed Rate of their choice (not less than $10 per bill). The Fixed Rate can be in any amount of Customer's choosing, but cannot be less than $10 per monthly bill.

At the time of enrollment, Commercial Customers will be given an estimate of the resulting Monthly Percentage of Offset being purchased for the Fixed Rate selected. The monthly Percentage of Offset amount will be calculated based on the Customer's past 12 months of usage at the time of enrollment and the cost of offsets as of June 29, 2007. The total offsets purchased from The Climate Trust may vary based on the cost of those offsets.

Industrial Customer Class Option.
Monthly pricing for Industrial Customers will be subject to negotiation, pursuant to the execution of a written contract.

FUNDS COLLECTION AND AGENCY ALLOCATIONS:
Each month, the Company will bill and collect Smart Energy™ funds in accordance with this Schedule 400. By the 20th of the month following the billing month, the amount collected, net of an allowance for uncollectibles, will be deposited into a market-based interest bearing bank account dedicated to the Smart Energy™ Program (Smart Energy™ Account). The reserve for uncollectibles shall be in an amount equal to NW Natural's average percentage of residential net write-offs.

PROGRAM ADMINISTRATION COSTS:
The Company will be reimbursed from the Smart Energy™ Account each month for actual program administration costs incurred.

REPORTS:
Annual Report. Beginning in 2012, the Company will file a report with the Commission within sixty (60) days following the end of the calendar year. The report will include participation details, an analysis of funds collected and expenditures related to the product and a review of offset expenditures by the Climate Trust on behalf of participants.

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.