Oregon
John A. Kitzhaber. MD. Governor

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May 3, 2012

Via Electronic Filing and U.S. Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: Docket No. UG 221 – In the Matter of
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,
Request for a General Rate Revision.

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Opening Testimony.

/s/ Kay Barnes
Kay Barnes
Filing on Behalf of Public Utility Commission Staff
(503) 378-5763
Email: kay.barnes@state.or.us

c: UG 221 Service List (parties)

CERTIFICATE OF SERVICE

UG 221

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

Dated this 3rd day of May, 2012 at Salem, Oregon.

Kay Barnes

Kay Barnes
Public Utility Commission
550 Capitol St NE Ste 215
Salem, Oregon 97301-2551
Telephone: (503) 378-5763

UG 221
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PUC STAFF--DEPARTMENT OF JUSTICE	
JASON W JONES **(C) (HC)**	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 jason.w.jones@state.or.us

CASE: UG 221
WITNESS: Fred Goodwin

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Fred Goodwin. I am a Senior Telecommunications Engineer in the Telecommunications section of the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I've summarized my educational background and work experience in the Witness Qualification Statement found in Exhibit Staff/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to introduce and summarize the Staff sponsored adjustments to Northwest Natural Gas Company's ("NWN" or "Company") filing in this docket.

Q. PLEASE PROVIDE A LIST OF STAFF WITNESSES, EXHIBIT NUMBERS, AND THE SUBJECTS ADDRESSED BY EACH WITNESS.

A. The following Staff witnesses provide opening testimony in this docket:

Witness	Exhibit	Subject(s)
Goodwin	100	Revenue Requirement Model and Summary of Staff Adjustments
Johnson	200	Summary Overview and Environmental Remediation
Andrus	300	Historical Review of Commission Treatment Relating to NW Natural by-Products
Phillips	400	Test Year Sales, Revenue Forecast and WARM
Garcia	500	Miscellaneous Labor and Miscellaneous Revenue
Rossow	600	Other Revenue
Gorsuch	700	Advertising
Bahr	800	D&O Insurance, Incentives, Medical Benefits, Workers' Compensation, and Various A&G Accounts
Cimmiyotti	900	Pensions and R&D
Zimmerman	1000	Rate Base, Gas Storage, SIP, and Schedules 185 and 186
Sobhy	1100	Prudency of Utility Plant in Service
Muldoon	1200	Cost of Long-Term Debt
Storm	1300	Return on Equity, Capital Structure, and Decoupling
Ordoñez	1400	Rate Spread and Long-Run Incremental Cost Study
Compton	1500	Rate Design

Q. HAVE YOU PREPARED EXHIBITS FOR THIS DOCKET?

A. Yes. I have prepared Exhibit Staff/Goodwin/102, comprising 19 pages. This exhibit contains tables summarizing the Staff proposal for Northwest Natural's Oregon-allocated revenue requirements in this docket.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony comprises two parts:

Part I explains Staff's revenue requirement model and all exhibits submitted in support of the model adjustments.

Part II introduces the adjustments proposed by other Staff Witnesses.

PART I – REVENUE REQUIREMENT MODEL SUMMARY

Q. PLEASE EXPLAIN STAFF'S REVENUE REQUIREMENT MODEL.

A. Staff Exhibit/102/Goodwin is a set of spreadsheets that summarizes Staff's position on the revenue requirement adjustments for UG 221. I give all dollar figures in the spreadsheets and in my testimony in thousands (000). I have formatted the spreadsheets as follows:

1. Staff/102, Goodwin/1 - 3 provides a narrative summary that begins at the top of page 1 with the Company's original revenue requirement request for the proceeding. For each individual Staff-proposed adjustment, I provide a short description summarizing the reason for the adjustment. The first column indicates an item number assigned to the adjustment (e.g., S-0, S-1, etc.). The second column provides the initials for the Staff Witness sponsoring the adjustment and the far right column indicates the revenue requirement impact of the proposed adjustment. I show Staff's proposed overall revenue requirement for this portion of the proceeding at the bottom of page 3, in the far right column.

2. Staff/102, Goodwin/4 is a summary table showing the Exhibit numbers assigned to each Staff witness in this proceeding.

3. Staff/102, Goodwin/5 is the actual revenue requirement model page. This table provides a summary showing the changes to revenues, expenses and rate base. The summary page links to the adjustments and tax calculations pages and ends with the percentage change from current rates. Column (1) represents the Company's results of operations per the Company's

application for the test period (Oregon-allocated basis, only). Column (2) shows the aggregate of the adjustments proposed by Staff. Column (3) shows the results of the adjustments proposed in Column (2). Column (4) shows the revenue requirement effect of Staff's proposed cost of capital, and Column (5) shows the results of operations per all adjustments proposed by Staff.

6. Staff/102, Goodwin/6 contains the income tax calculations for the revenue requirement model.

7. Staff/102, Goodwin/7 shows a summary of the cost of capital proposed by Staff as well as a summary of the original request filed by Northwest Natural.

8. Staff/102, Goodwin/8 shows the revenue sensitive costs associated with the revenue requirement calculation, as proposed by Northwest Natural. Staff had no recommended adjustments related to revenue sensitive costs.

9. Staff/102, Goodwin 9-11 show each of the specific adjustments proposed by Staff. The bottom box, shown on line 36, shows the revenue requirement impact for each separate adjustment. This can also be found on pages 1 and 2 of this exhibit, the Narrative Summary Sheets.

10. Staff/102, Goodwin/12-19 show the tax calculations associated with the adjustments shown on pages 8 through 10.

PART II – INTRODUCTION OF STAFF ADJUSTMENTS

Q. PLEASE SUMMARIZE STAFF'S ADJUSTMENTS.

A. The table below provides an item number for each Staff Adjustment, the initials of the Staff witness sponsoring testimony for the adjustment, a description of the adjustment and the revenue requirement effect of the adjustment:

Item	Staff	Issue	Revenue Requirement Effect
			$43,682
S-0	SS/MM	**Rate of Return** Based on 50% Debt, 50% Equity-5.924% cost of debt and 9.2% cost of equity	(11,012)
S-1	KZ	**Remove Working Gas Inventory** Removes working gas inventory from storage inventory in the company's proposed rate base; cost per therm is not changed	(3,863)
S-2	KZ	**Corvallis Reinforcement** Bidding anticipated but not begun at the time of the filing; no firm in-service date, 757.355	(1,936)
S-3	KZ	**Monmouth Reinforcement** Insufficient information to support that the project is prudent; see MS testimony.	(884)
S-4	KZ	**Nertec Replacement** Project still in planning phase; no contract signed for work -- 757.355	(229)
S-5	KZ	**Parkrose Retrofit** Adjusted to regional average cost per sq. ft., $180	(69)
S-6	KZ	**Perrydale to Monmouth** 757.355, timeline indicates will not be in-service by 10/31/12; Insufficient information to support that the project is prudent; see MS testimony	(1,982)
S-7	KZ	**Tualatin replacement, training facility & land** 757.355, timeline indicates not in-service till 4 Qtr. 2013	(2,175)
S-8	KZ	**Unified Communication Phase 1 (PBX Switch)** Project still in planning phase; no contract yet signed for the work.	(353)
S-9	KZ	**Westside Transmission Re-Rate** No in-service date that satisfies 757.355	(218)
S-10	BB	**Directors and Officers Insurance** 50% sharing between Company and customers of excess layers of D&O insurance consistent with Commission precedent per Order 09-020 at 19-20	(279)
S-11	BB	**Incentive Compensation** Removes 100% of officer bonuses, 75% of performance based non-officer bonuses, and 50% merit based non-officer bonuses consistent with Commission precedent in Order No. 99-033 at page 62, Order No. 97-171 at pages 74-76, and Order No. 99-697 at pages 44-45.	(3,532)
S-12	BB	**Medical Benefits & Workers Compensation** Adjusts medical benefits and workers compensation by the same percentage that DG adjusted FTEs. Also adjusted medical benefits and workers compensation by 1.78% to account for non-utility employees.	(2,121)

S-13	BB	**Various Customer Service, A&G Expenses** Removes 50% of Books & Magazines, Conference Travel, Dealer Relations, Education, Employee Awards, Meals & Entertainment, and Miscellaneous. Removes 100% of Donations, Dues/Memberships, Corporate Identity, Laundry, Non Employee Gifts & Refreshments.	(2,041)
S-14	NC	**Pensions** Removes $21.9 million from rate base for the Company's "out of test-period" cash contributions in excess of the amount authorized in UG 152. Remove $4.6 million from amortizable expenses, representing one-eighth of the $36.5 million prior period cash contributions.	(7,104)
S-15	NC	**Research & Development** Adjusted to .01% of test year gross sales, per the 2007 American Gas Foundation Study.	(7)
S-16	DG	**Miscellaneous Labor** Adjustment is based on a series of adjustments in multiple accounts related to compensation. Payroll taxes and O&M depreciation are adjusted accordingly.	(8,461)
S-17	DG	**Miscellaneous Revenue -- Taxes** Reverses the reduction to Miscellaneous Revenues related to the change in the Oregon State Tax rate for Tax Year 2009	(923)
S-18		**blank**	
S-19	LG	**Advertising** Adjusts Category A advertising expenditures per OAR 860-026-0022(3)(a). Category B advertising expenditures for 2010 are escalated using a 3-year average of CPI.	(956)
S-20		**blank**	
S-21	PR	**Miscellaneous Revenue** Adjusts Miscellaneous Revenue categories to a 3-year average using calendar years 2009, 2010, and 2011.	(916)
S-22		**blank**	
S-23		**blank**	
S-24	IP	**Revenue Adjustments** Corrects test year normalized revenues from sales of gas and transportation schedules, it also adjusts gas costs components	(5,356)
S*		**Rounding**	(2)
		Total Staff-Proposed Adjustments (Base Rates):	(54,419)
		Staff-Calculated Revenue Requirements Change (Base Rates):	**($10,737)**

1

Q. PLEASE IDENTIFY THE STAFF WITNESSES THAT WILL PROVIDE EVIDENCE FOR THE STAFF'S PROPOSED COST OF CAPITAL.

A. Adjustment S-0 represents Staff's recommended Cost of Capital. The components of the Cost of Capital are the Cost of Debt, the Cost of Equity and the Capital Structure. These components also comprise the overall Rate of Return (ROR).

Staff Witness **Steve Storm** prepared **Staff Exhibit 1300** in support of the Staff recommended ROR, Return on Equity (ROE) and the proposed Capital Structure. Staff Witness **Matt Muldoon** prepared **Staff Exhibit 1200** in support of Staff's proposed Cost of Debt.

Mr. Muldoon recommends a Cost of Debt of 5.924 percent. Mr. Storm recommends an ROE of 9.200 percent and an ROR of 7.562 percent. Staff did not adjust the Company's proposed capital structure of 50 percent debt and 50 percent equity. Staff calculated its recommended ROR by applying the company's proposed capital structure to Staff's recommended ROE of 9.200 percent and Cost of Debt of 5.924 percent.

Staff's proposed ROR of 7.562 percent compared to the Company's requested ROR of 8.283 percent results in a reduction in revenue requirement of **-$11,012**.

Q. PLEASE IDENTIFY THE STAFF WITNESS FOR ADJUSTMENTS S-1 THROUGH S-9.

A. In **Staff Exhibit 1000**, Staff Witness **Ken Zimmerman** provides evidence supporting Staff Adjustments S-1 through S-9.

Staff Adjustments S-1 through S-9 relate to NWN's rate base. Staff makes several adjustments to rate base because: working gas inventory should not be included in rate base (S-1); the Company did not provide sufficient evidence that a project was prudent (S-3); project costs exceed the regional average (S-5); and certain projects would not be in-service within the test year (S-2, S-4, and S-6 through S-9).

Staff Witness Zimmerman's nine proposed rate base adjustments result in a cumulative revenue requirement impact of **-$11,709**.

Q. PLEASE IDENTIFY THE STAFF WITNESS FOR STAFF ADJUSTMENTS S-10 THROUGH S-13.

A. In **<u>Staff Exhibit 800</u>**, Staff Witness **<u>Brian Bahr</u>** provides evidence in support of Staff Adjustments S-10 through S-13.

Staff Adjustments S-10 through S-13 relate to Directors and Officers (D&O) Insurance, Incentive Compensation, Medical Benefits and Workers Compensation, and Various Customer Service and Administrative and General (A&G) expenses. Staff Adjustments S-10, S-11 and S-13 are based on Commission policy and precedent established in prior Commission Orders. In Staff Adjustment S-12, Staff adjusts Medical Benefits and Workers Compensation by the same percentage that full-time equivalents (FTEs) were adjusted by Staff witness Deborah Garcia (see Staff Adjustment S-16).

Staff Witness Bahr's four proposed adjustments result in a cumulative revenue requirement impact of **-$7,973**.

Q. PLEASE IDENTIFY THE STAFF WITNESS FOR STAFF ADJUSTMENTS S-14 AND S-15.

A. In **Staff Exhibit 900**, Staff witness **Nick Cimmiyotti** provides evidence in support of Staff Adjustments S-14 and S-15.

Staff Adjustment S-14 relates to Pensions. Staff adjusts rate base and amortizable expenses in accordance with the requirements of the Commission's Final Order in UG 152. Staff Adjustment S-15 relates to Research and Development (R&D). Staff adjusts R&D expenses to 0.01% of test year gross sales, consistent with the 2007 American Gas Foundation study.

The revenue requirement effect of proposed Staff Adjustments S-14 and S-15 is **-$7,111**.

Q. PLEASE IDENTIFY THE STAFF WITNESS FOR STAFF ADJUSTMENTS S-16 AND S-17.

A. In **Staff Exhibit 500**, Staff witness **Deborah Garcia** provides evidence in support of Staff Adjustments S-16 and S-17.

Staff Adjustment S-16 relates to Miscellaneous Labor. Staff's adjustment is based on a series of adjustments in multiple accounts related to compensation. Payroll taxes and operations and maintenance (O&M) expense are adjusted accordingly. Staff Adjustment S-17 relates to Miscellaneous Revenue-Taxes. Staff reverses the reduction in Miscellaneous Revenue related to the change in the Oregon State Tax rate for Tax Year 2009.

The revenue requirement effect of proposed Staff Adjustments S-16 and S-17 is **-$9,384**.

Q. PLEASE IDENTIFY THE STAFF WITNESS FOR STAFF ADJUSTMENT S-19.

A. In **<u>Staff Exhibit 700</u>**, Staff witness **<u>Lisa Gorsuch</u>** provides evidence in support of Staff Adjustment S-19.

Staff Adjustment S-19 relates to Advertising. Staff adjusts Category A advertising expenses in accordance with Oregon Administrative Rule (OAR) 860-026-0022(3)(a). Staff escalates Category B advertising expenditures for 2010 using a three-year average of the Consumer Price Index (CPI).

The revenue requirement effect of proposed Staff Adjustment S-19 is **-$956**.

Q. PLEASE IDENTIFY THE STAFF WITNESS FOR STAFF ADJUSTMENT S-21.

A. In **<u>Staff Exhibit 600</u>**, Staff witness **<u>Paul Rossow</u>** provides evidence in support of Staff Adjustment S-21.

Staff Adjustment S-21 relates to Miscellaneous Revenue. Staff adjusted Miscellaneous Revenue categories to a three-year average using calendar years 2009, 2010, and 2011.

The revenue requirement effect of proposed Staff Adjustment S-19 is **-$916**.

Q. PLEASE IDENTIFY THE STAFF WITNESS FOR STAFF ADJUSTMENT S-24.

A. In **<u>Staff Exhibit 400</u>**, Staff witness **<u>Irina Phillips</u>** provides evidence in support of Staff Adjustment S-24.

Staff Adjustment S-24 relates to Revenue Adjustments. This adjustment corrects test year normalized revenue from sales of gas and transportation schedules; it also adjusts for gas cost components.

The revenue requirement effect of proposed Staff Adjustment S-24 is **-$5,356**.

Q. WHY ARE STAFF ADJUSTMENTS S-20, S-22 AND S-23 LABELED "BLANK"?

A. Staff Adjustments S-20, S-22 and S-23 related to issues considered during the April Settlement Conference. Staff is no longer sponsoring those proposed adjustments.

I left placeholders in Staff's Revenue Requirements Model to account for those items, so other Staff witnesses would not have to renumber their proposed adjustments.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: Fred Goodwin

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME: Fred Goodwin

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Telecommunications Engineer
Rates and Service Quality Section

ADDRESS: 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.

EDUCATION: Master of Business Administration, St. Edward's University
Bachelor of Science in Physics, University of Texas at Austin
Associate of Applied Science in Financial Accounting, Austin Community College

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since August of 2010. From November, 2009 to June, 2010 I was employed by GVNW Consultants, Inc. From March, 1979 to October, 2008, I was employed by Southwestern Bell Telephone Company (SWBT, later SBC and finally AT&T) in various departments including Network Engineering, Industry Relations, State Regulatory, Research and Development, and Federal Regulatory.

I have appeared before the Public Utility Commission of Texas as a witness for SWBT in the following cases:

Docket No. 10831, *Application of Southwestern Bell Telephone Company to Revise its Tariff to Redefine the Point of Demarcation and the Location of the Network Interface*

Docket No. 14295, *Complaint of Larry Wade on Behalf of Dunn Equipment Against Southwestern Bell Telephone Company*

Docket No. 14452, *Complaint of Carolyn Arnold Communications Consultant, Inc. on Behalf of Manor Downs Against Southwestern Bell Telephone Company*

Docket No. 14453, *Complaint of Carolyn Arnold Communications Consultant, Inc. on Behalf of Turbomachinery Repair, Inc. Against Southwestern Bell Telephone Company*

CASE: UG 221
WITNESS: Fred Goodwin

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibit in Support
Of Opening Testimony

May 3, 2012

Item	Staff	Issue	Revenue Requirement Effect
		Revenue Requirement on the Company's Filed Results	$43,682
		Proposed Staff Adjustments	
S-0	SS/MM	Rate of Return Based on 50% Debt, 50% Equity, 5.924% cost of debt and 9.2% cost of equity	(11,012)
S-1	KZ	Remove Working Gas Inventory Staff proposes to remove working gas inventory from storage inventory in the company's proposed rate base; cost per therm is not changed	(3,863)
S-2	KZ	Corvallis Reinforcement Bidding anticipated but not begun at the time of the filing; no firm in-service date, 757.355	(1,936)
S-3	KZ	Monmouth Reinforcement Insufficient information to support that the project is prudent; see MS testimony.	(884)
S-4	KZ	Nertec Replacement Project still in planning phase; no contract signed for work -- 757.355	(229)
S-5	KZ	Parkrose Retrofit Adjusted to regional average cost per sq. ft., $180	(69)
S-6	KZ	Perrydale to Monmouth 757.355, timeline indicates will not be in-service by 10/31/12; Insufficient information to support that the project is prudent; see MS testimony	(1,982)
S-7	KZ	Tualatin replacement, training facility & land 757.355, timeline indicates not in-service till 4 Qtr. 2013	(2,175)
S-8	KZ	Unified Communication Phase 1 (PBX Switch) Project still in planning phase; no contract yet signed for the work.	(353)
S-9	KZ	Westside Transmission Re-Rate No in-service date that satisfies 757.355	(218)
S-10	BB	Directors and Officers Insurance Staff proposes 50% sharing between Company and customers of excess layers of D&O insurance consistent with Commission precedent per Order 09-020 at 19-20	(279)

S-11	BB	Incentive Compensation Remove 100% of officer bonuses, 75% of performance based non-officer bonuses, and 50% merit based non-officer bonuses consistent with Commission precedent in Order No. 99-033 at page 62, Order No. 97-171 at page 74-76, and Order No. 99-697 at 44-45.	(3,532)
S-12	BB	Medical Benefits & Workers Comp Staff adjusted medical benefits and workers compensation by the same percentage that Deborah Garcia adjusted FTEs. Staff also adjusted medical benefits and workers compensation by 1.78% to account for non-utility employees.	(2,121)
S-13	BB	Various Customer Service, General & Administrative Expenses Staff removed 50% of Books & Magazines, Conference Travel, Dealer Relations, Education, Employee Awards, Meals & Entertainment, and Miscellaneous. Staff removed 100% of Donations, Dues/Memberships, Corporate Identity, Laundry, Non Employee Gifts & Refreshments.	(2,041)
S-14	NC	Pensions Remove $21.9 million from rate base for the Company's "out of test-period" cash contributions in excess of the amount authorized in UG 152. Remove $4.6 million from amortizable expenses, representing one-eighth of the $36.5 million prior period cash contributions.	(7,104)
S-15	NC	Research & Development Adjusted to .01% of test year gross sales, per the 2007 American Gas Foundation Study.	(7)
S-16	DG	Miscellaneous Labor Staff's adjustment is based on a series of adjustments in multiple accounts related to compensation. Payroll taxes and O&M depreciation expense are adjusted accordingly.	(8,461)
S-17	DG	Miscellaneous Revenue – Taxes Reverse the reduction to Miscellaneous Revenues related to the change in the Oregon State Tax rate for Tax Year 2009	(923)
S-18		blank	0
S-19	LG	Advertising Category A advertising expenditures were adjusted per OAR 860-026-0022(3)(a). Category B advertising expenditures for 2010 are escalated using a 3-year average of CPI.	(956)
S-20		blank	0
S-21	PR	Miscellaneous Revenue Increased Miscellaneous Revenue by $657; also removed state tax change ($895) and set each category to a three-year average using calendar years 2009, 2010, and 2011.	(916)

S-22		blank	0
S-23		blank	0
S-24	IP	Revenue Adjustments This adjustment corrects test year normalized revenues from sales of gas and transportation schedules, it also adjusts gas costs components	(5,356)
			0
S*		Rounding	(2)
		Total Staff-Proposed Adjustments (Base Rates):	(54,419)
		Staff-Calculated Revenue Requirements Change (Base Rates):	**($10,737)**

List of Staff Adjustments and Contact Information

S-0	Cost of Capital	SS/MM	Steve Storm / Matt Muldoon	503-378-5264 / 503-378-6164
S-1	Working Gas Inventory	KZ	Ken Zimmerman	503-373-1583
S-2	Corvallis Reinforcement	KZ	Ken Zimmerman	503-373-1583
S-3	Monmouth Reinforcement	KZ	Ken Zimmerman	503-373-1583
S-4	Nertec Replacement	KZ	Ken Zimmerman	503-373-1583
S-5	Parkrose Retrofit	KZ	Ken Zimmerman	503-373-1583
S-6	Perrydale to Monmouth	KZ	Ken Zimmerman	503-373-1583
S-7	Tualatin replacement, training facility & land	KZ	Ken Zimmerman	503-373-1583
S-8	Unified Communication Phase 1 (PBX Switch)	KZ	Ken Zimmerman	503-373-1583
S-9	Westside Transmission Re-Rate	KZ	Ken Zimmerman	503-373-1583
S-10	D&O Insurance	BB	Brian Bahr	503-378-4362
S-11	Incentive Compensation	BB	Brian Bahr	503-378-4362
S-12	Medical & Workers Comp	BB	Brian Bahr	503-378-4362
S-13	Various A&G Expenses	BB	Brian Bahr	503-378-4362
S-14	Pensions	NC	Nick Cimmiyotti	503-373-7867
S-15	R&D	NC	Nick Cimmiyotti	503-373-7867
S-16	Miscellaneous Labor	DG	Deborah Garcia	503-378-6688
S-17	Miscellaneous Revenue -- Taxes	DG	Deborah Garcia	503-378-6688
S-18	blank			
S-19	Advertising	LG	Lisa Gorsuch	503-378-3778
S-20	blank			
S-21	Miscellaneous Revenue	PR	Paul Rossow	503-378-6917
S-22	blank			
S-23	blank			
S-24	Revenue Adjustments	IP	Irina Phillips	503-378-6436

		October 2013 Results Per Company Filing (1)	Adjustments (2)	October 2013 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
	SUMMARY SHEET					
1	Operating Revenues					
2	General Business	$682,996	$9,370	$692,366	($10,737)	$681,629
3	Transportation	12,871	0	12,871	0	12,871
4	Other Revenues	3,429	1,784	5,213	0	5,213
5	Total Operating Revenues	$699,296	$11,154	$710,450	($10,737)	$699,713
6	Operating Expenses					
7	Gas Purchased	$395,039	$4,171	$399,210	$0	$399,210
8	Uncollectible Accrual for Gas Sales	2,110	0	2,110	121	2,231
9	Other O & M Expenses	118,219	(15,948)	102,271	0	102,271
10	Total Operation & Maintenance	$515,368	($11,777)	$503,591	$121	$503,712
11						
12	Depreciation & Amortization	60,094	(4,655)	55,439	0	55,439
13	PENSIONS	0	0	0	0	0
14	Taxes Other than Income	42,927	(528)	42,399	(280)	42,119
15	Income Taxes	22,912	12,794	35,706	(4,225)	31,481
16	Miscellaneous Revenue and Expense	0	0	0	0	0
17	Total Operating Expenses	$641,301	($4,166)	$637,135	($4,384)	$632,751
18	Net Operating Revenues	$57,995	$15,320	$73,315	($8,919)	$64,386
19	Average Rate Base					
20	Gas Plant in Service	$2,227,108	($74,857)	$2,152,251	$0	$2,152,251
21	Less: Accumulated Depreciation & Amortization	(990,862)	0	(990,862)	0	(990,862)
22	Accumulated Deferred Income Taxes	(329,082)	0	(329,082)	0	(329,082)
23	Accumulated Deferred Inv. Tax Credit		0	0	0	0
24	Net Utility Plant	$907,164	($74,857)	$832,307	$0	$832,307
25	Plant Held for Future Use	$0	$0	$0	$0	$0
26	PENSIONS	21,930	(21,930)	0	0	0
27	Working Capital	0	0	0	0	0
28	Gas Inventory	48,008	(35,318)	12,690	0	12,690
29	Materials & Supplies	7,422	0	7,422	0	7,422
30	Customer Advances for Construction	(1,994)	0	(1,994)	0	(1,994)
31	Leasehold Improvements	1,155	0	1,155	0	1,155
32	Prepayments	0	0	0	0	0
33	Misc. Deferred Debits	0	0	0	0	0
34	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0
35	Total Average Rate Base	$983,685	($132,105)	$851,580	$0	$851,580
36	Rate of Return	5.90%		8.61%		7.56%
37	Implied Return on Equity	5.87%		11.29%		0.092

	Income Tax Calculations	October 2013 Per Company Filing (1)	Adjustments (2)	October 2013 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Book Revenues	$699,296	$11,154	$710,450	($10,737)	$699,713
2	Book Expenses Other than Depreciation	558,295	(16,960)	541,335	(159)	541,176
3	State Tax Depreciation	60,094	0	60,094	0	60,094
4	Interest	29,137	(3,913)	25,224	0	25,224
5	PLUS: Schedule M Differences (Perm)	6,084	0	6,084	0	6,084
6	State Taxable Income	$57,854	$32,027	$89,881	($10,578)	$79,303
7	Add OR Depletion Adjustment	$0				
8	Total State Taxable Income	$57,854			($10,578)	
9	State Income Tax @ 7.60%	$4,397	$2,435	$6,832	($804)	$6,028
10	State Tax Credits	0	0	0	0	0
11	Net State Income Tax	$4,397	$2,435	$6,832	($804)	$6,028
12	Additional Tax Depreciation	0	0	0	0	0
13	Plus: Other Schedule M Differences	0	0	0	0	0
14	Federal Taxable Income	$53,457	$29,592	$83,049	($9,774)	$73,275
15	Federal Tax @ 35%	18,710	10,359	29,069	(3,421)	25,648
16	Federal Tax Credits	0	0	0	0	0
17	Current Federal Tax	$18,710	$10,359	$29,069	($3,421)	$25,648
18	ITC Adjustment					
19	Deferral	(197)	0	(197)	0	(197)
20	Less: Amortization	0	0	0	0	0
21	Total ITC Adjustment	($197)	$0	($197)	$0	($197)
22	Provision for Deferred Taxes	$0	$0	$0	$0	$0
23	Total Income Tax	$22,912	$12,794	$35,706	($4,225)	$31,481

Capital Structure Calculation

INPUT ASSUMPTIONS

COST OF CAPITAL - STAFF	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	50.00%	5.924%	2.962%
Preferred Stock	0.00%		0.000%
Common Equity	50.00%	9.200%	4.600%
OVERALL RATE OF RETURN	100.00%		7.562%

REVENUE SENSITIVE COSTS

Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00308
Taxes Other - Franchise	0.02358
- Other	0.00250
- Resource supplier	
State Taxable Income	0.97084
State Income Tax @ 7.6%	0.07378
Federal Taxable Income	0.89706
Federal Income Tax @ 35%	0.31397
ITC	
Current FIT	0.31397
Other	
Total Excise Taxes	0.38775
Total Revenue Sensitive Costs	0.41691
Utility Operating Income	0.58309
Net-to-Gross Factor	1.71501

Input:		
	7.600%	STATERATE (Income Tax Rate)
		WORKINGCAP

	Staff Adjustments	Remove Working Gas Inventory (S-1)	Corvallis Reinforcement (S-2)	Monmouth Reinforcement (S-3)	Nertec Replacement (S-4)	Parkrose Retrofit (S-5)	Perrydale to Monmouth (S-6)	Tualatin Replacement (S-7)	Unified Communications Phase 1 (S-8)	Westside Transmission Rerate (S-9)	D&O Insurance (S-10)	Incentive Compensation (S-11)
1	Operating Revenues											
2	General Business	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Transportation	0	0	0	0	0	0	0	0	0	0	0
4	Other Revenues	0	0	0	0	0	0	0	0	0	0	0
5	Total Operating Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Operating Expenses											
7	Gas Purchased	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
8	Uncollectible Accrual for Gas Sales	0	0	0	0	0	0	0	0	0	0	0
9	Other O & M Expenses	0	0	0	0	0	0	0	0	0	(272)	(3,430)
10	Total Operation & Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$0	($272)	($3,430)
11												
12	Depreciation and Amortization	0	0	0	0	0	0	0	0	0	0	0
13	PENSIONS	0	0	0	0	0	0	0	0	0	0	0
14	Taxes Other than Income	0	0	0	0	0	0	0	0	0	0	0
15	Income Taxes	418	210	96	25	7	215	235	38	24	109	1,370
16	Miscellaneous Revenue and Expense											
17	Total Operating Expenses	$418	$210	$96	$25	$7	$215	$235	$38	$24	($163)	($2,060)
18	Net Operating Revenues	($418)	($210)	($96)	($25)	($7)	($215)	($235)	($38)	($24)	$163	$2,060
19	Average Rate Base											
20	Gas Plant in Service	0	(17,703)	(8,087)	(2,100)	(621)	(18,131)	(19,880)	(3,220)	(2,000)	0	0
21	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0	0
22	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
23	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	0
24	Net Utility Plant	$0	($17,703)	($8,087)	($2,100)	($621)	($18,131)	($19,880)	($3,220)	($2,000)	$0	$0
25	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0
26	PENSIONS	0	0	0	0	0	0	0	0	0	0	0
27	Working Capital	0	0	0	0	0	0	0	0	0	0	0
28	Gas Inventory	(35,318)	0	0	0	0	0	0	0	0	0	0
29	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0
30	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0	0
31	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0
32	Prepayments	0	0	0	0	0	0	0	0	0	0	0
33	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	0
34	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	0	0
35	Total Average Rate Base	($35,318)	($17,703)	($8,087)	($2,100)	($621)	($18,131)	($19,880)	($3,220)	($2,000)	$0	$0
36	Revenue Requirement Effect	($3,863)	($1,936)	($884)	($229)	($69)	($1,982)	($2,175)	($353)	($218)	($279)	($3,532)

	Staff Adjustments	Med Benefits & Workers Comp (S-12)	Various A&G (S-13)	Pensions (S-14)	R&D (S-15)	Misc Labor (S-16)	Misc Revs Taxes (S-17)	blank (S-18)	Advertising (S-19)	blank (S-20)	Misc Rev (S-21)	blank (S-22)
1	Operating Revenues											
2	General Business	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Transportation	0	0	0	0	0	0	0	0	0	0	0
4	Other Revenues	0	0	0	0	0	896	0	0	0	888	0
5	Total Operating Revenues	$0	$0	$0	$0	$0	$896	$0	$0	$0	$888	$0
6	Operating Expenses											
7	Gas Purchased	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Uncollectible Accrual for Gas Sales	0	0	0	0	0	0	0	0	0	0	0
9	Other O & M Expenses	(2,059)	(1,982)	0	(6)	(7,270)	0	0	(930)	0	0	0
10	Total Operation & Maintenance	($2,059)	($1,982)	$0	($6)	($7,270)	$0	$0	($930)	$0	$0	$0
11												
12	Depreciation and Amortization	0	0	(4,569)	0	(86)	0	0	0	0	0	0
13	PENSIONS	0	0	0	0	0	0	0	0	0	0	0
14	Taxes Other than Income	0	0	0	0	(528)	0	0	0	0	0	0
15	Income Taxes	822	792	2,085	2	3,186	358	0	372	0	354	0
16	Miscellaneous Revenue and Expense											
17	Total Operating Expenses	($1,237)	($1,190)	($2,484)	($4)	($4,698)	$358	$0	($558)	$0	$354	$0
18	Net Operating Revenues	$1,237	$1,190	$2,484	$4	$4,698	$538	$0	$558	$0	$534	$0
19	Average Rate Base											
20	Gas Plant in Service	0	0	0	0	(3,116)	0	0	0	0	0	0
21	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0	0
22	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
23	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	0
24	Net Utility Plant	$0	$0	$0	$0	($3,116)	$0	$0	$0	$0	$0	$0
25	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0
26	PENSIONS	0	0	(21,930)	0	0	0	0	0	0	0	0
27	Working Capital	0	0	0	0	0	0	0	0	0	0	0
28	Gas Inventory	0	0	0	0	0	0	0	0	0	0	0
29	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0
30	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0	0
31	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0
32	Prepayments	0	0	0	0	0	0	0	0	0	0	0
33	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	0
34	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	0	0
35	Total Average Rate Base	$0	$0	($21,930)	$0	($3,116)	$0	$0	$0	$0	$0	$0
36	Revenue Requirement Effect	($2,121)	($2,041)	($7,104)	($7)	($8,461)	($923)	$0	($956)	$0	($916)	$0

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	Staff Adjustments	blank (S-23)	Revenue Adjustment (S-24)	(S-25)	(S-26)	(S-27)	(P-1)	(S-31,I-5)	(I-7,C-1)	(I-8)	Total Adjustments (Base Rates)
1	Operating Revenues										
2	General Business	$0	$9,370	$0	$0	$0	$0	$0	$0	$0	$9,370
3	Transportation	0	0	0	0	0	0	0	0	0	$0
4	Other Revenues	0	0	0	0	0	0	0	0	0	$1,784
5	Total Operating Revenues	$0	$9,370	$0	$0	$0	$0	$0	$0	$0	$11,154
6	Operating Expenses										
7	Gas Purchased	$0	$4,171	$0	$0	$0	$0	$0	$0	$0	$4,171
8	Uncollectible Accrual for Gas Sales	0	0	0	0	0	0	0	0	0	$0
9	Other O & M Expenses	0	0	0	0	0	0	0	0	0	($15,948)
10	Total Operation & Maintenance	$0	$4,171	$0	$0	$0	$0	$0	$0	$0	($11,777)
11											$0
12	Depreciation and Amortization	0	0	0	0	0	0	0	0	0	($4,655)
13	PENSIONS	0	0	0	0	0	0	0	0	0	$0
14	Taxes Other than Income	0	0	0	0	0	0	0	0	0	($528)
15	Income Taxes	0	2,076	0	0	0	0	0	0	0	$12,794
16	Miscellaneous Revenue and Expense										$0
17	Total Operating Expenses	$0	$6,247	$0	$0	$0	$0	$0	$0	$0	($4,166)
18	Net Operating Revenues	$0	$3,123	$0	$0	$0	$0	$0	$0	$0	$15,320
19	Average Rate Base										
20	Gas Plant in Service	0	0	0	0	0	0	0	0	0	($74,857)
21	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	0	$0
22	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	$0
23	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	$0
24	Net Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	($74,857)
25	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	$0
26	PENSIONS	0	0	0	0	0	0	0	0	0	($21,930)
27	Working Capital	0	0	0	0	0	0	0	0	0	$0
28	Gas Inventory	0	0	0	0	0	0	0	0	0	($35,318)
29	Materials & Supplies	0	0	0	0	0	0	0	0	0	$0
30	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	$0
31	Leasehold Improvements	0	0	0	0	0	0	0	0	0	$0
32	Prepayments	0	0	0	0	0	0	0	0	0	$0
33	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	$0
34	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	$0
35	Total Average Rate Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	($132,105)
36	Revenue Requirement Effect	$0	($5,356)	$0	$0	$0	$0	$0	$0	$0	($43,405)

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Goodwin/11

Income Tax Calculations for Adjustments

	Income Tax Calculations	Remove Working Gas Inventory (S-1)	Corvallis Reinforcement 0 (S-2)	Monmouth Reinforcement 0 (S-3)	Nertec Replacement 0 (S-4)	Parkrose Retrofit 0 (S-5)	Perrydale to Monmouth (S-6)	Tualatin Replacement 0 (S-7)	Unified Communications Phase 1 (S-8)
1	Book Revenues	$0	$0	$0	$0	$0	$0	$0	$0
2	Book Expenses Other than Depreciation	0	0	0	0	0	0	0	0
3	State Tax Depreciation	0	0	0	0	0	0	0	0
4	Interest	(1,046)	(524)	(240)	(62)	(18)	(537)	(589)	(95)
5	Schedule M Differences	0	0	0	0	0	0	0	0
6	State Taxable Income	$1,046	$524	$240	$62	$18	$537	$589	$95
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0
8	Total State Taxable Income	$1,046	$524	$240	$62	$18	$537	$589	$95
9	State Income Tax	$80	$40	$18	$5	$1	$41	$45	$7
10	State Tax Credits	0	0	0	0	0	0	0	0
11	Net State Income Tax	$80	$40	$18	$5	$1	$41	$45	$7
12	Additional Tax Depreciation	0	0	0	0	0	0	0	0
13	Other Schedule M Differences	0	0	0	0	0	0	0	0
14	Federal Taxable Income	$966	$484	$222	$57	$17	$496	$544	$88
15	Federal Tax @ 35%	338	170	78	20	6	174	190	31
16	Federal Tax Credits	0	0	0	0	0	0	0	0
17	Current Federal Tax	$338	$170	$78	$20	$6	$174	$190	$31
18	ITC Adjustment								
19	Deferral	0	0	0	0	0	0	0	0
20	Restoration	0	0	0	0	0	0	0	0
21	Total ITC Adjustment	0	0	0	0	0	0	0	0
22	Provision for Deferred Taxes	0	0	0	0	0	0	0	0
23	Total Income Tax	$418	$210	$96	$25	$7	$215	$235	$38

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Goodwin/12

REVENUE REQUIREMENTS
EFFECTS OF ADJUSTMENTS

	Remove Working Gas Inventory (S-1)	Corvallis Reinforcement 0 (S-2)	Monmouth Reinforcement 0 (S-3)	Nertec Replacement 0 (S-4)	Parkrose Retrofit 0 (S-5)	Perrydale to Monmouth (S-6)	Tualatin Replacement 0 (S-7)	Unified Communications Phase 1 (S-8)
Revenues and Expenses	$717	$360	$165	$43	$12	$369	$403	$65
Rate Base	(4580)	(2296)	(1049)	(272)	(81)	(2351)	(2578)	(418)
Total	($3,863)	($1,936)	($884)	($229)	($69)	($1,982)	($2,175)	($353)

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Goodwin/13

Income Tax Calculations for Adjustments

	Income Tax Calculations	Transmission Rerate 0 (S-9)	D&O Insurance 0 (S-10)	Incentive Compensation 0 (S-11)	Med Benefits & Workers Comp (S-12)	Various A&G 0 (S-13)	Pensions 0 0 (S-14)	R&D 0 0 (S-15)	Misc Labor 0 (S-16)	Misc Revs Taxes 0 (S-17)
1	Book Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$896
2	Book Expenses Other than Depreciation	0	(272)	(3,430)	(2,059)	(1,982)	(4,569)	(6)	(7,884)	0
3	State Tax Depreciation	0	0	0	0	0	0	0	0	0
4	Interest	(59)	0	0	0	0	(650)	0	(92)	0
5	Schedule M Differences	0	0	0	0	0	0	0	0	0
6	State Taxable Income	$59	$272	$3,430	$2,059	$1,982	$5,219	$6	$7,976	$896
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0	0
8	Total State Taxable Income	$59	$272	$3,430	$2,059	$1,982	$5,219	$6	$7,976	$896
9	State Income Tax	$5	$21	$261	$156	$151	$397	$0	$606	$68
10	State Tax Credits	0	0	0	0	0	0	0	0	0
11	Net State Income Tax	$5	$21	$261	$156	$151	$397	$0	$606	$68
12	Additional Tax Depreciation	0	0	0	0	0	0	0	0	0
13	Other Schedule M Differences	0	0	0	0	0	0	0	0	0
14	Federal Taxable Income	$54	$251	$3,169	$1,903	$1,831	$4,822	$6	$7,370	$828
15	Federal Tax @ 35%	19	88	1,109	666	641	1,688	2	2,580	290
16	Federal Tax Credits	0	0	0	0	0	0	0	0	0
17	Current Federal Tax	$19	$88	$1,109	$666	$641	$1,688	$2	$2,580	$290
18	**ITC Adjustment**									
19	Deferral	0	0	0	0	0	0	0	0	0
20	Restoration	0	0	0	0	0	0	0	0	0
21	Total ITC Adjustment	0	0	0	0	0	0	0	0	0
22	Provision for Deferred Taxes	0	0	0	0	0	0	0	0	0
23	Total Income Tax	$24	$109	$1,370	$822	$792	$2,085	$2	$3,186	$358

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Goodwin/14

REVENUE REQUIREMENTS
EFFECTS OF ADJUSTMENTS

	Transmission Rerate 0 (S-9)	D&O Insurance 0 (S-10)	Incentive Compensation 0 (S-11)	Med Benefits & Workers Comp (S-12)	Various A&G 0 (S-13)	Pensions 0 0 (S-14)	R&D 0 0 (S-15)	Misc Labor 0 (S-16)	Misc Revs Taxes 0 (S-17)
Revenues and Expenses	$41	($279)	($3,532)	($2,121)	($2,041)	($4,260)	($7)	($8,057)	($923)
Rate Base	(259)	0	0	0	0	(2844)	0	(404)	0
Total	($218)	($279)	($3,532)	($2,121)	($2,041)	($7,104)	($7)	($8,461)	($923)

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Goodwin/15

Income Tax Calculations for Adjustments

	Income Tax Calculations	blank 0 0 (S-18)	Advertising 0 0 (S-19)	blank 0 0 (S-20)	Misc Rev 0 0 (S-21)	blank 0 0 (S-22)	blank 0 0 (S-23)
1	Book Revenues	$0	$0	$0	$888	$0	$0
2	Book Expenses Other than Depreciation	0	(930)	0	0	0	0
3	State Tax Depreciation	0	0	0	0	0	0
4	Interest	0	0	0	0	0	0
5	Schedule M Differences	0	0	0	0	0	
6	State Taxable Income	$0	$930	$0	$888	$0	$0
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	
8	Total State Taxable Income	$0	$930	$0	$888	$0	$0
9	State Income Tax	$0	$71	$0	$67	$0	$0
10	State Tax Credits	0	0	0	0	0	0
11	Net State Income Tax	$0	$71	$0	$67	$0	$0
12	Additional Tax Depreciation	0	0	0	0	0	0
13	Other Schedule M Differences	0	0	0	0	0	0
14	Federal Taxable Income	$0	$859	$0	$821	$0	$0
15	Federal Tax @ 35%	0	301	0	287	0	0
16	Federal Tax Credits	0	0	0	0	0	0
17	Current Federal Tax	$0	$301	$0	$287	$0	$0
18	ITC Adjustment						
19	Deferral	0	0	0	0	0	0
20	Restoration	0	0	0	0	0	0
21	Total ITC Adjustment	0	0	0	0	0	0
22	Provision for Deferred Taxes	0	0	0	0	0	
23	Total Income Tax	$0	$372	$0	$354	$0	$0

Income Tax Calculations for Adjustments

REVENUE REQUIREMENTS
EFFECTS OF ADJUSTMENTS

	blank	Advertising	blank	Misc Rev	blank	blank
	0	0	0	0	0	0
	0	0	0	0	0	0
	(S-18)	(S-19)	(S-20)	(S-21)	(S-22)	(S-23)
Revenues and Expenses	$0	($956)	$0	($916)	$0	$0
Rate Base	0	0	0	0	0	0
Total	$0	($956)	$0	($916)	$0	$0

Staff/102
Goodwin/17

Income Tax Calculations for Adjustments

	Income Tax Calculations	Revenue Adjustment 0 (S-24)	0 0 0 (S-25)	0 0 0 (S-26)	0 0 0 (S-27)	0 0 0 (P-1)	0 0 0 (S-31,I-5)	0 0 0 (I-7,C-1)	0 0 0 (I-8)	Total Adjustments (Base Rates) 0
1	Book Revenues	$9,370	$0	$0	$0	$0	$0	$0	$0	$11,154
2	Book Expenses Other than Depreciation	4,171	0	0	0	0	0	0	0	($16,960)
3	State Tax Depreciation	0	0	0	0	0	0	0	0	$0
4	Interest	0	0	0	0					($3,913)
5	Schedule M Differences	0	0	0	0	0	0	0	0	$0
6	State Taxable Income	$5,199	$0	$0	$0	$0	$0	$0	$0	$32,027
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0	$0
8	Total State Taxable Income	$5,199	$0	$0	$0	$0	$0	$0	$0	$32,027
9	State Income Tax	$395		$0	$0	$0	$0	$0	$0	$2,435
10	State Tax Credits	0	0	0	0	0	0	0	0	$0
11	Net State Income Tax	$395	$0	$0	$0	$0	$0	$0	$0	$2,436
12	Additional Tax Depreciation	0	0	0	0	0	0	0	0	$0
13	Other Schedule M Differences	0	0	0	0	0	0	0	0	$0
14	Federal Taxable Income	$4,804	$0	$0	$0	$0	$0	$0	$0	$29,592
15	Federal Tax @ 35%	1,681		0	0	0	0	0	0	$10,359
16	Federal Tax Credits	0	0	0	0	0	0	0	0	$0
17	Current Federal Tax	$1,681	$0	$0	$0	$0	$0	$0	$0	$10,359
18	ITC Adjustment									$0
19	Deferral	0	0	0	0	0	0	0	0	$0
20	Restoration	0	0	0	0	0	0	0	0	$0
21	Total ITC Adjustment	0	0	0	0	0	0	0	0	$0
										$0
22	Provision for Deferred Taxes	0	0	0	0	0	0	0	0	$0
										$0
23	Total Income Tax	$2,076	$0	$0	$0	$0	$0	$0	$0	$12,794

Staff/102
Goodwin/18

Income Tax Calculations for Adjustments

REVENUE REQUIREMENTS
EFFECTS OF ADJUSTMENTS

	Revenue Adjustment 0 (S-24)	0 0 0 (S-25)	0 0 0 (S-26)	0 0 0 (S-27)	0 0 0 (P-1)	0 0 0 (S-31,I-5)	0 0 0 (I-7,C-1)	0 0 0 (I-8)	0 0 0 0	Total Adjustments (Base Rates) 0
Revenues and Expenses	($5,356)	$0	$0	$0	$0	$0	$0	$0	##	($26,273)
Rate Base	0	0	0	0	0	0	0	0	0	($17,132)
Total	($5,356)	$0	$0	$0	$0	$0	$0	$0		($43,405)

Staff/102
Goodwin/19

CASE: UG 221
WITNESS: Judy Johnson

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 200

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Judy Johnson. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is two-fold. First, I will discuss the overall reasonableness of Staff's Revenue Requirement. Second I will discuss Staff's position on NW Natural's request to begin amortization if its environmental remediation costs.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/201, consisting of 1 page and Exhibit Staff/202 consisting of 24 pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

ISSUE 1, ------ REASONABLENESS OF STAFF'S REVENUE REQUIREMENT

Q. WHAT IS STAFF'S RECOMMENDED CHANGE IN REVENUE REQUIREMENT?

A. Staff's Revenue Requirement is $(10,737) million from current rates.

Q. WHEN WAS NW NATURAL'S LAST GENERAL RATE CASE?

A. NW Natural has not participated in a rate case since 2002. Since that time, the Company sought and was granted various mechanisms to recover costs without requiring the Company to file a general rate case. During the time period between NW Natural's last rate case and the currently filed rate case, NW Natural has generally demonstrated strong financials and earnings.

Q. IF NW NATURAL HAS GENERALLY DEMONSTRATED STRONG FINANCIALS AND EARNINGS SINCE THE LAST RATE CASE, WHAY MAY HAVE DRIVEN IT TO FILE A GENERAL RATE CASE AT THIS TIME?

A. In Docket No. UG 152, Order No. 03-507, the WARM Mechanism was initiated and set to expire in September 2008. In Docket No. UG 163, Order No. 05-934, the Decoupling Mechanism was initiated and set to expire in September 2009. Dockets UG 152 and UG 163 were combined and Order No. 07-426, extended the WARM and Decoupling expiration date to October 30, 2012. These mechanisms are set to expire unless the mechanisms or some variant of them are re-authorized in a new general rate case. Based upon Staff's review of the revenue requirement needs of NW Natural in this case, it is my opinion that the main driver of this filing is to seek re-authorization of these mechanisms that the Company finds beneficial.

Q. WAS NW NATURAL GRANTED MECHANISMS TO HELP INSULATE THE COMPANY FROM CHANGES IN ECONOMIC FACTORS?

A. Yes. Since the last rate case the Commission authorized many mechanisms to help NW Natural avoid any regulatory lag.

Q. PLEASE IDENTIFY THESE MECHANISMS?

A. The first of these mechanisms was Decoupling, which is discussed in Witness Storm's Testimony. The next mechanism was the program called WARM, which is discussed in Witness Phillip's testimony. The final mechanism allowed has been called many different names over the years, but its current name is the System Integrity Program. This program allows the Company to collect the return on and of certain rate base items without having to file for rate recovery through a general rate case where all elements of costs and expenses would be thoroughly reviewed. Witness Zimmerman's testimony contains a fuller discussion of this program.

Q. HOW DID THESE MECHANISMS PROVIDE A BENEFIT TO NW NATURAL?

A. These mechanisms allowed the Company to avoid regulatory lag and actually improve its earnings even in a depressed economy. The table below highlights NW Natural's earnings during this time period. Please note that the ROE's shown below are calculated after Type 1 rate case adjustments have been made.

YEAR	ALLOWED ROE	EARNED ROE
2002	10.25%	9.4%
2003	10.20%	8.91%
2004	10.20%	9.82%
2005	10.20%	10.02%
2006	10.20%	10.26%
2007	10.20%	10.15%
2008	10.20%	9.59%
2009	10.20%	11.22%
2010	10.20%	11.10%

The table illustrates that NW Natural has not suffered from low earnings during the period since its last rate case.

Q. WHAT REASONS DOES NW NATURAL GIVE FOR THE REQUESTED RATE INCREASE?

A. NW Natural witnesses state there are three primary drivers: (1) the Company's need to comply with increasingly stringent safety requirements; (2) the Company's desire to respond to customer expectations of increased customer service; and (3) the Company's proposal to recover costs associated with its pension contributions that are not addressed in the current FAS 87 balancing account. See generally NWN/100, Kantor/3, NWN/200, Anderson/3.

Q. DOES STAFF DISAGREE WITH THESE OBJECTIVES?

A. Not necessarily, except that Staff does not support NW Natural's attempt to recover out-of-period pension contributions. However, there are many elements to a general rate case and some costs may go up, while some costs may go down. For example, Staff recommends removing $7.777 million from revenue requirement under ORS 757.355 because this amount is for investments that will not be in service on the date new rates go into effect. Staff also proposes an adjustment of over $11 million associated with its recommended ROE based on current market conditions, which is below the 10.3 percent ROE embedded in NW Natural's rates request. Furthermore, $4.8 million of Staff's adjustments result from the application of Commission precedent regarding recovery of expense for advertising, officer and director's incentives, catering, and other expense categories.

Q. WHAT ELSE WOULD STAFF LIKE THE COMMISSION TO CONSIDER IN RECOGNIZING THAT THE STAFF'S OVERALL REVENUE REQUIREMENT IS REASONABLE?

A. I have reviewed each of the Staff recommendations and find that there is no double-counting of cost changes. Further, I have found no pattern of excluding nonrecurring costs which is unwarranted. Based upon my review, I conclude that Staff's proposed revenue requirement results in overall rates that are just and reasonable based on the expected costs of the Company going forward.

Q. WHAT IS STAFF'S CONCLUSION?

A. Staff's recommended revenue requirement would establish just and reasonable rates.

ISSUE 2, ------ENVIRONMENTAL REMEDIATION

Q. WHAT IS THE HISTORY OF THIS COST?

A. NW Natural states that the costs came from two manufacturing gas plants, the Portland Gas Manufacturing (PGM) facility and the Gasco facility. The Oregon Department of Environmental Quality (DEQ) first identified contamination at the site of the former Gasco facility in the late 1980s. The Environmental Protection Agency (EPA) placed the larger Portland Harbor Superfund Site on the National Priority List (Superfund) in 2000.

Q. WHAT ARE THE SITES THAT ARE SUBJECT TO NW NATURAL'S ENVIRONMENTAL REMEDIATION EFFORTS?

A. There are currently six sites. The details of these sites are covered extensively in NWN/1300 Wyatt/4-5.

Q. HAS NW NATURAL TAKEN STEPS TO RECOVER REMEDIATION COSTS FROM OTHER PARTIES?

A. Yes. The Company has tried to identify other parties to the pollution and to collect remediation costs from its insurers. This topic is discussed extensively in NWN/1400.

Q. HAS NW NATURAL KEPT THE COMMISSION STAFF AWARE OF ITS EFFORTS IN REMEDIATION AND COLLECTION?

A. Yes. The Company met with Staff annually, or more often if needed.

Q. WHAT IS THE COMPANY PROPOSING IN UG 221 IN RESPECT TO COLLECTING ENVIRONMENTAL REMEDIATION COSTS?

A. NW Natural is requesting that the Commission establish a mechanism through which the Company can begin to collect the costs of remediation. The environmental deferral account is now approximately $64.5 million, and the Company expects the balance to grow each year for several years to come.

The Company states that deferral of environmental remediation costs would continue as they are now. Any proceeds recovered from insurance companies would be booked as an offset to these deferred costs. Each year, one-fifth of those deferred expenses (offset by any proceeds received) would be put into an amortization account for amortization during the November 1 through October 31 period, after the Commission has an opportunity to review the costs and ensure they were prudently incurred.

Q. DOES THE STAFF AGREE WITH THE COMPANY'S PROPOSED METHOD OF RECOVERY?

A. Yes, with conditions.

Q. WHAT ARE STAFF'S CONDITIONS?

A. The first condition is that there be a 90/10 sharing with shareholders, with customers paying 90 percent and shareholders paying 10 percent.

The second condition is that the deferred costs are subject to an earnings test. since the costs and proceeds of the environmental remediation are held in a deferral account the amortization of the amounts are subject to an earnings test under ORS 757.259(4) and also, is limited to an amount equal to three percent of NW Natural's revenues for the preceding year. The earnings tests must be performed using the years when the costs were incurred.

Third, on deferred accounts going forward, the Commission would be agreeing to allowing cost recovery, subject to a prudence review and an earnings review. As a result, it would be appropriate to only charge ratepayers the modified blended treasury rate as interest versus the Company's authorized ROE. Known amortization means less risk for the Company and it shouldn't get the normal authorized ROE as interest.

Q. WHY IS STAFF PROPOSING A 90/10 SHARING?

A. Staff believes that a sharing mechanism between customers and shareholders provides NW Natural an incentive to appropriately manage remediation costs, while at the same time maximizing any proceeds.

Q. HAVE OTHER STATE COMMISSIONS RULED ON THE SHARING ISSUE?

A. Yes.

Q. WHAT DID THESE OTHER COMMISSIONS CONCLUDE?

A. I have attached as Exhibit Staff 102, comments from Intervenors in the New York State Public Service Commission, Case 11-M-0034, Proceeding on Motion of the Commission to Commence a Review and Evaluation of the Treatment of the State's Regulated Utilities' Site Investigation and Remediation (SIR) Costs.

If you look, in particular, in Staff/202, Johnson/12-Johnson15, the actions of other state commissions are extensively identified. In all cases, some level of sharing was authorized and in at least one case, the Company's shareholders were directed to pick up all the costs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: Judy Johnson

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME:	JUDY A. JOHNSON
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	PROGRAM MANAGER – RATES AND TARIFFS
ADDRESS:	550 CAPITOL ST. N.E., SALEM, OREGON 97310-1380
EDUCATION:	MBA with an emphasis in Statistics from Eastern Washington University Cheney, Washington BA in Accounting from Eastern Washington University Cheney, Washington

EXPERIENCE:

3/95-Present	I have been employed by the Oregon Public Utility Commission since March of 1995. My current position is Program Manager of Rates & Tariffs. I was previously a Senior Analyst for the Revenue Requirements Section.
6/77-2/95	I was employed by Avista Corporation, an electric and natural gas utility located in Spokane, Washington. The majority of my employment was spent in the Rates and Regulatory Affairs Department as a Senior Rate Analyst. I have prepared testimony and exhibits in numerous electric and natural gas rate cases, primarily in the area of results of operations and cost of service.

CASE: UG 221
WITNESS: Judy Johnson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

May 3, 2012

COUCH WHITE
COUNSELORS AND ATTORNEYS AT LAW

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Jay Goodman

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April 22, 2011

VIA E-MAIL

Hon. Jaclyn A. Brilling
Secretary
New York State Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

Re: Case 11-M-0034 – Proceeding on Motion of the Commission to Commence a Review and Evaluation of the Treatment of the State's Regulated Utilities' Site Investigation and Remediation (SIR) Costs

Dear Secretary Brilling:

Attached for filing in the above-referenced proceeding are the Initial Comments of Multiple Intervenors.

Respectfully submitted,

COUCH WHITE, LLP

S. Jay Goodman

Jay Goodman

JG/dap
Attachment
cc: Hon. Eleanor Stein (via E-Mail; w/att.)
Active Parties (via E-Mail; w/att.)
S:\DATA\Client11 14501-14800\14598\Corres\Brilling 04-22-11.docx

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission to Commence a Review and Evaluation of the State's Regulated Utilities' Site Investigation and Remediation (SIR) Costs **Case 11-M-0034**

INITIAL COMMENTS OF MULTIPLE INTERVENORS

Dated: April 22, 2011

COUCH WHITE, LLP
540 BROADWAY
P.O. BOX 22222
ALBANY, NEW YORK 12201-2222
(518) 426-4600

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PRELIMINARY STATEMENT

Multiple Intervenors, an unincorporated association of approximately 55 large industrial, commercial and institutional energy consumers with manufacturing and other facilities located throughout New York State, hereby submits its Initial Comments on select policy issues in Case 11-M-0034.[1] This proceeding was instituted by the New York State Public Service Commission ("Commission") to examine "on a statewide or 'generic' basis the funding mechanisms used to support utility SIR expenditures" and to address its "uncertainty regarding the question of whether ratepayers should bear sole responsibility for the approximately $2 billion in costs still expected to be incurred in remediation efforts."[2]

As part of the investigation into SIR costs, New York State Department of Public Service Staff ("Staff") prepared a series of information requests that were modified and supplemented by other parties. Pursuant to the procedural ruling issued herein by Administrative Law Judge Eleanor Stein, the State's utilities were directed, and the New York State Department of Environmental Conservation ("DEC") was requested, to respond to Information Request ("IR") Nos. 1-13, which primarily are factual in nature.[3] Thereafter, all parties were accorded an opportunity to respond to IR Nos. 14-18, which primarily are policy-oriented questions.[4]

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[1] Case 11-M-0034, Proceeding on Motion of the Commission to Commence a Review and Evaluation of the Treatment of the State's Regulated Utilities' Site Investigation and Remediation (SIR) Costs.

[2] Case 11-M-0034, supra, Order Instituting Proceeding (issued February 18, 2011) at 1-2.

[3] Case 11-M-0034, supra, Ruling on Procedure and Schedule (issued March 8, 2011) at 2-3. The April 1, 2011 deadline for responding to IR Nos. 1-13 subsequently was extended until April 8, 2011.

[4] Id. at 4-5.

Multiple Intervenors' Initial Comments respond to IR Nos. 14-18. Additionally, Multiple Intervenors comments herein on one matter not covered in the IRs, as permitted by Judge Stein's procedural ruling.[5]

Multiple Intervenors is extremely concerned about the magnitude of current and projected SIR costs and their impacts on customers' electric and gas delivery bills. The Commission itself estimates that there is approximately $2 billion in SIR costs expected to be incurred related to future remediation efforts.[6] The events responsible for the present incurrence of SIR costs took place many decades, if not more than a century, ago. Current customers are not responsible for the utilities' SIR liabilities yet, with extremely-limited exceptions, they are being forced to fund 100% of these costs, regardless of the magnitude or the efficiency – or inefficiency – of utility remediation efforts. While it is hoped that utilities fulfill their legal obligations to remediate contaminated sites as cost-effectively as possible, the Commission's present ratemaking approach provides virtually no financial incentive for utilities to minimize the level of SIR costs incurred and imposed on customers. Rather, SIR costs essentially represent a "pass-through" expense for utilities.

Multiple Intervenors contends that the time is ripe – if not long overdue – for utility shareholders to bear some of the costs, and risks, associated with utility actions of long ago. For the reasons set forth herein, shareholders should be allocated some share of all SIR costs incurred. If, arguendo, that position is not adopted, then, alternatively, shareholders should be allocated some share of SIR costs incurred in excess of established rate allowances. If, arguendo, that alternative position is not adopted, then, at a minimum, utilities should be

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[5] Id. at 5 (providing that "parties are free to add comments as to any matters not covered in the Staff questions, as the last section of their documents and titled 'Other Matters'").

[6] Case 11-M-0034, supra, Order Instituting Proceeding at 1-2.

precluded from recovering carrying costs, or any interest payments, associated with the deferral of SIR costs.

Consistent with Multiple Intervenors' recommendation that some portion of SIR costs and risks be allocated to utility shareholders, a similar ratemaking approach should be adopted with respect to insurance proceeds and third-party reimbursements. If, arguendo, insurance proceeds and third-party reimbursements are utilized solely to reduce customer obligations for SIR costs, then utilities have limited financial incentive to pursue such funds aggressively. It would be preferable to expose utility shareholders to SIR costs, while, at the same time, also providing them with an opportunity to benefit financially from the successful pursuit of insurance proceeds and third-party reimbursements. Under this approach, the financial interests of utility shareholders and customers are aligned to minimize the incurrence of SIR costs (consistent with the fulfillment of all legal obligations).

Additionally, as described below, Multiple Intervenors urges that utility shareholders be directed to fund periodic, independent audits of their performance with respect to environmental remediation. If customers are going to fund all or most of utility SIR costs, there should at least be periodic, independent examinations into whether, inter alia, the utility's remediation efforts are being performed efficiently and in a cost-effective manner, and the costs being charged to customers were incurred prudently. Such an audit also would be expected to identify potential improvements to the utility's existing procedures. While Staff can and does audit the magnitude of utility SIR expenditures in rate proceedings, it appears to lack the resources necessary to investigate adequately the efficiency, cost-effectiveness and prudence of such expenditures. The proposed audits would help fill this void and, hopefully, provide independent verification that utility SIR expenditures are well-spent.

COMMENTS IN RESPONSE TO INFORMATION REQUESTS

IR No. 14: Please provide comments on the following ratemaking scenarios. Include "pros" and "cons" for each, which might include potential for financial impacts on the utilities (financial metrics, credit ratings), rate impacts, potential impacts on incentives to ensure timely remediation, etc.

a. Full recovery of prudent net remediation costs (costs less insurance/other proceeds)
b. Sharing of net costs between ratepayers/shareholders
c. Full recovery of prudent net costs but no carrying charges on deferred balances
d. Full recovery of prudent remediation costs with potential shareholder sharing of insurance/other proceeds
e. Set caps on annual amount to be recovered from ratepayers (with shareholders picking up excess)
f. Set target in rate cases of forecasted remediation costs with ratepayer/shareholder sharing above and/or below targeted amount
g. Discuss the timing of recoveries, *i.e.*, is there a preference for setting a target of forecasted remediation costs with costs recovered above and below the forecast, or a preference for full deferral with an amortization
h. Other ratemaking proposals

As noted above, Multiple Intervenors is extremely concerned about the impact to customers associated with the staggering amount of current and projected SIR costs. The magnitude of those projected costs – approximately $2 billion – demands the implementation of all policies and strategies likely to moderate the electric and gas delivery bill impacts to customers, as well as policies and strategies that require the State's utilities to satisfy their outstanding SIR obligations in the most cost-effective manner possible. Accordingly, for the reasons described below, the Commission should allocate a portion of SIR cost responsibility from customers to shareholders. Such cost sharing would: (a) provide utilities with a financial incentive to focus aggressively on the cost-effective remediation of contaminated sites; and (b) be consistent with prior precedent of this Commission as well as the precedent in selected other jurisdictions.

Initially, Multiple Intervenors emphasizes that the positions advocated herein pertain only to the equitable allocation of costs incurred by utilities for a purpose unrelated to the provision of service to current utility customers. Multiple Intervenors does not oppose utility efforts to satisfy their legal obligations to cleanup contaminated sites and, in fact, assumes that all necessary remediation efforts will be completed regardless of how SIR costs are allocated. These Initial Comments, therefore, focus on how best to promote the cost-effective remediation of contaminated sites, including former manufactured gas plant ("MGP") sites.[7]

It is inequitable to require customers to pay 100% of legacy costs that are wholly unrelated to the cost of providing service to current utility customers. Generally, the gas operations that contaminated certain utility property, thereby giving rise to current SIR liabilities, commenced during the mid-1800's and concluded in the 1950's.[8] A gulf of many decades divides the utility service received by current customers and the contamination of utility property; the two are wholly unrelated to each other.[9]

Accordingly, Multiple Intervenors respectfully urges the Commission to allocate a moderate portion of SIR costs (i.e., 20%) to utility shareholders. Assigning 20% of SIR costs to utilities would align the financial interests of customers and shareholders by providing the utilities with a strong incentive to moderate SIR costs by remediating contaminated property in

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[7] Upon information and belief, a portion of the SIR costs incurred by utilities relate to properties that either are not in rate base and/or were never "used and useful." It is especially difficult to conceive why customers should bear all –or, arguably, any – of such costs. SIR costs incurred related to these sites may warrant different regulatory treatment than other costs incurred at other sites.

[8] See, e.g., Case 11-M-0034, supra, DEC's Responses to Staff IRs, Exhibit B, *New York State's Approach to the Remediation of Former Manufactured Gas Plant Sites* (hereinafter, "MGP History") at 1-2.

[9] In fact, it should not be assumed that the prior contamination of property necessarily was part and parcel of the provision of utility service.

the most cost-effective manner possible. Notably, the specific level of sharing proposed (i.e., 20%) is consistent with an SIR cost allocation methodology adopted previously by the Commission.

In Cases 29327, et al., the Commission allocated 80% of SIR costs incurred by Niagara Mohawk Power Corporation ("Niagara Mohawk") to its customers, and 20% to the utility's shareholders.[10] The Commission directed the sharing of SIR costs upon concluding that such sharing would provide the utility with an incentive to moderate SIR costs and to be aggressive with respect to seeking insurance and third-party recoveries:

> Based on the facts and circumstances presented here, however, including Niagara Mohawk's financial exposure and the need to contain rates, we are requiring 20% utility sharing of rate year 1995 SIR costs. In the absence of price caps, sharing of SIR costs provides an additional incentive for Niagara Mohawk to contain SIR costs and for it to aggressively seek partial recovery of such expenditures from other responsible parties and/or insurance companies.[11]

The bases for the Commission's decision in Opinion 95-21 remain relevant, and continue to provide support for a Commission determination in this proceeding that a portion of utility SIR costs should be allocated to utility shareholders.

In its recent order concluding Case 10-E-0050, the Niagara Mohawk electric rate proceeding, the Commission echoed the concerns it voiced in Opinion 95-21 as the basis for allocating some of the risks associated with a share of SIR costs to the utility's shareholders. The Commission stated:

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[10] Cases 29327 *et al.*, Niagara Mohawk Power Corporation - Consolidated Proceedings, Opinion No. 95-21, Opinion and Order Concerning Revenue Requirement and Rate Design (issued December 29, 1995) at 23 (hereinafter, "Opinion 95-21").

[11] Id. at 23. Multiple Intervenors submits that "the need to contain rates" is as strong today – if not stronger – than it was when Opinion 95-21 was issued.

> We are concerned, however, that, in practice, the design and implementation of SIR projects may not cost effectively focus the utility's remediation efforts. The current process may lack an effective deterrent to excessive costs in the design and/or implementation of projects. **Where neither the agency overseeing the project, nor the company implementing it, has a tangible incentive to minimize costs, the goal of designing and implementing projects in the most reasonable and cost-effective manner, on behalf of ratepayers, might not be properly represented.**[12]

The Commission recognized that the environmental damage at MGP sites "was not incurred in service of today's customers, who are nonetheless bearing the burden of paying for the remediation."[13] The Commission also acknowledged its uncertainty regarding whether or not "today's ratepayers should bear the sole responsibility for all of these costs," and concluded that the current policy of burdening customers with 100% of SIR costs should be re-examined (in this proceeding) to provide customers with rate relief and a more equitable measure of cost sharing.[14] Although the Commission concluded that Niagara Mohawk should be responsible for 20% of all SIR costs incurred in excess of the base rate allowance, the reasoning set forth in support of that conclusion fully supports making utilities responsible instead for 20% of all SIR costs, as advocated by Multiple Intervenors.

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[12] Case 10-E-0050 et al., Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Electric Service, Order Establishing Rates for Electric Service (issued January 24, 2011) (hereinafter, "Niagara Mohawk Rate Order") at 105-06 (emphasis added).

[13] Id. at 106.

[14] Id. Multiple Intervenors notes that a credit report issued recently by Standard & Poor's did not even mention the Commission's decision to require Niagara Mohawk shareholders to pay 20% of all SIR costs incurred in excess of the annual base rate allowance, and it certainly had no impact on the utility's credit rating. See generally Niagara Mohawk Power Corporation, Standard & Poor's (issued February 14, 2011).

The State's electric and gas utilities currently have virtually no incentive to maximize the cost-effectiveness of their remediation efforts because they generally recover all SIR costs from customers, including amounts incurred in excess of base rate allowances that are deferred for future recovery with carrying costs (which also currently are paid fully by customers). Such guarantees provide no incentive for utilities to maintain SIR expenditures within their annual rate allowances, much less to seek cost-effective and creative solutions to their environmental liabilities. The need for such incentives is demonstrated by the fact that steadily-increasing SIR costs have been a material component of recent utility requests for rate relief.[15] Given the number of sites that still need to be remediated, the pace of such efforts, and the estimated $2 billion of remaining utility liability for SIR expenses, this expense will continue to burden electric and gas customers in New York State for the foreseeable future. It is critical that the Commission align the financial interests of customers and shareholders with respect to SIR costs, and the best way to accomplish such adjustment is to allocate a portion of SIR costs to shareholders.

Allocating a portion of SIR costs to utility shareholders also is supported by the fact that such expenditures are a legacy cost that provides no direct operational benefit to current customers. The environmental remediation accomplished by SIR expenditures does not improve either the reliability, quality or safety of utility service. Nevertheless, current customers now are obligated to pay the full cost of remediating properties contaminated by utilities as much as 166 years ago.[16]

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[15] See, e.g., Case 10-E-0050, supra, Niagara Mohawk Rate Order at 105 (authorizing the utility to increase the annual base rate allowance for SIR costs from $12 million to $30 million).

In addition to allocating a portion of SIR costs to shareholders, Multiple Intervenors also recommends that the Commission allow shareholders to retain up to 20% of all insurance claims and third-party recoveries, thereby providing a strong incentive for utilities to pursue aggressively all possible claims and recoveries. Under this proposal, shareholders would have the opportunity to recover all or a portion of their SIR cost responsibility, and also would have a strong financial incentive to moderate the cost of fulfilling their obligations to remediate contaminated utility property. The approach advocated herein by Multiple Intervenors would align the financial interests of customers and shareholders by ensuring that shareholders have a vested interest in controlling – and moderating – annual SIR expenditures.[17]

If the Commission elected to adopt the approach advocated herein by Multiple Intervenors, New York State would join the ranks of other states that also require utilities to bear all or part of their environmental cleanup costs. Indiana, for example, does not allow utilities to recover any portion of MGP site remediation costs because the state commission concluded that the environmental cleanup costs have no connection to the service rendered to utility customers.[18]

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[16] Multiple Intervenors acknowledges that there are environmental benefits associated with remediating contaminated sites, but those benefits are experienced by the public at-large and are not limited to utility customers or related to the provision of utility service.

[17] In the interests of equity to customers, the opportunity for shareholders to benefit financially from insurance proceeds and third-party recoveries needs to be linked to a sharing of SIR cost liability between customers and shareholders.

[18] See, e.g., *Indiana Gas Co., Inc. v. Off. of Util. Consumer Counselor*, 675 N.E.2d 739, 743-44 (2d Dist. 1997).

The California Public Utilities Commission ("CPUC") has allowed jurisdictional utilities to recover most of their SIR costs, but required shareholders to pay 10% of SIR costs.[19] The CPUC concluded that the costs allocated to shareholders were offset by: (a) allocating 70% of insurance recoveries to shareholders and 30% of same to customers until both groups recover fully their insurance litigation costs, after which shareholders receive 90% of all insurance recoveries until they recover their share of cleanup costs; and (b) allocating 90% of third-party litigation costs, and 90% of third-party recoveries, to shareholders.[20] Importantly, the CPUC adopted this cost-sharing approach in order to provide utilities with an incentive to moderate SIR costs and pursue insurance and third-party recoveries:

> The [settling parties] agree that allocation of Hazwaste Program expenses between shareholders and ratepayers … will provide the utility management with an incentive to minimize Hazwaste Program expenses and to pursue recovery from insurance carriers and other potentially responsible parties. … For the reasons cited by the Settling Parties, we agree with the majority of participants in the collaborative process that 90%/10% allocation of Hazwaste Program expenses between ratepayers and shareholders would achieve the desired results.***
>
> We will adopt the proposed 90%/10% Hazwaste Program expense allocation. In doing so we emphasize our desire to have the utilities aggressively pursue recovery from their respective insurers on behalf of themselves and the ratepayers. We believe the primary responsibility for paying for hazardous substance expenses should fall on the insurers under the policies issued by them to the utilities over the years. The purpose of having utilities

[19] See, e.g., Application No. 96-08-001 *et al.*, Decision No. 97-11-074, Interim Opinion: Transition Cost Eligibility (issued November 19, 1997) at 291 (stating that "[r]atepayers bear 90% of [remediating MGP sites]; shareholders, 10%"). See also Application No. 91-04-044 *et al.*, Decision No. 94-05-020, Opinion (issued May 4, 1994) at 6-7 (approving a settlement that provides for allocating 10% of SIR costs to shareholders).

[20] Application No. 91-04-044 *et al.*, supra, Decision No. 94-05-020 at 6-7.

> obtain insurance coverage is to ensure that neither the ratepayers nor the utilities have to bear the expenses of liability or losses.[21]

The New Hampshire Public Utilities Commission ("NHPUC") adopted a cost sharing mechanism with the intent to allocate approximately 20% of all SIR costs to the state's utilities. The NHPUC explained that:

> The Company's successful pursuit of the responsible third parties and insurance carriers has served to reduce the remediation costs to be recovered from ratepayers, as well as the associated carrying costs to be borne by ratepayers. … At the time the Commission issued its order approving the [SIR cost] recovery mechanism, it is reasonable to assume that if EnergyNorth were successful in pursing [sic] recoveries from responsible third parties and insurance carriers, the added incentive could result in shareholders bearing less than 20 percent of remediation costs. The fact that EnergyNorth shareholders have borne 18 percent of [SIR] costs to date indicates that the [SIR cost] recovery mechanism is working as intended and that EnergyNorth has been rewarded for successfully pursing [sic] recoveries from responsible third parties and insurance carriers.[22]

Notably, New Hampshire utilities amortize their annual SIR costs over a seven-year period via a surcharge and are precluded from recovering the carrying costs associated with unamortized balances.[23] The NHPUC adopted its particular policy of sharing SIR costs, insurance claims and

[21] Id. at 11-13.

[22] Docket DG 07-129, NHPUC Order no. 24,849 (issued April 23, 2008) at 13. See also Docket DG 99-060, NHPUC Order No. 23,303 (issued Sept. 20, 1999) at 6-7 (stating that "[w]e continue to believe that our decisions in those proceedings to apply third party recoveries to reduce the amortization period serve as a strong incentive for the utilities to reduce the costs borne by its ratepayers for environmental remediation").

[23] DR 98-040, NHPUC Order No. 23,046 (issued October 27, 1998); DG 07-129, NHPUC Order No. 23,303 (issued September 20, 1999) at 3-7; NHPUC Order No. 24,849 (issued April 23, 2008) at 12-14.

third-party recoveries with the specific intent of allocating approximately 20% of total SIR costs to the utilities, and the agency concluded recently that its policy is working as intended.[24]

Multiple Intervenors agrees that the utilities' respective insurers, both past and present, should pay to remediate contaminated, insured utility property, and that the utilities should be encouraged to pursue aggressively such claims and recoveries.[25] Allowing shareholders to retain 20% of all such claims and recoveries, as described above, would offset the financial responsibility created by requiring shareholders to pay 20% of utility SIR costs. As detailed above, the NHPUC adopted such a sharing mechanism to provide utilities with a financial incentive to pursue all such claims and recoveries so as to reduce the costs to be recovered from customers, and concluded recently that the incentive mechanism is working as intended.[26]

If, arguendo, the Commission declines to allocate 20% of utility SIR costs to shareholders, then, alternatively, Multiple Intervenors urges the Commission to allocate to

[24] See, e.g., NHPUC Order No. 24,849 at 13 (stating that "[t]he 80/20 sharing of the interest earnings between ratepayers and shareholders reflects the sharing anticipated at the time the Commission approved the [cost recovery] mechanism, the continuation of which we find to be appropriate under the circumstances….").

[25] Inasmuch as utilities – and not customers – were responsible for contaminating or purchasing the vast majority of the sites in question, and are responsible for remediating said sites and seeking insurance proceeds and third-party contributions, it is wholly appropriate to allocate a portion of SIR costs to utilities and their shareholders. There is no justification for allocating 100% of SIR costs to current customers who, with extremely-limited exceptions, did not receive utility service at the time of contamination and, without exception, are not responsible for the incurrence of SIR costs.

[26] Docket DG 07-129, NHPUC Order no. 24,849 at 13 (finding that the cost recovery mechanism "is working as intended and that [the company] has been rewarded for successfully pursing [sic] recoveries from responsible third parties and insurance carriers."). See also Docket DG 99-060, NHPUC Order No. 23,303 at 6-7 (stating that "[w]e continue to believe that our decisions in those proceedings to apply third party recoveries to reduce the amortization period serve as a strong incentive for the utilities to reduce the costs borne by its ratepayers for environmental remediation").

shareholders 20% of SIR costs incurred in excess of established rate allowances. The Commission recently adopted this allocation methodology for Niagara Mohawk in Case 10-E-0050, its recently-concluded electric rate case.[27] The rationale underlying the Commission's decision in that case to allocate a portion of deferred SIR costs to shareholders applies with equal force, and should be extended, to the State's other utilities. If the Commission declines to adopt Multiple Intervenors' primary recommendation, as described above (i.e., allocate 20% of net SIR costs to shareholders), then Multiple Intervenors alternatively urges the Commission to adopt an allocation methodology that would allocate to shareholders 20% of all SIR costs incurred in excess of base rate allowances.

If, arguendo, the Commission declines to adopt either of the preceding alternative SIR cost allocation methodologies, then, at a minimum, utilities should not be authorized to recover carrying costs, or any interest payments, associated with the deferral of SIR costs in excess of established rate allowances. This alternative recommendation is consistent with the ratemaking treatment of environmental remediation costs adopted by other states. The Michigan Public Service Commission, for example, explained its policy that SIR expenses:

> …should be fairly apportioned between a utility's shareholders and its ratepayers. The Commission has followed this policy in its treatment of MGP remediation costs for all Commission-jurisdictional entities. … While the Commission could have reasonably determined that these legacy costs were a shareholder responsibility, it did not. Equally so, the Commission determined that present ratepayers should not bear all of the cost related to long-past energy production.[28]

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[27] Case 10-E-0050 et al., supra, Niagara Mohawk Rate Order at 105-06.

[28] Case Nos. U-13898 and U-13899, Michigan Public Service Commission Opinion and Order Granting Rate Relief (April 28, 2005) at 24 (citation omitted). See also Docket 6680-UR-114, Public Service Commission of Wisconsin Final Decision (mailed July 19, 2005) at 53-54.

Although Multiple Intervenors has a strong preference for the two allocation alternatives described above, an SIR cost allocation methodology that achieves sharing by prohibiting the recovery of carrying costs on deferred amounts still would be an improvement over the status quo. Accordingly, if the Commission declines to allocate 20% of SIR costs to shareholders, or, in the alternative, declines to allocate to shareholders 20% of SIR expenses incurred in excess of the rate allowance, then Multiple Intervenors urges the Commission, at a minimum, to preclude utilities from recovering carrying costs on deferred SIR expense balances.

The sharing of SIR costs proposed herein by Multiple Intervenors would benefit customers by moderating a substantial expense that currently is passed-through to customers. Sharing the costs and risks of remediating contaminated sites is absolutely necessary to provide utilities with incentives to moderate SIR costs, as well as to manage ongoing and future remediation efforts, as efficiently as possible. It also is inequitable to continue holding current customers responsible for 100% of a legacy cost unrelated to the service received by those customers. Accordingly, for the reasons described above, Multiple Intervenors urges the Commission to allocate 20% of net SIR costs to utility shareholders.

IR No. 15: Please comment on the feasibility of jointly investigating and remediating sites with other utilities

IR No. 16: Please comment on the feasibility/benefits to seek jointly reimbursement from insurance carriers/third parties/other sources with other utilities.

Multiple Intervenors is combining its response to IR Nos. 15 and 16 because the response is the same for both questions. Utilities should be coordinating SIR efforts where feasible and cost-effective. Where practical, such coordination should result in efficiencies, thereby serving to moderate SIR costs incurred.

Specific information on the feasibility of utility coordination, as well as on the feasibility and the potential benefits and costs of such coordination, is not available to Multiple Intervenors. The State's utilities, in the first instance, would be the best source of information in response to these questions.

As described in response to IR No. 14, supra, Multiple Intervenors is concerned that the State's utilities currently have little or no financial incentive to moderate SIR costs and, therefore, also have no real incentive to collaborate and work creatively with other utilities, where feasible, on the remediation of contaminated utility property. In contrast, to the extent that utilities have a financial stake in reducing SIR costs, there would be ample motivation for them to pursue all opportunities to reduce the cost of remediating MGP sites by collaborating with other utilities where beneficial.[29]

Finally, as detailed, infra, the Commission should direct each utility to fund periodic, independent audits of their performance with respect to SIR costs. Such audits should provide additional information on, inter alia, the information requested by IR Nos. 15 and 16, as well as valuable information regarding the efficacy and efficiency of utility SIR efforts.

[29] It is difficult to overstate the importance of ensuring that utilities have "some skin in the game." Absent any financial risk being allocated to shareholders, the Commission (and Staff and customers) can never be sure that all reasonable efforts are being undertaken to moderate SIR costs. In contrast, however, once there is a sharing of costs and risks between customers and shareholders, the Commission would be able to assume that utility managements will be focused on complying with their cleanup obligations as cost-effectively as possible.

IR No. 17: Please comment on how the costs of remediation that are to be borne by the ratepayers should be allocated:

a. Between electric and gas operations

b. By service classes

c. Proper amortization periods for such costs

For the reasons detailed below, the Commission should: (a) increase the percentage of SIR costs allocated to gas operations; (b) classify SIR costs on the basis of delivery revenues in utility cost-of-service studies; and (c) refrain from adopting a "one-size-fits-all" amortization period for application to all utilities, while seeking to moderate total cost and rate impacts to customers.

a. The Commission should increase the percentage of SIR costs allocated to gas operations

The MGP History submitted by DEC states that responsibility for the MGP sites can be traced to the State's nine gas utilities, and also that manufactured gas was used widely for lighting, heating, and cooking.[30] Contamination of the MGP sites in issue, therefore, arose primarily from utility gas operations, and not from utility electric operations. Accordingly, consistent with cost-of-service principles, the cost of remediating those sites also should be allocated primarily to utility gas operations, subject to legitimate rate impact considerations.

Upon information and belief, the combined electric and gas utilities generally treat SIR costs as a common expense for purposes of allocating the expense between gas and electric customers, even though the vast majority of such costs relate to gas operations.[31] Such allocation methodologies are not cost-based and disregard the fact that SIR costs were not

[30] Case 11-M-0034, supra, MGP History at 1.

[31] See, e.g., Case 11-M-0034, supra, Responses of Central Hudson Gas & Electric Corporation ("Central Hudson"), Orange and Rockland Utilities, Inc., and Consolidated Edison Company of New York, Inc. ("Con Edison"), to IR No. 10.

incurred to provide service to current electric customers. Consequently, the current SIR allocation methodology is inequitable to electric customers.

Multiple Intervenors recognizes, however, that allocating the vast majority of utility SIR costs to gas operations may result in unacceptable rate impacts on gas customers. For this reason alone, Multiple Intervenors is not advocating that the Commission actually shift the vast majority of SIR costs to gas operations. Said reason, however, does not justify the current practice of allocating the vast majority of SIR costs to electric operations. Clearly, the amount of SIR costs allocated to gas operations should increase, subject to rate impact considerations.

Utilities should strive to allocate SIR costs between electric and gas operations in a manner consistent with cost causation principles, subject to a "cap" or "ceiling" on the maximum allowable impact on gas customers. For example, the percentage impact of SIR costs on gas customers could be limited to no more than three times the comparable impact on electric customers. Such an allocation would be far preferable to the status quo because it would represent a better balance between (i) allocating SIR costs on cost causation principles to the greatest extent practicable, and (ii) reducing the rate impact of SIR costs on electric operations, which bear even less responsibility for occurrence of the remediation costs than gas operations.

b. The Commission should classify SIR costs on the basis of delivery revenues

SIR costs should be assigned in a utility's cost-of-service study based on the delivery revenues associated with each class, and then treated as part of the utility's costs for future allocation. The activities that led to the incurrence of SIR costs occurred decades, if not more than a century, ago. Such activities (e.g., the operation of an MGP facility) are not part of a utility's current cost of service. Thus, there is no basis for allocating the customers' share of SIR costs on any basis other than delivery revenues. Moreover, the utilities' responses to the IRs do not provide a basis for any other potential interclass allocation methodology.[32]

c. The Commission should refrain from adopting a common amortization period

The optimal amortization period should be developed on a utility-specific basis in individual rate proceedings. Such proceedings would allow other factors, such as near-term rate impacts, to be considered in context. If adopted in this proceeding, a "one-size-fits-all" amortization period would fail entirely to account for utility-specific facts and circumstances including, but not limited to: (a) the amount of SIR costs to be amortized; (b) the rate impacts associated with that amortization; and (c) any other factor that may justify lengthening – or shortening – the amortization period.

The varying amounts of current and projected SIR liabilities, and their respective percentage of net operating costs, may allow for a shorter amortization period for certain utilities where the resulting rate impacts would be relatively small. In contrast, a shortened amortization period may elicit unacceptable bill impacts in other utility service territories. The Commission, therefore, should defer any judgment of the proper amortization period for SIR costs to individual utility rate proceedings.

IR No. 18: Please describe any possible cost sharing approach which would have SIR costs be borne by all of those who benefit from timely remediation efforts.

As a class, customers realize no unique benefits from the remediation efforts undertaken by their utilities. The beneficiaries of utility remediation efforts are: (a) the utilities,

[32] For example, there is no justification for allocating or recovering SIR costs on a volumetric basis, which obviously would be highly inequitable to high-load-factor customers. Neither SIR costs nor the contamination leading to them vary or varied based on the current energy consumption of customers.

who fulfill their legal obligations; and (b) the public-at-large (which includes, but is not limited to, utility customers and shareholders), who benefit from the improvement to public health and safety that is associated with the remediation of environmental contaminants. Multiple Intervenors recognizes that, absent some legislative solution, it not feasible to recover SIR costs from the public-at-large. Utilities, however, currently benefit from the timely remediation of MGP sites without having to bear any of the financial risk associated with those efforts. Importantly, it was the utilities – and not customers – that were responsible for contaminating property or purchasing already-contaminated property. As described in response to IR No. 14, supra, the fact that utilities also benefit from the remediation of contaminated sites further supports Multiple Intervenors' prior arguments in favor of allocating some portion of SIR costs to shareholders.

Other Matters:

As noted above, Multiple Intervenors respectfully urges the Commission to direct utility shareholders to fund periodic, independent audits of their performance with respect to environmental remediation. If customers are going to fund all or most of utility SIR costs, there should at least be periodic, independent investigations into whether, inter alia, the utility's remediation efforts are being performed efficiently and in a cost-effective manner, and the costs being charged to customers were incurred prudently. Whether or not a portion of SIR costs is allocated to shareholders, it is and will continue to be essential for the Commission to ensure that utilities maximize the cost-effectiveness of their remediation efforts, and pursue aggressively all insurance claims and third-party recoveries. Periodic reviews of utility SIR efforts by an independent auditor would provide critical information and insight regarding the strengths and weaknesses of the State's utilities' remediation and recovery efforts.

While Staff can and does audit the magnitude of utility SIR expenditures in rate proceedings, it appears to lack the resources necessary to investigate adequately the efficiency, cost-effectiveness and prudence of those expenditures. Multiple Intervenors believes that it is or will be difficult – if not impossible – for Staff to investigate thoroughly the remediation efforts of all State utilities at hundreds of MGP sites that are or will be remediated. An independent auditor, however, could provide much-needed information on what utilities are doing right and, perhaps more importantly, how utility remediation efforts could be improved prospectively.

Finally, similar to management audits, the State's utilities should pay the entire cost of hiring independent auditors to review their SIR efforts. As described above, SIR costs are a legacy expense that did not arise from providing service to current customers. The utilities alone should bear the auditing cost that is necessary to assist Staff and the Commission with their review and evaluation of utility SIR expenditures.

CONCLUSION

For all the foregoing reasons, the Commission should resolve SIR cost issues in a manner consistent with Multiple Intervenors' positions, as set forth herein.

Dated: April 22, 2011
Albany, New York

Respectfully submitted,

Michael B. Mager

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CASE: UG 221
WITNESS: Brittany Andrus

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Brittany Andrus. My occupation is Utility Analyst with the Oregon Public Utility Commission. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2148.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/301.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This testimony summarizes my research of historical Commission orders relating to the rate treatment of income derived from the sale of byproducts of the manufactured gas process by NW Natural's predecessor companies.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony explains the purpose and method of the research, cites the specific results, and summarizes my conclusion based on the research.

Q. WHAT WAS THE PURPOSE OF RESEARCHING THE HISTORICAL COMMISSION ORDERS?

A. NW Natural is seeking recovery of its costs incurred and expected to be incurred by NW Natural associated with environmental remediation related to its historic operations (NWN/1500, Miller/1-3). These historic operations at manufactured gas plant (MGP) sites produced residuals, as described in NWN/1600, Middleton/1-39. The residuals included both byproducts and wastes. Byproducts were materials that could be sold or beneficially used at the MGP (NWN/1600, Middleton/7-8). I was asked to research how revenues from byproduct sales were treated for ratemaking purposes over the course of regulation of NW Natural and its predecessors.

Q. WHY IS THE RATE TREATMENT OF REVENUE FROM THE SALE OF BYPRODUCTS IMPORTANT?

A. In developing Staff recommendations on the rate treatment of environmental remediation costs, this may be one factor to consider. Staff witness Judy Johnson is Staff's policy witness on this subject of recovery of environmental remediation costs.

Q. DID THE TIME PERIOD OF THE MANUFACTURED GAS PLANT ACTIVITY COINCIDE WITH THE HISTORICAL COMMISSION ORDERS RESEARCHED?

A. No. Gas manufacture in Portland started in 1860 (NWN/1600, Middleton/21), while public utility regulation in Oregon began in 1911, when the Legislature expanded the jurisdiction of the Railroad Commission of Oregon to include public utilities. I researched Commission orders dated from 1911 through the 1950's, when "traditional" natural gas service was introduced to Oregon.

Q. PLEASE DESCRIBE THE SOURCES AND THE PROCESSES USED IN YOUR RESEARCH.

A. I examined documents in the Oregon State Archives, as well as annual report books and bound orders located at the Public Utility Commission (PUC) library. I searched for dockets or orders referencing Portland Gas & Coke (PG&C), as that was the name of the company during the time period examined.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR RESEARCH.

A. My research yielded four categories of relevant information: 1) specific residuals' revenue as a portion of operating revenues; 2) information on the prescribed accounting treatment for residuals; 3) information regarding facilities improvements related to byproducts; and 4) rate orders which specify the contributions of individual byproduct revenues to operating income.

Q. PLEASE EXPAND ON THE ITEMS LISTED ABOVE.

A. In category 1, I located a specific citation of residuals revenue in the "Tenth Annual Report of the Public Service Commission of Oregon," dated December 15, 1916. It lists categories of operating revenues for PG&C in 1915, including residuals of $123,133.10. This represented 9.3 percent of the company's total operating revenues that year of $1,320,595.22.

In category 2, I located a Uniform Classification of Accounts booklet, effective January 1, 1925, bound into an order book in the PUC library. This booklet listed the following accounts relating to byproducts:

> *"616. Byproducts-Net: This account shall be credited with all revenues derived from the sale of byproducts produced from residuals of gas making.*
> *713. Residuals Produced-Cr.: This account shall be credited and the appropriate "residual stock" account charged periodically with the estimated value of residuals produced.*
> *714. Residuals Expense. This account shall include all expense incurred in preparing and handling residuals for sale, together with the cost of making deliveries."*

In category 3, I identified two items related to the financing of facilities in support of the production of byproducts. The first item, Order 6907, dated October 16, 1939, in Docket U-F-928, approves the sale of 6,000 shares of

PG&C stock to American Power & Light Company for $600,000.00. The Company was ordered to make monthly filings on the amount expended "for the installation of certain by-product plant additions." I found the second item in this category in the Annual Report of the State Public Utilities Commission, Year Ending December 31, 1939, where the Engineering Department stated that PG&C "has prepared plans for substantial improvements in its facilities making possible, when completed, large revenues from byproducts to be obtained in the manufacture of gas."

Finally, in category 4, I identified four Commission rate orders from the 1940's and early 1950's that make explicit reference to byproduct revenues:

1. Order 17243 in Docket U-F-1238, dated December 5, 1946, approves a rate increase, and cites specific byproduct revenue increases for "Gasco Briquets," petroleum coke, electrode pitch, and a revenue decrease for Benzol. The order states that, "after by-products credit, the production cost per M.C.F sold is 35 cents."

2. Order 21133 in Docket U-F-1404, dated December 2, 1948, approves a rate increase, and states, "for the twelve months ended September 30, 1948, the Company's net operating income was $774,612, including $274,864 of non-recurring income occasioned by the sale in July 1948 of 42,355 tons of lamp black to the Carborundum Company."

3. Order 29444 in Docket U-F-1656, dated March 10, 1952, approves a rate increase, and states, "For the twelve months ended December 31, 1951, the Company's system operating income was $11,106,954.00, of which $2,630,908.00 was derived from the net earnings from the sale of by-products…That economies of operation and greater efficiency have increased the net revenues from the sale of by-products from $1,889,008.00 in 1948, to $2,630,908.00 in 1951, an increase of $741,900.00, or approximately 39%."

4. Order 33143 in Docket U-F-1826, dated July 30, 1954, approves a rate increase, and states that, “During the year 1953, adjusted gross revenue from the sale of by-products was $2,529,197.67 and gross revenue from the sale of gas was $8,541,912.25, making total operating revenues of $11,071,109.92.”

Q. WHAT DO YOU CONCLUDE REGARDING THE HISTORICAL RATE TREATMENT OF BYPRODUCT SALES REVENUES FOR NW NATURAL'S PREDECESSOR COMPANIES?

A. From 1946 forward, it is clear from the specific rate orders that byproduct revenues were treated as a part of regulated activities, and were therefore used to reduce the overall gas rates. Between 1911 and 1946, no specific breakdown of the Company's revenue related to a specific rate case was found. However, because byproduct revenues and investments were regularly tracked and reported to the Commission prior to 1946, this leads to a reasonable assumption that they were treated similarly during this time period.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: Brittany Andrus

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME:	Brittany Andrus
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst
ADDRESS:	550 Capitol Street NE Suite 215 Salem, Oregon 97301-2148
EDUCATION:	M.B.A. Portland State University, Portland, Oregon B.A. English Michigan State University, East Lansing, Michigan
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission since September 2011 doing research, analysis, and investigations related to regulated public utilities. I was previously employed for 17 years by the Bonneville Power Administration, a wholesale power marketing agency within the federal Department of Energy. My duties included energy conservation program management, energy conservation planning, long term load and revenue forecasting, power sales contract implementation, rate impact analysis, short-term load forecasting, power and transmission scheduling, and management of load forecasting information technology projects.

CASE: UG 221
WITNESS: IRINA PHILLIPS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, PRESENT POSITION WITH OREGON PUBLIC UTILITY COMMISSION, AND BUSINESS ADDRESS.

A. My name is Irina Phillips. I am employed as an Economist at Economic Research and Financial Analysis Division. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is in Exhibit Staff/401.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I reviewed the sales and transportation revenue and load forecast prepared for the test year 2013 by Northwest Natural Gas Company (Company or NWN), the Company's weather normalization procedure, the billing determinants used in the revenue model, the Weather Adjustment Rate Mechanism (schedule 195, WARM Program), and the Company's jurisdictional allocations. At this stage in my review of these issues, I recommend adjustments to the Company's load forecast and WARM.

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS.

A. The Company assumes 1,022,984,729 therms for total test year deliveries. This projection is inconsistent with NWN's Integrated Resource Plan assumptions and with information regarding the Company's historical and current deliveries. Accordingly, I adjusted sales volumes by 5,429,268 therms for the Residential class and 1,444,193 therms for the Commercial class.

My recommendations for WARM are to update normal heating degree days (HDDs) and statistical coefficients relating to HDDs to the therm usage as filed. I revised the normalized use per customer in Exhibit 406.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

1. CUSTOMER FORECAST ADJUSTMENT

Q. PLEASE DESCRIBE THE DOCUMENTS YOU UTILILZED IN PREPARING THIS ADJUSTMENT.

A. I reviewed the Company's Exhibits 302-303, 1101-1102 and corresponding work papers. I also reviewed the customer forecast submitted with the Company's most recent Integrated Resource Plan (Modified 2011 IRP). I also sent several rounds of data requests and reviewed the responses.

Q. WHAT IS YOUR SUMMARY FINDING WITH RESPECT TO THE NUMBER OF CUSTOMERS?

A. These corrections are necessary because the Company did not update its 2011 number of customers. Furthermore, I do not support NWN's forecast of a loss of customers due to the implementation of the fixed/variable rate design because Staff is not supporting the fixed/variable rate design.

Compared to the filed forecast, I recommend increasing Residential schedule 2 customer count in January 2012 by 392 customers. I also recommend increasing customer count in November 2012 by 14,254 customers. In addition, Commercial schedule 3 customer count should be increased in January 2012 by 268 customers; and the number of Residential schedule 1 customers increased by 100 in November 2012.

Q. WHAT ISSUES DID YOU DISCOVER DURING YOUR REVIEW?

A. On page 1.2 of the Chapter 1- Executive Summary of the modified IRP the Company makes the following prediction: "The average annual customer growth rate for the entire planning horizon is projected to be 1.84%, while load is expected to grow annually by an average of 0.61%." On page 1.4 more details are added specific to jurisdictions: "The average annual forecasted customer growth rate across the planning horizon for the entire service area is projected to be 1.84%; with the Oregon customer base growing at a rate of 1.73% and Washington at 2.70%... Annual demand growth is forecast to be lower than customer growth due to declining use per customer. Excluding Demand-Side Management (DSM) savings, annual demand is forecast to grow at an average of 1.28% over the horizon; with Oregon load growing at an average rate of 1.17% and Washington at 2.22%."[1]

.

[1] *See* Exhibit 402.

Q. WHEN WAS THE MODIFIED IRP FILED?

A. It was submitted to the Commission on September 1, 2011.

Q. WHAT IS THE PICTURE OF CUSTOMER GROWTH FROM THE RATE CASE?

A. The Company discusses "the dramatic decrease in customer growth."[2]

Q. WHAT DID YOU DISCOVER DURING YOUR INVESTIGATION?

A. The Company uses a pragmatic simple chain model for modeling the growth in the customer base when the ending customer count of one month becomes the beginning balance of the following month. The Company models new customer additions and net losses during the month to derive the new ending balance. I do not criticize this model. When I was reviewing the Company's data response 114 (attached in the Exhibit 403), I noticed that the beginning customer count for January 2012 is exactly the same as the beginning customer count for January 2011. It is my current understanding that the Company does not take into account growth in customer numbers that happened during 2011. The Company provided me with an update of actual results for 2011, on April 20, 2012, and I made corresponding adjustment to the customer forecast model.

Q. WHAT IS THE TEST YEAR FOR THIS PROCEEDING?

A. It is November 01, 2012 through October 31, 2013.

Q. DID YOU NOTICE ANY ISSUES WITH TEST YEAR CUSTOMER COUNT?

According to NWN data response 114, (see Exhibit 403), the Company stated it expects to lose 13,132 Residential Schedule 2 customers and 100

[2] NWN/200, Anderson/18 at 16.

Residential Schedule 1 customers during the first month of the Test Year, which is November 2012. Because the Company's model is a month-over month-model, if you underestimate the beginning count it has an affect in each month of the test year.

Q. WHY DID NWN MAKE THIS ASSUMPTION?

A. The Company indicates that "a $5.00 or $6.00 per month charge is still far below the indicated LRIC (*Long-Run Incremental Cost)* of over $30 per month."[3] Based upon this study the Company requests approval of a different rate design for Residential schedules, expecting this change in rate design to drop the number of customers because of rate shock.

Q. DO YOU AGREE WITH THE COMPANY'S ASSUMPTION?

A. No. Currently, Staff opposes the straight fixed-variable rate design requested by the Company.

Q. WHAT IS THE COMPANY'S TYPICAL REGIONAL HISTORIC RESIDENTIAL CUSTOMER CHANGE FOR THE MONTH OF NOVEMBER?

A. The results of the pre-rate case audit show that during the years 2008-2010 the difference in customer count between months of October and November varied between positive 2,249 in 2009 to positive 2,979 in 2008. The difference for 2010 was reported as a positive 2,515 customers.

Q. WHAT IS THE SIZE OF STAFF'S ADJUSTMENT TO NOVEMBER 2012 CUSTOMER COUNT?

A. I have adjusted Residential schedule 2 customer count upwards by 1,122

[3] *See* NWN/1100 Feingold/38 at 16-18.

customers and left the number of Residential schedule 1 customers unchanged.[4]

2. IMPACT OF WEATHER NORMALIZED USE PER CUSTOMER ON SALES

Q. HOW DOES THE COMPANY PERFORM ITS WEATHER NORMALIZATION?

A. An annual HDD (Heating Degree Day) pattern was developed using daily HDD values from a data set spanning 25 years (1986-2010). A 59 degree set point was applied for the residential class and a 58 degree set point was used for the commercial class. According to the Company's data response 184, it ran a simple linear regression relating monthly average use per customer per day as a function of a monthly average HDD per day for the period of January 2007 through July of 2011. The intercept value represents customer base load use. The slope coefficient is multiplied by the daily HDD value to calculate the heating load. A daily use per customer is a sum of the base load and the heating load.

Q. HOW MANY WEATHER ZONES DOES THE COMPANY USE TO PERFORM THEIR WEATHER NORMALIZATION PROCEDURE FOR THE OREGON JURISDICTION?

A. Eight, which are: Albany, Astoria, The Dalles, Eugene, Coos-Bay, Newport, Portland and Salem. For the purposes of this rate case, the Company

[4] *See* Exhibit 404.

combined the weather zones of Eugene and Coos Bay into one weather zone.

Q. DID THE COMPANY PROVIDE YOU WITH AN EXPLANATION OF HOW USE PER CUSTOMER FOR THE TEST YEAR WAS CALCULATED?

A. Yes. It provided an explanation on how they arrived at the use per customer for the Test Year. *See* NWN data response 379 attached as exhibit 405. The Company explained that the use per customer resulting from the weather normalization was reduced by the estimated demand side management savings forecast.

Q. DID THE COMPANY PROVIDE YOU WITH THE GEOGRAPHICAL BREAKOUT OF CUSTOMERS?

A. Yes. The Company provided an explanation on how to perform a breakout of customers between zones in response to Staff's data request 379.

Q. HOW DID YOU CALCULATE RESIDENTIAL AND COMMERCIAL TEST YEAR VOLUMES?

A. I multiplied for each of seven geographical zones the normalized use per customer by forecasted customer counts. My calculations are provided in Exhibit 406.

3. CHANGES IN THE SCHEDULE 195 WEATHER ADJUSTED RATE MECHANISM

Q. WHAT IS WARM PROGRAM?

A. WARM is a weather normalization mechanism that adjusts Schedule 2

Residential and 3 Commercial customers' bills in real time to mitigate the effects of the weather. When the weather is colder than normal, billing rates are adjusted down. When the weather is warmer than normal, they are adjusted up.

Q. WHAT ARE WARM BENEFITS?

A. WARM has reduced bill variability due to weather for customers. The benefit to the Company is a smoothing of over- or under-collection of the Company's fixed costs.

Q. WHAT CHANGES DOES THE COMPANY REQUEST TO THEIR WARM PROGRAM?

A. The Company requests to update normalized use per customer, normal heating degree days (HDDs) and statistical coefficients relating HDDs to therm usage. These updates apply to both the WARM program and Decoupling Mechanism. WARM adjustments are made to bills issued during the heating season of December 1- May 15. The Company requests permission to normalize usage for the month of May by the actual WARM revenue effect.

Q. DOES THE COMPANY REQUEST ANYTHING ELSE?

A. Currently, WARM is the Company's default billing method. Customers are included in the WARM program unless they opt-out of the program. The Company requests that the WARM opt-out provision be removed.

Q. WHY IS THE COMPANY'S CONCERNED WITH THE OPT-OUT PROVISION?

A. According to NWN/1200 Siores/11 lines 20-22: "The opt-out provision has been confusing for customers and added complexity for the Company in communicating with customers."

Q. WHAT DID YOU DISCOVER DURING YOUR INVESTIGATION?

A. The number of customers who selected to Opt-out was 48,813 for the Residential Schedule 2 and 4,006 for the Commercial Schedule 3 as of December 1, 2010. If the Opt-out provision was removed, the Company will be communicating with more than 52 thousand customers who would be forced to opt-in to WARM even though they previously decided to opt out. Furthermore, the number of customer service phone calls related to WARM is declining with each year. During 2008-09 heating season, there were almost five thousand phone calls. During 2010-11 heating season, the number of phone calls declined to less than 400.

Q. DOES STAFF RECOMMEND TO REMOVE THE OPT-OUT PROVISION?

A. No. There does not appear to be much on-going confusion or complaints regarding WARM. It is reasonable to retain customer choice by retaining the opt-out provision of WARM. There does not appear to be a strong public policy reason for reversing the previous Commission decision to have an opt-out option.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME:	IRINA PHILLIPS
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	ECONOMIST ECONOMIC RESEARCH & FINANCIAL ANALYSIS DIVISION (ERFA)
ADDRESS:	550 CAPITOL STREET NE SUITE 215, SALEM, OREGON 97301-2115.
EDUCATION:	Master of Science, Economics Oregon State University, Corvallis, OR Bachelor of Science, Economics and Management St. Petersburg State University of Economics and Finance, St. Petersburg, Russia
EXPERIENCE:	Provided testimony or comments in a variety of OPUC dockets, including UM 1431, UE 213,215,217, 233, UG 186 and UG 201. Assisted in Staff review of Integrated Resource Plans (LC 48, 50-53 and 54). Participated in Staff audits of NW Natural and Cascade Natural Gas. Between 2005 and 2009, worked as an Adjunct Instructor for Linn-Benton Community College, Albany, OR and Western Oregon University, Monmouth, OR Between 1996 and 1999, worked as a Financial Analyst for Gillette International LLC, Russian Office, St. Petersburg, Russia Between 1991 and 1994, worked as a Senior and Chief Accountant for Korex, Fiton and Tandem companies, St. Petersburg, Russia

CASE: UG 221
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 402

Exhibits in Support Of Opening Testimony

May 3, 2012

Month - Year	Gas Year	IRP FCST OR RES CUST	IRP FCST OR COM CUST
11-2012	2012/2013	560,139	58,560
12-2012	2012/2013	561,681	58,774
1-2013	2012/2013	562,707	58,886
2-2013	2012/2013	563,386	58,949
3-2013	2012/2013	564,065	59,012
4-2013	2012/2013	564,744	59,075
5-2013	2012/2013	565,308	59,121
6-2013	2012/2013	565,160	59,032
7-2013	2012/2013	565,013	58,944
8-2013	2012/2013	564,866	58,855
9-2013	2012/2013	565,992	58,948
10-2013	2012/2013	567,713	59,159

CASE: UG 221
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 404

Exhibits in Support
Of Opening Testimony

May 3, 2012

Staff's Test Year Customer Forecast

NW Natural
Financial Planning & Analysis
Test Year
Margin Model
CUSTOMERS

Test Year

CUSTOMERS		CUSTOMERS	2012 January	2012 February	2012 March	2012 April	2012 May	2012 June	2012 July	2012 August	2012 September	2012 October
CUSTOMER DETAIL												
Oregon	Residential 2	Beginning of Period	547,283	548,271	549,076	549,355	549,403	549,402	548,950	548,627	548,104	547,953
		New Business	513	405	411	443	413	434	373	445	465	598
		Net Losses	475	400	(132)	(395)	(414)	(886)	(696)	(968)	(616)	96
		End of Period	548,271	549,076	549,355	549,403	549,402	548,950	548,627	548,104	547,953	548,647
	Residential 1	Beginning of Period	3,740	3,747	3,753	3,755	3,756	3,755	3,752	3,750	3,746	3,745
		New Business	3	3	3	3	3	3	3	3	3	4
		Net Losses	3	3	(1)	(2)	(3)	(7)	(4)	(7)	(4)	1
		End of Period	3,747	3,753	3,755	3,756	3,755	3,752	3,750	3,746	3,745	3,750
	Commercial - 3	Beginning of Period	55,997	56,216	56,347	56,365	56,343	56,344	56,290	56,240	56,187	56,194
		New Business	123	79	84	80	60	61	49	84	84	94
		Net Losses	95	52	(65)	(102)	(59)	(115)	(99)	(137)	(78)	(80)
		End of Period	56,216	56,347	56,365	56,343	56,344	56,290	56,240	56,187	56,194	56,208
	Commercial - 1	Beginning of Period	188	188	188	188	188	188	188	188	188	188
		New Business	0	0	0	0	0	0	0	0	0	0
		Net Losses	0	0	0	0	0	0	0	0	0	0
		End of Period	188	188	188	188	188	188	188	188	188	188
CUSTOMER SUMMARY												
Oregon	Sales	Residential 2	548,271	549,076	549,355	549,403	549,402	548,950	548,627	548,104	547,953	548,647
		Residential 1	3,747	3,753	3,755	3,756	3,755	3,752	3,750	3,746	3,745	3,750
		Commercial 3	56,216	56,347	56,365	56,343	56,344	56,290	56,240	56,187	56,194	56,208
		Commercial 1	188	188	188	188	188	188	188	188	188	188
CUSTOMER SUMMARY												
Oregon	Sales	Residential 2	552,018	552,829	553,110	553,159	553,157	552,702	552,377	551,850	551,698	552,397
		Commercial 3	57,648	57,780	57,802	57,778	57,777	57,723	57,674	57,622	57,628	57,641

Staff's Test Year Customer Forecast

Test Year

CUSTOMERS	2012 November	2012 December	2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October
Beginning of Period	548,647	550,298	551,664	552,771	553,671	554,042	554,187	554,276	553,916	553,673	553,243	553,192
New Business	529	438	628	497	504	543	506	532	457	545	570	733
Net Losses	1,122	928	478	403	(133)	(397)	(417)	(893)	(700)	(975)	(620)	97
End of Period	550,298	551,664	552,771	553,671	554,042	554,187	554,276	553,916	553,673	553,243	553,192	554,022
Beginning of Period	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750
New Business	0	0	0	0	0	0	0	0	0	0	0	0
Net Losses	0	0	0	0	0	0	0	0	0	0	0	0
End of Period	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750
Beginning of Period	56,208	56,253	56,463	56,692	56,831	56,856	56,842	56,849	56,800	56,755	56,709	56,724
New Business	91	111	134	86	91	88	65	67	53	91	92	103
Net Losses	(46)	99	95	52	(65)	(102)	(59)	(115)	(99)	(137)	(78)	(80)
End of Period	56,253	56,463	56,692	56,831	56,856	56,842	56,849	56,800	56,755	56,709	56,724	56,747
Beginning of Period	188	188	188	188	188	188	188	188	188	188	188	188
New Business	0	0	0	0	0	0	0	0	0	0	0	0
Net Losses	0	0	0	0	0	0	0	0	0	0	0	0
End of Period	188	188	188	188	188	188	188	188	188	188	188	188
Residential 2	550,298	551,664	552,771	553,671	554,042	554,187	554,276	553,916	553,673	553,243	553,192	554,022
Residential 1	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750
Commercial 3	56,253	56,463	56,692	56,831	56,856	56,842	56,849	56,800	56,755	56,709	56,724	56,747
Commercial 1	188	188	188	188	188	188	188	188	188	188	188	188
Residential 2	554,048	555,414	556,521	557,421	557,792	557,937	558,026	557,666	557,423	556,993	556,942	557,772
Commercial 3	57,682	57,897	58,126	58,265	58,295	58,279	58,283	58,235	58,191	58,146	58,159	60,496

Staff's Test Year Customer Forecast

Test Year

CUSTOMERS	Test Year
Beginning of Period	548,647
New Business	6,482
Net Losses	(1,107)
End of Period	554,022
Beginning of Period	3,750
New Business	0
Net Losses	0
End of Period	3,750
Beginning of Period	56,208
New Business	1,073
Net Losses	(535)
End of Period	56,747
Beginning of Period	188
New Business	0
Net Losses	0
End of Period	188
Residential 2	554,022
Residential 1	3,750
Commercial 3	56,747
Commercial 1	188
Residential 2	557,772
Commercial 3	60,496

Staff/404
Phillips/3

CASE: UG 221
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 405

Exhibits in Support Of Opening Testimony

May 3, 2012

Monthly Normalized UpC by District-Res2
Res2

BREAKOUT OF RESIDENTIAL USE PER CUSTOMER

		Albany	Astoria	Coos Bay	Dalles -OR	Eugene	Newport	Portland	Salem	Eug/Coos-RES
		681	669	583	789	678	647	628	668	675
	Residential 2 RS2 % of R									
January	1.006	107	93	77	132	106	83	105	105	105
February	1.006	88	82	67	107	87	73	85	87	87
March	1.005	78	80	69	88	77	75	72	77	77
April	1.006	58	65	58	60	57	64	49	57	57
May	1.006	38	46	42	36	39	48	30	36	39
June	1.003	21	27	26	20	21	32	17	19	21
July	1.003	16	18	20	16	16	24	16	16	16
August	1.003	16	17	19	16	16	23	15	16	16
September	1.004	19	24	24	22	19	29	16	18	19
October	1.005	46	48	40	57	48	46	38	46	47
November	1.005	81	73	60	98	82	65	75	80	81
December	1.005	112	96	80	136	111	85	109	110	110

Source of RS2% of R: Row 33 on breakout residential tab in 'NCS breakout of Res 1 & 2 and Commercial 1 & 3

Res2 UPC

	Nov	Dec	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct
Albany	81	112	107	88	78	58	38	21	16	16	19	46
Astoria	73	96	93	82	80	65	46	27	18	17	24	48
Dalles -OR	98	136	132	107	88	60	36	20	16	16	22	57
Eug/Coos-RES	81	110	105	87	77	57	39	21	16	16	19	47
Newport	65	85	83	73	75	64	48	32	24	23	29	46
Portland	75	109	105	85	72	49	30	17	16	15	16	38
Salem	80	110	105	87	77	57	36	19	16	16	18	46

Above is used in the Test Year Normalization workbook.

Staff/405
Phillips/1

Monthly Normalized UpC by District-Res1
Res1

BREAKOUT OF RESIDENTIAL USE PER CUSTOMER

Residential 1
RS1 % of R

		Albany	Astoria	Coos Bay	Dalles -OR	Eugene	Newport	Portland	Salem	Eug/Coos-RES
January	**0.263**	28	24	20	35	28	22	28	28	28
February	**0.261**	23	21	17	28	23	19	22	23	23
March	**0.274**	21	22	19	24	21	20	20	21	21
April	**0.283**	16	18	16	17	16	18	14	16	16
May	**0.299**	11	14	13	11	12	14	9	11	12
June	**0.393**	8	11	10	8	8	12	7	8	8
July	**0.509**	8	9	10	8	8	12	8	8	8
August	**0.516**	8	9	10	8	8	12	8	8	8
September	**0.554**	10	13	13	12	10	16	9	10	10
October	**0.385**	18	18	16	22	18	18	15	18	18
November	**0.286**	23	21	17	28	23	18	21	23	23
December	**0.266**	30	26	21	36	29	23	29	29	29

Source of RS1% of R: Row 41 on breakout residential tab in 'NCS breakout of Res 1 & 2 and Commercial 1 & 3'

Res1 UPC

	November	December	January	February	March	April	May	June	July	August	September	October
Albany	23	30	28	23	21	16	11	8	8	8	10	18
Astoria	21	26	24	21	22	18	14	11	9	9	13	18
Dalles -OR	28	36	35	28	24	17	11	8	8	8	12	22
Eug/Coos-RE!	23	29	28	23	21	16	12	8	8	8	10	18
Newport	18	23	22	19	20	18	14	12	12	12	16	18
Portland	21	29	28	22	20	14	9	7	8	8	9	15
Salem	23	29	28	23	21	16	11	8	8	8	10	18

Above is used in the Test Year Normalization workbook.

Staff/405
Phillips/2

Monthly Normalized UpC by District-COM3
COM3 UPC

BREAKOUT OF Commercial USE PER CUSTOMER

	Commercial 3 RS-C3 % of C	Albany	Astoria	Coos Bay	Dalles -OR	Eugene	Newport	Portland	Salem	Eug/Coos-COM
		2,854	2,758	2,299	3,422	2,837	2,616	2,594	2,789	2,807
January	1.0025	426	351	268	559	418	298	415	414	411
February	1.0025	346	312	236	445	342	265	329	341	337
March	1.0023	287	300	240	341	283	272	257	284	281
April	1.0028	216	251	215	224	211	246	170	210	211
May	1.0025	140	176	157	131	141	187	100	129	141
June	1.0023	87	107	104	83	85	129	71	79	86
July	1.0026	93	98	105	94	93	122	92	93	93
August	1.0026	99	102	109	100	99	126	99	99	99
September	1.0022	109	127	127	122	108	151	100	107	107
October	1.0028	218	228	190	277	227	219	182	218	225
November	1.0026	362	318	249	451	365	275	329	355	360
December	1.0024	471	387	300	595	464	327	451	461	456

From Row 33 on breakout Commercial tab in 'NCS breakout of Res 1 & 2 and Commercial 1 & 3

COM3 UPC

	November	December	January	February	March	April	May	June	July	August	September	October
Albany	362	471	426	346	287	216	140	87	93	99	109	218
Astoria	318	387	351	312	300	251	176	107	98	102	127	228
Dalles -OR	451	595	559	445	341	224	131	83	94	100	122	277
Eug/Coos-CO	360	456	411	337	281	211	141	86	93	99	107	225
Newport	275	327	298	265	272	246	187	129	122	126	151	219
Portland	329	451	415	329	257	170	100	71	92	99	100	182
Salem	355	461	414	341	284	210	129	79	93	99	107	218

Staff/405
Phillips/3

Monthly Normalized UpC by District-COM3
COM1 UPC

BREAKOUT OF Commercial USE PER CUSTOMER

	Commercial 1 RS-C1 % of C	Albany	Astoria	Coos Bay	Dalles -OR	Eugene	Newport	Portland	Salem	ıg/Coos-COM
		691	663	553	827	685	629	631	674	678
January	0.2475	105	87	66	138	103	74	102	102	101
February	0.2352	81	73	55	104	80	62	77	80	79
March	0.2498	71	75	60	85	70	68	64	71	70
April	0.2243	48	56	48	50	47	55	38	47	47
May	0.2327	33	41	36	30	33	43	23	30	33
June	0.2812	24	30	29	23	24	36	20	22	24
July	0.2562	24	25	27	24	24	31	24	24	24
August	0.2542	25	26	28	25	25	32	25	25	25
September	0.2780	30	35	35	34	30	42	28	30	30
October	0.1018	22	23	19	28	23	22	19	22	23
November	0.2782	100	88	69	125	101	76	91	99	100
December	0.2678	126	103	80	159	124	87	121	123	122

From Row 39 on breakout Commercial tab in 'NCS breakout of Res 1 & 2 and Commercial 1 & 3

	November	December	January	February	March	April	May	June	July	August	September	October
Albany	100	126	105	81	71	48	33	24	24	25	30	22
Astoria	88	103	87	73	75	56	41	30	25	26	35	23
Dalles -OR	125	159	138	104	85	50	30	23	24	25	34	28
Eug/Coos-COI	100	122	101	79	70	47	33	24	24	25	30	23
Newport	76	87	74	62	68	55	43	36	31	32	42	22
Portland	91	121	102	77	64	38	23	20	24	25	28	19
Salem	99	123	102	80	71	47	30	22	24	25	30	22

Staff/405
Phillips/4

CASE: UG 221
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 406

Exhibits in Support Of Opening Testimony

May 3, 2012

Residential Test Year Customers, UpC and Volumes by District (RES2)

Customers	District	2012 November	2012 December	2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	Test Year Total
End of Period	ALB	36,087	36,173	36,235	36,293	36,306	36,309	36,315	36,281	36,270	36,235	36,239	36,308	
End of Period	AST	10,617	10,642	10,664	10,680	10,686	10,688	10,690	10,682	10,677	10,669	10,669	10,688	
End of Period	DAL	4,392	4,399	4,403	4,408	4,404	4,402	4,402	4,393	4,393	4,386	4,391	4,408	
End of Period	EUG	34,361	34,441	34,509	34,561	34,577	34,583	34,587	34,559	34,545	34,516	34,519	34,585	
End of Period	NEW	8,821	8,841	8,858	8,871	8,873	8,875	8,876	8,867	8,864	8,856	8,858	8,876	
End of Period	POR	376,733	377,683	378,457	379,083	379,366	379,478	379,542	379,320	379,146	378,863	378,808	379,330	
End of Period	SAL	79,287	79,485	79,645	79,775	79,830	79,852	79,865	79,814	79,779	79,717	79,709	79,826	
		550,298	551,665	552,771	553,671	554,042	554,188	554,276	553,916	553,673	553,243	553,193	554,022	6,638,957
UpC-Normalized- RES2														
UpC-Normalized	Albany	81	112	107	88	78	58	38	21	16	16	19	46	
UpC-Normalized	Astoria	73	96	93	82	80	65	46	27	18	17	24	48	
UpC-Normalized	Dalles -OF	98	136	132	107	88	60	36	20	16	16	22	57	
UpC-Normalized	Eug/Coos-	81	110	105	87	77	57	39	21	16	16	19	47	
UpC-Normalized	Newport	65	85	83	73	75	64	48	32	24	23	29	46	
UpC-Normalized	Portland	75	109	105	85	72	49	30	17	16	15	16	38	
UpC-Normalized	Salem	80	110	105	87	77	57	36	19	16	16	18	46	
Normalized Volumes-Test Year without Heat Pump Adjustment														
	District													
Therms	Albany	2,932,698	4,063,844	3,889,539	3,200,002	2,817,948	2,111,978	1,392,436	773,877	574,844	568,116	685,086	1,657,267	
Therms	Astoria	774,878	1,026,822	992,760	872,266	855,671	697,212	494,589	286,743	191,399	182,671	251,845	511,263	
Therms	Dalles -OF	431,504	597,835	583,279	470,856	387,206	263,386	159,600	89,058	70,492	70,300	95,322	252,304	
Therms	Eug/Coos-	2,798,211	3,799,973	3,630,884	3,006,055	2,650,914	1,986,396	1,339,526	729,452	546,741	540,840	640,376	1,637,682	
Therms	Newport	571,226	752,809	735,755	644,943	664,331	570,375	429,272	280,833	213,061	206,417	256,402	409,866	
Therms	Portland	28,259,774	41,025,047	39,810,666	32,177,265	27,266,825	18,733,823	11,407,511	6,547,327	5,893,147	5,870,277	6,249,803	14,585,473	
Therms	Salem	6,339,673	8,779,378	8,365,422	6,955,129	6,147,615	4,564,501	2,885,118	1,538,516	1,253,664	1,245,923	1,461,209	3,648,610	
		42,107,965	60,045,708	58,008,305	47,326,515	40,790,511	28,927,670	18,108,052	10,245,807	8,743,347	8,684,544	9,640,042	22,702,465	355,330,929
UpC System		77	109	105	85	74	52	33	18	16	16	17	41	643

Staff/406
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Residential Test Year Customers, UpC and Volumes by District

Customers	District	2012 November	2012 December	2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	Test Year Total
End of Period	ALB	246	246	246	246	246	246	246	246	246	246	246	246	
End of Period	AST	72	72	72	72	72	72	72	72	72	72	72	72	
End of Period	DAL	30	30	30	30	30	30	30	30	30	30	30	30	
End of Period	EUG	234	234	234	234	234	234	234	234	234	234	234	234	
End of Period	NEW	60	60	60	60	60	60	60	60	60	60	60	60	
End of Period	POR	2,567	2,567	2,567	2,567	2,567	2,567	2,567	2,567	2,567	2,567	2,567	2,567	
End of Period	SAL	540	540	540	540	540	540	540	540	540	540	540	540	
		3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	3,750	44,998
UpC-Normalized														
	District													
UpC-Normalized	Albany	23.1	29.7	28.1	22.9	21.1	16.3	11.4	8.4	8.0	8.1	10.4	17.5	
UpC-Normalized	Astoria	20.8	25.5	24.4	21.2	21.8	18.3	13.8	10.5	9.1	8.8	13.0	18.3	
UpC-Normalized	Dalles -OR	28.0	35.9	34.7	27.7	24.0	16.8	10.8	7.9	8.1	8.2	12.0	21.9	
UpC-Normalized	Eug/Coos-	23.2	29.2	27.6	22.6	20.9	16.1	11.5	8.3	8.0	8.1	10.2	18.2	
UpC-Normalized	Newport	18.4	22.5	21.8	18.9	20.4	18.1	14.4	12.4	12.2	12.0	16.0	17.7	
UpC-Normalized	Portland	21.4	28.7	27.5	22.0	19.6	13.9	8.9	6.8	7.9	8.0	9.1	14.7	
UpC-Normalized	Salem	22.8	29.2	27.5	22.6	21.0	16.1	10.7	7.6	8.0	8.0	10.1	17.5	
Normalized Volumes-Test Year wihtout Heat Pump Adjustment														
	District													
Therms	Albany	5,693	7,303	6,913	5,624	5,200	4,018	2,805	2,055	1,978	1,983	2,567	4,304	
Therms	Astoria	1,504	1,845	1,764	1,533	1,578	1,326	996	761	658	637	943	1,327	
Therms	Dalles -OR	838	1,075	1,038	829	717	503	323	238	244	247	359	657	
Therms	Eug/Coos-	5,432	6,830	6,452	5,283	4,890	3,778	2,698	1,937	1,881	1,887	2,398	4,251	
Therms	Newport	1,109	1,353	1,308	1,134	1,226	1,085	865	746	733	721	961	1,064	
Therms	Portland	54,855	73,719	70,721	56,525	50,265	35,600	22,956	17,363	20,249	20,459	23,383	37,848	
Therms	Salem	12,306	15,776	14,862	12,219	11,334	8,675	5,807	4,081	4,308	4,343	5,468	9,469	
		81,735	107,902	103,057	83,146	75,210	54,985	36,450	27,181	30,051	30,277	36,078	58,919	724,992
UpC System		21.80	28.78	27.48	22.17	20.06	14.66	9.72	7.25	8.01	8.07	9.62	15.71	193.34

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Commercial Test Year Customers, UpC and Volumes by District

Customers		2012	2012	2013	2013	2013	2013	2013	2013	2013	2013	2013	2013	Test Year
	District	November	December	January	February	March	April	May	June	July	August	September	October	Total
End of Period	ALB	3,946	3,961	3,977	3,987	3,988	3,987	3,987	3,984	3,981	3,977	3,978	3,980	
End of Period	AST	1,612	1,618	1,625	1,629	1,629	1,628	1,629	1,627	1,626	1,625	1,625	1,626	
End of Period	DAL	1,059	1,064	1,068	1,071	1,071	1,070	1,070	1,069	1,068	1,068	1,068	1,069	
End of Period	EUG	5,288	5,309	5,332	5,343	5,345	5,343	5,343	5,338	5,334	5,331	5,332	5,335	
End of Period	NEW	1,243	1,247	1,252	1,255	1,256	1,256	1,256	1,255	1,254	1,253	1,253	1,254	
End of Period	POR	34,816	34,944	35,085	35,173	35,190	35,182	35,186	35,157	35,129	35,100	35,108	35,122	
End of Period	SAL	8,289	8,319	8,353	8,373	8,378	8,376	8,377	8,370	8,363	8,357	8,358	8,362	
		56,253	56,463	56,692	56,831	56,856	56,842	56,849	56,800	56,755	56,709	56,724	56,747	680,520
UpC-Normalized		11	12	1	2	3	4	5	6	7	8	9	10	
UpC-Normalized	Albany	362	471	426	346	287	216	140	87	93	99	109	218	
UpC-Normalized	Astoria	318	387	351	312	300	251	176	107	98	102	127	228	
UpC-Normalized	Dalles -OR	451	595	559	445	341	224	131	83	94	100	122	277	
UpC-Normalized	Eug/Coos-F	360	456	411	337	281	211	141	86	93	99	107	225	
UpC-Normalized	Newport	275	327	298	265	272	246	187	129	122	126	151	219	
UpC-Normalized	Portland	329	451	415	329	257	170	100	71	92	99	100	182	
UpC-Normalized	Salem	355	461	414	341	284	210	129	79	93	99	107	218	
Normalized Volumes-Test Year														
Therms	Albany	1,427,946	1,864,600	1,694,034	1,380,467	1,143,915	859,692	558,581	346,500	370,518	392,902	435,034	868,989	
Therms	Astoria	513,068	626,430	569,909	508,156	488,192	408,948	287,057	174,674	159,294	166,455	206,683	370,386	
Therms	Dalles -OR	478,111	633,022	596,742	475,949	365,499	240,280	139,983	88,991	100,059	106,934	130,200	296,519	
Therms	Eug/Coos-F	1,902,734	2,420,824	2,190,935	1,802,255	1,500,394	1,128,390	755,233	456,763	495,935	527,107	573,237	1,201,555	
Therms	Newport	341,708	408,139	372,922	332,548	342,265	308,894	234,363	162,305	152,641	157,640	188,982	274,061	
Therms	Portland	11,457,340	15,764,453	14,545,628	11,569,454	9,037,752	5,996,515	3,521,406	2,480,665	3,236,797	3,458,459	3,495,277	6,400,985	
Therms	Salem	2,944,072	3,833,090	3,456,587	2,856,286	2,376,084	1,759,859	1,078,468	657,652	775,232	826,170	892,484	1,826,358	
		19,064,978	25,550,560	23,426,757	18,925,116	15,254,101	10,702,579	6,575,091	4,367,550	5,290,476	5,635,667	5,921,897	11,238,855	151,953,627
UpC System		339	453	413	333	268	188	116	77	93	99	104	198	2682

Commercial Test Year Customers, UpC and Volumes by District

Customers	District	2012 November	2012 December	2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	Test Year Total
End of Period	ALB	12	12	12	12	12	12	12	12	12	12	12	12	
End of Period	AST	5	5	5	5	5	5	5	5	5	5	5	5	
End of Period	DAL	3	3	3	3	3	3	3	3	3	3	3	3	
End of Period	EUG	16	16	16	16	16	16	16	16	16	16	16	16	
End of Period	NEW	4	4	4	4	4	4	4	4	4	4	4	4	
End of Period	POR	105	105	105	105	105	105	105	105	105	105	105	105	
End of Period	SAL	25	25	25	25	25	25	25	25	25	25	25	25	
		169	169	169	169	169	169	169	169	169	169	169	169	2,028
UpC-Normalized														
UpC-Normalized	Albany	100	126	105	81	71	48	33	24	24	25	30	22	
UpC-Normalized	Astoria	88	103	87	73	75	56	41	30	25	26	35	23	
UpC-Normalized	Dalles -OR	125	159	138	104	85	50	30	23	24	25	34	28	
UpC-Normalized	Eug/Coos-f	100	122	101	79	70	47	33	24	24	25	30	23	
UpC-Normalized	Newport	76	87	74	62	68	55	43	36	31	32	42	22	
UpC-Normalized	Portland	91	121	102	77	64	38	23	20	24	25	28	19	
UpC-Normalized	Salem	99	123	102	80	71	47	30	22	24	25	30	22	
Normalized Volumes-Test Year														
Therms	Albany	1,190	1,491	1,247	963	847	572	385	289	282	297	360	263	
Therms	Astoria	428	501	419	354	362	272	198	146	121	126	171	112	
Therms	Dalles -OR	399	506	439	332	271	160	96.58	74	76	81	108	90	
Therms	Eug/Coos-f	1,586	1,936	1,612	1,257	1,112	750	521	381	377	398	474	363	
Therms	Newport	285	326	274	232	254	205	162	135	116	119	156	83	
Therms	Portland	9,551	12,606	10,705	8,071	6,696	3,988	2,430	2,070	2,463	2,613	2,889	1,935	
Therms	Salem	2,454	3,065	2,544	1,992	1,760	1,170	744	549	590	624	738	552	
		15,893	20,431	17,241	13,202	11,301	7,118	4,536	3,645	4,026	4,258	4,894	3,398	109,944
UpC System		94	121	102	78	67	42	27	22	24	25	29	20	651

Staff/406
Phillips/4

CASE: UG 221
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 407

Exhibits in Support
Of Opening Testimony

May 3, 2012

NW Natural
Oregon Jurisdictional Rate Case
Derivation of Forecasted Test Period Revenue
Derivation of Normalized Revenues
Excludes Special Contracts

						Calculation of Test Period Revenue								
		Therms in Block	Minimum Monthly Charge	Filed Rates		Test Year Normal Volumes	Volumetric Charge	Customer Charge	MDDV Dist & Stor Charges	MDDV Charge + Cust Charge + Vol Charge	Commodity Collection	Firm Demand Collection	Interruptible Demand Collection	Total Normalized Revenue
(a)	(b)		(c)			(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Schedule	Block					therms	dollars	dollars	dollars	dollars	dollars	dollars	dollars	dollars
1R		N/A	$8.19	$0.44857	R	724,992.1	$325,210	$368,530	$0	$693,739	$355,203	$97,671		$1,146,613
1C		N/A	$13.62	$0.39972	C	109,944.4	$43,947	$27,621	$0	$71,568	$53,866	$14,812		$140,246
2R		N/A	$13.70	$0.38228	R	355,330,929.5	$135,835,908	$90,953,711	$0	$226,789,619	$174,090,836	$47,870,183		$448,750,637
3C Firm Sales		N/A	$15.00	$0.37386	C	151,953,626.5	$56,809,383	$10,207,799	$0	$67,017,182	$74,448,160	$20,471,193		$161,936,534
Intentionally blank														
3I Firm Sales		N/A	$15.00	$0.36279	I	4,184,174.3	$1,517,977	$3,420	$0	$1,521,397	$2,049,994	$563,692		$4,135,083
Intentionally blank														
19	first mantle	N/A	$16.23											
19	add'l mtls	N/A	$16.02		R		$0	$0	$0	$0	$0	$0		$0
31C Firm Sales	Block 1	2,000	$260.00	$0.22185	C	24,749,351.7	$5,490,644	$3,737,214	$0	$9,227,858	$12,125,697	$8,047,459		$29,401,014
	Block 2	all additional		$0.20241	C	35,860,719.3	$7,258,568	$0	$0	$7,258,568	$17,569,601			$24,828,169
31C Firm Trans	Block 1	2,000	$510.00	$0.20592	FT	44,571.8	$9,178	$36,720	$0	$45,898				$45,898
	Block 2	all additional		$0.18790	FT	188,242.3	$35,371	$0	$0	$35,371				$35,371
31C Interr Sales	Block 1	2,000	$260.00	$0.22185	INT	228,881.2	$50,777	$37,440	$0	$88,217	$112,138		$3,667	$204,022
	Block 2	all additional		$0.20241	INT	1,144,577.8	$231,674	$0	$0	$231,674	$560,774		$18,336	$810,785
31I Firm Sales	Block 1	2,000	$260.00	$0.17994	I	4,447,875.4	$800,351	$702,000	$0	$1,502,351	$2,179,192	$2,102,447		$5,783,989
	Block 2	all additional		$0.16259	I	12,665,213.5	$2,059,237	$0	$0	$2,059,237	$6,205,195			$8,264,432
31I Firm Trans	Block 1	2,000	$575.00	$0.16816	FT	97,557.8	$16,405	$55,200	$0	$71,605				$71,605
	Block 2	all additional		$0.15196	FT	730,157.1	$110,955	$0	$0	$110,955				$110,955
31I Interr Sales	Block 1	2,000	$325.00	$0.17994	INT	58,762.9	$10,574	$27,300	$0	$37,874	$28,790		$941	$67,605
	Block 2	all additional		$0.16259	INT	249,948.4	$40,639	$0	$0	$40,639	$122,460		$4,004	$167,103
32C Firm Sales	Block 1	10,000	$675.00	$0.10066	C	5,059,321.0	$509,271	$429,300	$617,940	$1,556,512	$2,478,764	$1,434,337		$5,469,612
	Block 2	20,000		$0.08555	C	4,834,146.0	$413,561	$0	$0	$413,561	$2,368,441			$2,782,003
	Block 3	20,000		$0.06040	C	1,397,725.0	$84,423	$0	$0	$84,423	$684,801			$769,224
	Block 4	100,000		$0.35240	C	172,093.0	$60,646	$0	$0	$60,646	$84,315			$144,961
	Block 5	600,000		$0.02015	C		$0	$0	$0	$0	$0			$0
	Block 6	all additional		$0.01007	C		$0	$0	$0	$0	$0			$0
32I Firm Sales	Block 1	10,000	$675.00	$0.10103	I	4,284,027.1	$432,815	$364,500	$682,987	$1,480,302	$2,098,916	$1,411,023		$4,990,241
	Block 2	20,000		$0.08587	I	5,123,215.2	$439,930	$0	$0	$439,930	$2,510,068			$2,949,999
	Block 3	20,000		$0.06063	I	2,033,142.8	$123,269	$0	$0	$123,269	$996,118			$1,119,387
	Block 4	100,000		$0.03536	I	365,004.6	$12,907	$0	$0	$12,907	$178,830			$191,737
	Block 5	600,000		$0.02021	I		$0	$0	$0	$0	$0			$0
	Block 6	all additional		$0.01014	I		$0	$0	$0	$0	$0			$0
32 Firm Trans	Block 1	10,000	$925.00	$0.09991	FT	6,123,208.0	$611,770	$721,500	$496,070	$1,829,339				$1,829,339
	Block 2	20,000		$0.08490	FT	9,627,748.9	$817,396	$0	$0	$817,396				$817,396
	Block 3	20,000		$0.05996	FT	6,499,237.6	$389,694	$0	$0	$389,694				$389,694
	Block 4	100,000		$0.03498	FT	13,339,852.1	$466,628	$0	$0	$466,628				$466,628
	Block 5	600,000		$0.01999	FT	20,577,046.7	$411,335	$0	$0	$411,335				$411,335
	Block 6	all additional		$0.01002	FT	3,129,646.7	$31,359	$0	$0	$31,359				$31,359
32C Interr Sales	Block 1	10,000	$675.00	$0.10088	INT	4,180,366.9	$421,715	$421,200	$0	$842,915	$2,048,129		$66,969	$2,958,014
	Block 2	20,000		$0.08575	INT	5,441,419.0	$466,602	$0	$0	$466,602	$2,665,969		$87,172	$3,219,742
	Block 3	20,000		$0.06053	INT	3,043,549.3	$184,226	$0	$0	$184,226	$1,491,157		$48,758	$1,724,140
	Block 4	100,000		$0.03532	INT	5,715,124.1	$201,858	$0	$0	$201,858	$2,800,068		$91,556	$3,093,482
	Block 5	600,000		$0.02017	INT	2,648,467.8	$53,420	$0	$0	$53,420	$1,297,590		$42,428	$1,393,438
	Block 6	all additional		$0.01006	INT		$0	$0	$0	$0	$0		$0	$0
32I Interr Sales	Block 1	10,000	$675.00	$0.10049	INT	6,799,312.2	$683,263	$534,600	$0	$1,217,863	$3,331,255		$108,925	$4,658,043
	Block 2	20,000		$0.08542	INT	8,656,598.1	$739,447	$0	$0	$739,447	$4,241,214		$138,679	$5,119,339
	Block 3	20,000		$0.06030	INT	4,763,985.8	$287,268	$0	$0	$287,268	$2,334,067		$76,319	$2,697,655
	Block 4	100,000		$0.03518	INT	8,983,218.3	$316,030	$0	$0	$316,030	$4,401,238		$143,911	$4,861,179
	Block 5	600,000		$0.02010	INT	4,316,607.0	$86,764	$0	$0	$86,764	$2,114,878		$69,152	$2,270,794
	Block 6	all additional		$0.01006	INT	0.0	$0	$0	$0	$0	$0		$0	$0
32 Interr Trans	Block 1	10,000	$1,380.00	$0.09181	IT	8,025,070.0	$736,782	$1,473,840	$0	$2,210,622				$2,210,622
	Block 2	20,000		$0.07803	IT	13,347,959.3	$1,041,541	$0	$0	$1,041,541				$1,041,541
	Block 3	20,000		$0.05510	IT	10,296,468.2	$567,335	$0	$0	$567,335				$567,335
	Block 4	100,000		$0.03214	IT	32,663,183.8	$1,049,795	$0	$0	$1,049,795				$1,049,795
	Block 5	600,000		$0.01837	IT	65,455,539.5	$1,202,418	$0	$0	$1,202,418				$1,202,418
	Block 6	all additional		$0.00921	IT	84,185,134.4	$775,345	$0	$0	$775,345				$775,345
Intentionally blank		N/A			FT		$0	$0	$0	$0				$0
33		N/A	$38,000.00	$0.00541	IT		$0	$0	$0	$0				$0
Totals						943,856,944.1	$224,265,610	$110,101,895	$1,796,997	$336,164,501	$328,027,725	$82,012,814	$900,818	$747,105,859
Special Contracts Firm						67,652,388.0								$1,506,295
Special Contracts Interruptible						16,208,223.0								$307,870
Grand Total Revenue														$748,920,024
Residential					R	356,055,921.5	$136,161,117	$91,322,241	$0	$227,483,358	$174,446,038	$47,967,854	$0	$449,897,250
Commercial					C	224,136,926.9	$70,670,442	$14,401,934	$617,940	$85,690,317	$109,813,646	$29,967,799	$0	$225,471,762
Industrial Firm					I	33,102,652.8	$5,386,486	$1,069,920	$682,987	$7,139,393	$16,218,314	$4,077,161	$0	$27,434,868
Interruptible					INT	56,230,818.8	$3,774,256	$1,020,540	$0	$4,794,796	$27,549,727	$0	$900,818	$33,245,341
Trans Firm					FT	60,357,269.0	$2,900,091	$813,420	$496,070	$4,209,581	$0	$0	$0	$4,209,581
Trans Int					IT	213,973,355.1	$5,373,216	$1,473,840	$0	$6,847,056	$0	$0	$0	$6,847,056
						943,856,944.1	$224,265,610	$110,101,895	$1,796,997	$336,164,501	$328,027,725	$82,012,814	$900,818	$747,105,859

Staff/407
Phillips/1

CASE: UG 221
WITNESS: Deborah Garcia

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Deborah Garcia. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/502.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to propose adjustments to NW Natural's (NWN or Company) Miscellaneous Labor costs and to Miscellaneous Revenues – Taxes.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/501, which consists of 15 pages.

ISSUE 1, MISCELLANEOUS LABOR ADJUSTMENT

Q. PLEASE SUMMARIZE THIS ADJUSMENT.

A. The Miscellaneous Labor Adjustment is a series of adjustments in multiple accounts related to compensation. First, Wages and Salaries (W&S) are adjusted using Staff's three-year W&S model (Model). Second, the number of full-time equivalent employees (FTE) is adjusted based on actual calendar year 2011 FTE levels, minus the FTE associated with unregulated activities that should be excluded from rates. I then add back the FTE related to NWN's proposal to create four-hour service windows. Third, overtime is adjusted by applying the same principles used in the Model. Finally, Payroll taxes and, Operations and Maintenance (O&M) depreciation expense are adjusted to align with the prior adjustments.

Q. **PLEASE PROVIDE A TABLE OF YOUR PROPOSED OREGON-ALLOCATED ADJUSTMENTS.**

A.

Miscellaneous Labor Adjustment Oregon –Allocated (000s)		
	(O&M)	Rate Base
Wages & Salaries	(904)	(387)
FTE Adjustment	(6,558)	(2,810)
Overtime	(2)	(1)
Payroll Taxes	(542)	
Depreciation Expense	(86)	
Totals	($8,092)	($3,198)

Q. DID NWN BASE ITS MISCELLANEOUS LABOR REQUEST ON COMMISSION PRECEDENT, AND THE USE OF STAFF'S THREE-YEAR W&S MODEL?

A. No. Instead of adopting Staff's Model, NWN objected to using the Consumer Price Index as a basis for setting the appropriate level of test period W&S. The Company stated, "[t]he prudence of the Company's compensation packages for officers and NBU employees is met by showing that the Company's historical wages increases have been aligned with or slightly below both general industry and utility Company averages."[1] The testimony cites to NWN/803/Doolittle/1, which contains a table of 2002 through 2011 average increases for the Company, general Industry, and the utility Industry.

Q. DO YOU AGREE WITH THE COMPANY'S ARGUMENT?

A. Absolutely not. A simple comparison of percentage increases over time does not inform what constitutes a reasonable level of W&S in rates for the test period. The actual amount related to W&S that are associated with the percentage increases are unknown making the percent increase comparison potentially misleading.

Q. DO YOU BELIEVE THAT THE STAFF MODEL RESULTS IN A REASONABLE LEVEL FOR W&S?

A. Yes. The Staff Model employs a long-established technique for estimating appropriate payroll levels. This Staff Model was explicitly adopted in Order No. 95-322, where the Commission stated: "…this Commission has relied on staff's

[1] See NWN/800/Doolittle/6-7

model for over ten years to monitor energy utilities' wages and salaries for both general rate cases and earnings tests associated with deferred accounting. The current model produces a reasonable and reliable result."[2] Subsequently, Staff's Model has been used consistently as either a basis for stipulated results, or by the Commission in its determination of appropriate test year W&S.

Q. IS STAFF'S MODEL BASED ON MARKET DATA?

A. Yes.

Q PLEASE DESCRIBE THE STAFF W&S MODEL.

A. Staff's Model begins with NWN's actual W&S for the 12-month period this is three years prior to the test year. An implicit assumption is that a utility's actual annual W&S, which presumably are based upon market criteria, are reasonable. This is more likely when using a base period that is three years prior to the test period, rather than the most recent period when a utility may be in the process of preparing its general rate case. Escalating historical annual W&S based on inflation is intended to provide employees with the same real level of compensation and the model's sharing mechanism which can provide for a greater level of compensation. Overall the Staff model provides an incentive for the utilities to control compensation.

Q. WHAT BASE PERIOD DOES STAFF'S MODEL USE IN THIS CASE?

A. Because NWN filed for a future test period of November 1, 2012 through October 31, 2013, the Model's starting point is actual NWN wages for the last

[2] See Order No. 95-322 at 10.

two months of 2009 plus the first 10 months of 2010, divided by NWN's actual FTE for the same period. See Staff Exhibit 501, page 2/lines 1 and 2. This calculation provides an annual average salary for four categories, Officers, Exempt, Non Exempt, and Union.

Q. WHAT FACTOR DO YOU USE FOR INFLATION IN THE MODEL?

A. I used the percentage change in the Actual/Forecast Consumer Price Index – All Urban Consumers U.S. (CPI) for the last two months of 2010 through the first 10 months of 2013 (see Staff Exhibit 501, page 14.) This forecast is produced by the Oregon Department of Administrative Services, Office of Economic Analysis.[3]

Q. DOES THE MODEL APPLY CPI TO UNION WAGES?

A. No. Because union W&S negotiations are considered to be conducted at "arms length" the contract terms are generally accepted as negotiated. Using the information provided by NWN in its Data Response M97, I calculated the union increase factor based on the actual weighted average increases for the same periods that I used to calculate CPI for the other W&S categories. See Staff Exhibit/501Garcia/ 7-10 for the calculations.

Q. DOES THE MODEL LIMIT THE COMPANY'S W&S INCREASE TO INFLATION?

A. No. The Staff Model provides an opportunity for 50-50 sharing between customers and stockholders of the difference between Staff's and NWN's projected W&S for the test period. This adjustment allows the Company an

[3] To mirror the test period, it was necessary to use partial year CPI for years 2010 and 2013 to calculate the appropriate three years of CPI for the Model.

opportunity to be market competitive without allowing unchecked escalation to be embedded in rates.

Q. DID YOU MAKE AN ADJUSTMENT TO THE STAFF MODEL?

A. Yes. In NWN's data response M96, it indicated that a portion of test year labor expenses that were included in its case should have been allocated to below-the-line and non-utility expense. As no portion of below-the-line or non-utility expense should be included in rates, I requested and received clarification by e-mail from the Company.[4] Using the percentages provided by the Company, I updated the Staff Model to remove approximately $1.4 million of expense from NWN's test year amounts before the Staff Model calculated the 50-50 sharing.

Q. THE STAFF MODEL DOES NOT INCREASE NWN'S PROPOSED TEST YEAR W&S FOR EXEMPT, NON EXEMPT AND UNION THROUGH THE SHARING MECHANISM. PLEASE EXPLAIN.

A. If a utility's proposed W&S is lower for an FTE category than would be expected by applying CPI to the Model's base year, Staff assumes the utility has legitimate reasons for its proposal. This concept is supported by NWN's testimony at NWN/800/Doolittle/6-7.

Q. YOU PROPOSE TO REDUCE THE LEVEL OF TEST YEAR FTE TO AN APPROPRIATE LEVEL. PLEASE SUMMARIZE THE ADJUSTMENT.

A. The adjustment begins with actual 2011 FTE. I then add the 13 FTE related to NWN's four-hour service window proposal. Finally, I remove 42.7 FTE that

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[4] See Staff Exhibit at 11.

need to be excluded from customer rates because they are associated with unregulated activities.

Q. WHY DID YOU DECIDE TO BEGIN CALCULATION OF YOUR ADJUSTMENT WITH ACTUAL 2011 FTE?

A. As illustrated on Staff Exhibit 501 at 12, I considered two approaches to determine an appropriate level of FTE for the test period. I calculated an average of the actual 2009 through 2011 FTE and compared the average to the actual 2011 FTE. As shown on Table 1, line 1, the average FTE is 1034.5, and the actual 2011 FTE is 1029.8, a difference of approximately 4.7 FTE, or less than one half of one percent. Ultimately, I believe the 2011 FTE level better reflects the Company's current operations, because: 1) implementation of its automatic meter reading program is complete; 2) the Company has outsourced meter installation work; and 3) 2011 is the most current actual information.

Q. IS THE ADDITION OF 13 FTE RELATED TO FOUR-HOUR SERVICE WINDOWS BE CONTINGENT ON NWN'S ACCEPTANCE OF A SERVICE GUARANTEE?

A. Yes, this recommendation is described by Staff witness Gorsuch.

Q. WHY DID YOU REDUCE THE 2011 FTE LEVEL BY 42.7?

A. In Staff Exhibit 501 at 13, I include an excerpt of the FTE Forecast provided by NWN. The highlighted lines show that the FTE I propose to exclude are related to non-utility, below-the-line, areas normally excluded from customer rates. From wholesale gas operations, I propose excluding the FTE in the

Business Development and Marketing Strategy FTE categories. From customer acquisitions, I recommend disallowing the FTE related to the Appliance Center, Service Solutions, Marketing, and Conversion, and 0.64 percent of the Director's position. Finally, I recommend disallowing FTE related to the administration of the Customer Choice Program.

Q. DOES THIS FTE ADJUSTMENT DOUBLE COUNT THE ADJUSTMENT YOU MADE IN THE STAFF MODEL RELATED TO ALLOCATIONS?

A. No. This adjustment removes FTE that NWN has inappropriately included in its rate case. (See Staff Exhibit 501 at 13.) The previous adjustment to Staff's three-year W&S Model removes a portion of test year expense that should not have been included in the first place because that expense is associated with Merchandise or non-utility operations, per NWN. See Staff Exhibit 501 at 11. These two adjustments will bring the FTE count and total W&S expense to the appropriate levels.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE AMOUNT OF TEST YEAR OVERTIME.

A. As shown in Staff Exhibit 501, at 4, the adjustment to test year overtime mirrors the approach in Staff's W&S Model.

Q. DO YOU PROPOSE ANY OTHER ADJUSTMENTS?

A. Yes. Finally, I propose to adjust the payroll taxes and depreciation expense to reflect the Staff adjustments described earlier in this testimony.

ISSUE 2, ------MISCELLANEOUS REVENUES – TAXES ADJUSTMENT

Q. PLEASE DESCRIBE THE NATURE OF NWN'S ADJUSTMENT.

A. NWN proposes to reduce revenues annually by $895,000. This adjustment allows NWN to collect approximately $4.8 million of expense (assuming a 5-year amortization) that it incurred between rate cases due to a 2009 change in the State of Oregon tax rate.

Q. DO YOU AGREE WITH NWN'S APPROACH?

A. No. Between rate cases, expenses normally fluctuate. I recommend the Commission deny NWN'S proposal to selectively collect past expenses from customers while retaining the benefit of reduced expenses in other categories. Absent a Commission-approved deferral under ORS 757.259, or some other specific Commission-approved balancing account, the collection from, or refund to, customers of these fluctuating expenses is not consistent with the Commission's deferred accounting policy.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: Deborah Garcia

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Exhibits in Support
Of Opening Testimony

May 3, 2012

Northwest Natural UG 221
Test Year Ending 10/31/2013
000's

Staff's adjustment is based on a series of adjustments in multiple accounts related to compensation. Wages & Salaries are adjusted using Staff's 3-year Wage and Salary model. The level of full time equivalent employees (FTE) is based on actual 2011 FTE that is adjusted as follows: FTE related to 4-hour service windows are added, and FTE related to below-the-line, non-utility and promotional non-advertising sales and marketing expense are removed. Overtime is adjusted based on the same principles used in Staff's 3-year Wage and Salary model. Finally, Payroll taxes and O&M depreciation expense are adjusted to reflect Staff's Labor adjustments.

Description/ Account No.	Company-Wide Company Filing	Staff	O&M Adjustment	Capital Adjustment	OR- Allocated O&M Adjustment	Capital Adjustment
Wages & Salaries	$ 81,097	$ 79,657	$ (1,008)	$ (432)	$ (904)	$ (387)
FTE Adjustment	* $ 79,657	$ 69,521	$ (7,095)	$ (3,041)	$ (6,364)	$ (2,728)
Overtime	$ 3,050	$ 3,047	$ (2)	$ (1)	$ (2)	$ (1)

*Company Filing Amount Reduced by Staff's previous adjustment to Wages & Salaries to avoid double counting.

	Oregon Only					
Total OR - Allocated Adjustments					**$ (7,270)**	**$ (3,116)**
Payroll Taxes associated w/ W&S and OT	$ 3,834	$3,307	$ (528)		**$ (528)**	
Depreciation O&M Adjustment Associated with Capital Adjustment					**$ (86)**	

Staff Initiator:
Deborah Garcia

Northwest Natural

Staff's 3-Year Wage and Salary Model

12 Months Ending 10/31/2010 to Proforma 10/31/2013

Explanation: Staff's proposal adjusts Northwest Natural's test period base wages and salaries (W&S) in accordance with guidelines followed in previous rate cases. Hence, Staff allows wages and salaries (excluding union wages) to increase based on published CPI projections, and then allows the Company to share 50/50 the lesser of the difference between the Company's & Staff's calculated projections, or a 10% band around Staff's calculated projection. Union wage and salary negotiations are considered to be conducted at "arms length" and as such are calculated differently. Using the information in Data Response M97, Staff calculated the union increase factor based on the actual/projected weighted average for each year as shown on pages 3-6 of this exhibit. Union wages are then subject to the same sharing mechanism applied to other wages and salaries.

Line No.	Source		Officers	Exempt	Non Exempt	Union	Total
1	Standard DR Response M95	Base Year W&S (12 months ending 10/31/2010)	$2,555,209	$30,602,705	$1,746,601	$33,251,289	$68,155,804
2	Standard DR Response M95	Average. # of FTE (12 months ending 10/31/2010)	10	366	31	604	1011
3	(1)/(2)	Average Salary	$255,956	$83,507	$56,470	$55,087	
4	Actual/Forecast CPI Index*	Allowable % Increase	1.063 [1]	1.063 [1]	1.063 [1]	1.34 [2]	
5	Standard DR Response M95	Ave. # of FTE (2013 Test Year)	10	449	29	643	1130
6	(3)*(4)*(5)	Projected W&S	$2,720,115	$39,828,774	$1,710,332	$47,339,040	$91,598,261
7	Standard DR Response M95	Test Year W&S (12 months ending 10/31/2013)	$2,777,472	$38,767,484	$1,699,422	$37,852,290	$81,096,668
8	(7)*(0.96% +0.82%) Merchandise + Other	Adjust NWN Test Year W&S[3]	($49,439)	($690,061)	($30,250)	($673,771)	($1,443,521)
9	(7)+(8)	Adjusted Test Year W&S	$2,728,033	$38,077,423	$1,669,172	$37,178,519	$79,653,147
10	(9)-(6)	Total Difference eligible for Sharing	$7,918	$0	$0	$0	$7,918
11	(9)*.10	10% Band - Allowable	$272,803	$0	$0	$0	$272,803
12	[(10) or (11)] *0.5	50% Sharing of Lesser of Difference or Band	$3,959	$0	$0	$0	$3,959
13	(6)+/-(10)	Staff Proposed Level	$2,731,992	$38,077,423	$1,669,172	$37,178,519	$79,657,106
14	(13)-(7)	Net W&S Adjustment	($45,480)	($690,061)	($30,250)	($673,771)	($1,439,562)
15		O&M Expense as % of W&S Exp[4]	70.00%	70.00%	70.00%	70.00%	70.00%
16	(14)*(15)	O&M Expense Adjustment - Systemwide	($31,836)	($483,043)	($21,175)	($471,640)	($1,007,693)
17		Oregon Allocation Factor[5]	0.897	0.897	0.897	0.897	0.897
18	(16)*(17)	O&M Expense Adjustment	($28,557)	($433,289)	($18,994)	($423,061)	($903,901)
19		Rate Base as % of W&S Exp[4]	30.00%	30.00%	30.00%	30.00%	30.00%
20	(14)*(19)	Rate Base Adjustment - Systemwide	($13,644)	($207,018)	($9,075)	($202,131)	($431,868)
21	(20)*(17)	Rate Base Adjustment - Oregon	($12,239)	($185,695)	($8,140)	($181,312)	($387,386)

[1]Source - OR Dept of Admin Srvcs, Office of Economic Analysis
Oregon Economic & Revenue Forecast December 2011, Volume XXXI, No. 4, Table A.1, page 69
Actual/Forecast All-Urban Consumer Price Index

2010	1.6%
2011	3.0%
2012	1.3%
2013	1.9%
	1.063

[2] Union Factor Source: Derived from DR M97 (see Staff Exhibit 501/7-10)

Union Increase	2011	1.67%
	2011	1.7%
	2012	3.25%
	2013	3.25%
		1.34

[4] Payroll allocation (See Staff Exhibit 501/11)

O&M	68.17%	Other*	0.82%
COH	4.04%	Clearing	1.65%
Merchandise	0.96%	Capital	24.37%

*Clearing is allocated between O&M and Rate Base on the same basis as direct allocations.

	Original Allocation	"Other" allocated	Total	Convert O&M & Rate Base to 100%
O&M	68.17%	70.58%	0.68749	70%
Rate Base	28.41%	29%	0.28651	30%
	96.58%		0.97400	100%

[5] Oregon Allocation Source is an average of Account 908 allocation factors found on NWN spreadsheet "OM for Rate Case_12_09_11.xlsx, Tab "State Allocations"

Staff Exhibit 501/2

Northwest Natural UG 221

Wage & Salary Adjustment Based on Staff's FTE Adjustment

Test Year Ending 10/31/2013

Explanation: Staff's proposal adjusts NWN's test year FTE of 1,130 to the actual 2011 level of 1,029. 13 FTE related to 4-hour service windows are added, and a reduction to the FTE categories Exempt, Non Exempt and Union is made to remove FTE related to non-utility, below-the-line, or promotional duties that were included in the base year, as well as the test year. (See Staff Exhibit 501/12 for the related calculations, and 501/13 for the details of the excluded FTE.

Line No.	Source		Officers	Exempt	Non Exempt	Union	Total
1	Standard DR Response M95	Test Year W&S	$2,777,472	$38,767,484	$1,699,422	$37,852,290	**$81,096,668**
2	PUC 3-year W&S Adj, line 14	Less Staff Adj to Test Year W&S[1]	$45,480	$690,061	$30,250	$673,771	**$1,439,562**
3	(1)-(2)	Adjusted W&S	$2,731,992	$38,077,423	$1,669,172	$37,178,519	**$79,657,106**
4	Standard DR Response M95	Average # of FTE Test Year	10	449	29	643	1,130
5	(3)/(5)	Adjusted Average Salary	273,199	84,843	58,567	57,847	
6	See Explanation above	Staff Proposed FTE	10	352	28 [2]	611	1000.2
7	(5)*(6)	Staff Proposed Test Year W&S	**$2,731,992**	**$29,822,224**	**$1,616,462**	**$35,350,542**	**$69,521,219**
8	(3)-(7)	**Net Payroll Adjustment**	**$0**	**($8,255,199)**	**($52,711)**	**($1,827,978)**	**($10,135,887)**
9	PUC 3-year W&S Adj, line 15	O&M Expense as % of Payroll Expense					70.00%
10	(8)*(9)	O&M Expense Adjustment - Systemwide					($7,095,121)
11	PUC 3-year W&S Adj, line 17	Oregon Allocation Factor					0.897
12	(10)*(11)	**O&M Adjustment - Oregon**					**($6,364,324)**
13	PUC 3-year W&S Adj, line 19	Capitalized Labor as % of Payroll Expense					30.00%
14	(8)*(13)	Rate Base Adjustment - Systemwide					($3,040,766)
15	(13)*(11)	**Rate Base Adjustment - Oregon**					**($2,727,567)**

Northwest Natural UG 221

Calculation of Staff's 3-Year Overtime Formula

Annualized 12 months ending 10/31/2010 to Proforma 10/31/2013

Explanation: Staff's proposal adjusts NWN's adjusted test period overtime in accordance with guidelines followed in previous rate cases. Hence, Staff allows overtime to increase based on published actual/projected CPI , or actual/projected weighted average Union increases, and then allows the Company to share 50/50 the lesser of the eligible difference between the Company's & Staff's calculated projections, or a 10% band around Staff's calculated projection. Staff also modified the 3-year Overtime Model to remove Overtime related to nonutility and below-the-line allocations as done in Staff's 3-year W&S Model (See Staff Exhibit 501/2.)

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Line No.	Source		Officers	Exempt	Non Exempt	Union	Total
1	Standard DR Response M95	Base Period Overtime (12 months ending 10/31/2010)	$0	$0	$18,443	$3,347,038	$3,365,480
2	Standard DR Response M95	Base Period # of FTE (12 months ending 10/31/2010)	10	366	31	604	
3	(1)/(2)	Average Overtime per FTE	$0	$0	$596	$5,545	
4	PUC 3-year W&S Adj, line 4	Allowable % Increase	0	0	1.063	1.337	
5	Standard DR Response M95	Staff Proposed FTE for Test Period	10	352	29	611	
6	(3)*(4)*(5)	Projected Overtime	$0	$0	$18,061	$4,530,794	$4,548,854
7	Standard DR Response M95	Test Period Overtime	$0	$0	$21,452	$3,028,183	$3,049,635
8	(7)*(0.96% +0.82%) Merchandise + Other	Test Period Overtime Adjustment[1]	$0	$0	$382	$53,902	
9	(7)-(8)	Adjusted Test Period Overtime	$0	$0	$21,070	$2,974,281	
10	(9)-(6)	Total Difference	$0	$0	$3,010	$0	$3,010
11	(9)*.10	10% Band - Allowable	$0	$0	$1,806	$0	$1,806
12	[(10) or (11)] *0.5	50% Sharing of Lesser of Difference or Band	$0	$0	$903	$0	$903
13	(6)+/-(10)	Staff Proposed Level	$0	$0	$18,964	$3,028,183	$3,047,147
14	(11)-(7)	Net Payroll Adjustment	$0	$0	($2,488)	$0	($2,488)
15		O&M Expense as % of Payroll Exp	70.00%	70.00%	70.00%	70.00%	70.00%
16	(12)*(13)	O&M Expense Adjustment - Systemwide	$0	$0	($1,742)	$0	($1,742)
17		Oregon Allocation Factor	0.897	0.897	0.897	0.897	0.897
18	(14)*(15)	**O&M Expense Adjustment**	$0	$0	($1,562)	$0	($1,562)
19		Rate Base as % of Payroll Exp	30.00%	30.00%	30.00%	30.00%	30.00%
20	(14)*(19)	Rate Base Adjustment - Systemwide	$0	$0	($747)	$0	($747)
21	(20)*(17)	**Rate Base Adjustment - Oregon**	$0	$0	($670)	$0	($670)

Northwest Natural UG 221
Payroll Taxes
Test Year Ending October 31, 2013

		Company-Wide	OR-Alloc*
UG 221 Test Period Total Compensation (NWN/800/Doolittle/3)		$112,306,000	$ 100,738,482.00
UG 221 Payroll Taxes per NWN/308/McVay-Siores/1			$ 5,117,689
Calculated Payroll Taxes Factor			5.080%
UG 221 Test Period Wages & Salaries, and Overtime		$84,146,303	$75,479,234
Staff Proposed W&S and Overtime		$72,568,366	$65,093,824
Difference	(4)-(5)	$11,577,937	$10,385,410
Payroll Taxes factor from above			5.080%
Payroll Taxes associated with Staff's Adjustment	(6)*(7)		$ 527,597
NW Natural UG 221 Payroll Taxes associated with W&S and Overtime	(4)*(7)		$ 3,834,476
Staff Adjusted Payroll Taxes	(5)*(7)		$ 3,306,879
Payroll Tax Adjustment	(10)-(9)		**$ (527,597)**

* OR Allocation factor from S-16.1 PUC 3-year W&S, line 17

UG 221 NWN Adjustment Summary - Oregon Basis

	W&S		FTE		Overtime		**Total**		**Check**	
	Co-wide	OR-Alloc	Co-wide	OR-Alloc	Co-wide	OR-Alloc	Co-wide	OR-Alloc	Co-wide	OR-Alloc
O&M	($1,007,693)	(903,901)	(7,095,121)	($6,364,324)	($1,742)	($1,562)	($8,104,556)	($7,269,787)	($8,105)	($7,270)
Rate Base	($431,868)	(387,386)	(3,040,766)	($2,727,567)	($747)	($670)	($3,473,381)	($3,115,623)	($3,473)	($3,116)
							($11,577,937)	**($10,385,410)**	**($11,578)**	**($10,385)**

O&M Depreciation associated with Capital Adjustments $ (84,069)

* Gross Plant	$	2,227,108
* **Annual Test Year Depreci	$	60,094
% Avg. Depreciation to RB		2.6983%

* See NWN/310/McVay-Siores/1
**See NWN/309/McVay-Siores/1

Excerpt From EXHIBIT M97

UNION SALARY INFORMATION (2009-2013)

Union	Grade	Position	Year Ending 12/31/2010 FTE*	Entry Wage	% Diff.	FTE*	Exp Wage	% Diff
OPEIU	47	Accounting 2	1	$18.84	1.67%	9	$19.82	1.64%
OPEIU	47	Administration Coordination 2	1	$18.84	1.67%	13	$19.82	1.64%
OPEIU	47	Utility Support 3	0	$18.84	1.67%	13	$19.82	1.64%
OPEIU	41	Utility Support 1	N/A	N/A	N/A	12	$26.00	1.64%
OPEIU	59	Automotive 3	0	$13.52	1.65%	1	$14.23	1.64%
OPEIU	59	Compliance 1	1	$29.64	1.65%	7	$30.24	1.65%
OPEIU	59	Construction 3	1	$29.64	1.65%	4	$30.24	1.65%
OPEIU	59	Customer Field Service 3	0	$29.64	1.65%	5	$30.24	1.65%
OPEIU	59	Field Support 3	0	$29.64	1.65%	16	$30.24	1.65%
OPEIU	59	General Services 4	2	$21.00	1.65%	1	$22.11	1.66%
OPEIU	59	Specialty Construction 2	11	$21.00	1.65%	23	$22.11	1.66%
OPEIU	63	Construction 4	0	$21.00	1.65%	0	$22.11	1.66%
OPEIU	63	Field Support 4	N/A	N/A	N/A	15	$25.16	1.66%
OPEIU	63	Technical Services 2	N/A	N/A	N/A	0	$25.16	1.66%
OPEIU	63	Technical Services 2/Gas Storage 1	N/A	N/A	N/A	0	$25.16	1.66%
OPEIU	63	Transmission Line 2	0	$16.91	1.68%	6	$17.79	1.66%
OPEIU	49	Computer Support 1	0	$16.91	1.68%	1	$17.79	1.66%
OPEIU	49	Customer Service 2	3	$22.70	1.66%	6	$23.89	1.66%
OPEIU	49	Graphics 1	1	$22.70	1.66%	28	$23.89	1.66%
OPEIU	45	Administration Coordination 1	0	$22.70	1.66%	0	$23.89	1.66%
OPEIU	45	General Services 1	0	$22.70	1.66%	2	$23.89	1.66%
OPEIU	57	Automotive 2	10	$22.70	1.66%	46	$23.89	1.66%
OPEIU	57	Customer Field Service 2	0	$22.70	1.66%	1	$23.89	1.66%
OPEIU	57	Field Support 2	1	$15.70	1.68%	3	$16.52	1.66%
OPEIU	57	Gas Storage 1	0	$15.70	1.68%	1	$16.52	1.66%
OPEIU	57	General Services 3	0	$15.70	1.68%	3	$16.52	1.66%
OPEIU	57	Stores 3	0	$15.70	1.68%	3	$16.52	1.66%
OPEIU	57	System Ops 1	0	$28.65	1.67%	1	$29.23	1.67%
OPEIU	57	Technical Services 1	0	$28.65	1.67%	9	$29.23	1.67%
OPEIU	57	Transmission Line 1	1	$28.65	1.67%	45	$29.23	1.67%
OPEIU	51	Accounting 3	3	$28.65	1.67%	10	$29.23	1.67%
OPEIU	51	Administration Coordination 3	0	$28.65	1.67%	11	$29.23	1.67%
OPEIU	51	Computer Support 2	0	$28.65	1.67%	1	$29.23	1.67%
OPEIU	51	Customer Field Service 1 Honored	2	$28.65	1.67%	2	$29.23	1.67%
OPEIU	51	Customer Service 3	2	$30.39	1.67%	3	$31.01	1.67%
OPEIU	51	Transportation 2	1	$30.39	1.67%	8	$31.01	1.67%
OPEIU	43	Customer Service 1	0	$30.39	1.67%	12	$31.01	1.67%
OPEIU	43	Stores 1	0	$30.39	1.67%	0	$31.01	1.67%
OPEIU	43	Transportation 1	0	$30.39	1.67%	3	$31.01	1.67%
OPEIU	43	Utility Support 2	0	$27.40	1.67%	7	$27.96	1.67%
OPEIU	55	Construction 2	1	$27.40	1.67%	53	$27.96	1.67%
OPEIU	55	Customer Service 4	0	$27.40	1.67%	10	$27.96	1.67%
OPEIU	55	Field Support 1	0	$27.40	1.67%	7	$27.96	1.67%
OPEIU	55	General Services 2	0	$27.40	1.67%	1	$27.96	1.67%
OPEIU	55	Graphics 3	0	$27.40	1.67%	1	$27.96	1.67%
OPEIU	55	Meter Shop 2	1	$27.40	1.67%	6	$27.96	1.67%
OPEIU	55	Specialty Construction 1	0	$27.40	1.67%	2	$27.96	1.67%
OPEIU	61	Compliance 2	0	$27.40	1.67%	3	$27.96	1.67%
OPEIU	61	Customer Field Service 4	N/A	N/A	N/A	2	$27.96	1.67%
OPEIU	61	Gas Storage 2	1	$26.16	1.67%	51	$26.69	1.68%
OPEIU	61	System Ops 2	0	$26.16	1.67%	2	$26.69	1.68%
OPEIU	53	Accounting 4	1	$26.16	1.67%	17	$26.69	1.68%
OPEIU	53	Construction 1	0	$26.16	1.67%	4	$26.69	1.68%
OPEIU	53	Construction 1 Honored	0	$26.16	1.67%	8	$26.69	1.68%
OPEIU	53	Graphics 2	0	$26.16	1.67%	2	$26.69	1.68%
OPEIU	53	Meter Shop 1	0	$26.16	1.67%	0	$26.69	1.68%
OPEIU	53	Stores 2	0	$24.91	1.67%	5	$25.42	1.68%
OPEIU	53	Transportation 3	1	$24.91	1.67%	29	$25.42	1.68%
OPEIU	76	Gas Storage 1 - In Training 2	0	$24.91	1.67%	7	$25.42	1.68%
OPEIU	75	CFS 2 - In Training 2	1	$24.91	1.67%	0	$25.42	1.68%
OPEIU	74	CFS 2 - In Training 1	0	$24.91	1.67%	2	$25.42	1.68%
OPEIU	74	CFS In Training/Construction 1	0	$24.91	1.67%	13	$25.42	1.68%
OPEIU	74	Gas Storage 1 - In Training 1	0	$24.91	1.67%	1	$25.42	1.68%
OPEIU	47	Project Meter Reader	N/A	N/A	N/A	N/A	N/A	N/A
			47			557		

2010 Weighted Annual Average Increase

Entry # of Entry FTE	% of Entry FTE	% Inc.	Weighted Increase	Experienced # of Exp. FTE	% of Exp. FTE	% Inc.	Weighted Increase
15	31.9149%	1.65%	0.5266%	48	8.6176%	1.64%	0.1413%
14	29.7872%	1.66%	0.4945%	32	5.7451%	1.65%	0.0948%
17	36.1702%	1.67%	0.6040%	139	24.9551%	1.66%	0.4143%
1	2.1277%	1.68%	0.0357%	197	35.3680%	1.67%	0.5906%
				141	25.3142%	1.68%	0.4253%
47	100%		1.6609%	557	100%		1.6663%

	# of FTE	% of total FTE	Average Wtd Increase	Average Annual Increase	
Entry	47	7.7815%	1.6609%	0.1292%	
Exp.	557	92.2185%	1.6663%	1.5366%	
Totals	604	100%		1.6659%	2010 Avg Annual Increase

Staff Exhibit 501/7

Excerpt From EXHIBIT M97

UNION SALARY INFORMATION (2009-2013)

Union	Grade	Position	Year Ending 12/31/2011 FTE*	Entry Wage	% Diff	FTE*	Exp Wage	% Diff
OPEIU	47	Accounting 2	0	$19.16	1.70%	9	$20.16	1.72%
OPEIU	47	Administration Coordination 2	0	$19.16	1.70%	10	$20.16	1.72%
OPEIU	47	Utility Support 3	0	$19.16	1.70%	13.7	$20.16	1.72%
OPEIU	41	Utility Support 1	0	$13.75	1.70%	0.5	$14.47	1.69%
OPEIU	59	Automotive 3	0	$29.14	1.71%	1	$29.73	1.71%
OPEIU	59	Compliance 1	0	$29.14	1.71%	9	$29.73	1.71%
OPEIU	59	Construction 3	2	$29.14	1.71%	48	$29.73	1.71%
OPEIU	59	Customer Field Service 3	0	$29.14	1.71%	13	$29.73	1.71%
OPEIU	59	Field Support 3	0	$29.14	1.71%	11	$29.73	1.71%
OPEIU	59	General Services 4	0	$29.14	1.71%	1	$29.73	1.71%
OPEIU	59	Specialty Construction 2	0	$29.14	1.71%	6	$29.73	1.71%
OPEIU	63	Construction 4	0	$30.91	1.71%	5	$31.54	1.71%
OPEIU	63	Field Support 4	2	$30.91	1.71%	8	$31.54	1.71%
OPEIU	63	Technical Services 2	2	$30.91	1.71%	8	$31.54	1.71%
OPEIU	63	Technical Services 2/Gas Storage 1	0	$30.91	1.71%	4	$31.54	1.71%
OPEIU	63	Transmission Line 2	0	$30.91	1.71%	3	$31.54	1.71%
OPEIU	49	Computer Support 1	0	$21.36	1.71%	3	$22.49	1.72%
OPEIU	49	Customer Service 2	10.5	$21.36	1.71%	40.5	$22.49	1.72%
OPEIU	49	Graphics 1	0	$21.36	1.71%	0	$22.49	1.72%
OPEIU	45	Administration Coordination 1	0	$17.20	1.71%	5	$18.10	1.74%
OPEIU	45	General Services 1	0	$17.20	1.71%	1	$18.10	1.74%
OPEIU	57	Automotive 2	0	$27.87	1.72%	7	$28.44	1.72%
OPEIU	57	Customer Field Service 2	1	$27.87	1.72%	59	$28.44	1.72%
OPEIU	57	Field Support 2	0	$27.87	1.72%	11	$28.44	1.72%
OPEIU	57	Gas Storage 1	0	$27.87	1.72%	6	$28.44	1.72%
OPEIU	57	General Services 3	0	$27.87	1.72%	1	$28.44	1.72%
OPEIU	57	Stores 3	0	$27.87	1.72%	1	$28.44	1.72%
OPEIU	57	System Ops 1	0	$27.87	1.72%	6	$28.44	1.72%
OPEIU	57	Technical Services 1	0	$27.87	1.72%	2	$28.44	1.72%
OPEIU	57	Transmission Line 1	0	$27.87	1.72%	3	$28.44	1.72%
OPEIU	51	Accounting 3	0	$23.09	1.72%	9	$24.30	1.72%
OPEIU	51	Administration Coordination 3	0	$23.09	1.72%	26.5	$24.30	1.72%
OPEIU	51	Computer Support 2	0	$23.09	1.72%	0	$24.30	1.72%
OPEIU	51	Customer Field Service 1 Honored	0	$23.09	1.72%	2	$24.30	1.72%
OPEIU	51	Customer Service 3	0	$23.09	1.72%	54.5	$24.30	1.72%
OPEIU	51	Transportation 2	0	$23.09	1.72%	2	$24.30	1.72%
OPEIU	43	Customer Service 1	0	$15.97	1.72%	2.5	$16.80	1.69%
OPEIU	43	Stores 1	0	$15.97	1.72%	0.5	$16.80	1.69%
OPEIU	43	Transportation 1	0	$15.97	1.72%	3	$16.80	1.69%
OPEIU	43	Utility Support 2	0	$15.97	1.72%	3	$16.80	1.69%
OPEIU	55	Construction 2	0	$26.61	1.72%	51	$27.15	1.72%
OPEIU	55	Customer Service 4	0	$26.61	1.72%	2	$27.15	1.72%
OPEIU	55	Field Support 1	0	$26.61	1.72%	18	$27.15	1.72%
OPEIU	55	General Services 2	0	$26.61	1.72%	4	$27.15	1.72%
OPEIU	55	Graphics 3	0	$26.61	1.72%	9	$27.15	1.72%
OPEIU	55	Meter Shop 2	0	$26.61	1.72%	2	$27.15	1.72%
OPEIU	55	Specialty Construction 1	0	$26.61	1.72%	0	$27.15	1.72%
OPEIU	61	Compliance 2	0	$30.15	1.72%	8	$30.76	1.72%
OPEIU	61	Customer Field Service 4	0	$30.15	1.72%	5	$30.76	1.72%
OPEIU	61	Gas Storage 2	0	$30.15	1.72%	6	$30.76	1.72%
OPEIU	61	System Ops 2	1	$30.15	1.72%	16	$30.76	1.72%
OPEIU	53	Accounting 4	0	$25.34	1.73%	5	$25.86	1.73%
OPEIU	53	Construction 1	0	$25.34	1.73%	25	$25.86	1.73%
OPEIU	53	Construction 1 Honored	0	$25.34	1.73%	7	$25.86	1.73%
OPEIU	53	Graphics 2	0	$25.34	1.73%	0	$25.86	1.73%
OPEIU	53	Meter Shop 1	0	$25.34	1.73%	2	$25.86	1.73%
OPEIU	53	Stores 2	0	$25.34	1.73%	13.5	$25.86	1.73%
OPEIU	53	Transportation 3	0	$25.34	1.73%	1	$25.86	1.73%
OPEIU	76	Gas Storage 1 - In Training 2	N/A	N/A	N/A	1	$28.44	1.72%
OPEIU	75	CFS 2 - In Training 2	N/A	N/A	N/A	11	$26.45	1.73%
OPEIU	74	CFS 2 - In Training 1	N/A	N/A	N/A	2	$25.60	1.75%
OPEIU	74	CFS In Training/Construction 1	N/A	N/A	N/A	4	$25.60	1.75%
OPEIU	74	Gas Storage 1 - In Training 1	N/A	N/A	N/A	2	$25.60	1.75%
OPEIU	47	Project Meter Reader	N/A	N/A	N/A	N/A	N/A	N/A
			18.5				611.7	

2011 Weighted Annual Average Increase

Entry # of Entry FTE	% of Entry FTE	% Inc.	Weighted Increase	Experienced # of Exp. FTE	% of Exp. FTE	% Inc.	Weighted Increase
16.5	89.1892%	1.71%	1.5251%	9.5	1.6015%	1.69%	0.0271%
2	10.8108%	1.72%	0.1859%	117	19.7235%	1.71%	0.3373%
				388.2	65.4417%	1.72%	1.1256%
				64.5	10.8732%	1.73%	0.1881%
				6	1.0115%	1.74%	0.0176%
				8	1.3486%	1.75%	0.0236%
18.5	100%		1.7111%	593.2	100%		1.7192%

	# of FTE	% of total FTE	Average Wtd Increase	Average Annual Increase	
Entry	18.5	3.0244%	1.7111%	0.0517%	
Exp.	593.2	96.9756%	1.7192%	1.6672%	
Totals	611.7	100%		1.7190%	2011 Avg Annual Increase

*Excludes FTE created by overtime hours.

**A new contract and a job structure change occurred in 2009 with many positions modified, added, or eliminated. This prevents a one-to-one comparison with rates from the prior year; however, the average overall increase from

***The contract guarantees a 1% annual increase through June 1, 2013, plus the results of the wage adjuster. The wage adjuster may not be less than 0% or more than 2%.

Note 1: Incumbents may be paid at rates that differ from the contractually mandated rate for the position that they hold. In our line of progression families, incumbents may "work up" and be "rate retained" at a higher level and

Note 2: Two distinct wage rates exist for each grade: Entry, which represents the initial rate of pay for incoming incumbents into that classification; and, Experienced, which is the rate of pay for that grade after the required days on

Exerpt From EXHIBIT M97

UNION SALARY INFORMATION (2009-2013)

			Year Ending 12/31/2012					
Union	Grade	Position	FTE*	Entry Wage	% Diff	FTE*	Exp Wage	% Diff
OPEIU	57	Automotive 2	0	$ 28.78	3.27%	7	$ 29.36	3.23%
OPEIU	57	Customer Field Service 2	30	$ 28.78	3.27%	60	$ 29.36	3.23%
OPEIU	57	Field Support 2	0	$ 28.78	3.27%	11	$ 29.36	3.23%
OPEIU	57	Gas Storage 1	0	$ 28.78	3.27%	6	$ 29.36	3.23%
OPEIU	57	General Services 3	0	$ 28.78	3.27%	1	$ 29.36	3.23%
OPEIU	57	Stores 3	0	$ 28.78	3.27%	1	$ 29.36	3.23%
OPEIU	57	System Ops 1	0	$ 28.78	3.27%	6	$ 29.36	3.23%
OPEIU	57	Technical Services 1	0	$ 28.78	3.27%	2	$ 29.36	3.23%
OPEIU	57	Transmission Line 1	0	$ 28.78	3.27%	3	$ 29.36	3.23%
OPEIU	76	Gas Storage 1 - In Training 2	N/A	N/A	N/A	1	$ 29.36	3.23%
OPEIU	55	Construction 2	0	$ 27.47	3.23%	51	$ 28.03	3.24%
OPEIU	55	Customer Service 4	0	$ 27.47	3.23%	2	$ 28.03	3.24%
OPEIU	55	Field Support 1	0	$ 27.47	3.23%	18	$ 28.03	3.24%
OPEIU	55	General Services 2	0	$ 27.47	3.23%	4	$ 28.03	3.24%
OPEIU	55	Graphics 3	0	$ 27.47	3.23%	9	$ 28.03	3.24%
OPEIU	55	Meter Shop 2	0	$ 27.47	3.23%	2	$ 28.03	3.24%
OPEIU	55	Specialty Construction 1	0	$ 27.47	3.23%	0	$ 28.03	3.24%
OPEIU	74	CFS 2 - In Training 1	N/A	N/A	N/A	2	$ 26.43	3.24%
OPEIU	74	CFS In Training/Construction 1	N/A	N/A	N/A	4	$ 26.43	3.24%
OPEIU	74	Gas Storage 1 - In Training 1	N/A	N/A	N/A	2	$ 26.43	3.24%
OPEIU	49	Computer Support 1	0	$ 22.05	3.23%	3	$ 23.22	3.25%
OPEIU	49	Customer Service 2	0	$ 22.05	3.23%	51	$ 23.22	3.25%
OPEIU	49	Graphics 1	0	$ 22.05	3.23%	0	$ 23.22	3.25%
OPEIU	41	Utility Support 1	0	$ 14.20	3.27%	0.5	$ 14.94	3.25%
OPEIU	53	Accounting 4	0	$ 26.16	3.24%	5	$ 26.70	3.25%
OPEIU	53	Construction 1	0	$ 26.16	3.24%	25	$ 26.70	3.25%
OPEIU	53	Construction 1 Honored	0	$ 26.16	3.24%	7	$ 26.70	3.25%
OPEIU	53	Graphics 2	0	$ 26.16	3.24%	0	$ 26.70	3.25%
OPEIU	53	Meter Shop 1	0	$ 26.16	3.24%	2	$ 26.70	3.25%
OPEIU	53	Stores 2	0	$ 26.16	3.24%	13.5	$ 26.70	3.25%
OPEIU	53	Transportation 3	0	$ 26.16	3.24%	1	$ 26.70	3.25%
OPEIU	61	Compliance 2	0	$ 31.13	3.25%	8	$ 31.76	3.25%
OPEIU	61	Customer Field Service 4	0	$ 31.13	3.25%	5	$ 31.76	3.25%
OPEIU	61	Gas Storage 2	0	$ 31.13	3.25%	6	$ 31.76	3.25%
OPEIU	61	System Ops 2	0	$ 31.13	3.25%	17	$ 31.76	3.25%
OPEIU	51	Accounting 3	0	$ 23.84	3.25%	9	$ 25.09	3.25%
OPEIU	51	Administration Coordination 3	0	$ 23.84	3.25%	26.5	$ 25.09	3.25%
OPEIU	51	Computer Support 2	0	$ 23.84	3.25%	0	$ 25.09	3.25%
OPEIU	51	Customer Field Service 1 Honored	0	$ 23.84	3.25%	2	$ 25.09	3.25%
OPEIU	51	Customer Service 3	0	$ 23.84	3.25%	54.5	$ 25.09	3.25%
OPEIU	51	Transportation 2	0	$ 23.84	3.25%	2	$ 25.09	3.25%
OPEIU	75	CFS 2 - In Training 2	N/A	N/A	N/A	11	$ 27.31	3.25%
OPEIU	45	Administration Coordination 1	0	$ 17.76	3.26%	5	$ 18.69	3.26%
OPEIU	45	General Services 1	0	$ 17.76	3.26%	1	$ 18.69	3.26%
OPEIU	59	Automotive 3	0	$ 30.09	3.26%	1	$ 30.70	3.26%
OPEIU	59	Compliance 1	0	$ 30.09	3.26%	9	$ 30.70	3.26%
OPEIU	59	Construction 3	0	$ 30.09	3.26%	50	$ 30.70	3.26%
OPEIU	59	Customer Field Service 3	0	$ 30.09	3.26%	13	$ 30.70	3.26%
OPEIU	59	Field Support 3	0	$ 30.09	3.26%	11	$ 30.70	3.26%
OPEIU	59	General Services 4	0	$ 30.09	3.26%	1	$ 30.70	3.26%
OPEIU	59	Specialty Construction 2	0	$ 30.09	3.26%	6	$ 30.70	3.26%
OPEIU	63	Construction 4	0	$ 31.91	3.24%	5	$ 32.57	3.27%
OPEIU	63	Field Support 4	0	$ 31.91	3.24%	10	$ 32.57	3.27%
OPEIU	63	Technical Services 2	0	$ 31.91	3.24%	10	$ 32.57	3.27%
OPEIU	63	Technical Services 2/Gas Storage 1	0	$ 31.91	3.24%	4	$ 32.57	3.27%
OPEIU	63	Transmission Line 2	0	$ 31.91	3.24%	3	$ 32.57	3.27%
OPEIU	47	Accounting 2	0	$ 19.78	3.24%	9	$ 20.82	3.27%
OPEIU	47	Administration Coordination 2	0	$ 19.78	3.24%	10	$ 20.82	3.27%
OPEIU	47	Utility Support 3	0	$ 19.78	3.24%	13.7	$ 20.82	3.27%
OPEIU	43	Customer Service 1	0	$ 16.49	3.26%	2.5	$ 17.35	3.27%
OPEIU	43	Stores 1	0	$ 16.49	3.26%	0.5	$ 17.35	3.27%
OPEIU	43	Transportation 1	1	$ 16.49	3.26%	3	$ 17.35	3.27%
OPEIU	43	Utility Support 2	0	$ 16.49	3.26%	3	$ 17.35	3.27%
OPEIU	47	Project Meter Reader	N/A	N/A	N/A	N/A	N/A	N/A
			30			589		619

*Excludes FTE created by overtime hours.

**A new contract and a job structure change occurred in 2009 with many positions modified, added, or eliminated. This prevents a one-to-one comparison with rates from the prior year; however, the average overall increase from 2008 to 2009 was approximately 2.5%.

***The contract guarantees a 1% annual increase through June 1, 2013, plus the results of the wage adjuster. The wage adjuster may not be less than 0% or more than 2%.

Note 1: Incumbents may be paid at rates that differ from the contractually mandated rate for the position that they hold. In our line of progression families, incumbents may "work up" and be "rate retained" at a higher level and therefore receive a higher rate when performing the higher-level work.

Note 2: Two distinct wage rates exist for each grade: Entry, which represents the initial rate of pay for incoming incumbents into that classification; and, Experienced, which is the rate of pay for that grade after the required days on the job and a satisfactory performance evaluation have been obtained.

2012 Weighted Annual Average Increase

Entry				Experienced			
# of Entry FTE	% of Entry FTE	% Inc.	Weighted Increase	# of Exp. FTE	% of Exp. FTE	% Inc.	Weighted Increase
1	3.2258%	3.26%	0.1052%	98	16.0209%	3.23%	0.5175%
30	96.7742%	3.27%	3.1645%	94	15.3670%	3.24%	0.4979%
				249	40.7062%	3.25%	1.3230%
				97	15.8574%	3.26%	0.5170%
				73.7	12.0484%	3.27%	0.3940%
31	100%		3.2697%	611.7	100%		3.2493%

	# of FTE	% of total FTE	Average Wtd Increase	Average Annual Increase	
Entry	31	4.8234%	3.2697%	0.1577%	
Exp.	611.7	95.1766%	3.2493%	3.0925%	
Totals	642.7	100%		3.2502%	2012 Avg Annual Increase

Staff Exhibit 501/9

Exerpt From EXHIBIT M97

UNION SALARY INFORMATION (2009-2013)

Year Ending 10/31/2013								
Union	Grade	Position	FTE*	Entry Wage	% Diff	FTE*	Exp Wage	% Diff
OPEIU	43	Customer Service 1	0	$ 17.03	3.27%	2.5	$ 17.91	3.23%
OPEIU	43	Stores 1	0	$ 17.03	3.27%	0.5	$ 17.91	3.23%
OPEIU	43	Transportation 1	0	$ 17.03	3.27%	4	$ 17.91	3.23%
OPEIU	43	Utility Support 2	0	$ 17.03	3.27%	3	$ 17.91	3.23%
OPEIU	49	Computer Support 1	0	$ 22.77	3.27%	3	$ 23.97	3.23%
OPEIU	49	Customer Service 2	0	$ 22.77	3.27%	51	$ 23.97	3.23%
OPEIU	49	Graphics 1	0	$ 22.77	3.27%	0	$ 23.97	3.23%
OPEIU	57	Automotive 2	0	$ 29.72	3.27%	7	$ 30.31	3.24%
OPEIU	57	Customer Field Service 2	0	$ 29.72	3.27%	90	$ 30.31	3.24%
OPEIU	57	Field Support 2	0	$ 29.72	3.27%	11	$ 30.31	3.24%
OPEIU	57	Gas Storage 1	0	$ 29.72	3.27%	6	$ 30.31	3.24%
OPEIU	57	General Services 3	0	$ 29.72	3.27%	1	$ 30.31	3.24%
OPEIU	57	Stores 3	0	$ 29.72	3.27%	1	$ 30.31	3.24%
OPEIU	57	System Ops 1	0	$ 29.72	3.27%	6	$ 30.31	3.24%
OPEIU	57	Technical Services 1	0	$ 29.72	3.27%	2	$ 30.31	3.24%
OPEIU	57	Transmission Line 1	0	$ 29.72	3.27%	3	$ 30.31	3.24%
OPEIU	76	Gas Storage 1 - In Training 2	N/A	N/A	N/A	1	$ 30.31	3.24%
OPEIU	61	Compliance 2	0	$ 32.14	3.24%	8	$ 32.79	3.24%
OPEIU	61	Customer Field Service 4	0	$ 32.14	3.24%	5	$ 32.79	3.24%
OPEIU	61	Gas Storage 2	0	$ 32.14	3.24%	6	$ 32.79	3.24%
OPEIU	61	System Ops 2	0	$ 32.14	3.24%	17	$ 32.79	3.24%
OPEIU	55	Construction 2	0	$ 28.36	3.24%	51	$ 28.94	3.25%
OPEIU	55	Customer Service 4	0	$ 28.36	3.24%	2	$ 28.94	3.25%
OPEIU	55	Field Support 1	0	$ 28.36	3.24%	18	$ 28.94	3.25%
OPEIU	55	General Services 2	0	$ 28.36	3.24%	4	$ 28.94	3.25%
OPEIU	55	Graphics 3	0	$ 28.36	3.24%	9	$ 28.94	3.25%
OPEIU	55	Meter Shop 2	0	$ 28.36	3.24%	2	$ 28.94	3.25%
OPEIU	55	Specialty Construction 1	0	$ 28.36	3.24%	0	$ 28.94	3.25%
OPEIU	74	CFS 2 - In Training 1	N/A	N/A	N/A	2	$ 27.29	3.25%
OPEIU	74	CFS In Training/Construction 1	N/A	N/A	N/A	4	$ 27.29	3.25%
OPEIU	74	Gas Storage 1 - In Training 1	N/A	N/A	N/A	2	$ 27.29	3.25%
OPEIU	63	Construction 4	0	$ 32.95	3.26%	5	$ 33.63	3.25%
OPEIU	63	Field Support 4	0	$ 32.95	3.26%	10	$ 33.63	3.25%
OPEIU	63	Technical Services 2	0	$ 32.95	3.26%	10	$ 33.63	3.25%
OPEIU	63	Technical Services 2/Gas Storage 1	0	$ 32.95	3.26%	4	$ 33.63	3.25%
OPEIU	63	Transmission Line 2	0	$ 32.95	3.26%	3	$ 33.63	3.25%
OPEIU	59	Automotive 3	0	$ 31.07	3.26%	1	$ 31.70	3.26%
OPEIU	59	Compliance 1	0	$ 31.07	3.26%	9	$ 31.70	3.26%
OPEIU	59	Construction 3	0	$ 31.07	3.26%	50	$ 31.70	3.26%
OPEIU	59	Customer Field Service 3	0	$ 31.07	3.26%	13	$ 31.70	3.26%
OPEIU	59	Field Support 3	0	$ 31.07	3.26%	11	$ 31.70	3.26%
OPEIU	59	General Services 4	0	$ 31.07	3.26%	1	$ 31.70	3.26%
OPEIU	59	Specialty Construction 2	0	$ 31.07	3.26%	6	$ 31.70	3.26%
OPEIU	53	Accounting 4	0	$ 27.01	3.25%	5	$ 27.57	3.26%
OPEIU	53	Construction 1	0	$ 27.01	3.25%	25	$ 27.57	3.26%
OPEIU	53	Construction 1 Honored	0	$ 27.01	3.25%	7	$ 27.57	3.26%
OPEIU	53	Graphics 2	0	$ 27.01	3.25%	0	$ 27.57	3.26%
OPEIU	53	Meter Shop 1	0	$ 27.01	3.25%	2	$ 27.57	3.26%
OPEIU	53	Stores 2	0	$ 27.01	3.25%	13.5	$ 27.57	3.26%
OPEIU	53	Transportation 3	0	$ 27.01	3.25%	1	$ 27.57	3.26%
OPEIU	75	CFS 2 - In Training 2	N/A	N/A	N/A	11	$ 28.20	3.26%
OPEIU	45	Administration Coordination 1	0	$ 18.34	3.27%	5	$ 19.30	3.26%
OPEIU	45	General Services 1	0	$ 18.34	3.27%	1	$ 19.30	3.26%
OPEIU	47	Accounting 2	0	$ 20.42	3.24%	9	$ 21.50	3.27%
OPEIU	47	Administration Coordination 2	0	$ 20.42	3.24%	10	$ 21.50	3.27%
OPEIU	47	Utility Support 3	0	$ 20.42	3.24%	13.7	$ 21.50	3.27%
OPEIU	51	Accounting 3	0	$ 24.61	3.23%	9	$ 25.91	3.27%
OPEIU	51	Administration Coordination 3	0	$ 24.61	3.23%	26.5	$ 25.91	3.27%
OPEIU	51	Computer Support 2	0	$ 24.61	3.23%	0	$ 25.91	3.27%
OPEIU	51	Customer Field Service 1 Honored	0	$ 24.61	3.23%	2	$ 25.91	3.27%
OPEIU	51	Customer Service 3	0	$ 24.61	3.23%	54.5	$ 25.91	3.27%
OPEIU	51	Transportation 2	0	$ 24.61	3.23%	2	$ 25.91	3.27%
OPEIU	41	Utility Support 1	0	$ 14.66	3.24%	0.5	$ 15.43	3.28%
OPEIU	47	Project Meter Reader	N/A	N/A	N/A	N/A	N/A	N/A
								642.7

*Excludes FTE created by overtime hours.

**A new contract and a job structure change occurred in 2009 with many positions modified, added, or eliminated. This prevents a one-to-one comparison with rates from the prior year; however, the average overall increase from 2008 to 2009 was approximately 2.5%.

***The contract guarantees a 1% annual increase through June 1, 2013, plus the results of the wage adjuster. The wage adjuster may not be less than 0% or more than 2%.

Note 1: Incumbents may be paid at rates that differ from the contractually mandated rate for the position that they hold. In our line of progression families, incumbents may "work up" and be "rate retained" at a higher level and therefore receive a higher rate when performing the higher-level work.

Note 2: Two distinct wage rates exist for each grade: Entry, which represents the initial rate of pay for

2013 Weighted Annual Average Increase

Entry				Experienced			
# of Entry FTE	% of Entry FTE	% Inc.	Weighted Increase	# of Exp. FTE	% of Exp. FTE	% Inc.	Weighted Increase
0	0%	0%	0%	64	9.9580%	3.23%	0.3216%
0	0%	0%	0%	164	25.5173%	3.24%	0.8268%
				126	19.6048%	3.25%	0.6372%
				161.5	25.1284%	3.26%	0.8192%
				126.7	19.7137%	3.27%	0.6446%
				0.5	0.0778%	3.28%	0.0026%
0	0%		0.0000%	642.7	100%		3.2519%

	# of FTE	% of total FTE	Average Wtd Increase	Average Annual Increase	
Entry	0	0%	0%	0%	
Exp.	642.7	100%	3.2519%	3.2519%	
Totals	642.7	100%		3.2519%	2013 Avg Annual Increase

Staff Exhibit 501/10

From: Sohl, John W. [mailto:John.Sohl@nwnatural.com]
Sent: Thursday, February 16, 2012 11:56 AM
To: GARCIA Deborah
Cc: King, Onita
Subject: RE: Clarification of DR 96

Deborah:
"Merchandise" represents the labor costs charged to the NWN Appliance Center.

"Clearing" represents the labor costs charged to clearing (holding) accounts which are allocated internally by SAP to other activities (e.g., O&M and Capital) through overhead mechanisms.

"Other" represents the labor costs charged to Non-Utility expense, such as Interstate Storage at Mist.

John Sohl
NW Natural - Budget & Financial Planning
office: (503) 226-4211 x 3435
mobile: (503) 807-2798
email: john.sohl@nwnatural.com

From: GARCIA Deborah [mailto:deborah.garcia@state.or.us]
Sent: Wednesday, February 15, 2012 4:31 PM
To: Sohl, John W.
Cc: King, Onita
Subject: RE: Clarification of DR 96

John,

Thank you for your response, but I also need to know what the percentages assigned to "Merchandise", "Clearing", and "Other" represent.
Thank you for your help,

Deborah Garcia
SR. Rev. Req. Analyst
Revenue Requirement
PH - 503/378-6688
Fax - 503/373-7752

From: Sohl, John W. [mailto:John.Sohl@nwnatural.com]
Sent: Wednesday, February 15, 2012 3:22 PM
To: GARCIA Deborah
Cc: King, Onita
Subject: Clarification of DR 96

Deborah:
I pulled up the company's response to Request 96:

Request No. 96: For the test year, please provide the breakout between O&M and rate base for all labor expense expressed as percentages. If applicable, please also provide the breakout for all labor expense between Total Company and Oregon expressed as a percentage.

Response:

Test Year labor expenses expressed as percentages

O&M	68.17%
COH	4.04%
Merchandi:	0.96%
Other	0.82%
Clearing	1.65%
Capital	24.37%

The Company does not prepare budgeted or allocated total payroll by state.

The abbreviation "COH" refers to construction overhead, which is part of capital or rate base. If you combine COH with Capital the total for rate base is 28.41%

Let me know if you need anything else.

John Sohl
NW Natural - Budget & Financial Planning
office: (503) 226-4211 x 3435
mobile: (503) 807-2798
email: john.sohl@nwnatural.com

TABLE No. 1

Line		Alternative #1 Adjusted 2011	Alternative #2 Adjusted 3-yr average (2009-2011)
1	Beginning FTE	1029.8	1,034.5
2	Add 13 Union FTE related to 4-hr service windows	13.0	13.0
3	Remove FTE .[1]	(42.6)	(42.6)
4	Staff Prop. FTE	1000.2	1004.8
5	UG 221 FTE	1130.0	1130.0
6	Staff FTE Adj.	(129.8)	(125.2)

[1] This adjustment removes FTE related to miscellaneous expense not allowed in rates. See Staff Exhibit 501 at 8 for details.

TABLE No. 2

Staff Proposed FTE by Categories

Line		UG 221	Alt. # 1	Alt. # 2
1	Officers	10.0	10.0	10.0
2	Exempt	448.8	351.5	336.5
3	Non-exempt	28.5	27.6	27.4
4	Union	642.7	611.1	631.0
5	Total	1,130.0	1,000.2	1,004.8

TABLE No. 3

Customers per FTE

NWN Test Period Customers[2] 679,721

Line		UG 221	Alternative 1	Alternative 2
1	FTE	1130	1000.2	1004.8
2	No of customers per FTE	602	680	676

[2] See NWN/902/Williams/1

TABLE No. 4

Excerpt - NWN Standard Data Request M95

Line	Category	2009 Total Co FTE	2010 Total Co FTE	2011 Total Co FTE
1	Officers	9.9	10.0	10.0
2	Exempt	371.2	365.5	391.0
3	Non-exempt	30.1	31.1	30.7
4	Union	664.7	591.1	598.1
5	Total	1,075.9	997.7	1,029.8

TABLE No. 5

Alternative #1
Allocate Disallowed FTE to Exempt & Non-Exempt

Line		2011 FTE	Wt Avg.	Disallowed	Staff Proposed
1	Exempt	391.0	92.7%	39.50	351.50
2	Non-exempt	30.7	7.3%	3.10	27.60
3	Total	421.70	100%	42.60	379.10

TABLE No. 6

Alternative #2
Allocate Disallowed FTE to Exempt & Non-Exempt

Line		3-Yr Avg	Wt Avg.	Disallowed	Staff Proposed
1	Exempt	375.9	92.5%	39.39	336.51
2	Non-exempt	30.6	7.5%	3.21	27.42
3	Total	406.53	100%	42.60	363.93

	EXCERPT	TEST YEAR											
	FTE Forecast	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	Oct 2013		Positions associated with non utility, below-the-line, & promotional
1	CORP 5000 - NW NATURAL GAS	1,130.0	1,130.0	1,130.0	1,130.0	1,130.0	1,130.0	1,130.0	1,130.0	1,130.0	1,130.0	42.64 >	Total Adjusted FTE
	KEITH WHITE	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0		
2	GAS ACQ & PIPE SVCE	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0		
3	BUSINESS DEV, STR PL	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0		
4	PROJ DEVEL OFFICE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
5	BUSINESS DEVELOPMENT	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5	Related to wholesale business
6	STRATEGIC PLANNING	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
7	NWN STORG & PIPELINE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
8	PALOMAR PIPELINE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
9	MARKETING STRATEGY	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2	
10	UTILITY SERVICES	356.5	356.5	356.5	356.5	356.5	356.5	356.5	356.5	356.5	356.5		
11	DIR, ACQUIRE CUSTOME	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.64 >	Adjusts "Acquire Customers Director" by same percentage of "Acquire Customers FTE" that are disallowed.
12	ACQUIRE CUSTOMERS	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0		
13	APPLIANCE CENTER	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0		
14	SERVICE SOLUTIONS	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	32.0 >	64% FTE disallowed in "Acquire Customers" (32/50)
15	MARKETING	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0		
16	CONVERSION	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0		
	INCREMENTAL POSITIONS	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0		
17	CUSTOMER CHOICE PROGRAM	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3 >	Related to retention of customers eligible for competitive service

Source: OM for Rate Case 12_09_11, tab FTE Forecast (EXCERPT)

CASE: UG 221
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Paul Rossow. I am employed by the Public Utility Commission of Oregon as a Utility Analyst, Revenue Requirements Section, in the Electric and Natural Gas Division of the Utility Program. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/601.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present Staff's Miscellaneous Revenue adjustment.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/602, consisting of one page.

Q. PLEASE SUMMARIZE THIS ADJUSTMENT?

A. I recommend the following adjustment;

Miscellaneous Revenues	$657,671

This adjustment is shown in Exhibit Staff/602, Rossow/1.

Q. PLEASE EXPLAIN THE MISCELLANEOUS REVENUE ADJUSTMENT.

A. This adjustment reflects the difference between Staff's proposed test period Miscellaneous Revenue of $4,982,796, and NW Natural's forecast of Miscellaneous Revenues of $3,429,159 after adding back the amortization of state taxes of $895,966.

Q. HOW DID STAFF ESTIMATE TEST PERIOD MISCELLANEOUS REVENUES?

A. Staff averaged actual Miscellaneous Revenues for calendar years 2009 through 2011. The three-year average is $4,982,796. These calculations are shown in Exhibit Staff/602 Rossow/1.

Q. ARE YOU SUPPORTING THE ADJUSTMENT AND TESTIMONY REGARDING THE REMOVAL OF THE AMORTIAZTION OF STATE TAX CHANGE IN DEFERRED TAXES?

A. No. The amortization of state tax change in deferred taxes adjustment is supported in opening testimony from Deborah Garcia (See Staff/500, Garcia/9).

Q. WHY DOES STAFF BELIEVE ITS FORCAST OF MISCELLANEOUS REVENUES IS MORE REASONABLE THAN NW NATURAL'S FORECAST?

A. The Company's forecast does not use consistent multi-year averaging for Miscellaneous Revenues. For some revenue categories the Company uses a single year; for other categories the Company uses a two-year average, and for other groups of revenues the company uses a three-year average. Staff uses an overall three-year average in determining test year levels for Miscellaneous Revenues. Staff believes that an overall three-year average provides a more consistent approach and a more accurate result.

Q. WHAT IS STAFF'S RECOMMENDATION FOR MISCELLANEOUS REVENUES?

A. On an Oregon basis, I recommend that the Commission increase NW Natural's Miscellaneous Revenues by $657,671. The overall adjustment is to increase Miscellaneous Revenues to better reflect the level that can be expected during the test period.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME:	Paul Rossow
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst, Electric and Natural Gas Division, Revenue Requirement
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	Professional Accounting and Computer Application Diplomas, Trend College of Business 1987
EXPERIENCE:	I have been employed with the Public Utility Commission of Oregon as a Utility Analyst since October of 2002. Current responsibilities include research issues relating to energy utilities. I have actively participated in regulatory proceedings in Oregon, including UE 147, UE 167, UE 170, UE 179, UE 180, UE 197, UE 210, UE 213, UE 215, UE 217, UE 233, UG 152, UG 153, UG 181, UG 186, and UG 201. I have attended the Utility Rate School sponsored by the Committee on Water of the National Association of Regulatory Utility Commissioners in May of 2005 and the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2005.

CASE: UG 221
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Exhibits in Support
Of Opening Testimony

May 3, 2012

UG 221 NW Natural - Other Revenues

OREGON Misc. Revenues	Normalized 12 Months Ended Dec-09	Normalized 12 Months Ended Dec-10	Normalized 12 Months Ended Dec-11	1/1/2009 thru 12/31/2011 Base Year	Average Used
Reconnect Charges	$629,684	$607,649	$655,652	$630,995	3-year
Late Payment Charges	$3,001,953	$2,493,663	$2,621,754	$2,705,790	3-year
Automated Payment Charge	$125,740	$120,209	$110,776	$118,908	3-year
Returned Check	$127,138	$109,858	$232,627	$156,541	3-year
Field Collection	$284,225	$282,130	$314,827	$293,727	3-year
Meter Rentals	$190,996	$178,557	$189,964	$186,506	3-year
Utility Property Rental	$236,513	$386,278	$260,115	$294,302	3-year
Water Heater Program	$0	$0	$0	$0	Set at zero
Curtailment Unauthorized Take	$0	$0	$0	$0	Set at zero
Miscellaneous	$1,511,003	$132,654	$144,424	$596,027	3-year
Total Miscellaneous Revenues	$6,107,251	$4,310,998	$4,530,139	$4,982,796	

Staff's Proposed Test Year	$4,982,796
Company's Proposed Test Year See NWN/Exhibit 304	$3,429,159
Add Back Amortization of State Tax Change (NWN Exhibit/304 at Line 10)	$895,966
Total Adjusted Test Year	$4,325,125
Staff Porposed Adjustment	$657,671

CASE: UG 221
WITNESS: Lisa Gorsuch

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Lisa Gorsuch. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/701.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to propose reasonable levels of recovery for the expense categories Advertising and Schedule C, Miscellaneous Charges. I also recommend a reasonable amount of cost recovery for the Company's proposal to offer four hour service windows as long as the appropriate accountability conditions are required.

I. ADVERTISING

Q. WHAT DO YOU RECOMMEND AS A REASONABLE LEVEL OF CATEGORY A AND CATEGORY B ADVERTISING EXPENSE?

A. Staff proposes to adjust the Company's proposal for combined category A and B advertising expense downward by $930,000. Staff's adjustment is consistent with the Commission's rules on advertising expenses and are reasonable.

To determine the appropriate level of Category A advertising expenditures, Staff relied upon OAR 860-026-0022(3)(a), which reduces the test year expense by $646,000. To determine the appropriate level of Category B expenditures, Staff began with the 2010 actuals and escalated that amount using a 3-year average of CPI, which reduces the test year expense by $283,000. Combined, these adjustments to Category A and B advertising expense result in the overall Staff proposed adjustment of a downward $930,000.

Q. HAS THE COMMISSION EVER ALLOWED ANY REGULATED UTILITY CATEGORY A EXPENDITURES BEYOND THE CALCULATION SET FORTH IN OAR 860-026-0022(3)(A)?

A. Yes. To my knowledge, the Commission has only allowed a higher Category A level of expenditure once, in the context of a partial stipulation involving settlement of numerous revenue requirement adjustments, when it allowed NWN Category A expenditures higher than the calculation allowed in OAR 860-026-0022(3)(a) in the Company's last rate case, decided in 2003. Under the Commission's rule, expenditures for Category A advertising up to 0.125 percent of gross revenues are deemed just and reasonable. The burden is on the Company to show a higher amount is just and reasonable. In 2003, the Commission allowed a higher percentage of gross revenues related to the Company's claim that the calculation is disproportionately low for local distribution companies (LDC) as compared with electric utilities. [1]

Q. SHOULD THE COMMISSION ALLOW CATEGORY A EXPENDITURES IN RATES BEYOND THE CALCULATION DEEMED JUST AND REASONABLE BY THE COMMISSION'S RULE IN THIS CASE?

[1] Docket No. UG 152, Order No. 03-507.

A. No. A consistent and permanent resolution, if necessary, should be sought through a separate investigation and rule revision to address the possible disparity between LDCs and electric utilities with regard to the calculation of just and reasonable Category A advertising. Without specific factual support that a higher percentage of Category A expenditures are appropriate in this specific case, the Commission should not make ad hoc adjustments to the rule for only one Company.

II. CUSTOMER SERVICE

Q. PLEASE PROVIDE STAFF'S POSITION RELATED TO THE COMPANY'S PROPOSED SERVICE APPOINTMENT WINDOWS.

A. Staff proposes to allow the expense associated with the implementation of service appointment windows as described in NWN 900, contingent upon the Company's agreement to instigate a service guarantee for each service appointment window it fails to meet. Additional FTE associated with the Company's offering service appointment windows are accounted for in the opening testimony of Deborah Garcia, Staff 500.

Q. WHY DO YOU RECOMMEND THAT SERVICE GURANTEES ARE NECESSARY?

A. If ratepayers are paying for the costs of the service appointments windows, there should be some accountability metric to make sure the ratepayers get delivery of what they have paid for in their rates.

Q. PLEASE DESCRIBE THE TERMS OF THE SERVICE GUARANTEE ASSOCIATED WITH THE IMPLEMENTATION OF SERVICE APPOINTMENT WINDOWS.

A. Staff proposes the Company pay a $100.00 service guarantee for each service appointment window it fails to meet. Of the $100.00 penalty paid by shareholders, $25.00 would be credited to the impacted customer with the $75.00 balance going into an account to be distributed to the customer base as a whole.

Q. HOW DID STAFF DERTERMINE AN APPROPRIATE AMOUNT FOR THE SERVICE GUARANTEE FOR MISSED SERVICE APPOINTMENT WINDOWS?

A. Staff developed the penalty amount by using an average of the hourly wage of customer service field technicians multiplied by four (representative of the four-hour service windows). This amount is an approximation and actually slightly below the calculation that totaled nearly $120.00. This calculation is illustrated in Exhibit 703.

Q. DOES STAFF PROPOSE ADDITIONAL REVISIONS TO CUSTOMER SERVICE, NWN 900?

A. No. Staff supports allowing the costs associated with bill payments options as described in NWN 900.

<u>SCHEDULE C, MISCELLANEOUS CHARGES</u>

Q. PLEASE PROVIDE STAFF-PROPOSED REVISIONS TO SCHEDULE C, MISCELLANEOUS CHARGES.

A. Staff proposes to allow the Company to increase its service reconnection charges from $25.00 to $30.00 for reconnections scheduled from 8:00 - 5:00. For Monday - Friday. (except Holidays), an increase from $75.00 to $80.00 for reconnection the same day or after 5:00pm. Monday - Friday. In addition, Staff supports the Company's change from a two-tiered structure to a three-tiered structure for reconnection charges, implementing a $175.00 charge for reconnection on Saturday & Sunday or on a Holiday. Staff's proposed revisions to this schedule are illustrated in Exhibit 704.

Q. PLEASE EXPLAIN THE BASIS FOR STAFF'S PROPOSED INCREASES TO NWN'S CHARGES FOR RECONNECTION.

A. Staff-proposed increases to the Company's reconnection charges take into consideration impact on low-income customers. Costs associated with tariffed miscellaneous charges often exceed the amount charged to an individual customer with the difference spread to all rate payers to avoid imposing a hardship on low-income customers. In addition, Staff-proposed increases are in line with other energy utilities in Oregon, and the increases meet with the test for "gradualism" and protect customers from rate shock.

Q. DOES STAFF SUPPORT NWN'S PROPOSED INCREASE TO ITS FIELD VISIT CHARGE?

A. Yes. Staff supports allowing NWN to increase its Field Visit charge from $15.00 to $20.00 as described in NWN 1700.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: Lisa Gorsuch

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME:	Lisa M. Gorsuch
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst/Rates & Tariffs
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	College-level coursework in financial accounting, business law, business management, and economics. The Center For Public Utilities at New Mexico University. National Association of Regulatory Utility Commissioners Annual Regulatory Studies Program at Michigan State University.
EXPERIENCE:	Utility Analyst with the Public Utility Commission of Oregon since April 2008. Primarily responsible for review of electric and natural gas company tariff filings and other electric and natural gas company rates and costs. Provide expertise to Consumer Services Division on consumer-related issues. Compliance Specialist with the Public Utility Commission of Oregon from June 2004 until April 2008. Responsibilities included acting as a liaison between the public, regulated utilities and various Commission staff. Review of proposed tariffs, administrative rules, and policies for evaluation of the potential impact on consumers and the regulated utilities. Identified trends, services, and policies where no statute, rule or precedent applied and recommended the appropriate action.
OTHER EXPERIENCE:	Enforcement Agent with the Oregon Department of Revenue as a member of a multijurisdictional task force including Oregon Department of Justice and Oregon State Police from June 1999 until May 2004. Responsibilities included investigating cases of tax evasion involving smuggling of illegal cigarette and other tobacco products. Review of administrative rules, and compliance and enforcement standards for multiple tax programs. Serving as liaison between task force and Oregon State Legislators to determine appropriate tax rate for two different tax programs.

CASE: UG 221
WITNESS: Lisa Gorsuch

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 702

Exhibits in Support Of Opening Testimony

May 3, 2012

UG 221 Category A Advertising

$ 742,978,000	NWN Test Year Operating Revenue (NWN Exhibit 302, McVay-Siores/1, line 4 column e)
0.125%	Per OAR 860-026-0022(3)(a)

$ 928,723 (Calculation = $742,978 x .00125 = $928,723)

$	1,575,000	Test Year Cat A
$	928,723	Staff-Proposed Cat A
$	(646,278)	Staff-Proposed Adjustment

Exhibit 702/2 UG 221 Category B Advertising Adjustment

$	650,000.00	Test Year Category B
$	(150,000.00)	Remove Payroll Exp (See payroll-related adj.)
$	**500,000.00**	**Adjusted Category B Expenditures**
$	344,850.00	2010 Category B Expenditures (DR 362 See Below)
$	**366,649.49**	**2010 escalated by 2011-2013 CPI factor**

CPI	
2011	3.0%
2012	1.3%
2013	1.9%
	1.0632

NWN DR 362 Response

Category B Expense 2010

						Exp. by Internal Acct (IA) (Pls extend number of IA Col as necessary)				
						Name	Name	Name	Name	Name
Item No	Description	Total Co	OR alloc	Or Situs	FERC Acct	No.	No.	No.	No.	No.
1	TV Media "Smell. Go. Let us Know, Smells for a reason"	$89,662.66	100%	$89,662.66	909	11550	505200	909-28000		
2	TV/Online production "Smell. Go. Let us Know"	$101,809.91	100%	$101,809.91	909	11550	505200	909-28000		
3	Radio media "Smell. Go. Let us Know"	$57,155.00	100%	$57,155.00	909	11550	505200	909-28000		
4	Online Media "Smell. Go. Let us Know"	$16,231.00	100%	$16,231.00	909	11550	505200	909-28000		
5	Print media "Smell. Go. Let us Know"	$7,627.00	90%	$6,864.30	909	11550	505200	909-28000		
6	Public safety mailings (mail services)	$18,792.26	90%	$16,913.03	909	11550	505100	909-28000		
7	Public safety mailings (printing)	$30,368.00	90%	$27,331.20	909	11550	503100	909-28000		
8	Public safety mailings (postage)	$21,699.35	90%	$19,529.42	909	11550	502800	909-28000		
9	Professional services (design production)	$548.50	90%	$493.65	909	11550	505100	909-28000		
10	Misc. expenses (images, graphics, etc)	$264.00	90%	$237.60	909	11550	505200	909-28000		
11	Misc. expenses (courier)	$5.58	90%	$5.02	909	11550	502100	909-28000		
12	Misc. expenses (purchased lists)	$686.44	90%	$617.80	909	11550	502400	909-28000		
		$344,849.70								

Category B Expense Forecast 2013

						Exp. by Internal Acct (IA) (Pls extend number of IA Col as necessary)				
						Name	Name	Name	Name	Name
Item No	Description	Total Co	OR alloc	Or Situs	FERC Acct	No.	No.	No.	No.	No.
1	Payroll overhead	$60,000.00	90%	$54,000.00	909	11550	501000	909-28000		
2	Payroll salary	$70,000.00	90%	$63,000.00	909	11550	500100	909-28000		
3	Vacation, sick & holiday	$20,000.00	90%	$18,000.00	909	11550	500900	909-28000		
4	TV Media "Smell, Leave, 811" NEW	$125,000.00	100%	$125,000.00	909	11550	505200	909-28000		
5	TV production "Smell. Go. Let us Know, 811"	$75,000.00	100%	$75,000.00	909	11550	505100	909-28000		
6	Radio media "Smell. Go. Let us Know, 811" NEW	$85,000.00	100%	$85,000.00	909	11550	505200	909-28000		
7	Radio production "Smell. Go. Let us Know, 811"	$15,000.00	100%	$15,000.00	909	11550	505100	909-28000		
8	Print media "Smell. Go. Let us Know"	$80,000.00	90%	$72,000.00	909	11550	505200	909-28000		
9	Public Safety Mailings (mail services)	$20,000.00	90%	$18,000.00	909	11550	505100	909-28000		
10	Public Safety Mailings (printing)	$35,000.00	90%	$31,500.00	909	11550	503100	909-28000		
11	Public Safety Mailings (postage)	$20,000.00	90%	$18,000.00	909	11550	502800	909-28000		
12	Professional services (design production)	$6,000.00	90%	$5,400.00	909	11550	505100	909-28000		
13	Misc. expenses (images, graphics, etc)	$5,000.00	90%	$4,500.00	909	11550	505200	909-28000		
14	Misc. expenses (courier)	$3,000.00	90%	$2,700.00	909	11550	502100	909-28000		
15	Misc. expenses (purchased lists)	$1,000.00	90%	$900.00	909	11550	502400	909-28000		
16	School program	$30,000.00	90%	$27,000.00	909	11550	505200	909-28000		

CATEGORY B ADVERTISING
UG 221

Annual totals from NWN response to DR 362

2003	$	62,612
2004	$	373,441
2005	$	371,658
2006	$	440,262
2007	$	325,213
2008	$	353,507
2009	$	349,764
2010	$	344,850
2011	$	410,058
2012	$	475,000
2013	$	650,000
Total	$	4,156,365
11-Year Average	$	377,851
2007	$	325,213
2008	$	353,507
2009	$	349,764
2010	$	344,850
2011	$	410,058
Total	$	1,783,391
5-Year Average	$	356,678

CASE: UG 221
WITNESS: Lisa Gorsuch

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 703

Exhibits in Support
Of Opening Testimony

May 3, 2012

Service Guarantee Calculation for Service Window Appointments

Customer Field Service 2	$ 29.72
Customer Field Service 4	$ 32.14
Customer Field Service 3	$ 31.07
Customer Field Service 1 Honored	$ 24.61
Average Wage	$ 29.39
Average Wage x 4	$ 117.54

CASE: UG 221
WITNESS: Lisa Gorsuch

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 704

Exhibits in Support
Of Opening Testimony

May 3, 2012

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~~30.00
~~Scheduled after 5:00 p.m., Mon.-Fri.~~ Same Day or after 5:00 p.m. Mon-Fri. or on a Holiday	$ 80.00
~~Same Day after 5:00 p.m. Mon-Fri, or on Saturday or on a Holiday~~ Saturday &Sunday or on a Holiday	$~~185.00~~175.00
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

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)

Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

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~~$30 $80 ~~$185~~$80
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~~$30 ~~$185~~$30 ~~$185~~$175
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~~$30 ~~$80~~$30 ~~$185~~$80 ~~$185~~$175
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..~~
*The time frame for all service reconnection options (charge for reconnection) is based on when the customer requests service be reconnected. The reconnection charge will not increase based on the company's scheduling.

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)

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.

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

CASE: UG 221
WITNESS: Brian Bahr

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Brian Bahr. I am a Financial Analyst for the Corporate Analysis and Water Regulation Section of the Oregon Public Utility Commission. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/801.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe proposed adjustments to the Company's director and officer (D&O) insurance expense, incentive compensation expense, medical benefits expense and workers compensation expense, and non-labor administrative and general (A&G) expense. The proposed adjustments I recommend are derived from review of numerous data request responses, analysis of industry trends and common practices, and Commission precedent found in past Commission orders.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Adjustment	Exhibit Bahr/800 page #	Exhibit
D&O Insurance	2	Staff/802
Incentive Compensation	4	Staff/803
Medical Benefits & Workers Compensation	8	Staff/804
Non-labor A&G	10	Staff/805

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/801, consisting of one page, Exhibit Staff/802, consisting of seven pages, Exhibit Staff/803, consisting of 13 pages, Exhibit Staff/804, consisting of five pages, and Exhibit Staff/805, consisting of 10 pages. Again, my Witness Qualification Statement is found in Exhibit Staff/801; Exhibit Staff/802 contains my adjustment to D&O Insurance expense; Exhibit Staff/803 contains my adjustment to incentive compensation expenses; Exhibit Staff/804 contains my adjustments to medical benefits expenses and workers compensation expenses; and Exhibit Staff/805 contains my adjustment to various A&G expenses.

D&O INSURANCE EXPENSE ADJUSTMENT

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT TO D&O INSURANCE EXPENSE.

A. This adjustment is shown in Exhibit Staff/802, Bahr/1-2, and focuses on the Company's D&O liability insurance. I propose the following adjustment (Oregon-allocated):

D & O Insurance	($271,909)

In its application, the Company requested a total system test year amount of $1,103,571.[1] Decreasing the Company's requested amount by my proposed adjustment results in a total system test year D&O insurance amount of $801,785. As shown in Exhibit Staff/802, Bahr/2, the difference of $301,785, is

[1] This amount includes $500,000 of self insured retention. *See* Company's response to Staff Data Request No. 386, included as Exhibit Staff/802, Bahr/3-4.

allocated using the 3-factor allocation percentage of 90.1 percent, found on Line 98 of Exhibit NWN/312, McVay-Siores/1, to arrive at the Oregon-allocated reduction of $271,909.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO D&O INSURANCE EXPENSE.

A. I examined the Company's total D&O insurance costs and reduced the excess layers of D&O Liability Insurance by 50 percent. The amount the Company is requesting in rates is the total D&O insurance expense, which includes a self-insured retention and all excess layers. Staff standard practice is to recommend allowing 100 percent of the primary layer, and 50 percent sharing between ratepayers and shareholders of the excess layers. As the Company has only excess layers, Staff treated the self-insured retention amount as the primary layer. Please refer to Exhibit Staff/802, Bahr/2, for details of the calculations relating to this adjustment.

Q. WHAT IS THE BASIS FOR YOUR ADJUSTMENT TO D&O INSURANCE EXPENSE?

A. As stated previously, Staff's standard practice, which has been adopted and approved by the Commission in past cases, is to recommend use of a 50/50 sharing of Excess D&O Liability Insurance with 50 percent assigned to ratepayers and the remaining 50 percent assigned to shareholders. D&O insurance protects senior management in the event they are sued in conjunction with the performance of their duties, whether by customers, shareholders, or others.

This sharing approach is reasonable for several reasons. First, a sharing approach aligns the interests of customers and shareholders. Second, customers typically have no say in electing or appointing utility directors or officers, and therefore should not be held financially responsible for providing the entirety of the insurance coverage for protection against business decisions or improprieties by management which could result in lawsuits. Additionally, according to the 2011 Towers Watson Directors and Officers Liability Survey, "the lion's share of claims continue to come from shareholders."[2]

Customers should not be required to pay the full costs of total D&O insurance. As determined in UE 197, Order No. 09-020 at 19-20, the excess insurance should be considered a joint shareholder/customer cost. The Commission stated:

> We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost.[3]

INCENTIVE COMPENSATION EXPENSE ADJUSTMENT

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT TO INCENTIVE COMPENSATION EXPENSE.

A. This adjustment is shown in Exhibit Staff/803, Bahr/1-2, and focuses on the Company's incentive compensation expense. I propose the following adjustment (Oregon-allocated):

---

[2] *See* page 19 of http://www.towerswatson.com/assets/pdf/6532/Towers-Watson-Directors-and-Officers-Liability-2011-Survey.pdf, included as Exhibit Staff/802, Bahr/5.
[3] *See* Order No. 09-020 at 20, included as Exhibit Staff/802, Bahr/6-7.

Incentive Compensation ($3,429,674)

The Company requested a total-system-test year amount of $6,101,000.[4] Using the 3-factor percentage found on Line 98 of Exhibit NWN/312, McVay-Siores/1, the Oregon-allocated amount of this is $5,497,001. My adjustment removes 100 percent of officer bonuses, 75 percent of bonuses based upon Company performance, and 50 percent of bonuses based upon employee merit. I also took into account two labor-related adjustments, one for Staff's proposed reduction to FTE and the other based on the ratio of utility to non-utility labor provided by the Company.[5]

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO INCENTIVE COMPENSATION EXPENSE.

A. The Company requested a total system test year amount of $6,101,000.[6] First, using information provided by the Company in its response to Staff Data Request No. 392, I sorted this amount into the following three categories: bonuses paid to officers, bonuses paid to non-officers based on Company performance, and bonuses paid to non-officers based on employee merit. I then found the Oregon-allocated portion of these amounts by multiplying them by the 3-factor allocation percentage of 90.1 percent, found on Line 98 of Exhibit NWN/312, McVay-Siores/1.

As shown in Exhibit Staff/500, Staff Garcia proposed an adjustment to FTE from 1,130 to 1,000, which is 88.5 percent. This percentage was multiplied by

4 *See* Company's response to Staff Data Request No. 392, included as Exhibit Staff/803, Bahr/3-4.
5 *See* Exhibit Staff/500 for a detailed description of the FTE and non-utility labor expense adjustments.
6 *See* Company's response to Staff Data Request No. 392, included as Exhibit Staff/803, Bahr/3-4.

the Oregon-allocated bonus expense amounts. Staff then adjusted these amounts to take into account a proposed 1.78 percent reduction to labor expense due to inclusion of non-utility labor included in the rate case, as provided in the Company's response to Staff Data Request No. 96.[7] Finally, Staff removed 100 percent of officer bonuses, 75 percent of the bonuses based on Company performance, and 50 percent of bonuses based on merit. Please refer to Exhibit Staff/802, Bahr/2, for details of the calculations relating to this adjustment.

Q. WHAT IS THE BASIS FOR YOUR ADJUSTMENT TO INCENTIVE COMPENSATION EXPENSE?

A. The first adjustment to incentive compensation was to account for Staff's proposed reduction to FTE. An explanation of Staff's FTE adjustment can be found in Exhibit Staff/500. In proposing a reduction to FTE, it is necessary to address the total compensation of each employee. Whereas Staff Garcia reduces the wages and salary related to those employees, my adjustment accounts for their incentive compensation. I reduce non-officer incentive compensation by the same proportion by which Staff Garcia proposes to reduce FTE.

The second adjustment I make is to reduce the incentive compensation expense by 1.78 percent, which is the sum of the 'Merchandise' category and the 'Other' category of test year labor expense as provided by the Company in

[7] This adjustment to labor expense for non-utility labor is explained in further detail in Exhibit Staff/500.

response to Staff Data Request No. 96.[8] Based on discussion with Staff Garcia, these categories of labor expense are not directly related to the provision of utility service and should not be allowed in rates.[9]

The third adjustment I make is to allow for a sharing of incentive compensation between customers and shareholders, which is Staff's standard practice. I propose removal of 100 percent of officer bonuses. The Commission has not allowed utilities to charge customers for bonuses paid to company executives because they are typically based on the financial performance of the utility or its parent company.[10]

I also propose disallowance of 75 percent of the bonus expense that is based on Company performance and 50 percent of the bonus expense that is based on employee merit. Union and non-union bonuses are both given equal treatment. This treatment of bonuses is consistent with Commission precedent found in various Commission Orders, including Order No. 99-697 at 44-45:

> Staff proposes a 75 percent disallowance of performance-based bonuses, and a 50/50 sharing of merit-based bonuses. Staff explains that the Commission has traditionally disallowed 75 percent of performance-based bonuses, because they are generally focused on the company's increased earnings and, therefore, bring more benefit to shareholders. It adds that the Commission has generally allowed equal sharing of merit-based bonuses, because they equally benefit shareholders and ratepayers. It contends that the company's Key Goals program should be similarly treated, noting that shareholders clearly benefit through increased earnings if the profitability and market share goals are achieved. Finally, it contends that the

[8] *See* Company's response to Staff Data Request No. 96, included as Exhibit Staff/803, Bahr/5.
[9] *See* Exhibit Staff/500 for a more thorough explanation of why the Merchandise and Other categories should not be allowed in rates.
[10] *See* Order No. 87-406 at 42-43, included as Exhibit Staff/803, Bahr/6-7.

> Commission should apply these recommendations to all bonuses, including those paid to union employees. It notes that the Commission has always treated union bonuses in the same manner, because the same rationale applies.
>
> **Commission Resolution**
> After our review, we find Staff's bonus adjustments to be reasonable and adopt them. Staff's recommendations are consistent with past ratemaking treatment of bonuses in prior electric and natural gas rate cases. NW Natural has not persuaded us that a change in policy is warranted.[11]

MEDICAL BENEFITS EXPENSE AND WORKERS COMPENSATION EXPENSE ADJUSTMENT

Q. PLEASE SUMMARIZE THE ADJUSTMENT TO MEDICAL BENEFITS EXPENSE AND WORKERS COMPENSATION EXPENSE.

A. This adjustment is shown in Exhibit Staff/804, Bahr/1-2, and focuses on the Company's medical benefits expense and workers compensation expense. I propose the following adjustment (Oregon-allocated):

Medical Benefits and Workers Compensation ($2,058,948)

In its application, the Company requested a total-system-test year amount of $[redacted] in medical benefits expense and $[redacted] in workers compensation expense.[12] I adjusted these amounts to account for two adjustments described in Exhibit Staff/500, a proposed reduction to FTE and a proposed reduction in labor expense due to the inclusion of non-utility labor in the test year.

[11] *See* Order No. 99-697 at 44-45, included as Exhibit Staff/803, Bahr/8-9. *See also* Order No. 99-033 at 62, included as Exhibit Staff/803, Bahr/10; Order No. 97-171 at 74-76, included as Exhibit Staff/803, Bahr/11-13.

[12] *See* Company's confidential response to Staff Data Request No. 63 and response to Staff Data Request No. 384c, included as Exhibit Staff/804, Bahr/3-4, and Exhibit Staff/804, Bahr/5, respectively.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO MEDICAL BENEFITS EXPENSE AND WORKERS COMPENSATION EXPENSE.

A. This adjustment modifies the Company's proposed medical benefits expense and workers compensation expense based on Staff Garcia's adjustment to FTE found in Exhibit Staff/500. To calculate the adjustment, Staff first obtained the amount of medical benefits expense and workers compensation expense included by the Company in the test year.[13] These amounts were multiplied by the 3-factor allocation percentage found on Line 98 of Exhibit NWN/312, McVay-Siores/1, to arrive at the Oregon-allocated amount.

As shown in Exhibit Staff/500, Staff Garcia proposed an adjustment to FTE from 1,130 to 1,000, which is 88.5 percent. Staff applied this percentage to the medical benefits expense for active employees (Staff allowed medical benefits expenses for retired employees at 100 percent) and to the workers compensation expense amount. Once again allowing medical benefits expense for retired employees at 100 percent, Staff reduced the medical benefits expense for active employees and workers compensation expense by 1.78 percent, which is the percentage of non-utility labor expense included in the test year, as provided by the Company in its response to Staff Data Request No. 96.[14] These calculations result in Oregon-allocated adjustments to medical benefits expenses of $1,890,552, and to workers compensation

[13] *See* Company's confidential response to Staff Data Request No. 63 and response to Staff Data Request No. 384c, included as Exhibit Staff/804, Bahr/3-4, and Exhibit Staff/804, Bahr/5, respectively.
[14] *See* Company's response to Staff Data Request No. 96, included as exhibit Staff/803, Bahr/5. See also Exhibit Staff/500 for a more thorough explanation of why the Merchandise and Other categories should not be allowed in rates.

expenses of $168,396. Please refer to Exhibit Staff/804, Bahr/2, for details of the calculations relating to this adjustment.

Q. WHAT IS THE BASIS FOR YOUR ADJUSTMENT TO MEDICAL BENEFITS EXPENSE AND WORKERS COMPENSATION EXPENSE?

A. This adjustment reflects the effects of Staff Garcia's adjustments to FTE and to labor expense described more fully in Exhibit Staff/500. Staff recommends this adjustment based on Staff's reasoning that an adjustment to FTE and labor expense also affects the Company's medical benefits and workers compensation expenses.

NON-LABOR A&G EXPENSE ADJUSTMENT

Q. PLEASE SUMMARIZE THE ADJUSTMENT TO NON-LABOR A&G EXPENSE.

A. This adjustment is shown in Exhibit Staff/805, Bahr/1, and focuses on the Company's administrative and general expenses found in FERC accounts 900 through 935. I propose the following adjustment (Oregon-allocated):

Various A&G	($1,981,842)

In its application, the Company requested a total system test year amount of $[redacted] in non-labor A&G expenses for FERC accounts 900 through 935.[15] I adjusted this amount to allow for sharing between customers and shareholders in accordance with Commission precedent found in Order No. 09-

[15] *See* Company's confidential updated response to Staff Data Request No. 58 (update requested in Staff Data Request No. 163), included as Exhibit Staff/805, Bahr/4-6.

020.[16] The adjustment was then allocated to Oregon based on the calculated allocation of 2011 expenses and escalated to test year using the Company-provided CPI to arrive at the Oregon-allocated adjustment amount. Finally, 50 percent of the Oregon-allocated, CPI-adjusted expense of membership fees to certain industry organizations was added back, the effect of which is to reduce the amount of my adjustment.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO NON-LABOR A&G EXPENSE.

A. Using 2011 non-labor expense amounts recorded to FERC accounts 900 to 935 provided in electronic spreadsheet format by the Company in its confidential response to Staff Data Request No. 57, Staff created pivot tables to summarize these expenses by cost element.[17] Staff then identified from the pivot tables cost elements that should not be included in rates charged to customers and cost elements that should be shared between customers and shareholders equally. Table 1 on the following page indicates the cost elements that were identified, the total dollar amount of each cost element for FERC accounts 900 through 935, the disallowance percentage, and proposed amount disallowed:

[16] *See* Order No. 09-020 at 21, included as Exhibit Staff/805, Bahr/7.
[17] The data in the Company's confidential updated response to Staff Data Request No. 57 (update requested in Staff Data Request No. 162) is too voluminous to include as an exhibit; however, Staff does include the summary page, which shows the FERC account totals for each account, as Exhibit Staff/805, Bahr/8-9.

Table 1. Cost Elements Adjusted by Staff

Cost Element	Total $ Amount	Disallowance	Disallowed Amount ($)
CORPORATE IDENTITY	284,239	100%	284,239
DONATIONS	8,550	100%	8,550
DUES/MEMBERSHIP	1,015,306	100%	1,015,306
LAUNDRY	59,620	100%	59,620
NON EMPLOYEE GIFTS	2,601	100%	2,601
REFRESHMENTS	84,686	100%	84,686
BOOKS AND MAGAZINES	71,366	50%	35,683
CONFERENCE TRAVEL	447,036	50%	223,518
DEALER RELATIONS	342,946	50%	171,473
EDUCATION	316,587	50%	158,294
EMPLOYEE AWARDS	211,028	50%	105,514
EMPLOYEE AWARDS MLS &	105,824	50%	52,912
MEALS AND ENTERTAIN	327,623	50%	163,811
MISCELLANEOUS	5,080	50%	2,540
Total	**3,316,570**	**Total**	**2,368,747**

Table 2 below indicates the proposed amounts to be disallowed from each FERC account:

Table 2. Disallowed Amounts by FERC Account

FERC Account #	Proposed Disallowance ($)
901	14,113
902	4,916
903	64,160
907	10
908	84,310
909	29,200
910	8,855
911	3,499
912	320,833
913	117,378
921	621,390
925	6,930
926	218,443
930	797,819
935	76,892
Total	**2,368,747**

To calculate an appropriate factor to allocate the proposed disallowed amounts to Oregon, Staff divided the 2011 system non-labor expense amount for each FERC account by the 2011 Oregon allocated non-labor expense amount for each FERC account, both provided by the Company in its confidential response to Staff Data Request No. 58.[18] Using these allocation percentages, Staff then calculated the 2011 Oregon-allocated proposed disallowance amount. Staff then escalated these amounts by 3.785 percent, which is a compounded escalation factor of two months at the 2012 CPI escalation factor of 2.0 percent and ten months at the 2013 CPI escalation factor of 2.1 percent. These CPI escalation factors were provided by the Company in its response to Staff Data Request No. 386.[19] These calculations resulted in an Oregon-allocated test year adjustment of ($2,215,324).

The Company's 2012 Annual Budget of Expenditures Report indicates that the Company has budgeted for 2012 membership fees to four organizations of the gas utility industry: American Gas Association, Institute of Gas Research (and other R&D), Western Energy Institute, and Northwest Gas Association.[20] For only the three organizations not related to research and development, Staff calculated 50 percent of the 2012 budgeted cost, allocated that amount to Oregon using the 3-factor formula, and escalated it for CPI using 10 months at

[18] *See* Company's confidential updated response to Staff Data Request No. 58 (update requested in Staff Data Request No. 163), included as Exhibit Staff/805, Bahr/4-6.
[19] *See* Company's response to Staff Data Request No. 386, included as Exhibit Staff/802, Bahr/3-4.
[20] *See* the Company's 2012 Annual Budget of Expenditures Report, pg. A-5, included as Exhibit Staff/805, Bahr/10.

2.1 percent.[21] When added back to the adjustment amount of ($2,215,324), Staff proposes an adjustment to the Oregon-allocated test year amount of ($1,981,842). Please refer to Exhibit Staff/805, Bahr/1-3, for details of the calculations relating to this adjustment.

Q. WHAT IS THE BASIS FOR YOUR ADJUSTMENT TO NON-LABOR A&G EXPENSE?

A. This adjustment to non-labor A&G expenses is routinely proposed by Staff in general rate cases, and its purpose is to align rates charged to customers with the expenses necessary to provide safe and reliable service. Staff recommends allowing for sharing of certain discretionary expenses and disallowance of others, in accordance with the necessity of those expenses in providing safe and reliable service to customers. In proposing this adjustment, Staff generally followed precedent set by the Commission in previous rate cases. In Order No. 09-020 (UE 197), the Commission adopted Staff's recommendations regarding disallowance of various A&G expenses. The Commission stated:

> We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders. We also adopt Staff's recommendation with respect to contributions to charities, community affairs, and economic development organizations. …and we conclude that all contributions to charities, community affairs, and economic development organizations should be disallowed.[22]

[21] *See* Company's response to Staff Data Request No. 386, included as Exhibit Staff/802, Bahr/3-4.
[22] *See* Order No. 09-020 at 21, included as Exhibit Staff/805, Bahr/7.

Regarding Staff's proposed adjustment to dues and memberships, because the Institute of Gas Research (and other R&D) is a research and development cost, Staff proposes excluding the amount associated with this organization from the amount of dues and membership expenses that should be paid by ratepayers. Rather, it is subject to Staff Cimmiyotti's proposed adjustment to research and development expenses (expressed as a percentage of overall revenue requirement), which is described in Exhibit Staff/900.

Regarding the membership fees in the three other gas utility industry organizations, Staff proposes a 50/50 sharing between customers and shareholders. While not absolutely necessary to provide safe and reliable service to customers, membership in these organizations does provide benefit to customers to some degree. However, ratepayers should not bear the entire burden of expense as some of the organizations' activities are promotional or lobbying in nature.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: Brian Bahr

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME:	BRIAN BAHR
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	FINANCIAL ANALYST, CORPORATE ANALYSIS AND WATER REGULATION
ADDRESS:	550 CAPITOL ST. NE, SALEM, OR 97308-2148
EDUCATION:	Bachelor of Science, Accountancy, Brigham Young University, Provo UT
EXPERIENCE:	Employed with the Oregon Public Utility Commission from March 2011 to present, currently serving as Financial Analyst, Corporate Analysis and Water Regulation.
	Employed by Modern Seouf Plastics in Alexandria, Egypt as a Managerial Intern from January 2010 to June 2010. Assisted in variety of duties including supervision of production facilities and staff, market analysis, budget forecasting, sales, and office administration.
	Employed by PricewaterhouseCoopers LLP in New York City as a Financial Assurance Associate from October 2007 to November 2009. Performed audits of various financial institutions, including investment banks, hedge funds, and insurance companies.
	Employed by TESRA, SA in Antofagasta, Chile as a Project Management Assistant from September 2005 to April 2006. Assisted in design process and implementation of rail road crossing and other civil engineering projects.

CASE: UG 221
WITNESS: Brian Bahr

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 802

Exhibits in Support Of Opening Testimony

May 3, 2012

Northwest Natural UG 221
Test Year Ending October 31, 2013
000's of Dollars

This adjustments reflects Staff's proposal to allow for a 50% sharing of the excess layers of the Directors & Officers Insurance between the Company and customers in order to properly reflect the benefits and burdens of the expense. This adjustment is commonly proposed by Staff and follows Commission precedent found in Order No. 09-020 at 19-20.

Description/ Account No.	Company Filing	Staff	Adjustment
D&O Insurance	$994	$722	($272)

Staff Initiator:
Brian Bahr

	Total System	OR Alloc % ****	OR Alloc
Self Insured Retention*	$ 500,000		
First Excess Layer D&O Insurance**	$ 239,803		
Second Excess Layer D&O Insurance**	$ 112,206		
Third Excess Layer D&O Insurance**	$ 211,660		
Other D&O - Broad Form Side A - DIC Premium**	$ 39,901		
Total D&O Insurance	$ 1,103,571	90.10%	$ 994,317
Self Insured Retention per Staff (100%)	$ 500,000		
First Excess Layer D&O Insurance per Staff (50%)	$ 119,902		
Second Excess Layer D&O Insurance per Staff (50%)	$ 56,103		
Third Excess Layer D&O Insurance per Staff (50%)	$ 105,830		
Other D&O - Broad Form Side A - DIC Premium per Staff (50%)	$ 19,951		
Total Staff D&O Insurance***	$ 801,785	90.10%	$ 722,409
Total Test Year D&O Insurance per NW Natural	$ 1,103,571		
Total Test Year D&O Insurance per Staff	$ 801,785		
Adjustment (total company)	$ (301,785)	90.10%	$ (271,909)

* NWN carries only Excess D&O. NWN has a self insured retention of $500,000.
** See Company's response to Staff Data Request No. 386.
*** Staff proposes a 50% sharing of excess D&O Insurance. The self insured retention is allowed at 100%.
**** Staff used the 3-factor formula provided by the Company in NWN/312, McVay-Siores/1.

Note: D&O insurance protects senior management in the event they are sued, whether by customers, shareholders or others in conjunction with the performance of their duties. Customers, who have no say in electing or appointing Utilities Directors or Officers, should not be held fiancially responsible for providing 100 percent of the insurance coverage against business decisions or improprieties by management which results in lawsuits. Additonally, a large number of claims are brought by shareholders, customers should not have to pay the full costs of total D&O insurance. The excess insurance should be considered a joint shareholder/customer costs.

In UE 197, the Commission adopted Staff's principle that D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of the expense (Order 09-020 at 19-20).

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 386:
Regarding the Company's response to Staff Data Request No. 164, please update the original table with the following information:

Insurance	2012 Forecasted	2013 Forecasted	Included in Test Year
D & O Liability Premium			
D & O Liability Deductible			
First Excess D & O Liability			
First Excess D & O Deductible			
Second Excess D & O Liability			
Second Excess D & O Deductible			
Total Premium (primary, first excess & secondary excess)			

Response: 3/7/2012

Please see OPUC-DR 386 Attachment-1.

Insurance is a Non-Payroll O&M expense. Non-Payroll O&M Expense for 2012 & 2013 was escalated using a CPI of 2.0% for 2012 and 2.1% for 2013. The test year amount was prorated using 2 months of the 2012 forecast and 10 months of the 2013 forecasted amounts.

NW Natural
OPUC DR 386

	A	B	C
Insurance	**2012 Forecast**	**2013 Forecast**	**Included in Test Year**
D & O Liability Premium	(1)	(1)	(1)
D & O Liability Deductible	(1)	(1)	(1)
First Excess D & O Liability Premium	235,679	240,628	239,803
First Excess D & O Deductible	(2)	(2)	(2)
Second Excess D & O Liability Premium	110,276	112,592	112,206
Second Excess D&O Deductible	(2)	(2)	(2)
Third Excess D & O Liability Premium	208,019	212,388	211,660
Third Excess D & O Deductible	(2)	(2)	(2)
Other D&O - Broad Form Side A - DIC Premium	39,215	40,039	39,901
Other D&O - Broad Form Side A - DIC Deductible	(3)	(3)	(3)
Total Premium	593,190	605,647	603,571

(1) NW Natural only carries Excess D&O. NW Natural has a self insured retention of $500,000.
(2) There are no deductibles for this policy.
(3) There is no deductible or self insured retention for Broad Form Side A - DIC.

Column A - was forecasted by taking our 2011 response in Data Request 164, and grossing it up by the CPI used in the O&M for 2012 of 2.0%
Column B - was forecasted by taking Column A and grossing it up by the CPI used in the O&M for 2013 of 2.1%
Column C - was a prorated amount using 2 months of the 2012 forecast (Column A), and 10 months of the 2013 forecast (Column B).

The lion's share of claims continues to come from shareholders (both direct, with 45% of respondents reporting these, and derivative, with 42% of respondents reporting these) *(Figure 38)*. Employment-related matters continued to be the primary source of claims for private and nonprofit organizations, with EPL-related claims reported by 36% and 73% of these respondents, respectively *(Figure 39)*.

Figure 38. Types of claims in the last 10 years
Those organizations having claims during the past 10 years

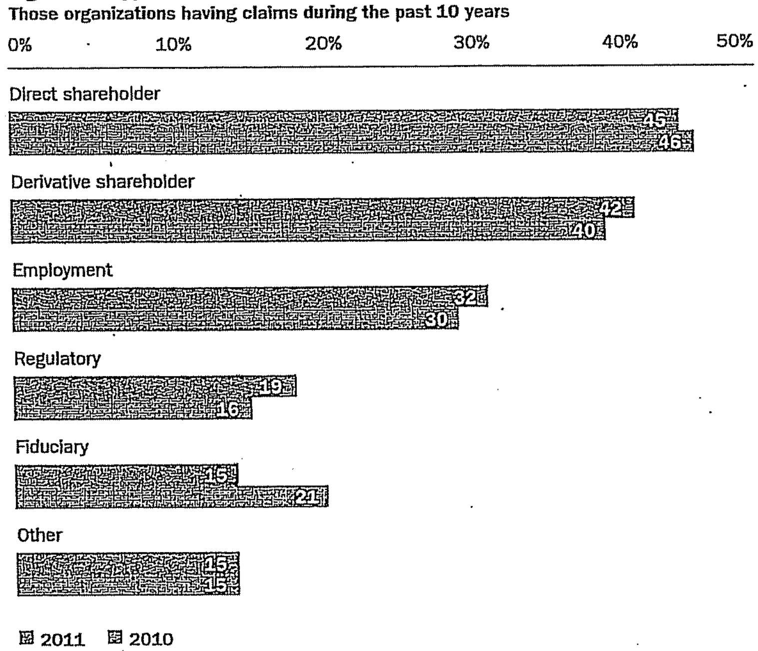

Figure 39. Types of claims in the last 10 years by ownership
Those organizations having claims during the past 10 years

	Direct shareholder/ investor suit	Derivative shareholder/ investor suit	Employment-related	Regulatory	Fiduciary	Other
Nonprofit	0%	3%	73%	23%	13%	27%
Private	21%	7%	36%	14%	14%	29%
Public	69%	65%	15%	18%	17%	6%
All groups (total respondents)	45%	42%	32%	19%	15%	15%

Staff supports Occupational Health Benefits, but disagrees with PGE's proposed increase in funding for the program. Although participation has increased 46 percent between 2006 and 2008, Staff notes that actual program costs have only increased about 1.7 percent. Staff proposes to allow $224,434 in funding for Occupational Health Benefits for 2009, which is an increase of approximately 19 percent over two years.[67] With respect to the IAM program, designed to reduce employee absences, Staff asserts that PGE has failed to link the program to cost reductions benefitting customers, and therefore costs associated with the program should be disallowed.[68] Staff supports Occupational Fitness, but believes that PGE's requested level of funding is unsupported by the record, which shows a recent decrease in costs.[69] Staff also proposes to remove the Recreation Program from the revenue requirement, as these activities are discretionary, take place outside the workplace, and are not required to provide safe and adequate service to customers.[70] Staff supports the Health Club Partial Reimbursement program, but questions whether increasing classes and activities will almost double program costs as indicated by PGE. Instead, Staff supports allowing a 20 percent increase resulting from increased participation for the test year.[71] Staff proposes to adjust the proposed expense for Service Awards in a manner similar to the adjustment for merit-based bonuses—50 percent to customers and 50 percent to shareholders. Finally, Staff recommends disallowance of expenses for Retiree Association and Retiree Luncheon because they are not required to provide safe and adequate service to customers, and to disallow all other unidentified, and therefore unjustified, expenses.[72]

In response, PGE claims that these benefits represent a comparatively small amount of overall benefits yet are a critical part of an overall package designed to attract and retain qualified employees.

Resolution

We concur with Staff's analysis and adopt the calculations contained in Staff/900, Ball/10, to adjust PGE's 2009 revenue requirement through the disallowance of $319,000.

g. Insurance

Staff proposes several adjustments to PGE's requested test-period, insurance-related expense. First, Staff cites falling premiums in the current soft market and recommends no escalation for property and liability premiums.[73] Second, Staff proposes to eliminate 50 percent of the excess Directors' and Officers' (D&O) insurance

[67] Staff/900, Ball/5-6.
[68] *Id. at* 6-7.
[69] *Id.* at 7.
[70] *Id.* at 8.
[71] *Id.*
[72] *Id.* at 9.
[73] Staff/300, Ball-Dougherty/9; Staff/901, Ball/3.

as a shareholder cost. D&O insurance protects PGE senior management in the event that they are sued, whether by customers, stockholders, or others in conjunction with the performance of their Company duties. According to Staff, "[c]ustomers, who have no say in electing or appointing PGE's Directors or Officers, should not be held financially responsible in providing 100 percent of insurance coverage against business decisions or improprieties by management which results in lawsuits."[74] Third, Staff proposes to apply a utility allocation percentage to the overall insurance premiums to allocate the cost between the utility and non-utility aspects of PGE's operations.[75] Finally, Staff proposes a $1.75 million adjustment to PGE's Uninsured Losses based on escalating the five-year historical average by inflation.[76]

PGE contends that D&O liability insurance is a normal cost of doing business, and the entire cost should be included in its revenue requirement. PGE also includes updates to its policies in rebuttal testimony and claims Staff did not properly consider certain policies. PGE further noted that flat insurance rates can still result in increased premiums when property values increase. The Company proposed that the utility allocation factor adjustment should be applied only to a limited number of specific categories.[77]

Resolution

We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost. We also adopt Staff's proposal to hold premiums steady for 2009 property and liability insurance and apply the utility allocation percentage to overall policy premiums. In addition, we adopt Staff's adjustment to Uninsured Losses. PGE's 2009 revenue requirement is therefore reduced by $3.717 million.

h. Miscellaneous Expenses

These expenses consist primarily of costs for catering, gifts, promotional items, and civic activities, including lunch meetings and gifts to employees for overtime work or as retirement gifts, sympathy gifts to employees' families, holiday activities and "team-building days for employees."

Staff proposes that 50 percent of the meal and entertainment expenses, office refreshments and catering, gifts of flowers, and awards be disallowed. In Staff's view, these expenses should be shared equally between ratepayers and shareholders. This approach somewhat mirrors the policy associated with bonuses and the handling of meal and entertainment expenses for income tax purposes.[78]

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[74] *See* Staff/900, Ball/11.
[75] *Id.* at 15.
[76] Staff/300, Ball-Dougherty/11; Staff/900, Ball/14; Staff/901, Ball/4.
[77] PGE Opening Brief at 33-36 and testimony cited therein.
[78] Staff Opening Brief, citing Staff/300, Ball-Dougherty/13-15.

CASE: UG 221
WITNESS: Brian Bahr

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 803

Exhibits in Support
Of Opening Testimony

May 3, 2012

Northwest Natural UG 221
Test Year Ending October 31, 2013
000's of Dollars

This adjustment reflects Staff's proposal to remove 100% of officer bonuses, 75% of performance based non-officer bonuses, and 50% merit based non-officer bonuses. Staff also reduced incentive compensation to account for disallowed FTE and non-utility FTE included in the rate case. This adjustment is commonly proposed by Staff and reflects Commission precedent found in Commission Order No. 99-033 at page 62, Order No. 97-171 at page 74-76, and Order No. 99-697 at 44-45.

Description/ Account No.	Company Filing	Staff	Adjustment
Incentive Compensation	$5,497	$2,067	($3,430)

Staff Initiator:
Brian Bahr

	Included in TY (per DR 392)	3 factor allocation (per NWN/312)	included in OR test year	FTE adjustment % (see box A)		Nonutility adjustment % (see box B, 100% - 1.78%)		Sharing % allowance		Adjustment (OR)
officers	$ 339,000	90.10%	$ 305,439	88.50%	$ 270,300	98.22%	$ 265,489	0%	$ -	$ 305,439
NBU non-officers based on employee merit	$ 3,781,000	90.10%	$ 3,406,681	88.50%	$ 3,014,762	98.22%	$ 2,961,099	50%	$ 1,480,550	$ 1,926,131
NBU non-officers based on Company performance	$ 558,000	90.10%	$ 502,758	88.50%	$ 444,919	98.22%	$ 436,999	25%	$ 109,250	$ 393,508
BU non-officers based on employee merit	$ 1,016,000	90.10%	$ 915,416	88.50%	$ 810,103	98.22%	$ 795,683	50%	$ 397,841	$ 517,575
BU non-officers based on Company performance	$ 407,000	90.10%	$ 366,707	88.50%	$ 324,519	98.22%	$ 318,743	25%	$ 79,686	$ 287,021
	$ 6,101,000		$ 5,497,001		$ 4,864,603		$ 4,778,013		$ 2,067,327	$\boxed{\$ 3,429,674}$

Staff recommends disallowing 100% of officer bonuses.
Staff recommends disallowing 75% of performance-based bonuses
Staff recommends disallowing 50% of merit based bonuses

BU & NBU bonuses treated the same
(Order 99-033 at 62, Order 97-171 at 74-76, Order 99-697 at 44-45, etc)

A. Per FTE Adjustment In Exhibit Staff 500

FTE per NWN	1130
FTE per Staff	1000
%	88.50%

B. Test Year labor expenses expressed as percentages per Staff Data Request No. 96

Utility	
68.17%	O&M
4.04%	COH
1.65%	Clearing
24.37%	Capital
98.23%	
Non-Utility	
0.96%	merchandise
0.82%	other
1.78%	

Staff/803
Bahr/2

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 392:
Per the Company's response to the previous Data Request, and in regard to Table 5 on NWN/800, Doolittle/12, please fill in the requested information in the following tables:

a.

	2011 actual	2012 Forecast	Test Year
Incentive compensation to non-officers			
Incentive compensation to officers			
Total incentive compensation requested for recovery	$5,231	$5,812	$6,101

b.

	2011 Actual	2012 Forecast	Test Year
% of incentive compensation to BU non-officers based on employee merit			
% of incentive compensation to NBU non-officers based on employee merit			
% of incentive compensation to BU non-officers based on Company performance			
% of incentive compensation to NBU non-officers based on Company performance			
Total incentive compensation to non-officers requested for recovery	100%	100%	100%

c.

	2011 Actual	2012 Forecast	Test Year
$ of incentive compensation to BU non-officers based on employee merit			
$ of incentive compensation to NBU non-officers based on employee merit			
$ of incentive compensation to BU non-officers based on Company performance			
$ of incentive compensation to NBU non-officers based on Company performance			
Total incentive compensation to non-officers requested for recovery			

Response: 3/7/2012

a.

	2011 actual ($000)	2012 Forecast ($000)	Test Year ($000)
Incentive compensation to non-officers	$5,946	$5,482	$5,762
Incentive compensation to officers	$ 275	$ 330	$ 339
Total incentive compensation requested for recovery	$6,221	$5,812	$6,101

b.

	2011 Actual	2012 Forecast	Test Year
% of incentive compensation to BU non-officers based on employee merit	24%	17%	18%
% of incentive compensation to NBU non-officers based on employee merit	64%	66%	65%
% of incentive compensation to BU non-officers based on Company performance	5%	7%	7%
% of incentive compensation to NBU non-officers based on Company performance	7%	10%	10%
Total incentive compensation to non-officers requested for recovery	100%	100%	100%

c.

	2011 actual ($000)	2012 Forecast ($000)	Test Year ($000)
$ of incentive compensation to BU non-officers based on employee merit	$1,457	$ 960	$1,016
$ of incentive compensation to NBU non-officers based on employee merit	$3,828	$3,606	$3,781
$ of incentive compensation to BU non-officers based on Company performance	$ 270	$ 384	$ 407
$ of incentive compensation to NBU non-officers based on Company performance	$ 391	$ 532	$ 558
Total incentive compensation to non-officers requested for recovery	$5,946	$5,482	$5,762

Notes:

- Please refer to NW Natural's Response to OPUC DR 391 for an explanation of the individual and Company performance measures used to allocate incentive compensation.
- The 2011 amount above has been updated to reflect actuals for 2011 and therefore does not match the amount for 2011 in Table 5 of NWN/800, which was based on nine months of actuals and three months of forecasted amounts for 2011.
- NBU Goals Incentive Plan amounts are based on employee merit.
- Key Goals are based:
    a. Projected 2012 and Test Year: 71% on employee merit and 29% on Company performance.
    b. Actual 2011: 84% on employee merit and 16% on Company performance.
    c. Non-officer Long-Term Incentive Plan (LTIP) amounts are based on Company performance.
- 2011 amounts are:
    a. Officers: based on actual 1.04% factor, times grade 25/26 target percentage, times grade 25/26 average salary.
    b. BU and NBU:
        i. Actual Key Goal amounts.
        ii. Actual NBU Goals Incentive Plan amounts.
        iii. Actual non-officer LTIP amounts.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Standard Data Request Response

Request No. 96: For the test year, please provide the breakout between O&M and rate base for all labor expense expressed as percentages. If applicable, please also provide the breakout for all labor expense between Total Company and Oregon expressed as a percentage.

Response:

Test Year labor expenses expressed as percentages

O&M	68.17%
COH	4.04%
Merchandise	0.96%
Other	0.82%
Clearing	1.65%
Capital	24.37%

The Company does not prepare budgeted or allocated total payroll by state.

V

(OPERATING EXPENSES)

OFFICER COMPENSATION
(Issue 10)

OVERVIEW

Staff proposed to exclude $32,000 in officer compensation based on the performance of PNB's parent, US West. The rationale is that Oregon ratepayers should not be charged for expenses arising from other US West operations.

PNB asserts that (1) PNB's officers significantly influence US West's financial performance, (2) tying officer compensation to US West's performance will produce stable growth in earnings, and (3) stable earnings growth will minimize US West's cost of capital to the benefit of PNB's ratepayers.

Staff responds that (1) PNB's Oregon operations represent only 9 percent of US West's total operations, and (2) compensation for PNB's officers should be based only on factors directly under their control.

FINDINGS

The stipulated Forecasted Results of Operations includes $32,000 on an Oregon intrastate basis for compensation of PNB's officers based on the performance of its parent, US West. US West's performance is predominantly a function of the performance of its Bell Operating Companies because they represent 93.2 percent of US West's profits and 99.2 percent of its assets.

PNB represents approximately 25 percent of the three Bell Operating Companies. Oregon operations represent approximately 40 percent of PNB's total. As a result, PNB's Oregon operations account for approximately 9 percent of US West's total operations.

EXISTING POLICY

Only expenditures necessary for furnishing utility service should be reflected in rates. <u>Portland General Electric Company</u>, UF 3218, Order No. 76-601 @ 13; <u>Cascade Natural Gas</u>, UF 3246, Order No. 77-125 @ 10.

RESOLUTION

The problem with the compensation plan is that Oregon ratepayers will provide the proper amount of compensation only if PNB's performance is exactly the same as the combined performance of US West's other operations. The situation of concern to the Commissioner would arise if poor management resulted in poor service and/or poor financial performance for PNB while US West's other operations had banner years. Disgruntled Oregon ratepayers could pay bonuses to PNB's officers at a time they should be removed from office.

CONCLUSION

The Commissioner concludes that the contribution of Oregon ratepayers to PNB's officer compensation should be related only to PNB's performance. Staff's proposed $32,000 adjustment is adopted.

ISSUE S-15: BONUS ADJUSTMENT

Summary of Issue

Two questions are presented regarding performance bonuses. For non-officer performance bonuses, NW Natural proposes a 50/50 sharing with shareholders and ratepayers, while Staff proposes a 75 percent disallowance. For merit-based bonuses, NW Natural proposes that 100 percent of the non-officers' bonuses be included in utility expense. Staff recommends a 50/50 sharing for both non-officers' and union employees' merit-based bonuses.

Positions of the Parties

NW Natural first contends that performance bonuses paid to supervisors and managers be shared 50/50 between customers and shareholders. The company believes that the 50/50 sharing of non-officer bonuses is reasonable because the bonuses are designed to make the company's total compensation package for these employees competitive with comparable jobs in the regional labor market.

Second, NW Natural proposes that 100 percent of the non-officers merit-based bonuses, Key Goals program, be included in rates. NW Natural explains that there are five Key Goals, three of which directly relate to customer interests. These include rate stability, customer satisfaction, and productivity. The other two goals, profitability and market share, benefit customers over time. Because the Key Goal program benefits customers, NW Natural maintains that the merit-based bonuses—including those paid to union employees—should be included in utility expense.

Staff proposes a 75 percent disallowance of performance-based bonuses, and a 50/50 sharing of merit-based bonuses. Staff explains that the Commission has traditionally disallowed 75 percent of performance-based bonuses, because they are generally focused on the company's increased earnings and, therefore, bring more benefit to shareholders. It adds that the Commission has generally allowed equal sharing of merit-based bonuses, because they equally benefit shareholders and ratepayers. It contends that the company's Key Goals program should be similarly treated, noting that shareholders clearly benefit through increase earnings if the profitability and market share goals are achieved. Finally, it contends that the Commission should apply these recommendations to all bonuses, including those paid to union employees. It notes that the Commission has always treated union bonuses in the same manner, because the same rationale applies.

Commission Resolution

After our review, we find Staff's bonus adjustments to be reasonable and adopt them. Staff's recommendations are consistent with past ratemaking treatment of bonuses in prior electric and natural gas rate cases. NW Natural has not persuaded us that a change in policy is warranted.

ISSUE S-18: CIS

Summary of Issue

The history of NW Natural's Customer Information System (CIS) development is complex. The analysis of the argument is also difficult, caused primarily by the different approaches used by the parties to evaluate the CIS. There are, however, just two primary questions presented for Commission resolution.

First, the Commission must decide the standard of review for the recovery of NW Natural's CIS investment. Second, the Commission must determine whether the CIS stipulation allows for a reasonable level of CIS recovery and, therefore, should be approved. To fully understand this issue, a review of the history of NW Natural's CIS development is necessary.

Facts

In 1991, NW Natural began an effort to develop a new CIS to serve its residential and commercial accounts. The company's old CIS, the Legacy system, had been constructed in stages beginning in the 1960s. Over the years, NW Natural made numerous modifications and upgrades to the system, but encountered increasing reliability problems and functional limitations. Moreover, the Legacy system was not Year-2000 compliant.

After a bidding process, NW Natural hired IBM to perform a study on CIS implementation strategies. Based on the results of the study, NW Natural awarded a fixed-price contract to IBM for the development of a customized CIS. The overall projected budget, as approved by NW Natural's Board of Directors, was $24 million, which included a $12 million fixed fee to be paid to IBM for its services. NW Natural hoped to have the new system in place and operational by January 1996.

The CIS project was intended to proceed in five phases, whereby each succeeding phase added increased functionality. The first phase, called Application Function Group 1 (AFG1), was intended to allow inquiry of customer data that had been converted from the Legacy system. During AFG1 development, however, the project team experienced significant difficulties in two primary areas. The first problem pertained to the use of an object-oriented database. The project team initially chose to use a relational database[11] in combination with an object-oriented graphical user

[11] A relational database essential stores data in a matrix format of columns and rows, while an object-oriented

11. Incentive Pay

Staff proposed two adjustments concerning incentive pay. PGE does not challenge Staff's adjustment to the "Our Teamworks Program" of $1,390,078. Staff also proposed an adjustment of $1,273,200 to the Officer Incentive Plan. PGE claims that this adjustment is inconsistent with past Commission practice (in UE 88, for example), where the Commission allowed inclusion in revenue requirement of the 25 percent portion of the Officer Incentive Plan applicable to non-officers. Staff now accepts the allowance of a portion of the plan covering non-officer employees and asks that the Commission approve the following principle for incentive pay:

> One-half of Our Teamworks expense, all of the Officers portion of the Officer Incentive Plan and seventy-five percent of the non-officer portion of the OIP pay should be excluded from utility rates, consistent with past Commission practice.

12. Commission Disposition

The Commission adopts Staff's principle as set out above.

13. Administrative and General (A&G) Costs

Staff proposed a reduction in the A&G costs of nine full-time employees (FTEs) resulting in a revenue requirement adjustment of $321,000. Staff made its calculation through a "trend" analysis under which it used known or forecasted values for customer accounts and customers per FTE in the years 1991 through 1997 to forecast an appropriate account of customers/FTE for 1998, the last year before the company proposed to become a distribution-only utility. The forecasted value was then used to determine the appropriate FTE in 1999.

PGE criticizes this trend analysis. It states that Staff has provided no statistical test to support the use of this analysis and no test to indicate that it produces statistically accurate forecasts. PGE also claims that an appropriate analysis of the level of the A&G FTEs should take into account the specific activities the FTEs support. If the utility provides functions that are in the interest of its customers but that require additional human resource, accounting, and budgeting personnel necessary to support the function, the A&G FTEs would increase even if the number of customers remains constant. Thus, according to PGE, Staff's trend analysis would penalize such a utility by making an A&G FTE adjustment even if the functions involved were in the best interests of the customer. PGE also asserts that Staff's method is flawed because it assumes that the rate of increase in efficiency in recent years will continue into the future. PGE asserts that there is no assurance that a past rate of improvement in efficiency will continue.

Issue 8a: Incentive Plans (Bonuses)

USWC proposes to include in the test year $4 million in bonuses that were paid to its management and executive employees in 1995 under three incentives programs: (1) Team Performance Award Plan (TPA); (2) Executive Short Term Incentive Plan (STIP), and (3) Executive Long Term Incentive Plan (LTIP).

Bonuses paid under these plans were based on the achievement of certain financial, business, and corporate goals. The 1995 TPA bonuses were paid for meeting or exceeding goals regarding (1) Earnings before Interest, Taxes, Depreciation, and Amortization (EBITDA); (2) USWC Net Income; and (3) Business Unit Results & Strategic Measures, and Customer Service. The 1995 STIP bonuses were paid for meeting or exceeding goals regarding (1) Financial Performance (new product development, net income, EBIDTA); (2) Reengineering Benefits; and (3) Customer Loyalty. The 1995 LTIP bonuses were paid for meeting or exceeding goals regarding (1) increase in the price of USWC stock; and (2) stock dividend growth.

Staff takes the position that these bonuses should be excluded from the test year because the financial, business, and corporate goals on which the bonuses were based primarily benefited USWC's shareholders. Therefore, Staff reasons, the shareholders should pay for the bonuses.

Staff notes that in the past, the Commission has not allowed a utility's revenue requirement to include employee bonuses that were based on the utility's financial results of operations. *See, e.g., Pacific Northwest Bell Telephone Company*, UT 43, Order No. 87-406 at 42, where we stated:

> Only expenditures necessary for furnishing utility service should be reflected in rates. *Portland General Electric*, UF 3218, Order No. 76-601 at 13; *Cascade Natural Gas*, UF 3246, Order No. 77-125 at 10.

Staff contends that USWC's base salaries for management and executive employees are reasonable, but maintains that USWC has not shown that the goals on which the bonuses were based were justified by benefits to ratepayers. For instance, Staff notes that although quality of service deteriorated in 1995, the total TPA did not decline.

Staff concludes that the performance goals under USWC's management incentive plans were designed to benefit shareholders but were not in the ratepayers' interests. Staff argues that it is inappropriate for USWC's Oregon ratepayers to pay for bonuses for the utility's management and executive employees at a time when USWC's service quality problems in Oregon have increased significantly and when, as Staff believes, USWC is overearning by $100 million. Including the bonuses in the revenue requirement in this situation, Staff argues, would add insult to injury for ratepayers.

Finally Staff notes that although it recommends excluding USWC's executive and management bonuses from the test year in this case, in future rate cases it would consider including employee incentive plans with goals that would benefit both ratepayers and shareholders.

USWC argues that its overall level of compensation, including bonuses, is not only reasonable but is below market. USWC argues that Staff is asking the Commission to preclude recovery of expenses that the record shows were actually incurred by the company, and that are reasonable. USWC also argues that excluding bonuses would amount to micromanaging the company.[37] That is, the Commission would be deciding what form compensation of company management should take.

USWC further argues that paying market wage levels including incentive compensation is necessary for the provision of utility service. If bonuses were eliminated, USWC points out, salaries would have to be raised an equal amount to attract employees. Therefore, USWC argues, Staff's proposed disallowance is arbitrary, because it is based only on the manner in which compensation is administered.

USWC maintains that Staff has never previously challenged manager bonuses, and asserts that the facts in UT 43, the case on which Staff relies, are distinguishable from those in this case. USWC contends that use of incentive pay is common in the industry and encourages enhanced USWC employee performance toward ratepayers. If Staff's proposal is adopted, USWC maintains, it will send a signal to the company that it should not try to provide financial incentives for employee performance.

Finally, USWC argues that the Commission should allow recovery of bonuses to prevent discriminatory treatment of USWC in a competitive environment. USWC notes that its major competitors rely on incentive pay to compensate their employees. According to USWC, this indicates both that the practice of offering incentive pay is widespread and that the Commission should allow USWC's bonuses because to do so would be competitively neutral.

Disposition. The record shows that USWC's base salaries before bonuses are within a reasonable range, as is USWC's compensation including bonuses. Because its compensation is reasonable compared to the market, USWC concludes that its expense for management and executive bonuses is reasonable. USWC conflates two separate issues. The level of overall compensation is reasonable compared to the market. That

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[37] USWC argues that most commissions follow the principle that "managers of a utility have broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers," including compensation decisions. *Violet v. FERC*, 800 F2d 280, 282 (1st Cir. 1986). USWC also cites two California cases that advocate leaving the allocation of compensation between salaries and incentives to the utility's discretion *In re Pacific Gas and Electric Co.*, 1992 WL 438101 slip op at 46 (Cal. PUC); *In re Southern California Edison Co.*, 130 PUR 4th 97, 126 (1991) ("The Commission's duty is to authorize reasonable expenses for employee compensation as a whole, without micromanaging the distribution of employee salaries, wages, and benefits.").

does not determine whether it is reasonable to ask ratepayers to fund bonuses with the declared goals of USWC's incentive plans.

USWC is correct in stating that Order No. 87-406 (UT 43) does not preclude recovery of incentive pay linked to financial performance. The disallowance in that case occurred because the proposed compensation was based on the performance of the utility's parent, not the utility itself. Still, the principle that Staff quotes from that order is our policy: "Only expenditures necessary for furnishing utility service should be reflected in rates." Order No. 87-406 at 42.

We disagree that submitting USWC compensation expenditures to scrutiny is micromanaging; rather, it is our role as regulators to determine the reasonableness of USWC's claimed expenses. On review of the stated goals for the incentive programs at issue, we note that some of the goals on which bonuses were awarded deal with earnings, net income, financial performance, reengineering benefits, and stock prices and dividend growth. These goals benefit shareholders rather than ratepayers.

Two of the goals deal with customer service and customer loyalty. In view of the problems USWC has had with customer service (see discussion at Issue 9c below), we agree with Staff that it is inappropriate to award bonuses for performance in this area.[38] We point out that here our decision deals with bonuses for management and supervisory personnel. We do not mean our comments to reflect negatively on front line employees, who have done well under a difficult set of circumstances.

Under the circumstances of this case, we conclude that USWC has not shown that its incentive plans are reasonable expenses for the provision of utility service. We note that our disallowance is not based on the manner in which compensation is administered but on the purpose for which the bonuses are awarded. We also note that this conclusion does not prevent USWC from paying bonuses; it merely dictates that bonuses be paid from funds that would go to shareholders, not from funds provided by ratepayers. Therefore, we do not believe that the resolution of this issue places USWC at a competitive disadvantage.

We limit the findings on this issue to the facts before us. If in a future rate case USWC submits employee incentive plans with goals that would benefit both ratepayers and shareholders, we will include those expenditures in revenue requirement.

Issue 8b(2): Other Payroll Changes

In this adjustment, Staff proposes to add the effects of wage rate changes for 1996 and 1997 to the 1995 test year. USWC agrees with the mechanics of Staff's adjustment but disagrees about the need for pro forma adjustments. *See* discussion at Issue 1a(1)

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[38] USWC appears to argue that Staff raises the argument of disallowance based on service quality issues for the first time in its brief. This is incorrect. *See* Revised Staff/1 Lambeth/65.

CASE: UG 221
WITNESS: Brian Bahr

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 804

Exhibits in Support
Of Opening Testimony

May 3, 2012

Northwest Natural UG 221
Test Year Ending October 31, 2013
000's of Dollars

This adjustment reflects Staff's proposed adjustments to FTE. Based on Staff's adjustments to FTE found in Exhibit Staff/500, Staff removed the same percentage from active employee medical benefits and from workers compensation amounts included in the test year. Per the Company's response to Staff Data Request No. 96, Staff also removed 1.78% of medical benefits and workers compensation to account for non-utility employees included in the test year.

Description/ Account No.	Company Filing	Staff	Adjustment
Medical Benefits & Workers Comp	$16,565	$14,506	($2,059)

Staff Initiator:
Brian Bahr

	TY per NWN (DR 63)	3 factor allocation (per NWN/312)	Included in OR test year	FTE % allowance (see box A)		Nonutility adjustment % (see box B, 100% - 1.78%)	per Staff	Adjustment
Medical Benefits								
Bargaining Unit Health - Active Employees	$ 8,455,751	90.1%	$ 7,618,632	88.50%	$ 6,742,152	98.22%	$ 6,622,142	$ 996,490
Bargaining Unit Health - Retirees	$ 913,387	90.1%	$ 822,962	100.00%	$ 822,962	100.00%	$ 822,962	$ -
Non-Bargaining Unit Health - Active Employees, plus Other Benefits for Active Employees*	$ 7,586,596	90.1%	$ 6,835,523	88.50%	$ 6,049,136	98.22%	$ 5,941,461	$ 894,062
	$ 16,955,734		$ 15,277,117					$ 1,890,552

	TY per NWN (DR 384c)	3 factor allocation (per NWN/312)	Included in OR test year	FTE % allowance (see box A)		Nonutility adjustment % (see box B, 100% - 1.78%)	per Staff	Adjustment
Workers Comp	$ 1,428,928	90.1%	$ 1,287,464	88.50%	$ 1,139,349	98.22%	$ 1,119,068	$ 168,396
			Total OR allocated				Total per Staff	Total Adjustment
			$ 16,564,581				$ 14,505,633	$ 2,058,948

* Other Benefits include: Long Term Disability Insurance, Short Term Disability Administration, Flexible Spending Administration, and Employee Assistance Programs

A. Per FTE Adjustment in Exhibit Staff 500

FTE per NWN	1130
FTE per Staff	1000
%	88.50%

B. Test Year labor expenses expressed as percentages per Staff Data Request No. 96

Utility	
68.17%	O&M
4.04%	COH
1.65%	Clearing
24.37%	Capital
98.23%	
Non-Utility	
0.96%	merchandise
0.82%	other
1.78%	

Staff/804
Bahr2

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response
UPDATED

Request No. GR1-OPUC-SDR 63:
In the following table format, please provide medical benefit costs for the test year, historical base year, and the three years prior to the historical base year. Please also explain if the amounts reflected in the Company's response are before or after employer/employee sharing. For the test year estimates, please explain the assumptions relied upon (i.e. increased employees, specific escalation factor to premiums, etc) in arriving at the forecasted amounts.

	Test Year	Base Year	Base Year – 1	Base Year – 2	Base Year – 3
Medical					
Dental					
401(k)					
Group Life Insurance					
Retiree Life Insurance					
Long-Term Disability					
Other (*Please Label*)					
Total					

Response: Updated 2/3/2012

The worksheet provided in the Company's initial data request has been updated to include the 4th quarter 2011 actual results. This updated information is confidential subject to Order No. 12-001.

Please see OPUC-SDR 63 Updated Attachment-1 CONFIDENTIAL.

This page is confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 384:
For the following list of Staff Data Requests requesting data for the historical base year or prior years or both, please also provide the amounts included in the application for the forecasted base year and forecasted test year:

a. Staff Data Request No. 70 (Property Damage loss)
b. Staff Data Request No. 71 (Liability loss)
c. Staff Data Request No. 72 (Workers' Compensation)

Response: 3/7/2012

a & b. For the base year and test year, these two items are grouped together under Claims Accruals. For the base year, the actual total claims accrual in O&M is $88,287. For the test year the claims accrual amount is $350,000. The test year amount is the average actual claims accrual expenses for the years 2008 through 2010.

c. For the base year, the actual workers compensation expense was $1,437,713. For the test year, workers compensation expense forecast is $1,428,928.

CASE: UG 221
WITNESS: Brian Bahr

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 805

Exhibits in Support Of Opening Testimony

May 3, 2012

Northwest Natural UG 221
Test Year Ending October 31, 2013
000's of Dollars

This adjustment reflects Staff's proposal to remove various A&G expense amounts. Staff removed 50% of the following costs: Books and Magazines, Conference Travel, Dealer Relations, Education, Employee Awards, Employee Awards MLS, Meals and Entertainment, and Miscellaneous. Staff also removed 100% of the following cost elements: Donations, Dues/Memberships, Corporate Identity, Laundry, Non Employee Gifts, and Refreshments. 50% of dues to certain natural gas industry organizations were then added back in. Staff routinely proposes this adjustment in rate cases.

Description/ Account No.	Company Filing	Staff	Adjustment
901 - 904 (Customer Accounts)	$18,715	$18,637	($78)
907 - 910 (Customer Service & Info)	$6,013	$5,902	($111)
911 - 916 (Sales)	$3,151	$2,738	($413)
920 - 935 (Admin & General)	$38,545	$36,932	($1,613)
50% allowance of membership dues to certain Natural Gas Industry Organizations			$233
Total	$66,423	$64,442	($1,982)

Staff Initiator:

Brian Bahr

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You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

Non-labor amounts removed from accounts 901 - 935

Cost Element	Disallowance	Disallowed Amount	901	902	903	907	908	909	910	911	912	913	921	925	926	930	935
DONATIONS	100%	$ 8,550									$ 1,000		$ 7,550		$ -		
DUES/MEMBERSHIP	100%	$ 1,015,306			$ 1,941		$ 11,676	$ 729		$ 1,299	$ 6,414	$ 25,445	$ 175,930	$ 2,473	$ 14,117	$ 774,861	$ 421
CORPORATE IDENTITY	100%	$ 284,239					$ 15,352	$ 28,471			$ 134,767	$ 90,839	$ 7,458		$ 6,817	$ 535	
LAUNDRY	100%	$ 59,620					$ 444				$ 6,275	$ 45	$ 1,257		$ 483	$ 115	$ 51,001
NON EMPLOYEE GIFTS	100%	$ 2,601			$ 467		$ 699						$ 981	$ 91	$ 68	$ 224	$ 72
REFRESHMENTS	100%	$ 84,686	$ 2,174		$ 18,633		$ 3,079		$ 7,136	$ 513	$ 1,228		$ 32,112	$ 1,691	$ 11,500	$ 131	$ 6,489
BOOKS AND MAGAZINES	50%	$ 35,683			$ 729	$ 10	$ 1,360		$ 449	$ 150	$ 1,050	$ 51	$ 30,213	$ 134	$ 1,146		$ 390
CONFERENCE TRAVEL	50%	$ 223,518	$ 10,131	$ 4,913	$ 15,000		$ 11,005			$ 494	$ 2,110		$ 154,846	$ (29)	$ 17,052	$ 1,942	$ 6,054
DEALER RELATIONS	50%	$ 171,473			$ 96		$ 10,965		$ (170)		$ 159,383	$ 28	$ 552		$ 620		
EDUCATION	50%	$ 158,294	$ (2)		$ 4,148		$ 5,665				$ 1,095		$ 73,499	$ 155	$ 65,616	$ 2,619	$ 5,498
EMPLOYEE AWARDS	50%	$ 105,514			$ 14,975		$ 4,822		$ 595		$ 1,091	$ 50	$ 24,566	$ 943	$ 56,838		$ 1,634
EMPLOYEE AWRDS MLS &	50%	$ 52,912			$ 3,171		$ 1,852		$ 393	$ 223	$ 313		$ 10,675	$ 303	$ 35,860	$ 19	$ 103
MEALS AND ENTERTAIN	50%	$ 163,811	$ 1,809	$ 4	$ 3,856		$ 16,922		$ 451	$ 820	$ 9,539	$ 733	$ 93,428	$ 1,164	$ 12,781	$ 17,315	$ 4,986
MISCELLANEOUS	50%	$ 2,540			$ 1,142		$ 469				$ (3,434)	$ 189	$ 8,322	$ 7	$ (4,455)	$ 60	$ 241
	TOTAL	$ 2,368,747	$ 14,113	$ 4,916	$ 64,160	$ 10	$ 84,310	$ 29,200	$ 8,855	$ 3,499	$ 320,833	$ 117,378	$ 621,390	$ 6,930	$ 218,443	$ 797,819	$ 76,892

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 163:
As a follow up to the Company's response to Standard Data Request No. 58, please provide an updated response which includes the actual for the last quarter of 2011 rather than forecasted amounts.

Response: 2/14/2012

See the Company's updated response to SDR 58 which has been posted on the Company's FTP site in the folder titled CONFIDENTIAL SUBJECT TO PROTECTIVE ORDER 12-001.

Pages 5 and 6 are confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 162:
As a follow up to the Company's response to Standard Data Request No. 57, please provide an updated response which includes the last quarter of 2011.

Response: 2/14/2012

See the Company's updated response to SDR 57 which has been posted on the Company's FTP site in the folder titled CONFIDENTIAL SUBJECT TO PROTECTIVE ORDER 12-001.

This page is confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

NW Natural

2012 Contributions Budget

Name of Organization	Account	Amount
Audubon Society of Portland	426	10,000
Big Brothers/Big Sisters	426	40,000
Black Parent Initiative	426	10,000
Black United Fund of Oregon	426	22,000
Camp Fire, USA	426	40,000
CASA for Kids	426	5,000
Central City Concern	426	5,000
Children's Relief Nursery	426	15,000
Classroom Law Project	426	3,500
Community Foundation of SW Washington	426	12,000
Earth Share of Oregon	426	32,000
Employers for Education Excellence	426	5,000
Friends of the Children	426	7,500
Freshwater Trust	426	80,000
Gas Assistance Program	426	50,000
Guide Dogs for the Blind	426	10,000
Habitat for Humanity	426	25,000
Hands on Portland	426	10,000
Junior Achievement	426	10,000
LifeWorks NW	426	5,000
Metropolitan Family Services	426	7,500
Nature Conservancy	426	5,000
New Avenues for Youth	426	3,000
Newspapers in Education (ONF)	426	5,500
Northwest Business for Culture & Arts	426	5,000
Medical Teams International	426	10,000
Mercy Corp International	426	10,500
Oregon Burn Center	426	4,000
Oregon Museum of Science and Industry	426	5,000
Work for Art/RACC	425	22,000
Oregon Community Foundation	426	70,000
Oregon Environmental Council	426	5,000
Oregon Food Bank Network	426	10,000
Oregon Independent College Foundation	426	12,000
Oregon State Parks Trust	426	5,000
Oregon State University Foundation	426	15,000
Oregon Symphony	426	10,000
Portland Art Museum	426	10,000
Portland Center Stage	426	20,000
Portland Community College Foundation	426	5,000
Portland Opera	426	10,000
Portland Parks Foundation	426	5,000
Portland Public Schools Foundation	426	5,000
Portland State University Foundation	426	15,000
Poverty Bridge	426	5,000
REACH Community Development	426	5,000
Salvation Army	426	5,000
Schoolhouse Supplies	426	15,000
SMART	426	10,000
Stop Oregon Litter and Vandalism	426	10,000
Transition Projects	426	4,500
United Way Chapters throughout Oregon	426	120,000
Unitversity of Oregon Foundation	426	20,000
Urban League of Portland	426	20,000
Uncommitted	426	232,545
Sub-Total		1,118,545
Chamber of Commerce		
Oregon & Washington	426	28,860
Organizations of the Gas Utility Industry:		
American Gas Association	930	405,360
Institute of Gas Research (and other R&D)	930	400,000
Western Energy Institute	930	29,000
Northwest Gas Association	921	75,000
Sub-Total		909,360
TOTAL		2,056,765

Staff also proposes removing 100 percent of civic activities recorded in Administrative & General (A&G) accounts, noting "the Commission has not previously allowed regulated utilities to recover contributions to charities, community affairs, and economic development organizations through rates charged for regulated services. . . . In addition, Commission policy does not require customers to support causes in which they do not believe."[79]

PGE asserts that these discretionary costs are appropriately included in rates, because these miscellaneous expenses create a business culture that allows the utility to attract and retain qualified workers.[80]

Resolution

We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders. We also adopt Staff's recommendation with respect to contributions to charities, community affairs, and economic development organizations. PGE provides no rationale to change our existing policies, and we conclude that all contributions to charities, community affairs, and economic development organizations should be disallowed. PGE's 2009 revenue requirement is reduced by $710,000 to reflect the disallowance of these expenses.

We also acknowledge PGE's removal of Directors' Compensation and Officer Vehicles from the proposed 2009 test-year budget. The total revenue-requirement reduction for miscellaneous expenses is $1.18 million.

i. Senate Bill 408 Ratio Adjustment

Senate Bill 408 (SB 408) requires the Commission to establish certain ratios in general ratemaking proceedings, which will be used to determine the amounts of "taxes collected" from customers for the purpose of the SB 408 true-up of "taxes paid" to "taxes collected." PGE believes that, in setting the tax rate and margin ratios here for SB 408 purposes, the Commission should consider the impact of costs that have been disallowed. PGE explains that, "[t]o do otherwise would effectively allow customers to receive tax benefits from utility costs for which customers are not responsible."[81]

Staff opposes PGE's proposal as an attempt to insulate its shareholders from sharing the tax benefit of disallowed expenses with ratepayers when truing up the amount of taxes collected. Staff believes PGE's request is inconsistent with the terms of SB 408, as well as Commission rules implementing the bill.[82] According to Staff, the Commission indirectly addressed this issue when it declined PGE's request for a deferral

[79] *Id.*, citing Staff/300, Ball-Dougherty/15.
[80] PGE Opening Brief at 37, citing PGE/2700, Piro-Tooman/12.
[81] PGE/2300, Tooman-Tinker/24.
[82] *See* ORS 757.268 and OAR 860-022-0041.

CASE: UG 221
WITNESS: Nick Cimmiyotti

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Nicholas (Nick) Cimmiyotti. I am employed by the Public Utility Commission of Oregon as Senior Financial Analyst, Corporate Analysis and Water Regulation Section, in the Economic Research and Financial Analysis Division of the Utility Program. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/901.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am recommending three adjustments to the Company's filing. Two of my adjustments are designed to reverse NW Natural Gas Company's (NW Natural or Company) request to capture in rate base and receive a return "of" and a return "on" their cash contributions made by the Company to two defined benefit plans. The Company states that these contributions were in excess of the amount calculated using the standard Financial Accounting Statement (FAS) 87 Net Periodic Pension Costs calculation. The third adjustment reduces the requested Research and Development (R&D) expenditures booked to Federal Energy Regulatory Commission account 930 to a level that is consistent with the average annual R&D spending by gas distribution companies.

Q. PLEASE DESCRIBE IN DETAIL YOUR RATE BASE RELATED PENSION ADJUSTMENTS.

A. I recommend the removal of the $21,929,876, net of deferred taxes, which the Company added to their requested rate base to recover cash pension contributions by the Company to their defined benefit plans, in the years prior to the Test Year, as shown in NWN/409, Feltz/1. The Company states that this rate base item is the after-tax amount of the cumulative cash contributions to the defined benefit plans that they made in excess of their accrual accounting based FAS 87 Net Periodic Pension Costs (NPPC) recovered in rates. As stated in the Company's testimony, these cash contributions were made by the Company from 2004 through to the Test Year NWN/409, Feltz/1. Removing this pension related rate base item nullifies the Company's attempt to earn a return "on" this added rate base item made in prior periods, which results in a reduction of the Company's requested revenue requirement in the amount of $3,114,000.

The second adjustment I recommend is the removal of the return "on" the Company's cash contributions in excess of the NPPC amount made prior to the test period. I am recommending the removal of the Company's pension related expense amortization of $4,568,724, or $36,549,793 (cumulative excess difference) amortized over eight years, which is based on the Company's pre-tax excess cumulative cash pension contribution shown in NWN/400, Feltz/28.

Q. WHAT METHOD HAS THE COMMISSION UTILIZED IN SETTING THE LEVEL OF PENSION EXPENSES IN RATES?

A. Since its adoption in 1986, the Commission has relied upon an actuarial calculation of a company's Net Periodic Pension Costs (NPPC) in determining the appropriate level of pension expense to include in rates. The NPPC is calculated as of December 31 of the previous year, using the guidelines established by the Federal Accounting Standards Board's (FASB) in their Financial Accounting Statement (FAS) 87, "Employer Accounting for Pensions." An independent actuary is used to perform this calculation which includes pension variables such as the fair value of the plan, actual/estimated value of the plan, benefits paid, funding status, service costs, interest costs, expected return on assets, amortization of the transitions asset, amortization of prior service cost, and recognition of gains or losses, in order to calculate the Company's NPPC. A major benefit of relying on the NPPC as opposed to cash accounting, beyond maintaining compliance with FASB accounting standards, is the fact that the NPPC calculation smoothes out the losses and gains over time in an attempt to smooth out some of the market volatility associated with equity markets.

Q. ABSENT NEW GUIDANCE FROM FASB, WHY WOULD IT BE INAPPROPRIATE FOR THE COMMISSION TO DEVIATE FROM UTILIZING THE COMPANY'S NPPC IN DETERMINING THE PENSION EXPENSES TO INCLUDE IN RATES FOR NW NATURAL?

A. Based on FASB SFAS – 87, the Commission established the precedent of using the NPPC. FASB is responsible for establishing changes in financial accounting standards. Any deviation from the current precedent established through FASB guidance would have to be initiated by the issuance of a new statement of financial accounting standard (SFAS) by FASB.

Q. HAS THE FASB RESINDED SFAS-87?

A. No. SFAS 58 was amended first by SFAS 132R in December 2003 and was amended again by the issuance of SFAS No. 158 in September 2006. SFAS 87 is still in effect for the calculation of a company's pension expense.

Q. DOES THE COMPANY CURRENTLY OPERATE UNDER ANY COMMISSION ORDERS REGARDING PENSION EXPENSE?

A. Yes, in their Order 11-05 in Docket UM 1475, the Commission allowed NW Natural to establishment of a balancing account to track the differences between its actual pension expense and the amount recovered in rates,

Q. DOES THE BALANCING ACCOUNT, ESTABLISHED BY THE COMMISSION IN ORDER NO. 11-051 IN DOCKET UM 1475, ALLOW THE COMPANY THE OPPORTUNITY EARN A RETURN ON THE BALANCE IN THE ACCOUNT AT THE COMPANY'S AUTHORIZED RATE-OF-RETURN?

A. Yes. It is also expected that the balance, currently estimated at $5.56m for calendar year 2011, as shown in NWN/409, Feltz/1, will decline after the next few years and the balancing account amounts will ultimately turn negative and net to zero.[1] Normally, only expenses that were "used and useful" during the Company's Test Year are included for recovery in rates.

[1] Oregon Public Commission Docket 1475, Order No.11-051.

Q. WOULD IT BE JUST AND REASONABLE TO REIMBURSE THE COMPANY FOR THEIR CASH CONTRIBUTIONS, MADE IN PRIOR PERIODS, WITHOUT A FULL EXAMINATION OF ALL REGULATED COST AND REVENUES DURING THE SAME PRIOR TIME PERIOD?

A. No. To include some prior expense increases while not fully examining all expenses and revenues for their respective increases and decreases could lead to overstatement of expenses as well as an understatement of revenues. Each incident could result in a Company over earning their authorized return-on-equity (ROE).

Q. SHOULD STAFF CONTINUE TO MONITOR THE BALANCING ACCOUNT?

A. Yes. Should the NPPC balance in the account appear to grow to a level that raises concerns, Staff recommends revisiting the balancing account mechanism and develop a recommendations to modify the mechanism to improve the Company's NPPC expense recovery.

Q. WHAT WASTHE LEVEL OF ROE AUTHORIZED FOR THE COMPANY IN ORDER NO., 10-028 IN DOCKET UG 152.

A. The Commission authorized a 10.2 percent ROE. [2]

Q. SINCE NW NATURAL'S LAST GENERAL RATE CASE AND AFTER THE STIPULATED AND RATES WENT INTO EFFECT SEPTEMBER 1 2003, HAS THE COMPANY EARNED THEIR AUTHORIZED ROE?

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[2] Oregon Public Commission Docket 1475, Order No.11-051.

A. Yes. As shown in NWN/200, Anderson/18, from 2004 through 2010, while the Company accumulated $12,923,909 [3] in cash contribution to pensions in excess of their NPPC, including the weighted average cost of gas, at the same time NW Natural earned $20,048,000 in excess of their authorized 10.2 percent return-on-equity (ROE). More importantly, hese excess earnings provided NW Natural the flexibility needed to fund their pension. Once Staff receives the results-of-operations (ROO) on May 1, 2012, the earnings in excess of the Company's authorized 10.2 percent ROE, will be added to the cumulative approximately $20.0m earned in excess of their authorized ROE through 2010.

Q. COULD YOU PLEASE SUMMARIZE YOUR PENSION ADJUSTMENTS?

A. Yes. The information provided in the summary adjustment table below contains the description of item adjusted, the amounts, and references, which were sourced from the Company's response to Staff's data request 364.

Ln.	Descriptions	Amount ($000)	Exhibit /Reference
1	Pension in proposed rate base	$21,930	Exhibit NWN/302, line 19 col. c
2	Company Proposed rate of return	8.28%	Exhibit NWN/302, line 26 col. e
3	Net to gross factor used	171.5%	Exhibit NWN/311, line 17
4	Removal of the revenue requirement return **"on"** portion of the impact of adding cash pension contributions to rate base.	($3,114)	Line 1 * Line 2 * Line 3
5	Removal of the Test Year revenue requirement return **"of"** cash pension contributions amortized cash pension contributions added to rate base.	($4,569)	Company witness work paper 302
6	Total Revenue Requirement Adjustment	($7,683)	Line 4 + Line 5

[3] NWN/409, Feltz/1..

Q. PLEASE DESCRIBE YOUR RESEARCH AND DEVELOPMENT ADJUSTMENT.

A. I am requesting a reduction of $6,319 in the amount of Research and Development (R&D) requested by the Company for the Test Year and allocated to Oregon rate payers.

Q. PLEASE DESCRIBE YOUR RESEARCH AND DEVELOPMENT ADJUSTMENT.

A. The Company's data request response 335, Staff Exhibit 903 shows that NW Natural's average annual R&D expenditure in FERC Account 930 was $338,103 per year from 2008 to 2011. The Company's R&D request for the Test Year of $750,000 is approximately 222% higher than that average. The American Gas Foundation studies natural gas distribution and transportation companies R&D expenses.[4] Their 2007 study "Research and Development in Natural Gas Transmission and Distribution," shows that on average, natural gas distribution companies spend approximately 0.1 percent of gross sales on R&D. Applying the industry average of 0.1 percent to the Company's projection of total sales revenue produces a R&D cap of $742,978, which when subtracted from the Company's $750,000 request producers a ($7,022) total adjustment and an allocated adjustment for Oregon ratepayers of ($6,320).

Q. IS THE COMPANY'S RESEARCH AND DEVELOPMENT EXPENDITURE REQUEST IDENTIFIED IN THE COMPANY'S TESTIMONY?

[4] "Research and Development in Natural Gas Transmission and Distribution", March 2007, American Gas Foundation, http://www.gasfoundation.org/ResearchStudies/researchgas.htm., (3/2012)

A. Yes. A list of the research and development expenditures, as shown in NWN/602, Yoshihara/1, is contained in the table provided below:

Ln.	Descriptions	Amount ($)
1	Operations Technology Development	$305,000
2	Utilization Technology for Development	$240,000
3	Energy Solutions Center	$ 20,000
4	Sustaining Membership Program	$ 75,000
5	Various	$110,000
6	Oregon R&D Allocated Adjustment	$750,000

Q. COULD YOU PLEASE SUMMARIZE YOUR R&D ADJUSTMENTS?

A. Yes. The information provided in the summary adjustment table below contains the description of item adjusted, the amounts, and references, which were sourced from the Company's response to Staff's data request 364.

Ln.	Descriptions	Amount ($)	Exhibit /Reference
1	Projected and Adjusted Revenues	742,978,000	Exhibit NWN/302, Line 4. Col. e.
2	American Gas Institute study findings of percent of R&D found as an average percentage of distribution company total revenues [5]	0.1%	American Gas Institute Study, Pg.8.
3	Cap for R&D, which is based on an industry average.	$742,978	Line 1 x Line 2.
4	Company's R&D Request	$750,000	NWN/602, Yoshihara/1.
5	Applying Industry Average	($7,022)	Line 3 minus Line 4.
6	Oregon Allocation	90.0%	Exhibit NWN/311, line 17
7	Oregon R&D Allocated Adjustment	($6,320)	Line 4 * Line 5

Q. IN THE EVENT ADDITIONAL R&D EXPENDITURES, BEYOND THOSE IDENTIFIED IN NWN/602, YOSHIHARA/1, ARE IDENTIFIED, WOULD YOU MODIFY YOUR ADJUSTMENT?

[5] "Research and Development in Natural Gas Transmission and Distribution", March 2007, American Gas Foundation, http://www.gasfoundation.org/ResearchStudies/researchgas.htm., (3/2012)
.

A. Yes. As can be seen in the table above, based on industry averages, the Company's R&D expenditures should be capped at $742,978 for the Test year. If the Company were to ask for an additional $400,000 to fund, for example, the American Gas Institute, which was included in NW Natural's 2012 operating budget, the funds for the expenditure would be disallowed and result in an additional adjustment of $360,000, which equates to the $400,000 times the 90 percent allocation factor for Oregon ratepayers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: Nick Cimmiyotti

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME: Nicholas (Nick) Cimmiyotti

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: SENIOR FINANCIAL ANALYST, CORPORATE ANALYSIS AND WATER REGULATION

ADDRESS: 550 CAPITOL ST. NE, SALEM, OR 97308-2148

EDUCATION: Bachelor of Science in Finance, University of Oregon, Eugene, OR.

Masters of Business Administration in Management, Regis University, Denver, CO.

EXPERIENCE: Employed with the Public Utility Commission of Oregon from June 2011 to present, currently serving as Senior Financial Analyst, Corporate Analysis and Water Regulation.

Employed with PacifiCorp from October 1978 to March 2009, As the Lead Senior Business Consultant, in the Corporate Finance, my responsibilities included the following:

- Produced regulatory construction budget reports and the responses related to data request for information on financial performance, budgeting, and planning related questions from the Utah, Oregon, California, Washington, and Wyoming state utility regulatory entities;
- Reviewed, all major construction proposals for their conformance with the regulatory rulings, corporate governance, and financial guidelines. Deliver a recommendation regarding approval to the CFO;
- As the liaison to the Power Supply, Pacific and Rocky Mountain Power business units, I consulted them in the production of their input to the 10-Year plan forecast.
- Facilitated the developed the annual corporate goals and performance tracking metrics;
- Produced the monthly PacifiCorp President's report delivered to the MidAmerican Energy Holding Company; and
- Prepared the monthly financial and operational performance report of the corporate goals.

CASE: UG 221
WITNESS: Kenneth R. Zimmerman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Kenneth R. Zimmerman. I am a Senior Analyst with the Oregon Public Utility Commission, Electric and Gas Rates Division. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/1001.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony has four purposes:

1. To explain staff's adjustments to Northwest Natural Gas Company's ("NWN" or "Company") rate base related to major capital projects and storage inventory natural gas.
2. To present staff's review of the financing and operation of the Mist Storage Facility, along with a recommendation for further examination of these areas.
3. To present staff's recommendations related to Schedules 185 and 186.
4. To present staff's recommendation for the future of the System Integrity Program ("SIP") tracker mechanism.

I. RATE BASE

<u>Major Capital Projects</u>

Q. WHAT IS THE STANDARD FOR ADDING COSTS TO ANY UTILITY'S RATE BASE

A. Oregon Revised Statute 757.355 is clear about the circumstances under which property of any sort may be added to a utility's rate base. The property must be presently in use and that use must provide utility service to the utility's customers. The statute provides:

> **757.355 Costs of property not presently providing utility service excluded from rate base.** No public utility shall, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates which are derived from a rate base which includes within it any construction, building, installation or real or personal property not presently used for providing utility service to the customer. [1979 c.3 §2]

Q. HAVE YOU EXAMINED EACH OF THE MAJOR CAPITAL PROJECTS NWN PROPOSES TO INCLUDE IN RATE BASE?

A. Yes. These are listed in the table below. The 2013 projects are not relevant for UG 221 because they cannot be included in rate base in accordance with 757.355. The Washington only projects also are not relevant for this docket because they do not provide service to Oregon customers.

2012	
	System Reinforcement, SIP, Gas Supply
1.	Windsor Island (SIP)
2.	Westside Transmission Re-Rate
3.	Corvallis Reinforcement
4.	Felida Gate Piping (Washington Only)
5.	Perrydale to Monmouth
6.	Monmouth Reinforcement
7.	Portland System Optimization - 2012
	Information Technology
8.	Nertec Replacement
9.	Unified Communication Phase 1 (PBX Switch)

	Facilities
10.	Vancouver relocate (Washington)
11.	Tualatin bio-swale (tentative project)
12.	Tualatin replacement, training facility & land
13.	Sunset sheds
14.	Generators (4)
15.	Parkrose Retrofit
16.	Salem Retrofit
2013	
	System Reinforcement, SIP, Gas Supply
1.	Portland System Optimization - 2013
	Resource Management
2.	CNG vehicles, 7 crew trucks & 18 service window vehicles
	Information Technology
3.	Unified Communication Phase 2 (PBX Switch)
	Facilities
4.	Coos Bay Retrofit
5.	Astoria Retrofit
6.	Generators (5)

Q. PLEASE DESCRIBE THE ADJUSTMENTS YOU ARE PROPOSING TO THE COMPANY'S RATE BASE?

A. Based upon NWN's data responses (156-158, 159-161, and 165-168) [1] NWN did not provide documented in-service dates that satisfy the requirements of ORS 757.355 for the projects listed below. Consequently, I have removed the costs for

[1] See Staff Exhibit 1002 for NWN data request responses; Staff Exhibit 1003 for staff's annotations to the original responses.

these projects from NWN's proposed rate base.[2] [3] The projects removed are as follows:

1. Westside Transmission Re-rate.
2. Corvallis Reinforcement.
3. Perrydale to Monmouth (to Independence).
4. Nertec Replacement.
5. Unified Communication Phase 1 (PBX Switch).
6. Tualatin replacement, training facility & land.

Based upon NWN's data responses (156-158, 159-161, and 165-168)[4] for each of the plant projects listed below, NWN has not demonstrated that the project is prudent. *See* Sobhy/1100 for information on these prudence adjustments. The cost of each project has been removed from NWN's proposed rate base.[5]

1. Perrydale to Monmouth (to Independence).
2. Willamette Crossing near Corvallis.[6]

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[2] Since overhead (Allowance for Funds Used during Construction – AFUDC) and contingency costs follow the projects, I also removed these costs.

[3] The criteria I apply for this examination are straightforward.

1. Has NWN presented clear and fully documented evidence that the facility has completed construction and is fully operational serving the utilities purposes for which IRP or other analysis indicated it was intended? This I call the "steel-in-the-ground" test.
2. If the answer to question 1. is no, then has NWN presented a fully documented final construction schedule and final construction budget for the facility both of which show it in-service no later than October 31, 2012 (the date UG 221 rates go into effect) that are endorsed by written signature of a Company Officer authorized to make such approvals?
3. An answer of no to both questions is the basis for my adjustments in this testimony to the inclusion of major capital projects in NWN's rate base.

[4] See Staff Exhibit 1002 for NWN data request responses; Staff Exhibit 1003 for staff's annotations to the original responses.

[5] Because overhead (Allowance for Funds Used during Construction – AFUDC) and contingency costs follow the projects, I also removed these costs.

[6] NWN's response to staff's data request 267 indicates this project is scheduled for completion in 2013 and that its costs were not included in NWN's proposed rate base. Thus its costs have not been removed from NWN's proposed rate base. See Staff Exhibits 1002 and 1003 and the testimony of staff witness Moshrek Sobhy.

Based on NWN's data responses (156-158, 159-161, and 165-168)[7] the cost for the projects listed below has been reduced to the regional average cost per square foot for inclusion in rate base, $180/sq. ft.[8]

1. Parkrose Retrofit. Adjustment to proposed rate base of ($621,000).

Storage Gas Inventory in Rate Base

Q. WHAT IS YOUR NEXT ADJUSTMENT TO NWN'S RATE BASE?

A. NWN has included in its proposed rate base[9] average natural gas inventory (commodity/methane working gas[10]) at all the facilities where it stores natural gas. I have removed these inappropriate costs from NWN's proposed rate base. This is a reduction of $35,318,000 in NWN's proposed rate base.

Q. PLEASE EXPLAIN.

A. Local Distribution Companies (LDCs) such as NWN use storage primarily to ensure peak season (winter) reliability for core sales customers (e.g., does not include interruptible or transportation only customers). The cost for the gas withdrawn each year to meet that requirement is considered and, if prudent, recovered each year via NWN's Purchased Gas Adjustment (PGA) mechanism. If this task is carried out properly the volume of gas held in storage each year to ensure reliable service should closely match the actual gas withdrawn each peak season to serve peaking load. This is usually expressed as storage that is cycled

[7] See Staff Exhibit 1002 for original data request responses; Staff Exhibit 1003 for staff's annotations to the original responses.
[8] Construction Cost Data. Data source: Reed Construction Data – RSMeans/Charts: Reed Construction Data – CanaData, for 2009. Escalated for inflation at 3%/year to 2012.
[9] Rate Case Model – Working with base year to test year comparison, Exhibit 310, Rate Base. WP 310 – Gas in Storage.
[10] Working gas is to be distinguished from "cushion gas." The former flows into and out of storage to meet the needs of customers. The latter does not flow but remains in the storage underground facility to ensure that appropriate pressure in maintained so that working gas can flow.

annually. That is, under normal operating conditions little or no gas should be left in storage at the end of the peak winter season. Each PGA year (November through March) the injections and withdrawals of gas should come near to being the same. The injections and withdrawals are hardly ever identical in practice so working gas inventory in storage is either slightly short or more likely slightly long at the end of the peak heating season. If operated and managed correctly there should be little inventory from year to year that could be labeled as a gas inventory (commodity/methane working gas) that could be included in rate base. This arrangement is intended to meet peaking gas customers' need for reliability -and no more than this amount - at the lowest achievable cost for customers.

However, there is another problem with attempting to include storage gas inventory (commodity/methane working gas) in rate base, even at an annual average level. The cost of gas injected into storage (if prudently priced when injected) will be recovered by NWN through its PGA mechanism. As part of the PGA process NWN always has the opportunity to ask for recovery of any extraordinary or unexpected costs related to natural gas injected or withdrawn from storage facilities. This process allows NWN to be made whole for prudently priced gas it places into and withdraws from storage for the benefit of its core customers while at the same time ensuring that these customers do not pay extra or unwarranted costs not related directly to the cost of these gas injections and withdrawals. Both these objectives are achieved by timely and contemporary review of the actual costs of storage injections and withdrawals of commodity/methane working gas (gas inventory). To place some average dollar amount in rate base that supposedly represents the cost of the gas NWN injects/withdraws from storage to provide this service is bad regulatory policy because:

1. It denies customers the real time review of these costs that ensures their rates are appropriate;
2. It places an amount into rate base for the annual cost of the gas NWN injects and withdraws from storage that is unlikely to match the actual cost NWN files with each annual PGA;
3. NWN's proposal fixes a dollar amount in rate base that can only be changed via a future general rate review (instead of NWN's annual PGA filing). In light of the historical and likely future volatility of gas prices, this is an unreasonable position;[11] and
4. NWN's proposal thus forces its core customers to pay a return to the Company each year on this "incorrect" dollar amount fixed in rate base.

I also note that it is uncommon for LDCs like NWN to include natural gas storage inventory (commodity/methane working gas) in rate base because it is not a capital investment. Rather, it is paid for wholly by customers on a year-by-year basis with no shareholder funds involved. The recovery of these costs from customers is established each year through the annual PGA review. If these costs are found prudent by the Commission then they are recovered by NWN. There may be an issue of delay in recovery of costs because gas is injected and paid for

[11] No individual rate based cost is likely to reflect the actual value of this cost in the future. But most items placed into rate base do not exhibit the extreme volatility of natural gas prices over the last 10-15 years. It is better that such highly volatile costs be reviewed each year to ensure both that NWN is not penalized by under recovery and NWN's customers are not penalized by over payment.

during the injection season (April through July usually) and withdrawn during the next winter heating season (November through March). The PGA review for these costs is not completed until the October of the same year the heating season ends. Therefore, it may be more than a year and a half before NWN is made whole for the cost of gas injections made to storage during April of the preceding year. However, if NWN is harmed by having to borrow money or delay other projects to pay for injected storage gas these issues can be handled during the PGA review process and NWN can be made whole, including carrying charges if established as appropriate.

Mist Storage Facility

Q. HAVE YOU REVIEWED THE OPERATIONAL AND FINANCIAL HISTORY OF NWN'S MIST STORAGE FACILITY?

A. Yes, within the limited time allowed by the schedule in this proceeding I have examined the operational and financial history of the Mist storage facility.

Q. WHAT RESULTS CAN YOU REPORT FROM THIS REVIEW?

A. In Order No. 89-1372, the Commission allowed NWN to add the Mist storage facility to its rate base beginning November 1, 1989. The Commission reaffirmed this position in subsequent Orders.[12] According to NWN's data response 370,[13] the initial amount placed into rate base for the facility was $46,915,552 as of December 31, 1989. Through the end of 2011, the rate base amount for Mist grew as expansions and other projects were completed, until as of December 31, 2011,

[12] For example, Order No. 96-100.
[13] *See* Staff Exhibit 1002 for NWN responses; Staff Exhibit 1003 for staff's annotations to the original responses.

the net book value in rate base was $169,429,189.[14] [15] The balance for the storage facility included the following categories of investment:

LAND
RIGHTS-OF-WAY
STRUCTURES AND IMPROVEMENTS
WELLS
STORAGE LEASEHOLD & RIGHTS
RESERVOIRS
NON-RECOVERABLE NATURAL GAS
LINES
COMPRESSOR STATION EQUIPMENT
MEASURING / REGULATING EQUIPM
PURIFICATION EQUIPMENT
OTHER EQUIPMENT

Please note that inventory or working gas is not included in these categories, but "NON-RECOVERABLE NATURAL GAS" (cushion gas) is included in these categories. It is NWN's proposal to include inventory or working gas in rate base, discussed above, that I recommend be denied as bad regulatory policy.

Beginning December 31, 2000, NWN accounting began to show a plant balance for "NON-UTILITY PLANT" for the Mist storage facility. The categories for those investments are:

WELLS
STORAGE LEASEHOLD & RIGHTS
RESERVOIRS
LINES
COMPRESSOR STATION EQUIPMENT
MEASURING / REGULATING EQUIPM
OTHER EQUIPMENT
NON-UTIL PROP-STORAGE

[14] $48,326,182for the storage facility itself and $121,103,007 for transmission plant related to the storage facility. On December 31, 1989, these two amounts were 30,259,346 and 16,381,170, respectively.
[15] Net book value is the amount included in rate base after accumulated depreciation has been deducted.

Only the "NON-UTIIL PROP-STORAGE" account showed a balance until December 31, 2003. Subsequently balances for the other categories appeared. The initial "NON-UTILITY PLANT" balance on December 31, 2000, was $4,929,261. The "NON-UTILITY PLANT" balance as of December 31, 2011, was $40,673,735 (net of depreciation). This amount differs by more than $10 million from what was submitted by NWN in the "2011 Annual Report of Interstate and Intrastate Gas Storage and Optimization Activities." It appears this difference is due in large part to the inclusion of "Cushion Gas" and "Distribution Mains" in the latter, but not the former. Please note that the "NON-UTILITY PLANT" balance does not include related transmission facilities. This means the non-utility parties using the Mist facility either provided separate transmission facilities for which they incurred the cost, or the Mist utility related transmission facilities were used to serve some or all of these non-utility customers. Based upon the net book values from December 31, 2011, utility core customers are responsible for the rate of return for about 81 percent of the total net book rate base (utility and non-utility) of the Mist facility. If we assume that the "NON-UTILITY PLANT" was never intended to serve core customer needs then as of December 31, 2011, utility core customers are responsible for the rate of return for 100 percent of the total net book rate base of the Mist facility (serving core utility customers).

As to the deliverability of the Mist facility based on NWN's data response 372,[16] the original deliverability of the facility was about 80,000 Dekatherms/day (Dth/d)

[16] See Staff Exhibit 1002 for NWN responses; Staff Exhibit 1003 for staff's annotations to the original responses.

to core utility customers. Currently, that deliverability to core customers is about 260,000 Dth/d. Based on NWN's current IRP work (LC-51, Figure 2.12 and Appendix 2) the Company design weather event demand is between 800,000 and 900,000 Dth/day and normal peak demand is between 400,000 and 500,000 Dth/day. In simple terms, this means that the current Mist storage allocated to core utility customers can alone meet between 52 and 65 percent of normal peak demand for NWN. When the 46,000 Dth/day from the Jackson Prairie storage facility is added, Mist and Jackson Prairie can together meet 61 to 77 percent of normal peak demand for NWN. If the other storage facilities available to NWN are added to the total daily Dekatherms available then the Company has more than enough to meet the higher 500,000 Dth/day normal peak demand.[17] This situation becomes a greater concern when the deliverability NWN says it currently has available from Mist, but is not yet assigned to core customers is considered. NWN data response 372 indicates that it has an additional 305,000 Dth/day of deliverability being used to serve the interstate and intrastate off-system storage markets that can be recalled to serve core utility customers. If this is added to the 306,000 Dth/day already assigned to core service, the result is 611,000 Dth/day of deliverability. This is 122 percent of the deliverability needed to meet the 500,000 Dth/day normal peak demand. Staff is concerned that NWN may have too much daily storage deliverability under contract or owned, even at the 61 to 77 percent of normal peak demand deliverability level.

[17] The other storage facilities are Plymouth LNG, Gasco LNG, and Newport LNG. As these are all LNG facilities they are available each winter for only a few days.

My initial review raises a number of concerns about the operation and financing of the facility since its construction. For example, Staff is concerned about the sharing of the capital and operating costs between utility and non-utility customers using the facility. In addition, Staff is concerned about the tracking and accurate assessment of the working capacity and deliverability of the facility over its life. More time and information is needed to reach a final conclusion regarding these issues.

Q. WHAT DO YOU RECOMMEND?

A. I recommend the Commission order NWN to conduct an independent review of the operation and financing of the Mist storage facility since its construction through an outside third party chosen by the Commission. This review should be conducted over the six-nine months following the final order in UG 221, with a report detailing the results and recommendations of the reviewers delivered to staff and UG 221 Parties no later than December 31, 2013. Using the report as its foundation, staff and UG 221 Parties can make recommendations to the Commission regarding changes needed to the future operations and financing of the Mist storage facility. Until these recommendations are acted on by the Commission, I recommend that no changes be made to current expected operational and financial parameters for the facility.

SCHEDULE 185, SPECIAL ANNUAL INTERSTATE STORAGE AND TRANSPORTATION CREDIT, AND SCHEDULE 186, SPECIAL ANNUAL CORE STORAGE AND PIPELINE CAPACITY OPTIMIZATION CREDIT

Q. WHAT ARE THE PURPOSES FOR NWN'S SCHEDULE 185 AND SCHEDULE 186?

A. Schedule 185 provides a credit for customers served under Schedules 1, 2, 3, 31FS, 31IS, 32FS, and 32IF for the Oregon share of revenues received by NWN for (a) interstate storage and related transportation service provided under a Limited-Jurisdiction Blanket Certificate from Federal Energy Regulatory Commission ("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. Schedule 185 was approved during the Commission's Public Meeting of April 25, 2000, based on the recommendation of staff for Advice No. OPUC 00-4A ("Staff's memo 4-25-2000").[18] This approval included an 80/20 sharing of net revenues from the services listed in the Schedule. This sharing allows NWN to retain 80 percent of net revenues while sending 20 percent of net revenues to NWN customers. The memo notes that the interstate and intrastate storage/transportation services ("off-system services") would require some use of existing utility facilities (such as the North Coast Feeder and Miller Station). The 20 percent of net revenues going to core utility customers was, according to the Staff memo, intended to compensate these customers for the use of these facilities. That the Staff memo accepts this division of revenues indicates staff and other parties to the docket at the time considered it reasonable.

Schedule 186 provides a credit for Sales Service Customers served under Schedules 1, 2, 3, 31FS, 31IS, 32FS, and 32IS for the Oregon share of revenues received by NWN for the optimization of core customer Pipeline and Storage capacity. Schedule 186 was approved during the Commission's May 7, 2003,

[18] There is only oral approval for the Schedule from the Public Meeting; there is no written order.

Public Meeting based on the recommendation of staff for Advice No. 03-6 ("Staff memo Advice No. 03-6").[19] While Staff's memo includes no discussion of the exact sharing arrangement for this Schedule, the Schedule itself includes a 67/33 sharing arrangement, with 33 percent of net revenues retained by NWN while 67 percent are given to NWN's customers. According to Staff's memo Advice No. 03-6, NWN has an agreement with a third party energy marketing/trading company to optimize storage and transportation assets[20] on an as available basis. Under the agreement, NW Natural maintains control of the assets and continues to purchase gas supply on behalf of its retail firm sales customers, while some industrial customers only transport on the Company's system and assume responsibility for their own commodity supply. The optimization firm uses underutilized pipeline capacity to take advantage of supply price differentials. This broadens the pool of customers sharing in the optimization activities beyond those customers paying for Mist storage (as is the case in the Schedule 185 credit, discussed above). Any proceeds from capacity optimization are shared with core customers on a 67/33 percentage basis, with 33 percent retained by the Company and 67 percent shared with customers. Staff's memo for Advice No. 03-6 also indicates that NWN has added new language to Rate Schedules 185 and D that adds a credit to customers for their share of the net margin revenues received by the Company for core storage optimization activities. These margin revenues are shared on a 67/33 basis; 33 percent will be retained by NW Natural, and 67 percent will be shared with customers through the credit provided for in these schedules. This

[19] There is only oral approval for the Schedule from the Public Meeting; there is no written order.
[20] I assume this refers to core utility assets.

change seems duplicative since Schedule 186 already makes provision for a 67/33 sharing of revenues from NWN's optimization of its core storage.

Q. WHAT ARE YOUR CONCLUSIONS FROM YOUR REVIEW OF SCHEDULE 185?

A. These schedules actually involve two very different uses of Mist Storage and related transportation, mixed together, particularly in Schedule 185. The first service is the use of core utility NWN assets for off-system sales. In this instance, these off-system sales are interstate storage and related transportation sales under a limited FERC interstate certificate. The other off-system use of Mist is for intrastate storage service under Rate Schedule 80. Staff's memo 4-25-2000 outlines the conditions for and potential benefits to core utility customers from these sales. Review of the memo shows:

1. NW Natural wanted to begin offering storage services into the interstate market using storage capacity that is temporarily in excess to the Company's core customer needs. Without impacting its Hinshaw exemption, NWN would be able to provide such services pursuant to a Limited Jurisdiction Blanket Certificate from FERC under 18 C.F .R. §284.224. The Company's proposal to provide such service would involve the expansion of storage reservoir capacity at Mist at shareholder expense and in advance of its core customers' needs. However, because some use of existing utility facilities (such as the North Coast Feeder and Miller Station) would be required, NW Natural proposed a sharing mechanism to compensate the core customers for such use. Any incremental expansion costs associated with this service would be borne by

the Company's shareholders and such costs would not be included in utility rates until such time as the capacity is recalled for the core's use, and ratemaking treatment is approved by the Commission.

2. Eventually NWN suggested an annual credit to core customers to compensate them for use of core utility facilities to provide the off-system sales.
3. The memo does not discuss the provisions of intrastate state storage and related transportation services.
4. Storage service used for retail core customers would continue to take precedence over interstate service, hence reliability, according to NWN, would not be affected.
5. For interstate storage service under §284.224, NWN proposed a different revenue sharing mechanism because initially the incremental capital investment required to make this service available would be borne by its shareholders. According to the Staff memo, NWN also believed that there was considerably more risk to the shareholders for this type of investment. The primary risk is the market-driven price the Company would be able to achieve in the competitive interstate market. The prospective return from the Company's proposed investment in an interstate storage offering is in the view of NWN, highly sensitive to the assumption regarding price.
6. Under the 80/20 methodology, the Company would retain all revenues until it reached a breakeven point on an incremental cost basis. At such point, the Company's shareholders have earned a zero return. Beyond this point customers would begin to share in 20 percent of the net revenue, i.e., net

margin before income taxes. The Staff memo makes clear both NWN and staff prefer this 80/20 sharing methodology.

7. Staff's memo indicated the NWN proposal has the following advantages and benefits for core utility customers:
   a. Mist storage assets recalled for core utility use would return at depreciated costs after being used to provide off-system services.
   b. The 80/20 revenues split provides the most potential for core customers to receive a credit, with the least amount of risk for these customers.
   c. Earlier development of the Mist storage facility provides greater certainty for core customers about the future availability of storage to meet their needs at the least cost, while also helping to assure the physical security of the reservoirs from which Mist storage is developed.
   d. All the risk of losing money on the early development of the Mist storage facility is borne by NWN shareholders.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING SCHEDULE 185?

A. My conclusions are:

1. Staff's memo 4-25-2000 discusses several cost studies prepared by NWN regarding use of Mist storage to provide off-system sales and the sharing of revenues from such services. I have no reason to believe staff is mistaken when it accepts these studies as reasonable. However, I can find no indication that new studies have been prepared regarding the costs and sharing of revenues from off-system sales since 2000.

2. As indicated above, NWN claimed that the prospective return from the Company's proposed investment in an interstate storage offering is highly sensitive to the assumption regarding price. However, this is incorrect. NWN's interstate sales of storage and related transportation from Mist under §284.224 are governed, established and approved by FERC. These rates are cost-based, not market-based. Consequently, NWN could lose money on its build-out of Mist for the interstate market only if it failed to sell at the level assumed in the FERC-approved rates. And NWN has never experienced difficulty in marketing its Mist capacity in the interstate market. The latest filing with the Commission regarding such sales indicates NWN has sold about 90 percent of the available deliverability and almost 100 percent of the available capacity. The average net revenue from off-system storage sales under Mist's §284.224 certificate for the period 2007-2011 was just over $9 million per year. It appears the risk to NWN of this service is minimal.

My recommendation is:

1. To adopt my rewritten Schedule 185, attached as Staff Exhibit 1004.
   a. Until such time as new cost and sharing studies for the Mist off-system (both interstate and intrastate) sales services can be completed, reviewed, and approved by the Commission I have set the sharing percentage in Schedule 185 at 50/50, with both NWN and core utility customers each receiving 50 percent of net revenues as defined in the Schedule. This should ensure fairness in sharing for both core customers and NWN.

b. I have removed all reference to optimization activities from Schedule 185 so that it now deals only with off-system sales of Mist storage and related transportation. Only Schedule 186 would address optimization of core storage and pipeline capacity and deliverability.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING SCHEDULE 186?

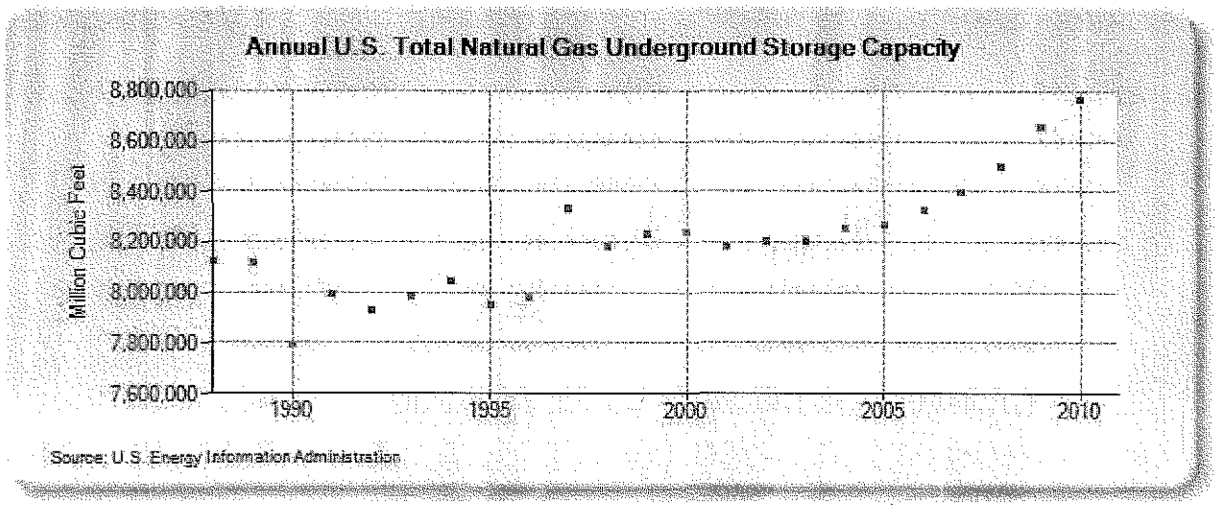
A. My recommendation is:

1. To adopt my rewritten Schedule 186, attached as Exhibit 1004.
   a. The inclusion of 67/33 sharing of revenues from optimization of core storage and pipeline assets by NWN in both Schedule 185 and 186 is duplicative. Therefore, I have removed such revenue sharing from Schedule 185.
   b. I have added deliverability optimization to the core storage and pipeline services covered by Schedule 186. Deliverability is the amount of gas that can be delivered during one day's time. Core customers should receive the benefits of deliverability optimization as well.
   c. I have altered the sharing percentage in Schedule 186 from 67/33 to 90/10 with core utility customers receiving 90 percent of the revenues from NWN's optimization of core storage and pipeline assets. In all instances, as a public utility NWN is obligated to optimize the use of core utility storage and pipeline capacity, particularly that owned by NWN, and to credit all of the benefits in terms of revenue from such optimization activities to its core utility customers. However, recognizing

that a revenue incentive may prompt NWN to greater diligence in core storage and pipeline optimization I recommend here that NWN retain 10 percent of the revenues from such optimization.

Q. IS THERE GENERAL BACKGROUND INFORMATION ON STORAGE FACILITIES SUCH AS MIST THAT COULD HELP US PUT YOUR RECOMMENDATIONS IN CONTEXT?

A. Yes. As indicated in the graph below US storage has grown since 2000, and particularly since 2005.



This growth is the result of greater need for and use of natural gas storage and related ancillary services. This is caused by more use of natural gas in electric generation and to backup renewable generation options. This trend will continue as significant portions of coal-fired generation are replaced with gas-fired generation. It is likewise the result of the increase in natural gas production since 2001, and particularly since 2005.[21] Also, the expansion of LNG exports over the next decade will increase the need for storage capacity. All this makes natural gas

[21] Currently there is concern in the natural gas industry and among energy analysts and regulators that the approximately 4 Tcf of natural gas storage in the US will not be sufficient to meet the requirements for gas storage by the end of 2012.

storage facilities, including NWN's Mist facility, ever more important and potentially of higher value. Ratepayers who paid for the construction and operations of Mist should reap the vast majority of any growth in the value of the facility.

I have reviewed several reports that examine the future of natural gas storage in the US and its relative importance. In particular, the report from the Interstate Natural Gas Association of America ("INGAA"), *Natural Gas in a Smart Energy Future* notes the importance of Automated/Dispatchable Market Area Storage (such as Mist) in a "Smart Energy" future. (pp. 3, 13, 27) The report from eCORP, the Energy Company, *Natural Gas Storage in the US* contends,

> Five significant marketplace changes driven by the combination of regulatory changes and technology changes have significantly altered how natural gas storage facilities will be used in the future. … What this means for the future of natural gas storage facilities is that storage will not only have to satisfy the traditional demands for fuel supply reliability, but it will also have to satisfy the significant and expanding swings in demand for gas that can only be accommodated by high performance, multiple cycle natural gas storage facilities. (p. 1)

Finally the report *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030* released in 2009 examines three possible futures for natural gas – base case or expected growth, high growth in gas consumption, and low growth in gas consumption. The report concludes that, "All three cases result in the need for significant and continuous capital expenditures on natural gas infrastructure." (p. 9)

SYSTEM INTEGRITY PROGRAM TRACKER MECHANISM

Q. WHAT IS THE SYSTEM INTEGRITY PROGRAM?

A. According to the stipulation attached to Order No. 09-067, the Order and stipulation renew "...the existing programs for Bare Steel and Transmission Integrity Management; consolidating such programs into a single System Integrity Program ("SIP"); and including within the SIP a new program for Distribution Integrity Management. The new integrated SIP, with its three focus areas, will allow for a risk-based approach to addressing system integrity issues." That Order and stipulation also classify SIP costs as capital costs, require NWN to track SIP costs on a project basis, and accumulate the SIP project costs in SIP capital accounts. The SIP costs for a year would be the total in these accounts for the SIP tracking year November 1 to October 31. After some exclusions listed in the Order, this total would constitute the annual SIP cost of service. After approval by the Commission, this cost of service would be included in permanent rates for customer schedules 1-3, 31, 32, 33, and 54.

Q. WHAT IS THE PROCESS FOR DETERMINING THE LEVEL OF COSTS ASSOCIATED WITH SIP-LIKE PROJECTS THAT SHOULD BE RECOVERED FROM NWN CUSTOMERS?

A. NWN monitors SIP issues on its system and the resources that could be utilized to address these issues, both current and in the future. NWN then carries out integrated resource planning in which it, in consultation with its regulators and other stakeholders, develops a preferred and several alternative resource portfolios that assign resources to satisfy these current and expected future SIP needs. Next, NWN selects the resources from the IRP portfolios (or other sources) it will use to satisfy these needs. NWN then acquires these resources and puts them into service. Once the resources are operational and fully in-service meeting customer needs (in regulatory parlance referred to as "used and useful") NWN files a formal application (generally in the form of a general rate review) with the OPUC asking that the capital costs of these investments be added to rate base and expenses (O&M) be included in customer rates. In this filing, NWN bears the burden of proof to demonstrate to the satisfaction of the OPUC that costs of these investments and associated O&M are prudent.

Q. IS THERE ANY NEED TO CONTINUE THE SIP COST RECOVERY PROCESS (TRACKER MECHANISM) CONTINUED IN ORDER 09-067?

A. No.

Q. HOW THEN SHOULD SIP INVESTMENT COSTS AND EXPENSES BE ASSESSED FOR INCLUSION IN CUSTOMER RATES?

A. Such investment costs and expenses should be considered as part of the current general rate review and as part of subsequent general rate reviews. I recommend the SIP tracker mechanism end on October 31, 2012. There is no reason to continue this tracker and these types of costs can be included in customer rates established by the Commission via the normal regulatory process

Q. IF THE COMMISSION FINDS THESE INVESTMENT COSTS AND EXPENSES APPRORIATE FOR INCLUDION IN RATES, SHOULD THEY TO BE INCLUDED IN CUSTOMER RATES?

A. Capital costs should be included in rate base and O&M expenses should be added to expense accounts for inclusion in customer rates.

Q. WHAT IS THE TOTAL COST FOR SIP CAPITAL YOU RECOMMEND BE ADDED TO NWN'S RATE BASE AT OCTOBER 31, 2012?

A. The annual amount for SIP projects to be recovered in cost of service cannot exceed $8,176,000, consistent with the requirements of Order 09-067 in UM 1406. In order for the SIP tracker mechanism to cease functioning, I recommend that as of October 31, 2012 NWN be allowed to add $8,750,000 in SIP project costs to its rate base for the period November 1, 2011 to October 31, 2012. This is the total of the $8,176,000 cap and the $574,000 in O&M costs currently embedded in rates, from Order 09-067.[22]

I also recommend that the SIP and all related tariffs and schedules be terminated as of October 31, 2012. After that date all project costs (capital expenditures and expenses) relating to integrity management, bare steel replacement, and all the other categories of costs included in the SIP tracker mechanism should be reviewed and determinations regarding their recovery in rates be made during future general rate cases.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[22] See NWN responses to staff data requests 320 and 321. Exhibit 1002 contains original responses. Exhibit 1003 contains the responses annotated by staff.

CASE: UG 221
WITNESS: Ken Zimmerman

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1001

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATIONS STATEMENT

NAME Kenneth R. Zimmerman

EMPLOYER Oregon Public Utility Commission

TITLE Senior Utility Analyst

ADDRESS 550 Capitol Street NE, Suite 215, Salem, OR 97301

EXPERIENCE Having retired as Chief of Energy with the Oklahoma Corporation Commission's Public Utility Division (1985- 2005), Dr. Zimmerman is now Senior Utility Analyst with the Oregon Public Utility Commission (2005- Current). His primary responsibilities in that position are: natural gas price, supply, and demand forecasting; natural gas integrated resource planning; the flow through of natural gas costs to end-users by gas utilities; and analysis of the general structure and operation of the current, past, and future networks for energy exploration, production, and distribution (including financial and physical energy markets). Prior to his work in energy utility regulation Dr. Zimmerman was a legislative staffer, private consultant, and university professor. Dr. Zimmerman holds PhDs in Sociology/Anthropology and History from the University of North Texas and The University of Texas, respectively; an MA (Sociology and Psychology) from St. Mary's University (TX); an MA from Lancaster University (UK) in Economics, Science, and Technology; and undergraduate degrees in History (BA), Mathematics (BS), American Literature (BA), and philosophy (BA) from Baylor University. Dr. Zimmerman also holds a BSEE in electrical engineering from the University of Houston (TX) and is a certified professional engineer (PE) in Texas and Florida (certificates permanently inactive).

CASE: UG 221
WITNESS: Ken Zimmerman

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1002

Exhibits in Support Of Opening Testimony

REDACTED
May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 156:
Please provide full details on where and how each of the following "Large Projects" were considered and examined in the current pending IRP (LC 51) and the most recently acknowledged IRP.

2012
System Reinforcement, SIP, Gas Supply
1. Windsor Island (SIP)
2. Westside Transmission Re-Rate
3. Corvallis Reinforcement
4. Felida Gate Piping (Washinton Only)
5. Perrydale to Monmouth
6. Monmouth Reinforcement
7. Portland System Optimization - 2012

Information Technology
8. Nertec Replacement
9. Unified Communication Phase 1 (PBX Switch)

Facilities
10. Vancouver relocate (Washington)
11. Tualatin bio-swale (tentative project)
12. Tualatin replacement, training facility & land
13. Sunset sheds
14. Generators (4)
15. Parkrose Retrofit
16. Salem Retrofit

2013
System Reinforcement, SIP, Gas Supply
1. Portland System Optimization - 2013

Resource Management
2. CNG vehicles, 7 crew trucks & 18 service window vehicles

Information Technology
3. Unified Communication Phase 2 (PBX Switch)

Facilities
4. Coos Bay Retrofit
5. Astoria Retrofit
6. Generators (5)

Response: 1/23/12

The Integrated Resource Plan (IRP) is a high-level, long term plan. The purpose of the IRP as defined in Commission Order 89-507 is to "assure an adequate supply of energy to the utility and its customers consistent with the long-run customer interest." Two of the projects listed below (#5, #6 in year 2012) are related to the Mid-Willamette Valley, a supply-side resource option modeled in the Company's 2011 Modified IRP filed in LC 51, and the Company's 2008 IRP filed in LC 45 and acknowledged by the Commission in Order 09-005, issued on January 1, 2009. All of the other projects on the list are outside the scope of the IRP as they are system reinforcement or System Integrity Program (SIP) projects that will be undertaken to maintain the distribution system or to comply with pipeline safety regulations. They are not within the scope of the IRP because they do not relate to our acquisition of resources to meet load in a least cost manner.

Project	2008 Oregon IRP	2011 Modified IRP (LC51)
2012		
System Reinforcement, SIP, Gas Supply		
1. Windsor Island (SIP)	Outside the scope of the IRP.	
2. Westside Transmission Re-Rate	Outside the scope of the IRP.	
3. Corvallis Reinforcement	Outside the scope of the IRP.	
4. Felida Gate Piping (Washington Only)	Outside the scope of the IRP.	
5. Perrydale to Monmouth	This project is related to the Mid-Willamette Valley Feeder. In the 2008 Oregon IRP, the most recently acknowledged IRP, the Willamette Valley Feeder (which includes the Mid-Willamette Valley Feeder) is considered as a supply side resource. The table on page 3A-3 lists the segments of the Willamette Valley Feeder. The Mid-Willamette Valley portion of the Willamette Valley Feeder is defined in the 2008 Oregon IRP as the following three sections: Perrydale-Independence, Independence-N. Albany and N. Albany to S. Albany. These sections of the Mid-Willamette Valley Feeder are modeled with maximum daily capacity of 82 MDT, 50 MDT, and 38 MDT, respectively; capital costs of $14.4 million, $13.7 million and $8.8 million, respectively; and with earliest date available as November 2011.	This project is related to the Mid-Willamette Valley Feeder. The filed IRP (LC51) considers the Mid-Willamette Valley Feeder as a supply side resource option. Supply side resources are described in Chapter 3, with the Willamette Valley Feeder described on pages 3.18 and 3.19. Appendix 3 lists the modeled supply side resources with size, cost and earliest date available. The Mid-Willamette Valley Feeder is modeled in the Modified 2011 IRP with maximum daily capacity of 41 MDT, capital cost of $40 million and earliest date available of November 2012.

6. Monmouth Reinforcement	This project is related to the Mid-Willamette Valley Feeder. In the 2008 Oregon IRP, the most recently acknowledged IRP, the Willamette Valley Feeder (which includes the Mid-Willamette Valley Feeder) is considered as a supply side resource. The table on page 3A-3 lists the segments of the Willamette Valley Feeder. The Mid-Willamette Valley portion of the Willamette Valley Feeder is defined in the 2008 Oregon IRP as the following three sections: Perrydale-Independence, Independence-N. Albany and N. Albany to S. Albany. These sections of the Mid-Willamette Valley Feeder are modeled with maximum daily capacity of 82 MDT, 50 MDT, and 38 MDT, respectively; capital costs of $14.4 million, $13.7 million and $8.8 million, respectively; and with earliest date available as November 2011.	This project is related to the Mid-Willamette Valley Feeder. The filed IRP (LC51) considers the Mid-Willamette Valley Feeder as a supply side resource option. Supply side resources are described in Chapter 3, with the Willamette Valley Feeder described on pages 3.18 and 3.19. Appendix 3 lists the modeled supply side resources with size, cost and earliest date available. The Mid-Willamette Valley Feeder is modeled in the Modified 2011 IRP with maximum daily capacity of 41 MDT, capital cost of $40 million and earliest date available of November 2012.
7. Portland System Optimization - 2012	Outside the scope of the IRP.	
Information Technology		
8. Nertec Replacement	Outside the scope of the IRP.	
9. Unified Communication Phase 1 (PBX Switch)	Outside the scope of the IRP.	
Facilities		
10. Vancouver relocate (Washington)	Outside the scope of the IRP.	
11. Tualatin bio-swale (tentative project)	Outside the scope of the IRP.	
12. Tualatin replacement, training facility & land	Outside the scope of the IRP.	
13. Sunset sheds	Outside the scope of the IRP.	
14. Generators (4)	Outside the scope of the IRP.	
15. Parkrose Retrofit	Outside the scope of the IRP.	
16. Salem Retrofit	Outside the scope of the IRP.	

2013	
System Reinforcement, SIP, Gas Supply	
1. Portland System Optimization - 2013	Outside the scope of the IRP.
Resource Management	
2. CNG vehicles, 7 crew trucks & 18 service window vehicles	Outside the scope of the IRP.
Information Technology	
4. Unified Communication Phase 2 (PBX Switch)	Outside the scope of the IRP.
Facilities	
5. Coos Bay Retrofit	Outside the scope of the IRP.
6. Astoria Retrofit	Outside the scope of the IRP.
7. Generators (5)	Outside the scope of the IRP.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 157:
For project numbers 3, 6, and 7 in 2012, please provide the date when work on each project was begun. (Refer to DR 156)

Response: 1/23/12

Project 3 - Corvallis Reinforcement (Corvallis Loop Project)

Formal analysis and planning began on this project in February 2010. Engineering design started in May 2010. Currently, the project is in the permitting / easement acquisition phase. It is estimated that construction will begin in March 2012.

Project 6 – Monmouth Reinforcement

This project is one of the four remaining phases of the Mid-Willamette Valley Feeder which extends from the Central Coast Feeder south to the Albany-Corvallis Feeder. The engineering design and construction of the already completed portion of this feeder was done in September 2005.

The engineering design of the remaining phases of the Mid-Willamette Valley Feeder began in April 2009. Currently, construction is scheduled to begin on the Monmouth Reinforcement Project in January 2012.

Project 7 – Portland System Optimization

Conceptual planning for this project began in January 2002. The Portland System Optimization is a series of sub projects in the Portland Metropolitan area that is a continuation of a larger plan to optimize takeaway capacity from Mist. Detailed engineering design for these sub projects began in August of 2011. Construction for some of the sub projects began in September 2011.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 158:
For each of the projects in the above table provide the sources for the estimate of in-service date provided. What is the range of error for each in-service date? (Refer to DR 156)

Response: 2/8/2012

All of the in-service dates referenced in the Company's filed case, and updated in the attached OPUC DR 158 Attachment-1 are based on the best judgment of the project team, after reviewing all relevant facts. OPUC DR 158 Attachments 1-7 contain data supporting the project teams' judgment. The actual in-service dates may continue to change slightly, but at this time, the Company is reasonably certain that these completion dates will be met.

The Company does not perform a range of error calculation. Nevertheless, barring extraordinary circumstances, the Company expects that all 2012 projects will be completed by October 31, 2012 and that 2013 projects referenced will be completed within the test year (November 1 through October 31, 2013).

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 159:
Please provide a copy of the Company's education reimbursement policy.

Response: 1/23/2012

See OPUC DR 159 Attachment-1.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 160:

In the below cost elements shown in the transaction summaries for FERC accounts 920 – 935 in Column J provided in the Company's response to Standard Data Request No. 57, please indicate whether meals and entertainment amounts are contained within those expenses:

a) Education
b) Employee Awards
c) Employee Awards MLS &
d) Travel in Territory
e) Conference Travel
f) Business Travel

Response: 1/23/12

		Includes meals & entertainment (Yes or No)
a)	Education	No
b)	Employee Awards	No
c)	Employee Awards MLS &	Yes
d)	Travel in Territory	No
e)	Conference Travel	No
f)	Business Travel	No

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 161:

Please explain in narrative the difference between "Meals & Entertainment" and "Meal Ticket" listed in Column J as shown in the transaction summaries for FERC accounts 920 – 935 provided in the Company's response to Standard Data Request No. 57.

Response: 1/23/2012

Meal Tickets (Account 585800), represents payments to union employees for contractual meal allowances. If a union employee works in excess of the number of hours specified in the Joint Accord, the employee is paid a meal allowance. Historically, these were referred to as Meal Tickets.

Meals & Entertainment (Account 512100), represents reimbursement to non-union employees for the cost of meals and entertainment paid by the employee for business purposes.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

SUPPLEMENT

Request No. GR1-OPUC-DR 165:
For each major project listed below, please provide:
a. Request for bids issued.
b. All bids received in response to the request for bids issued by NWN.
c. The bids sheets or tables where NWN compared and evaluated the bids received.
d. The winning bid for the work, including the reasons the bid was selected as winner.
e. The construction budget for the project developed by the winning bidder and approved by NWN.
f. The construction schedule for the project developed by the winning bidder and approved by NWN.
g. All changes to the initial construction budget, with explanations.
h. All changes to the initial construction schedule, with explanations.

2012
System Reinforcement, SIP, Gas Supply
1. Windsor Island (SIP)
2. Westside Transmission Re-Rate
3. Corvallis Reinforcement
4. Felida Gate Piping (Washington Only)
5. Perrydale to Monmouth
6. Monmouth Reinforcement
7. Portland System Optimization - 2012

Facilities
8. Vancouver relocate (Washington)
9. Tualatin bio-swale (tentative project)
10. Tualatin replacement, training facility & land
11. Sunset sheds
12. Generators (4)
13. Parkrose Retrofit
14. Salem Retrofit

2013
System Reinforcement, SIP, Gas Supply
1. Portland System Optimization - 2013

Facilities
2. Coos Bay Retrofit
3. Astoria Retrofit
4. Generators (5)

Response: Supplemented 4/16/2012

In the Company's initial response to this data request on February 8, 2012, the Company provided as Attachment 9 a memorandum regarding the proposal for initiation of the Perrydale to Monmouth project. The memorandum stated that the possible start date of the project was September 1, 2012 and that the project would take 10 months to complete. The start date listed in the project initiation memorandum, which was drafted by an engineering summer intern, was in error. When the project initiation memo was created, the final proposed schedule for the project was not yet know and was developed at a later date by the Capital Projects Project Manager utilizing inputs from all other projects planned for the year and resource availability.

The correct start date for construction of this project is May, 2012 and the expected completion date is October, 2012. These dates are shown in Attachment 13 to the Company's response to OPUC Data Request 165 and Attachments 1 and 2 to the Company's response to OPUC Data Request 158.

Also attached as OPUC DR 165 Attachment-1A is a request for proposals issued by the Company related to this project after it posted its original response to OPUC DR 165.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 165:
For each major project listed below, please provide:
a. Request for bids issued.
b. All bids received in response to the request for bids issued by NWN.
c. The bids.sheets or tables where NWN compared and evaluated the bids received.
d. The winning bid for the work, including the reasons the bid was selected as winner.
e. The construction budget for the project developed by the winning bidder and approved by NWN.
f. The construction schedule for the project developed by the winning bidder and approved by NWN.
g. All changes to the initial construction budget, with explanations.
h. All changes to the initial construction schedule, with explanations.

2012
System Reinforcement, SIP, Gas Supply
1. Windsor Island (SIP)
2. Westside Transmission Re-Rate
3. Corvallis Reinforcement
4. Felida Gate Piping (Washington Only)
5. Perrydale to Monmouth
6. Monmouth Reinforcement
7. Portland System Optimization - 2012

Facilities
8. Vancouver relocate (Washington)
9. Tualatin bio-swale (tentative project)
10. Tualatin replacement, training facility & land
11. Sunset sheds
12. Generators (4)
13. Parkrose Retrofit
14. Salem Retrofit

2013
System Reinforcement, SIP, Gas Supply
1. Portland System Optimization - 2013

Facilities
2. Coos Bay Retrofit
3. Astoria Retrofit
4. Generators (5)

Response: 2/8/2012

See OPUC DR 165 Attachment-1 for a list of associated documentation related to each project. OPUC DR 165 Attachment-1 contains references to OPUC DR 165 Attachments-2 through Attachment-24. Many of these documents are considered confidential subject to protective order and are posted on the Company's FTP site in the folder titled CONFIDENTIAL SUBJECT TO PROTECTIVE ORDER 12-001.

This page is confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 166:
For each project below, provide the basis for the "in service" date provided by NWN, including full documentation (invoices, construction schedules, etc.)

2012
System Reinforcement, SIP, Gas Supply
1. Windsor Island (SIP)
2. Westside Transmission Re-Rate
3. Corvallis Reinforcement
4. Felida Gate Piping (Washington Only)
5. Perrydale to Monmouth
6. Monmouth Reinforcement
7. Portland System Optimization - 2012

Information Technology
8. Nertec Replacement
9. Unified Communication Phase 1 (PBX Switch)

Facilities
10. Vancouver relocate (Washington)
11. Tualatin bio-swale (tentative project)
12. Tualatin replacement, training facility & land
13. Sunset sheds
14. Generators (4)
15. Parkrose Retrofit
16. Salem Retrofit

2013
System Reinforcement, SIP, Gas Supply
17. Portland System Optimization - 2013

Resource Management
18. CNG vehicles, 7 crew trucks & 18 service window vehicles

Information Technology
19. Unified Communication Phase 2 (PBX Switch)

Facilities
20. Coos Bay Retrofit
21. Astoria Retrofit
22. Generators (5)

Response: 2/8/2012

See the Company's responses to OPUC DR 158, OPUC DR 165, and OPUC DR 168.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 167:
With regard to peak day demand,
a. What is that value for the test year?
b. How was the peak day demand forecasted for the test year?
c. What portion of test year forecasted peak day demand does NWN propose to serve from existing storage working gas?
d. What portion of test year forecasted peak day demand does NWN propose to serve from incremental storage working gas?

Response: 1/26/2012

a. What is that value for the test year?

The test year load forecast is based on normal weather and does not contain a peak day weather event or peak day demand (such as would be used for design day purposes in the Company's IRP filings). Instead, the test year load forecast is an annual load projection under normalized weather.

b. How was the peak day demand forecasted for the test year?

See a. above.

c. What portion of test year forecasted peak day demand does NWN propose to serve from existing storage working gas?

See a. above.

d. What portion of test year forecasted peak day demand does NWN propose to serve from incremental storage working gas?

See a. above.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 168:
In regard to forecasted capital spending, please answer the following:
a. Provide the details of all bare steel projects proposed for 2012 and 2013, including bidding, construction schedules, construction budgets, and engineering specifications.
b. Provide the details of all TIMP projects proposed for 2012 and 2013, including bidding, construction schedules, construction budgets, and engineering specifications.
c. Provide the details of all DIMP projects proposed for 2012 and 2013, including bidding, construction schedules, construction budgets, and engineering specifications.
d. Provide the details of all Public Works-Mains projects proposed for 2012 and 2013, including bidding, construction schedules, construction budgets, and engineering specifications.
e. Provide the details of all Relocates/Abandonments-Mains projects proposed for 2012 and 2013, including bidding, construction schedules, construction budgets, and engineering specifications.
f. Provide the details of all System Reinforcement projects proposed for 2012 and 2013, including bidding, construction schedules, construction budgets, and engineering specifications.
g. Provide the details of all Transportation-32 projects proposed for 2012 and 2013, including bidding, construction schedules, construction budgets, and engineering specifications.
h. Provide the details of all Information Technology projects proposed for 2012 and 2013, including bidding, construction schedules, construction budgets, and engineering specifications.
i. Provide the details of all Structures-36 projects proposed for 2012 and 2013, including bidding, construction schedules, construction budgets, and engineering specifications.

Response: 2/8/2012

See the following attachments:

OPUC DR 168 Attachment-1 through OPUC DR 168 Attachment-12.

See also the Company's responses to OPUC DR 158 and OPUC DR 165.

Because the capital spending included in the forecast for Transportation-32 projects are routine replacements and additions the Company has not included any documentation for these items.

Please note that the following attachments are confidential subject to protective order and are posted on the Company's FTP site in the folder titled CONFIDENTIAL SUBJECT TO PROTECTIVE ORDER 12-001.

OPUC DR 168 Attachment-5 CONFIDENTIAL
OPUC DR 168 Attachment-6 CONFIDENTIAL
OPUC DR 168 Attachment-7 CONFIDENTIAL
OPUC DR 168 Attachment-9 CONFIDENTIAL
OPUC DR 168 Attachment-11 CONFIDENTIAL

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 267:
See pages 4-7 of testimony by witness Yoshihara.
a. Explain how the Mid-Willamette Valley Feeder Project is included in the projects listed on the "Capital Projects Timeline" document provided by NWN.
b. Explain how the forecasted costs of the Mid-Willamette Valley Feeder Project are divided among the projects listed on the "Capital Projects Timeline" document.
c. For the Mid-Willamette Valley Feeder Project provide the following:
i. Request for bids issued.
ii. All bids received in response to the request for bids issued by NWN.
iii. The bids sheets or tables where NWN compared and evaluated the bids received.
iv. The winning bid for the work, including the reasons the bid was selected as winner.
v. The construction budget for the project developed by the winning bidder and approved by NWN.
vi. The construction schedule for the project developed by the winning bidder and approved by NWN.
vii. All changes to the initial construction budget, with explanations.
viii. All changes to the initial construction schedule, with explanations.
d. For the Mid-Willamette Valley Feeder Project, provide the basis for the "in service" date provided by NWN, including full documentation (invoices, construction schedules, etc.)
e. Please explain why the capital cost for the Corvallis Loop Project ($12.8 million) differs from the projected capital cost for this project in the "Capital Projects Timeline" document ($9.3 million).

Response: 2/9/2012

a) The Mid-Willamette Valley Feeder Project is broken down into four phases. The first two phases are scheduled for completion in 2012 and are listed as "Perrydale to Monmouth" and "Monmouth Reinforcement" on the "Capital Projects Timeline" document. The second two phases are scheduled for completion in 2013 and are not listed on the "Capital Projects Timeline". They are "South of Monmouth Bare Replacement" and "Willamette River Crossing near Corvallis". The phases being completed in 2013 are not included in the

"Capital Projects Timeline" due to the in-service dates being projected as October 2013.

b) The forecasted costs of the Mid-Willamette Valley Feeder Project is as follows:

Perrydale to Monmouth $13,500,000

Monmouth Reinforcement $8,100,000

South of Monmouth Bare Replacement $14,300,000

Willamette Crossing near Corvallis $11,000,000

Note: Some expenses have occurred in 2011 on the MWVF.

c) Please see the Company's response to OPUC DR 165.

d) Please see the Company's response to OPUC DR 158.

e) The estimated capital cost of the Corvallis Loop Project is $ 12.8 million. Approximately $3.5 million of expense occurred in 2011. The remaining $9.3 million is forecast to be spent in 2012 as stated in the "Capital Projects Timeline".

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 320:
Assume for these data requests that the System Integrity Program (SIP) tracker ends October 31, 2012.

Please identify each SIP project NWN would propose be placed into rate base as the SIP tracker ends.

Response: 2/21/2012

SIP activity from 2002 through 2011 is already in base rates, as last updated in the 2011-12 PGA. Therefore, only the incremental SIP activity expected to occur between November 1, 2011 and October 31, 2012 is considered in the Company's response to Data Requests 320 through 323.

Identification of planned SIP projects that are expected to be completed and costs placed into rate base at the end of the 2012 tracker year are consolidated with the Company's response to Data Request 321.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 321:
Assume for these data requests that the System Integrity Program (SIP) tracker ends October 31, 2012.

For each project named above, provide full details on total cost (including AFUDC), in-service dates, operational life, and construction schedule. Provide full documentation for these answers for each project identified.

Response: 2/21/2012

See OPUC DR 321 Attachment-1 which contains a table showing the known and planned SIP projects projected to be completed and placed into rate base at the end of the 2012 PGA tracker year. AFUDC is included in the budgeted cost.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 370:
Provide the original cost of the Mist storage facility.

Response: 3/2/2012

See OPUC DR 370 Attachment-1 which shows the original cost of the Mist Facility by FERC Plant Account as of December 31, 1989.

The Excel file also shows the following:

- Subsequent year-end balances by FERC Plant Account for all years through December 31, 2011, in response to DR 372 (cost of additions);
- Accumulated Depreciation balances by year by FERC Plant Account for all years through December 31, 2011, in response to DR 374 (depreciation history)
- Net Book Value by year by FERC Plant Account for all years through December 31, 2011, in response to DR 375 (value in Rate Base).

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 372:
Provide the history of each Mist storage upgrade or addition since the original facility was constructed, including engineering descriptions, changes in capacity, changes in deliverability, changes in operating pressures, and costs.

Response: 3/2/2012

See OPUC DR 372 Attachment-1 for a chronology of major projects at or supporting Mist underground storage.

See OPUC DR 372 Attachment-2 for a history of Mist Storage development

See the Company's response to OPUC DR 370 for cost information relating to Mist Storage.

NW NATURAL
Rates & Regulatory Affairs
Oregon General Rate Case – December 2011
Data Request Response

Request No. GR1-OPUC-DR 158: 2/8/2012

For each of the projects in the above table provide the sources for the estimate of in-service date provided. What is the range of error for each in-service date? (Refer to DR 156)

Project	Updated In-Service Date	Source of the Estimate
2012		
System Reinforcement, SIP, Gas Supply		
1. Windsor Island (SIP)	10/31/2012	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
2. Westside Transmission Re-Rate (TIMP)	Under Review	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
3. Corvallis Reinforcement	10/31/2012	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
4. Felida Gate Piping (Washington Only)	NOT RELEVENT - THIS IS A WASHINGTON PROJECT	
5. Perrydale to Monmouth (to Independence)	10/31/2012	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
6. Monmouth Reinforcement (to Granger)	8/3/2012	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
7. Portland System Optimization (Phase 1) - 2012	9/30/2012	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
Information Technology		
8. Nertec Replacement	10/31/2012	See Project Charter at OPUC DR 158 Attachment - 3. See also documents provided in response to OPUC DR 168
9. Unified Communication Phase 1 (PBX Switch)	10/31/2012	See Project Charter at OPUC DR 158 Attachment - 4. See also documents provided in response to OPUC DR 168
Facilities		
10. Vancouver relocate (Washington)	NOT RELEVENT - THIS IS A WASHINGTON PROJECT	
11. Tualatin bio-swale (tentative project)	On hold	This is part of the Tualatin Retrofit project on-hold due to Sherwood property option that would eliminate this project.
12. Tualatin replacement, training facility & land	10/31/2012	See Project Charter at OPUC DR 158 Attachment-7
13. Sunset sheds	1/31/2012	This is work remaining from a retrofit project at the site. We are waiting for final permits from the city of Hillsboro.
14. Generators (4)	10/31/2012	Thse are routine maintenance/repair/replacements
15. Parkrose Retrofit	6/30/2012	See Project Charter at OPUC DR 158 Attachment - 5
16. Salem Retrofit	6/30/2012	See Project Charter at OPUC DR 158 Attachment - 6
2013		
System Reinforcement, SIP, Gas Supply		
1. Portland System Optimization (Phase 2)- 2013 (Restore 400 psi MAOP to 10" Westside Feeder between Jean Rd and West Linn and 10x12" Boones Ferry pipeline between Barbur and Slavin and Jean Rd Station)	10/31/2013	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
Resource Management		
2. CNG vehicles, 7 crew trucks & 18 service window vehicles	By 10/31/13	The CNG vehicles and 7 crew trucks are routine replacements/additions based on normal run rate. The in-service date is for the 18 service window vehicles and is based upon the Company's proposal in this general rate case. See NWN/900.
Information Technology		
3. Unified Communication Phase 2 (PBX Switch)	10/31/2013	See Project Charter at OPUC DR 158 Attachment - 4
Facilities		
4. Coos Bay Retrofit	9/30/2013	This project is still in the planning phase. The project is expected to start in spring 2013 and is currently estimated to take 4 months to complete.

Project	Updated In-Service Date	Source of the Estimate
2012		
5. Astoria Retrofit	6/30/2013	This project is still in the planning phase. The project is expected to start in spring 2013 and is currently estimated to take 2 months to complete.
6. Generators (5)	5/31/2013	These are routine maintenance/repair/replacements.

NW Natural

220 NW Second Avenue
Portland, OR 97209

REQUEST FOR PROPOSAL

Title: Phase II Perrydale To Rickreall Project

Date: March 5, 2012

NW Natural
220 NW Second Avenue
Portland, OR 97209
Proposal Due Date: April 20, 2012 at 2:00 PM

REQUEST FOR PROPOSAL (RFP)

TITLE: PHASE II PERRYDALE TO RICKREALL PROJECT
PROPOSAL SUBMITTAL DATE AND TIME: APRIL 20, 2012, 2:00 PM PDT
NOTE: Proposals received after 2:00 PM on the Proposal Submittal Date may be considered non-responsive.

DELIVER PROPOSAL TO:

NW NATURAL
Purchasing Department
Attn.: Craig Gagner
220 NW Second Avenue
Portland, OR 97209

Telephone: (503) 226-4211 Ext. 2550
Facsimile: (503) 273-4825
Email: csg@nwnatural.com

REFERENCE TIMETABLE:
Below is a timetable for your quick reference. It contains key tasks and dates that you will be responsible for in order to successfully respond to this RFP. Please take note of all dates and times.

Task	Due Date/Time
RFP Distribution	March 5, 2012
Job Walk	March 9, 2012
Deadline for Question Submissions	April 9, 2012
RFP Due Date	April 20, 2012 2:00 PM PDT
Award Contract	April 26, 2012
Field Work Starts	May1, 2012 (On or about)
Work Completed	October 1, 2012
Submit As-builts	October 29, 2012

NOTE: Field work start date(s) may vary depending on work space agreements with private property owners

NW NATURAL CONTACT FOR RFP ISSUES AND INFORMATION REQUEST:

All inquiries concerning this RFP and/or requests for additional information must be directed to Craig Gagner in writing at the above address.

PURPOSE:
NW Natural Gas Company, doing business as NW Natural, is seeking proposals for construction services for the Phase II Perrydale To Rickreall project as further defined in the attachments that follow.

NW Natural provides reliable, cost-effective natural gas service to more than 650,000 residential, commercial and industrial customers through 13,000 miles of mains and service lines in western Oregon and southwestern Washington.

You are invited to submit a proposal for the services defined herein. Your proposal shall be in compliance with all referenced documents, whether included herein, or incorporated by reference.

INSTRUCTIONS TO BIDDERS:

- Each Bidder shall submit its Proposal using the Proposal Form that is supplied herewith. Any qualifications, additions, or clarifications thereto shall be submitted by way of separate document. Proposal Form shall be manually signed. If erasures or other changes appear on the form, the person signing the Proposal Form must initial each erasure or change.

- Each Bidder shall submit **two copies of their proposal** complete with all attachments and supplemental correspondence in order for the Proposal to be considered.

- Proposals shall be submitted in a **sealed envelope** clearly addressed with Bidder's company name clearly labeled ***"RFP – PHASE II PERRYDALE TO RICKREALL PROJECT."*** Modifications to Proposals already submitted will be considered if received in NW Natural's offices by the RFP Due Date listed above. Also, Proposals may be withdrawn by the RFP Due Date.

- Unless expressly solicited by NW Natural, alternative Proposals will not be considered. However, value-engineering and cost reduction recommendations are encouraged and will be accepted for review with the Proposal. Any proposals for value engineered cost reductions shall be submitted, in written form, on the Bidder's letterhead and shall be included with the submitted sealed Proposal.

- All Proposal submittals, as required by this request, shall be included with the Proposal, on the specified due date and time.

- Bidder shall comply with all state and federal laws in regards to formulation and submittal of proposal. Prospective bidders should note that this is a competitive bidding situation, and that conferring with separate bidders about pricing or other specific details of the proposal may violate antitrust law.

- Proposals *shall remain firm for a period of ninety (90) days after the RFP Due Date.* NW Natural **may,** when it is in its best interest, reject any or all bids, or waive any formality of the RFP contents in any Proposal received.

- Bidder is deemed to have satisfied itself by submission of its Proposal as to the correctness and sufficiency of the Proposal to cover all requirements as requested per this document.

- Bidder(s) or awarded Bidder shall under no circumstances use NW Natural 's name or logos in advertising, marketing materials, printed matter, reference lists, or in any other way that could be construed as advertising (e.g., memo pads, tee shirts, binders, reference list, etc.) without NW Natural 's prior written consent.

NEGOTIATION TERMS:

NW Natural retains the right to select, request further information from, and negotiate with those bidders it deems qualified for competitive negotiations. NW Natural also reserves the right to reject any or all Proposals submitted and to terminate negotiations with any party at any time without incurring liability. This RFP gives rise to no contractual obligations, implied or otherwise.

RFP TERMS AND CONDITIONS APPLIED TO FINAL CONTRACT:

All terms and conditions outlined in this RFP, including the specifications and the Bidder's completed proposal, will become, at NW Natural's sole discretion, part of the final Purchase Order contract (the "Agreement") between NW Natural and the selected Contractor.

HOLD HARMLESS:
In submitting a Proposal, Bidder understands that NW Natural will determine which proposal, if any, is accepted. Bidder waives any right to claim damages of any nature whatsoever based on the selection process, final selection, and any communications associated with the selection.

CONFIDENTIALITY PROVISION:
The terms of this RFP, and all other information provided by NW Natural in connection with this RFP, are confidential and proprietary to NW Natural. Such materials are to be used solely for the purpose of responding to this request. By submitting a proposal, Bidder agrees not to disclose any such information to any third party without the prior written consent of NW Natural (which consent shall be conditional upon the written agreement of the intended recipient to treat the same as confidential). NW Natural may request at any time that any or all NW Natural material be returned or destroyed.

Should you choose not to respond to this RFP, all materials and any duplicates thereof must be returned to NW Natural at the address listed on Page 2 of this RFP.

CONTRACT EVALUATION AND AWARD:
NW Natural has no obligation to reveal the basis for contract award or to provide any information to bidders relative to the evaluation or decision-making process. All participating bidders will be notified promptly of bid acceptance or rejection.

CONTRACT NEGOTIATION AND EXECUTION:
As discussed above, NW Natural intends that the successful Bidder will enter into a Purchase Order which contains all of the terms and conditions of the proposed relationship between Bidder and NW Natural. Any acceptance of a Proposal is contingent upon the execution of a Purchase Order contract (the "Agreement"), and neither party shall be contractually bound to the other prior to the execution of such written "Agreement".

SPECIFICATIONS:
It is Contractor's responsibility to understand and adhere to all municipal and jurisdictional technical specifications for the work performed. Should there be questions and/or concerns regarding NW Natural or jurisdictional requirements or specifications, Contractor shall notify the NW Natural technical representative prior to the commencement of work.

GUARANTEE / WARRANTY:
The Contractor warrants that all Work performed shall be of the quality required by the Contract, or of the best grade or performed in a first-class workmanlike manner if no quality is specified,, that all such materials and equipment shall be suitable for the purposes intended to the extent selected by the Contractor or Subcontractors, and that all Work and such materials and equipment shall conform to the Specifications, Drawings, samples, and other descriptions set forth in the Contract. Upon receipt of written notice from the Company of a breach of warranty, the affected item or Work shall be redesigned, repaired, replaced, or reperformed by the Contractor; and the Contractor shall perform such tests as the Company may require to verify that such redesign, repair, replacement or reperformance complies with the requirements of the Contract. The Company reserves the right to itself have such redesign, repair, replacement, or reperformance Work done when it deems it advisable. All costs incidental to redesign, repair, replacement or reperformance Work, and the testing thereof, including but not limited to the removal, replacement, and reinstallation of equipment necessary to gain access, the repair or replacement of damage to the Work and the project resulting therefrom, and all other costs incurred as the result of a breach of warranty, shall be borne by the

Contractor. Should the Contractor fail promptly to make the necessary redesigns, repairs, replacements, reperformances, or tests, the Company may perform or cause to be performed the necessary Work or tests at the Contractor's expense.

The above warranties are not intended as a limitation but are in addition to all other express warranties set forth in the Contract and such other warranties as are implied by law, custom or usage of trade.

The above warranties shall be for a period of not less than two (2) years from the date of final completion of the entire Work and shall include but not be limited to site restoration and fabrication. A performance bond may be required to ensure compliance of warranties; the cost of such bond shall be paid by the Contractor.

INSPECTION AND ACCEPTANCE:
NW Natural and/or its representatives reserve the right to retain access to Contractor's work for the purposes of inspection and work acceptance. Failure to inspect, accept or reject the work shall not relieve the Contractor from its responsibility to furnish the requirements of the Contract. Approval and inspection shall be the responsibility of NW Natural.

QUALITY CONTROL ASSURANCE:
NW Natural will perform periodic quality assurance audits of contractor work. Work rejected due to poor quality/non-conformance shall be removed, replaced and/or re-performed by Contractor at Contractor's expense.

SITE CONDITIONS:
Contractor has the sole responsibility of satisfying itself concerning the nature and locations of work and the general and local conditions.

CONTRACTOR'S ENVIRONMENTAL OBLIGATIONS AND INDEMNITIES:
Contractor shall (a) abide by and comply strictly with all governmental permits and authorizations held by NW Natural in connection with the work; (b) acquire and comply with all governmental permits and authorizations that are necessary for Contractor's work on the project and that have not been obtained by NW Natural; (c) comply with all federal, state and local laws, regulations and ordinances relating to protection or enhancement of the environment and that are applicable to Contractor's activities hereunder; and (d) assume the risk that Contractor has identified all such applicable laws, obtained all such necessary governmental permits and authorizations, and that it has the capability to comply.

DRUG, ALCOHOL AND SUBSTANCE ABUSE TESTING COMPLIANCE:
Contractors who drive interstate commercial motor vehicles that are rated at over 26,000 lbs. or are engaged in safety-sensitive pipeline operations are required by the U.S. Department of Transportation ("DOT") to implement a program of drug, alcohol and substance abuse testing, education and training (49 CFR Parts 40, 199, 325, 355-379 and 381-399). NW Natural is required to confirm that its independent contractors and their employees, if any, comply with these regulations. Any contractor who drives a truck as described above or performs services identified as safety-sensitive must comply with the appropriate regulations and provide evidence of compliance to the NW Natural Purchasing Department. Failure to provide such evidence will disqualify the Contractor from performing work or services for NW Natural. NW Natural is authorized by regulations to audit the Contractor's drug, alcohol and substance abuse program records. **The work and/or services described in this RFP have been identified as being covered by the regulations.**

NOTE: All costs associated with Contractor Drug, Alcohol, and Substance Abuse testing shall be the sole responsibility of the Contractor.

ADHERENCE TO OPERATORS QUALIFICATIONS:
Federal law requires that all personnel, including independent contractors, who perform "Covered Tasks" on pipeline facilities or appurtenances owned or operated by NW Natural must meet certain qualification standards administered by NW Natural in accordance with regulations promulgated by the U.S. Department of Transportation's Office of Pipeline Safety (49 CFR Part 192, Subpart N, as currently in effect and as may be amended from time to time). Some or all of the services to be performed by Contractor pursuant to the Purchase Order constitute "Covered Tasks" for purposes of the aforementioned regulations, and such services are therefore subject to the NW Natural Operator Qualification Program. NW Natural and its representatives have sole authority (subject only to the terms and standards set by the Office of Pipeline Safety and other regulatory agencies, if applicable) for all elements of its Operator Qualification program, including but not limited to setting qualification standards, recordkeeping and conducting audits under the program. NW Natural agrees to administer operator qualification testing for Contractor and its personnel at no charge. Contractors are not eligible for payment for time spent on the testing process.

CONTRACTOR INDEMNITY/PERFORMANCE OF THE WORK:
Contractor shall indemnify and save harmless NW Natural and its directors, officers, shareholders, partners, employees and agents (including their successors and assigns), against and from any and all actions, proceedings, audits, investigations, claims, demands, damages, fines, penalties, response costs, loss and liability, expenses and costs (including attorneys' fees in any suit, action or proceeding, whether groundless or not, that may be brought against NW Natural) caused or arising out of the acts or omissions of Contractor and Contractor's agents and employees. This includes, but is not limited to, (a) injury or death of any persons; (b) damage to or loss of any property and natural resources; (c) degradation or contamination of the environment; and (d) noncompliance with any applicable law, regulation, ordinance, permit or authorization, caused or arising out of the acts or omissions of Contractor and Contractor's agents and employees.

Provided, however, that this section shall not require Contractor to indemnify and save harmless NW Natural and its directors, officers, partners, employees and agents (including their successors and assigns) against and from any responsibility or liability for their own negligence.

INSURANCE REQUIREMENTS:
Contractor shall carry at its own expense, insurance with reliable insurance companies satisfactory to NW Natural and authorized to do business in the State or the States in which work is to be performed by the Contractor hereunder, the following types of insurance limits not less than shown on the respective items:

A. Workers Compensation Insurance and occupational disease insurance with statutory limits, and employers' liability insurance with a minimum limit of $1,000,000.
B. Comprehensive General Liability Insurance with a combined single limit for bodily injury, personal injury and property damage of $2,000,000 for injuries to or death of anyone or destruction of any property, including loss of use thereof, arising out of an occurrence.
C. Automobile Liability Insurance, including all owned, hired, or non-owned vehicles and equipment, with limits the same as those provided above for Comprehensive General Liability Insurance.

Any and all deductibles in the above-described insurance policies shall be assumed by, for the account of, and at the sole risk of the Contractor. Modification or cancellation of policies providing coverage listed above shall be effective only after written notice is received by NW Natural from the insurance company at least thirty (30) days in advance of such modification or cancellation.

NW Natural shall be named as an additional insured on Comprehensive General Liability Insurance and the policy shall contain a cross liability endorsement and contractual liability coverage for obligations assumed by the Contractor under the indemnity provisions of this contract.

SUB-CONTRACT WORK:
Contractor may utilize sub-contractors as approved by NW Natural. Contractor will be held to all requirements within this RFP and any subsequent contract, whether work is self-performed or sub-contracted.

CHANGE ORDER / EXTRA WORK:
Any changes or extra work not included in the original scope of this contract must be agreed upon in advance by both parties and approved by NW Natural prior to beginning such work.

NONDISCRIMINATORY PROVISIONS:
NW Natural is an Equal Opportunity Employer. NW Natural does not discriminate based on race, color, national origin, sex, sexual orientation, age, marital status, religion, veteran status or Vietnam-era veteran status, or sensory, mental or physical disabilities in matters or conditions of employment. NW Natural expects and requires its' Contractors to abide by all laws regarding equal opportunities for employees.

CORPORATE IMAGE:
NW Natural maintains a respected corporate image. The company's employees pride themselves on customer service and satisfaction in the office and in the field. NW Natural's Contractors represent not only their company but also NW Natural. It is the responsibility of the Contractor to maintain professional, courteous, caring and safe employees. If the Contractor provides employees to perform work on NW Natural projects who do not possess these traits, the contract could be in jeopardy of termination.

CONTRACTORS' EMPLOYEES:
NW Natural reserves the right to terminate the Agreement if any Contractor or employee of a Contractor fails to conform to contract specifications.

ACCOUNTING / AUDIT PROVISIONS:
Contractor shall maintain records and accounting procedures sufficient to support invoices. Contractor's records pertaining to the performance of the Agreement shall be subject at reasonable times to inspection and audit by NW Natural or its representative(s). Contractor shall preserve and make available records supporting any particular payment for a minimum of two (2) years after the date of such payment.

Attachments

Attachment A - Proposal Form

Attachment B - Scope of Work

Attachment C - Responsibilities

Attachment A

Proposal Form

**BIDDER SHALL USE THIS PROPOSAL FORM IN SUBMITTING PROPOSAL FOR CONSIDERATION.
BIDDER SHALL ENTER "N/A" IN SECTIONS THAT DO NOT APPLY TO PROPOSAL.**

Proposal for: Phase II Perrydale To Rickreall PROJECT

NW Natural retains the right to:

- Accept or reject any or all bids.
- Make an award without discussion with any bidder.
- Negotiate with one or more bidders.
- Make award based on factors other than price.

VALIDITY PERIOD OF PROPOSAL:
This Proposal shall remain *valid for a period of ninety (90) days* from the RFP Due Date. Bidder agrees to accept a Purchase Order, if its Proposal is selected by NW Natural, if notification of award is received on or before the expiration of the validity period. Bidder's prices shall be considered "firm" throughout the validity period, unless stipulated otherwise in the Proposal.

BIDDER INFORMATION:

Company Name: ______________________________
Address: ______________________________
Federal Taxpayer ID Number: ______________________________
Dun & Bradstreet Number: ______________________________
Construction Contractor No.: ______________________________
Date of Bidders Proposal: ______________________________
Telephone Number: ______________________________
Fax Number: ______________________________
Email Address: ______________________________
Bidding Contact: ______________________________

Payment Terms: ______________________

Experience Modification Rating (EMR) ____________

Bargaining Unit Affiliation: (Circle) Yes No If yes, Union ______________

Proposal Pricing

	Unit	Price	Total Cost
HDD Bore #8 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 5,400 feet).	FT	$/FT	$
HDD Bore #7 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximate 4,500 feet).	FT	$/FT	$
HDD Bore #6 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 5,000 feet)	FT	$/FT	$
HDD Bore #5 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately1,700 feet)	FT	$/FT	$

Proposal Pricing

	Unit	Price	Total Cost
HDD Bore #4 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 2,025 feet).	FT	$/FT	$
HDD Bore #3 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 1,600 feet).	FT	$/FT	$
HDD Bore #2 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 2,925 feet)	FT	$/FT	$
HDD Bore #1 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 2,950 feet)	FT	$/FT	$

Mobilization and demobilization (lump sum). Bore locations 1 thru 8 – see stationing in Geo Report.	**Total Cost**	$

Total Cost Bores #1 Thru #8	**Total Cost**	$

Total Cost Bores #1 Thru #8 Mob & De-Mob	**Total Proposal Cost**	$

Stationing (All Footage is Approximate)

N Pacific State Highway

Open Excavation Trench #5 3950 ft. –

Open Excavation Trench #4 900 ft. –

Open Excavation Trench #3 6300 ft. –

Open Excavation Trench #2 1300 ft. –

Open Excavation Trench #1 5075 ft. –

Note:

Total Price

OPEN EXCAVATION TRENCH COST	Cost per ft.	$
TOTAL PROJECT COST	**Total Project Cost**	$

NOTE:

1. Contractor shall provide all labor, materials and equipment for the scope of work as stated within this RFP.
2. This project is to be quoted as per foot installed. Pricing is all-inclusive and will be paid on actual footage installed for successful directional bores as accepted by NW Natural.
3. Mobilization and demobilization will be paid on a prorated basis.

Equipment:

Make **Model**

List Directional Drill Machine(s) to be utilized on this project: ______________________________

____

CERTIFICATION AND SIGNING OF PROPOSAL:

The undersigned certifies that the RFP package and the attachments have been examined and is understood; that all shown figures checked and understands that NW Natural is not responsible for any errors, or omissions on the Bidder's part in preparing this Proposal.

If the Bidder takes exception to any part of this RFP, the Bidder shall itemize those exceptions and submit them with this Proposal with the heading: **"EXCEPTION (S) TO RFP PACKAGE"**.

THE UNDERSIGNED ACKNOWLEDGES CONDITIONS OF THIS PROPOSAL:

Dated this _________ day of ______________________________

Signature ________________________________ in the capacity of ____________________________
(Company Title)

Printed Name: ________________________________

Address: ________________________________

____

____

ITEMS TO ACCOMPANY BID:

Item Submitted

- ☐ 1. This completed Proposal Form
- ☐ 2. Drug / Alcohol Testing Program Information
- ☐ 3. Safety Management Plan & Procedures
- ☐ 4. Quality Assurance / Quality Control Manual
- ☐ 5. Insurance Certificates
- ☐ 6. Proposed Construction Schedule, including crew size, work days per week, hours per day
- ☐ 7. Equipment Rental Rate Sheet
- ☐ 8. Hourly Labor Rates (all inclusive)
- ☐ 9. Exceptions (if any) to RFP package as stated herein
- ☐ 10. Any other documentation bidder feels will aid NW Natural in making their selection

Attachment B

Scope of Work

The work to be performed consists of the installation of approximately 26,100 lineal feet of 12" .312" wall, API 5L PSL 2, Grade X-52, FBE -Lilly coated steel pipe in double random lengths utilizing Horizontal Directional Drilling (HDD) and installation of approximately 17,525 lineal feet 12" .312" wall, API 5L PSL 2, Grade X-52, coated steel pipe open excavation construction methods detailed within this RFP package. The pipeline shall be installed along N. Pacific Highway W between Willamina – Dallas Hwy and the Central Coast Feeder pipeline.

All work shall be performed in accordance with all Specifications contained within this document and documents as referenced herein including but not limited to drawings and permits as listed below:

The Geotechnical Data Report and limited Horizontal Directional Drill (HDD) study will be provided by NW Natural. The study profiles the 8 bore sites and soil classifications.
Bore profiles will be provided by NW Natural.
The pilot-hole operation is to be drilled as closely as possible to the designed HDD profile with as little horizontal curvature as is practical while still maintaining three-joint vertical radii as referenced in the Geotechnical report. A horizontal tolerance of 5 feet left and 5 feet right of the designed alignment and a vertical tolerance of 2 feet above and 8 feet below the designed profile.

NOTE: The Contractor is responsible for creating, utilizing, maintaining and submitting bore profiles for final as-built drawings.

Upon completion of the entire pipeline installation a caliper pig (and possibly an MFL pig) will be run to look for construction defects. Contractor at its sole expense will immediately mitigate and repair any construction defects discovered as a result of this inspection.

All work shall be performed in accordance with all Specifications contained within this document and documents as referenced herein including but not limited to drawings and permits as listed below:

- Drawings – Provided at pre-bid meeting
- ODOT Permits – Prior to Construction
- County Permits – Prior to Construction
- Geo Engineers Report – Mid-Willamette – Perrydale Segment

Products and services furnished by the Contractor shall be provided and performed in accordance with the best industry standard and practices and as stated within the contract. Except for the materials to be furnished by NW Natural listed on Attachment C and other obligations to be performed by NW Natural as expressly set forth in the contract, the work shall include all supervision, labor, services, equipment, tools, materials, consumables, transportation and incidentals.

CONCERN FOR EXISTING UNDERGROUND UTILITIES:

The work will be performed in areas that contain existing distribution mains and other underground utilities. Therefore, the contractor must exercise caution and undertake the following steps, which include, but are not limited to:

1. Contact the "One Call System" requesting underground locations at least 48 hours before beginning operations. The telephone number in Oregon is (800)322-2DIG or 811.
2. Verify the location of all underground utilities at or adjacent to the work site. This shall include exposing any utilities that are located within the designed drill path. The exact location of the existing high-pressure transmission mains must be known at all times. Particular care must be taken to protect these lines, making sure that additional stresses are not added to the lines due to machinery crossing or working over them.
3. Modify drilling practices or down hole assemblies to prevent damage to adjacent underground utilities.

Attachment C

Responsibilities

Contractor

- Provide all labor, equipment and applicable material necessary to directional drill and pullback 12" steel pipe.
- Mobilization, demobilization and set up of horizontal drilling equipment at the bore sites.
- Contractor must not exceed the maximum bend radius of said pipe. Profiles must be approved by NW Natural prior to commencing work.
- Provide a Sizing Plate 11.5" ID (95%) to verify pipe integrity as installed.
- Brush Pigs

  Provide a Multi-Channel Caliper Pig Vendor

  Typical Detection Specifications

Reporting Threshold,	2%
Deformation (depth),	+/-0.14"
Ovality (depth),	+/-0.14"
Location Accuracy Axial	+/-0.1%
Circumferential	+/-15°

- Provide the required amount of pipe rollers necessary for protecting pipe during pull back of 12" steel pipe.
- Operated vacuum truck.
- Verification and acceptance of all underground utility locates and depths to avoid damages to existing structures.
- Control, removal and disposal of all drill fluid (mud).
- Minimizing the opportunities for runoff of water and sediments. Specific measures to prevent the runoff of water and sediments to include the installation of silt fences and hay bales.
- Drilling mud shall be contained and will not be dispersed by vehicle tires or treads.
- Immediately cleaning up all locations where drilling fluid inadvertently surfaces. Contractor will assume all liabilities and costs associated with directional drill "frac-outs".
- When required contractor will haul off spoils and replace with select backfill.
- Perform work in accordance with all drawings as issued by NW Natural and GeoEngineers.

- Work to conform to OQ and QA standards.
- Construction to conform to Department of Transportation Administration 49 CFR Part 192.
- The bore profile that is provided by NW Natural is to be used for bid purposes only. Contractor is responsible for creating and submitting final as-built drawings for review. As builts will include ground to pipeline depth profile. Horizontal stationing will be referenced from R/W including cross streets.

Site Work Requirements And Responsibilities:

1. Provide all labor, equipment and material necessary to install pipeline (except NW Natural furnished materials as listed in RFP document).
2. Perform work in accordance with all permits as issued. ODOT permit to be provided at bid walk.
3. Perform work in accordance with all drawings as issued by NW Natural
4. Provide all utility locating and potholing.
5. Provide traffic control as per ODOT requirements and approved TCP.
6. All NW Natural required and approved pipe coating (including labor, materials, equipment and expendables) shall be the responsibility of the contractor. All welds must be sand blasted (per NW Natural specs.) prior to installing pipe coating.

   a. Powercrete R60 or R60 HB Kits for joint coating of directional bore pipe and ground-to-surface transitions extending at least one (1) foot above and below ground level.

   b. Raychem (or equal) wrap around heat shrink sleeves (one per joint).
   (Raychem # WPCT-045)

   c. Calibrated Holiday Detectors/Jeeps. All pipe and joints must be quality assured prior to lowering pipeline in the trench and/or bores.

7. Provide welding of pipe per NW Natural specifications. All welders to be tested and certified by NW Natural. 100 % of the welds will be x-rayed at NW Natural's discretion and expense.
8. Provide a Multi Channel Caliper Pig run. NW Natural is requesting to have the vendor submit plans and specifications for the pig run. The vendor must have NW Natural approval prior to performing work.
9. Installation of pipe to include cleaning, hydro testing, pigging and drying to dew point of zero degree's . Testing requirements for the pipe are as follows;
   a. Minimum of 8 hours
   b. Minimum pressure of 1080 psig
   c. Maximum pressure of 1300 psig
   d. Witnessed and approved by NW Natural
   e. Hydrostatic test chart recording shall include temperature and pressure
   f. All testing equipment must have approved calibration records.
   g. All testing documents and completed charts are to be submitted with as builts.
10. Pipe shall be buried with a minimum of 5ft. (60") of cover. Any variations shall be with the approval of NW Natural Engineer. The pipe shall have 72" of cover from Ireland Rd to the termination point at the Willamette River HDD bore site.

11. All existing facilities must be identified and located by potholing or vacuum methods prior to crossing.
12. New pipe shall be installed at least 12" from all existing facilities.
13. All spoils hauled off and disposed of.
14. Imported sand back fill shall be to a minimum of 6-inches below and 12-inches above pipe.
15. All rocks, debris, road materials shall be removed from ditch prior to backfill.
16. All roads and road crossings shall be restored to pre-construction condition.
17. Road crossings shall be compacted to ODOT permit requirements. Test results to be submitted with as builts.
18. Disturbed roadways shall be cleaned of all dirt, mud, and construction materials and maintained to like new condition. Resurfacing may be required by local jurisdiction.
19. As-Built drawings to be submitted prior to final invoice payment. As-Built drawings to be provided per NW Natural's requirements. Final payment will not be released until as-builts are submitted and approved by NW Natural.
20. The pipe for this project is being stored at a HWY 34 and Oakville Rd.
21. Contractor shall coordinate delivery of pipe to jobsite, including all handling.
22. The Contractor shall coordinate delivery and handling of other NW Natural supplied materials. Materials other than pipe are stored at NW Natural's Tualatin facility located at 7100 McEwan Rd., Lake Oswego, OR 97035.

Contractor's Other Responsibilities:

I. Transportation of all equipment, labor, consumables and NW Natural supplied material to and from the job sites.
II. Provide a secure lay down area for all materials including pipe
III. Fire protection of jobsite. Contractor to follow all Federal, County and Jurisdictional requirements.
IV. Transporting, transferring, and storing any water required for hydrostatic testing.
V. Hauling and disposing of all hydrostatic test water at approved site (TBD)
VI. Management of the erosion control plan and BMP's are the responsibility of the contractor.
VII. Right of Way shall be fully cleaned, restored, seeded and fertilized to ODOT specifications
VIII. Dewatering of trench lines and bores pits must be filtered prior to discharging into public lands
IX. Operator Qualifications compliance-it is the contractor's responsibility to schedule, coordinate and administer documented training and testing with NW Natural.
X. Compensate welders for testing.

NW Natural

- Provide 12" .312" wall, API 5L PSL 2, Grade X52, Lilly/ FBE coated steel pipe in double random lengths
- Provide 12" .312" wall, API 5L PSL 2, Grade X52, coated steel pipe in double random lengths
- Valves, pipe fittings, flanges, and flange hardware (except for hydrostatic testing)
- All NDT, x-ray inspections of welds
- Testing of welders: To include testing materials and electrodes.
- Gas control and tie-ins
- Field staking of pipe center line and HDD entry and exit.
- Traffic control plan
- Erosion control plan
- Job (work) drawing
- ODOT and DEQ 1200C permits

Attachment C

Responsibilities

Contractor

- Provide all labor, equipment and applicable material necessary to directional drill and pullback 12" steel pipe.
- Mobilization, demobilization and set up of horizontal drilling equipment at the bore sites.
- Contractor must not exceed the maximum bend radius of said pipe. Profiles must be approved by NW Natural prior to commencing work.
- Provide a Sizing Plate 11.5" ID (95%) to verify pipe integrity as installed.
- Brush Pigs

  Provide a Multi-Channel Caliper Pig Vendor

  Typical Detection Specifications

Reporting Threshold,	2%
Deformation (depth),	+/-0.14"
Ovality (depth),	+/-0.14"
Location Accuracy Axial	+/-0.1%
Circumferential	+/-15°

- Provide the required amount of pipe rollers necessary for protecting pipe during pull back of 12" steel pipe.
- Operated vacuum truck.
- Verification and acceptance of all underground utility locates and depths to avoid damages to existing structures.
- Control, removal and disposal of all drill fluid (mud).
- Minimizing the opportunities for runoff of water and sediments. Specific measures to prevent the runoff of water and sediments to include the installation of silt fences and hay bales.
- Drilling mud shall be contained and will not be dispersed by vehicle tires or treads.
- Immediately cleaning up all locations where drilling fluid inadvertently surfaces. Contractor will assume all liabilities and costs associated with directional drill "frac-outs".
- When required contractor will haul off spoils and replace with select backfill.
- Perform work in accordance with all drawings as issued by NW Natural and GeoEngineers.

- Work to conform to OQ and QA standards.

- Construction to conform to Department of Transportation Administration 49 CFR Part 192.

- The bore profile that is provided by NW Natural is to be used for bid purposes only. Contractor is responsible for creating and submitting final as-built drawings for review. As builts will include ground to pipeline depth profile. Horizontal stationing will be referenced from R/W including cross streets.

Site Work Requirements And Responsibilities:

23. Provide all labor, equipment and material necessary to install pipeline (except NW Natural furnished materials as listed in RFP document).
24. Perform work in accordance with all permits as issued. ODOT permit to be provided at bid walk.
25. Perform work in accordance with all drawings as issued by NW Natural
26. Provide all utility locating and potholing.
27. ~~Provide traffic control as per ODOT requirements and approved TCP.~~
28. All NW Natural required and approved pipe coating (including labor, materials, equipment and expendables) shall be the responsibility of the contractor. All welds must be sand blasted (per NW Natural specs.) prior to installing pipe coating.

    a. Powercrete R60 or R60 HB Kits for joint coating of directional bore pipe and ground-to-surface transitions extending at least one (1) foot above and below ground level.

    b. Raychem (or equal) wrap around heat shrink sleeves (one per joint).
(Raychem # WPCT-045)

    c. Calibrated Holiday Detectors/Jeeps. All pipe and joints must be quality assured prior to lowering pipeline in the trench and/or bores.

29. Provide welding of pipe per NW Natural specifications. All welders to be tested and certified by NW Natural. 100 % of the welds will be x-rayed at NW Natural's discretion and expense.
30. Provide a Multi Channel Caliper Pig run. NW Natural is requesting to have the vendor submit plans and specifications for the pig run. The vendor must have NW Natural approval prior to performing work.
31. Installation of pipe to include cleaning, hydro testing, pigging and drying to dew point of zero degree's . Testing requirements for the pipe are as follows;
    a. Minimum of 8 hours
    b. Minimum pressure of 1080 psig
    c. Maximum pressure of 1300 psig
    d. Witnessed and approved by NW Natural
    e. Hydrostatic test chart recording shall include temperature and pressure
    f. All testing equipment must have approved calibration records.
    g. All testing documents and completed charts are to be submitted with as builts.
32. Pipe shall be buried with a minimum of 5ft. (60") of cover. Any variations shall be with the approval of NW Natural Engineer. The pipe shall have 72" of cover from Ireland Rd to the termination point at the Willamette River HDD bore site.

33. All existing facilities must be identified and located by potholing or vacuum methods prior to crossing.
34. New pipe shall be installed at least 12" from all existing facilities.
35. All spoils hauled off and disposed of.
36. Imported sand back fill shall be to a minimum of 6-inches below and 12-inches above pipe.
37. All rocks, debris, road materials shall be removed from ditch prior to backfill.
38. All roads and road crossings shall be restored to pre-construction condition.
39. Road crossings shall be compacted to ODOT permit requirements. Test results to be submitted with as builts.
40. Disturbed roadways shall be cleaned of all dirt, mud, and construction materials and maintained to like new condition. Resurfacing may be required by local jurisdiction.
41. As-Built drawings to be submitted prior to final invoice payment. As-Built drawings to be provided per NW Natural's requirements. Final payment will not be released until as-builts are submitted and approved by NW Natural.
42. The pipe for this project is being stored at a HWY 34 and Oakville Rd.
43. Contractor shall coordinate delivery of pipe to jobsite, including all handling.
44. The Contractor shall coordinate delivery and handling of other NW Natural supplied materials. Materials other than pipe are stored at NW Natural's Tualatin facility located at 7100 McEwan Rd., Lake Oswego, OR 97035.

Contractor's Other Responsibilities:

XI. Transportation of all equipment, labor, consumables and NW Natural supplied material to and from the job sites.
XII. Provide a secure lay down area for all materials including pipe
XIII. Fire protection of jobsite. Contractor to follow all Federal, County and Jurisdictional requirements.
XIV. Transporting, transferring, and storing any water required for hydrostatic testing.
XV. Hauling and disposing of all hydrostatic test water at approved site (TBD)
XVI. Management of the erosion control plan and BMP's are the responsibility of the contractor.
XVII. Right of Way shall be fully cleaned, restored, seeded and fertilized to ODOT specifications
XVIII. Dewatering of trench lines and bores pits must be filtered prior to discharging into public lands
XIX. Operator Qualifications compliance-it is the contractor's responsibility to schedule, coordinate and administer documented training and testing with NW Natural.
XX. Compensate welders for testing.

NW Natural

- Provide 12" .312" wall, API 5L PSL 2, Grade X52, Lilly/ FBE coated steel pipe in double random lengths
- Provide 12" .312" wall, API 5L PSL 2, Grade X52, coated steel pipe in double random lengths
- Valves, pipe fittings, flanges, and flange hardware (except for hydrostatic testing)
- All NDT, x-ray inspections of welds
- Testing of welders: To include testing materials and electrodes.
- Gas control and tie-ins
- Field staking of pipe center line and HDD entry and exit.
- Traffic control plan
- Erosion control plan
- Job (work) drawing
- ODOT and DEQ 1200C permits

NW NATURAL
Rates & Regulatory Affairs
Oregon General Rate Case – December 2011
Data Request Response

Request No. GR1-OPUC-DR 165

For each major project listed below, provide (a) request for bids issued; (b) All bids received in response to the request for bids issued by NWN; (c) The bids sheets or tables wher eNWN compared and evaluated the bids received; (d) The winning bid for the work, including the reasons the bid was selected as winnter; (e) The construction budget for the project developed by the winning bidder and approved by NWN; (f) The construction schedule for the project developed by the winning bidder and approved by NWN; (g) All changes to the initial construction budget, with explanations; (h) All changes to the initial construction schedule with explanations.

Project	Comments	Document References [1]
2012		
System Reinforcement, SIP, Gas Supply		
1. Windsor Island (SIP)	Only the boring portion of the project was sent to bid. Other portions of the project will be performed by NWN Company crews.	OPUC DR 165 Attachments 2 thru 3
2. Westside Transmission Re-Rate (TIMP)	There are no bids for this project. All work will be performed by NWN crews.	OPUC DR 165 Attachment-4
3. Corvallis Reinforcement	The bid process has not started.	OPUC DR 165 Attachments 5 thru 7
4. Felida Gate Piping (Washington Only)	NOT RELEVANT - THIS IS A WASHINGTON PROJECT	
5. Perrydale to Monmouth (to Independence)	All work will be performed by NWN Company crews.	OPUC DR 165 Attachments 8 thru 10
6. Monmouth Reinforcement (to Granger)	Only a portion of the project was sent to bid. Other portions of the project will be performed by NWN Company crews.	OPUC DR 165 Attachments 11 thru 19
7. Portland System Optimization (Phase 1) - 2012	Work will be performed by NWN Company crews.	OPUC DR 165 Attachment 20 and OPUC DR 158 Attachment-2
Facilities		
8. Vancouver relocate (Washington)	NOT RELEVANT - THIS IS A WASHINGTON PROJECT	
9. Tualatin bio-swale (tentative project)	This project is on hold.	None
10. Tualatin replacement, training facility & land	The bid process is pending.	See OPUC DR 165 Attachments 21 thru 24
11. Sunset sheds	Routine replacements/additions	None
12. Generators (4)	Routine replacements/additions	None
13. Parkrose Retrofit	The bid process has not started	None
14. Salem Retrofit	The bid process has not started	None
2013		
System Reinforcement, SIP, Gas Supply		
1. Portland System Optimization (Phase 2)- 2013	Work will be performed by NWN Company crews. Phase 2 will: Restore 400 psi MAOP to 10" Westside Feeder between Jean Rd and West Linn and 10x12" Boones Ferry pipeline between Barbur and Slavin and Jean Rd Station)	See OPUC DR 165 Attachment-20
Facilities		
2. Coos Bay Retrofit	This project is still in the planning phase	None
3. Astoria Retrofit	This project is still in the planning phase	None
4. Generators (5)	There are routine maintenance/repair/replacements	None

[1] Many of these documents are considered confidential subject to protective order.

This page is confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

PRELIMINARY CONSTRUCTION ESTIMATE
Monmouth 200580

Monmouth Reinforcement

Working Hours	10
Working Days	100
Calendar Weeks	20
Calendar Months	5

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
1	Internal staff charges	$50,000.00	1	LS	$50,000.00	
2	Design - HDD.	$30,000.00	1	LS	$30,000.00	GeoEngineers
2	Survey	$25,000.00	1	LS	$25,000.00	
2	Permits	$3,000.00	1	LS	$3,000.00	1200 c = $1500. Polk County EFU & floodplain = $1500
3	Pothole crew	$1,000.00	5	day	$5,000.00	Sure flow = $125/hr
4	Flaggers	$600.00	75	day	$90,000.00	2 flaggers per day = $600/day
5	Work Staging area/Easements	$6,000.00	13	each	$78,000.00	$6000/easement - 13 properties
6	Traffic Control Standard	$0.00	0	0	$0.00	5 flaggers for 2400 hrs
7	Traffic Control Equipment	$20,000.00	1	LS	$20,000.00	Misc - Barriers signs etc
8	Erosion Control / Dewatering	$30,000.00	1	LS	$30,000.00	Rain for Rent tanks,silt fence, Inlet protection, sandbags, etc.
9	Porta Johns	$240.00	5	each	$6,000.00	5 months - 2 each. $120 per month each
10	Shrink Sleeves	$20.00	20	each	$400.00	Majority will be powercrete
10	Powercrete	$50.00	670	kit	$33,500.00	$50 per 4 lb kits - 1 kit per joint
11	Skids	$5,000.00	1	LS	$5,000.00	
12	Plywood	$5,000.00	1	LS	$5,000.00	
13	Light plants	$1,600.00	2	months	$3,200.00	$800 per month per light
14	Steel plates	$125.00	40	each	$25,000.00	$125 per plate per month
15	Pipeline drying equipment	$4,000.00	1	LS	$4,000.00	One time rental
16	Sideboom	$26,000.00	3.75	month	$97,500.00	$13,000 per month per boom - use 3.75 months
17	Equipment Rental - Trackhoes	$6,500.00	2	each	$65,000.00	$6500 per month per trackhoe - use 5 months
17	Equipment Rental - Backhoes	$3,500.00	2	each	$35,000.00	$3500 per month per backhoe - use 5 months
18	Equipment Rental - Dozer	$8,000.00	1	each	$8,000.00	$8,000 per month per dozer - use 1 month
19	Water Truck	$4,000.00	1	month	$4,000.00	2 water trucks $2000 per month per truck
19	Misc hardware & rent - pigs, pumps etc	$10,000.00	1	LS	$10,000.00	pumps $1500/month
20	Shoring Rental	$10,000.00	4	month	$40,000.00	$2100/month per box DP Nicoli - $10,000 per month - use 4 months
21	Drill Pipe - 12"	$47.18	27553	ft	$1,299,950.54	Guess price on pipe - assumed all drill pipe
22	Other Pipe - 12"	$32.75	0	ft	$0.00	
23	Dump Trucks	$1,360.00	40	day	$54,400.00	2 Dump Trucks for 40 days $85/day per truck
24	Haul / Dump fee (spoils)	$5.00	940	cy	$4,700.00	47 yd per hole (7x30x6) - $5.00 per yd - use 20 holes thus 20*47 = 940 cy
24	Pee Gravel	$3.00	0	cy	$0.00	
25	Rock	$14.25	940	cy	$13,395.00	
26	Asphalt Paving	$11.71	1000	sf	$11,710.00	10 holes to pave 5 x20 each = 100sf ea - 1000sf total
27	Concrete Paving	$15.25	500	sf	$7,625.00	5 holes to cast - 5x20 each 100sf ea - 500 sf total

PRELIMINARY CONSTRUCTION ESTIMATE
Monmouth 200580

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
28	Sawcut	$1.00	5000	lf	$5,000.00	
29	Sand	$15.00	940	cy	$14,100.00	
30	Elbows, Tees, Stopples, etc.	$60,000.00	1	LS	$60,000.00	see material list - Pipe Bender?
31	Other Misc stores	$10,000.00	1	LS	$10,000.00	misc fittings, nitrogen, weld rods, sanders, etc.
32	Valves	$40,000.00	1	LS	$40,000.00	see material list
33	Electrostop	$6,000.00	1	each	$6,000.00	1-12" Electrostop
34	Gas Supply Meter set	$5,000.00	0	each	$0.00	Re-build meter set at OSU (materials only)
34	District Regulator/Relief	$20,000.00	3	each	$60,000.00	3 dist regs
	Equipment/Material Total				**$2,259,480.54**	
Item #	**Item**	**Cost/Unit**	**Quantity**	**Unit**	**Cost**	**Comments**
35	Tual Crew Labor - 'A'	$3,810.00	100	days	$381,000.00	10 hours per day 6 man crews 100 days
36	Tual Crew Labor - 'B'	$0.00	0	hours	$0.00	10 hours per day 1 - 6 man crews 200 days
37	Welder - Standard	$1,300.00	80	days	$104,000.00	2 welders for 100 days at 10 hr days
38	Specialty Crew	$1,200.00	70	days	$84,000.00	2 man crew for 70 days
39	X-Ray	$1,300.00	50	days	$65,000.00	
40	Trans Crew	$2,520.00	20	days	$50,400.00	4 man crew - $63*10*4 = 2520 per day - R/W crew - hydro test - 20 days
41	Gas Supply	$960.00	10	days	$9,600.00	2 man crew - $60*8*2 = 960 per day
42	Flatbed Truck & Operator	$80.00	80	hours	$6,400.00	Pipe Delivery
43	Per Diem	$324.00	80	day	$25,920.00	$54/day
44	Lodging	$480.00	100	day	$48,000.00	$100/day
	Labor Total				**$774,320.00**	
Item #	**Item**	**Cost/Unit**	**Quantity**	**Unit**	**Cost**	**Comments**
45	Caliper Pig - Post Construction	$0.00	1	ea	$0.00	Quote from Integrity Dept
46	Contract HDD Bore - Steel	$100.00	27553	ft	$2,755,300.00	
	Contract Total				**$2,755,300.00**	
	Equipment/Material Total				$2,259,480.54	
	Labor Total				$774,320.00	
	Contract Total				$2,755,300.00	
	Total				**$5,789,100.54**	
	Construction Overhead (27% for System Reinforcement)				$1,563,057.15	
	Total Cost				**$7,352,157.69**	
	Contingency (10%)				$735,215.77	
	Total Project Cost w/ OH				**$8,087,373.45**	

MEMORANDUM

NW Natural
220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

Date: August 12, 2011
To: Steve Nelson, Ryan Truair, Katie Gough, Joe Karney
From: Greg Bronson
Subject: Proposal for Project Initiation 200580

PROJECT NAME
Monmouth

PROJECT LOCATION
Monmouth

PROJECT PLATS
Start 2-121-025. End 2-128-021.

SCOPE
This project is for installation of approximately 27,400 feet (5 miles) of 12-inch steel natural gas pipeline tested and certified at a Maximum Allowable Operating Pressure (MAOP) of 720 psig. This pipeline is part of the Perrydale to Corvallis/Albany (Mid-Willamette Valley Feeder - P30 pipeline). This project starts North of Monmouth at Hoffman Rd heading south on Hwy 99, continues through Monmouth, heads East on Stapleton, South on Corvallis Rd and ends 2790' to the South of Stapleton.

Phase 1 will be a bore though Monmouth in public ROW
Phase 2 will be bore/open cut South of Monmouth ending South of Stapleton

PURPOSE
System Reinforcement

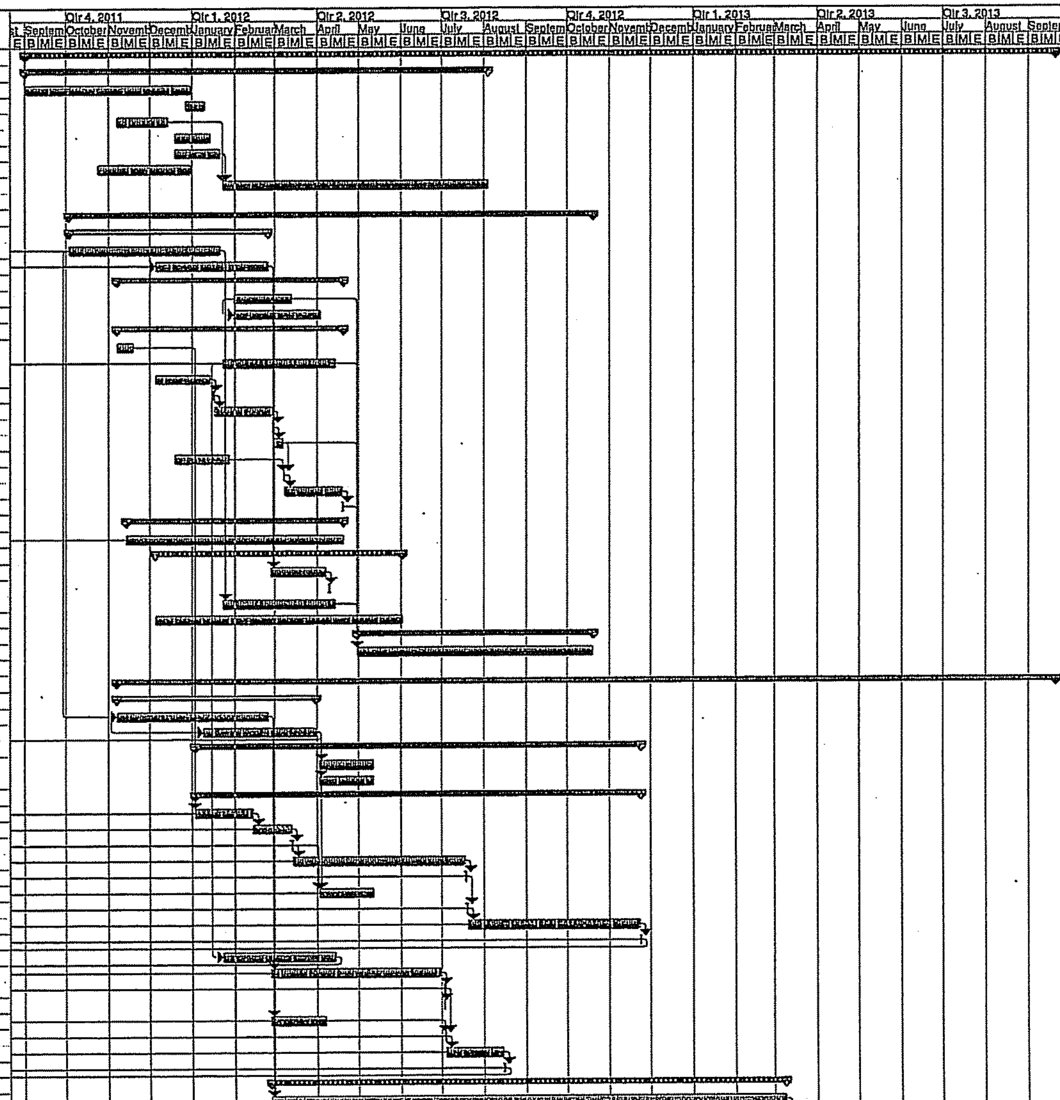
COST
Rough Estimated Cost:$7,500,000

FUNDING
System Reinforcement 115
COH – 27%

SCHEDULE
Possible Start date: 11/1/2011 for Phase 1 and 3/1/2012 for Phase 2
Estimated Construction Duration: 8 months

Staff/1002
Zimmerman/53

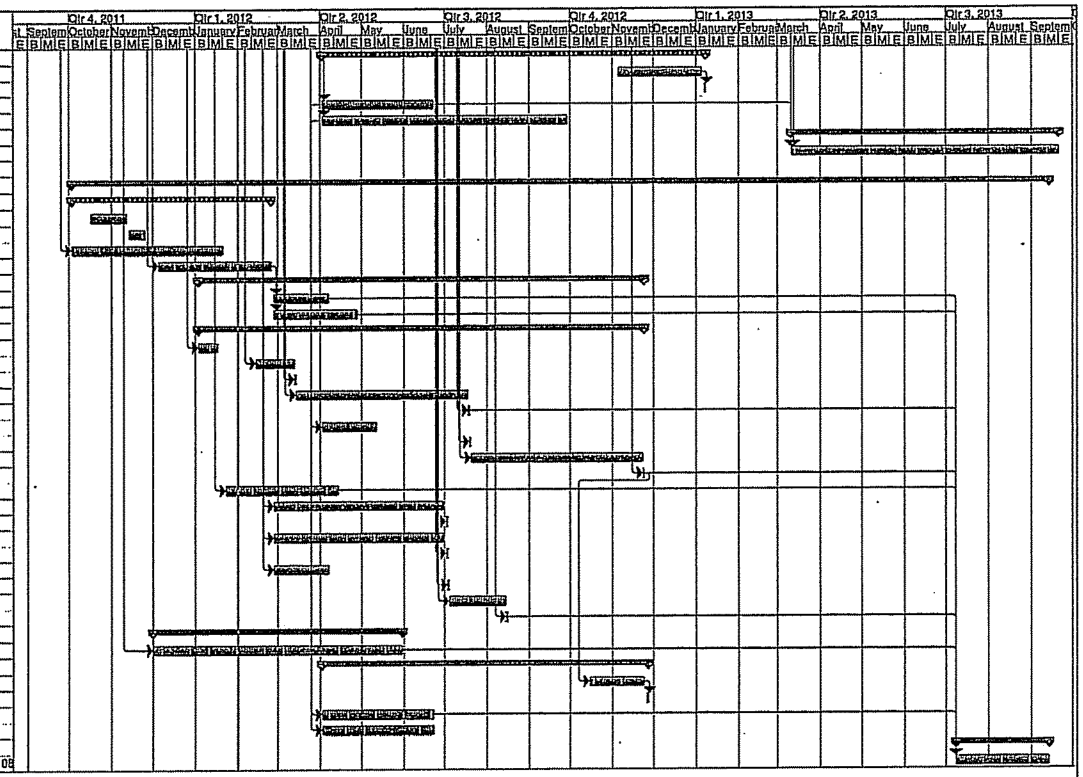
ID		Task Name	Duration	Start	Finish	Predecessors
1		Perrydale to Corvallis	537 days	Thu 9/1/11	Fri 9/20/13	
2		Phase 1 - Monmouth (P200580)	242 days	Thu 9/1/11	Fri 8/3/12	
3		Design & Survey	87 days	Thu 9/1/11	Fri 12/30/11	
4		Bid & Award HDD Contract	10 days	Tue 12/27/11	Mon 1/9/12	
5		Permit - ODOT	27 days	Mon 11/7/11	Tue 12/13/11	
6		Permit - Railroad	20 days	Mon 12/19/11	Fri 1/13/12	
7		Permit - DEQ	25 days	Mon 12/19/11	Fri 1/20/12	
8		Workspace Acquistion	50 days	Mon 10/24/11	Fri 12/30/11	
9		Construction (7 miles of pipeline)	140 days	Mon 1/23/12	Fri 8/3/12	5,7
10						
11		Phase 2- Perrydale to Monmouth (P200581)	275 days	Mon 10/3/11	Fri 10/19/12	
12		Design	105 days	Mon 10/3/11	Fri 2/24/12	
13		Final Alignment	80 days	Mon 10/3/11	Fri 1/20/12	
14		Geotechinal HDD Design	60 days	Mon 12/5/11	Fri 2/24/12	13SS+45 days
15		Permitting	119 days	Mon 11/7/11	Thu 4/19/12	
16		ODOT	30 days	Tue 1/31/12	Mon 3/12/12	
17		RR	45 days	Tue 1/31/12	Mon 4/2/12	16SS
18		Environmental	119 days	Mon 11/7/11	Thu 4/19/12	
19		Wetland Field Delineation	10 days	Mon 11/7/11	Fri 11/18/11	
20		Archaology	60 days	Mon 1/23/12	Fri 4/13/12	
21		Polk County - Prepare Floodplain Application	30 days	Mon 12/5/11	Fri 1/13/12	
22		Polk County -Submit Floodplain Application	1 day	Mon 1/16/12	Mon 1/16/12	21
23		Polk County - App. Review (up to 120 days)	30 days	Tue 1/17/12	Mon 2/27/12	22
24		Polk County - Floodplain Approval	1 day	Tue 2/28/12	Tue 2/28/12	23
25		Polk County - LUCS Approval	5 days	Wed 2/29/12	Tue 3/6/12	24
26		DEQ - Prepare Erosion Control Plans	30 days	Mon 12/19/11	Fri 1/27/12	
27		DEQ - Submit 1200C application	1 day	Wed 3/7/12	Wed 3/7/12	26,25
28		DEQ - App. Review	30 days	Thu 3/8/12	Wed 4/18/12	27
29		DEQ -1200C Approval	1 day	Thu 4/19/12	Thu 4/19/12	28
30		Land Acquistion	114 days	Mon 11/14/11	Thu 4/19/12	
31		Procure Easements & Workspaces	114 days	Mon 11/14/11	Thu 4/19/12	
32		Construction Pre Work	130 days	Mon 12/5/11	Fri 6/1/12	
33		Bid	30 days	Mon 2/27/12	Fri 4/6/12	14
34		Award	1 day	Mon 4/9/12	Mon 4/9/12	33
35		Procure Pipe	60 days	Mon 1/23/12	Fri 4/13/12	13
36		Procure Materials	130 days	Mon 12/5/11	Fri 6/1/12	
37		Construction (8 miles of pipeline)	125 days	Mon 4/30/12	Fri 10/19/12	
38		Construction	125 days	Mon 4/30/12	Fri 10/19/12	29,20,35,16,25
39						
40		Phase 3- South of Monmouth Bore (P200583)	490 days	Mon 11/7/11	Fri 9/20/13	
41		Design	105 days	Mon 11/7/11	Fri 3/30/12	
42		Final Alignment	80 days	Mon 11/7/11	Fri 2/24/12	13SS
43		Geotechinal HDD Design	60 days	Mon 1/9/12	Fri 3/30/12	42SS+45 days
44		Permitting	234 days	Tue 1/3/12	Fri 11/23/12	
45		Polk County	30 days	Mon 4/2/12	Fri 5/11/12	43
46		Benton County	30 days	Mon 4/2/12	Fri 5/11/12	43
47		Environmental	234 days	Tue 1/3/12	Fri 11/23/12	
48		DSL - Wetland Field Delineation	30 days	Tue 1/3/12	Mon 2/13/12	19
49		DSL - Prepare Wetland Application	20 days	Tue 2/14/12	Mon 3/12/12	48
50		DSL - Submit Wetland Application	1 day	Tue 3/13/12	Tue 3/13/12	49
51		DSL - App. Review (up to 120 days)	90 days	Wed 3/14/12	Tue 7/17/12	50
52		DSL - Concurrence Approval	1 day	Wed 7/18/12	Wed 7/18/12	51
53		JPA - Prepare Application	30 days	Mon 4/2/12	Fri 5/11/12	50,43
54		JPA- Submit to DSL/COE	1 day	Thu 7/19/12	Thu 7/19/12	52
55		JPA - App. Review (up to 150 days)	90 days	Fri 7/20/12	Thu 11/22/12	54
56		JPA - DSL/COE Approvals	1 day	Fri 11/23/12	Fri 11/23/12	55
57		Archaology	60 days	Mon 1/23/12	Fri 4/13/12	20SS
58		Benton County -Land Use Application	90 days	Mon 2/27/12	Fri 6/29/12	42
59		Benton County - LUCS Approval	1 day	Mon 7/2/12	Mon 7/2/12	58
60		Polk County - LUCS Approval	1 day	Mon 7/2/12	Mon 7/2/12	58
61		DEQ - Prepare Erosion Control Plans	30 days	Mon 2/27/12	Fri 4/6/12	42
62		DEQ - Submit 1200C application	1 day	Tue 7/3/12	Tue 7/3/12	61,59
63		DEQ - App. Review	30 days	Wed 7/4/12	Tue 8/14/12	62
64		DEQ -1200C Approval	1 day	Wed 8/15/12	Wed 8/15/12	63
65		Land Acquistion	270 days	Mon 2/27/12	Fri 3/8/13	
66		Procure Easements & Workspaces	270 days	Mon 2/27/12	Fri 3/8/13	42



Project: Date: W

Task | Summary | External Milestone | Inactive Summary | Manual Summary Rollup | Finish-only
Split | Project Summary | Inactive Task | Manual Task | Manual Summary | Progress
Milestone | External Tasks | Inactive Milestone | Duration-only | Start-only | Deadline

ID		Task Name	Duration	Start	Finish	Predecessors
67		Construction Pre Work	201 days	Mon 4/2/12	Mon 1/7/13	
68		Bid	45 days	Mon 11/5/12	Fri 1/4/13	
69		Award	1 day	Mon 1/7/13	Mon 1/7/13	68
70		Procure Pipe	60 days	Mon 4/2/12	Fri 6/22/12	43
71		Procure Materials	130 days	Mon 4/2/12	Fri 9/28/12	43
72		Construction (12 miles of pipeline)	140 days	Mon 3/11/13	Fri 9/20/13	
73		Construction - 2 spreads	140 days	Mon 3/11/13	Fri 9/20/13	56,57,64,70,66
74						
75		Phase 3- Willamette River (P200584)	510 days	Mon 10/3/11	Fri 9/13/13	
76		Design	105 days	Mon 10/3/11	Fri 2/24/12	
77		Initial Meeting w/ Landowners	20 days	Mon 10/17/11	Fri 11/11/11	
78		Survey	10 days	Mon 11/14/11	Fri 11/25/11	
79		Final Alignment	80 days	Mon 10/3/11	Fri 1/20/12	13SS
80		Geotechinal HDD Design	60 days	Mon 12/5/11	Fri 2/24/12	14SS
81		Permitting	234 days	Tue 1/3/12	Fri 11/23/12	
82		ODOT	30 days	Mon 2/27/12	Fri 4/6/12	80
83		RR	45 days	Mon 2/27/12	Fri 4/27/12	80
84		Environmental	234 days	Tue 1/3/12	Fri 11/23/12	
85		DSL - Wetland Field Delineation	10 days	Tue 1/3/12	Mon 1/16/12	48SS
86		DSL - Prepare Wetland Application	20 days	Tue 2/14/12	Mon 3/12/12	49SS
87		DSL - Submit Wetland Application	1 day	Tue 3/13/12	Tue 3/13/12	50SS
88		DSL - App. Review (up to 120 days)	90 days	Wed 3/14/12	Tue 7/17/12	51SS
89		DSL - Concurrence Approval	1 day	Wed 7/18/12	Wed 7/18/12	52SS
90		JPA - Prepare Application	30 days	Mon 4/2/12	Fri 5/11/12	53SS
91		JPA- Submit to DSL/COE	1 day	Thu 7/19/12	Thu 7/19/12	54SS
92		JPA - App. Review (up to 150 days)	90 days	Fri 7/20/12	Thu 11/22/12	55SS
93		JPA - DSL/COE Approvals	1 day	Fri 11/23/12	Fri 11/23/12	56SS
94		Archaelogy	60 days	Mon 1/23/12	Fri 4/13/12	20SS
95		Linn County -Land Use Application	90 days	Mon 2/27/12	Fri 6/29/12	58SS
96		Linn County - LUCS Approval	1 day	Mon 7/2/12	Mon 7/2/12	59SS
97		Benton County -Land Use Application	90 days	Mon 2/27/12	Fri 6/29/12	58SS
98		Benton County - LUCS Approval	1 day	Mon 7/2/12	Mon 7/2/12	59SS
99		DEQ - Prepare Erosion Control Plans	30 days	Mon 2/27/12	Fri 4/6/12	61SS
100		DEQ - Submit 1200C application	1 day	Tue 7/3/12	Tue 7/3/12	62SS
101		DEQ - App. Review	30 days	Wed 7/4/12	Tue 8/14/12	63SS
102		DEQ -1200C Approval	1 day	Wed 8/15/12	Wed 8/15/12	64SS
103		Land Acquistion	130 days	Thu 12/1/11	Wed 5/30/12	
104		Procure Easements & Workspaces	130 days	Thu 12/1/11	Wed 5/30/12	31SS
105		Construction Pre Work	171 days	Mon 4/2/12	Mon 11/26/12	
106		Bid	30 days	Mon 10/15/12	Fri 11/23/12	93FS-30 days
107		Award	1 day	Mon 11/26/12	Mon 11/26/12	106
108		Procure Pipe	60 days	Mon 4/2/12	Fri 6/22/12	70SS
109		Procure Materials	60 days	Mon 4/2/12	Fri 6/22/12	71SS
110		Construction (3 miles of pipeline)	50 days	Mon 7/8/13	Fri 9/13/13	
111		Construction	50 days	Mon 7/8/13	Fri 9/13/13	82,94,102,104,108



Project: Date: W

Task		Summary		External Milestone	◆	Inactive Summary		Manual Summary Rollup		Finish-only	]
Split		Project Summary		Inactive Task		Manual Task		Manual Summary		Progress	
Milestone	◆	External Tasks		Inactive Milestone	◇	Duration-only		Start-only	[	Deadline	⇩

Pages 55 to 62 are confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

NW Natural

220 NW Second Avenue
Portland, OR 97209

REQUEST FOR PROPOSAL

Title: Phase I Monmouth Project

Date: December 16, 2011

NW Natural
220 NW Second Avenue
Portland, OR 97209
Proposal Due Date: January 26, 2012 at 2:00 PM

REQUEST FOR PROPOSAL (RFP)

TITLE: PHASE I MONMOUTH PROJECT
PROPOSAL SUBMITTAL DATE AND TIME: JANUARY 26, 2012, 2:00 PM PDT
NOTE: Proposals received after 2:00 PM on the Proposal Submittal Date may be considered non-responsive.

DELIVER PROPOSAL TO:

NW NATURAL
Purchasing Department
Attn.: Craig Gagner
220 NW Second Avenue
Portland, OR 97209

Telephone: (503) 226-4211 Ext. 2550
Facsimile: (503) 273-4825
Email: csg@nwnatural.com

REFERENCE TIMETABLE:
Below is a timetable for your quick reference. It contains key tasks and dates that you will be responsible for in order to successfully respond to this RFP. Please take note of all dates and times.

Task	Due Date/Time	
RFP Distribution	December 16, 2011	
Job Walk	December 27, 2011	
Deadline for Question Submissions	January 20, 2012	
RFP Due Date	January 26, 2012 2:00 PM PDT	
Award Contract	January 31, 2012	
Field Work Starts	February 1, 2011 (On or about)	
Work Completed	March 16, 2012 –	Bore #1
	April 30, 2012 –	Bore #2
	June 15, 2012 –	Bore #3
	July 31, 2012 –	Bore #4
	September 15, 2012 –	Bore #5
	October 15, 2012 –	Bore #6

Submit As-builts

NOTE: Field work start date(s) may vary depending on work space agreements with private property owners

NW NATURAL CONTACT FOR RFP ISSUES AND INFORMATION REQUEST:
All inquiries concerning this RFP and/or requests for additional information must be directed to Craig Gagner in writing at the above address.

PURPOSE:

NW Natural Gas Company, doing business as NW Natural, is seeking proposals for construction services for the Monmouth HDD project as further defined in the attachments that follow.

NW Natural provides reliable, cost-effective natural gas service to more than 650,000 residential, commercial and industrial customers through 13,000 miles of mains and service lines in western Oregon and southwestern Washington.

You are invited to submit a proposal for the services defined herein. Your proposal shall be in compliance with all referenced documents, whether included herein, or incorporated by reference.

INSTRUCTIONS TO BIDDERS:

- Each Bidder shall submit its Proposal using the Proposal Form that is supplied herewith. Any qualifications, additions, or clarifications thereto shall be submitted by way of separate document. Proposal Form shall be manually signed. If erasures or other changes appear on the form, the person signing the Proposal Form must initial each erasure or change.

- Each Bidder shall submit **two copies of their proposal** complete with all attachments and supplemental correspondence in order for the Proposal to be considered.

- Proposals shall be submitted in a **sealed envelope** clearly addressed with Bidder's company name clearly labeled ***"RFP – PHASE I MONMOUTH PROJECT."*** Modifications to Proposals already submitted will be considered if received in NW Natural's offices by the RFP Due Date listed above. Also, Proposals may be withdrawn by the RFP Due Date.

- Unless expressly solicited by NW Natural, alternative Proposals will not be considered. However, value-engineering and cost reduction recommendations are encouraged and will be accepted for review with the Proposal. Any proposals for value engineered cost reductions shall be submitted, in written form, on the Bidder's letterhead and shall be included with the submitted sealed Proposal.

- All Proposal submittals, as required by this request, shall be included with the Proposal, on the specified due date and time.

- Bidder shall comply with all state and federal laws in regards to formulation and submittal of proposal. Prospective bidders should note that this is a competitive bidding situation, and that conferring with separate bidders about pricing or other specific details of the proposal may violate antitrust law.

- Proposals *shall remain firm for a period of ninety (90) days after the RFP Due Date.* NW Natural **may**, when it is in its best interest, reject any or all bids, or waive any formality of the RFP contents in any Proposal received.

- Bidder is deemed to have satisfied itself by submission of its Proposal as to the correctness and sufficiency of the Proposal to cover all requirements as requested per this document.

- Bidder(s) or awarded Bidder shall under no circumstances use NW Natural 's name or logos in advertising, marketing materials, printed matter, reference lists, or in any other way that could be construed as advertising (e.g., memo pads, tee shirts, binders, reference list, etc.) without NW Natural 's prior written consent.

NEGOTIATION TERMS:

NW Natural retains the right to select, request further information from, and negotiate with those bidders it deems qualified for competitive negotiations. NW Natural also reserves the right to reject any or all Proposals submitted and to terminate negotiations with any party at any time without incurring liability. This RFP gives rise to no contractual obligations, implied or otherwise.

RFP TERMS AND CONDITIONS APPLIED TO FINAL CONTRACT:
All terms and conditions outlined in this RFP, including the specifications and the Bidder's completed proposal, will become, at NW Natural's sole discretion, part of the final Purchase Order contract (the "Agreement") between NW Natural and the selected Contractor.

HOLD HARMLESS:
In submitting a Proposal, Bidder understands that NW Natural will determine which proposal, if any, is accepted. Bidder waives any right to claim damages of any nature whatsoever based on the selection process, final selection, and any communications associated with the selection.

CONFIDENTIALITY PROVISION:
The terms of this RFP, and all other information provided by NW Natural in connection with this RFP, are confidential and proprietary to NW Natural. Such materials are to be used solely for the purpose of responding to this request. By submitting a proposal, Bidder agrees not to disclose any such information to any third party without the prior written consent of NW Natural (which consent shall be conditional upon the written agreement of the intended recipient to treat the same as confidential). NW Natural may request at any time that any or all NW Natural material be returned or destroyed.

Should you choose not to respond to this RFP, all materials and any duplicates thereof must be returned to NW Natural at the address listed on Page 2 of this RFP.

CONTRACT EVALUATION AND AWARD:
NW Natural has no obligation to reveal the basis for contract award or to provide any information to bidders relative to the evaluation or decision-making process. All participating bidders will be notified promptly of bid acceptance or rejection.

CONTRACT NEGOTIATION AND EXECUTION:
As discussed above, NW Natural intends that the successful Bidder will enter into a Purchase Order which contains all of the terms and conditions of the proposed relationship between Bidder and NW Natural. Any acceptance of a Proposal is contingent upon the execution of a Purchase Order contract (the "Agreement"), and neither party shall be contractually bound to the other prior to the execution of such written "Agreement".

SPECIFICATIONS:
It is Contractor's responsibility to understand and adhere to all municipal and jurisdictional technical specifications for the work performed. Should there be questions and/or concerns regarding NW Natural or jurisdictional requirements or specifications, Contractor shall notify the NW Natural technical representative prior to the commencement of work.

GUARANTEE / WARRANTY:
The Contractor warrants that all Work performed shall be of the quality required by the Contract, or of the best grade or performed in a first-class workmanlike manner if no quality is specified,, that all such materials and equipment shall be suitable for the purposes intended to the extent selected by the Contractor or Subcontractors, and that all Work and such materials and equipment shall conform to the Specifications, Drawings, samples, and other descriptions set forth in the Contract. Upon receipt of written notice from the Company of a breach of warranty, the affected item or Work shall be redesigned, repaired, replaced, or reperformed by the Contractor; and the Contractor shall perform such tests as the Company may require to verify that such redesign, repair, replacement or reperformance complies with the requirements of the Contract. The Company reserves the right to itself have such redesign, repair,

replacement, or reperformance Work done when it deems it advisable. All costs incidental to redesign, repair, replacement or reperformance Work, and the testing thereof, including but not limited to the removal, replacement, and reinstallation of equipment necessary to gain access, the repair or replacement of damage to the Work and the project resulting therefrom, and all other costs incurred as the result of a breach of warranty, shall be borne by the

Contractor. Should the Contractor fail promptly to make the necessary redesigns, repairs, replacements, reperformances, or tests, the Company may perform or cause to be performed the necessary Work or tests at the Contractor's expense.

The above warranties are not intended as a limitation but are in addition to all other express warranties set forth in the Contract and such other warranties as are implied by law, custom or usage of trade.

The above warranties shall be for a period of not less than two (2) years from the date of final completion of the entire Work and shall include but not be limited to site restoration and fabrication. A performance bond may be required to ensure compliance of warranties; the cost of such bond shall be paid by the Contractor.

INSPECTION AND ACCEPTANCE:
NW Natural and/or its representatives reserve the right to retain access to Contractor's work for the purposes of inspection and work acceptance. Failure to inspect, accept or reject the work shall not relieve the Contractor from its responsibility to furnish the requirements of the Contract. Approval and inspection shall be the responsibility of NW Natural.

QUALITY CONTROL ASSURANCE:
NW Natural will perform periodic quality assurance audits of contractor work. Work rejected due to poor quality/non-conformance shall be removed, replaced and/or re-performed by Contractor at Contractor's expense.

SITE CONDITIONS:
Contractor has the sole responsibility of satisfying itself concerning the nature and locations of work and the general and local conditions.

CONTRACTOR'S ENVIRONMENTAL OBLIGATIONS AND INDEMNITIES:
Contractor shall (a) abide by and comply strictly with all governmental permits and authorizations held by NW Natural in connection with the work; (b) acquire and comply with all governmental permits and authorizations that are necessary for Contractor's work on the project and that have not been obtained by NW Natural; (c) comply with all federal, state and local laws, regulations and ordinances relating to protection or enhancement of the environment and that are applicable to Contractor's activities hereunder; and (d) assume the risk that Contractor has identified all such applicable laws, obtained all such necessary governmental permits and authorizations, and that it has the capability to comply.

DRUG, ALCOHOL AND SUBSTANCE ABUSE TESTING COMPLIANCE:
Contractors who drive interstate commercial motor vehicles that are rated at over 26,000 lbs. or are engaged in safety-sensitive pipeline operations are required by the U.S. Department of Transportation ("DOT") to implement a program of drug, alcohol and substance abuse testing, education and training (49 CFR Parts 40, 199, 325, 355-379 and 381-399). NW Natural is required to confirm that its independent contractors and their employees, if any, comply with these regulations. Any contractor who drives a truck as described above or performs services identified as safety-sensitive must comply with the appropriate regulations and provide evidence of compliance to the NW Natural Purchasing Department. Failure to provide such evidence will disqualify the Contractor from performing work or services for NW Natural. NW Natural is authorized by regulations to audit the Contractor's drug, alcohol and substance abuse program records. **The work and/or services described in this RFP have been identified as being covered by the regulations.**

NOTE: All costs associated with Contractor Drug, Alcohol, and Substance Abuse testing shall be the sole responsibility of the Contractor.

ADHERENCE TO OPERATORS QUALIFICATIONS:
Federal law requires that all personnel, including independent contractors, who perform "Covered Tasks" on pipeline facilities or appurtenances owned or operated by NW Natural must meet certain qualification standards administered by NW Natural in accordance with regulations promulgated by the U.S. Department of Transportation's Office of Pipeline Safety (49 CFR Part 192, Subpart N, as currently in effect and as may be amended from time to time). Some or all of the services to be performed by Contractor pursuant to the Purchase Order constitute "Covered Tasks" for purposes of the aforementioned regulations, and such services are therefore subject to the NW Natural Operator Qualification Program. NW Natural and its representatives have sole authority (subject only to the terms and standards set by the Office of Pipeline Safety and other regulatory agencies, if applicable) for all elements of its Operator Qualification program, including but not limited to setting qualification standards, recordkeeping and conducting audits under the program. NW Natural agrees to administer operator qualification testing for Contractor and its personnel at no charge. Contractors are not eligible for payment for time spent on the testing process.

CONTRACTOR INDEMNITY/PERFORMANCE OF THE WORK:
Contractor shall indemnify and save harmless NW Natural and its directors, officers, shareholders, partners, employees and agents (including their successors and assigns), against and from any and all actions, proceedings, audits, investigations, claims, demands, damages, fines, penalties, response costs, loss and liability, expenses and costs (including attorneys' fees in any suit, action or proceeding, whether groundless or not, that may be brought against NW Natural) caused or arising out of the acts or omissions of Contractor and Contractor's agents and employees. This includes, but is not limited to, (a) injury or death of any persons; (b) damage to or loss of any property and natural resources; (c) degradation or contamination of the environment; and (d) noncompliance with any applicable law, regulation, ordinance, permit or authorization, caused or arising out of the acts or omissions of Contractor and Contractor's agents and employees.

Provided, however, that this section shall not require Contractor to indemnify and save harmless NW Natural and its directors, officers, partners, employees and agents (including their successors and assigns) against and from any responsibility or liability for their own negligence.

INSURANCE REQUIREMENTS:
Contractor shall carry at its own expense, insurance with reliable insurance companies satisfactory to NW Natural and authorized to do business in the State or the States in which work is to be performed by the Contractor hereunder, the following types of insurance limits not less than shown on the respective items:

A. Workers Compensation Insurance and occupational disease insurance with statutory limits, and employers' liability insurance with a minimum limit of $1,000,000.
B. Comprehensive General Liability Insurance with a combined single limit for bodily injury, personal injury and property damage of $2,000,000 for injuries to or death of anyone or destruction of any property, including loss of use thereof, arising out of an occurrence.
C. Automobile Liability Insurance, including all owned, hired, or non-owned vehicles and equipment, with limits the same as those provided above for Comprehensive General Liability Insurance.

Any and all deductibles in the above-described insurance policies shall be assumed by, for the account of, and at the sole risk of the Contractor. Modification or cancellation of policies providing coverage listed above shall be effective only after written notice is received by NW Natural from the insurance company at least thirty (30) days in advance of such modification or cancellation.

NW Natural shall be named as an additional insured on Comprehensive General Liability Insurance and the policy shall contain a cross liability endorsement and contractual liability coverage for obligations assumed by the Contractor under the indemnity provisions of this contract.

SUB-CONTRACT WORK:
Contractor may utilize sub-contractors as approved by NW Natural. Contractor will be held to all requirements within this RFP and any subsequent contract, whether work is self-performed or sub-contracted.

CHANGE ORDER / EXTRA WORK:
Any changes or extra work not included in the original scope of this contract must be agreed upon in advance by both parties and approved by NW Natural prior to beginning such work.

NONDISCRIMINATORY PROVISIONS:
NW Natural is an Equal Opportunity Employer. NW Natural does not discriminate based on race, color, national origin, sex, sexual orientation, age, marital status, religion, veteran status or Vietnam-era veteran status, or sensory, mental or physical disabilities in matters or conditions of employment. NW Natural expects and requires its' Contractors to abide by all laws regarding equal opportunities for employees.

CORPORATE IMAGE:
NW Natural maintains a respected corporate image. The company's employees pride themselves on customer service and satisfaction in the office and in the field. NW Natural's Contractors represent not only their company but also NW Natural. It is the responsibility of the Contractor to maintain professional, courteous, caring and safe employees. If the Contractor provides employees to perform work on NW Natural projects who do not possess these traits, the contract could be in jeopardy of termination.

CONTRACTORS' EMPLOYEES:
NW Natural reserves the right to terminate the Agreement if any Contractor or employee of a Contractor fails to conform to contract specifications.

ACCOUNTING / AUDIT PROVISIONS:
Contractor shall maintain records and accounting procedures sufficient to support invoices. Contractor's records pertaining to the performance of the Agreement shall be subject at reasonable times to inspection and audit by NW Natural or its representative(s). Contractor shall preserve and make available records supporting any particular payment for a minimum of two (2) years after the date of such payment.

Attachments

Attachment A - Proposal Form

Attachment B - Scope of Work

Attachment C - Responsibilities

Attachment A

Proposal Form

BIDDER SHALL USE THIS PROPOSAL FORM IN SUBMITTING PROPOSAL FOR CONSIDERATION.
BIDDER SHALL ENTER "N/A" IN SECTIONS THAT DO NOT APPLY TO PROPOSAL.

Proposal for: Phase I Monmouth PROJECT

NW Natural retains the right to:

- Accept or reject any or all bids.
- Make an award without discussion with any bidder.
- Negotiate with one or more bidders.
- Make award based on factors other than price.

VALIDITY PERIOD OF PROPOSAL:
This Proposal shall remain *valid for a period of ninety (90) days* from the RFP Due Date. Bidder agrees to accept a Purchase Order, if its Proposal is selected by NW Natural, if notification of award is received on or before the expiration of the validity period. Bidder's prices shall be considered "firm" throughout the validity period, unless stipulated otherwise in the Proposal.

BIDDER INFORMATION:

Company Name: ______________________________
Address: ______________________________
Federal Taxpayer ID Number: ______________________________
Dun & Bradstreet Number: ______________________________
Construction Contractor No.: ______________________________
Date of Bidders Proposal: ______________________________
Telephone Number: ______________________________
Fax Number: ______________________________
Email Address: ______________________________
Bidding Contact: ______________________________

Payment Terms: ______________________

Experience Modification Rating (EMR) ____________

Bargaining Unit Affiliation: (Circle) Yes No If yes, Union ______________

Proposal Pricing

	Unit	Price	Total Cost
Middle Fork Ash Creek HDD #1 (2012) Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (approximate range of pipe footage 4500 feet).	FT	$/FT	$
South Fork Ash Creek HDD #3 (2012) Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (approximate range of pipe footage 5200 feet).	FT	$/FT	$
Railroad Tracks HDD Bore #6 (2012) Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 675 feet)	FT	$/FT	$
		Total Proposal Cost	$

Mobilization and demobilization (lump sum). Bore locations 1 thru 6 -- see stationing below.	**Total Proposal Cost**	$

Stationing (All Footage is Approximate)

*Stationing is approximate and referenced from HDD bore plans

2011

Bore #1 4450 Ft/ Station xx+00 to xx+00 (Middle Fork Ash Creek) – Completion March 16, 2012

Bore #2 3900 Ft/ Station xx+00 to xx+00 (Hwy 99W to Marr Brothers) – Completion April 30, 2012

Bore #3 5200 Ft/ Station xx+00 to xx+00 (S. Fork Ash Creek) – Completion June 15, 2012

Bore #4 4800 Ft/ Station xx+00 to xx+00 – (Hwy 99W to Stapleton Rd) Completion July 31, 2012

Bore #5 4200 Ft/ Station xx+00 to xx+00 (Hwy 99W to Parker Rd) – Completion September 15, 2012

Bore #6 675 Ft/ Station xx+00 to xx+00 (Railroad Tracks) – Completion October 15, 2012

Note:

Bores profiles will not be developed in time for the bid distribution.

NOTE:

1. Contractor shall provide all labor, materials and equipment for the scope of work as stated within this RFP.
2. This project is to be quoted as per foot installed. Pricing is all-inclusive and will be paid on actual footage installed for successful directional bores as accepted by NW Natural.
3. Mobilization and demobilization will be paid on a prorated basis.

Equipment:

	Make	**Model**
List Directional Drill Machine(s) to be utilized on this project: ____		

____

CERTIFICATION AND SIGNING OF PROPOSAL:

The undersigned certifies that the RFP package and the attachments have been examined and is understood; that all shown figures checked and understands that NW Natural is not responsible for any errors, or omissions on the Bidder's part in preparing this Proposal.

If the Bidder takes exception to any part of this RFP, the Bidder shall itemize those exceptions and submit them with this Proposal with the heading: **"EXCEPTION (S) TO RFP PACKAGE".**

THE UNDERSIGNED ACKNOWLEDGES CONDITIONS OF THIS PROPOSAL:

Dated this ________ day of ______________________

Signature ______________________ in the capacity of ______________________
(Company Title)

Printed Name: ______________________

Address: ______________________

____

____

ITEMS TO ACCOMPANY BID:

Item Submitted

- ☐ 1. This completed Proposal Form
- ☐ 2. Proposed construction schedule, crew size, work days per week, hours per day
- ☐ 3. Exceptions (if any) to RFP package as stated herein
- ☐ 4. Any other documentation bidder feels will aid NW Natural in making their selection

Attachment B

Scope of Work

The work to be performed consists of the Horizontal Directional Drilling (HDD), of approximately 23,225 lineal feet of 12" .312" wall, API 5L PSL 2, Grade X-52, FBE coated steel pipe in 40 foot lengths in six separate bores. Contractor will work in conjunction with NW Natural pipeline crew, which will provide construction support prior to and during pullback of 12" steel pipe. NW Natural will provide a dedicated workspace for construction purposes.

The Geotechnical Data Report and limited Horizontal Directional Drill (HDD) study will be provided by NW Natural. The study profiles the 6 bore sites and soil classifications.

The pilot-hole operation is to be drilled as closely as possible to the designed HDD profile with as little horizontal curvature as is practical while still maintaining three-joint vertical radii as referenced in the Geotechnical report. A horizontal tolerance of 5 feet left and 5 feet right of the designed alignment and a vertical tolerance of 2 feet above and 8 feet below the designed profile.

NOTE: The Contractor is responsible for creating, utilizing, maintaining and submitting bore profiles for final as-built drawings.

Upon completion of the entire pipeline installation a caliper pig (and possibly an MFL pig) will be run to look for construction defects. Contractor at its sole expense will immediately mitigate and repair any construction defects discovered as a result of this inspection.

All work shall be performed in accordance with all Specifications contained within this document and documents as referenced herein including but not limited to drawings and permits as listed below:

- Drawings – Provided at pre-bid meeting
- ODOT Permits – Prior to Construction
- County Permits – Prior to Construction
- City Permits-- Prior to Construction
- Geo Engineers Report – Mid-Willamette - Monmouth Segment

Products and services furnished by the Contractor shall be provided and performed in accordance with the best industry standard and practices and as stated within the contract. Except for the materials to be furnished by NW Natural listed on Attachment C and other obligations to be performed by NW Natural as expressly set forth in the contract, the work shall include all supervision, labor, services, equipment, tools, materials, consumables, transportation and incidentals.

CONCERN FOR EXISTING UNDERGROUND UTILITIES:

The work will be performed in areas that contain existing distribution mains and other underground utilities. Therefore, the contractor must exercise caution and undertake the following steps, which include, but are not limited to:

1. Contact the "One Call System" requesting underground locations at least 48 hours before beginning operations. The telephone number in Oregon is (800)322-2DIG or 811.
2. Verify the location of all underground utilities at or adjacent to the work site. This shall include exposing any utilities that are located within the designed drill path. The exact location of the existing high-pressure transmission mains must be known at all times. Particular care must be taken to protect these lines, making sure that additional stresses are not added to the lines due to machinery crossing or working over them.
3. Modify drilling practices or down hole assemblies to prevent damage to adjacent underground utilities.

Attachment C

Responsibilities

Contractor

- Provide all labor, equipment and applicable material necessary to directional drill and pullback 12" steel pipe.
- Mobilization, demobilization and set up of horizontal drilling equipment at the bore sites.
- Provide a Sizing Plate 11.5" ID (95%) to verify pipe integrity as installed.
- Contractor must not exceed the maximum bend radius of said pipe.
- Provide the required amount of pipe rollers necessary for protecting pipe during pull back of 12" steel pipe.
- Operated vacuum truck.
- A minimum depth of Fifteen **(20)** feet from the bottom of the S. Fork of Ash Creek is required.
- A minimum depth of Fifteen **(20)** feet from the bottom of the Middle Fork of Ash Creek is required.
- A minimum depth of Twenty **(20)** feet from the top of the railroad tracks is required.
- Verification and acceptance of all underground utility locates and depths to avoid damages to existing structures.
- Control, removal and disposal of all drill fluid (mud).
- Minimizing the opportunities for runoff of water and sediments. Specific measures to prevent the runoff of water and sediments to include the installation of silt fences and hay bales.
- Drilling mud shall be contained and will not be dispersed by vehicle tires or treads.
- Immediately cleaning up all locations where drilling fluid inadvertently surfaces. Contractor will assume all liabilities and costs associated with directional drill "frac-outs".
- When required contractor will haul off spoils and replace with select backfill.
- Perform work in accordance with all drawings as issued by NW Natural and GeoEngineers.
- Work to conform to OQ and QA standards.
- Construction to conform with Department of Transportation Research and Special Programs Administration 49 CFR Part 192.
- The bore profile that is provided by NW Natural is to be used for bid purposes only. Contractor is responsible for final as-built bore profile drawings.

NW Natural

- Provide 12" .312" wall, API 5L PSL 2, Grade X52, FBE coated steel pipe in 40 foot lengths
- Delivery of 12" (W) pipe and materials
- Handling of 12" pipe consisting of welding, wrapping, and staging/placement prior to and during pull back.
- All NDT, x-ray inspections of welds
- All excavating and backfilling of bore entry/exit points.
- Valves, pipe fittings, flanges, and flange hardware (except for hydrostatic testing)
- Pipe coating material
- Steel plates
- Gas control and evacuation for tie-ins
- Center line of pipe route/termination point of service
- Traffic control per State/ County/ City permits
- Work space/ Easements
- Job (work) drawing
- All necessary permits
- NW Natural shall restore the Right-Of-Way (ROW), landscaping for the pipeline to a like condition prior to completion of construction.

Pages 78 to 83 are confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

WINDSOR ISLAND -WILLAMETTE RIVER HDD 10-INCH

Windsor Island

Working Hours	360
Working Days	36
Calendar Weeks	6
Calendar Months	2

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
1	Work Staging area/Easements	$150,000.00	1	LS	$150,000	Estimate only at this time
2	Property Restoration	$30,000.00	1	LS	$30,000	Cleanup post construction
3	Erosion Control / Dewatering	$10,000.00	1	LS	$10,000	Construction entrance, straw, sandbags, silt fencing,
4	Porta Johns	$125.00	4	each	$1,000	
5	Shrink Sleeves	$14.00	100	each	$1,400	
6	Skids	$2,000.00	1	LS	$2,000	
7	Plywood	$2,000.00	1	LS	$2,000	
8	Light plants	$0.00	4	each	$0	4 each for 26 weeks
9	Steel plates	$125.00	20	each	$5,000	40 each for 2 months
10	PowerCrete	$40.00	50	each	$2,000	150 each for a 4 lb kit
11	Sideboom	$94.00	360	Hr	$33,840	1 sideboom for 6 weeks at $94/hr
12	Equipment Rental - Trackhoes	$3,750.00	2	each	$16,375	2 Trackhoes for 2 months
13	Equipment Rental - Backhoes	$46.58	360	Hr	$33,538	2 Backhoes
14	Water Truck, Pigs, Pump & Hardware	$30,000.00	1	LS	$30,000	water trucks, dryer, compresser, etc.
15	Shoring Rental	$100,000.00	1	LS	$100,000	DP Nicoli
16	Drill Pipe - 10"	$48.09	1500	ft	$72,135	
17	Other Pipe - 10"	$34.94	200	ft	$6,988	
18	HDPE Sleeve - 16"	$13.75	1500	ft	$20,625	
19	Casing Spacers	$93.00	200	ft	$18,600	
20	Conducter Barrel - 24"	$24.00	200	ft	$4,800	
21	Other Pipe	$0.00	0	ft	$0	
22	Haul/Dump Trucks	$85.00	100	Hr	$8,500	2 Dump Trucks for 200 hrs
23	Haul / Dump fee (spoils)	$5.00	200	yds	$1,000	
24	Rock	$20.00	200	cy	$4,000	
25	Asphalt Paving	$11.71	0	sf	$0	
26	Concrete Paving	$15.25	0	sf	$0	
27	Sawcut	$1.00	0	lf	$0	
28	Sand	$15.00	100	cy	$1,500	
29	Elbows, Stopple, Reducer	$25,000.00	1	LS	$25,000	see material list
30	Other Misc stores	$20,000.00	1	LS	$20,000	misc fittings, nitrogen, weld rods, sanders, markers etc.
31	Electrostop	$2,425.00	1	each	$2,425	
	Equipment/Material Total				**$602,726**	

WINDSOR ISLAND -WILLAMETTE RIVER HDD 10-INCH

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
	Internal staff charges	$65.00	300	hours	$19,500	
32	Tual Crew Labor	$63.50	360	hours	$22,860	10 hours per day 1 - 6 man crews 36 days
33	Welder - Standard	$65.00	360	hours	$23,400	2 welders for 36 days
34	Specialty Crew	$60.00	180	hours	$10,800	2 man crew for 18 days
35	X-Ray	$1,300.00	17	days	$22,100	
36	Trans Crew	$63.00	60	hours	$3,780	4 man crew for 6 days
37	Gas Supply	$60.00	20	hours	$1,200	2 man crew 2 days
38	Flatbed Truck & Operator	$80.00	30	hours	$2,400	Pipe Delivery
39	Pier Diem	$140.00	300	days	$42,000	
	Labor Total				**$148,040**	
Item #	**Item**	**Cost/Unit**	**Quantity**	**Unit**	**Cost**	**Comments**
40	Survey	$40,000.00	1	LS	$40,000	Westlake topo, construction staking, legals for easements
41	HDD Bore Explorations, Design	$60,000.00	1	LS	completed	GeoEngineers bore explorations, HDD Feasbility & Design
42	Construction Monitoring	$40,000.00	1	LS	$40,000	GeoEngineers on site monitoring, report during HDD
43	Concrete Mats	$25,000.00	1	LS	$40,000	Rockford installed in 2009
44	Contract HDD Bore - Steel	$272.00	1475	ft	$401,200	Estimate $272 per ft
	Contract Total				**$521,200**	
	Equipment/Material Total				$602,726	
	Labor Total				$148,040	
	Contract Total				$521,200	
	Total				**$1,271,966**	
	Construction Overhead (81% for System Reinforcement)				$1,030,292	
	Total				**$2,302,258**	
	Contingency (10%)				$230,226	
	Total Cost				**$2,532,484**	
	Project costs through December 2011				$170,995	
	Total Project Cost w/ COH				**$2,703,479**	

	Total Project Cost without COH (81%)	**$1,493,635**	

Project	Assigned person	Comments	Current Cost Est (k$)	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Gasco/Mixer Station - Add RCV	S. Lundgren	Will separate GASCO LNG and Storage gas and prevent them from competing. Will facilitate sending storage gas to east metro by sending it north through Sauvie Island.	$ 100		$ 50	$ 50																					
Sauvie Island - Add RCV or Control Valve	S. Lundgren	Would allow flow from Williams to be isolated and would allow either GASCO LNG or Storage gas to flow to east side of Portland.	$ 250				$ 50	$ 50	$ 100	$ 50																	
Rivergate - Control Valve	S. Lundgren	Would facilite switching between MAOP 450 and 400 without a pressue drop	$ 250					$ 50	$ 150	$ 50																	
82nd and Killingsworth - Add RCV	S. Lundgren	Would allow tail gas to be sent to eastside of Portland.	$ 150								$ 75	$ 75															
Bell Rd (King Rd) - Add RCV/back up reg	S. Lundgren	Would allow tail gas to be sent to eastside of Portland. The backup reg would be for times when demand exceeds supply from Tail Gas (similar situation exists at Jean Rd)	$ 250		$ 50	$ 100	$ 100																				
Restore 400 psi MAOP to 10" Westside Feeder between Jean Rd and West Linn	Van Gordon	Would allow additional storage gas into the eastside of Portland.	TIMP																								
Complete Boones Ferry 400 psi pipeline	Van Gordon/ New Westside		$ 800		$ 150	$ 150						$ 200	$ 200	$ 100		$ 250	$ 250	$ 250	$ 250								
Examine eastside regs examine if modifications are necessary due to lower inlet pressure	G. Dye	May have to replace some smaller inlets or regulators	$ 200					$ 50	$ 50	$ 50	$ 50																
Felida	S. Lundgren		$ 1,500							$ 250	$ 250	$ 500	$ 250	$ 250													
		Total	$ 3,500	$ -	$ 250	$ 300	$ 150	$ 150	$ 300	$ 400	$ 375	$ 775	$ 450	$ 350	$ -	$ 250	$ 250	$ 250	$ 250	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

NW Natural

220 NW Second Avenue
Portland, OR 97209

Request for Proposal

Title: BMC Architectural Design Services

Date: December 20, 2011

<u>NW Natural</u>
220 NW Second Avenue
Portland, OR 97209
Bid Due Date: January 20 2012 at 2:00 PM

REQUEST FOR PROPOSAL (RFP)

December 20, 2011

TITLE: *BMC Architectural Design Services*
PROPOSAL SUBMITTAL DATE AND TIME: JANUARY 20, 2011; 2:00PM
NOTE: Proposals received after 2:00 PM on the Proposal Submittal Date may be considered non-responsive

DELIVER PROPOSAL TO:

NW NATURAL
Purchasing Department
Attn.: Judy Redding
220 NW Second Avenue
Portland, OR 97209

Telephone: (503) 721-2566
Facsimile: (503) 273-4825
Email: judy.redding@nwnatural.com

REFERENCE TIMETABLE

Below is a timetable for your quick reference. It contains key tasks and dates that you will be responsible for in order to successfully respond to this RFP. Please take note of all dates and times.

Task	Due Date/Time
RFP Distribution	December 20, 2011
Job Walk	December 22, 2011 9am
Deadline for Question Submissions (RFI)	January 10, 2012 by 12:00 PM (Noon)
Response Answers	January 16, 2012
RFP Due Date	January 20, 2012 by 2:00 PM
Award Contract	Estimated on or about January 30, 2011

NW NATURAL CONTACT FOR ISSUES AND INFORMATION REQUEST:
All inquiries concerning this RFP and/or requests for additional information must be directed to Judy Redding in written format at:
E-mail address: **judy.redding@nwnatural.com**

SUMMARY

NW Natural is accepting proposals from an Architectural firm to combine two of NW Natural's existing centers and incorporate a training facility as well as a business continuity center into another existing structure. The purpose of this RFP is to provide a fair evaluation for all candidates and to provide the candidates with the evaluation criteria against which they will be judged.

NW NATURAL BACKGROUND

NW Natural is a natural gas distribution company, headquartered in Portland, Oregon serving over 650,000 residential, commercial, and industrial customers. There are approximately 1,100 employees serving our primary location and several smaller resource centers located throughout the company's distribution territory, covering western Oregon and a portion of southwest Washington.
We build, maintain and operate the local natural gas distribution system—that is, the pipes and related equipment that transport natural gas to homes and businesses.
In recent years, NW Natural's growth rate has exceeded the national average for local distribution companies. This growth is due to strong customer preference for natural gas for space heating and water heating and the relative cost-efficiency of natural gas.

SUPPORTING THE ENVIRONMENT

NW Natural is committed to enhancing the quality of life in its service area through environmental protection. Since natural gas produces substantially less pollution than either oil or coal, the wise use of natural gas is one of the most practical means of addressing the nation's air quality problems.

GIVING BACK TO COMMUNITIES

NW Natural is committed to being a friend to our neighbors by supporting the communities we serve. And providing efficient, reliable and safe energy backed by outstanding customer service is our primary concern.

PURPOSE

NW Natural is looking for an Architect firm that offers a quality product for a competitive price. The firm should share NW Natural's commitment to supporting the environment and giving back to the community.

SCOPE

The architect will design the interior, exterior, and landscape capabilities for a multi-use facility. The facility being designed currently exists as two buildings. Building A is 119,600 sq. ft. and consists of office space and large enclosed industrial space. Building B is 37,500 sq. ft. and consists of enclosed industrial space with a single office and conference room. Both buildings sit on 18.86 land acres and 6.8 yard acres of industrial zoned land.

The redesigned buildings will accommodate three core functions. Those functions consist of a training center, a business continuity center, and an industrial construction component with supporting administrative facilities.

The training center will include interior classroom space, as well as an outdoor hands-on training area. The necessary components of the outdoor training center will be designed by the owner, but will require exterior accommodation, shared with the other site components.

The business continuity center will consist of multi-use office space. The expectation is that this center will be designed for the relocation of core personnel from corporate headquarters in the event of a catastrophic event. When used for this purpose, the training classrooms will also be converted to business continuity use.

The industrial construction space will include secure warehouse capabilities, carpentry capabilities, welding capabilities, equipment painting capabilities, meter shop, automotive repair capabilities and exterior steel pipe storage area. This is not an all-inclusive list.

It is anticipated that this building will initially be used by the training component, followed at a later date by the industrial and business continuity components.

The building's exterior design will incorporate existing corporate colors and logos.

The interior space should be designed to make the most use of energy saving materials, ~~as~~ is possible and or reasonable.

SERVICES PROVIDED BY ARCHITECT

1. Architect will consult with owner to ascertain the requirements of the project and prepare schematic designs
2. Will provide preliminary floor plans, interior and exterior work flow and landscape plan
3. Finalize design development documents
4. Prepare pricing sets
5. Prepare construction permit sets
6. Prepare applications for permit submittal
7. Limited Construction Observation and Administration
8. As-Builts for Architectural drawings

PROPOSAL GUIDELINES AND REQUIREMENTS

You are invited to submit an estimated cost proposal (1-8 above) to accomplish the scope of the project for the services defined herein. In addition to pricing your Proposal must include a project schedule, qualification answers (1-4 below) as well as any other documentation that you feel is pertinent for bid awards. Even though we are asking for price quotes for all aspects of the entire project NW Natural's expectation is the first area of focus will be on the training center. Time line for the pricing set & construction sets will be crucial as it is expected to have full occupancy of the completed training center no later than October 1, 2012.

QUALIFICATIONS

1. Provide a company profile, length of time in business and core competencies.
2. Describe the level of expertise and qualifications of individual staff members who would be involved with the NW Natural project. List titles and experience.
3. Describe any value you may add that causes you to stand out from other competitors.
4. Provide current reference information from two former or current clients.

CONTRACT TERMS

- Bidder shall comply with all state and federal laws in regards to formulation and submittal of proposal. Prospective bidders should note that this is a competitive bidding situation, and that conferring with separate bidders about pricing or other specific details of the proposal may violate antitrust law.

- Proposals *shall remain firm for a period of ninety (90) days after the RFP Due Date.* NW Natural **may**, when it is in its best interest, reject any or all bids, or waive any formality of the RFP contents in any Proposal received.

- Bidder is deemed to have satisfied itself by submission of its Proposal as to the correctness and sufficiency of the Proposal to cover all requirements as requested per this document.

- Bidder(s) or awarded Bidder shall under no circumstances use NW Natural 's name or logos in advertising, marketing materials, printed matter, reference lists, or in any other way that could be construed as advertising (e.g., memo pads, tee shirts, binders, reference list, etc.) without NW Natural 's prior written consent.

NEGOTIATION TERMS:

NW Natural retains the right to select, request further information from, and negotiate with those bidders it deems qualified for competitive negotiations. NW Natural also reserves the right to reject any or all Proposals submitted and to terminate negotiations with any party at any time without incurring liability. This RFP gives rise to no contractual obligations, implied or otherwise.

RFP TERMS AND CONDITIONS APPLIED TO FINAL CONTRACT:
All terms and conditions outlined in this RFP, including the specifications and the Bidder's completed proposal, will become, at NW Natural's sole discretion, part of the final Purchase Order contract (the "Agreement") between NW Natural and the selected Contractor.

HOLD HARMLESS:
In submitting a Proposal, Bidder understands that NW Natural will determine which proposal, if any, is accepted. Bidder waives any right to claim damages of any nature whatsoever based on the selection process, final selection, and any communications associated with the selection.

CONFIDENTIALITY PROVISION:
The terms of this RFP, and all other information provided by NW Natural in connection with this RFP, are confidential and proprietary to NW Natural. Such materials are to be used solely for the purpose of responding to this request. By submitting a proposal, Bidder agrees not to disclose any such information to any third party without the prior written consent of NW Natural (which consent shall be conditional upon the written agreement of the intended recipient to treat the same as confidential). NW Natural may request at any time that any or all NW Natural material be returned or destroyed.

CONTRACT EVALUATION AND AWARD:
NW Natural has no obligation to reveal the basis for contract award or to provide any information to bidders relative to the evaluation or decision-making process. All participating bidders will be notified promptly of bid acceptance or rejection.

CONTRACT EXECUTION:
As discussed above, NW Natural intends that the successful Bidder will enter into a contract (attachment 1) which contains all of the terms and conditions of the proposed relationship between Bidder and NW Natural. Any acceptance of a Proposal is contingent upon the execution of a Purchase Order & contract (the "Agreement"), and neither party shall be contractually bound to the other prior to the execution of such written "Agreement".

NONDISCRIMINATORY PROVISIONS:

NW Natural is an Equal Opportunity Employer. NW Natural does not discriminate based on race, color, national origin, sex, sexual orientation, age, marital status, religion, veteran status or Vietnam-era veteran status, or sensory, mental or physical disabilities in matters or conditions of employment. NW Natural expects and requires its Contractors to abide by all laws regarding equal opportunities for employees.

ATTACHMENTS:

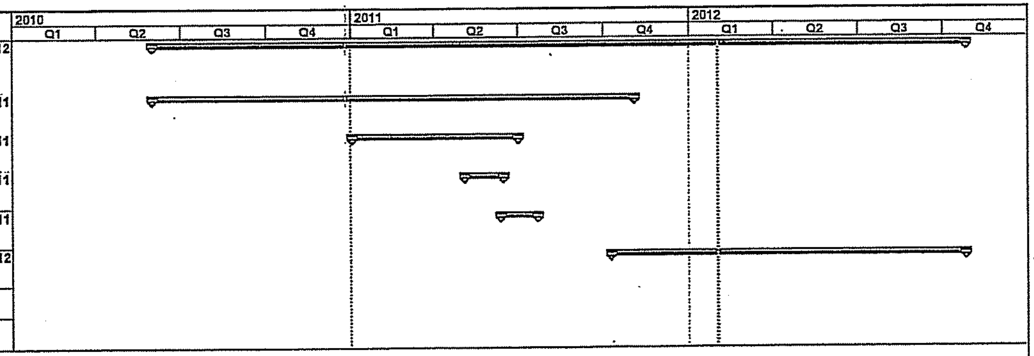
1. Revised B101 contract (to follow)
2. Aerial and Floor plans from Tualatin Center
3. Aerial and Floor plans from South Center
4. Cad drawings of BMC

Pages 94 to 252 are confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

Project	Assigned person	Comments	Current Cost Est (k$)	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Phase 1																											
Obtain Pipe Samples	Van Gordon	The pipe samples will be used to support the feasibility of project. The data and information gathered will be evaluated and a decision to proceed will be made in 2012.	$ 400			$ 50	$ 50		$ 100	$ 100		$ 50	$ 50														
Construction activities to support Rerate	Van Gordon	The bulk of the rerate work will be completed in 2013.	$ 1,600													$ 100	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 100			
		Total	$ 2,000	$ -	$ -	$ 50	$ 50	$ -	$ 100	$ 100	$ -	$ 50	$ 50	$ -	$ -	$ 100	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 100	$ -	$ -	$ -

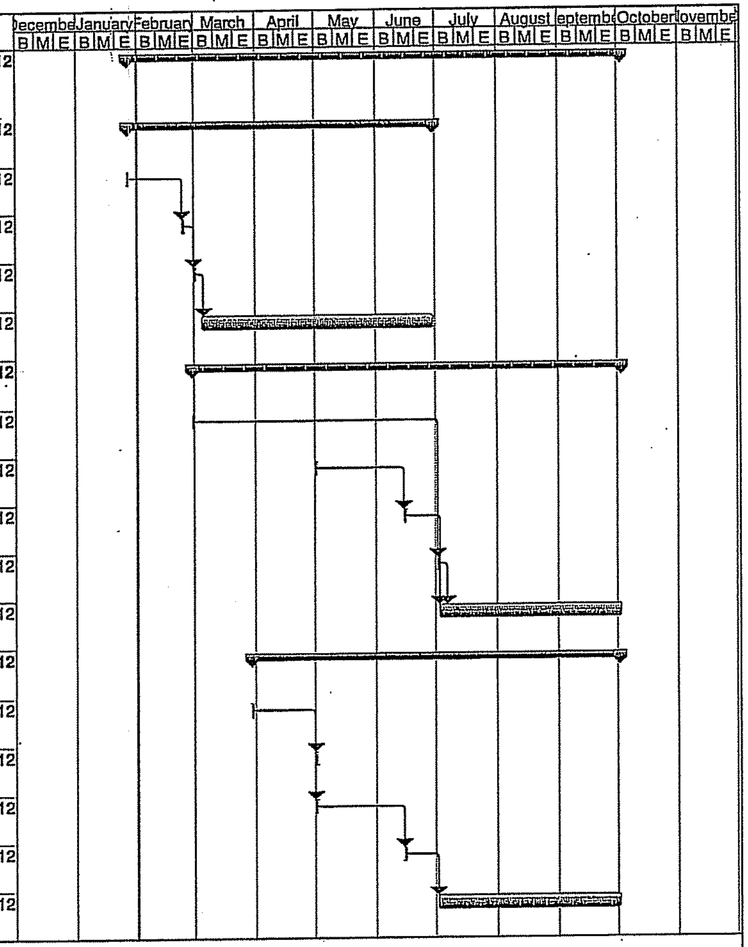
ID		Task Name	Duration	Start	Finish
1		Corvallis Reinforcement - 200363	629 days	Tue 6/1/10	Fri 10/26/12
2		Design	373 days	Tue 6/1/10	Thu 11/3/11
22		Permitting	130 days	Mon 1/3/11	Fri 7/1/11
27		Bore Contract	30 days	Thu 5/5/11	Wed 6/15/11
30		Pipe Delivery	30 days	Mon 6/13/11	Fri 7/22/11
33		Pipe Installation - 12" (W)	275 days	Mon 10/10/11	Fri 10/26/12
34					
45					



Project: Corvallis 200363 October 201

Task | Progress | Summary | External Tasks | Split
Split | Milestone | Project Summary | External MileTask

ID		Task Name	Duration	Start	Finish
1		**Corvallis Reinforcement - 200363**	178 days	Fri 1/27/12	Tue 10/2/12
2		**Phase 2: (Hwy 34) ~ 5 miles**	111 days	Fri 1/27/12	Fri 6/29/12
3		RFP Distribution	1 day	Fri 1/27/12	Fri 1/27/12
4		Open Bids	1 day	Fri 2/24/12	Fri 2/24/12
5		Award Contract	1 day	Thu 3/1/12	Thu 3/1/12
6		Construction in Hwy 34	85 days	Mon 3/5/12	Fri 6/29/12
7		**Phase 1: (Riverside Drive to Hwy 34) ~ 2.5 miles**	155 days	Wed 2/29/12	Tue 10/2/12
8		Complete Land Acquisition	1 day	Wed 2/29/12	Wed 2/29/12
9		RFP Distribution	1 day	Tue 5/1/12	Tue 5/1/12
10		Award Contract	1 day	Fri 6/15/12	Fri 6/15/12
11		Complete Permitting	1 day	Mon 7/2/12	Mon 7/2/12
12		Construction Riverside Drive to Hwy 34	66 days	Tue 7/3/12	Tue 10/2/12
13		**Phase 3: (City of Corvallis) ~ 2 miles**	132 days	Fri 3/30/12	Mon 10/1/12
14		Complete survey and design	1 day	Fri 3/30/12	Fri 3/30/12
15		Complete Permitting	1 day	Tue 5/1/12	Tue 5/1/12
16		RFP Distribution	1 day	Tue 5/1/12	Tue 5/1/12
17		Award Contract	1 day	Fri 6/15/12	Fri 6/15/12
18		Construction City of Corvallis	66 days	Mon 7/2/12	Mon 10/1/12



Project: 120201 C
Date: Wed 2/1/12

Task
Split
Milestone
Summary
Project Summary
External Tasks
External Milestone
Inactive Task
Inactive Task
Inactive Milestone
Inactive Summary
Manual Task
Duration-only
Manual Summary Rollup
Manual Summary
Start-only
Finish-only
Progress
Deadline

Corvallis Reinforcement

45,000 feet
9 months

Willamette River Crossing				$900,000
Project cost	45,000	$175 /ft		$7,875,000
				$8,775,000

25% of the project bored	11,250 $100/ft		$1,125,000
Pipe cost - Green Coat	$24.62 /ft	33,750	$830,925
Pipe cost - Directional Drill	$37.82 /ft	11,250	$425,475

Bore Crossings	Footage	
ODOT Hwy 34 crossing	300	
Willamette River	700	
ODOT Hwy 99 crossing	900	
RR - crossing 35th Ave	400	
Oak Creek crossing 35th Ave	200	
Oak Creek at 26th St	300	
RR - near SW 7th St	200	3,000

Rickreall

Project cost for 8" HP	17,150	$125	$2,143,750	
25% of the project bored	4,300	$50 /ft		$430,000
Pipe cost - Green Coat	$20.29 /ft			$285,014
Pipe cost - Directional Drill	$44.57 /ft			$138,301

Crossings	Footage	
RR	1,800	
ODOT Hwy	200	
Creek	2,300	4,300

2012 PRELIMINARY CONSTRUCTION ESTIMATE
Corvallis Reinforcement 200363

Working Hours	1,250
Working Days	125
Calendar Weeks	25
Calendar Months	5

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
1	Internal staff charges	$65.00	900	hours	$58,500.00	
2	Design	$350,000.00	1	LS	$350,000.00	WH Pacific, GeoEngineers, Epic Land Solutions
3	Pothole crew	$20,000.00	1	LS	$20,000.00	Armadello
4	Traffic control (pothole crew)	$36.00	120	hours	$8,640.00	2 flaggers for 240 hrs
5	Work Staging area/Easements	$110,000.00	1	LS	$110,000.00	Estimate from Risk and Land
6	Traffic Control Standard	$36.00	5	flaggers	$172,800.00	5 flaggers for 960 hrs
7	Traffic Control Equipment	$20,000.00	1	LS	$20,000.00	Barrier rental - 500 LF at $10/LF for 4 months & Mob
8	Erosion Control / Dewatering	$90,000.00	1	LS	$90,000.00	Rain for Rent tanks,silt fence, Inlet protection, sandbags, etc.
9	Porta Johns	$125.00	6	each	$3,750.00	5 months - 4 each
10	Shrink Sleeves	$14.00	420	each	$5,880.00	
11	Skids	$25,000.00	1	LS	$25,000.00	
12	Plywood	$10,000.00	1	LS	$10,000.00	
13	Light plants	$240.00	4	each	$19,200.00	4 each for 20 weeks
14	Steel plates	$125.00	12	each	$7,500.00	12 each for 5 months
15	PowerCrete	$45.50	650	each	$29,575.00	150 each for a 4 lb kit
16	Sideboom	$19,000.00	4	each	$380,000.00	4 sidebooms for 5 working months
17	Equipment Rental - Trackhoes	$4,200.00	6	each	$126,000.00	6 Trackhoes for 5 working months
17	Equipment Rental - Backhoes	$46.58	2	each	$116,450.00	2 Backhoes for 5 working months
18	Equipment Rental - Dozer	$8,000.00	1	each	$40,000.00	1 Bulldozer for 5 months
19	Water Truck, Pigs, Pump & Hardware	$100,000.00	1	LS	$100,000.00	3 water trucks, dryer, compresser, etc.
20	Shoring Rental	$50,000.00	1	LS	$50,000.00	DP Nicoli
21	Drill Pipe - 12"	$59.30	26150	ft	$1,550,695.00	
22	Other Pipe - 12"	$35.00	17525	ft	$613,375.00	
23	Dump Trucks	$368,000.00	1	LS	$368,000.00	4 Dump Trucks for 5 working months
24	Haul / Dump fee (spoils)	$5.00	12000	yds	$60,000.00	
24	Pee Gravel	$3.00	0	cy	$0.00	
25	Rock	$14.25	16000	cy	$228,000.00	
26	Asphalt Paving	$6.00	4000	sf	$24,000.00	
27	Concrete Paving	$15.25	0	sf	$0.00	
28	Sawcut	$1.00	2600	lf	$2,600.00	
29	Sand	$15.00	4000	cy	$60,000.00	
30	Elbows, Tees, Stopples, etc.	$55,000.00	1	LS	$55,000.00	see material list
31	Other Misc stores	$20,000.00	1	LS	$20,000.00	misc fittings, nitrogen, weld rods, sanders, etc.
32	Valves	$54,000.00	1	LS	$54,000.00	see material list
33	Electrostops	$12,000.00	1	LS	$12,000.00	see material list

2012 PRELIMINARY CONSTRUCTION ESTIMATE
Corvallis Reinforcement 200363

	Equipment/Material Total				**$4,790,965.00**	
Item #	**Item**	**Cost/Unit**	**Quantity**	**Unit**	**Cost**	**Comments**
34	Tual Crew Labor	$63.50	14400	hours	$914,400.00	10 hours per day 2 - 6 man crews 120 days
35	Welder - Standard	$65.00	7200	hours	$468,000.00	6 welders for 120 days
36	Specialty Crew	$60.00	3200	hours	$192,000.00	4 man crew for 80 days
37	X-Ray	$1,300.00	108	days	$140,400.00	
38	Trans Crew	$63.00	600	hours	$37,800.00	4 man crew for 15 days
39	Gas Supply	$60.00	40	hours	$2,400.00	2 man crew 5 days
40	Flatbed Truck & Operator	$80.00	1200	hours	$96,000.00	Pipe Delivery
41	Per Diem	$54.00	2400	each	$129,600.00	
42	Lodging	$80.00	2400	each	$192,000.00	
	Labor Total				**$2,172,600.00**	
Item #	**Item**	**Cost/Unit**	**Quantity**	**Unit**	**Cost**	**Comments**
43	Caliper Pig - Post Construction	$50,000.00	1	ea	$50,000.00	Quote from Integrity Dept
44	Contract HDD Bore - Steel	$100.00	26150	ft	$2,615,000.00	
	Contract Total				**$2,665,000.00**	
	Equipment/Material Total				$4,790,965.00	
	Labor Total				$2,172,600.00	
	Contract Total				$2,665,000.00	
	Total				**$9,628,565.00**	
	Construction Overhead (27% for System Reinforcement)				$2,599,712.55	
	Total Cost				**$12,228,277.55**	
	Contingency (10%)				$1,222,827.76	
	Total Project Cost w/ OH				**$13,451,105.31**	

MEMORANDUM

NW Natural
220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

Date: August 24, 2011

To: Steve Nelson, Ryan Truair, Katie Gough, Joe Karney

From: Peter Cathcart

Subject: Proposal for Project Initiation 200581

PROJECT NAME
Perrydale to Monmouth

PROJECT LOCATION
NE of Dallas

PROJECT PLATS
Start 2-094-026. End 2-111-025.

SCOPE
This project is for installation of approximately 53,200 feet (10 miles) of 12-inch steel natural gas pipeline tested and certified at a Maximum Allowable Operating Pressure (MAOP) of 720 psig. This pipeline is part of the Perrydale to Corvallis/Albany (Mid-Willamette Valley Feeder - P30 pipeline). This project starts 4 miles SSE of Amity at Perrydale Reg. Station heading East along Central Coast Trans, then south down Highway 99W, ends 1820' North of Highway 99W and Highway 22 Junction.

PURPOSE
System Reinforcement

COST
Rough Estimated Cost:$13,300,000

FUNDING
System Reinforcement

SCHEDULE
Possible Start date: 9/1/2012
Estimated Construction Duration: 10 months

NW Natural

Project Type	Project Name	PS #	Schedule	Project Details	Budget
Bare Steel	SE Holgate Bare	200413	3/12	682' 2" P, 6 srv	$68,027
Bare Steel	Rivergate Bare	200414	8/12	1120' 2" P, 200' 2" W	$68,027
Bare Steel	Schnitzer Steel Bare	200415	9/12	2200' 2" P - hazmat	$106,803
Bare Steel	River Road - Milwaukie	200435	8/12 - 9/12	1050' 6" P	$54,422
Bare Steel	Laughlin 7th to 10th - The Dalles	200466	5/12 - 8/12	560' 4" P, 3100' 2" P, 50 srv	$246,259
Bare Steel	NE 21st Ave Columbia Slough Bore	200469	3/12	200' 4" P	$78,571
Bare Steel	SW Glen Rd and Midvale	200537	3/12	1500' 2" P, 300' 2" W	$51,020
Bare Steel	Tigard St	200673	8/12 - 10/12	2000' 2" P, services	$129,252
Bare Steel	Iron Mountain Rd	200674	8/12 - 10/12	1200' 2" P, services	$85,034
Bare Steel	West View Rd	200676	10/12 - 11/12	2000' 2" P, services	$125,850
Cat	Bare PROJECTS				$1,013,265
2	119 Bare Steel NON-PROJECT	200027			$1,873,772
	319 Bare Services NON-PROJECT	200035			$212,963
	Projected Bare Steel/Srvcs				$3,100,000

TIMP	Keizer - Windsor Island Crossing	200204	7/12 - 9-12	1475' 10" W	$1,400,000
TIMP	P-72 Miller Sta to Rock Creek ILI	200631	3/12 - 4/12	Modify for ILI	$547,889
TIMP	P-48 East Metro ILI Reassessment		2012	Reassess ILI	$250,000
TIMP	P11 Jean Rd to West Linn	200652	2/12 - 9/12	Obtain pipe samples	$220,994
TIMP	P-39 Clatskanie to Deer Island ILI	200662	3/12 - 5/12	Modify for ILI	$662,983
TIMP	P-39 North Coast ECDA		2012	ECDA Reassessment	$200,000
TIMP	P-30 Central Coast ECDA		2012	ECDA Reassessment	$200,000
TIMP	S-06 Salem to Bethel ECDA		2012	ECDA Reassessment	$50,000
TIMP	P-09 North Coast ECDA		2012	ECDA Reassessment	$150,000
TIMP	P-65 PGE Gate to Meter ECDA		2012	ECDA Reassessment	$25,000
TIMP	S-05 Salem Industrial ECDA		2012	ECDA Reassessment	$25,000
TIMP	S-04 Salem Industrial ECDA		2012	ECDA Reassessment	$25,000
TIMP	ASV/RCV - Salem		2012	Evaluation and Installation of RCV/ASV	$200,000
TIMP	ASV/RCV - Front Ave		2012	Evaluation and Installation of RCV/ASV	$250,000
TIMP	Natural Forces - Landslide Study		2012	Evaluate LIDAR to identify landslides	$150,000
TIMP	Natural Forces - Monitor/Remediate		2012	Monitor or Remediate indentified landslides	$100,000
TIMP	Class Location and HCA analysis		2012	Systemwide reevaluation of Class Location,HCAs	$250,000
Cat	TIMP PROJECTS				$4,706,867
2	112 TIMP NON-PROJECT	200021			$3,793,133
	Projected TIMP				$8,500,000

DIMP	Sewer Cross Bores		2012	various	$250,000
DIMP	Yamhill Crossing	200367	7/12 - 9/12	500' 6" W	$663,717
Cat	DIMP PROJECTS				$913,717
2	120 DIMP Mains NON-PROJECT	200028			$486,283
	320 DIMP Services NON-PROJECT	200036			$600,000
	Projected DIMP				$2,000,000

Public Works	Central Relocate - Milwaukie Light Rail	200408	1/12 - 4/12	HP main relocate	$387,097
Public Works	Lancaster Dr - Market St	200420	1/12 - 2/12	1100' 6" W, 600' 2" W, 14 srv	$122,581
Public Works	Hawthorne & Hyacinth - Salem	200461	1/12 - 3/12	2000' 2" P, 900' 2" W, 20 srvs	$119,355
Public Works	SW Sheridan Trans Relocate	200476	1/12 - 2/12	16" Trans	$580,645
Public Works	NE 88th St, St Johns to 36th	200632	1/12	2025' 4" P, 200' 2" P	$64,516
Public Works	Rose City Sewer Rehab NE	200637	2/12 - 3/12	1230' 2" P, 32 srv	$161,290
Public Works	Rose City Sewer Rehab SE	200638	2/12	90' 2" P, 2 srv	$28,387
Public Works	Sellwood Bridge	200642	1/12	Abandon 1700' 6" W, Install 430' 2" P	$58,065
Public Works	Main St Reconstruction - Tigard	200644	1/12	1700' 6" W	$64,516
Public Works	SR 14 Phase 2	200646	2/12 - 3/12	300' 6" W CI D, 300' 6" W, 300' 2" W, 100' 2" P	$96,774
Public Works	Macrum Crossing of UPRR	200648	2/12 - 3/12	300' 6" W CI D, 300' 6" W, 300' 2" W, 100' 2" P	$193,548
Public Works	Royal - Eugene	200653	3/12	760' 4" W. 60' 2" W, 16 srv	$83,871
Public Works	Mill Creek ODOT - Astoria	200654	1/12 - 2/12	500' 4" W	$90,323
Public Works	Washington Jefferson Grading	200656	2/12 - 3-12	500' 4" W	$154,839
Public Works	Scholls Ferry Rd - Fanno Creek Bridge	200657	4/12	400' 2" P	$58,065
Public Works	Bethany Blvd Widening	200658	5/12 - 7/12	4" P	$148,387
Public Works	Madras St Grading - Salem	200661	3/12	150' 4" W	$77,419
Public Works	SW Boones Ferry Rd Day to Norwood	200672	6/12 - 8/12	12" HP unknown impact	$322,581
Public Works	Augusta Riverview - Eugene	200684	3/12 - 4-12	50' 1" P, services	$54,839
Cat	Public Works PROJECTS				$3,002,097
3	114 Public Works Mains NON-PROJECT	200023			$5,772,903
	314 Public Works Services NON-PROJECT	200031			$195,000
	Projected Public Works				$8,970,000

Sys Reinforcement	Aurora to Brooks - Willamette Valley Replace	200174	1/12 - 3/12	14,700 8" W	$236,220
Sys Reinforcement	Corvallis Reinforcement	200363	3/12 - 10/12	12,700' 12" W	$9,300,000
Sys Reinforcement	Meadowview Rd DR	200567	2/12	new DR	$66,929
Sys Reinforcement	Monmouth	200580	2/12 - 7/12	27,400' 12" W	$5,600,000
Sys Reinforcement	May St - Hood River	200600	1/12	2600' 4" P	$196,850
Sys Reinforcement	Glenridge & Ponderosa - Corvallis	200613	3/12 - 4-12	1450' 4" P	$94,488
Sys Reinforcement	Perrydale to Monmouth		1/12 - 10/12	12" W	$13,500,000
Cat	Reinforcement PROJECTS	-			$29,154,488
3	115 Reinforcement NON-PROJECT	200024			$3,611,653
	Projected Reinforcement				$32,766,142

Main Relocate	Front Ave Casing Replacement	200389	6/12 - 9/12	1800' 20" W	$1,257,862
Main Relocate	Grand Ronde Reservation Bulldovers	200532	6/12	500' 2" P, 6 srv	$56,604
Main Relocate	Port of Portland Relocate	200643	2/12 - 3/12	unknown scope	$330,189
Cat	Relocates/Abandonments PROJECTS	-			$1,644,654
3	116 Rel/Aband-Mains NON-PROJECT	200025			$1,855,346
	Projected Relocate/Abandon				$3,500,000

NW Natural

REQUEST FOR PROPOSAL

Unified Communications – NW Natural

September 1, 2011

NW Natural
220 NW Second Avenue

Portland, OR 97209

Bid Due Date: Noon October 3, 2011

Contents

1.0 RFP Instructions

1.1 Executive Summary

Include an executive summary highlighting your offerings and outlining the benefits to your company.

1.2 Business Objectives

NW Natural is a natural gas distribution company, headquartered in Portland, Oregon serving over 650,000 residential, commercial, and industrial customers. There are approximately 1,100 employees serving our primary location and several smaller resource centers located throughout the company's distribution territory, covering western Oregon and a portion of southwest Washington.

NW Natural is embarking on a major initiative to implement a Unified Communications IP based telephony environment planned for deployment to the enterprise over the next 18 months. We have various departments poised to take advantage of this technology, including distributed Customer Contact Centers, general staff, information workers, resource management centers (dispatchers), and home office workers to name a few.

1.2.1 Vision Statement

The NW Natural Unified Communication Vision Statement is attached to provide you additional guidance for our project goals.

UNIFIED COMMUNICATIONS manages employee **status**, supplemented with knowledge, skills and abilities (KSA) so other employees in need of these resources can access them and collaborate in a transparent and intuitive method at any time and from anywhere.

- Vision
  - Create a real-time, instantaneous collaborative work environment for NW Natural, business partners, and customers.
  - Support the transformable workforce.
  - Facilitate a more efficient and adaptive workforce.
  - Support employee mobility.
- Objectives
  - Provide wireless computing/communications technology for NW Natural.
  - Support anytime/anywhere advanced interoperability with business partners and customers.
  - Enable unified messaging that integrates email, voicemail, fax and text messaging in a single delivery method and combines it with instant messaging, voice, video and applications sharing.

- Optimize efficiency by integrating voice and data infrastructure.
- Support presence supplemented with KSA.
- Simplify and streamline the multiple end-user communication options.
- Improve internal and external communications.

- Benefits
  - Reduce unnecessary travel and better utilize out-of-office time.
  - Eliminate need for specialized support of traditional telephony systems.
  - Provide flexible and forward-looking infrastructure for the future.
  - Enable disaster recovery options not currently available with existing systems.
  - Eliminate the requirement for a desk phone by providing flexible alternatives.
  - Enable process improvements by providing robust, spontaneous collaboration tools.
  - More effectively utilize network capacity.

- Assumptions
  - Encompasses the entire corporation.
  - Is a multiple-year project.
  - Uses technology proven within the industry.
  - No negative impact to the businesses.

1.3 Overview of Present Communications Environment

Voice and data traffic is hubbed out of our corporate headquarters building (OPS) in downtown Portland, Oregon. In the equipment room of OPS is a Nortel Networks Meridian 81C which functions as the voice network controller for all our remote site Meridian 11C's and dedicated private DS1 and DS0 facilities at designated locations.

The Option 81C processes all of the local call traffic from the Portland calling area as well as our 800 out of area and LD/International call traffic. In addition, calls received at our local district offices and resource centers are redirected over dedicated private microwave DS3/DS1 lines or private telco DS1 lines to the Option 81C for distribution to our contact centers or other appropriate destinations. Standard Q.931 CSS is used for voice control signaling between all remote centers and the OPS hub, and all telco incoming circuits utilize PRI interfaces supported directly on the Option 81C and 11C's.

The remote site Option 11C's provide local office call management and access to the public switched network and private microwave facilities. Private DS0 and DS1 facilities serve those locations too small to warrant direct PBX services or those overflow contact center locations providing virtual connectivity to the Portland voice switch fabric.

Existing top – level voice menus, auto-attendant features, through dialing, and customer service voice portal functions are provided by twin 48-port Edify systems configured for 1+1 redundancy and support of a completely independent duplicate development environment. Standard web services interfaces link the IVR to our backend CRMS systems, utilizing a common development platform to provide extranet presence and IVR internal services.

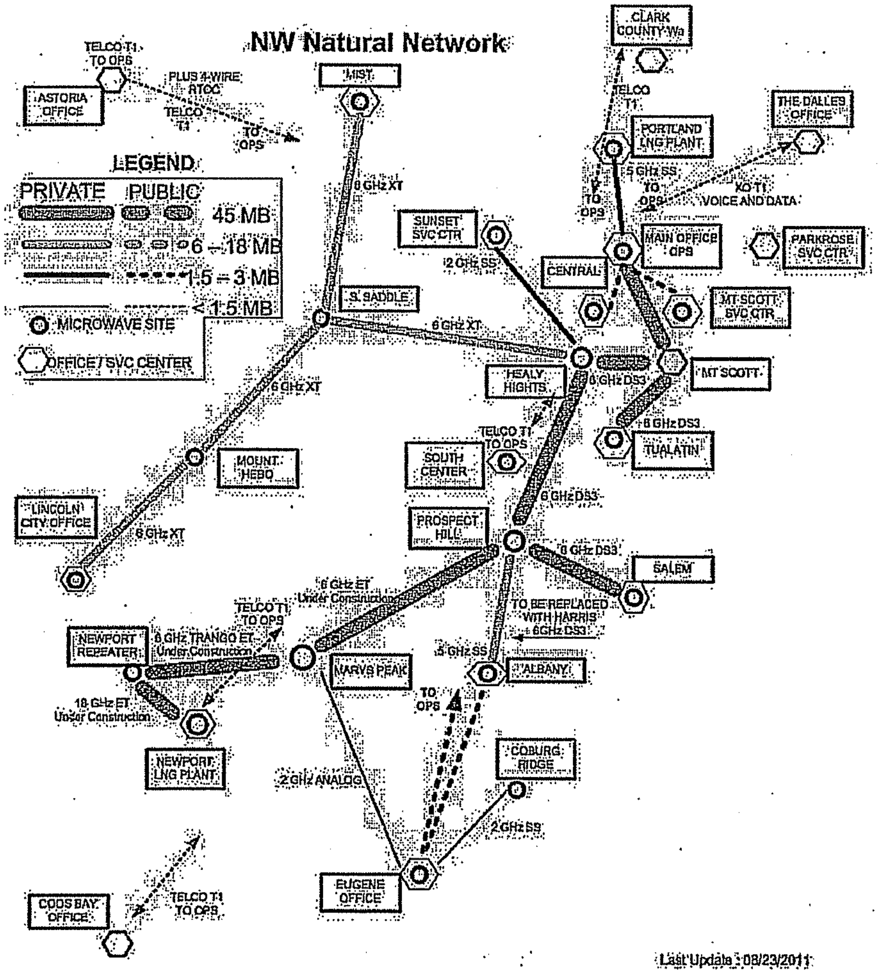
Voicemail services for all users and voice menuing for smaller departmental applications or isolated needs are provided by a fully integrated Nortel Meridian Mail EC at the OPS location, with a sight port tandem/backup Modular EC system providing limited redundancy and disaster recovery options in a secondary location, which also serves as the secondary contact center location.

A Nortel Symposium system manages numerous (50+) independent contact center and other non-contact center agent pools, while several other disparate systems manage virtual queuing, auto callback, agent screen pops, supervisor feedback, call recording/monitoring, virtual reader boards, reporting and other ancillary call center functions. Extensive work coding is provided by the existing system through up to 50 different login codes used by each individual agent to track and manage his/her phone and non-phone work as well as queue assignments. Real time tracking of agent login information is matched against an integrated workforce management system used to manage schedules, forecast manpower needs and track real-time adherence. Most features are provided by Symposium and its adjunct tightly coupled systems provide rich operational functions of the order associated with contact centers approximately ten times our current size (i.e. 2,000 vs. 200 agents).

The following represents current approximate NW Natural call metrics. Some data has been provided as informational only, while other data represents design criteria for one or more system operational objectives associated with this RFP. Metrics are assumed to be typical figures for "busy" months driven by weather and other normal operational variations; exceptional call handling capacities should address double or treble these numbers in the vendor response, as well as metrics and limitations associated with operation in "survival" mode (if supported). Gross numbers include all switched voice calls, including those served by the contact center and automated systems. System sizing should factor in an approximate 20% increase in call volumes per year for initial build-out (depending on project schedule) and subsequent maintenance intervals.

Gross non-contact center inbound calls (typical month):132,183 /mo.
Gross non-contact center outbound calls (typical month):76,991 / mo.
Gross non-contact center average call duration (typical month):3.59 min.
Busy time calls handled in IVR applications: 32,805 / mo.
Busy time call arrival rate in IVR applications: 689 /hr.
Busy time calls handled by contact center: 73,704 /mo.
Busy time contact center call arrival rate: 1,276 /hr.
Busy time contact center call duration: 4.5 min.
Busy time contact center agents staffed: 130

Below is a map representing the geographic layout overview of the extant NW Natural voice communications infrastructure. The legend supplies information on the type and size of the links connecting the facilities, and relative number of "hops" between facilities. Along with section 2 detail specifications (below), this overview and map should provide the vendor with an adequate view of the magnitude and breadth of basic telephony services that must be maintained with any proposed replacement system.



1.4 Objectives/Scope of Work

NW Natural is replacing its aging Telephony infrastructure. As a result, the decision has been made to replace this technology with an architecture that supports a Unified Communications philosophy and Collaboration environment. The Unified Communications and Collaboration environment will employ new voice, data, and presence capabilities to:

1. Enhance existing Contact Center(s) technologies and provide new Contact Center(s) functionality that will enable NW Natural to maintain our high level of customer satisfaction.
2. Enhance the network architecture to achieve a fully integrated voice and data network.
3. Create a real time presence and collaboration work environment with knowledge base functionality.
4. Enable our mobile workforce with enhanced UC functionality to improve current and future work processes.

1.5 Liability and Reserved Rights

This RFP does not commit NW Natural to pay any cost incurred in the preparation or submission of any proposal, or to procure or contract for any services. NW Natural will, at its discretion, award the contract to the vendor submitting the best proposal that complies with the RFP.

Bid evaluation and awards will be based on a combination of pricing, delivery, supplier performance, value-added service, and/or any other points of consideration that may be of importance to NW Natural.

It is understood that submission of a bid in response to this invitation shall not constitute a contract. NW Natural reserves the right to reject any and all bids; or to award any select portion of your bid. NW Natural may, at its sole discretion, reject any or all proposals received, or waive minor defects, irregularities or informalities therein.

NW Natural reserves the right to amend this RFP by an addendum issued up to five business days prior to the date set for receipt of proposals. Addenda or amendments will be emailed, mailed or faxed to all vendors that have procured copies of the RFP. If revisions are of such a magnitude to warrant the postponement of the date for receipt of proposals, then an addendum will be issued announcing the new date.

1.6 Instructions to Vendors (i.e., Prospective Suppliers)

This section outlines specific instructions for proposal submission. Vendors not adhering to these instructions may be subject to disqualification without further consideration.

- Please submit five hard copies and one soft copy of the proposal. Proposals shall be submitted in a **sealed envelope** clearly addressed to Richard Kenney, with Proposers company name clearly labeled, listing the project and RFP Title thereon. Modifications to Proposals already submitted will be considered if received in NW Natural's offices by Noon October 3, 2011. Proposals may be withdrawn by written facsimile request received from Proposers prior to Noon October 3, 2011

- All Proposal submittals, as required by this request, shall be included with the Proposal, on the specified due date and time.

- The notice of award is expected to be made to the successful Proposers November 8, 2011. However; Proposals *shall remain firm for a period of six months from November 8, 2011.* Award will be made to the responsible Proposers whose Proposal conforms to the bidding documents and is most advantageous to NW Natural, price and other factors considered. NW Natural may, when in it is in their best interest, reject any or all bids, or waive any informality in any Proposal received.

- Proposers is deemed to have satisfied himself before submitting Proposal as to the correctness and sufficiency of his Bid and that it is sufficient to cover all requirements as requested per this document.

- Proposers or awarded Proposer shall under no circumstances use NW Natural 's name or logos in advertising, marketing materials, printed matter, listed as a reference, or in any other way that could be construed as advertising (e.g., memo pads, tee shirts, binders, reference list, etc.) without NW Natural 's prior written consent.

1.7 General Procedures

1.7.1 Issuing Authority

This RFP is issued by NW Natural Gas Company, referred to here as NW Natural.

Contact Name and Title: Richard Kenney, Buyer
Department: Purchasing
Street Address: 220 NW 2nd Ave
City, State and ZIP Code: Portland, OR 97209
Telephone Number: 503.220.2398
Fax Number: 503.273.4825
E-Mail Address: r1k@nwnatural.com

1.7.2 Price Guarantee

Vendors are asked to guarantee their prices for a period of six months from the bid due date of October 3, 2011.

1.7.3 Pre-proposal Questions

Vendors must submit questions in writing to:

NW Natural, Carl Landre, Project Manager:
Street Address: 220 NW 2nd Ave
Telephone Number: 503.226.4211 EXT 4650
Fax Number: 503.721.2518
E-Mail Address: carl.landre@nwnatural.com

All questions must be received by September 8, 2011 to allow for answer preparation. Answers to questions will be provided at the proposal conference scheduled for September 14, 2011.

1.7.4 Final Questions

Vendors must submit questions in writing to:

NW Natural, Carl Landre, Project Manager:
Street Address: 220 NW 2nd Ave
Telephone Number: 503.226.4211 EXT 4650
Fax Number: 503.273.4825
E-Mail Address: carl.landre@nwnatural.com

All questions must be received by September 22, 2011 to allow for answer preparation. Answers to questions will be provided by September 28, 2011.

1.8 RFP Response Terminology

It is important for vendors to respond in a brief but concise manner to each section of this document.

1.8.1 General Response Terminology

Sections related to Functionality and Features in the RFP MUST be addressed in accordance with the guidelines provided below. Your responses will be validated during the demonstration activities; any failure to provide an honest response may disqualify you from the RFP process at NW Natural's sole discretion. Under the Capability section, you should choose from the five options to indicate your compliance with each requirement as follows:

Option	Capabilities
0	Functionality/Feature not provided
1	Functionality/Feature provided; requires customized integration with third party
2	Functionality/Feature provided by the vendor, but requires customization
3	Functionality/Feature provided seamlessly by third-party product
4	Functionality/Feature provided out-of-the-box
5	Functionality/Feature provided by a cloud solution

Providing a system manual is not an acceptable response to any of the questions in this RFP. Include a detailed answer and include graphics and/or screen shots to help explain or illustrate when appropriate. Vendors must also cite any system feature limitations relating to software or interaction with other features.

Vendors are cautioned not to indicate functionality as "included in standard offering" when, in fact, that particular feature is in development. When that is the case, vendors should note that fact in the RFP response and indicate the expected date that such a feature will be made available to the general public*.

- **Functionality not provided:** Not included in the proposed version of the application.

- **Functionality/Feature provided; requires customized integration with third party:** Vendor has established a relationship with a business partner to provide this functionality, but it needs customizing or working around.
- **Functionality/Feature provided by the vendor, but requires customization:** The functionality can be accomplished with the vendor's products, but some customizing or working around is required.
- **Functionality/Feature provided seamlessly by third-party product:** The vendor has established a relationship (for example, as an OEM) with a business partner to provide this functionality integrated in its application. No customizing or working around is needed.
- **Functionality/Feature provided out-of-the-box:** The vendor provides the functionality from its own code base. No customizing or working around is required. This functionality is included in the proposed version of the application.
- **Functionality/Feature provided by a cloud solution:** The vendor provides the functionality from its own or partner based cloud solution. Nature and scope of the cloud vs. on-site components must be specified in the vendor's detailed response for each applicable section using this solution form. This functionality is included in the proposed version of the application and associated pricing model.

*NOTE: Proposed version of the application should be generally available and used in production by, at least, several companies.

For those questions that do not pertain to Functionality or UC&C Features, please respond with verbiage that addresses the subject matter.

1.9 Preparation of Proposals

1.9.1 Proposal Format

The complete proposal must include the proposal document with a point-by-point response to the RFP and all other materials requested. Vendors may include any additional materials they feel could assist in the evaluation of their proposed systems. However, vendors must provide complete responses to each question. References to other documents will not be accepted.
Vendors are cautioned that proposals that do not follow the format required by this RFP will be subject to rejection without review.

1.9.2 Proposal Due Date

All proposals will be received by 12:00 pm on 10/3/11, and will be labeled: "Unified Communications - NW Natural."

1.9.3 Proposal Delivery

Submit Five (5) complete copies of the proposal to :
Name: Richard Kenney
Title: Buyer
Company: NW Natural
Address: 220 NW 2nd Ave
City, State, ZIPCode: Portland, OR 97209

Telephone Number: 503.220.2398

1.9.4 Proposal Inclusions

All equipment, accessories, database information, training, software, hardware, labor and materials must be furnished for the installation in a bill-of-material format. Any additional material or equipment necessary for installation and operation of the system not specified or described herein will be deemed to be part of these specifications.

1.9.5 Standard Agreements

The vendor must provide a copy of its standard product agreements that NW Natural will sign if it awards the bid to that vendor.

1.9.6 Proposal Modification and Withdrawal

Once submitted by a vendor, a proposal may be modified or withdrawn only by appropriate notice to NW Natural. Such notice will be in writing over the signature of the vendor. A withdrawn proposal may be resubmitted up to the time designated for the receipt of proposals, provided it then fully conforms to the general terms and conditions.

1.9.7 Confidentiality

This Request for Proposal (RFP) contains information that is confidential and proprietary to NW NATURAL. The Recipient shall under no circumstances use the information contained herein for any purposes other than the evaluation of the requirements of this RFP and the preparation of a response to this RFP. The Recipient shall not disclose the information contained in this RFP to any third parties and shall limit the distribution of this RFP to any third parties and shall limit the distribution of this RFP to those employees of Recipient who have a need to have access thereto for the purposes of evaluating the requirements of the RFP and preparing a response thereto. The Recipient shall employ the same degree of care in preventing the unauthorized release of the information in this RFP to a third party (or parties) as it uses with regards to its own confidential information, provided that in no event shall the Recipient employ less than a reasonable degree of care. The Recipient shall inform its employees of the foregoing obligations.

If the Recipient determines at any point in time after receipt of this RFP that it does not wish to submit a response to this RFP the Recipient shall return this RFP to NW NATURAL and shall certify in writing that it has not retained any copies or made any unauthorized use or disclosure of the information contained herein. If the Recipient submits a response to this RFP to NW NATURAL it may retain a copy of the RFP in its files.

NW NATURAL shall employ the same degree of care in preventing the unauthorized use of the information supplied in response to this RFP to a third party (or parties) as it uses with regards to its own confidential information. NW NATURAL shall inform its employees of the foregoing obligation.

1.9.8 Calendar of Events

The following reflects the project schedule at a high level.

Project Schedule Activity
RFP released to vendors : 9/1/11
Preproposal conference questions deadline : 9/8/11
Preproposal conference : 9/14/11
Final questions deadline : 9/22/11
Final questions answered: 9/28/11
Proposal delivery and opening : 10/3/11
Vendor Demo : week of 11/1/11
Notification of selection : 11/8/11
Contract negotiations completed : 11/25/11
Final contract signed : 12/5/11
System installation and testing TBD
System cutover (no later than) 10/31/2012

2.0 Voice Requirements

Current NW Natural Telephony Infrastructure

Current PBX Make / model

- Nortel Meridian One Option 81, Succession 3 at One Pacific Square, Corporate Headquarters + 13 Nortel Meridian One Option 11's Release 18.3 + 5 off-premises nodes serviced through proprietary Meridian digital extender modules linked to One Pacific Square by dedicated private point-to-point DS1 tielines

Current Contact Center make / model

- Same; Symposium V4 + 3rd party adjuncts: virtual hold, workforce management, softphone, call monitoring, recording & scoring, reporting services, custom CIS and custom screen-pop

Number of Phones currently deployed

- 600 sets & 300 phantoms at One Pacific Square, Corporate Headquarters + 20-80 sets at each Option 11 site + 12-50 sets at each off premises node

Percentage of Phones that are Contact Center, Knowledge Worker, Conference Room and Public Areas

- All sites: approximately 25% contact center, 60% knowledge/general worker, 15% conference room/public area/other

Approximate number of analog stations/lines

- 400 analog stations at One Pacific Square, Corporate Headquarters + 10 analog stations at each remote site; average 10 incoming analog trunks per site

Number of T1 trunks

- 9 T1 LEC lines at One Pacific Square (OPS), Corporate Headquarters + 3 remote sites with T1 LEC lines + 18 remote sites with T1 tie lines to OPS

Number of Contact Center Agents

- 325 ACD sets total, including phantoms; 200 contact center agents in all workgroups combined with 20 "supervisor" positions (feature set implemented comparable to 2,000 seat contact center)

Texts to Speech and Speech Recognition software in the Contact Center

- Convergys/Intervoice Edify IVR platform

Voice recognition modules currently supported in existing IVR customer service applications:

AcctStmtConfirmCommand
AcctnumCollect
AcctnumConfirm
AddressConfirmZipCity
AfterHoursQueryReturnToSS
AutoPayMenu
BankNumberCollect
BankNumberConfirmName
BillingNext
CheckPayConfirmCharge
ChkAcctNumberCollect
ChkAcctNumberConfirm
CreditNext
DatePaymentCollect
DatePaymentConfirm
DateServiceCollect
DateServiceConfirm
DateServiceConfirmNextAvailable
DateStartCollect
DateStartConfirm
DateStopCollect
DateStopConfirm

ECheckQueryUseStored
EnrollPayMenu
EqualPayMenu
EqualPaySignupConfirmCommand
ExtendDueDateQueryPayByTermsDate
ExtendDueDateQueryPayOnTime
MainMenu
MainNext
MoreMainMenu
MoveMenu
OtherPayMenu
PaymentAmountCollect
PaymentAmountConfirm
PaymentAssistanceMenu
PaymentMenu
PaymentNext
PaymentQueryBalance
PhonePayMenu
RoutineInspectionConfirmCommand
RoutingMenu
SecondaryAddressCollect
SecondaryAddressConfirm
SecondaryAddressQueryExists
ServiceMenu
StopServiceConfirmCommand
StopServiceQueryNewAddress
StopServiceQueryNewPhone
StreetAddressCollect
StreetAddressConfirm
StreetNumberCollect
TelnumCollect
TelnumConfirm
TransferServiceConfirmCommand
TranferServiceQueryBillToPremises
TranferServiceQueryNewPhone
WalkInQueryFinal
WalkInQueryLoop
WalkInZipCollect
ZipCollect
ZipConfirm

NW Natural would like your solution to the following subsections taking into account our present Telephony Architecture.

2.1 Voice UC Integration

Multiple scenarios exist for using voice in new ways within a UC environment. Vendors must specify how their solutions support the following integrations:

- Business and Contact Center(s) applications:
  - Review and respond to all categories and requirements listed in sections 2.2.1 and 2.2.2
- Desktop clients, such as Microsoft Office Communications Server (OCS) or vendor optimized solutions
- Conferencing systems, whether enterprise- or service-provider-based (universal desktop conferencing and full dedicated video conferencing at OPS (12 rooms) and remote sites (one room per site) – solutions can be segregated into "tiers" of service and associated hardware/software requirements)
- IM and presence - Also review this category in section 2.2.1 "Business applications"
- Short Message Service (SMS)
- Calendaring – integrated across user terminal device types
- Mobile integration – DECT sets, cellular, WiFi, private mobile radio, etc.

E-mail systems (Exchange)

- Applications that use analog interfaces and devices (analog modems, fax machines, 2500 sets, security/alarm devices, gate/entry control devices, fire/life safety systems, etc.)
- Private or public voice networks (DS0, DS1, DS3 LEC provided and private microwave)
- Telephony dial plans (four digit universal dialing/one number reach for mobiles)

2.2 System and User Features for Voice

The following tables outline various required telephony system and station features. Vendors should provide a narrative response to each item, and should indicate which features are standard and which are extra-cost options. The vendor must also provide a comparison of various set type features with different models of phone appliances offered, as well as the same comparison for the different models or tiers of softphone applications offered. Providing a system manual is not an acceptable response to this section. Vendors must also cite any system feature limitations relating to software or interaction with other features.

Station User Features

- ADD-ON CONFERENCE (6 party or more)
- AUTOMATIC CALLBACK
- AUTOMATIC INTERCOM
- BRIDGED CALL APPEARANCE
- CALLBACK LAST INTERNAL CALLER
- CALL COVERAGE (PROGRAMMED)
- INTERNAL & EXTERNAL CALL PROGRAMMING
- TIME OF DAY/DAY OF WEEK CALL PROGRAMMING
- ANI/DNIS/CLID CALL PROGRAMMING
- INTERNAL CALLER ID PROGRAMMING
- CALL FORWARDING - ALL CALLS
- CALL FORWARDING - BUSY/DON'T ANSWER
- CALL FORWARDING - FOLLOW-ME
- CALL FORWARDING - OFF-PREMISES
- CALL FORWARDING: RINGING

- CALL HOLD
- CALL PARK
- CALL PICKUP - INDIVIDUAL
- CALL PICKUP - GROUP
- CALL TRANSFER
- CALL WAITING
- CONSECUTIVE SPEED DIALING
- CONSULTATION HOLD
- CUSTOMER STATION REARRANGEMENT
- DIAL BY NAME
- DISCRETE CALL OBSERVING
- DISTINCTIVE RINGING
- DO NOT DISTURB
- ELAPSED CALL TIMER
- EMERGENCY ACCESS TO ATTENDANT
- EXECUTIVE ACCESS OVERRIDE
- EXECUTIVE BUSY OVERRIDE
- FACILITY BUSY INDICATION
- GROUP LISTENING
- HANDS-FREE DIALING
- HANDS-FREE ANSWER INTERCOM
- HELP INFORMATION ACCESS
- HOT LINE
- INCOMING CALL DISPLAY
- INDIVIDUAL ATTENDANT ACCESS
- INTERCOM DIAL
- LAST NUMBER REDIALED
- LINE LOCKOUT
- LOUDSPEAKER PAGING ACCESS
- MALICIOUS CALL TRACE
- MANUAL INTERCOM
- MANUAL ORIGINATING LINE SERVICE
- USER CONTROLLED MEET ME CONFERENCING (6-Party or more)
- MESSAGE WAITING ACTIVATION
- MULTI-PARTY ASSISTED CONFERENCE w/SELECTIVE CALL DROP
- MUSIC ON HOLD
- OFF-HOOK ALARM
- PADLOCK
- PAGING/CODE CALL ACCESS
- PERSONAL CO LINE (PRIVATE LINE)
- PERSONAL SPEED DIALING
- PERSONALIZED RINGING
- PRIORITY CALLING
- PRIVACY - ATTENDANT LOCKOUT
- PRIVACY - MANUAL EXCLUSION
- RECALL SIGNALING
- RINGER CUT-OFF

- RINGING TONE CONTROL
- SAVE AND REDIAL
- SECONDARY EXTENSION FEATURE ACTIVATION
- SEND ALL CALLS
- SILENT MONITORING
- STORE/REDIAL
- SUPERVISOR/ASSISTANT CALLING
- SUPERVISOR/ASSISTANT SPEED DIAL
- TEXT MESSAGES
- TIMED QUEUE
- TRUNK FLASH
- TRUNK-TO-TRUNK CONNECTIONS
- WHISPER PAGE

Attendant/Operator/Administrator Console Features

- AUTO-MANUAL SPLITTING
- AUTO-START/DON'T SPLIT
- BACK-UP ALERTING
- BUSY VERIFICATION OF TERMINALS/TRUNKS
- CALL WAITING
- CAMP-ON
- CONFERENCE
- CONTROL OF TRUNK GROUP ACCESS
- DELAY ANNOUNCEMENT
- DIRECT STATION SELECTION w/BLF
- DIRECT TRUNK GROUP SELECTION
- DISPLAY
- INTERCEPT TREATMENT
- INTERPOSITION CALL & TRANSFER
- INTRUSION (BARGE-IN)
- OVERFLOW
- OVERRIDE OF DIVERSION FEATURES
- PAGING/CODE CALL ACCESS
- PRIORITY QUEUE
- RECALL
- RELEASE LOOP OPERATION
- SERIAL OPERATION
- STRAIGHT FORWARD OUTWARD COMPLETION
- THROUGH DIALING
- TRUNK-TO-TRUNK TRANSFER
- TRUNK GROUP BUSY/WARNING INDICATOR
- TRUNK ID

System Features

- ACCOUNT CODES
- ADMINISTERED CONNECTIONS
- ANSWER DETECTION
- AUTHORIZATION CODES
- AUTOMATED ATTTENDANT
- AUTOMATIC CALL DISTRIBUTION
- AUTOMATIC ALTERNATE ROUTING
- AUTOMATIC CAMP-ON
- AUTOMATIC CIRCUIT ASSURANCE
- AUTOMATIC NUMBER ID
- AUTOMATIC RECALL
- AUTOMATIC ROUTE SELECTION - BASIC
- AUTOMATIC TRANSMISSION MEASUREMENT SYSTEM
- CALL-BY-CALL SERVICE SELECTION
- CALL DETAIL RECORDING
- CALL LOG
- CENTRALIZED ATTENDANT SERVICE
- CLASSES OF RESTRICTION (SPECIFY #)
- CLASSES OF SERVICE (SPECIFY #)
- CODE CALLING ACCESS
- CONTROLLED PRIVATE CALLS
- DELAYED RINGING
- DIAL PLAN
- DIALED NUMBER ID SERVICE
- DIRECT DEPARTMENT CALLING
- DIRECT INWARD DIALING
- DID CALL WAITING
- DIRECT INWARD SYSTEM ACCESS
- DIRECT INWARD TERMINATION
- DIRECT OUTWARD DIALING
- E-911 SERVICE SUPPORT
- EXTENDED TRUNK ACCESS
- FACILITY RESTRICTION LEVELS
- FACILITY TEST CALLS
- FIND ME- FOLLOW ME
- FORCED ENTRY ACCOUNT CODES
- HOTELING (/PERSONAL ROAMING)
- HOUSE PHONE
- HUNTING
- INTEGRATED SYSTEM DIRECTORY
- LEAST COST ROUTING (Tariff-based, TOD/DOW)
- MULTIPLE LISTED DIRECTORY NUMBERS
- MUSIC ON HOLD
- NIGHT SERVICE –FIXED
- NIGHT SERVICE - PROGRAMMABLE

- OFF-HOOK ALARM
- OFF-PREMISES STATION (OPX)
- OPEN SYSTEM SPEED DIAL
- PASSWORD AGING
- POWER FAILURE TRANSFER STATION
- RECENT CHANGE HISTORY
- RESTRICTION FEATURES:
- CONTROLLED
- FULLY RESTRICTED
- INWARD/OUTWARD
- MISCELLANEOUS TERMINAL
- MISCELLANEOUS TRUNK
- TOLL/CODE
- TRUNK
- VOICE TERMINAL (IN/OUT)
- ROUTE ADVANCE
- SECURITY VIOLATION NOTIFICATION
- SHARED TENANT SERVICE
- SNMP SUPPORT
- SYSTEM SPEED DIAL
- SYSTEM STATUS REPORT
- TIME OF DAY ROUTING
- TIMED REMINDER
- TRUNK ANSWER ANY STATION
- TRUNK CALLBACK QUEUING
- UNIFORM CALL DISTRIBUTION
- UNIFORM DIAL PLAN
- VIRTUAL EXTENSION
- VOICE MESSAGE SYSTEM INTERFACE

2.2.1 Business and Contact Center(s) Applications

For Business and Contact Center requirements as detailed in this Section 2.2.1 vendor MUST answer each item in accordance with the guidelines provided above. Your responses will be validated during the demonstration activities; any failure to provide an honest response may disqualify you from the RFP process at NW Natural's sole discretion. Providing a system manual is not an acceptable response to this section. Vendors must also cite any system feature limitations relating to software or interaction with other features.

(ACD) Functionalities - Provides skill-based call routing and extensive ACD reporting. Allows routing parameters and skillset rules to be defined by the system administrator and various levels of contact center management personnel.

Routing:	
3	An agent must have the ability to receive various call types in accordance with their abilities.
3	Ability to build and define routing parameters, thresholds, and priorities to all skills.
2	Ability to route calls to agents with the greatest time since last call rather than time since last status change (i.e. Collective time since last call handled per agent).
3	Advanced Auto attendant capabilities that can respond to oral questions and statements from customers *(...or contained in an IVR functionality see below).*
2	Up to ten overflows between queues (i.e. Having the capability to overflow from one queue to another).
3	Multi-site routing (single queue) also to include small office\home offices (SOHO) and mobile office (i.e. Field workers in transit).
2	The ability to whisper and barge on all call types received whether throughout enterprise to include; small office, home office, mobile office and multiple contact center sites.
3	Ensure there are no limitations to the number of users a line can be assigned and the number of lines that can be utilized simultaneously.
2	The ability to reach an internal resource on one number at minimal by "four-digit dialing" on whatever device they are available at *(...also see IVR Functionality and non-ACD end points).*
2	The ability to pre-set composite skillsets for different types of agent qualifications (i.e. "new workers" may take "move-in/out", and "service" calls, while "experienced workers" take "Credit" calls, "Emergency" calls).
2	The ability to collect/report/distinguish between customer calls (i.e. called the Company #) and personal calls to a CSR's private line/extension which may be secondary to the keys or lines designated for receiving external customer calls.
Reporting & Tracking: (Historical & Real Time)	
3	Interface for end users to view real-time information, on hold times (expected and actual), calls in queue, agent status, extensions, service level, calls holding, etc. and also for aggregated queue

	types.
3	Ability to track and report on different types of work for agents separately (Example: If Agent 1 has 2 login states, "Calls" and "Paperwork," we should be able to easily gather reports on Calls that do not include the time they were logged into Paperwork and reports on Paperwork that do not include activity from the time spent logged into Calls).
2	Stores agent login information and allows the agent to select a work state list from a desktop application. Corresponding login info for the phone state selected is sent to the phone/ACD system to eliminate the need for manual login. (Needs may change depending on ability of ACD system to track multiple work states within a single login ID *(see ACD/User Administration section below).*
2	Ability for end-users to easily filter real-time displays to view their own assigned agents within their associated department and groups of agents within the organization.
3	Ability to simultaneously track multiple service level thresholds (calls answered in *n* seconds or less).
3	"Cradle to Grave" call analysis: Ability to locate a specific call and easily track caller's movement through each menu option/transfer/agent interaction until the call is released and everything in between.
3	Ability to run and export reports on a schedule or ad hoc.
2	Ability to customize canned reports to include/exclude certain skillsets/users/non-business hours (should be able to run a report to pull data for a range of dates, but only include 7am-6pm from each day, for example).
3	ACD reports should provide the following by agent, skillset, and summarize by user-defined report groups/filters. Data should also be available in monthly, daily, and 15 minute interval summaries: ACD calls offered ACD calls answered ACD calls abandoned ACD calls answered within *n* seconds *(must be able to track at multiple thresholds)* ACD calls answered after *n* seconds *(must be able to track at multiple thresholds)* ACD calls abandoned after *n* seconds *(must be able to track at multiple thresholds)* Logged In Time "Not Ready," and/or "After Call," and/or "Unavailable time DN call detail. Separate incoming from outgoing, and external from internal. Should include the number of each type of DN call and talk time Number of calls that last less than *n* seconds *(must be able to track at multiple thresholds)* Number of calls returned to queue during the routing process
2	Ability to create custom calculated fields that allows mathematical operations as well as "if then else" logic for historical reports and real time dashboards.
2	Ability to fully customize the layout of historical reports and real time displays (dashboards). User should be able to add or remove fields and filter results based on agents, agent groups or skill sets.

3	The ability to create a data warehouse for T-SQL and SSRS reporting (i.e. The applications database should be translatable to an MS SQL database).
3	Provide an ERD (Entity-Relationship Diagram) or database definitions document.
2	Provide multiple levels of reporting within the application interface.
3	Provide real time levels of reporting categories (i.e. callers in queue, hold times, ATT, AHT, etc.) on a reader board and/or desktop dashboard "at" and "for" various levels of end users (i.e. manager, supervisor, analyst, agent, etc.).
3	Ability to store and extract data for analysis reporting 24/7 on all ACD reporting functionalities and at multiple retention schedules based on defined parameters.
1	Ability to export ACD report data to a variety of formats (i.e. Excel, SharePoint, and HTML). In Excel files especially, data should be arranged in continuous rows and columns. Column headings should be included and data should reliably export to the appropriate columns.
3	Dashboard and Reader board applications (currently report views) - allows real-time visuals of service level by queue in intervals of no less than every fifteen minute updates "and at" fifteen minute increments.
1	The ability to run reports on a schedule and define automatic delivery options such as email, web publication, or exporting to a shared location. User should be able to define and easily modify delivery audience and schedule.
3	The ability to search calls by time, phone number, by agent and by customer information.
3	The ability to view cradle to grave call activity to include IVR routing through and outside of the ACD system. This should all be obtainable on a single report through a single user friendly interface.
3	Cradle to Grave call tracking for any and all calls no matter how they enter or exit the system.
User Administration:	
3	End user "Alerts" and "Alarms" (i.e. visual and/or audio indicators that a problem exist) separate than those provided at a system administrator's level.
3	Ability to track several (we currently have 30+) different types of work states for a single agent, preferably without having to build a separate user profile for each state. If separate profiles are necessary, we should have the ability to easily duplicate profiles to minimize the amount of manual work required.
1	Ability to run a batch process to assign and/or associate agents to supervisors.
2	Ability to schedule and easily change skill set assignment to a single or group of agents on demand.
3	The ability to create and add aggregate groups of skillsets at the individual agent level and group level.

Simulated Hold Functionality - A queue of both callers on hold and callers who opted to be called back. The callers' places in line are marked as they come in, and are either answered or called back when they have reached the front of the Combined Queue. The end user can view statistics and see calls in queue real-time, generate historical reports over a wide range of data, and make real-time parameter settings to the call back system.

Interface:	
1	Easy to navigate, interpret, and understand real time statistical data interface for end-users.
2	Real-time queue displays with seamless screen appearance - no flickering.
3	Changes to occur in real-time and are not dependent on a restart of software to initiate.
3	Allows end-users to monitor queues, agents, and customers holding in real-time.
Features:	
2	Web Callback, Web Cancel callback, Web Rendezvous (appointments) callback: Allow online Web users to place themselves in queue. They can monitor their place in queue from their computers, and will be called when it is their turn to speak with a representative.
3	Provide notifying features which identify and flag a duplicate request from the same customer for a callback. Flags the first request and eliminates subsequent requests which would avoid multiple call backs to the same customer once the initial contact has been successfully completed.
1	Provide recall dialer features for customer utilization and system dialing accuracy.
2	Specialized and\or enhanced features that disables a "Today" request or allows a "Only Today" when requesting rendezvous (appointment or method of contact).
2	Provides caller with a "Fast Forward" feature which allows alternative, available time choices if the original scheduled callback request time was not available.
1	The ability to return a customer request for call back on any mode preferred by the customer (i.e. text, e-mail etc. -- ACD and/or non-ACD callers).
Functionality:	
3	The ability for a customer to hear the current hold time to receive an agent or service and request a call back without losing their place in the queue or by specifically selecting a call back time which does not impact service levels and does not log as an abandoned call. (Describe if your technology for the placement in queue is a "true" place holder or an algorithm).
2	The ability for a customer to leave pertinent information which becomes available to the receiving agent prior to connecting the call back (i.e. name, address, nature of call, populated as agent received customer).
2	The ability to manually terminate a call back request with an easily "search and identify" method.
1	The ability to block specific phone numbers from requesting or receiving call backs (i.e. A non-customer has had their phone number entered into the system by mistake and does not want to be called by NWN ever again).
3	Desktop dashboard application to include site name, skill, operation mode, estimated wait time for each skill queue, number of first in, first out calls, number of Web callbacks, number of callbacks in queue, number of calls currently holding, number of calls in the IVR, number of calls on hold, number of scheduled callbacks.

3	Call Back dashboard & reader board adapter (Displays callers on hold statistics on the user desktop and adapts intervals that display the Queue statistics).
3	Real-time queue stats and line stats delivered through a Web configuration (Visibility when observing the Queue).
3	Saves the caller's place in line. Gives the caller the option to be called back when it's their turn to speak to a representative (same day functionality - first queue available).
2	Call scheduling flexibility (i.e. call backs scheduled later in the day provide time options to select from).
3	Ability to define parameters around average expected wait time, time of day, to determine whether a callback will be offered.
3	Call blocks that enable the system's ability to block specific call back requests which fall outside of normal operating hours and staff levels(i.e. Customers could not request a callback after 6 pm(PT) and not prior to 8 am (PT)).
3	Give the caller the ability to schedule an appointment to speak with a representative at **"a time and place"** that is more convenient, up to a minimum of seven days in the future.
3	Skills-based and Agent-based routing support.
3	Prompt recording, voice files re-recorded and made active without restarting the software
3	WFM adapter or comparable (*Blue Pumpkins*).
3	Ability to control playing the choose hold prompt, which allows the caller to choose hold.
3	Associate and support user data through the callback submission.
3	Hold applications can run as services (i.e. Ability to rename applications).
3	IVR support.
3	Screen Pop Support *(CTI integration).*
3	Real-time accuracy for agents staffed functionality *(reader board accuracy - separate from reporting).*
3	The ability to interoperate with ACD data accurately and display the same "real-time" queue statistics as those displayed within the ACD (i.e. The number of calls in a specific queue illustrated in the ACD functionality should match the number of calls in "that same" specific queue in the simulated hold displays/dashboard/reader boards).
3	End user "Alerts" and "Alarms" (i.e. visual and/or audio indicators that a problem exist) separate than those provided at a system administrator's level.
Reporting:	
2	100% Punctuality Callback reporting (Reports are not artificially inflated).
3	Multi-site and group reporting and support.
3	Accuracy (real values) reporting for agent staffed functions.
3	The ability to create a data warehouse for T-SQL and SSRS reporting. (i.e. The applications database should be translatable to an MS SQL database).
3	Provide an ERD (Entity-Relationship Diagram) or database definitions document.
1	The ability to run reports on a schedule and define automatic delivery options such as email, web publication, or exporting to a shared location. User should be able to define and easily modify delivery audience.

2	Ability to customize canned reports to include/exclude certain skillsets/users/non-business hours (i.e. should be able to run a report to pull data for a range of dates, but only include 7am-6pm from each day).
1	No third party reporting installation required.
Security:	
3	Fault tolerant communication between applications.
1	Enhanced level of security (minimum of 128-bit encryption).

Interactive Voice Recognition - This automated interface is the initial (first) interaction between the customer and the Company. The IVR enables customers to call any NW Natural phone number to receive information, select routing and interaction options and\or automatically complete various transactions\options throughout the enterprise.

Enterprise Routing Options:	
3	The customer may interact with the enterprise based on emergency needs, known extension, by business need, new customer status or other customer service options by pressing the associated number DTMF on their phone or by speech.
3	Automation options and methods are provided: The customer may maneuver by speech or by pressing the associated number button DTMF on their phone.
3	Language options provided: The customer may select English or Spanish from main menu and be routed to the appropriate transfer targets or additional language appropriate self-service options. *(i.e. select by DTMF or by speech)*
3	The ability for identical menuing services and call flows *(see menu options below)* in three languages: English, Spanish and Russian.
2	Company Information option - information pertaining to the company in general, not department specific.
3	Automated "After Hours" options and routing methods that allow the customer initial information and a second opportunity to select "self-service" if call is initiated after regular business hours.
3	Special Programs - programs offered such as seasonal and marketing programs.
Multiple Menu Options:	
3	Account information, account number, urgent menu, meters, payment menu, other payment methods, extend payment terms, auto pay, equal pay, payment locations menu, outbound application, start\stop\transfer service, known account, check phone number, conversion to gas, appliance sales menu, equipment services, service date menu, accept date menu, pick service date menu, additional service orders menu... ***(current system contains over 76 call flow menus with varying self-service options)***
Functionality:	
3	Account Look Up - a method by which accounts are identified in the IVR. This is the customer's input that will be compared to information provided by stored procedures.

3	Account Verification - a method by which accounts are verified in the IVR this is a customer input that will be compared to information provided by stored procedures.
3	Account Information - information pertaining to the customer's account, account balance, payments received, billing information, and past due status and\or information. Provided by stored procedures.
3	Payment Options - options for payment of account balance or payment programs, banking information, payment type options (credit card or checking account)
3	Payment Arrangements - programs offered to customers to extend due date, balance payments, offer customer payment programs for past due balances.
3	Form Mail outs - mail outs to customers for information or program applications.
3	Service\Service Orders - orders for types of service, including start, stop and transfer of service.
3	Scheduling specific appointments types while providing multiple time availabilities. Provided by stored procedures. (i.e. A Service Order Scheduler application).
3	Outbound Applications - outgoing calls to customers to inform the customer of activity that will occur at their service address.
3	The ability to reach an internal resource on one number by "four digit dialing" on whatever device they are available at *(...also applicable to ACD and non-ACD end points).*
3	Provide support for real-time notifications services through e-mail, fax, paging, and the ability to invoke custom workflow processing (i.e. web-based callback).
3	Ability to Interface with CTI applications.
3	Ability to Interface with Customer Information Systems.
3	Ability to Interface to Interactive Payment Solutions (IPS).
2	Text to Speech and VoiceXML.
3	Speech Recognition required.
3	Ability to have various default messages, barge in by speech options and administrative controls.
3	Advanced Auto attendant capabilities that can respond to oral questions and statements from customers *(... or contained in ACD functionality see above).*
3	The ability to support a minimum of over 60 Speech Recognition Modules *(e.g. please review section 2.0 "voice requirements").*
3	End user "Alerts" and "Alarms" (i.e. visual and/or audio indicators that a problem exist) separate than those provided at a system administrator's level
Reporting:	

3	The ability to create a data warehouse for T-SQL and SSRS reporting. (i.e. The applications database should be translatable to an MS SQL database)
3	Provide an ERD (Entity-Relationship Diagram) or database definitions document.
1	The ability to run reports on a schedule and define automatic delivery options such as email, web publication, or exporting to a shared location. User should be able to define and easily modify delivery audience.
2	User friendly interface that allows analysis of a caller's experience in the IVR. User should be able to view IVR verbiage at each step as well as data keyed in or spoken by the caller.
2	Ability to easily run daily reports to show how many calls are completed in the IVR *(or calls that do not result in a transfer to a live agent).*
3	"Cradle to Grave" call analysis: Ability to locate a specific call and easily track caller's movement through each IVR menu option/transfer/agent interaction until the call is released and everything in between.
3	Ability to report on and analyze number and percentage of calls that are completed\dropped out/transferred/abandoned at **"each"** IVR menu location. *(Must maintain our current ability and functionality of 30.5% IVR Contact Center Calls Handled, from a monthly average of total calls taken equaling 87,000).*

<u>Quality Monitoring and Recording System</u> - Enables the end-users to capture agent-customer interactions to train, coach, evaluate and score according to predefined business rules. QM assists in identifying trends, issues and department compliance.

Functionality : (Audio and Screen)	
3	End User Interface that is easy to access, understand, logical, which provides "Help" instructions and tools to navigate.
3	Provide Time Zones and Time Shifts that compensate for Daylight Savings Time automatically.
3	Automated and On-Demand recording with extensive screen recording. Capture internal and external customer interactions with end-user method options.
2	Allow agents to initiate on-demand recording while also alerting the supervisor of the agent's recording activation.
3	Screen Capture synchronization with audio, dual or triple monitor support - multiple monitors in-sync with audio of call.
3	Screen capture is recorded even when agents are not engaged with a customer via the phone interaction.
3	Provide for event based screen recordings, the ability to capture specific on-screen data fields and desktop events, such as words and values typed, application windows opened, and buttons pressed.
3	Record customers (internal & external) communications (voice and screen) from multiple channels (voice, e-mail, web chat etc...) for use in evaluations and training.
3	Capture recordings across multiple locations and provide Terminal Server interoperability.
3	Recording capacity has ability to be scaled to meet the enterprise evolving needs.
3	Automated scheduling options with 24\7 recording functionality.

3	100% recordings with on demand functionality without limitation to the number of lines and users. (The ability for the server to record all calls full time and simultaneously allowing end-users (Supervisor) to execute a live monitoring of an agent conversation via the system).
3	100% recordings and playback without limitations due to DN/Key capabilities (i.e. the ability to record any call regardless of which channel, key, line or DN the call originated on and from).
2	Advanced Monitoring capabilities - silent live monitoring, barge-in capabilities (join agents call), and intercept a contact (take call from agent), ability to remotely monitor live and recorded contacts silently.
3	Continuous recording and screen captures through completion of calls (i.e. tracking customer throughout system: excessive hold\wait time, disconnects, multiple transfers).
3	Recording any call on an ad hoc basis whether the call is received by an ACD agent or non-ACD agent.
3	Multiple line capabilities (i.e. keys, phone numbers, lines etc...) and recording interoperability - examples include an emergency line\key separate from customer contact center's skillset queues; or an acquisition department's contractor phone number\key separate from the acquisitions new customers contact center's queue etc. .
2	Call segment review available in the contact information and segment information visible in the evaluation forms.
3	Full SIP and softphone support; embedded CTI integration.
3	Provide quick intuitive methods to search and retrieve archived recordings (i.e. date ranges, contact data, advanced data).
3	The ability to retrieve 100% of calls within the user interface for a minimum of 6 months and a minimum 1 year of achieved/stored calls with the ability to limit call retention based on business rules.
3	Search functionality, which differs for each application, enables creating queries with criteria parameters relevant for the specific application. Once a search has been performed, matching contacts are displayed in a search results list. If you have already performed a search in your current browser session, the criteria you defined in your last search appears when you click on the Search button.
3	All functionality of the system to be compatible with MS 2003, IE6, and above and all Word 2003 and above applications *(i.e. must be compatible both, with NWN infrastructures existing versions as well as the current versions).*
3	Screen search if a contact has a screen capture associated with the audio the end-user may search for contacts by requesting an audio only or screen w/ audio search; by agent, phone ext., ANI, DNIS, etc. .
3	End user "Alerts" and "Alarms" (i.e. visual and/or audio indicators that a problem exist) separate than those provided at a system administrator's level.
Features:	
3	Playback features: Once you have searched for contacts or accessed a specific folder, you can play back the audio directly from the list without having to open it in a Workspace page.
3	Playback features with auto control: You can control the playback of a contact's audio and screens (if available) from the playback area on a Workspace page. You can also view the voice energy levels of the audio to detect silence and loudness.
2	Contact and evaluation flag features - flags contacts by pre-defined words, phrases or evaluation scores which enable a search by flag parameters.

3	Calibration features to achieve consistency of administrative observations (i.e. all end-users score the same sample call with reporting for score comparison.
3	Contact Search mechanisms, including phrase, tone, word, or customer record (CTI application interface).
Evaluations (Scoring) and Forms:	
3	Enable scoring recorded contacts or external contacts (i.e. customer interactions not recorded within the system) by filling out forms. Allow a user to also score contacts that you hear in real-time (evaluating contacts) or when scoring recordings (assessing contacts).
3	Provide customizable forms that can be tailored for different needs, users fill out forms that review the agent or customer contacts against a set of criteria (*Elements*). The Elements are grouped into *Categories* that represent parts of the conversation that will be reviewed (i.e. opening, handling, closing separate from knowledge). Each form can contain numerous Categories. Categories are grouped into *Sections*. A form may have one or more Sections depending on the desired review and report breakdown.
3	The ability to evaluate any contact in real-time either during the call you want to monitor, or after the call has already ended and before a new call begins.
3	Ability to modify the evaluation form due to changes in policy and procedure and the ability to create multiply monitoring forms with different scoring parameters and categories for different departments and workgroups.
1	The ability to modify any existing form for a specific workgroup easily *(i.e. not required re-creating a duplicate form if one element or value is changed).*
3	Option for customer survey of representatives after contact completion\call interaction.
Security:	
1	Encryption to protect data when recording, in transit and archived from unauthorized access.
Reporting:	
3	Real-time reports that provide instant access to consolidated information about individuals, groups and contact centers, providing metrics that make it easy to set and maintain consistent quality standards across an enterprise.
3	Cradle to Grave tracking on 100% of all calls no matter how they enter or exit the systems. (i.e. to include all transfers, times of transfers, call answered time, hold time, talk time, ACD and non-ACD calls, etc.).
3	The ability to create a data warehouse for T-SQL and SSRS reporting. (i.e. The applications database should be translatable to an MS SQL database).
3	Provide an ERD (Entity-Relationship Diagram) or database definitions document.
1	The ability to run reports on a schedule and define automatic delivery options such as email, web publication, or exporting to a shared location. User should be able to define and easily modify delivery audience.
2	Ability to generate reports on specific questions or definable sections of an evaluation form. Results should not be limited to overall call score.
3	Historical reporting - hierarchical and non-contiguous.
3	Trend reporting for overall representative performance (i.e. to identify training needs, system improvements or call types).

3	Track and analyze employee performance using pre-defined key performance indicators (KPIs) displayed in role appropriate scorecards.
3	Reports that are integrated within the software and compatible with MS SQL with access provided to the dataset.
3	Provide ERD for customizable scorecard reporting.
3	Enhanced Reporting functionality features (Dashboard style features with data and graphs).

Softphone Application:

3	The ability to continue a call in progress while moving from one device to another (i.e. desk phone, home phone, cell phone and PC).
3	The ability to access my desk phone from my home location and/or cell phone (i.e. softphone interoperability's)
3	Softphone capabilities from Mobile (field) worker laptops with "voice activated" access to voicemail and e-mail *(also see mobile communications).*

Workforce Management Systems: The system stores and processes historical ACD data to predict and refine staffing requirements in situations where there are continuous, but varying, streams of work that must be handled promptly by large numbers of agents, as well as perform scheduling and tracking functions for ACD agents and non-ACD workgroups where applicable.

Scheduling:	
3	Allows for creation of user-defined schedule/shift templates.
3	Allows for definition of segment window rules, to prevent breaks from being scheduled too close to the start/end of a shift or to other breaks/lunches.
3	Provides means to generate schedules automatically or manually, or a "hybrid" process (so that additional schedules can be added manually to an auto-generated base staff, or vice versa).
3	Ability to easily modify one or more schedules on demand, either individually or as a batch process.
2	Ability to assign schedules for a minimum of one year in the future.
2	Ability to easily manage shift trades, both temporary and permanent. Ideally, agents can request and accept shift trades electronically through the application.
2	Electronic shift bidding functionality. Agents should be able to bid on shifts by seniority and possible additional criteria to be determined in the future.
1	The ability for employees to access information about their schedules and personal time off (PTO) from the home, field and office.

1	No restrictions or limitations to the number of end users.
Tracking:	
3	Functionality to create a daily intra-day "snapshot" of coverage at each interval during business hours.
3	Adding/modifying segments and seeing changes in "real-time" and updates are easily administered.
3	Agent interface to allow agents to see their own schedules only, with real time updates.
3	Ability to easily apply adjustments to one or more shifts in a date range with a single request.
3	Agent desktop or web client to allow reps real time access to schedule information. We should be able to restrict agents to only view their own schedule.
3	Real-time dashboard for supervisors to immediately see deviations from agent schedules such as tardies, long breaks or lunches, taking break/lunch at the wrong time, or being logged into a work activity they are not scheduled for.
3	The ability to provide "real-time" adherence data in a visual format (i.e. desktop dashboard) which illustrates real-time updates (i.e. pre-scheduled agents "for the phone" verses real-time agents actually "on the phone" at any time of the day).
3	End user "Alerts" and "Alarms" (i.e. visual and/or audio indicators that a scheduling deviation/variance exists).
Forecasting:	
3	Ability to read or import ACD data to build history with options to set automatic updates.
2	Automatic calculation of intra-day, daily, and monthly patterns. Ability to define holiday factors and shrinkage (non-phone) categories and factors. Automatic calculation of historical growth rate.
3	Ability to adjust or create any forecasting inputs manually.
3	Service Analysis Forecast - ability to forecast to meet a user-defined service level (i.e. *x*% of calls answered in *n* seconds or less).
3	Ability to import historical data for the past two calendar years plus the current year from Aspect WFM or Symposium for use in forecasting. Data should include, but not be limited to: daily, monthly, and 15-minute interval call volumes and daily average handle times.
3	Ability to store and retain historical data directly from the ACD system - no manual intervention required.

Reporting:	
3	The ability to create a data warehouse for T-SQL and SSRS reporting. (i.e. The applications database should be translatable to an MS SQL database).
3	Provide an ERD (Entity-Relationship Diagram) or database definitions document.
1	The ability to run reports on a schedule and define automatic delivery options such as email, web publication, or exporting to a shared location. User should be able to define and easily modify delivery audience.
3	Ability for end users to track early/late logins or absenteeism in real time.
3	Ability to report on agent adherence to schedule as a percentage.
3	Ability to report on agent punctuality and attendance. At a minimum, this report should show if an agent is late and by how long. Ideally it will also report long breaks,lunches and early departures.
1	Ability to create custom reports, and custom calculated fields within a report. Ideally, the creator can add, remove, and modify the order of included fields.
Administration:	
3	Ability to create several custom levels of application access for administrators, supervisors, schedulers, etc.
3	Ability to easily link an agent profile with one or more profiles (to include all types of scheduled work) in the ACD system.
2	Ability to define seniority in agent profiles.
Compatibilities:	
3	The ability for the out-of-box solution to integrate with e-Workforce Management (Aspect) and Telestaff (PDSI) applications.

Screen Pop Application: A screen which is automatically populated with stored data defined by determined parameters which is populated when a customer uses one of the defined parameters when initiating contact with the Company.

3	Populate ANI or DNIS and customer-defined workflow data.
3	Picks up caller ID info from ACD system and delivers it to the call center desktop software for account recognition.
3	Automatically start any Microsoft Windows or other compatible application.

3	Populate and <u>send data</u> to any Microsoft Windows or compatible application.
3	Populate data to any browser-based application.
3	Populate customer's name, account number, phone number, etc.
3	Allow Screen pops based on any contact type, including e-mail, web, voice messaging, callback and outbound.
3	When an agent transfers a contact, all customer data, including screen pop data is transferred along with the contact.
3	Screen pop data and contact association are simultaneously contained within the workflow.
3	The ability to populate real time and historical data.
3	The ability to transfer data from our customer information systems and the "caller" simultaneously from one workgroup to another while freeing up the first workgroup to continue working without interruption due to manual transfer processes, etc. (i.e. interface CTI and API's or other methods) *(... also see mobile communication).*
3	Link "A Specific" caller to "A Specific customer record based on IVR and CTI information tied to a back end CRMS system.

Non-Contact Center Reporting:

2	Multiple reporting capabilities similar to those described in ACD category for non-contact center phone lines to be utilized by non-contact center administrators (i.e. enterprise phone/calls reporting).

Conferencing: Business Applications

2	The ability to have multiple users interacting at the same time on a common call *(one to many selectable focus and real time full motion for video conference).*
2	The ability to share documents, desktop, and administer a polling survey along with receiving the results instantaneously and support private/group chat capability.
2	The ability to set and pass hierarchy permission (i.e. presenter, attendee, invitee etc.).
3	The ability to record video and audio of all parties during the call with playback functionality.
3	The ability to share a desktop during a conference call in "real time" and share/trade control.
3	The ability to conduct ad hoc audio or video conference without limitation to number of participants internal and/or external with a "join" feature for multiple lines.
2	The ability to use video collaboration utilizing various media types (i.e. cell phone, desktop, other). Describe the feature capabilities.
1	The ability to perform all of the above with one or more entities outside the NWN network.

Presence and Instant Messaging: Business Applications

3	The ability to set default presence state at either phone, mobile device, or desktop PC login and track based on activity from that time forward.
3	The ability to search, identify and locate any resource, anywhere at any time on any device (i.e. desk phone, mobile phone or PC) and contact, communicate and collaborate instantaneously through any mode (i.e. voice, e-mail, text).
1	The ability to escalate and de-escalate seamlessly from media to media depending on the business need (i.e. go from a voice call to chat to document sharing and the reverse).
2	The ability to enhance presence with location information based on mobile handset GPS information (also see Mobile Communications).
2	The ability to control presence status from a hierarchy permissions level.
3	The ability to see an agent's real time phone presence information (i.e. call processing / ACD/ switch hook status) and additional presence status indicator for other availability modes (i.e. IM, e-mail, etc.).
3	The ability to see other non-phone presence information (i.e. break, paperwork)
1	Passive presence detection (i.e. IR detection or facial recognition).
3	The ability to update status information on all devices simultaneously (i.e. out of office, private meeting, do not disturb, etc.).
2	The ability to search internal resources with specific KSA information in real time with real time presence displayed from one platform and/or integration capabilities with an authoritative directory (i.e. SAP, SharePoint)

Unified Messaging - Business Applications

Functions:	
2	The ability to instantaneously utilize multilingual translation capabilities with various modes/channels (i.e. voice, e-mail, text, instant messaging).
3	The ability to have voicemail systematically transcribed from voice into text or e-mail and then presented within a visual voicemail client on any device.
3	Visual voicemail that allows the message to be listened to in any order, paused, fast forwarded, locked (prevent accidental deletion) and return the message without making an actual voice call.
3	The ability to access and respond to all message mode types by a voice command only "hands

	free".
3	The ability to read voice mail, listen to e-mail and text with intelligent filtering of text to speech and speech to text.
3	The ability to convert voicemail to text with the ability to tag as "urgent"" and/or page using text messaging.
2	The ability to have specific "internal notification" options and tracking method (i.e. options a Helpdesk resource would utilize).
2	The ability to route non-contact center calls and look up an end users skills within the UC unified messaging system (i.e. not required to leave one platform to find information from another platform).
1	The ability for self-service portal capabilities "outside" of an IVR application.
3	The ability for a customer to use the NWN web site and utilize a "click-to-chat" feature/function that is routed to predetermined resource(s) through any mode (i.e. voice target, e-mail, web chat, text, etc.).
3	The ability for anyone to utilize a "click-to-talk" feature/function from any mode (i.e. e-mail, IM, web-chat) that is routed with the switch (i.e. "click name to call" feature in any document).
3	The ability to track all media types; voice, e-mails, chats, outbound notifications/communications through a single reporting interface with hierarchical parameters.
3	The ability to retrieve 100% of Voicemail messages for a minimum of 3 months and the ability to limit call retention based on business rules.

Social Networking: Business Applications

3	The ability to route a customer's request via social media and automatically route to the appropriate company resource based on specified parameters and the ability to respond back to the customer via the preferred social media (i.e. a tweet goes to a customer rep, a customer rep responds via an e-mail).
3	The ability for NWN to search for key words or phrases through all social media channels on the internet (i.e. Twitter, Facebook, Blogging; etc.).
1	A notification activated based on keywords discovered on a social network or NWN website to one and multiple groups based on KSA or predetermined parameters (i.e. data mining activates an internal notification).
2	The ability for a customer to use the current functionality within the NWN web site and select a "click to chat" feature/function that is routed to predetermined resource(s).

Mobile Communications: Business Applications *(ACD and non-ACD interoperability may be applicable).*

3	The ability to continue a call in progress while moving from one device to another (i.e. desk phone, home phone, cell phone and PC ...also see softphone requirements).
3	The ability to use one phone number and be reached on any device while only displaying the designated default number to the recipient (i.e. displays an office # or selectable # for any user).
2	The ability to initiate a call to an external party (customer) from one phone# (personal, company cell, DID) and the number displayed back to the external party (customer) is specific to the knowledge resource for a follow-up contact (i.e. a technician calls a customer from their personal cell and the number displayed back to the customer is the phone number of a specific KSA resource -- not the technician and not a general company #).
3	The ability to transfer data from our customer information systems and the "caller" simultaneously while call is in progress from one device to another without interruption. (i.e. a desk phone to a mobile device seamlessly).
2	The ability to instantaneously do the same job in the office, at home, or from the field utilizing all the Company operational technologies in addition to integration compatibility of Terminal Services.
3	Softphone capabilities from Mobile (field) worker laptops with "voice activated" access to voicemail and e-mail (also see Softphone Applications).
?	The ability for a mobile worker (field) to have Virtualized Private Network (sign-on network) functionality on a mobile device (i.e. specifically a cell phone, a mobile enabling applications).
1	Single device communications and application access from anywhere (home, traveling, etc.) which converts to any mode (i.e. voice to text, text to voice, translation capabilities (English to Spanish), text to sign language, etc. -- also see Unified Messaging Requirements).
3	GPS capabilities through a mobile device which also has integrated presence information within the Company's presence and IM application (i.e. GPS and presence visible on OCS, for example).
3	The ability to access my desk phone from my home phone and cell phone.
3	The ability to have pager integration with voice processing platform.
3	The ability to have access to the Radio system.
3	The ability to operate as a mobile contact center from home instantaneously (i.e. all contact center functionality, visibility, controls, customer information, ACD functionality, etc.).

Outbound Communications: Business Applications

3	The ability to perform outbound services that "access the customer information" using voice, e-mail, text with authorization parameters/permissions if fee/cost involved.
3	The ability to send out communications to a select group of people (by sender and/or receivers preferred notification method) in a blast and in defined intervals.
3	The ability for outbound communications/notifications to alert the receivers by an urgent indicator (i.e. tags, alarms, specific ring, buzzing or flashing etc.).
3	The ability to send outbound notifications to an "All Group" and/or to "Specified Group" through various media channels (i.e. an internal "All Group" would receive a message via e-mail while another "Specified Group" receives the same message via text).
3	The ability for an outbound communication/notification to automatically create a contact/note on a customer's account information, once the notification/communication was sent with time stamp functionality and type of notification sent (i.e. e-mail, text, outbound call, visual voicemail, etc.).
3	The ability to send outbound notifications/communications to large groups internal and external in a select mode (i.e. e-mail, voice message,) and be received on any device in any mode (i.e. e-mail, visual voicemail, text, etc.).

Performance Specifications: Voice, Call Processing and Contact Center Specific

3	Reliability: The ability to achieve and maintain no less than a 99.999% specification.
3	Availability: The ability to achieve and maintain no less than a 99.999% specification.
3	Quality: The ability to achieve and maintain a Means Opinion Score (MOS) of no less than a level four (4).
3	In the event of a system outage there must be a proven back-up plan for Voice/Call Processing and Survivability operations. Describe your solutions plan in detail.
3	The ability to provide "additional" back/up and redundancy plan for "Emergency Calls" along with technologies associated with any Emergency Response communications and collaboration efforts.
3	Latency, Capacity and Survivability: Refer to the Network Assessment and QoS Requirements in section 2.5
3	End user "Alerts" and "Alarms" (i.e. visual and/or audio indicators that a problem exist) separate than those provided at a system administrator's level

2.2.2 Business and Contact Center Processes

The following section outlines various Business and Contact Center processes and/or application scenarios associated with the requirements listed in section 2.2.1. Vendors should provide an "additional narrative" response to each item within section 2.2.2. * When applicable also reference the Business and Contact Center categories and line item(s), in 2.2.1 for which your functional/technology response was provided.

Add the ones below as priority = 3

- Provide documentation that illustrates how many "successful" installs you have done of similar size and make up as the NW Natural enterprise?
- Provide documentation that illustrates how many "successful" installs you and/or third party partners have done of similar complexity and size as NW Natural's Contact Center(s).
- What percentage of your business is the production of VoIP processing products?
- Describe how your solution enables and has "proven" continuity for emergency response operational workgroups.
- What Contact Center operational technologies are encompassed within your VoIP Server platform? Which technologies are not?
- Describe your solutions proven ability to support a "Mobile Contact Center" at home agents with full Contact Center functionality?
- Describe what sign language reader or foreign language translation capability is available that would allow us to replace our current options to assist hearing-impaired or non-English speaking customers?
- Describe the kind of 911 capability/enhancements provided within your solution that enables more efficiency in an emergency call process?
- Describe your solutions ability to provide or enhance support to an Incident Command Systems solution?
- Describe what kind of Mobility of full technology does your solution support - That is, ability to do the same job in the field, at the office, or at home. Allowing for instant access to all functionality from offsite for an emergency situation?
- What Utility marketing vertical solutions do you provide?
- Describe how to enable visibility of a mobile agents' physical location and send data instantaneously to that agent on any device?
- Describe how presence "indicators" parameters/permissions are determined and controlled?
- Describe how KSA information is interfaced with other applications and what ways can they be utilized with presence functionality and/or tools?

2.3 System Features for Converged Networking

With voice traffic being transported as data packets over local- and wide-area data communications networks, and over links to the PSTN, networking features and capabilities are critical.
Vendors should answer these questions:
Priority = 3

- How will the proposed system interface with established local and long-distance public networks? Is CSU functionality provided at the edge of the network? What telco diagnostic standards does it support?

- What is the system's capability to support trunk aggregation? What types aggregation protocols are natively supported? What is the hardware specified for trunk aggregation (appliance, hybrid-gateway, DSP card, etc.)
- How does the system support the Session Initiation Protocol (SIP) at the system level and at a handset level? What are the assumptions in the proposed solution regarding non-SIP endpoints or transport legs? What proprietary SIP "extensions" are presumed in the proposed solution? How and where do these extensions "fit" in the overall system architecture? What are the interoperability restrictions that they present to standard SIP nodes/stations?
- What standards and techniques for quality of service (QoS) are supported to ensure acceptable voice quality over the data network? How are those techniques validated on an operating network? What proactive monitoring tools are provided? Is trending analysis supported to predict network growth requirements? Does the monitoring solution also cover ongoing quality analysis for public internet and PSTN fallback connectivity?
- How does the system support temporal and heuristic routing, which allows the routing patterns by the nodes and trunks accessed to be changed based on network conditions, defined date/day/time combinations or other triggers? How flexible can these routing decisions be? How many triggers may be specified and how often can the triggers be programmed to change?
- What classes of service and classes of restriction does the system support? What other system, station, and trunk restrictions can be set to minimize fraudulent use of PSTN resources? What monitoring tools and systems are provided to detect and manage possible unauthorized intrusions of the system on the PSTN,station access, and local IP network levels?
- What is the proposed solution's ability to interoperate with other in-house and external common voice communication resources, such as PBX systems, voice mail systems, conferencing systems, private or public voice networks directly or through software or hardware gateways? What common-channel or in-band signaling standards are supported when communicating with external or tightly coupled systems?
- What types of federation standards and trust levels are supported and what features/functions are available (or not supported) with other federated enterprises? What on and off-network (including PSTN and public internet) encryption and other data security methods are employed to maintain confidentiality of voice/video/data traffic to external federated and non-federated entities (including the general public)?
- How do IP communications devices learn about their voice VLAN, including IP addresses, default gateways, call controller, TFTP server, QoS settings, VLANs, and other parameters? Does the proposed system solution employ proprietary protocols for IP communications devices to learn their voice VLAN or is an industry standard, such as Dynamic Host Control Protocol (DHCP) used?

2.4 Telephones, Softphones and Features

Priority = 3 – one score for this section
Describe the various telephone handsets, softphones and associated station features that are being proposed.
You should focus on:

- The variety of telephone set sizes and configurations, including the number of actual buttons available per set, and the mix of line and feature buttons for each instrument style.

- The type of alphanumeric displays available with the proposed telephone sets, display resolution, and availability of color displays.
- The proposed configuration of IP handsets or multibutton telephone sets and whether soft or hard labeling of user templates is used or required.
- Proposed IP handset speakerphone capability and suitability for office and small/large conference room use.
- Softphone voice quality, ease of deployment and simplicity of user interface.
- Softphone compatibility with various cameras, headsets, speakers, etc. as proposed and as available in the secondary market.
- Power requirements of IP phones and support for Power Over Ethernet (PoE), including compatibility with router injected power, multi-line wiring closet power injectors, and individual desktop power injectors.
- Mix of softphone only, hard phone only, and hybrid stations in the proposed solution, by user type, end department, site/location, and applications supported (or other suitable equivalent matrix).

2.5 Network Assessment and QoS Requirements

Priority = 3
Voice over IP (VoIP) traffic is sensitive to a number of data transmission parameters. In this section, the vendor should specify the unique transmission parameters that the proposed system will require, including:

- Latency requirements
- Jitter requirements
- Packet-loss requirements
- Tandem node and overall link requirement differences
- Timing synchronization to master clock source requirements
- Minimum bandwidth requirements for voice/video/data transport based on endpoint and node specifications
- Backup/failover/survivability mode PSTN requirements
- Requirements for use of public/private internet as failover media

Additionally, the vendor should describe if specific QoS or class-of-service parameters will be required in the enterprise communications network to achieve the specified transmission characteristics. How many class-of-service tiers are required by the proposed solution to meet specified voice/video/data needs? What are the transport expectations for traffic using the non-voice tier(s)?

The included network traffic management system used to validate these performance metrics should collect and store data to track usage and call data of IP gateway devices, IP phones, and VoIP intercom/trunk calls. VoIP information reports should include: tracking of IP gateway devices and calls that pass through each gateway; gateway congestion; assignment of services or routes to gateways; tracking of phone numbers dialed or originating off-site numbers; and IP gateway addresses.

The vendor should confirm that the proposed management system will track and record the following VoIP call, gateway, and common control/network parameters, based on user defined data retention policies and in conformance with established data security and confidentiality policies.

Individual call parameters

- CODEC type
- Frame size
- Packets per frame
- Call type
- State of echo canceller
- State of silence suppression
- Total packets sent
- Total packets received
- Total packets late
- Total packets early
- Current jitter buffer level
- Maximum jitter buffer level
- Minimum jitter buffer level
- Packets discarded
- Silence frames inserted
- Effective packet loss
- Service state of each port

Gateway parameters

- CODEC type
- Frame size
- Number of active calls
- Total Calls
- Total Successful calls
- Total Connected calls
- Total RNA calls
- Total user Busy calls.
- Top ten termination reasons
- Average call hold time
- Maximum call hold time
- Average BHCA
- Maximum BHCA
- Top 10 busy minutes
- Number of Call signaling messages of type (x) received
- Number of Call signaling messages of type (x) sent
- Average response time for call signaling message type (x)
- Current active calls, including ANI, DNIS, call start time, call type, current connect time, etc

VoIP transmission parameters

- Timestamp Information - start and stop time for the metric measurement interval
- Stream Identification Information - differentiating between multiple streams in which a given endpoint may be involved at a point in time
- Source - IP address, RTP port, and SSRC for monitored transmission stream
- Destination - destination IP address, RTP port, and SSRC for monitored transmission stream
- Codec Information Line – info for vocoder used for session
- Sample Rate - rate, in kiloHertz (kHz), at which the source audio is sampled

• Frame Size - RTP packet size (bytes of the RTP frame)
• Packet Loss Concealment - indicator of whether packet loss concealment is used

VoIP jitter buffer parameters

• Jitter Buffer Information Line – info re jitter buffer within the media endpoint.
• Jitter Buffer Type – indication if jitter buffer is adaptive or static.
• Jitter Buffer Adaptation Rate - specific adjustment rate of a jitter buffer in adaptive mode.
• Jitter Buffer Nominal Delay - current nominal jitter buffer delay in milliseconds, which corresponds to the nominal jitter buffer delay for packets that arrive exactly on time.
• Jitter Buffer Maximum Delay - current maximum jitter buffer delay in milliseconds corresponding to the earliest arriving packet that would not be discarded
• Jitter Buffer Absolute Maximum Delay - absolute maximum delay in milliseconds that the adaptive jitter buffer can reach under worst case conditions

VoIP packet parameters

• Packet Loss Information Line - general packet loss metrics
• Packet Loss Ratio - percentage of packets lost within the network during the time period captured by the report
• Packet Discard Rate - percentage of packets discarded due to jitter within the network during the time period captured by the report
• Burst Loss Information Line - parameters in this provide burst loss metrics
• Burst Density - percentage of packets lost and discarded within a burst (high loss rate) period.
• Burst Length (mS) - mean length of a burst.
• Gap Loss Information Line - parameters in this provide random loss metrics

3.0 Voice Mail with Unified Messaging Requirements
Priority = 3
Basic requirements are:

- Out-of-office reply options – integrated across all media types (e-mail, voice-mail, presence status, etc.)
- Auto attendant – integrated directory and flexible name dialing with speech and DTMF support
- Message waiting indication – multiple sites/multiple devices/multiple mailboxes with distinctive user programmable notification for each.
- Multilingual capabilities – also refer to Business applications section 2,2,1 – Unified Messaging
- Integration capabilities with enterprise-based or hosted e-mail applications, such as Microsoft Office Outlook
- Web-based messaging features – also refer to Business applications, section 2.2.1 – Unified Messaging
- Message broadcast capabilities – also refer to Business application, 2.2.1 – Outbound communications
- Mobility options for devices and message send/listen and notification
- Message classification options that protect confidentiality and limit distribution
- Scalability of proposed solution
- Personal user interface tools and capabilities – also refer to Business applications 2.2.1
- Business continuity options – Also refer to Business & Contact Center applications 2.2.1
- Message storage and archiving capabilities / business policy retention and discovery support

- Infrastructure design and upgrade requirements
- Features that support hardware/software compliance with existing IT infrastructure and systems
- System maintenance and support features, including reporting, trending, comprehensive diagnostics, pro-active failure detection and mitigation, etc.

The following outline various required features. Vendors should provide a narrative response to each item, and should indicate which features are standard and which are extra-cost options. Providing a system manual is not an acceptable response to this section. Vendors must also cite any system feature limitations relating to software or interaction with other features.

Voicemail System Core and User Features:

- Automated attendant capabilities
- Caller options
- Support for multilingual capabilities and multiple time zones
- Broadcast message options
- ~~Login announcement options~~
- User messages storage and delete options
- User greetings options
- Message creation and addressing capabilities
- Dial-by-name feature
- Mailing list options for users and system administrators
- Choices for message delivery markings
- User message notification options
- Message retrieval options
- Fax messaging capabilities
- User mailbox security options
- System security capabilities
- Mailbox system administration capabilities
- System diagnostics and alarms capabilities
- System management reports capabilities
- Integration between the IP PBX, voice messaging system and e-mail application
- Methods of user message waiting notification
- Proposed and future mailbox capacity
- SMS integration
- Ability to call voicemail system remotely and control voicemail system through voice-based mechanisms.
- Ability to have other media read back to the user including voicemail, emails, calendar appointments with the system able to modify voicemail, appointments or emails based on voice commands
- Visual voicemail integrated in outlook with translated voicemail in preview window for voicemail triage functionality.

- Should also include visual voicemail adapted for mobile clients
- Ability to modify voicemail system easily and provided customizable voicemail menus depending on caller(ie, friend vs. employee vs outside customer would all receive different options with voicemail)

Announcement and Music Services:
Priority = 3
How many different announcements can be provided by the core system?

- How many announcements can be played concurrently?
- Are digitally recorded announcements supported? What is the mechanism to add/change/delete announcements? What are the announcement message length limitations?
- How many different music sources can be supported? How are these interfaced to the core and remote systems?
- How many simultaneous music channels are available to callers on individual hold or in queue? What happens when this number is exceeded?
- Can multiple announcements and music treatment be provided to a call, and can announcements and music treatment be specific for each call path (menu, ACD, IVR, etc.)?
- Can announcements and music treatment provided depend upon queue conditions or call related information, and how many different announcements can be provided for this situation?
- How do you handle feedback (music/announcements) for calls that are queued remotely?
- How do you manage music and announcements provided to remote sites in order to decrease the number of packets sent over the IP trunk?

4.0 E-Mail Messaging Requirements
Priority = 3
Please describe how your proposed solution supports the following attributes:

- Scheduling features and tools
- Calendaring capabilities
- Speech access options for users and callers
- Recommendations for backing up and restoring
- Message search features
- Out-of-office reply options
- Web-based messaging features
- Single in-box capabilities for e-mail, fax and voice mail messages
- Integration capabilities with desktop UC clients, such as Microsoft OCS
- Mobility options for devices, message send/read, search, document retrieval
- Message classification options that can protect confidentiality and limit distribution
- Scalability of proposed solution
- System and personal management tools and capabilities
- Message storage and archiving capabilities
- Infrastructure design and upgrade requirements
- Features that support compliance requirements

- System maintenance and support
- Anti-spam/antivirus features

5.0 Presence and IM Requirements
Priority = 2
Describe how your solution supports these capabilities:

- IM must have compliance support
- Should support persistent chat rooms for topic/group based communications
- Ability to maintain persistent records from chat sessions for compliance or business related process documentation
- Ability to integrate with other collaboration tools (SharePoint, etc.)
- Support federation and external IM support for other IM systems (Windows Live/AOL/Yahoo/Google Chat/etc.)
- In addition, refer to Section 2.2.1 for Business applications/requirements related to section 5.0

5.1 Enterprise Presence
Priority = 3
Describe how your solution supports these capabilities:

- For authorized users to visually observe the status of another person on the network — mandatory requirement.
- To adjust the user name or nickname displayed with the presence indication.
- For presence status to be rich in capabilities including at least these three features:
    - Number of modes of status sufficient to support optimal work habits, such as online, offline, do not disturb, on a call/conference, busy, limited availability
    - Manual adjustment of presence status
    - Automatic adjustment of presence status based on calendar information, communication mode, device type, network connectivity status, location, type of activity, identity of other parties in communication, etc.
- For presence to be viewed in lists or groups based on user, administrator or software assignments of groups.
- For presence to be determined across groups of people, based on the highest level of availability for one or more members of that group.
- For initiation of any mode of communication from the presence indication, including IM, e-mail, calling, conferencing, collaboration, etc.
- To change from one mode to another, as appropriate, during a session.
- To limit the communication modes based on the presence status of the selected user (e.g., call user is not presented, or active, if the user is in "do not disturb" mode).
- For group chat functionality — Users must have the ability to initiate a group chat at any time and to populate the invited members from a predefined or automated group list (from e-mail) or

buddy list (from IM). In addition, specify the cost standards required to securely federate IM with other specific enterprises or systems.

- In addition, refer to Section 2.2.1 for Business and Contact Center applications/requirements and **"describe"** how your solution enables those specific business processes, as they relate to this section 5.1.

5.2 Peer-to-Peer IP Communications

Priority = 3
Please specify how your solution supports the following capabilities:

Initiate a communication by selecting a user from a variety of sources, including:

- User's presence indication in buddy list, in e-mail address, in e-mail group list, etc.
- An enterprise directory or a personal contact list

Communicate with a selected party via a range of methods and media, including:

- Instant messages (or chat)
- VoIP call between appropriately equipped endpoints
- Desktop sharing (or Web sharing) between endpoints
- Video conversation (video and voice) between appropriately equipped endpoints
- Combinations of the above communication methods and media, as appropriate
- Amount of bandwidth required to various modes of video communication

6.0 Audio, Video and Web-Based Conferencing

Priority = 3
Describe how your solution supports the following capabilities to:

Provide conferencing (i.e., simultaneous shared communication) between two to 100 parties with any combination of the following four functional types:

- Voice communications
- Video communications
- Web collaboration via presentation of documents
- Web collaboration via editing of documents
- Initiate a conference via a meeting invitation or via ad hoc formation of a conference by calling a person or by adding people to an existing call.
- Invite users to a conference through an invitation that is consistent with an e-mail-based calendar, including accepting, rejecting or proposing alternate times for a meeting.
- Integrate existing conferencing products with the new conferencing function.
- Log conferencing activity for billing and usage analysis.
- Enable the use of capabilities such as IM, desktop sharing, voice and video calls to expand a session in real time (e.g., from call to conference) and/or to add or remove communication modes (e.g., desktop sharing, video).
- Enable linking to collaboration tools such as Microsoft Office SharePoint. Integration with calendar, tasks and documents to allow prompt, appropriate action on pending project steps.

- In addition, refer to Section 2.2.1 for Business applications/requirements/processes related to section 6.0

6.1 Mobile Communications

Priority = 2

Describe how the proposed solution provides mobile users with tools that enable them to access UC functions, as well as relevant information from enterprise business applications for specific processes and jobs.

- Solution should support mobile clients that we use within our corporate network – Blackberry/iPhone/Android as well as Windows Phone 7 support.
- Solution must support VOIP/IM/Presence on our Mobile clients
- Solution must extend full desktop functionality to Mobile clients, including hold, transfer, conference, join, uniform dialing plan, etc.
- Solution must provide seamless continuity of calls between Mobile client, softphone, and physical deskset (and back) with a minimum of call taker intervention.
- Solution dependencies on specific mobile carriers, specific mobile devices, and any public/private trunking assumptions (SIP, MPLS, etc.) to effect this functionality must be clearly articulated by the vendor.
- In addition, refer to Section 2.2.1 for Business and Contact Center applications/requirements/processes related to section 6.1

7.0 Desktop Clients

Priority = 3

Please describe the desktop communicator clients, softphones and dashboards proposed that provide a single desktop interface to many or all communication functions. Include communication modes and devices, collaboration and business applications, integrated presence, use of SIP compliant trunks and devices, and Lightweight Directory Access Protocol (LDAP), as well as compliance, security, mobility, extensibility and open interfaces for programmatic control.

8.0 Communications-Enabled Business Processes (CEBPs)

Priority = 3

Business applications are separate from communication applications. It is possible, however, to invoke communication functions directly from a business application, which can facilitate how business processes are handled and completed.

Please describe:

- The APIs, service interfaces, development tools and prepackaged functionality that your products offer to facilitate the integration of business applications with your communications tools and applications.

- How CEBP can be initiated by a person or an application that raises alerts and notifications, sets up conference calls or leverages presence.

- In addition, refer to Section 6.1 for recommended voice UC integration requirements.

9.0 System Redundancy, Reliability and Survivability

Priority = 3

Please define the reliability, redundancy or duplication and survivability options your products offer to support the ability to configure systems to 99.999% of uptime in all solution components (call processing, presence, voicemail, recordings and announcements, IVR, etc.) for the following options:

- Redundancy within a site
- Redundancy and hot failover at an alternate site
- Support of multiple redundant sites in a "mesh" configuration
- Redundancy and warm (manual intervention) or cold (date restoration and system configuration) failover at an alternate site
- Automatic data and content backup and restoration at a local or remote site
- In addition, refer to Section 2.2.1 for Business and Contact Center applications. Specifically, "Performance Specifications" listed for Voice, Call Processing, Contact Center(s) related to section 9.0

Also describe:

- The connectivity, and how access to the solution is accomplished in the event of partial or full system failure of the solution
- How the redundancy, reliability and survivability are affected with system growth
- Survivability options in the event of common control failure or LAN/WAN connectivity problems due to switch, router, or private network transmission service errors or failures.
- Seamless switchover (and back) operation to the local common control while all active calls (intercom and trunk) and programmed feature states, e.g. call forwarding, are preserved.
- Capability for support of forced switchover (and back) from survivability mode.
- Overall time it takes (in seconds) to perform the switchover if not instantaneous and if the customer can optionally program the switchover time (in seconds) to accommodate infrequent short disruptions in LAN/WAN transmission signaling.
- Capability (if any) to warn station users via telephone/PC soft phone display of a delay in dial tone and call implementation occurring during the switchover process.

10.0 Standards
Priority = 2

- Specify the various standards supported by your solution and explain whether or not your solution provides industry-standard APIs.
- NW Natural is a Microsoft Windows shop. Describe how your solution will fit in to a company that has Windows on the desktop and as a server platform.

11.0 System Networking

Priority = 3

Please describe:

- How the proposed presence and IM capabilities will interface with the proposed voice solution.
- Differences in the networking integration between local and remote users.
- How the solution is centralized or decentralized.
- Any messaging feature/functionality that does not carry through the network.
- Options for networking this solution with other systems.
- The reroute/backup plan incorporated into your design in the event of a network failure.
- Any limitations on the number of networked users.
- How remote and main-site messaging users can be part of the same "logical network" as related to applications.
- How system supports overflow of voice traffic across locations if WAN links are not available, busy, call admission control thresholds are exceeded or other call quality measures exceed their thresholds, respectively.
- How public internet and PSTN services are used for network voice traffic overflow.
- What conditions trigger a return to WAN voice transport services in the event of call overflow to the public internet or PSTN.

12.0 System Security

Priority = 3

The proposed system must provide for secure, encrypted communications between endpoints for peer-to-peer communications, and between endpoints and servers for all other communications. Both signaling channels and media streams must be secured. The response must address the methods used for securing this communications function.
Users of the system from outside the enterprise premises (i.e., outside the enterprise firewalls) must have the ability to maintain the security of the communications signaling and media streams. Securing the communications should not require additional hardware or software elements (such as virtual private networks [VPNs]) to create and maintain the secure communications channels.

Please describe the:

- System security measures in place with your solutions
- Access entry security for system administrators
- Access entry security for users
- Security associated with accessing databases and other files
- System diagnostics and alarms
- Tools available for security monitoring
- Method of logging and notification of security violations

Security factors covered must include:

- Use of a dedicated virtual LAN (VLAN) segment for voice
- No split tunneling for voice over the VPN
- Effective encryption over VPN
- Firewall protection at the application layer
- Protection from unauthorized access
- User authentication
- Protection from unauthorized use
- Protection from unauthorized invasion of privacy during calls
- Protection from voice spam
- Protection from denial-of-service attacks

Administration security factors covered must include:

- Non-secure management interfaces such as telnet must be disabled by default
- A patch management process and administration system must be available
- A secure alternative to TFTP must be provided
- Authentication should be provided for SIP connections
- Firmware loads for phones should be signed to insure authenticity
- Remote administration and OS access must be disabled by default
- All physical hardware administration ports must be locked or disabled by default

13.0 System Management

Priority = 2

Vendors are required to describe the system management capabilities of the proposed solution, including:

- User interface
- System monitoring
- User and system provisioning, including dial plans, group assignments, user and feature restrictions, etc.
- Routing and route selection, forced announcements, and forced busy and node up/down management
- Standard and custom report generation with external database storage and/or access
- Remote accessibility over LAN, WAN or Web browser
- Support for multiple simultaneous administration sessions with appropriate record locking
- Full telco standard CDR recording and associated traffic, trunking, and forecasting reports available on and ad-hoc and pre-programmed basis
- Full trace capability for calls based on dialed number, trunk, IP address, time of day, duration, repeat/harassing/user marked calls, etc.
- Full "live" line monitoring capability for all sets, trunks, and interfaces
- Storage usage profiling and active alerts when thresholds are exceeded
- Real time moves/adds/changes (in ALL systems) supported by administration terminal or station user without requiring pre-determined maintenance intervals

- Batch moves/adds/changes supported for scheduled deployment of services or features
- Full logging and audit trail of all changes by administration terminal or station users
- "Linked" administration between subsystems to facilitate "single step" provisioning of users across platforms
- Support of multiple templates for standard user and system profiles
- Active alerts of "must configure" fields (such as E911 location) when stations or nodes relocate
- Seamless administration of multiple sites using a single administration interface
- Segregation of survivability mode administration to prevent accidental mis-configuration or triggering of mode switch
- Full complement of major/minor/warning/etc. alarms for all systems visible on a common dashboard, including processor, storage, and call processing resource limits for each node, in addition to trunking, transmission, IP, MOS and operational performance alarms
- Ability to initiate loopback, IP traffic, and other common transport tests (with live traffic automatically redirected to an alternate path) and monitor/track/log the results realtime
- Full trunk, network, and station utilization reports system wide including realtime display on-demand and the ability to "zoom" into an "area" of interest and view detailed data
- Full station feature utilization reports, including features used by set, type of set, softphones, mobile devices, etc.
- Directory record support to include published and displayed names, numbers, locations, etc.
- Inventory record support to include common equipment, voice terminals, module options, jacks, cross-connects, service locations, serial numbers, asset tags, etc.

14.0 Vendor Design Summary

Priority = 3

Vendors must provide one or more illustrations showing all physical distribution of the software modules on servers, routers, appliances, etc., by location and geography, as appropriate.

14.1 Solution Architecture

Priority = 3

Vendors must provide detailed answers to these questions:

- Can your solution for presence and IM be architecturally independent from the proposed voice solution? Could it work without the support of the rest of the proposed solution?
- How does the proposed solution work and interface with IP- and time-division-multiplexing (TDM)-based systems?
- Additional questions in Section 23 Appendix C

14.2 Network Diagrams

Priority = 3

Vendors should provide one or more (as needed) illustrations showing the network topology and connectivity of the solution for:

- Specific network elements included in the proposal
- Interoperation with existing or prerequisite network elements
- Interoperation with external networks (PSTN, Internet, cellular, wireless LAN [WLAN]/WAN, etc.)

15.0 Physical Requirements

Priority = 2

Vendors should specify:

- Floor space to support the proposed solution
- Floor-loading requirements
- Raised-floor requirements
- Minimum ceiling height

16.0 Environmental Requirements

Priority = 2

Vendors should specify:

- System power circuit breaker panel location
- Lighting requirements
- Long- and short-term environmental ranges that the system can tolerate, including the:
    - Desirable temperature range
    - Desirable humidity range
    - Heat dissipation of the system at maximum configuration in British thermal units (BTUs) per hour

17.0 Power Requirements

Priority = 2

Vendors should specify:

- Voltage and phase parameters of the main components, such as server and gateways
- Circuit breaker panel requirements relative to the number of circuits and amperage ratings
- Recommendations for reserve power requirements in "stand-by hours" and battery capacity (ampere-hours), if an uninterruptible power supply (UPS) is proposed
- PoE requirements for handsets
- Centralized and local power and cooling requirements

18.0 Warranty, Maintenance and Training

After the warranty period, the successful vendor will be required to service, maintain and provide training support for the entire working life of the proposed system.

18.1 Warranty

Specify the warranty periods for all solution hardware, as well as the software associated with running the proposed systems and applications.

18.2 Maintenance

Priority = 2
Please quote maintenance on a contractual basis — indicating the annual fixed maintenance rate after warranty expiration, including the rate for the next three years. The quotes for system maintenance options should include annual hardware and software support, software upgrades and remote monitoring.
Vendor must be able to support an emergency response time of no more than two hours, 24/7. NW Natural will want to be able to choose different service levels for different locations. For instance, branch locations and headquarters may need different service levels.

In addition:

- Define the number of factory-trained service technicians available through the local service depot, and identify the centers from which technicians will be dispatched after hours, on holidays and during weekends.
- Provide a copy of the standard maintenance contract and details of optional extras.
- Describe committed response times and mean time to repair (MTTR) by type of service disruption.
- Provide a copy of normal maintenance escalation procedures, and include communications with affected parties — with names and contact details of all parties affected.
- Provide an emergency contact number if normal channels of fault-reporting communications fail. Describe how that emergency contact number will be answered and by whom:
- Provide any times or restrictions by day, week or month on this service.
- What information will those answering a call have available?
- Will they have specific information on the system being proposed for the organization?
- Describe the procedures for software updates and upgrades; detail what, if any, costs would be associated with upgrades.
- Define major and minor alarm conditions, and how the system responds to each circumstance.
- Describe the capabilities for remotely monitoring the system.
- Describe the capabilities for automatically reporting fault conditions, both to organizational and supplier personnel.
- Describe supporting tools, such as expert systems, used to assist in problem diagnosis and service restoration.
- Indicate where the local and regional parts depots are located.
- Provide a roster of all spare parts, including pricing that will need to be maintained in on-site inventory.

18.3 Training

The successful vendor will be required to provide on-site training to Contact Center management communities, General Contact Center users,, General Knowledge users and system management communities. If training costs are not included as part of the system pricing response, then the vendor must provide those costs along with a detailed training schedule and methodology. The schedule should denote class sizes, length of a typical training session (i.e. a detailed timeline) and how one-on-one executive training and "Train-the-Trainer(s)" training will be organized. Pricing for alternate modes of training delivery is also required.

19.0 Emergency Response

Priority = 2

The vendor must provide a detailed in-place plan to restore service if the system is rendered totally inoperative as a result of a major malfunction or catastrophe. The vendor must specify the maximum time to provide limited service. In the event of a major system failure, a replacement system must be made available. The vendor must state where the replacement system is located and the time required to restore full service.

Further, the vendor must install telephones within the organization to be connected directly to the PSTN so that emergency communications will be possible in the event of a total system failure.

20.0 Implementation

Priority = 2

Describe how you will manage the implementation project, stating who will provide the necessary resources, and who will pay for them.

Vendors must provide an implementation plan that includes:

- Project stages and milestones
- Resources required
- Responsibilities of each of the parties
- Sources and skills required of the project manager(s)
  - A Contact Center(s) implementation plan and methodology for third party project management (partner integration as it relates to a complete contact center solution).
  - A separate Project Manager for Networking
- Sources and skills required of other resources, and who will pay for them
- Integration with other telephony systems
- Integration with applications
- Communications processes for reporting the project's progress
- Recommendations for briefing the project manager, and possibly the organization working party or steering committee members
- Training schedule by type of audience
- Fallback plans

21.0 System Pricing and Licensing

Vendors should describe the system and user application licensing model for the proposed solution, and provide a table or document in editable electronic format with all pricing information showing line-item detail for any item that has a separate price, even if the item is sold as part of a bundle.

Column headings should reflect:

- Item description
- List price
- Discount amount
- Net unit price
- Quantity
- Total net price

Vendors should provide pricing for the following components:

- Voice, messaging, IM and presence, conferencing, CEBP
- Contact Center (based on Business Applications and Requirements in section 2.2.1)
- Standard features
- Optional features
- Data network upgrades, including PoE
- Field system design
- Installation and cabling
- Database development
- Software
- Documentation
- Training
- Delivery costs
- Project management costs
- Applicable taxes

21.1 Incremental Costs
Priority = 2
Provide itemized cost schedules for the following scenarios:

- Adding 25 IP telephones and two IP trunks to the base configuration. This information must include which major hardware and software components would be reused, as well as those that would not be reused.
- Adding twice the number of telephones (50) and twice the number of IP trunks (four).
- Adding a small external office of 75 people. Provide quotes for the site using their own telephony servers, as well as supported by a server in another enterprise location such as OPS.
- Adding 25 unified messaging users to the specified voice mail system. This information must include which major hardware and software components would be reused, as well as those that would not be reused.
- Adding twice the number of unified messaging users (50).

Provide pre- and post-cutover unit prices and the associated labor costs on principal system components, such as line, trunk cards and station equipment.

As the buyer, we require confirmation that all prices for additional equipment and software remain firm for a period of one year after system acceptance.

21.2 Finance

If leasing arrangements are available, then vendor shall provide a sample lease, or lease and purchase agreement, with the terms and conditions.

When there are currency exchange rate considerations in the prices quoted, the vendor must define them and spell out policies to allow for fluctuations in exchange rates.

22.0 Vendor Qualifications

22.1 Company History

Make sure and read to score Pass/NoPass

The vendor must provide:

- A brief description of its company.
- Description of its experience in providing communications systems.
- Evidence of financial stability with an annual report, Form 10-K, or audited financial statement.
- Name of the manufacturer of the proposed system.
- Name/location of a technical support center that provides remote maintenance.
- List of other types of customer support available from the technical support center.
- Options for emergency service.
- At least three reference customers with systems similar to the one proposed. Reference information must include company name and location, contact person, telephone number, and the system name with model number.
- The quantity and location of qualified personnel available to support the proposed solution.

22.2 Responsibility for Proposed System Implementation

The vendor must include a statement describing the terms of the agreement with the manufacturer(s) of the proposed solutions. The statement must define the distributor's authorized territory, note the current contract expiration date, and include a statement from the manufacturer agreeing to support the product, the distributor and the purchaser for a minimum of seven years.

If the bid is from more than one party, such as a combined proposal from a manufacturer and a distributor or system integrator, then the accountabilities of each party must be spelled out clearly. The prime contractor and the account management structure proposed must be acceptable to the customer.

22.3 Vendor Support and Structure

If the proposed system will function within a multisite, networked environment, then the vendor must explain its capability to provide regional and national support for multiple locations.

Please describe the structure of your organization, with organizational charts showing the executive, engineering, sales and field support (installation, service and training) entities within your company. Also state how many people you employ in each of the following job categories:

- Project management
- Engineering support
- Customer service
- Interface to telephone service provider
- Switch installation
- Data networking
- Station and cable installation
- Training

In addition:

- Provide a copy of your latest annual report, or at least a financial status statement including annual revenue, profit, net worth and other data.
- Have a technical support center that provides remote maintenance.
- Explain what other types of customer support are available from the technical support center.
- Describe your standards and processes for providing emergency service.

Finally, provide references from at least three customers with comparable systems in terms of size, geography and features. Customer references should be germane to our vertical market as a Utility. References should include the company name, contact name, telephone number and the system names or model numbers installed and used.

23.0 Infrastructure Specifications
Priority = 3

- Can your application be virtualized? If so, what platforms are supported?
- What operating system does each component of your solution require?
- What is the directory service integration? With Active Directory, LDAP, other?
- What tier of SAN storage is recommended for your application (RAID10, RAID5, etc)?
- How much storage is needed? Is there a formula per user?
- How is your software licensed? Based on the number of phones, by the size of the server, number of concurrent users, maximum possible users?
- Will applying security updates to a server hosting your application cause issues with the application?
- How are application updates applied? In one single executable for each major release, or a list of instructions with a group of files to be installed at various locations on the server?
- What is the DBMS that is used for the solution?

Pages 320 to 408 are confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

CASE: UG 221
WITNESS: Ken Zimmerman

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1003

Exhibits in Support Of Opening Testimony

REDACTED
May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 156:
Please provide full details on where and how each of the following "Large Projects" were considered and examined in the current pending IRP (LC 51) and the most recently acknowledged IRP.

2012
System Reinforcement, SIP, Gas Supply
1. Windsor Island (SIP)
2. Westside Transmission Re-Rate
3. Corvallis Reinforcement
4. Felida Gate Piping (Washinton Only)
5. Perrydale to Monmouth
6. Monmouth Reinforcement
7. Portland System Optimization - 2012

Information Technology
8. Nertec Replacement
9. Unified Communication Phase 1 (PBX Switch)

Facilities
10. Vancouver relocate (Washington)
11. Tualatin bio-swale (tentative project)
12. Tualatin replacement, training facility & land
13. Sunset sheds
14. Generators (4)
15. Parkrose Retrofit
16. Salem Retrofit

2013
System Reinforcement, SIP, Gas Supply
1. Portland System Optimization - 2013

Resource Management
2. CNG vehicles, 7 crew trucks & 18 service window vehicles

Information Technology
3. Unified Communication Phase 2 (PBX Switch)

Facilities
4. Coos Bay Retrofit
5. Astoria Retrofit
6. Generators (5)

Response: 1/23/12

The Integrated Resource Plan (IRP) is a high-level, long term plan. The purpose of the IRP as defined in Commission Order 89-507 is to "assure an adequate supply of energy to the utility and its customers consistent with the long-run customer interest." Two of the projects listed below (#5, #6 in year 2012) are related to the Mid-Willamette Valley, a supply-side resource option modeled in the Company's 2011 Modified IRP filed in LC 51, and the Company's 2008 IRP filed in LC 45 and acknowledged by the Commission in Order 09-005, issued on January 1, 2009. All of the other projects on the list are outside the scope of the IRP as they are system reinforcement or System Integrity Program (SIP) projects that will be undertaken to maintain the distribution system or to comply with pipeline safety regulations. They are not within the scope of the IRP because they do not relate to our acquisition of resources to meet load in a least cost manner.

Project	2008 Oregon IRP	2011 Modified IRP (LC51)
2012		
System Reinforcement, SIP, Gas Supply		
1. Windsor Island (SIP)	Outside the scope of the IRP.	
2. Westside Transmission Re-Rate	Outside the scope of the IRP.	
3. Corvallis Reinforcement	Outside the scope of the IRP.	
4. Felida Gate Piping (Washington Only)	Outside the scope of the IRP.	
5. Perrydale to Monmouth	This project is related to the Mid-Willamette Valley Feeder. In the 2008 Oregon IRP, the most recently acknowledged IRP, the Willamette Valley Feeder (which includes the Mid-Willamette Valley Feeder) is considered as a supply side resource. The table on page 3A-3 lists the segments of the Willamette Valley Feeder. The Mid-Willamette Valley portion of the Willamette Valley Feeder is defined in the 2008 Oregon IRP as the following three sections: Perrydale-Independence, Independence-N. Albany and N. Albany to S. Albany. These sections of the Mid-Willamette Valley Feeder are modeled with maximum daily capacity of 82 MDT, 50 MDT, and 38 MDT, respectively; capital costs of $14.4 million, $13.7 million and $8.8 million, respectively; and with earliest date available as November 2011.	This project is related to the Mid-Willamette Valley Feeder. The filed IRP (LC51) considers the Mid-Willamette Valley Feeder as a supply side resource option. Supply side resources are described in Chapter 3, with the Willamette Valley Feeder described on pages 3.18 and 3.19. Appendix 3 lists the modeled supply side resources with size, cost and earliest date available. The Mid-Willamette Valley Feeder is modeled in the Modified 2011 IRP with maximum daily capacity of 41 MDT, capital cost of $40 million and earliest date available of November 2012.

Comment [K2]: $975,610/MDT. If we go back to the cost estimate in the 2008 IRP, the resulting costs are nearly identical. Or $0.976/DTH, plus return at 10% and 5% depreciation (CRF) is $1.12/DTH

Comment [K1]: $36.9 million and 38 MDT (most that can move through the three together) or $971,053/MDT. Or $0.971/DTH, plus return at 10% and 5% depreciation (CRF) is $1.12/DTH

6. Monmouth Reinforcement	This project is related to the Mid-Willamette Valley Feeder. In the 2008 Oregon IRP, the most recently acknowledged IRP, the Willamette Valley Feeder (which includes the Mid-Willamette Valley Feeder) is considered as a supply side resource. The table on page 3A-3 lists the segments of the Willamette Valley Feeder. The Mid-Willamette Valley portion of the Willamette Valley Feeder is defined in the 2008 Oregon IRP as the following three sections: Perrydale-Independence, Independence-N. Albany and N. Albany to S. Albany. These sections of the Mid-Willamette Valley Feeder are modeled with maximum daily capacity of 82 MDT, 50 MDT, and 38 MDT, respectively; capital costs of $14.4 million, $13.7 million and $8.8 million, respectively; and with earliest date available as November 2011.	This project is related to the Mid-Willamette Valley Feeder. The filed IRP (LC51) considers the Mid-Willamette Valley Feeder as a supply side resource option. Supply side resources are described in Chapter 3, with the Willamette Valley Feeder described on pages 3.18 and 3.19. Appendix 3 lists the modeled supply side resources with size, cost and earliest date available. The Mid-Willamette Valley Feeder is modeled in the Modified 2011 IRP with maximum daily capacity of 41 MDT, capital cost of $40 million and earliest date available of November 2012.
7. Portland System Optimization - 2012	Outside the scope of the IRP.	
Information Technology		
8. Nertec Replacement	Outside the scope of the IRP.	
9. Unified Communication Phase 1 (PBX Switch)	Outside the scope of the IRP.	
Facilities		
10. Vancouver relocate (Washington)	Outside the scope of the IRP.	
11. Tualatin bio-swale (tentative project)	Outside the scope of the IRP.	
12. Tualatin replacement, training facility & land	Outside the scope of the IRP.	
13. Sunset sheds	Outside the scope of the IRP.	
14. Generators (4)	Outside the scope of the IRP.	
15. Parkrose Retrofit	Outside the scope of the IRP.	
16. Salem Retrofit	Outside the scope of the IRP.	

2013	
System Reinforcement, SIP, Gas Supply	
1. Portland System Optimization - 2013	Outside the scope of the IRP.
Resource Management	
2. CNG vehicles, 7 crew trucks & 18 service window vehicles	Outside the scope of the IRP.
Information Technology	
4. Unified Communication Phase 2 (PBX Switch)	Outside the scope of the IRP.
Facilities	
5. Coos Bay Retrofit	Outside the scope of the IRP.
6. Astoria Retrofit	Outside the scope of the IRP.
7. Generators (5)	Outside the scope of the IRP.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 157:
For project numbers 3, 6, and 7 in 2012, please provide the date when work on each project was begun. (Refer to DR 156)

Response: 1/23/12

Project 3 - Corvallis Reinforcement (Corvallis Loop Project)

Formal analysis and planning began on this project in February 2010. Engineering design started in May 2010. Currently, the project is in the permitting / easement acquisition phase. It is estimated that construction will begin in March 2012.

Project 6 – Monmouth Reinforcement

This project is one of the four remaining phases of the Mid-Willamette Valley Feeder which extends from the Central Coast Feeder south to the Albany-Corvallis Feeder. The engineering design and construction of the already completed portion of this feeder was done in September 2005.

The engineering design of the remaining phases of the Mid-Willamette Valley Feeder began in April 2009. Currently, construction is scheduled to begin on the Monmouth Reinforcement Project in January 2012.

Project 7 – Portland System Optimization

Conceptual planning for this project began in January 2002. The Portland System Optimization is a series of sub projects in the Portland Metropolitan area that is a continuation of a larger plan to optimize takeaway capacity from Mist. Detailed engineering design for these sub projects began in August of 2011. Construction for some of the sub projects began in September 2011.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

SUPPLEMENT

Request No. GR1-OPUC-DR 165:
For each major project listed below, please provide:
a. Request for bids issued.
b. All bids received in response to the request for bids issued by NWN.
c. The bids sheets or tables where NWN compared and evaluated the bids received.
d. The winning bid for the work, including the reasons the bid was selected as winner.
e. The construction budget for the project developed by the winning bidder and approved by NWN.
f. The construction schedule for the project developed by the winning bidder and approved by NWN.
g. All changes to the initial construction budget, with explanations.
h. All changes to the initial construction schedule, with explanations.

2012
System Reinforcement, SIP, Gas Supply
1. Windsor Island (SIP)
2. Westside Transmission Re-Rate
3. Corvallis Reinforcement
4. Felida Gate Piping (Washington Only)
5. Perrydale to Monmouth
6. Monmouth Reinforcement
7. Portland System Optimization - 2012

Facilities
8. Vancouver relocate (Washington)
9. Tualatin bio-swale (tentative project)
10. Tualatin replacement, training facility & land
11. Sunset sheds
12. Generators (4)
13. Parkrose Retrofit
14. Salem Retrofit

2013
System Reinforcement, SIP, Gas Supply
1. Portland System Optimization - 2013

Facilities
2. Coos Bay Retrofit
3. Astoria Retrofit
4. Generators (5)

Response: Supplemented 4/16/2012

In the Company's initial response to this data request on February 8, 2012, the Company provided as Attachment 9 a memorandum regarding the proposal for initiation of the Perrydale to Monmouth project. The memorandum stated that the possible start date of the project was September 1, 2012 and that the project would take 10 months to complete. The start date listed in the project initiation memorandum, which was drafted by an engineering summer intern, was in error. When the project initiation memo was created, the final proposed schedule for the project was not yet know and was developed at a later date by the Capital Projects Project Manager utilizing inputs from all other projects planned for the year and resource availability.

The correct start date for construction of this project is May, 2012 and the expected completion date is October, 2012. These dates are shown in Attachment 13 to the Company's response to OPUC Data Request 165 and Attachments 1 and 2 to the Company's response to OPUC Data Request 158.

Also attached as OPUC DR 165 Attachment-1A is a request for proposals issued by the Company related to this project after it posted its original response to OPUC DR 165.

Pages 8 and 9 are confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 267:
See pages 4-7 of testimony by witness Yoshihara.
a. Explain how the Mid-Willamette Valley Feeder Project is included in the projects listed on the "Capital Projects Timeline" document provided by NWN.
b. Explain how the forecasted costs of the Mid-Willamette Valley Feeder Project are divided among the projects listed on the "Capital Projects Timeline" document.
c. For the Mid-Willamette Valley Feeder Project provide the following:
i. Request for bids issued.
ii. All bids received in response to the request for bids issued by NWN.
iii. The bids sheets or tables where NWN compared and evaluated the bids received.
iv. The winning bid for the work, including the reasons the bid was selected as winner.
v. The construction budget for the project developed by the winning bidder and approved by NWN.
vi. The construction schedule for the project developed by the winning bidder and approved by NWN.
vii. All changes to the initial construction budget, with explanations.
viii. All changes to the initial construction schedule, with explanations.
d. For the Mid-Willamette Valley Feeder Project, provide the basis for the "in service" date provided by NWN, including full documentation (invoices, construction schedules, etc.)
e. Please explain why the capital cost for the Corvallis Loop Project ($12.8 million) differs from the projected capital cost for this project in the "Capital Projects Timeline" document ($9.3 million).

Response: 2/9/2012

a) The Mid-Willamette Valley Feeder Project is broken down into four phases. The first two phases are scheduled for completion in 2012 and are listed as "Perrydale to Monmouth" and "Monmouth Reinforcement" on the "Capital Projects Timeline" document. The second two phases are scheduled for completion in 2013 and are not listed on the "Capital Projects Timeline". They are "South of Monmouth Bare Replacement" and "Willamette River Crossing near Corvallis". The phases being completed in 2013 are not included in the

"Capital Projects Timeline" due to the in-service dates being projected as October 2013.

b) The forecasted costs of the Mid-Willamette Valley Feeder Project is as follows:

Perrydale to Monmouth $13,500,000

Monmouth Reinforcement $8,100,000

South of Monmouth Bare Replacement $14,300,000

Willamette Crossing near Corvallis $11,000,000

Note: Some expenses have occurred in 2011 on the MWVF.

c) Please see the Company's response to OPUC DR 165.

d) Please see the Company's response to OPUC DR 158.

e) The estimated capital cost of the Corvallis Loop Project is $ 12.8 million. Approximately $3.5 million of expense occurred in 2011. The remaining $9.3 million is forecast to be spent in 2012 as stated in the "Capital Projects Timeline".

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 320:
Assume for these data requests that the System Integrity Program (SIP) tracker ends October 31, 2012.

Please identify each SIP project NWN would propose be placed into rate base as the SIP tracker ends.

Response: 2/21/2012

SIP activity from 2002 through 2011 is already in base rates, as last updated in the 2011-12 PGA. Therefore, only the incremental SIP activity expected to occur between November 1, 2011 and October 31, 2012 is considered in the Company's response to Data Requests 320 through 323.

Identification of planned SIP projects that are expected to be completed and costs placed into rate base at the end of the 2012 tracker year are consolidated with the Company's response to Data Request 321.

NW NATURAL
Rates & Regulatory Affairs
Oregon General Rate Case – December 2011
Data Request Response

Staff/1003
Zimmerman/13

Request No. GR1-OPUC-DR 158: 2/8/2012

For each of the projects in the above table provide the sources for the estimate of in-service date provided. What is the range of error for each in-service date? (Refer to DR 156)

Project	Updated In-Service Date	Source of the Estimate
2012		
System Reinforcement, SIP, Gas Supply		
1. Windsor Island (SIP)	10/31/2012	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
2. Westside Transmission Re-Rate (TIMP)	Under Review	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
3. Corvallis Reinforcement	10/31/2012	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
4. Felida Gate Piping (Washington Only)	NOT RELEVENT - THIS IS A WASHINGTON PROJECT	
5. Perrydale to Monmouth (to Independence)	10/31/2012	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
6. Monmouth Reinforcement (to Granger)	8/3/2012	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
7. Portland System Optimization (Phase 1) - 2012	9/30/2012	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
Information Technology		
8. Nertec Replacement	10/31/2012	See Project Charter at OPUC DR 158 Attachment - 3. See also documents provided in response to OPUC DR 168
9. Unified Communication Phase 1 (PBX Switch)	10/31/2012	See Project Charter at OPUC DR 158 Attachment - 4. See also documents provided in response to OPUC DR 168
Facilities		
10. Vancouver relocate (Washington)	NOT RELEVENT - THIS IS A WASHINGTON PROJECT	
11. Tualatin bio-swale (tentative project)	On hold	This is part of the Tualatin Retrofit project on-hold due to Sherwood property option that would eliminate this project.
12. Tualatin replacement, training facility & land	10/31/2012	See Project Charter at OPUC DR 158 Attachment-7
13. Sunset sheds	1/31/2012	This is work remaining from a retrofit project at the site. We are waiting for final permits from the city of Hillsboro.
14. Generators (4)	10/31/2012	Thse are routine maintenance/repair/replacements
15. Parkrose Retrofit	6/30/2012	See Project Charter at OPUC DR 158 Attachment - 5
16. Salem Retrofit	6/30/2012	See Project Charter at OPUC DR 158 Attachment - 6
2013		
System Reinforcement, SIP, Gas Supply		
1. Portland System Optimization (Phase 2)- 2013 (Restore 400 psi MAOP to 10" Westside Feeder between Jean Rd and West Linn and 10x12" Boones Ferry pipeline between Barbur and Slavin and Jean Rd Station)	10/31/2013	See 2012-2013 Project Schedule at OPUC DR 158 Attachment - 2
Resource Management		
2. CNG vehicles, 7 crew trucks & 18 service window vehicles	By 10/31/13	The CNG vehicles and 7 crew trucks are routine replacements/additions based on normal run rate. The in-service date is for the 18 service window vehicles and is based upon the Company's proposal in this general rate case. See NWN/900.
Information Technology		
3. Unified Communication Phase 2 (PBX Switch)	10/31/2013	See Project Charter at OPUC DR 158 Attachment - 4
Facilities		
4. Coos Bay Retrofit	9/30/2013	This project is still in the planning phase. The project is expected to start in spring 2013 and is currently estimated to take 4 months to complete.

Project	Updated In-Service Date	Source of the Estimate
2012		
5. Astoria Retrofit	6/30/2013	This project is still in the planning phase. The project is expected to start in spring 2013 and is currently estimated to take 2 months to complete.
6. Generators (5)	5/31/2013	These are routine maintenance/repair/replacements.

NW NATURAL
Rates & Regulatory Affairs
Oregon General Rate Case – December 2011
Data Request Response

Request No. GR1-OPUC-DR 165

For each major project listed below, provide (a) request for bids issued; (b) All bids received in response to the request for bids issued by NWN; (c) The bids sheets or tables wher eNWN compared and evaluated the bids received; (d) The winning bid for the work, including the reasons the bid was selected as winnter; (e) The construction budget for the project developed by the winning bidder and approved by NWN; (f) The construction schedule for the project developed by the winning bidder and approved by NWN; (g) All changes to the initial construction budget, with explanations; (h) All changes to the initial construction schedule with explanations.

Project	Comments	Document References [1]
2012		
System Reinforcement, SIP, Gas Supply		
1. Windsor Island (SIP)	Only the boring portion of the project was sent to bid. Other portions of the project will be performed by NWN Company crews.	OPUC DR 165 Attachments 2 thru 3
2. Westside Transmission Re-Rate (TIMP)	There are no bids for this project. All work will be performed by NWN crews.	OPUC DR 165 Attachment-4
3. Corvallis Reinforcement	The bid process has not started.	OPUC DR 165 Attachments 5 thru 7
4. Felida Gate Piping (Washington Only)	NOT RELEVANT - THIS IS A WASHINGTON PROJECT	
5. Perrydale to Monmouth (to Independence)	All work will be performed by NWN Company crews.	OPUC DR 165 Attachments 8 thru 10
6. Monmouth Reinforcement (to Granger)	Only a portion of the project was sent to bid. Other portions of the project will be performed by NWN Company crews.	OPUC DR 165 Attachments 11 thru 19
7. Portland System Optimization (Phase 1) - 2012	Work will be performed by NWN Company crews.	OPUC DR 165 Attachment 20 and OPUC DR 158 Attachment-2
Facilities		
8. Vancouver relocate (Washington)	NOT RELEVANT - THIS IS A WASHINGTON PROJECT	
9. Tualatin bio-swale (tentative project)	This project is on hold.	None
10. Tualatin replacement, training facility & land	The bid process is pending.	See OPUC DR 165 Attachments 21 thru 24
11. Sunset sheds	Routine replacements/additions	None
12. Generators (4)	Routine replacements/additions	None
13. Parkrose Retrofit	The bid process has not started	None
14. Salem Retrofit	The bid process has not started	None
2013		
System Reinforcement, SIP, Gas Supply		
1. Portland System Optimization (Phase 2)- 2013	Work will be performed by NWN Company crews. Phase 2 will: Restore 400 psi MAOP to 10" Westside Feeder between Jean Rd and West Linn and 10x12" Boones Ferry pipeline between Barbur and Slavin and Jean Rd Station)	See OPUC DR 165 Attachment-20
Facilities		
2. Coos Bay Retrofit	This project is still in the planning phase	None
3. Astoria Retrofit	This project is still in the planning phase	None
4. Generators (5)	There are routine maintenance/repair/replacements	None

[1] Many of these documents are considered confidential subject to protective order.

NW Natural

220 NW Second Avenue
Portland, OR 97209

REQUEST FOR PROPOSAL

Title: Phase II Perrydale To Rickreall Project

Date: March 5, 2012

NW Natural
220 NW Second Avenue
Portland, OR 97209
Proposal Due Date: April 20, 2012 at 2:00 PM

REQUEST FOR PROPOSAL (RFP)

TITLE: PHASE II PERRYDALE TO RICKREALL PROJECT
PROPOSAL SUBMITTAL DATE AND TIME: APRIL 20, 2012, 2:00 PM PDT
NOTE: Proposals received after 2:00 PM on the Proposal Submittal Date may be considered non-responsive.

DELIVER PROPOSAL TO:

NW NATURAL
Purchasing Department
Attn.: Craig Gagner
220 NW Second Avenue
Portland, OR 97209

Telephone: (503) 226-4211 Ext. 2550
Facsimile: (503) 273-4825
Email: csg@nwnatural.com

REFERENCE TIMETABLE:
Below is a timetable for your quick reference. It contains key tasks and dates that you will be responsible for in order to successfully respond to this RFP. Please take note of all dates and times.

Task	**Due Date/Time**
RFP Distribution	March 5, 2012
Job Walk	March 9, 2012
Deadline for Question Submissions	April 9, 2012
RFP Due Date	April 20, 2012 2:00 PM PDT
Award Contract	April 26, 2012
Field Work Starts	May1, 2012 (On or about)
Work Completed	October 1, 2012
Submit As-builts	October 29, 2012

NOTE: Field work start date(s) may vary depending on work space agreements with private property owners

NW NATURAL CONTACT FOR RFP ISSUES AND INFORMATION REQUEST:

All inquiries concerning this RFP and/or requests for additional information must be directed to Craig Gagner in writing at the above address.

PURPOSE:
NW Natural Gas Company, doing business as NW Natural, is seeking proposals for construction services for the Phase II Perrydale To Rickreall project as further defined in the attachments that follow.

NW Natural provides reliable, cost-effective natural gas service to more than 650,000 residential, commercial and industrial customers through 13,000 miles of mains and service lines in western Oregon and southwestern Washington.

You are invited to submit a proposal for the services defined herein. Your proposal shall be in compliance with all referenced documents, whether included herein, or incorporated by reference.

INSTRUCTIONS TO BIDDERS:

- Each Bidder shall submit its Proposal using the Proposal Form that is supplied herewith. Any qualifications, additions, or clarifications thereto shall be submitted by way of separate document. Proposal Form shall be manually signed. If erasures or other changes appear on the form, the person signing the Proposal Form must initial each erasure or change.

- Each Bidder shall submit **two copies of their proposal** complete with all attachments and supplemental correspondence in order for the Proposal to be considered.

- Proposals shall be submitted in a **sealed envelope** clearly addressed with Bidder's company name clearly labeled ***"RFP – PHASE II PERRYDALE TO RICKREALL PROJECT."*** Modifications to Proposals already submitted will be considered if received in NW Natural's offices by the RFP Due Date listed above. Also, Proposals may be withdrawn by the RFP Due Date.

- Unless expressly solicited by NW Natural, alternative Proposals will not be considered. However, value-engineering and cost reduction recommendations are encouraged and will be accepted for review with the Proposal. Any proposals for value engineered cost reductions shall be submitted, in written form, on the Bidder's letterhead and shall be included with the submitted sealed Proposal.

- All Proposal submittals, as required by this request, shall be included with the Proposal, on the specified due date and time.

- Bidder shall comply with all state and federal laws in regards to formulation and submittal of proposal. Prospective bidders should note that this is a competitive bidding situation, and that conferring with separate bidders about pricing or other specific details of the proposal may violate antitrust law.

- Proposals *shall remain firm for a period of ninety (90) days after the RFP Due Date.* NW Natural **may,** when it is in its best interest, reject any or all bids, or waive any formality of the RFP contents in any Proposal received.

- Bidder is deemed to have satisfied itself by submission of its Proposal as to the correctness and sufficiency of the Proposal to cover all requirements as requested per this document.

- Bidder(s) or awarded Bidder shall under no circumstances use NW Natural 's name or logos in advertising, marketing materials, printed matter, reference lists, or in any other way that could be construed as advertising (e.g., memo pads, tee shirts, binders, reference list, etc.) without NW Natural 's prior written consent.

NEGOTIATION TERMS:
NW Natural retains the right to select, request further information from, and negotiate with those bidders it deems qualified for competitive negotiations. NW Natural also reserves the right to reject any or all Proposals submitted and to terminate negotiations with any party at any time without incurring liability. This RFP gives rise to no contractual obligations, implied or otherwise.

RFP TERMS AND CONDITIONS APPLIED TO FINAL CONTRACT:

All terms and conditions outlined in this RFP, including the specifications and the Bidder's completed proposal, will become, at NW Natural's sole discretion, part of the final Purchase Order contract (the "Agreement") between NW Natural and the selected Contractor.

HOLD HARMLESS:
In submitting a Proposal, Bidder understands that NW Natural will determine which proposal, if any, is accepted. Bidder waives any right to claim damages of any nature whatsoever based on the selection process, final selection, and any communications associated with the selection.

CONFIDENTIALITY PROVISION:
The terms of this RFP, and all other information provided by NW Natural in connection with this RFP, are confidential and proprietary to NW Natural. Such materials are to be used solely for the purpose of responding to this request. By submitting a proposal, Bidder agrees not to disclose any such information to any third party without the prior written consent of NW Natural (which consent shall be conditional upon the written agreement of the intended recipient to treat the same as confidential). NW Natural may request at any time that any or all NW Natural material be returned or destroyed.

Should you choose not to respond to this RFP, all materials and any duplicates thereof must be returned to NW Natural at the address listed on Page 2 of this RFP.

CONTRACT EVALUATION AND AWARD:
NW Natural has no obligation to reveal the basis for contract award or to provide any information to bidders relative to the evaluation or decision-making process. All participating bidders will be notified promptly of bid acceptance or rejection.

CONTRACT NEGOTIATION AND EXECUTION:
As discussed above, NW Natural intends that the successful Bidder will enter into a Purchase Order which contains all of the terms and conditions of the proposed relationship between Bidder and NW Natural. Any acceptance of a Proposal is contingent upon the execution of a Purchase Order contract (the "Agreement"), and neither party shall be contractually bound to the other prior to the execution of such written "Agreement".

SPECIFICATIONS:
It is Contractor's responsibility to understand and adhere to all municipal and jurisdictional technical specifications for the work performed. Should there be questions and/or concerns regarding NW Natural or jurisdictional requirements or specifications, Contractor shall notify the NW Natural technical representative prior to the commencement of work.

GUARANTEE / WARRANTY:
The Contractor warrants that all Work performed shall be of the quality required by the Contract, or of the best grade or performed in a first-class workmanlike manner if no quality is specified,, that all such materials and equipment shall be suitable for the purposes intended to the extent selected by the Contractor or Subcontractors, and that all Work and such materials and equipment shall conform to the Specifications, Drawings, samples, and other descriptions set forth in the Contract. Upon receipt of written notice from the Company of a breach of warranty, the affected item or Work shall be redesigned, repaired, replaced, or reperformed by the Contractor; and the Contractor shall perform such tests as the Company may require to verify that such redesign, repair, replacement or reperformance complies with the requirements of the Contract. The Company reserves the right to itself have such redesign, repair, replacement, or reperformance Work done when it deems it advisable. All costs incidental to redesign, repair, replacement or reperformance Work, and the testing thereof, including but not limited to the removal, replacement, and reinstallation of equipment necessary to gain access, the repair or replacement of damage to the Work and the project resulting therefrom, and all other costs incurred as the result of a breach of warranty, shall be borne by the

Contractor. Should the Contractor fail promptly to make the necessary redesigns, repairs, replacements, reperformances, or tests, the Company may perform or cause to be performed the necessary Work or tests at the Contractor's expense.

The above warranties are not intended as a limitation but are in addition to all other express warranties set forth in the Contract and such other warranties as are implied by law, custom or usage of trade.

The above warranties shall be for a period of not less than two (2) years from the date of final completion of the entire Work and shall include but not be limited to site restoration and fabrication. A performance bond may be required to ensure compliance of warranties; the cost of such bond shall be paid by the Contractor.

INSPECTION AND ACCEPTANCE:
NW Natural and/or its representatives reserve the right to retain access to Contractor's work for the purposes of inspection and work acceptance. Failure to inspect, accept or reject the work shall not relieve the Contractor from its responsibility to furnish the requirements of the Contract. Approval and inspection shall be the responsibility of NW Natural.

QUALITY CONTROL ASSURANCE:
NW Natural will perform periodic quality assurance audits of contractor work. Work rejected due to poor quality/non-conformance shall be removed, replaced and/or re-performed by Contractor at Contractor's expense.

SITE CONDITIONS:
Contractor has the sole responsibility of satisfying itself concerning the nature and locations of work and the general and local conditions.

CONTRACTOR'S ENVIRONMENTAL OBLIGATIONS AND INDEMNITIES:
Contractor shall (a) abide by and comply strictly with all governmental permits and authorizations held by NW Natural in connection with the work; (b) acquire and comply with all governmental permits and authorizations that are necessary for Contractor's work on the project and that have not been obtained by NW Natural; (c) comply with all federal, state and local laws, regulations and ordinances relating to protection or enhancement of the environment and that are applicable to Contractor's activities hereunder; and (d) assume the risk that Contractor has identified all such applicable laws, obtained all such necessary governmental permits and authorizations, and that it has the capability to comply.

DRUG, ALCOHOL AND SUBSTANCE ABUSE TESTING COMPLIANCE:
Contractors who drive interstate commercial motor vehicles that are rated at over 26,000 lbs. or are engaged in safety-sensitive pipeline operations are required by the U.S. Department of Transportation ("DOT") to implement a program of drug, alcohol and substance abuse testing, education and training (49 CFR Parts 40, 199, 325, 355-379 and 381-399). NW Natural is required to confirm that its independent contractors and their employees, if any, comply with these regulations. Any contractor who drives a truck as described above or performs services identified as safety-sensitive must comply with the appropriate regulations and provide evidence of compliance to the NW Natural Purchasing Department. Failure to provide such evidence will disqualify the Contractor from performing work or services for NW Natural. NW Natural is authorized by regulations to audit the Contractor's drug, alcohol and substance abuse program records. **The work and/or services described in this RFP have been identified as being covered by the regulations.**

NOTE: All costs associated with Contractor Drug, Alcohol, and Substance Abuse testing shall be the sole responsibility of the Contractor.

ADHERENCE TO OPERATORS QUALIFICATIONS:
Federal law requires that all personnel, including independent contractors, who perform "Covered Tasks" on pipeline facilities or appurtenances owned or operated by NW Natural must meet certain qualification standards administered by NW Natural in accordance with regulations promulgated by the U.S. Department of Transportation's Office of Pipeline Safety (49 CFR Part 192, Subpart N, as currently in effect and as may be amended from time to time). Some or all of the services to be performed by Contractor pursuant to the Purchase Order constitute "Covered Tasks" for purposes of the aforementioned regulations, and such services are therefore subject to the NW Natural Operator Qualification Program. NW Natural and its representatives have sole authority (subject only to the terms and standards set by the Office of Pipeline Safety and other regulatory agencies, if applicable) for all elements of its Operator Qualification program, including but not limited to setting qualification standards, recordkeeping and conducting audits under the program. NW Natural agrees to administer operator qualification testing for Contractor and its personnel at no charge. Contractors are not eligible for payment for time spent on the testing process.

CONTRACTOR INDEMNITY/PERFORMANCE OF THE WORK:
Contractor shall indemnify and save harmless NW Natural and its directors, officers, shareholders, partners, employees and agents (including their successors and assigns), against and from any and all actions, proceedings, audits, investigations, claims, demands, damages, fines, penalties, response costs, loss and liability, expenses and costs (including attorneys' fees in any suit, action or proceeding, whether groundless or not, that may be brought against NW Natural) caused or arising out of the acts or omissions of Contractor and Contractor's agents and employees. This includes, but is not limited to, (a) injury or death of any persons; (b) damage to or loss of any property and natural resources; (c) degradation or contamination of the environment; and (d) noncompliance with any applicable law, regulation, ordinance, permit or authorization, caused or arising out of the acts or omissions of Contractor and Contractor's agents and employees.

Provided, however, that this section shall not require Contractor to indemnify and save harmless NW Natural and its directors, officers, partners, employees and agents (including their successors and assigns) against and from any responsibility or liability for their own negligence.

INSURANCE REQUIREMENTS:
Contractor shall carry at its own expense, insurance with reliable insurance companies satisfactory to NW Natural and authorized to do business in the State or the States in which work is to be performed by the Contractor hereunder, the following types of insurance limits not less than shown on the respective items:

A. Workers Compensation Insurance and occupational disease insurance with statutory limits, and employers' liability insurance with a minimum limit of $1,000,000.
B. Comprehensive General Liability Insurance with a combined single limit for bodily injury, personal injury and property damage of $2,000,000 for injuries to or death of anyone or destruction of any property, including loss of use thereof, arising out of an occurrence.
C. Automobile Liability Insurance, including all owned, hired, or non-owned vehicles and equipment, with limits the same as those provided above for Comprehensive General Liability Insurance.

Any and all deductibles in the above-described insurance policies shall be assumed by, for the account of, and at the sole risk of the Contractor. Modification or cancellation of policies providing coverage listed above shall be effective only after written notice is received by NW Natural from the insurance company at least thirty (30) days in advance of such modification or cancellation.

NW Natural shall be named as an additional insured on Comprehensive General Liability Insurance and the policy shall contain a cross liability endorsement and contractual liability coverage for obligations assumed by the Contractor under the indemnity provisions of this contract.

SUB-CONTRACT WORK:
Contractor may utilize sub-contractors as approved by NW Natural. Contractor will be held to all requirements within this RFP and any subsequent contract, whether work is self-performed or sub-contracted.

CHANGE ORDER / EXTRA WORK:
Any changes or extra work not included in the original scope of this contract must be agreed upon in advance by both parties and approved by NW Natural prior to beginning such work.

NONDISCRIMINATORY PROVISIONS:
NW Natural is an Equal Opportunity Employer. NW Natural does not discriminate based on race, color, national origin, sex, sexual orientation, age, marital status, religion, veteran status or Vietnam-era veteran status, or sensory, mental or physical disabilities in matters or conditions of employment. NW Natural expects and requires its' Contractors to abide by all laws regarding equal opportunities for employees.

CORPORATE IMAGE:
NW Natural maintains a respected corporate image. The company's employees pride themselves on customer service and satisfaction in the office and in the field. NW Natural's Contractors represent not only their company but also NW Natural. It is the responsibility of the Contractor to maintain professional, courteous, caring and safe employees. If the Contractor provides employees to perform work on NW Natural projects who do not possess these traits, the contract could be in jeopardy of termination.

CONTRACTORS' EMPLOYEES:
NW Natural reserves the right to terminate the Agreement if any Contractor or employee of a Contractor fails to conform to contract specifications.

ACCOUNTING / AUDIT PROVISIONS:
Contractor shall maintain records and accounting procedures sufficient to support invoices. Contractor's records pertaining to the performance of the Agreement shall be subject at reasonable times to inspection and audit by NW Natural or its representative(s). Contractor shall preserve and make available records supporting any particular payment for a minimum of two (2) years after the date of such payment.

Attachments

Attachment A - Proposal Form

Attachment B - Scope of Work

Attachment C - Responsibilities

Attachment A

Proposal Form

BIDDER SHALL USE THIS PROPOSAL FORM IN SUBMITTING PROPOSAL FOR CONSIDERATION.
BIDDER SHALL ENTER "N/A" IN SECTIONS THAT DO NOT APPLY TO PROPOSAL.

Proposal for: Phase II Perrydale To Rickreall PROJECT

NW Natural retains the right to:

- Accept or reject any or all bids.
- Make an award without discussion with any bidder.
- Negotiate with one or more bidders.
- Make award based on factors other than price.

VALIDITY PERIOD OF PROPOSAL:
This Proposal shall remain *valid for a period of ninety (90) days* from the RFP Due Date. Bidder agrees to accept a Purchase Order, if its Proposal is selected by NW Natural, if notification of award is received on or before the expiration of the validity period. Bidder's prices shall be considered "firm" throughout the validity period, unless stipulated otherwise in the Proposal.

BIDDER INFORMATION:

Company Name: ______________________________
Address: ______________________________
Federal Taxpayer ID Number: ______________________________
Dun & Bradstreet Number: ______________________________
Construction Contractor No.: ______________________________
Date of Bidders Proposal: ______________________________
Telephone Number: ______________________________
Fax Number: ______________________________
Email Address: ______________________________
Bidding Contact: ______________________________

Payment Terms: ______________________________

Experience Modification Rating (EMR) ____________________

Bargaining Unit Affiliation: (Circle) Yes No If yes, Union ____________________

Proposal Pricing

	Unit	Price	Total Cost
HDD Bore #8 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 5,400 feet).	FT	$/FT	$
HDD Bore #7 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximate 4,500 feet).	FT	$/FT	$
HDD Bore #6 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 5,000 feet)	FT	$/FT	$
HDD Bore #5 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately1,700 feet)	FT	$/FT	$

Proposal Pricing

	Unit	Price	Total Cost
HDD Bore #4 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 2,025 feet).	FT	$/FT	$
HDD Bore #3 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 1,600 feet).	FT	$/FT	$
HDD Bore #2 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 2,925 feet)	FT	$/FT	$
HDD Bore #1 Installation of 12" (W) pipe (per foot) all inclusive as per requirements of RFP (Approximately 2,950 feet)	FT	$/FT	$

Mobilization and demobilization (lump sum). Bore locations 1 thru 8 – see stationing in Geo Report.	**Total Cost**	$

Total Cost Bores #1 Thru #8	**Total Cost**	$

Total Cost **Bores #1 Thru #8** **Mob & De-Mob**	**Total Proposal Cost**	$

Stationing (All Footage is Approximate)

N Pacific State Highway

Open Excavation Trench #5 3950 ft. –

Open Excavation Trench #4 900 ft. –

Open Excavation Trench #3 6300 ft. –

Open Excavation Trench #2 1300 ft. –

Open Excavation Trench #1 5075 ft. –

Note:

Total Price

~~OPEN EXCAVATION TRENCH COST~~	~~Cost per ft.~~	~~$~~
TOTAL PROJECT COST	**Total Project Cost**	$

NOTE:

1. Contractor shall provide all labor, materials and equipment for the scope of work as stated within this RFP.
2. This project is to be quoted as per foot installed. Pricing is all-inclusive and will be paid on actual footage installed for successful directional bores as accepted by NW Natural.
3. Mobilization and demobilization will be paid on a prorated basis.

Equipment:

Make **Model**

List Directional Drill Machine(s) to be utilized on this project: ______________________

____

CERTIFICATION AND SIGNING OF PROPOSAL:

The undersigned certifies that the RFP package and the attachments have been examined and is understood; that all shown figures checked and understands that NW Natural is not responsible for any errors, or omissions on the Bidder's part in preparing this Proposal.

If the Bidder takes exception to any part of this RFP, the Bidder shall itemize those exceptions and submit them with this Proposal with the heading: **"EXCEPTION (S) TO RFP PACKAGE"**.

THE UNDERSIGNED ACKNOWLEDGES CONDITIONS OF THIS PROPOSAL:

Dated this _________ day of ________________________________

Signature ________________________________ in the capacity of ______________________________
(Company Title)

Printed Name: ____________________________________

Address: ____________________________________

____

____

ITEMS TO ACCOMPANY BID:

Item Submitted

- ☐ 1. This completed Proposal Form
- ☐ 2. Drug / Alcohol Testing Program Information
- ☐ 3. Safety Management Plan & Procedures
- ☐ 4. Quality Assurance / Quality Control Manual
- ☐ 5. Insurance Certificates
- ☐ 6. Proposed Construction Schedule, including crew size, work days per week, hours per day
- ☐ 7. Equipment Rental Rate Sheet
- ☐ 8. Hourly Labor Rates (all inclusive)
- ☐ 9. Exceptions (if any) to RFP package as stated herein
- ☐ 10. Any other documentation bidder feels will aid NW Natural in making their selection

Attachment B

Scope of Work

The work to be performed consists of the installation of approximately 26,100 lineal feet of 12" .312" wall, API 5L PSL 2, Grade X-52, FBE -Lilly coated steel pipe in double random lengths utilizing Horizontal Directional Drilling (HDD) and installation of approximately 17,525 lineal feet 12" .312" wall, API 5L PSL 2, Grade X-52, coated steel pipe open excavation construction methods detailed within this RFP package. The pipeline shall be installed along N. Pacific Highway W between Willamina – Dallas Hwy and the Central Coast Feeder pipeline.

All work shall be performed in accordance with all Specifications contained within this document and documents as referenced herein including but not limited to drawings and permits as listed below:

The Geotechnical Data Report and limited Horizontal Directional Drill (HDD) study will be provided by NW Natural. The study profiles the 8 bore sites and soil classifications.
Bore profiles will be provided by NW Natural.
The pilot-hole operation is to be drilled as closely as possible to the designed HDD profile with as little horizontal curvature as is practical while still maintaining three-joint vertical radii as referenced in the Geotechnical report.
A horizontal tolerance of 5 feet left and 5 feet right of the designed alignment and a vertical tolerance of 2 feet above and 8 feet below the designed profile.

NOTE: The Contractor is responsible for creating, utilizing, maintaining and submitting bore profiles for final as-built drawings.

Upon completion of the entire pipeline installation a caliper pig (and possibly an MFL pig) will be run to look for construction defects. Contractor at its sole expense will immediately mitigate and repair any construction defects discovered as a result of this inspection.

All work shall be performed in accordance with all Specifications contained within this document and documents as referenced herein including but not limited to drawings and permits as listed below:

- Drawings – Provided at pre-bid meeting
- ODOT Permits – Prior to Construction
- County Permits – Prior to Construction
- Geo Engineers Report – Mid-Willamette – Perrydale Segment

Products and services furnished by the Contractor shall be provided and performed in accordance with the best industry standard and practices and as stated within the contract. Except for the materials to be furnished by NW Natural listed on Attachment C and other obligations to be performed by NW Natural as expressly set forth in the contract, the work shall include all supervision, labor, services, equipment, tools, materials, consumables, transportation and incidentals.

CONCERN FOR EXISTING UNDERGROUND UTILITIES:

The work will be performed in areas that contain existing distribution mains and other underground utilities. Therefore, the contractor must exercise caution and undertake the following steps, which include, but are not limited to:

1. Contact the "One Call System" requesting underground locations at least 48 hours before beginning operations. The telephone number in Oregon is (800)322-2DIG or 811.
2. Verify the location of all underground utilities at or adjacent to the work site. This shall include exposing any utilities that are located within the designed drill path. The exact location of the existing high-pressure transmission mains must be known at all times. Particular care must be taken to protect these lines, making sure that additional stresses are not added to the lines due to machinery crossing or working over them.
3. Modify drilling practices or down hole assemblies to prevent damage to adjacent underground utilities.

Attachment C

Responsibilities

Contractor

- Provide all labor, equipment and applicable material necessary to directional drill and pullback 12" steel pipe.
- Mobilization, demobilization and set up of horizontal drilling equipment at the bore sites.
- Contractor must not exceed the maximum bend radius of said pipe. Profiles must be approved by NW Natural prior to commencing work.
- Provide a Sizing Plate 11.5" ID (95%) to verify pipe integrity as installed.
- Brush Pigs

  Provide a Multi-Channel Caliper Pig Vendor

  Typical Detection Specifications

Reporting Threshold,	2%
Deformation (depth),	+/-0.14"
Ovality (depth),	+/-0.14"
Location Accuracy Axial	+/-0.1%
Circumferential	+/-15°

- Provide the required amount of pipe rollers necessary for protecting pipe during pull back of 12" steel pipe.
- Operated vacuum truck.
- Verification and acceptance of all underground utility locates and depths to avoid damages to existing structures.
- Control, removal and disposal of all drill fluid (mud).
- Minimizing the opportunities for runoff of water and sediments. Specific measures to prevent the runoff of water and sediments to include the installation of silt fences and hay bales.
- Drilling mud shall be contained and will not be dispersed by vehicle tires or treads.
- Immediately cleaning up all locations where drilling fluid inadvertently surfaces. Contractor will assume all liabilities and costs associated with directional drill "frac-outs".
- When required contractor will haul off spoils and replace with select backfill.
- Perform work in accordance with all drawings as issued by NW Natural and GeoEngineers.

- Work to conform to OQ and QA standards.
- Construction to conform to Department of Transportation Administration 49 CFR Part 192.
- The bore profile that is provided by NW Natural is to be used for bid purposes only. Contractor is responsible for creating and submitting final as-built drawings for review. As builts will include ground to pipeline depth profile. Horizontal stationing will be referenced from R/W including cross streets.

Site Work Requirements And Responsibilities:

1. Provide all labor, equipment and material necessary to install pipeline (except NW Natural furnished materials as listed in RFP document).
2. Perform work in accordance with all permits as issued. ODOT permit to be provided at bid walk.
3. Perform work in accordance with all drawings as issued by NW Natural
4. Provide all utility locating and potholing.
5. Provide traffic control as per ODOT requirements and approved TCP.
6. All NW Natural required and approved pipe coating (including labor, materials, equipment and expendables) shall be the responsibility of the contractor. All welds must be sand blasted (per NW Natural specs.) prior to installing pipe coating.

   a. Powercrete R60 or R60 HB Kits for joint coating of directional bore pipe and ground-to-surface transitions extending at least one (1) foot above and below ground level.

   b. Raychem (or equal) wrap around heat shrink sleeves (one per joint). (Raychem # WPCT-045)

   c. Calibrated Holiday Detectors/Jeeps. All pipe and joints must be quality assured prior to lowering pipeline in the trench and/or bores.

7. Provide welding of pipe per NW Natural specifications. All welders to be tested and certified by NW Natural. 100 % of the welds will be x-rayed at NW Natural's discretion and expense.
8. Provide a Multi Channel Caliper Pig run. NW Natural is requesting to have the vendor submit plans and specifications for the pig run. The vendor must have NW Natural approval prior to performing work.
9. Installation of pipe to include cleaning, hydro testing, pigging and drying to dew point of zero degree's . Testing requirements for the pipe are as follows;
   a. Minimum of 8 hours
   b. Minimum pressure of 1080 psig
   c. Maximum pressure of 1300 psig
   d. Witnessed and approved by NW Natural
   e. Hydrostatic test chart recording shall include temperature and pressure
   f. All testing equipment must have approved calibration records.
   g. All testing documents and completed charts are to be submitted with as builts.
10. Pipe shall be buried with a minimum of 5ft. (60") of cover. Any variations shall be with the approval of NW Natural Engineer. The pipe shall have 72" of cover from Ireland Rd to the termination point at the Willamette River HDD bore site.

11. All existing facilities must be identified and located by potholing or vacuum methods prior to crossing.
12. New pipe shall be installed at least 12" from all existing facilities.
13. All spoils hauled off and disposed of.
14. Imported sand back fill shall be to a minimum of 6-inches below and 12-inches above pipe.
15. All rocks, debris, road materials shall be removed from ditch prior to backfill.
16. All roads and road crossings shall be restored to pre-construction condition.
17. Road crossings shall be compacted to ODOT permit requirements. Test results to be submitted with as builts.
18. Disturbed roadways shall be cleaned of all dirt, mud, and construction materials and maintained to like new condition. Resurfacing may be required by local jurisdiction.
19. As-Built drawings to be submitted prior to final invoice payment. As-Built drawings to be provided per NW Natural's requirements. Final payment will not be released until as-builts are submitted and approved by NW Natural.
20. The pipe for this project is being stored at a HWY 34 and Oakville Rd.
21. Contractor shall coordinate delivery of pipe to jobsite, including all handling.
22. The Contractor shall coordinate delivery and handling of other NW Natural supplied materials. Materials other than pipe are stored at NW Natural's Tualatin facility located at 7100 McEwan Rd., Lake Oswego, OR 97035.

Contractor's Other Responsibilities:

I. Transportation of all equipment, labor, consumables and NW Natural supplied material to and from the job sites.
II. Provide a secure lay down area for all materials including pipe
III. Fire protection of jobsite. Contractor to follow all Federal, County and Jurisdictional requirements.
IV. Transporting, transferring, and storing any water required for hydrostatic testing.
V. Hauling and disposing of all hydrostatic test water at approved site (TBD)
VI. Management of the erosion control plan and BMP's are the responsibility of the contractor.
VII. Right of Way shall be fully cleaned, restored, seeded and fertilized to ODOT specifications
VIII. Dewatering of trench lines and bores pits must be filtered prior to discharging into public lands
IX. Operator Qualifications compliance-it is the contractor's responsibility to schedule, coordinate and administer documented training and testing with NW Natural.
X. Compensate welders for testing.

NW Natural

- Provide 12" .312" wall, API 5L PSL 2, Grade X52, Lilly/ FBE coated steel pipe in double random lengths
- Provide 12" .312" wall, API 5L PSL 2, Grade X52, coated steel pipe in double random lengths
- Valves, pipe fittings, flanges, and flange hardware (except for hydrostatic testing)
- All NDT, x-ray inspections of welds
- Testing of welders: To include testing materials and electrodes.
- Gas control and tie-ins
- Field staking of pipe center line and HDD entry and exit.
- Traffic control plan
- Erosion control plan
- Job (work) drawing
- ODOT and DEQ 1200C permits

Attachment C

Responsibilities

Contractor

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25. Perform work in accordance with all drawings as issued by NW Natural
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(Raychem # WPCT-045)

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XII. Provide a secure lay down area for all materials including pipe
XIII. Fire protection of jobsite. Contractor to follow all Federal, County and Jurisdictional requirements.
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XV. Hauling and disposing of all hydrostatic test water at approved site (TBD)
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- Traffic control plan
- Erosion control plan
- Job (work) drawing
- ODOT and DEQ 1200C permits

Construction Estimate
Corvallis Loop Project
Project 200363

2009 Project Actual Costs - Corvallis	
2010 Previous Charges	$170,000
Total 2010 Project Actual Costs w/ OH	**$170,000**

2011 Project Estimated Costs - Corvallis	
Equipment/Material Total	$5,020,050
Labor Total	$1,383,800
Contract Total	$1,575,000
Total	**$7,978,850**
Construction Overhead (22% for System Reinforcement)	$2,154,290
Total Cost	$10,133,140
Contingency (10%)	$5,020,050
Total 2011 Project Cost w/ OH	**$11,146,453**

2012 Project Estimated Costs - Corvallis	
Equipment/Material Total	$1,898,450
Labor Total	$1,393,200
Contract Total	$1,325,000
Total	**$4,616,650**
Construction Overhead (22% for System Reinforcement)	$1,246,496
Total Cost	$5,863,146
Contingency (10%)	$586,315
Total 2012 Project Cost w/ OH	**$6,449,460**

Total Project Cost w/ OH 2010-2012	**$17,765,914**

$12,595,500

MEMORANDUM

NW Natural
220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

Date: August 12, 2011
To: Steve Nelson, Ryan Truair, Katie Gough, Joe Karney
From: Greg Bronson
Subject: Proposal for Project Initiation 200580

PROJECT NAME
Monmouth

PROJECT LOCATION
Monmouth

PROJECT PLATS
Start 2-121-025. End 2-128-021.

SCOPE
This project is for installation of approximately 27,400 feet (5 miles) of 12-inch steel natural gas pipeline tested and certified at a Maximum Allowable Operating Pressure (MAOP) of 720 psig. This pipeline is part of the Perrydale to Corvallis/Albany (Mid-Willamette Valley Feeder - P30 pipeline). This project starts North of Monmouth at Hoffman Rd heading south on Hwy 99, continues through Monmouth, heads East on Stapleton, South on Corvallis Rd and ends 2790' to the South of Stapleton.

Phase 1 will be a bore though Monmouth in public ROW
Phase 2 will be bore/open cut South of Monmouth ending South of Stapleton

PURPOSE
System Reinforcement

COST
Rough Estimated Cost:$7,500,000

FUNDING
System Reinforcement 115
COH – 27%

SCHEDULE
Possible Start date: 11/1/2011 for Phase 1 and 3/1/2012 for Phase 2
Estimated Construction Duration: 8 months

Pages 42 through 55 are confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

WINDSOR ISLAND -WILLAMETTE RIVER HDD 10-INCH

Windsor Island

Working Hours	360
Working Days	36
Calendar Weeks	6
Calendar Months	2

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
1	Work Staging area/Easements	$150,000.00	1	LS	$150,000	Estimate only at this time
2	Property Restoration	$30,000.00	1	LS	$30,000	Cleanup post construction
3	Erosion Control / Dewatering	$10,000.00	1	LS	$10,000	Construction entrance, straw, sandbags, silt fencing,
4	Porta Johns	$125.00	4	each	$1,000	
5	Shrink Sleeves	$14.00	100	each	$1,400	
6	Skids	$2,000.00	1	LS	$2,000	
7	Plywood	$2,000.00	1	LS	$2,000	
8	Light plants	$0.00	4	each	$0	4 each for 26 weeks
9	Steel plates	$125.00	20	each	$5,000	40 each for 2 months
10	PowerCrete	$40.00	50	each	$2,000	150 each for a 4 lb kit
11	Sideboom	$94.00	360	Hr	$33,840	1 sideboom for 6 weeks at $94/hr
12	Equipment Rental - Trackhoes	$3,750.00	2	each	$16,375	2 Trackhoes for 2 months
13	Equipment Rental - Backhoes	$46.58	360	Hr	$33,538	2 Backhoes
14	Water Truck, Pigs, Pump & Hardware	$30,000.00	1	LS	$30,000	water trucks, dryer, compresser, etc.
15	Shoring Rental	$100,000.00	1	LS	$100,000	DP Nicoli
16	Drill Pipe - 10"	$48.09	1500	ft	$72,135	
17	Other Pipe - 10"	$34.94	200	ft	$6,988	
18	HDPE Sleeve - 16"	$13.75	1500	ft	$20,625	
19	Casing Spacers	$93.00	200	ft	$18,600	
20	Conducter Barrel - 24"	$24.00	200	ft	$4,800	
21	Other Pipe	$0.00	0	ft	$0	
22	Haul/Dump Trucks	$85.00	100	Hr	$8,500	2 Dump Trucks for 200 hrs
23	Haul / Dump fee (spoils)	$5.00	200	yds	$1,000	
24	Rock	$20.00	200	cy	$4,000	
25	Asphalt Paving	$11.71	0	sf	$0	
26	Concrete Paving	$15.25	0	sf	$0	
27	Sawcut	$1.00	0	lf	$0	
28	Sand	$15.00	100	cy	$1,500	
29	Elbows, Stopple, Reducer	$25,000.00	1	LS	$25,000	see material list
30	Other Misc stores	$20,000.00	1	LS	$20,000	misc fittings, nitrogen, weld rods, sanders, markers etc.
31	Electrostop	$2,425.00	1	each	$2,425	
	Equipment/Material Total				**$602,726**	

WINDSOR ISLAND -WILLAMETTE RIVER HDD 10-INCH

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
	Internal staff charges	$65.00	300	hours	$19,500	
32	Tual Crew Labor	$63.50	360	hours	$22,860	10 hours per day 1 - 6 man crews 36 days
33	Welder - Standard	$65.00	360	hours	$23,400	2 welders for 36 days
34	Specialty Crew	$60.00	180	hours	$10,800	2 man crew for 18 days
35	X-Ray	$1,300.00	17	days	$22,100	
36	Trans Crew	$63.00	60	hours	$3,780	4 man crew for 6 days
37	Gas Supply	$60.00	20	hours	$1,200	2 man crew 2 days
38	Flatbed Truck & Operator	$80.00	30	hours	$2,400	Pipe Delivery
39	Pier Diem	$140.00	300	days	$42,000	
	Labor Total				**$148,040**	
Item #	**Item**	**Cost/Unit**	**Quantity**	**Unit**	**Cost**	**Comments**
40	Survey	$40,000.00	1	LS	$40,000	Westlake topo, construction staking, legals for easements
41	HDD Bore Explorations, Design	$60,000.00	1	LS	completed	GeoEngineers bore explorations, HDD Feasbility & Design
42	Construction Monitoring	$40,000.00	1	LS	$40,000	GeoEngineers on site monitoring, report during HDD
43	Concrete Mats	$25,000.00	1	LS	$40,000	Rockford installed in 2009
44	Contract HDD Bore - Steel	$272.00	1475	ft	$401,200	Estimate $272 per ft
	Contract Total				**$521,200**	
	Equipment/Material Total				$602,726	
	Labor Total				$148,040	
	Contract Total				$521,200	
	Total				**$1,271,966**	
	Construction Overhead (81% for System Reinforcement)				$1,030,292	
	Total				**$2,302,258**	
	Contingency (10%)				$230,226	
	Total Cost				**$2,532,484**	
	Project costs through December 2011				$170,995	
	Total Project Cost w/ COH				**$2,703,479**	

	Total Project Cost without COH (81%)	**$1,493,635**	

less internal costs $1,345,595

Project	Assigned person	Comments	Current Cost Est (k$)	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Gasco/Mixer Station - Add RCV	S. Lundgren	Will separate GASCO LNG and Storage gas and prevent them from competing. Will facilitate sending storage gas to east metro by sending it north through Sauvie Island.	$ 100		$ 50	$ 50																					
Sauvie Island - Add RCV or Control Valve	S. Lundgren	Would allow flow from Williams to be isolated and would allow either GASCO LNG or Storage gas to flow to east side of Portland.	$ 250				$ 50	$ 50	$ 100	$ 50																	
Rivergate - Control Valve	S. Lundgren	Would facilite switching between MAOP 450 and 400 whithout a pressue drop	$ 250					$ 50	$ 150	$ 50																	
82nd and Killingsworth - Add RCV	S. Lundgren	Would allow tail gas to be sent to eastside of Portland.	$ 150								$ 75	$ 75															
Bell Rd (King Rd) - Add RCV/back up reg	S. Lundgren	Would allow tail gas to be sent to eastside of Portland. The backup reg would be for times when demand exceeds supply from Tail Gas (similar situation exists at Jean Rd)	$ 250		$ 50	$ 100	$ 100																				
Restore 400 psi MAOP to 10" Westside Feeder between Jean Rd and West Linn	Van Gordon	Would allow additional storage gas into the eastside of Portland.	TIMP																								
Complete Boones Ferry 400 psi pipeline	Van Gordon/ New Westside		$ 800		$ 150	$ 150						$ 200	$ 200	$ 100		$ 250	$ 250	$ 250	$ 250								
Examine eastside regs examine if modifications are necessary due to lower inlet pressure	G. Dye	May have to replace some smaller inlets or regulators	$ 200					$ 50	$ 50	$ 50	$ 50																
Felida	S. Lundgren		$ 1,500							$ 250	$ 250	$ 500	$ 250	$ 250						$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total	$ 3,500	$ -	$ 250	$ 300	$ 150	$ 150	$ 300	$ 400	$ 375	$ 775	$ 450	$ 350	$ -	$ 250	$ 250	$ 250	$ 250								

Pages 59 through 80 are confidential.

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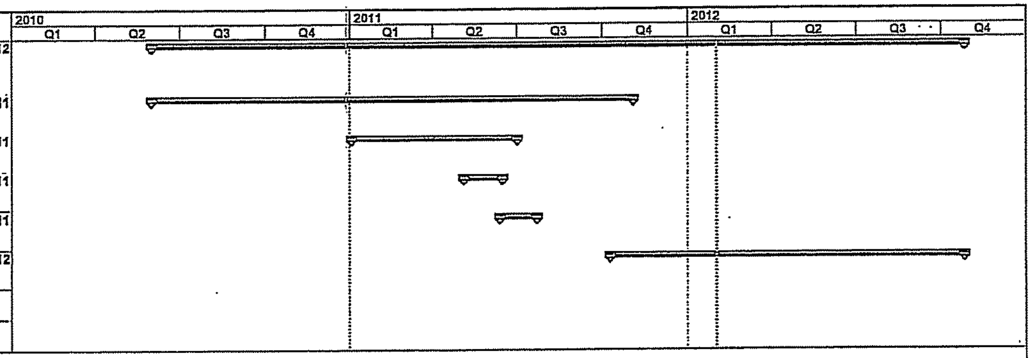
Project	Assigned person	Comments	Current Cost Est (k$)	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	
Phase 1																												
Obtain Pipe Samples	Van Gordon	The pipe samples will be used to support the feasibility of project. The data and information gathered will be evaluated and a decision to proceed will be made in 2012.	$ 400			$ 50	$ 50		$ 100	$ 100		$ 50	$ 50															
Construction activities to support Rerate	Van Gordon	The bulk of the rerate work will be completed in 2013.	$ 1,600													$ 100	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 100				
		Total	$ 2,000	$ -	$ -	$ 50	$ 50	$ -	$ 100	$ 100	$ -	$ 50	$ 50	$ -	$ -	$ 100	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 100	$ -	$ -	$ -	$ 1,700

$ at effective date of rerate = $ [illegible]

ID		Task Name	Duration	Start	Finish
1		**Corvallis Reinforcement - 200363**	629 days	Tue 6/1/10	Fri 10/26/12
2		Design	373 days	Tue 6/1/10	Thu 11/3/11
22		Permitting	130 days	Mon 1/3/11	Fri 7/1/11
27		Bore Contract	30 days	Thu 5/5/11	Wed 6/15/11
30		Pipe Delivery	30 days	Mon 6/13/11	Fri 7/22/11
33		Pipe Installation - 12" (W)	275 days	Mon 10/10/11	Fri 10/26/12
34					
45					

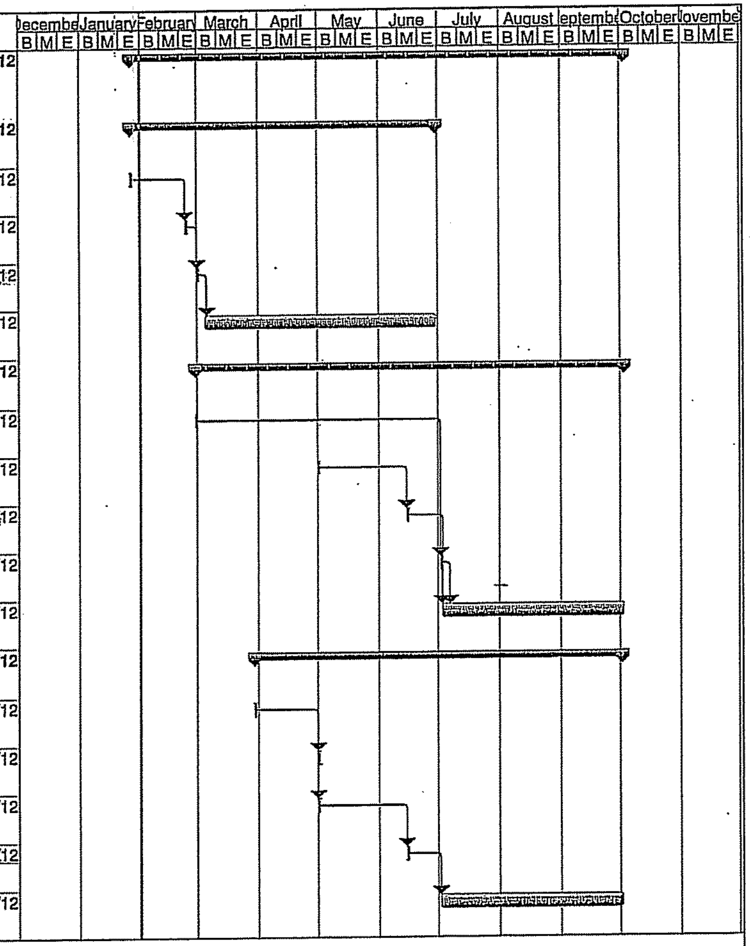


Project: Corvallis 200363 October 201

Task | Split | Progress | Milestone | Summary | Project Summary | External Tasks | External MileTask | Split

Staff/1003
Zimmerman/82

ID		Task Name	Duration	Start	Finish
1		**Corvallis Reinforcement - 200363**	178 days	Fri 1/27/12	Tue 10/2/12
2		**Phase 2: (Hwy 34) ~ 5 miles**	111 days	Fri 1/27/12	Fri 6/29/12
3		RFP Distribution	1 day	Fri 1/27/12	Fri 1/27/12
4		Open Bids	1 day	Fri 2/24/12	Fri 2/24/12
5		Award Contract	1 day	Thu 3/1/12	Thu 3/1/12
6		Construction in Hwy 34	85 days	Mon 3/5/12	Fri 6/29/12
7		**Phase 1: (Riverside Drive to Hwy 34) ~ 2.5 miles**	155 days	Wed 2/29/12	Tue 10/2/12
8		Complete Land Acquisition	1 day	Wed 2/29/12	Wed 2/29/12
9		RFP Distribution	1 day	Tue 5/1/12	Tue 5/1/12
10		Award Contract	1 day	Fri 6/15/12	Fri 6/15/12
11		Complete Permitting	1 day	Mon 7/2/12	Mon 7/2/12
12		Construction Riverside Drive to Hwy 34	66 days	Tue 7/3/12	Tue 10/2/12
13		**Phase 3: (City of Corvallis) ~ 2 miles**	132 days	Fri 3/30/12	Mon 10/1/12
14		Complete survey and design	1 day	Fri 3/30/12	Fri 3/30/12
15		Complete Permitting	1 day	Tue 5/1/12	Tue 5/1/12
16		RFP Distribution	1 day	Tue 5/1/12	Tue 5/1/12
17		Award Contract	1 day	Fri 6/15/12	Fri 6/15/12
18		Construction City of Corvallis	66 days	Mon 7/2/12	Mon 10/1/12



Project: 120201 C
Date: Wed 2/1/12

Task	External Tasks	Inactive Summary	Start-only
Split	External Milestone	Manual Task	Finish-only
Milestone	Inactive Task	Duration-only	Progress
Summary	Inactive Task	Manual Summary Rollup	Deadline
Project Summary	Inactive Milestone	Manual Summary	

Corvallis Reinforcement

45,000 feet
9 months

Willamette River Crossing				$900,000
Project cost	45,000	$175 /ft		$7,875,000
				$8,775,000
25% of the project bored	11,250	$100/ft		$1,125,000
Pipe cost - Green Coat	$24.62 /ft		33,750	$830,925
Pipe cost - Directional Drill	$37.82 /ft		11,250	$425,475

Bore Crossings	Footage	
ODOT Hwy 34 crossing	300	
Willamette River	700	
~~ODOT Hwy 99 crossing~~	900	
RR - crossing 35th Ave	400	
Oak Creek crossing 35th Ave	200	
Oak Creek at 26th St	300	
RR - near SW 7th St	200	3,000

Rickreall

Project cost for 8" HP	17,150	$125	$2,143,750	
25% of the project bored	4,300	$50 /ft		$430,000
Pipe cost - Green Coat	$20.29 /ft			$285,014
Pipe cost - Directional Drill	$44.57 /ft			$138,301

Crossings	Footage	
RR	1,800	
ODOT Hwy	200	
Creek	2,300	4,300

2012 PRELIMINARY CONSTRUCTION ESTIMATE
Corvallis Reinforcement 200363

Working Hours	1,250
Working Days	125
Calendar Weeks	25
Calendar Months	5

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
1	Internal staff charges	$65.00	900	hours	$58,500.00	
2	Design	$350,000.00	1	LS	$350,000.00	WH Pacific, GeoEngineers, Epic Land Solutions
3	Pothole crew	$20,000.00	1	LS	$20,000.00	Armadello
4	Traffic control (pothole crew)	$36.00	120	hours	$8,640.00	2 flaggers for 240 hrs
5	Work Staging area/Easements	$110,000.00	1	LS	$110,000.00	Estimate from Risk and Land
6	Traffic Control Standard	$36.00	5	flaggers	$172,800.00	5 flaggers for 960 hrs
7	Traffic Control Equipment	$20,000.00	1	LS	$20,000.00	Barrier rental - 500 LF at $10/LF for 4 months & Mob
8	Erosion Control / Dewatering	$90,000.00	1	LS	$90,000.00	Rain for Rent tanks,silt fence, Inlet protection, sandbags, etc.
9	Porta Johns	$125.00	6	each	$3,750.00	5 months - 4 each
10	Shrink Sleeves	$14.00	420	each	$5,880.00	
11	Skids	$25,000.00	1	LS	$25,000.00	
12	Plywood	$10,000.00	1	LS	$10,000.00	
13	Light plants	$240.00	4	each	$19,200.00	4 each for 20 weeks
14	Steel plates	$125.00	12	each	$7,500.00	12 each for 5 months
15	PowerCrete	$45.50	650	each	$29,575.00	150 each for a 4 lb kit
16	Sideboom	$19,000.00	4	each	$380,000.00	4 sidebooms for 5 working months
17	Equipment Rental - Trackhoes	$4,200.00	6	each	$126,000.00	6 Trackhoes for 5 working months
17	Equipment Rental - Backhoes	$46.58	2	each	$116,450.00	2 Backhoes for 5 working months
18	Equipment Rental - Dozer	$8,000.00	1	each	$40,000.00	1 Bulldozer for 5 months
19	Water Truck, Pigs, Pump & Hardware	$100,000.00	1	LS	$100,000.00	3 water trucks, dryer, compresser, etc.
20	Shoring Rental	$50,000.00	1	LS	$50,000.00	DP Nicoli
21	Drill Pipe - 12"	$59.30	26150	ft	$1,550,695.00	
22	Other Pipe - 12"	$35.00	17525	ft	$613,375.00	
23	Dump Trucks	$368,000.00	1	LS	$368,000.00	4 Dump Trucks for 5 working months
24	Haul / Dump fee (spoils)	$5.00	12000	yds	$60,000.00	
24	Pee Gravel	$3.00	0	cy	$0.00	
25	Rock	$14.25	16000	cy	$228,000.00	
26	Asphalt Paving	$6.00	4000	sf	$24,000.00	
27	Concrete Paving	$15.25	0	sf	$0.00	
28	Sawcut	$1.00	2600	lf	$2,600.00	
29	Sand	$15.00	4000	cy	$60,000.00	
30	Elbows, Tees, Stopples, etc.	$55,000.00	1	LS	$55,000.00	see material list
31	Other Misc stores	$20,000.00	1	LS	$20,000.00	misc fittings, nitrogen, weld rods, sanders, etc.
32	Valves	$54,000.00	1	LS	$54,000.00	see material list
33	Electrostops	$12,000.00	1	LS	$12,000.00	see material list

2012 PRELIMINARY CONSTRUCTION ESTIMATE
Corvallis Reinforcement 200363

	Equipment/Material Total				**$4,790,965.00**	
Item #	**Item**	**Cost/Unit**	**Quantity**	**Unit**	**Cost**	**Comments**
34	Tual Crew Labor	$63.50	14400	hours	$914,400.00	10 hours per day 2 - 6 man crews 120 days
35	Welder - Standard	$65.00	7200	hours	$468,000.00	6 welders for 120 days
36	Specialty Crew	$60.00	3200	hours	$192,000.00	4 man crew for 80 days
37	X-Ray	$1,300.00	108	days	$140,400.00	
38	Trans Crew	$63.00	600	hours	$37,800.00	4 man crew for 15 days
39	Gas Supply	$60.00	40	hours	$2,400.00	2 man crew 5 days
40	Flatbed Truck & Operator	$80.00	1200	hours	$96,000.00	Pipe Delivery
41	Per Diem	$54.00	2400	each	$129,600.00	
42	Lodging	$80.00	2400	each	$192,000.00	
	Labor Total				**$2,172,600.00**	
Item #	**Item**	**Cost/Unit**	**Quantity**	**Unit**	**Cost**	**Comments**
43	Caliper Pig - Post Construction	$50,000.00	1	ea	$50,000.00	Quote from Integrity Dept
44	Contract HDD Bore - Steel	$100.00	26150	ft	$2,615,000.00	
	Contract Total				**$2,665,000.00**	
	Equipment/Material Total				$4,790,965.00	
	Labor Total				$2,172,600.00	
	Contract Total				$2,665,000.00	
	Total				**$9,628,565.00**	
	Construction Overhead (27% for System Reinforcement)				$2,599,712.55	
	Total Cost				**$12,228,277.55**	
	Contingency (10%)				$1,222,827.76	
	Total Project Cost w/ OH				**$13,451,105.31**	

MEMORANDUM

NW Natural
220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

Date: August 24, 2011
To: Steve Nelson, Ryan Truair, Katie Gough, Joe Karney
From: Peter Cathcart
Subject: Proposal for Project Initiation 200581

PROJECT NAME
Perrydale to Monmouth

PROJECT LOCATION
NE of Dallas

PROJECT PLATS
Start 2-094-026. End 2-111-025.

SCOPE
This project is for installation of approximately 53,200 feet (10 miles) of 12-inch steel natural gas pipeline tested and certified at a Maximum Allowable Operating Pressure (MAOP) of 720 psig. This pipeline is part of the Perrydale to Corvallis/Albany (Mid-Willamette Valley Feeder - P30 pipeline). This project starts 4 miles SSE of Amity at Perrydale Reg. Station heading East along Central Coast Trans, then south down Highway 99W, ends 1820' North of Highway 99W and Highway 22 Junction.

PURPOSE
System Reinforcement

COST
Rough Estimated Cost:$13,300,000

FUNDING
System Reinforcement

SCHEDULE
Possible Start date: 9/1/2012
Estimated Construction Duration: 10 months

Project Type	Project Name	PS #	Projected Completion Date (month/Year)
Bare Steel	SE Holgate Bare	200413	12-Sep
Bare Steel	River Road - Milwaukie	200435	12-Sep
Bare Steel	Laughlin 7th to 10th - The Dalles	200466	12-Aug
Bare Steel	NE 21st Ave Columbia Slough Bore	200469	12-Jun
Bare Steel	SW Glen Rd and Midvale	200537	12-Mar
Bare Steel	Tigard St	200673	12-Oct
Bare Steel	Iron Mountain Rd	200674	12-Oct
Bare Steel	West View Rd	200676	12-Oct
Bare Steel	Firestone Service Replacement	200295	12-Jun
Bare Steel	West Berkley St	200410	12-Jun
Bare Steel	Rupert Dr	200411	12-Aug
Bare Steel	Division St	200703	12-Oct
Bare Steel	G St, Hubbard	200704	12-Mar
Bare Steel	5th-6th Alley, Independence	200706	12-Jun
Bare Steel	Third St - Kingwood - W Salem	200711	12-Jul
Cat		Bare PROJECTS	
	2-119 Bare Steel NON-PROJECT		
	319 Bare Services NON-PROJECT		
	Projected Bare Steel/Services		
TIMP	Keizer - Windsor Island Crossing	200204	12-Sep
TIMP	P-72 Miller Sta to Rock Creek ILI	200631	12-Jun
TIMP	P-48 East Metro ILI Reassessment		12-Jun N/A
TIMP	P11 Jean Rd to West Linn	200652	12-Sep
TIMP	P-39 Clatskanie to Deer Island ILI	200662	12-Oct
TIMP	P-39 North Coast ECDA		12-Sep N/A
TIMP	P-30 Central Coast ECDA		12-Sep N/A
TIMP	S-06 Salem to Bethel ECDA		12-Sep N/A
TIMP	P-09 North Coast ECDA		12-Sep N/A
TIMP	P-65 PGE Gate to Meter ECDA		12-Sep N/A
TIMP	S-05 Salem Industrial ECDA		12-Sep N/A
TIMP	S-04 Salem Industrial ECDA		12-Sep N/A

TIMP	ASV/RCV - Front Ave		12-Oct	N/A
TIMP	ASV/RCV - Salem Industrial		12-Oct	N/A
TIMP	Natural Forces - Landslide Study		12-Oct	N/A
TIMP	Natural Forces - Monitor/Remediate		12-Oct	N/A
TIMP	Class Location and HCA analysis		12-Oct	N/A
Cat		**TIMP PROJECTS**		
	2 112 TIMP NON-PROJECT			
Projected TIMP				
DIMP	Sewer Cross Bores		12-Oct	N/A
DIMP	Deathman Ridge - Odell	200455		12-Mar
DIMP	Yamhill Crossing	200367		12-Oct
Cat		**DIMP PROJECTS**		
	2 120 DIMP Mains NON-PROJECT			
320 DIMP Services NON-PROJECT				
Projected DIMP				

Note: The NON-PROJECT line item for each category includes the budget amounts for both p

Operational Life	Project Details	Budget
50 years	Install 682' 2" Poly, 6 services to replace existing bare pipe.	$68,027
50 years	Install 1050' 6" Poly to replace existing bare pipe.	$54,422
50 years	Install 560' 4" Poly, 3100' 2" Poly, 50 services to replace existing bare pipe	$246,259
50 years	Install 200' 4" Poly to replace existing bare pipe	$78,571
50 years	Install 1500' 2" Poly, 300' 2" Coated Steel to replace existing bare pipe	$51,020
50 years	Install 2000' 2" Poly and associated services to replace existing bare pipe	$129,252
50 years	Install 1200' 2" Poly and associated services to replace existing bare pipe	$85,034
50 years	Install 2000' 2" Poly and associated services to replace existing bare pipe	$125,850
50 years	Install 220' of 4" Poly and associated services to replace existing bare pipe	$53,457
50 years	Install 260' of 2" Poly and associated services to replace existing bare pipe	$40,816
50 years	Install 670' of 2"Poly and associated services to replace existing bare pipe	$68,027
50 years	Install 1700' of main, various sizes, to replace existing bare pipe	$102,041
50 years	Install 200' 2" Poly to replace existing bare pipe	$20,408
50 years	Install 1000' 2" Poly to replace existing bare pipe	$68,027
50 years	Install 300' 2"Poly and associated services to replace existing bare pipe	$20,408
		$1,211,620
	200027	$1,675,417
200035		$212,963
		$3,100,000
100 years	Replacement of approximately 1400' of 10" (W) Class D Pipeline due to exposed pipeline in the waterway.	
N/A	Modify and reassess pipeline using inline inspection (ILI)	
	Reassess pipeline with ILI	
N/A	Obtain pipe samples to investigate long seam manufacturing process	
N/A	Modify pipeline for ILI for reassessment	
	ECDA Reassessment of pipeline	
	ECDA Reassessment of pipeline	$200,000
	ECDA Reassessment of pipeline	$50,000
	ECDA Reassessment of pipeline	$150,000
	ECDA Reassessment of pipeline	$25,000
	ECDA Reassessment of pipeline	$25,000
	ECDA Reassessment of pipeline	$25,000

	Evaluation and installation of RCV/ASV on Front Ave transmission pipeline in Portland	$250,000
	Evaluation and installation of RCV/ASV on Salem Industrial transmission pipeline in Salem	$200,000
	Evaluate LiDAR to identify landslides	$150,000
	Monitor or Remediate identified landslides	$100,000
	System wide reevaluation of High Consequence Areas (HCAs)	$500,000
		$4,956,867
	200021	$3,543,133
		$8,500,000
	Investigate and remediate services and mains inadvertently installed in sewer laterals.	$250,000
100 years	Bore approx. 400' of 4" (W) high pressure under Odell Creek to replace an exposed pipe.	$110,619
100 years	Replace river crossing at railroad bridge trestle with 500" of 6" (W). Pipe location is on the upstream side and when the trestle is cleared	$663,717
		$1,024,336
	200028	$500,000
200036		$475,664
		$2,000,000

ɔrojects that are too early in the design phase to have set up a formal project or for work that does

	check	
$1,211,619	$3,100,000	okay

$1,400,000

$547,889

$250,000

$220,994

$662,983

$200,000

$200,000

$50,000

$150,000

$25,000

$25,000

$25,000

ECDA is External Corrosion Direct Assessment
Step 1 - Pre-Analysis (Use the DCVG Direct Pre
Step 2 - Indirect Inspection (Use Quantum CIPS
Step 3 - Direct Examination (Use EXCAVAT Sec
Analysis of data from Steps 1 & 2 to select sites
Step 4 - Post-Assessment (Use the DCVG Direc
The assessment of all available data to evaluat

$250,000 RCV/ASV is Remote Control valves and Automa

$200,000

$150,000 X LIDAR (Light Detection And Ranging, also LADA

$100,000 X

$500,000 X

check

$4,956,866 $8,500,000 okay

$250,000 X

$110,619 X

$663,717 check

$1,024,336 $2,000,000 okay

$7,192,821 Total Capital costs for Nov. 1, 2011 – Oct. 31, 2012. For inclusion in rate base.

Maximum into rate base Oct. 31, 2012

$6,407,177 Non-project and services costs

$13,600,000 Total Projected Bare steel DIMP and TIMP

$13,599,998 check

not meet the NW Natural requirements for setting up a formal project (typically work that is less than

Assessment Software). Collect historical data.
and Analogue DCVG as a one pass survey and DCVG Direct Assessment Software for Analysis)
ion of Direct Assessment Software)
for excavation and pipe metal examination.
t Post-Assessment Software)
e the effectiveness of the ECDA process and determine reassessment intervals.

tic shut-off valves.

R) is an optical remote sensing technology that can measure the distance to, or other properties of a targe

Marked with 'X' — not $1,110,619 capital cost.	$6,082,202	Net to rate base Oct. 31, 2012

$25k).

[redacted]

by illuminating the target with light, often using pulses from a laser

3/1/2012

NW NATURAL
MIST STORAGE DEVELOPMENT HISTORY

	1989	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
UTILITY PROJECTS															
Project Name:	Original Dev. Bruer & Flora	Calvin Creek I Al's Pool	S. Mist Feeder Looping	Miller Station Improvements				SMPE							
Deliverability (MMcfd):															
Reservoir	80	130	0	0				0							
Compression	134	111	0	0				0							
Dehydration	100	50	0	165				0							
Pipeline	145	0	45	0				340							
Working Gas Capacity (Bcf)	5.5	3.0	0.0	0.0				0.0							
NON-UTILITY PROJECTS															
Project Name:				Reichhold Pool Mist northflow	317 Project		Sapphire	Sapphire	Pearl Phase I	Pearl Phase I	Pearl Phase II Molalla Gate				
Non-Utility Deliverability - Mcf/Dth/d				45,000	65,000	0	0	65,000	50,000	0	80,000	0	0		305,000
Deliverability (MMcfd):															
Reservoir				45	65		0	65	50	0	80		0		
Compression				0	180		0	0	0	0	0		0		
Dehydration				0	0		0	195	0	0	0		0		
Pipeline				130	0		0	0	0	0	75 (Note 2)		0		
Incremental Working Gas Capacity (Bcf)				2.00	0.00		1.50	0.85	0.00	0.23	2.71		0.15 (Note 3)		7.43
Net Bcf				2.00	0.00	0.00	1.50	0.46	0.00	0.23	2.71	0.22	0.07		6.60
UTILITY RECALL FROM NON-UTILITY															
Deliverability (MMcfd):															
Reservoir								20				10	10		10
Compression								0				0	5		10
Dehydration								0				0	0		0
Working Gas Capacity (Bcf)								0.39				0.22	0.22		0.22
								20 million cf/day/0.02 Bcf/day							
UTILITY CUMULATIVE															
cf/d	80,000,000	210,000,000	210,000,000	210,000,000	210,000,000	210,000,000	210,000,000	230,000,000	230,000,000	230,000,000	230,000,000	240,000,000	250,000,000	250,000,000	260,000,000
Mcf/Dth/d	80,000	210,000	210,000	210,000	210,000	210,000	210,000	230,000	230,000	230,000	230,000	240,000	260,000	260,000	260,000
Total Deliverability (MMcfd):															
Reservoir	80	210	210	210	210	210	210	230	230	230	230	240	250	250	260
Compression	134	245	245	245	245	245	245	245	245	245	245	245	250	250	260
Dehydration	100	150	150	315	315	315	315	315	315	315	315	315	315	315	315
Pipeline	145	145	190	190	190	190	190	530 (See Note 1)	530 (See Note 1)	530 (See Note 1)	530 (See Note 1)	530 (See Note 1)	530 (See Note 1)	530 (See Note 1)	530 (See Note 1)
Net Deliverability (Lowest Constraint)	80	145	150	190	190	190	190	230	230	230	230	240	250	250	260
Working Gas Capacity (Bcf)	5.50	8.50	8.50	8.50	8.50	8.50	8.50	8.89	8.89	8.89	8.89	9.11	9.33	9.33	9.55

Original enough to meet normal peak
(2010 IRP) 800,000-900,000 Dth/Day design peak
(2010 IRP) 400,000-500,000 Dth/Day normal peak

NOTES:
1) SMPE designed to handle future load growth. The actual capacity is system load dependent and varies over time
2) Increased deliverability based on incremental off-system delivery at Molalla Gate
3) Working gas capacity true-up.
4) All volumes expressed as MMcfd and Bcf, assuming 1,000 Btu/cf

DR 370 -375

Mist Storage Facility System Balances, 2003 through 2011

Note: The amounts "Allocated to Oregon" are generally 90% of these System Balances.

FERC Plant Account	ASSET BALANCES	BALANCE @ 12/31/2011	BALANCE @ 12/31/2010	BALANCE @ 12/31/2009	BALANCE @ 12/31/2008	BALANCE @ 12/31/2007	BALANCE @ 12/31/2006	BALANCE @ 12/31/2005
UTILITY PLANT (SYSTEM BALANCES)								
Natural Gas Underground Storage								
350.1	LAND	$ 106,549	$ 106,549	$ 106,549	$ 106,549	106,549	106,549	106,549
350.2	RIGHTS-OF-WAY	109,625	109,625	109,625	109,625	51,122	51,122	51,122
351	STRUCTURES AND IMPROVEMENTS	6,555,425	6,555,425	6,542,426	6,538,592	6,247,670	6,239,196	6,223,128
352	WELLS	20,047,076	20,047,076	20,041,504	20,041,504	20,041,504	20,039,708	19,733,974
352.1	STORAGE LEASEHOLD & RIGHTS	3,538,491	3,538,491	3,538,491	3,538,491	3,538,491	3,538,491	3,538,491
352.2	RESERVOIRS	5,130,395	4,654,246	4,654,246	4,178,097	3,701,948	3,701,948	3,701,948
352.3	NON-RECOVERABLE NATURAL GAS	6,440,890	6,440,890	6,440,890	6,440,890	6,440,890	6,440,890	6,440,890
353	LINES	6,552,220	6,552,220	6,552,220	6,552,220	6,553,282	6,453,175	6,453,175
354	COMPRESSOR STATION EQUIPMENT	27,957,660	27,431,454	27,422,924	27,090,280	26,981,225	26,967,185	26,961,369
355	MEASURING / REGULATING EQUIPM	6,471,635	6,318,797	6,318,797	6,165,959	5,687,193	5,685,483	5,702,347
356	PURIFICATION EQUIPMENT	297,363	297,363	297,363	297,363	297,363	297,363	297,363
357	OTHER EQUIPMENT	1,331,924	1,331,924	1,331,924	1,218,731	702,587	702,587	702,587
	Natural Gas Utility Underground Storage Subtotal	$ 84,539,254	$ 83,384,061	$ 83,356,960	$ 82,278,300	80,349,825	80,223,697	79,912,943
Transmission Plant								
367.21	NORTH MIST TRANSMISSION LINE	1,993,874	1,563,157	1,563,157	1,563,157	1,514,343	1,514,343	1,514,343
367.22	SOUTH MIST TRANSMISSION LINE	14,949,264	14,949,264	14,949,264	14,949,264	14,949,264	14,949,264	14,949,264
367.23	SOUTH MIST TRANSMISSION LINE	34,007,331	34,007,331	34,007,331	34,007,331	34,007,331	34,010,048	33,959,912
367.24	11.7M S MIST TRANS LINE	17,466,182	17,466,182	17,466,182	17,466,182	17,466,182	17,466,182	17,466,182
367.25	12M NORTH S MIST TRANS	18,530,259	18,530,259	18,530,259	18,530,259	18,530,259	18,530,259	18,409,593
367.26	38M NORTH S MIST TRANS	68,232,676	68,232,676	68,232,676	68,232,676	68,232,676	68,221,196	68,299,558
	Mist Utility Transmission Plant Subtotal	$ 155,179,586	$ 154,748,868	$ 154,748,868	$ 154,748,868	154,700,055	154,691,292	154,598,852
	Total Mist Utility SYSTEM BALANCES	$ 239,718,840	$ 238,132,929	$ 238,105,828	$ 237,027,168	$ 235,049,879	$ 234,914,989	$ 234,511,795
NON-UTILITY PLANT (SYSTEM BALANCES)								
Natural Gas Underground Storage								
352	WELLS	$ 16,792,086	16,792,086	16,791,221	15,960,717	16,286,242	7,151,129	7,209,563
352.1	STORAGE LEASEHOLD & RIGHTS	1,020	1,020	1,020	1,020	1,020	479	479
352.2	RESERVOIRS	5,686,159	6,162,308	6,162,308	6,638,457	7,114,606	7,128,626	7,130,458
353	LINES	1,649,744	1,649,744	1,649,744	1,649,744	1,688,608	1,070,337	1,059,832
354	COMPRESSOR STATION EQUIPMENT	15,163,121	14,759,826	14,691,773	14,954,876	14,954,876	14,954,876	14,850,240
355	MEASURING / REGULATING EQUIPMENT	8,872,031	8,656,907	8,589,046	8,741,884	8,637,541	3,770,389	3,659,486
357	OTHER EQUIPMENT	63,256	63,256	63,256	-	-	-	-
121.8	NON-UTIL PROP-STORAGE	384,149	448,174	448,174	512,199	576,224	576,224	576,224
	Total Mist Non-Utility SYSTEM BALANCES	$ 48,611,565	$ 48,533,321	$ 48,396,542	$ 48,458,897	$ 49,259,117	$ 34,652,060	$ 34,486,283
	Total Mist Utility and Non-Utility SYSTEM BALANCES	$ 288,330,405.05	$ 286,666,250.13	$ 286,502,369.83	$ 285,486,065.51	$ 284,308,996.60	$ 269,567,048.78	$ 268,998,077.13

FERC Plant Account	ACCUMULATED DEPRECIATION	BALANCE @ 12/31/2011	BALANCE @ 12/31/2010	BALANCE @ 12/31/2009	BALANCE @ 12/31/2008	BALANCE @ 12/31/2007	BALANCE @ 12/31/2006	BALANCE @ 12/31/2005
	UTILITY PLANT ACCUMULATED DEPRECIATION (SYSTEM BALANCES)							
	Natural Gas Underground Storage							
350.1	LAND	$ -	$ -	$ -	$ -	-	-	-
350.2	RIGHTS-OF-WAY	18,040	16,264	14,488	12,712	11,641	10,618	9,596
351	STRUCTURES AND IMPROVEMENTS	2,072,376	1,960,279	1,848,227	1,736,354	1,626,182	1,516,229	1,406,577
352	WELLS	9,315,665	8,900,691	8,485,827	8,070,968	7,595,984	7,121,015	6,648,831
352.1	STORAGE LEASEHOLD & RIGHTS	1,230,738	1,161,738	1,092,737	1,023,737	965,352	906,966	848,581
352.2	RESERVOIRS	1,245,146	1,068,560	975,010	826,577	705,485	644,403	583,317
352.3	NON-RECOVERABLE NATURAL GAS	2,714,352	2,593,263	2,472,175	2,351,086	2,244,811	2,138,537	2,032,262
353	LINES	2,366,202	2,231,190	2,096,214	1,961,016	1,839,799	1,720,338	1,600,955
354	COMPRESSOR STATION EQUIPMENT	12,943,818	12,047,560	11,317,669	10,525,872	9,692,012	8,858,708	8,025,454
355	MEASURING / REGULATING EQUIPM	3,442,995	3,256,945	3,119,827	2,943,698	2,728,754	2,551,889	2,390,214
356	PURIFICATION EQUIPMENT	188,197	180,823	173,448	166,074	156,409	146,745	137,081
357	OTHER EQUIPMENT	675,543	645,176	614,805	585,650	529,243	474,512	419,780
	Natural Gas Underground Storage Subtotal	$ 36,213,072	$ 34,062,488	$ 32,210,428	$ 30,203,743	28,095,672	26,089,960	24,102,647
	Transmission Plant							
367.21	NORTH MIST TRANSMISSION LINE	829,551	789,834	750,599	711,257	682,750	654,280	625,810
367.22	SOUTH MIST TRANSMISSION LINE	8,462,518	8,094,602	7,726,850	7,358,082	7,081,521	6,804,960	6,528,398
367.23	SOUTH MIST TRANSMISSION LINE	8,118,755	7,210,387	6,302,391	5,392,085	4,752,747	4,113,407	3,474,070
367.24	11.7M S MIST TRANS LINE	3,010,007	2,557,441	2,105,067	1,651,506	1,323,142	994,778	666,414
367.25	12M NORTH S MIST TRANS	2,878,823	2,394,980	1,911,340	1,426,441	1,077,924	729,407	381,232
367.26	38M NORTH S MIST TRANS	10,776,925	9,002,128	7,228,078	5,449,392	4,166,072	2,882,922	1,599,688
	Mist Transmission Plant Subtotal	$ 34,076,579	$ 30,049,372	$ 26,024,326	$ 21,988,765	$ 19,084,156	16,179,753	13,275,611
	Total Mist Utility Accum. Depreciation Balances	$ 70,289,651	$ 64,111,860	$ 58,234,753	$ 52,192,508	$ 47,179,828	$ 42,269,713	$ 37,378,258
	NON-UTILITY PLANT ACCUMULATED DEPRECIATION (SYSTEM BALANCES)							
	Natural Gas Underground Storage							
352	WELLS	$ 1,846,599	1,499,003	1,151,424	808,860	423,290	244,696	75,344
352.1	STORAGE LEASEHOLD & RIGHTS	102	82	62	42	25	16	8
352.2	RESERVOIRS	871,686	834,365	714,200	649,025	591,971	474,580	356,943
353	LINES	185,289	151,295	117,311	83,270	52,099	31,822	12,174
354	COMPRESSOR STATION EQUIPMENT	3,832,043	3,604,712	3,213,836	2,884,348	2,422,242	1,960,137	1,498,570
355	MEASURING / REGULATING EQUIPM	1,199,168	1,059,874	873,435	725,810	493,784	359,913	245,424
357	OTHER EQUIPMENT	2,945	1,502	60	-	-	-	-
121.8	NON-UTIL PROP-STORAGE				-	-	-	-
	Total Mist Non-Utility Accum. Depreciation Balances	$ 7,937,831	$ 7,150,833	$ 6,070,328	$ 5,151,354	$ 3,983,412	$ 3,071,164	$ 2,188,463
	Total Mist Utility and Non-Utility Accum Dep'n. SYSTEM BALAN	$ 78,227,481	$ 71,262,693	$ 64,305,081	$ 57,343,862	$ 51,163,240	$ 45,340,877	$ 39,566,721

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FERC Plant	NET BOOK VALUE	BALANCE @	BALANCE @	BALANCE @	BALANCE @	BALANCE @	BALANCE @	BALANCE @

Account		12/31/2011	12/31/2010	12/31/2009	12/31/2008	12/31/2007	12/31/2006	12/31/2005
UTILITY PLANT NET BOOK VALUE (SYSTEM)								
Natural Gas Underground Storage								
350.1	LAND	$ 106,549	$ 106,549	$ 106,549	$ 106,549	$ 106,549	$ 106,549	$ 106,549
350.2	RIGHTS-OF-WAY	91,585	93,361	95,137	96,913	39,481	40,504	41,526
351	STRUCTURES AND IMPROVEMENTS	4,483,049	4,595,146	4,694,199	4,802,237	4,621,488	4,722,966	4,816,551
352	WELLS	10,731,411	11,146,385	11,555,677	11,970,536	12,445,520	12,918,694	13,085,143
352.1	STORAGE LEASEHOLD & RIGHTS	2,307,753	2,376,753	2,445,754	2,514,755	2,573,140	2,631,525	2,689,910
352.2	RESERVOIRS	3,885,249	3,585,686	3,679,236	3,351,521	2,996,463	3,057,545	3,118,632
352.3	NON-RECOVERABLE NATURAL GAS	3,726,538	3,847,626	3,968,715	4,089,804	4,196,079	4,302,353	4,408,628
353	LINES	4,186,019	4,321,030	4,456,006	4,591,204	4,713,483	4,732,837	4,852,220
354	COMPRESSOR STATION EQUIPMENT	15,013,843	15,383,894	16,105,255	16,564,407	17,289,213	18,108,477	18,935,915
355	MEASURING / REGULATING EQUIPM	3,028,640	3,061,852	3,198,970	3,222,260	2,958,439	3,133,593	3,312,133
356	PURIFICATION EQUIPMENT	109,166	116,540	123,915	131,289	140,954	150,618	160,282
357	OTHER EQUIPMENT	656,381	686,749	717,119	633,081	173,344	228,075	282,807
	Natural Gas Underground Storage Subtotal	$ 48,326,182	$ 49,321,573	$ 51,146,532	$ 52,074,557	52,254,152	54,133,737	55,810,296
Transmission Plant								
367.21	NORTH MIST TRANSMISSION LINE	1,164,323	773,323	812,558	851,899	831,593	860,063	888,533
367.22	SOUTH MIST TRANSMISSION LINE	6,486,746	6,854,662	7,222,414	7,591,182	7,867,743	8,144,304	8,420,866
367.23	SOUTH MIST TRANSMISSION LINE	25,888,576	26,796,944	27,704,940	28,615,246	29,254,584	29,896,640	30,485,842
367.24	11.7M S MIST TRANS LINE	14,456,175	14,908,740	15,361,115	15,814,675	16,143,040	16,471,404	16,799,768
367.25	12M NORTH S MIST TRANS	15,651,436	16,135,280	16,618,919	17,103,818	17,452,335	17,800,853	18,028,361
367.26	38M NORTH S MIST TRANS	57,455,750	59,230,548	61,004,598	62,783,283	64,066,603	65,338,275	66,699,870
	Mist Transmission Plant Subtotal	$ 121,103,007	$ 124,699,497	$ 128,724,543	$ 132,760,104	$ 135,615,899	138,511,539	141,323,241
	Total Mist Utility Net Book Value	$ 169,429,189	$ 174,021,070	$ 179,871,075	$ 184,834,660	$ 187,870,051	$ 192,645,276	$ 197,133,537
NON-UTILITY PLANT NET BOOK VALUE								
Natural Gas Underground Storage								
352	WELLS	$ 14,945,487	$ 15,293,083	$ 15,639,797	$ 15,151,858	$ 15,862,952	$ 6,906,433	$ 7,134,219
352.1	STORAGE LEASEHOLD & RIGHTS	919	938	958	978	995	463	471
352.2	RESERVOIRS	4,814,474	5,327,943	5,448,108	5,989,432	6,522,635	6,654,046	6,773,515
353	LINES	1,464,455	1,498,448	1,532,433	1,566,474	1,636,509	1,038,516	1,047,658
354	COMPRESSOR STATION EQUIPMENT	11,331,078	11,155,115	11,477,936	12,070,528	12,532,634	12,994,739	13,351,671
355	MEASURING / REGULATING EQUIPM	7,672,863	7,597,033	7,715,612	8,016,075	8,143,757	3,410,476	3,414,061
357	OTHER EQUIPMENT	60,312	61,754	63,196	0	0	0	0
121.8	NON-UTIL PROP-STORAGE	384,149	448,174	448,174	512,199	576,224	576,224	576,224
	Total Mist Non-Utility Net Book Value	$ 40,673,735	$ 41,382,487	$ 42,326,214	$ 43,307,543	$ 45,275,705	$ 31,580,896	$ 32,297,819
Total Mist Utility and Non-Utility Net Book Value		$ 210,102,924	$ 215,403,557	$ 222,197,289	$ 228,142,203	$ 233,145,756	$ 224,226,172	$ 229,431,356
	CHECK FIGURE	210,102,924	215,403,557	222,197,289	228,142,203	233,145,756	224,226,172	229,431,356
		80.64%						
		19.36%						

DR 370 -375

Mist Storage Facility System Balances, 2

Note: The amounts "Allocated to Oregoı

FERC Plant Account	ASSET BALANCES	BALANCE @ 12/31/2004	BALANCE @ 12/31/2003	BALANCE @ 12/31/2002	BALANCE @ 12/31/2001	BALANCE @ 12/31/2000	BALANCE @ 12/31/1999	BALANCE @ 12/31/1998	BALANCE @ 12/31/1997
UTILITY PLANT (SYSTEM BALANCES)									
Natural Gas Underground Storage									
350.1	LAND	106,549	106,549	106,549	106,549	106,549	106,549	106,549	106,549
350.2	RIGHTS-OF-WAY	51,122	51,122	51,122	51,122	47,318	47,318	47,319	46,690
351	STRUCTURES AND IMPROVEMENTS	6,221,913	6,164,049	6,156,413	5,913,514	5,029,273	4,996,462	4,991,499	2,516,340
352	WELLS	19,733,974	18,338,288	18,338,288	18,353,065	18,138,203	18,138,203	18,153,567	11,810,679
352.1	STORAGE LEASEHOLD & RIGHTS	3,538,491	3,538,491	3,538,491	3,535,500	3,535,500	3,535,500	3,530,407	3,038,080
352.2	RESERVOIRS	3,701,948	3,685,786	3,685,786	3,685,286	3,685,286	3,685,094	3,679,091	1,679,184
352.3	NON-RECOVERABLE NATURAL GAS	6,440,890	6,375,402	6,375,402	6,375,402	6,375,402	6,375,402	6,376,195	6,312,953
353	LINES	6,453,175	6,453,175	6,445,334	6,445,334	6,445,334	6,445,334	6,392,472	2,538,843
354	COMPRESSOR STATION EQUIPMENT	26,960,006	26,960,006	26,960,006	26,829,760	25,130,209	21,911,652	21,816,930	8,143,343
355	MEASURING / REGULATING EQUIPM	5,628,658	5,557,476	5,557,476	5,556,979	5,508,129	4,950,253	4,711,612	3,621,492
356	PURIFICATION EQUIPMENT	297,363	297,363	297,363	297,363	297,363	297,363	297,366	294,282
357	OTHER EQUIPMENT	702,587	702,587	702,586	702,586	702,586	702,586	646,258	82,037
	Natural Gas Utility Underground Storage	79,836,676	78,230,293	78,214,816	77,852,460	75,001,152	71,191,716	70,749,265	40,190,472
Transmission Plant									
367.21	NORTH MIST TRANSMISSION LINE	1,514,343	1,514,162	1,514,162	1,514,162	1,514,162	1,514,162	1,514,162	1,514,162
367.22	SOUTH MIST TRANSMISSION LINE	14,949,264	14,949,264	14,949,264	14,949,264	14,949,264	14,949,264	14,949,264	14,949,264
367.23	SOUTH MIST TRANSMISSION LINE	38,244,077	51,774,789	33,580,870	33,580,870	33,580,267	33,516,134	-	-
367.24	11.7M S MIST TRANS LINE	17,895,192	-	-	-	-	-	-	-
367.25	12M NORTH S MIST TRANS	15,692,636	-	-	-	-	-	-	-
367.26	38M NORTH S MIST TRANS	65,881,392	-	-	-	-	-	-	-
	Mist Utility Transmission Plant Subtotal	154,176,904	68,238,215	50,044,296	50,044,296	50,043,693	49,979,560	16,463,426	16,463,426
	Total Mist Utility SYSTEM BALAN	$ 234,013,580	$ 146,468,508	$ 128,259,112	$ 127,896,756	$ 125,044,845	$ 121,171,276	$ 87,212,691	$ 56,653,898
NON-UTILITY PLANT (SYSTEM BALANCES)									
Natural Gas Underground Storage									
352	WELLS	2,480,875	-	-	-	-	-	-	-
352.1	STORAGE LEASEHOLD & RIGHTS	479	-	-	-	-	-	-	-
352.2	RESERVOIRS	5,067,315	-	-	-	-	-	-	-
353	LINES	571,970	-	-	-	-	-	-	-
354	COMPRESSOR STATION EQUIPMENT	14,225,421	-	-	-	-	-	-	-
355	MEASURING / REGULATING EQUIPM	1,978,349	-	-	-	-	-	-	-
357	OTHER EQUIPMENT	-	-	-	-	-	-	-	-
121.8	NON-UTIL PROP-STORAGE	576,224	18,507,151	17,036,615	14,479,594	4,929,261	-	-	-
	Total Mist Non-Utility SYSTEM BA	$ 24,900,633	$ 18,507,151	$ 17,036,615	$ 14,479,594	$ 4,929,261	$ -	$ -	$ -
	Total Mist Utility and Non-Utility SYSTEM	$ 258,914,212.41	$ 164,975,659.20	$ 145,295,727.00	$ 142,376,350.00	$ 129,974,106.00	$ 121,171,276.00	$ 87,212,691.00	$ 56,653,898.00

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FERC Plant Account	ACCUMULATED DEPRECIATION	BALANCE @ 12/31/2004	BALANCE @ 12/31/2003	BALANCE @ 12/31/2002	BALANCE @ 12/31/2001	BALANCE @ 12/31/2000	BALANCE @ 12/31/1999	BALANCE @ 12/31/1998	BALANCE @ 12/31/1997
UTILITY PLANT ACCUMULATED DEPRECIATIO									
Natural Gas Underground Storage									
350.1	LAND	-	-	-	-	-	-	-	-
350.2	RIGHTS-OF-WAY	8,573	7,551	6,554	5,608	4,673	3,738	2,802	1,866
351	STRUCTURES AND IMPROVEMENTS	1,297,053	1,188,359	1,079,939	985,477	894,828	806,707	718,813	674,525
352	WELLS	6,181,136	5,729,979	5,295,362	4,862,581	4,430,884	3,993,967	3,598,509	3,284,233
352.1	STORAGE LEASEHOLD & RIGHTS	790,196	731,811	673,426	615,041	556,705	498,369	442,883	389,905
352.2	RESERVOIRS	522,220	376,021	315,214	237,911	177,104	116,297	55,455	27,707
352.3	NON-RECOVERABLE NATURAL GAS	1,925,987	1,820,253	1,715,059	1,609,865	1,504,671	1,399,477	1,294,271	1,190,107
353	LINES	1,481,571	1,362,187	1,242,948	1,123,612	1,004,373	885,134	886,853	718,940
354	COMPRESSOR STATION EQUIPMENT	7,196,863	6,358,786	5,525,601	4,747,431	3,997,854	3,312,826	2,664,741	2,386,281
355	MEASURING / REGULATING EQUIPM	2,214,945	2,042,107	1,869,269	1,695,497	1,527,592	1,369,212	1,313,796	1,106,342
356	PURIFICATION EQUIPMENT	127,416	117,752	108,088	98,424	88,760	79,096	69,432	59,868
357	OTHER EQUIPMENT	365,049	310,317	255,585	200,853	146,119	91,387	48,168	32,459
	Natural Gas Underground Storage Subtot	22,111,010	20,045,123	18,087,045	16,182,300	14,333,563	12,556,210	11,095,723	9,872,233
Transmission Plant									
367.21	NORTH MIST TRANSMISSION LINE	597,341	568,873	540,407	511,941	483,475	455,009	426,543	398,077
367.22	SOUTH MIST TRANSMISSION LINE	6,251,837	5,975,276	5,694,230	5,413,184	5,132,138	4,855,577	1,511,705	4,235,144
367.23	SOUTH MIST TRANSMISSION LINE	2,750,511	2,583,702	1,910,384	1,224,456	672,317	51,675	-	-
367.24	11.7M S MIST TRANS LINE	336,573							
367.25	12M NORTH S MIST TRANS	86,085							
367.26	38M NORTH S MIST TRANS	360,590							
	Mist Transmission Plant Subtotal	10,382,936	9,127,851	8,145,021	7,149,581	6,287,930	5,362,261	1,938,248	4,633,221
	Total Mist Utility Accum. Depreciat	$ 32,493,946	$ 29,172,974	$ 26,232,066	$ 23,331,881	$ 20,621,493	$ 17,918,471	$ 13,033,971	$ 14,505,454
NON-UTILITY PLANT ACCUMULATED DEPRECI									
Natural Gas Underground Storage									
352	WELLS	2,450	-	-	-	-	-	-	-
352.1	STORAGE LEASEHOLD & RIGHTS	0	-	-	-	-	-	-	-
352.2	RESERVOIRS	267,148	-	-	-	-	-	-	-
353	LINES	441	-	-	-	-	-	-	-
354	COMPRESSOR STATION EQUIPMENT	1,028,890	-	-	-	-	-	-	-
355	MEASURING / REGULATING EQUIPM	175,087	-	-	-	-	-	-	-
357	OTHER EQUIPMENT	-	-	-	-	-	-	-	-
121.8	NON-UTIL PROP-STORAGE	-	1,084,689	633,297	237,121	-	-	-	-
	Total Mist Non-Utility Accum. Depre	$ 1,474,016	$ 1,084,689	$ 633,297	$ 237,121	$ -	$ -	$ -	$ -
	Total Mist Utility and Non-Utility Accum Dep'l	$ 33,967,962	$ 30,257,663	$ 26,865,363	$ 23,569,002	$ 20,621,493	$ 17,918,471	$ 13,033,971	$ 14,505,454

FERC Plant	NET BOOK VALUE	BALANCE @	BALANCE @	BALANCE @	BALANCE @	BALANCE @	BALANCE @	BALANCE @	BALANCE @

Account		12/31/2004	12/31/2003	12/31/2002	12/31/2001	12/31/2000	12/31/1999	12/31/1998	12/31/1997
UTILITY PLANT NET BOOK VALUE (SYSTEM)									
Natural Gas Underground Storage									
350.1	LAND	$ 106,549	$ 106,549	$ 106,549	$ 106,549	$ 106,549	$ 106,549	$ 106,549	$ 106,549
350.2	RIGHTS-OF-WAY	42,549	43,571	44,568	45,514	42,645	43,580	44,517	44,824
351	STRUCTURES AND IMPROVEMENTS	4,924,859	4,975,690	5,076,474	4,928,037	4,134,445	4,189,755	4,272,686	1,841,815
352	WELLS	13,552,838	12,608,309	13,042,926	13,490,484	13,707,319	14,144,236	14,555,058	8,526,446
352.1	STORAGE LEASEHOLD & RIGHTS	2,748,295	2,806,680	2,865,065	2,920,459	2,978,795	3,037,131	3,087,524	2,648,175
352.2	RESERVOIRS	3,179,728	3,309,765	3,370,572	3,447,375	3,508,182	3,568,797	3,623,636	1,651,477
352.3	NON-RECOVERABLE NATURAL GAS	4,514,902	4,555,149	4,660,343	4,765,537	4,870,731	4,975,925	5,081,924	5,122,846
353	LINES	4,971,604	5,090,988	5,202,386	5,321,722	5,440,961	5,560,200	5,505,619	1,819,903
354	COMPRESSOR STATION EQUIPMEN1	19,763,143	20,601,220	21,434,405	22,082,329	21,132,355	18,598,826	19,152,189	5,757,062
355	MEASURING / REGULATING EQUIPM	3,413,713	3,515,369	3,688,207	3,861,482	3,980,537	3,581,041	3,397,816	2,515,150
356	PURIFICATION EQUIPMENT	169,947	179,611	189,275	198,939	208,603	218,267	227,934	234,414
357	OTHER EQUIPMENT	337,538	392,270	447,001	501,733	556,467	611,199	598,090	49,578
	Natural Gas Underground Storage Subtot	57,725,666	58,185,170	60,127,771	61,670,160	60,667,589	58,635,506	59,653,542	30,318,239
Transmission Plant									
367.21	NORTH MIST TRANSMISSION LINE	917,002	945,289	973,755	1,002,221	1,030,687	1,059,153	1,087,619	1,116,085
367.22	SOUTH MIST TRANSMISSION LINE	8,697,427	8,973,988	9,255,034	9,536,080	9,817,126	10,093,687	13,437,559	10,714,120
367.23	SOUTH MIST TRANSMISSION LINE	35,493,565	49,191,087	31,670,486	32,356,414	32,907,950	33,464,459	-	-
367.24	11.7M S MIST TRANS LINE	17,558,619							
367.25	12M NORTH S MIST TRANS	15,606,551							
367.26	38M NORTH S MIST TRANS	65,520,801							
	Mist Transmission Plant Subtotal	143,793,967	59,110,364	41,899,275	42,894,715	43,755,763	44,617,299	14,525,178	11,830,205
	Total Mist Utility Net Book Value	$ 201,519,634	$ 117,295,534	$ 102,027,046	$ 104,564,875	$ 104,423,352	$ 103,252,805	$ 74,178,720	$ 42,148,444
NON-UTILITY PLANT NET BOOK VALUE									
Natural Gas Underground Storage									
352	WELLS	$ 2,478,425	$ -	$ -	$ -	$ -			
352.1	STORAGE LEASEHOLD & RIGHTS	479	0	0	0	0			
352.2	RESERVOIRS	4,800,167	0	0	0	0			
353	LINES	571,529	0	0	0	0			
354	COMPRESSOR STATION EQUIPMEN1	13,196,531	0	0	0	0			
355	MEASURING / REGULATING EQUIPM	1,803,262	0	0	0	0			
357	OTHER EQUIPMENT	0	0	0	0	0			
121.8	NON-UTIL PROP-STORAGE	576,224	17,422,462	16,403,318	14,242,473	4,929,261			
	Total Mist Non-Utility Net Book Valu	$ 23,426,617	$ 17,422,462	$ 16,403,318	$ 14,242,473	$ 4,929,261	$ -	$ -	$ -
Total Mist Utility and Non-Utility Net Book Va		$ 224,946,250	$ 134,717,996	$ 118,430,364	$ 118,807,348	$ 109,352,613	$ 103,252,805	$ 74,178,720	$ 42,148,444
		224,946,250	134,717,996	118,430,364	118,807,348	109,352,613	103,252,805	74,178,720	42,148,444

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Mist Storage Facility System Balances, 2

Note: The amounts "Allocated to Oregoı

FERC Plant Account	ASSET BALANCES	BALANCE @ 12/31/1996	BALANCE @ 12/31/1995	BALANCE @ 12/31/1994	BALANCE @ 12/31/1993	BALANCE @ 12/31/1992	BALANCE @ 12/31/1991	BALANCE @ 12/31/1990	BALANCE @ 12/31/1989
	UTILITY PLANT (SYSTEM BALANCES)								
	Natural Gas Underground Storage								
350.1	LAND	106,549	106,549	106,549	106,549	106,549	106,549	106,549	106,549
350.2	RIGHTS-OF-WAY	47,121	46,505	46,505	46,105	40,841	40,841	40,841	40,841
351	STRUCTURES AND IMPROVEMENTS	2,516,340	2,516,340	2,480,692	2,483,626	2,464,204	2,422,299	2,146,801	2,101,010
352	WELLS	12,663,008	11,810,679	11,810,679	11,808,321	11,625,429	11,492,192	9,370,235	8,834,153
352.1	STORAGE LEASEHOLD & RIGHTS	1,821,179	1,210,801	1,210,801	1,210,801	1,210,801	1,210,801	1,210,801	1,210,801
352.2	RESERVOIRS	2,506,094	-	-	-	-	-	-	-
352.3	NON-RECOVERABLE NATURAL GAS	6,374,886	4,057,953	4,057,953	4,057,953	4,057,953	4,057,953	4,057,953	4,057,953
353	LINES	2,545,524	2,538,843	2,538,843	2,538,843	2,538,843	2,490,017	2,552,840	2,521,354
354	COMPRESSOR STATION EQUIPMENI	8,149,334	8,121,118	8,055,960	8,048,312	8,045,172	8,034,912	7,983,205	7,903,744
355	MEASURING / REGULATING EQUIPM	3,621,492	3,606,120	3,596,262	3,596,227	3,594,442	3,576,623	3,555,213	3,488,264
356	PURIFICATION EQUIPMENT	294,282	245,456	171,575	171,575	168,697	152,757	139,236	126,422
357	OTHER EQUIPMENT	82,037	82,037	82,037	82,037	82,037	76,057	69,748	69,748
	Natural Gas Utility Underground Storage	40,727,846	34,342,401	34,157,856	34,150,349	33,934,968	33,661,001	31,233,422	30,460,839
	Transmission Plant								
367.21	NORTH MIST TRANSMISSION LINE	1,514,162	1,514,162	1,514,162	1,514,162	1,514,162	1,514,162	1,514,162	1,514,162
367.22	SOUTH MIST TRANSMISSION LINE	14,949,264	14,949,264	14,949,264	14,949,264	14,940,551	14,940,551	14,940,551	14,940,551
367.23	SOUTH MIST TRANSMISSION LINE	-	-	-	-	-	-	-	-
367.24	11.7M S MIST TRANS LINE	-	-	-	-	-	-	-	-
367.25	12M NORTH S MIST TRANS	-	-	-	-	-	-	-	-
367.26	38M NORTH S MIST TRANS	-	-	-	-	-	-	-	-
	Mist Utility Transmission Plant Subtotal	16,463,426	16,463,426	16,463,426	16,463,426	16,454,713	16,454,713	16,454,713	16,454,713
	Total Mist Utility SYSTEM BALAN	$ 57,191,272	$ 50,805,827	$ 50,621,282	$ 50,613,775	$ 50,389,681	$ 50,115,714	$ 47,688,135	$ 46,915,552
	NON-UTILITY PLANT (SYSTEM BALANCES)								
	Natural Gas Underground Storage								
352	WELLS	-	-	-	-	-	-	-	-
352.1	STORAGE LEASEHOLD & RIGHTS	-	-	-	-	-	-	-	-
352.2	RESERVOIRS	-	-	-	-	-	-	-	-
353	LINES	-	-	-	-	-	-	-	-
354	COMPRESSOR STATION EQUIPMENI	-	-	-	-	-	-	-	-
355	MEASURING / REGULATING EQUIPM	-	-	-	-	-	-	-	-
357	OTHER EQUIPMENT	-	-	-	-	-	-	-	-
121.8	NON-UTIL PROP-STORAGE	-	-	-	-	-	-	-	-
	Total Mist Non-Utility SYSTEM BA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Mist Utility and Non-Utility SYSTEM	$ 57,191,272.00	$ 50,805,827.00	$ 50,621,282.00	$ 50,613,775.00	$ 50,389,681.00	$ 50,115,714.00	$ 47,688,135.00	$ 46,915,552.00

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FERC Plant Account	ACCUMULATED DEPRECIATION	BALANCE @ 12/31/1996	BALANCE @ 12/31/1995	BALANCE @ 12/31/1994	BALANCE @ 12/31/1993	BALANCE @ 12/31/1992	BALANCE @ 12/31/1991	BALANCE @ 12/31/1990	BALANCE @ 12/31/1989
UTILITY PLANT ACCUMULATED DEPRECIATIO									
Natural Gas Underground Storage									
350.1	LAND	-	-	-	-	-	-	-	-
350.2	RIGHTS-OF-WAY	930	-	-	-	-	-	-	-
351	STRUCTURES AND IMPROVEMENTS	630,237	585,949	486,008	386,722	287,765	190,037	-	-
352	WELLS	3,014,420	2,724,407	2,251,980	1,779,600	1,310,925	848,860	-	-
352.1	STORAGE LEASEHOLD & RIGHTS	323,181	298,167	249,735	201,627	153,195	104,763	-	-
352.2	RESERVOIRS	-	-	-	-	-	-	-	-
352.3	NON-RECOVERABLE NATURAL GAS	1,086,454	1,000,383	838,065	675,747	513,429	351,111	-	-
353	LINES	672,033	625,003	523,449	421,895	320,341	216,898	-	-
354	COMPRESSOR STATION EQUIPMENT	2,135,334	1,883,956	1,611,626	1,289,523	967,671	648,589	-	-
355	MEASURING / REGULATING EQUIPM	993,714	881,325	737,277	593,427	449,614	306,257	-	-
356	PURIFICATION EQUIPMENT	50,304	41,533	33,192	26,329	19,524	13,328	-	-
357	OTHER EQUIPMENT	26,068	19,677	16,396	13,115	9,834	6,792	-	-
	Natural Gas Underground Storage Subtot	8,932,675	8,060,400	6,747,728	5,387,985	4,032,298	2,686,635	1,438,019	201,493
Transmission Plant									
367.21	NORTH MIST TRANSMISSION LINE	369,611	341,145	280,579	220,013	159,447	98,881	-	-
367.22	SOUTH MIST TRANSMISSION LINE	3,958,583	3,682,022	3,084,051	2,486,080	1,888,284	1,290,662	-	-
367.23	SOUTH MIST TRANSMISSION LINE	-	-	-	-	-	-	-	-
367.24	11.7M S MIST TRANS LINE								
367.25	12M NORTH S MIST TRANS								
367.26	38M NORTH S MIST TRANS								
	Mist Transmission Plant Subtotal	4,328,194	4,023,167	3,364,630	2,706,093	2,047,731	1,389,543	731,543	73,543
	Total Mist Utility Accum. Depreciat	$ 13,260,869	$ 12,083,567	$ 10,112,358	$ 8,094,078	$ 6,080,029	$ 4,076,178	$ 2,169,562	$ 275,036
NON-UTILITY PLANT ACCUMULATED DEPRECI									
Natural Gas Underground Storage									
352	WELLS	-	-	-	-	-	-	-	-
352.1	STORAGE LEASEHOLD & RIGHTS	-	-	-	-	-	-	-	-
352.2	RESERVOIRS	-	-	-	-	-	-	-	-
353	LINES	-	-	-	-	-	-	-	-
354	COMPRESSOR STATION EQUIPMENT	-	-	-	-	-	-	-	-
355	MEASURING / REGULATING EQUIPM	-	-	-	-	-	-	-	-
357	OTHER EQUIPMENT	-	-	-	-	-	-	-	-
121.8	NON-UTIL PROP-STORAGE	-	-						
	Total Mist Non-Utility Accum. Depre	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Mist Utility and Non-Utility Accum Dep'l	$ 13,260,869	$ 12,083,567	$ 10,112,358	$ 8,094,078	$ 6,080,029	$ 4,076,178	$ 2,169,562	$ 275,036

FERC Plant	NET BOOK VALUE	BALANCE @	BALANCE @	BALANCE @	BALANCE @	BALANCE @	BALANCE @	BALANCE @	BALANCE @

Account		12/31/1996	12/31/1995	12/31/1994	12/31/1993	12/31/1992	12/31/1991	12/31/1990	12/31/1989
UTILITY PLANT NET BOOK VALUE (SYSTEM)									
Natural Gas Underground Storage									
350.1	LAND	$ 106,549	$ 106,549	$ 106,549	$ 106,549	$ 106,549	$ 106,549		
350.2	RIGHTS-OF-WAY	46,191	46,505	46,505	46,105	40,841	40,841		
351	STRUCTURES AND IMPROVEMENTS	1,886,103	1,930,391	1,994,684	2,096,904	2,176,439	2,232,262		
352	WELLS	9,648,588	9,086,272	9,558,699	10,028,721	10,314,504	10,643,332		
352.1	STORAGE LEASEHOLD & RIGHTS	1,497,998	912,634	961,066	1,009,174	1,057,606	1,106,038		
352.2	RESERVOIRS	2,506,094	0	0	0	0	0		
352.3	NON-RECOVERABLE NATURAL GAS	5,288,432	3,057,570	3,219,888	3,382,206	3,544,524	3,706,842		
353	LINES	1,873,491	1,913,840	2,015,394	2,116,948	2,218,502	2,273,119		
354	COMPRESSOR STATION EQUIPMENT	6,014,000	6,237,162	6,444,334	6,758,789	7,077,501	7,386,323		
355	MEASURING / REGULATING EQUIPM	2,627,778	2,724,795	2,858,985	3,002,800	3,144,828	3,270,366		
356	PURIFICATION EQUIPMENT	243,978	203,923	138,383	145,246	149,173	139,429		
357	OTHER EQUIPMENT	55,969	62,360	65,641	68,922	72,203	69,265		
	Natural Gas Underground Storage Subtot	31,795,171	26,282,001	27,410,128	28,762,364	29,902,670	30,974,366	29,795,403	30,259,346
Transmission Plant									
367.21	NORTH MIST TRANSMISSION LINE	1,144,551	1,173,017	1,233,583	1,294,149	1,354,715	1,415,281		
367.22	SOUTH MIST TRANSMISSION LINE	10,990,681	11,267,242	11,865,213	12,463,184	13,052,267	13,649,889		
367.23	SOUTH MIST TRANSMISSION LINE	-	-	-	-	-	-		
367.24	11.7M S MIST TRANS LINE								
367.25	12M NORTH S MIST TRANS								
367.26	38M NORTH S MIST TRANS								
	Mist Transmission Plant Subtotal	12,135,232	12,440,259	13,098,796	13,757,333	14,406,982	15,065,170	15,723,170	16,381,170
	Total Mist Utility Net Book Value	$ 43,930,403	$ 38,722,260	$ 40,508,924	$ 42,519,697	$ 44,309,652	$ 46,039,536	$ 45,518,573	$ 46,640,516
NON-UTILITY PLANT NET BOOK VALUE									
Natural Gas Underground Storage									
352	WELLS								
352.1	STORAGE LEASEHOLD & RIGHTS								
352.2	RESERVOIRS								
353	LINES								
354	COMPRESSOR STATION EQUIPMENT								
355	MEASURING / REGULATING EQUIPM								
357	OTHER EQUIPMENT								
121.8	NON-UTIL PROP-STORAGE								
	Total Mist Non-Utility Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Mist Utility and Non-Utility Net Book Va		$ 43,930,403	$ 38,722,260	$ 40,508,924	$ 42,519,697	$ 44,309,652	$ 46,039,536	$ 45,518,573	$ 46,640,516
		43,930,403	38,722,260	40,508,924	42,519,697	44,309,652	46,039,536	45,518,573	46,640,516

Staff/1003
Zimmerman/106

Following is a summary of the major projects at or supporting Mist underground storage, in chronological order:

1989 – The original storage project was put into service. It consisted of the development of 2 depleted gas reservoirs, Bruer and Flora, the construction of a central compression facility (Miller Station) with a single dehydration unit and 2 - 1,350 BHP reciprocating compressors. Mist was connected to NW Natural's North Coast Feeder by a 12" pipeline, used primarily for injection purposes, and a 16" pipeline (South Mist Feeder) connected to the Portland area transmission system and used primarily during withdrawal operations.

1998 – The first expansion of the Mist facility included the development of Al's Pool in the Calvin Creek area, the construction of a new high capacity gathering pipeline to the Calvin Creek area, and upgrades to Miller Station including the addition of a single 5,000 BHP centrifugal (turbine) compressor and improvements to the dehydration system.

1999 – The northern segment of the 16" South Mist Feeder was looped with 28 miles of 24" pipeline, improving the withdrawal capacity.

2000 – Numerous improvements to Miller Station were completed including replacement of the dehydration system and upgrades to the system controls and metering. In addition, the Reichhold Pool in the Calvin Creek area was developed for storage operations. The North Mist Pipeline and North Coast Feeder were configured for northbound flows (withdrawals) for delivery off system.

2001 – Miller Station was expanded to include a second centrifugal compressor (7,500 BHP) and Reichhold Pool was upgraded with additional injection/withdrawal wells.

2003 – Maximum pressures in the Bruer and Flora Pools were increased by 5% over their original discovery pressure (referred to as "delta pressure"), increasing their working gas capacity in order to complement the high deliverability profile of the Busch and Schlicker Pools being added in the Sapphire project.

2004 – The 24" South Mist Pipeline Extension (SMPE) was completed from the endpoint of the 1999 looping project all the way to Molalla, providing significant improvements in the takeaway capability from Mist. The Sapphire project at Mist was completed, which included development of 2 new storage reservoirs - Busch and Schlicker Pools - both in the Calvin Creek area. At Miller Station, a second dehydration system was added.

2005 – Two additional injection/withdrawal wells were completed in Bruer Pool, increasing its deliverability.

2006 – Bruer and Flora Pools were delta pressured to 10% over their original discovery pressure, resulting in additional increases in their working gas capacity in order to complement the additional deliverability from the injection/withdrawal wells added to the Bruer Pool in 2005.

2007 – The Meyer Pool was developed and 2 additional injection/withdrawal wells were drilled into Flora Pool. The Molalla Gate project was completed, which installed two centrifugal compressors totaling approximately 2,000 HP at the gate station for physical redelivery of gas off of NW Natural's system into the interstate system.

CASE: UG 221
WITNESS: Ken Zimmerman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1004

Exhibits in Support
Of Opening Testimony

May 3, 2012

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 (b~~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 20xx~~11~~**
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 50/50~~80/20~~ basis; 5~~8~~0% will be retained by NW Natural, and 5~~2~~0% 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 221~~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.~~

4~~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)

Issued ~~December 30, 2011~~
~~NWN Advice No. OPUC 11-19~~

Effective with service on
and after ~~February 1, 2012~~

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 and deliverability.

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 20xx~~11~~**

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, 20xx~~10~~ through December 31, 20xx~~10~~:

~~($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 90/10~~67/33~~ basis; ~~33~~10% will be retained by NW Natural, and 90%~~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.

Issued ~~December 30, 2011~~
~~NWN Advice No. OPUC 11-19~~

Effective with service on
and after ~~February 1, 2012~~

CASE: UG 221
WITNESS: Moshrek Sobhy

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Moshrek Sobhy. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/1101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony responds to the testimony of Grant Yoshihara in the Company's Exhibit NWN/600. The purpose of my testimony is to evaluate the need and justification for the proposed Mid Willamette Valley Feeder (MWVF) project and the Corvallis Loop project in this proceeding. I also provide testimony proposing to recover the expenses of the Company's Industrial Demand Side Management (DSM) Program through a permanent tariff rate instead of the current deferral mechanism.

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibits Staff/1102 through Staff/1116.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Section 1: Recommendations.

Section 2: Analysis of the MWVF and Corvallis Loop projects.

Section 3: The Industrial Demand Side Management Program.

SECTION 1: RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The summary of my recommendations is:

- Remove $8.1 million for the Monmouth Reinforcement phase of the MWVF project from the Company's rate base in this proceeding.
- Allow the Corvallis Loop project in rate base in this proceeding in accordance to the principle of cost causation and subject to the fulfillment of the in-service date requirement per ORS 757355.
- Terminate the current recovery of the Industrial DSM expenses through deferral accounts and implement a permanent tariff rate through a balancing account.

I recommend the Commission find that the Company did not provide sufficient information to justify the rate base treatment of the MWVF project. This recommendation does not apply to the South of Monmouth Bare Replacement phase, which the Company proposes to recover through the annual Purchased Gas Adjustment (PGA) filing as part of the System Integrity Program (SIP).[1] As explained in detail later in my testimony, the Company provided information indicating that the additional capacity from this project will not be needed until 2025/2026.[2] The Company did not sufficiently demonstrate that this project is cost-effective and most efficient for the purpose of increasing winter deliverability and peak demand capability whether due to long term future

[1] The Commission authorized the Company to recover costs related to complying with federal pipeline safety regulations in Order Nos. 09-067 and 11-337.
[2] See Docket No. LC 51: The Company's modified 2011 Integrated Resource Planning in.

growth or due to reduction of service on the Northwest Pipeline's Grant's Pass Lateral. Furthermore, the Company's reason that the project provides additional capacity and deliverability to meet future growth is not consistent with the results of its analysis in the modified 2011 IRP and its projections for load reduction in the near and midterm. Additionally, due to the Company successfully meeting firm demand to its customers under colder-than-normal weather combined with incidents of reduced service on the Grant's Pass Lateral, the Company did not provide demonstrate the need for the MWVF project in the near and midterms. Moreover, the Company did not conduct a financial analysis for the MWVF project to determine whether the project was the least-cost and most-efficient means to accomplish the stated project's benefits. For ratemaking purposes, the result of my recommendation is to remove $8.1 million from rate base for the Monmouth Reinforcement phase. As explained below in my analysis, the remaining phases of the MWVF project are not included in the rate base in this proceeding. However, the need analysis is inclusive of all phases of the project except for the bare steel replacement phase. As my analysis will show, the information provided by the Company does not support that the ratepayers start paying the return of and return on the $8.1 million investment in the Monmouth Reinforcement phase in November 2012 while the evidence shows that the project will not be needed until the year 2025. With respect to the Corvallis Loop project, I recommend that the Commission allow the recovery of the Corvallis Loop project through rates in accordance to the cost causality principle as I explain in detail below, and subject to fulfilling the in-service date requirement of ORS 757.355.

I also recommend that the Company recovers the expenses of the Industrial Demand Side Management (Industrial DSM) program through a permanent tariff rate subject to annual true-up instead of the current deferral mechanism.

SECTION 2: EVALUATION OF THE MWVF AND CORVALLIS LOOP PROJECTS

Q. DID THE COMPANY DESCRIBE THE MWVF AND CORVALLIS LOOP PROJECTS?

A. Yes. The description of these projects is found in the testimony of the Company's witness, Grant Yoshihara, in NWN/600. The Corvallis Loop project is a system reinforcement project that consists of two 12-inch diameter transmission lines to increase capacity and reliability to the Corvallis and Philomath areas. (NWN/600, Yoshihara/2.) The first segment will operate at a pressure of 720 pounds per square inch gauge (psig) and will connect to the existing 10-inch Albany-Corvallis Feeder. The second segment will operate at 400 psig and will connect to the existing distribution system serving west Corvallis and Philomath. The MWVF consists of four phases of 12-inch diameter transmission lines designed to operate at 720 psig. The four phases of the MWVF project are Perrydale to Monmouth, Monmouth Reinforcement, Willamette Crossing near Corvallis, and South of Monmouth Bare Replacement.

Q. WHAT AREAS WILL THESE TWO PROJECTS SERVE?

A. The MWVF and Corvallis Loop projects will serve the Albany-Corvallis-Philomath areas as explained in the Company's Exhibit NWN/600.

Q. WHAT IS THE COMPANY'S PROPOSAL IN THIS PROCEEDING WITH RESPECT TO THESE PROJECTS?

A. The Company proposes to recover the cost of these capital projects through rates effective November 1, 2012. Mr. Yoshihara describes the Company's reasons to construct the MWVF and the Corvallis Loop projects and placing them in service by November 1, 2012, in Exhibit NWN/600. In summary, the drivers for these two projects are:

- Increase 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;
- Increase peak day delivery capability and winter delivery capability into the west end of the Albany-Corvallis corridor to address existing system limitations;
- Extend on-system storage delivery capability from Mist and Newport LNG as far south as the Corvallis service area;
- Reduce the reliance on Northwest Pipelines' Grant's Pass Lateral for meeting peak day delivery requirements, and reduce potential consequences of a service disruption on Northwest Pipeline; and
- Increase safety by replacing the remaining bare steel in the Company's Oregon distribution system. (See NWN/600, Yoshihara/1-7)

Q. WHAT IS THE ESTIMATED COST OF THE MWVF AND CORVALLIS LOOP PROJECTS?

A. The estimated total cost of the MWVF project is $32,600,000 as follows:

- Perrydale to Monmouth (MWVF): $13,500,000.
- Monmouth Reinforcement (MWVF): $8,100,000.

- Willamette Crossing near Corvallis (MWVF): $11,000,000.
- South of Monmouth Bare Replacement (MWVF): $14,300,000.

The Corvallis Loop project is estimated at a cost of $12,800,000.

Q. ARE THE CORVALLIS LOOP AND MWVF PROJECTS OPERATIONALLY AND PHYSICALLY CONNECTED?

A. Yes. Mr. Yoshihara states: "The Corvallis Loop Project and the Mid-Willamette Valley Feeder Project are closely tied operationally, as will be described later in this testimony". (NWN/600, Yoshihara/2, lines 16-17.)

Mr. Yoshihara/also states:

"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." (NWN/600, Yoshihara/4, lines 1-5.) Further, in response to Staff DR 171, the Company explained that the southern end of the MWVF project will be physically tied to the northeastern end of the Corvallis Loop at the Albany-Corvallis Feeder east of Corvallis. (See Staff/1102.)

Q. WHY IS YOUR ADJUSTMENT TO RATE BASE LIMITED ONLY TO THE MONMOUTH REINFORCEMENT PHASE OF THE MWVF PROJECT?

A. In response to data requests from Staff, the Company has clarified that it is not including the Willamette Crossing near Corvallis and the Perrydale to Monmouth phases in rate base because they will not be completed and placed in service on or before, November 1, 2012, which is the required in-service date for rate recovery purposes per ORS 757.355. (Staff/1103; Company response to Staff DR 267.) Also, the Company proposes to recover the South of Monmouth Bare Replacement through the System Integrity Program (SIP) mechanism as part of its annual Purchased Gas Adjustment (PGA) filing in 2013 and therefore this phase is not subject to rate base treatment in this proceeding. (NWN/600,Yoshihara/12-13.) After excluding the above phases of the MWVF project, the remaining phase that is subject to rate base treatment in this proceeding is the Monmouth Reinforcement phase. The Company estimates the cost of this phase to be$8.1 million.

Q. DID STAFF REQUEST ADDITIONAL INFORMATION FROM THE COMPANY TO JUSTIFY THE NEED FOR THESE PROJECTS?

A. Yes. The Company provided the following response to Staff DR 177: "The need for the MWVF is explained in the Company's modified IRP, Docket No. LC-51 ("IRP"). See Chapter 1, page 1.9 and Chapter 3, pages 3.12 through 3.19 and in iii below." (See Staff/1104). On page 1.9, of its IRP in items 2(b) and 5(a) and (c), the Company concludes that completion of the Harrisburg River Crossing project will help to solve supply shortages to the south in the near term. The Company further explains in its IRP that additional resources will be required further down the valley in the longer term. (See Staff/1105; NWN's modified 2011 IRP, pages 1.8 and 1.9.)

Q. HOW DOES THE COMPANY DEFINE THE "NEAR-TERM" AND THE "LONG-TERM"?

A. With respect to distribution system projects, the Company uses “near-term” for one to two years, “mid-term” for three to five years, and “long-term” for projects beyond five years. (See Staff/1106, NWN modified 2011 IRP, pages 3.17 and 3.18.)

Q. DID THE COMPANY INCLUDE BOTH THE MWVF PROJECT AND THE CORVALLIS LOOP PROJECT IN ITS 2011 INTEGRATED RESOUCE PLANN (IRP)?

A. For purposes of modeling and planning for additional resources over the planning horizon, the Company modeled the MWVF project. The Company excluded the Corvallis Loop project from its 2011 IRP modeling but provided a general discussion about distribution system improvements. (See response to Staff DR 216, Staff/1107). Additionally, the Company included the MWVF project in the 2008 IRP, which was acknowledged by the Commission in Docket No. LC 45.

Q. IS RATE RECOVERY GUARANTEED FOR RESOURCES INCLUDED IN A COMMISSION-ACKNOWLEDGED IRP?

A. No. In Order No. 89-507, the Commission established its role in reviewing and acknowledging a utility’s least-cost plan:

> “Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan.”

Q. WHAT ARE THE RESULTS OF MODELING THE MWVF PROJECT IN THE COMPANY'S 2011 IRP?

A. The Company's modified 2011 IRP did not include the MWVF in the base case model, which is the Company's selected portfolio of resources in Docket No. LC 51.[3] The Company concluded that additional capacity in the Willamette Valley (south of Salem) will not be needed until the 2025/2026 time frame. (See Staff/1108, NWN modified 2011 IRP, pages 5.30 and 5.33.) Nonetheless, when the Company imposed disruption of service on Northwest Pipeline's Grant's Pass Lateral, two Sendout® model runs selected the MWVF as a resource to provide additional capacity during the imposed service disruption event.[4] (See Staff/1104.)

Accordingly, in absence of the imposed service disruption on the interstate pipeline, the base case model in the modified 2011 IRP does not select the MWVF project until the 2025/2026 time frame, i.e., for the long-term. This result is consistent with the Company's projection for reduction in sales, i.e. reduction in demand in UG 221.

Q. HOW DID THE COMPANY MEET PEAK DEMAND DURING PREVIOUS COLDER-THAN-NORMAL EVENTS AND DURING UNEXPECTED SERVICE OUTAGES?

A. The Company experienced two significantly colder-than-normal events in January 2004 and December 2009. (See Staff/1109, NWN modified 2011 IRP,

[3] See Appendix 5, page 5A.17 of the modified 2011 IRP filed September 1, 2011 in Docket No. LC 51.
[4] Sendout® is the computer software used by the Company to model and plan for resources to meet future demand.

pages 2.20 and 2.21.) In addition, the Company experienced two major unplanned service reductions on Northwest Pipeline's Grant's Pass Lateral due to compressor failures in February 5, 1990 and January 4, 2004. (See NWN/600, Yoshihara/6-7.) During these events the Company curtailed service to interruptible customers to maintain firm service. Please note that all these events occurred during the months of December, January and February, which is the typical heating season, when the system is typically most stressed. Furthermore, according to actual weather information, the January 4, 2004 service outage coincided with a colder-than-normal event. The Company experienced its highest daily firm demand ever (718 MDT) on January 5, 2004, and successfully managed to meet demand with the existing resources as shown in Staff/1109. Consequently, the Company managed to meet firm demand during a much colder-than-normal weather event (peak) that was combined with a service outage on the Grant's Pass Lateral.

Q. DOES THE COMPANY USUALLY PLAN TO USE SERVICE CURTAILMENT DURING PEAK DEMAND AND SERVICE OUTAGES?

A. Yes. The Company describes in detail the process of planning and implementing service curtailment to its interruptible customers. In response to Staff DR 428, the Company states: "On a daily basis, a curtailment requirement is determined through the use of a sophisticated mathematical model that determines the pressure limits of the Company's distribution system in areas where we know there are infrastructure constraints, which today is predominantly in the Albany-Corvallis and Canby areas, but historically, also included the Silverton area." (See Staff/1110; Company response to Staff DR 428.)

Q. DID SERVICE OUTAGE ON THE GRANT'S PASS LATERAL IMPACT FIRM CUSTOMERS?

A. During the last five years, one incident of service outage occurred due to compressor failure at Jackson Prairie storage facility, which the Company leases. This resulted in reduced pressure on the Grant's Pass Lateral. However, this disruption did not impact any of the Company's firm customers. It only affected the interruptible customers. (See Staff/1111; Company response to Staff DR 359.)

Q. HOW FREQUENTLY HAS THE COMPANY CURTAILED SERVICE DURING THE LAST FIVE YEARS?

A. Based on the information provided by the Company in response to Staff's DR 275 (Staff/1112), the number of hours during which service to interruptible customers was curtailed since January 2007 to December 2011 was 2,889 hours representing 6.6 percent of the total service time during these five years of 43,800 hours (2,899/[5 years * 365 days * 24 hours] = 6.6 percent). All of these service curtailment incidents occurred during the months of December, January and February. As I mentioned previously, this is the highest heating load period of the season due to the relatively colder weather temperatures during that time. The Company curtailed service to its interruptible customers to meet firm demand.[5]

Q. ARE THERE OTHER ISSUES REGARDING THE NEED FOR THE MWVF PROJECT?

A. Yes. The Company projects in this rate case an overall reduction in load during the test year by approximately 4.8 percent when compared to the base year. (See Staff/1113; NWN/303, McVay-Siores/1). Additionally, the Company projects a net loss of 951 residential customers in the Albany-Corvallis area. With an average annual usage of 636 therms per customer (See NWN/300, McVay-Siores/7, lines10 and 11), the projected net loss in load is 604,836 therms. Unless the Company included this projection in its 2011 IRP analysis, this should result in delaying the need for the MWVF even beyond the IRP's modeling results.

When considering the negative growth projected in this proceeding, it becomes clear that the results of the IRP modeling are aggressive, outdated and do not validate the need for the MWVF project in the near-and mid-term.

Furthermore, the Company's residential UPC in the 2011/2012 PGA filing is 700 therms/year, which is about nine percent higher than the Company's use per customer projection in the test year. The overall reduction in residential UPC between 2003 (724 therms per year) and 2011 (700 therms per year) is 3.3 percent. Therefore, if the UPC during the 2013 falls closer to this average,

[5] Source: Attachment 1 to the Company's response to Staff DR 275 (confidential information subject to Protective Order No. 12-01).

the net reduction in residential load would be 643,732 therms, i.e. less firm demand in the future.

Q. WHY IS THE PEAK WEATHER DESIGN CRITERIA RELEVANT TO EVALUATING THE NEED FOR THE MWVF PROJECT?

A. The Peak Day Demand under the Company's weather criteria occurs when the weather temperature reaches 12 degrees Fahrenheit (or 53 Heating Degree Days "HDD"). This is a much colder-than-normal weather event that, according to the Company's HDD forecast, would last for three days. (See Staff/1108.) The peak demand event consists of the day before the peak day, the peak day, and the day after the peak day. It is possible that this event may occur in the future, and I agree that the Company should plan to meet firm demand during peak day events and improve service reliability. With respect to the Design Weather HDD pattern, the Company forecasts that the system would experience between 40 HDD and 53 HDD during this event (i.e. temperatures ranging between 11 and 25 degree Fahrenheit.).[6] This event typically lasts for few days as depicted in Staff/1109. However, the question becomes: What is the appropriate cost burden for ratepayers to bear to meet the objective of additional service reliability or other long term needs? This is relevant especially since the Company managed to meet peak demand during significantly colder-than-normal weather combined with a service reduction on the Grant's Pass Lateral during the January 2004 event, and again during the peak event on December 2009. Therefore, the justification of the need for the

[6] Source: See Design Weather Heating Degree Day (HDD) forecast in the Company's 2011 IRP, Appendix 2.17.

MWVF project to provide service reliability and increase winter peak deliverability must be during service outage needs to be assessed based on cost effectiveness and benefit-cost analysis. The MWVF should be compared with other alternatives to determine the most efficient and cost effective measure or resource to address this objective. This analysis should consider the reasonableness of the amount to be spent on capital projects for average or normal weather demand versus peak demand. In the latter, the resource's or measure's primary use is expected for only few days of the heating season, whereas in the former, the resource would be used throughout the heating season. To further clarify, in many instances, colder-than-normal does not recur in consecutive heating seasons. When new plant is added to rate base, the ratepayers will be paying for this investment in addition to associated depreciation, operation and maintenance and other expenses for the entire useful life of the plant. Hence, demonstrating the balancing of cost versus risk is necessary to justify the cost to be incurred by the ratepayers.

Q. DID THE COMPANY CONDUCT A FINANCIAL STUDY FOR THE MWVF PROJECT?

A. No. Staff has asked the Company through data requests whether the Company conducted financial analyses, benefit-cost analysis or other studies to support a conclusion that the MWVF is a cost-effective solution to meet peak day demand, i.e. improve the system reliability. The Company generally referred to certain sections of its 2011 IRP citing that additional benefits of the project are qualitative in nature. (See Staff/1103 and Staff/1106.)

Q. DID YOU EXPECT THE COMPANY TO PROVIDE THIS INFORMATION?

A. Yes. It is evident from the Company's modified 2011 IRP that the Company recognized and acknowledged the need to perform such studies and to update them on a regular basis in order to ensure that future distribution system investments are prudent. Item 2.5 of the modified 2011 IRP action plan as filed by the Company states the following: "Refine cost estimates, conduct more detailed system modeling, and investigate siting/permitting constraints on satellite LNG facilities and the specific NW Natural distribution system investments--including the Willamette Valley Feeder and Newport LNG Compressor project--identified as potential cost-effective resources in this IRP." However, there is no evidence of this information on record in this proceeding.

Q. ARE YOU OPPOSED TO IMROVING SYSTEM RELIABILITY?

A. No. To the contrary, I fully support this objective. More importantly, the Commission's IRP process requires utilities to plan for the future. However, the company must provide evidence in support of the prudence of the capital project. In addition to demonstrating the need for the project based on accurate information, the evidence should include, but not be limited to, financial studies, benefit-cost analysis, and cost-effectiveness analysis.

Q. ARE THERE OTHER ISSUES WITH RESPECT TO JUSTIFYING THE NEED FOR THE MWVF PROJECT IN THIS RATE CASE?

A. Yes. Staff asked the Company to provide "the financial analysis of new distribution-classified investment referenced in NWN/110, Feingold/16, lines 11-22, including all underlying assumptions and the present value of revenue requirement (PVRR) in electronic spreadsheet format with all formulae and cell references intact."(Staff/1107; Staff DR 216(b)(5). The Company responded that <u>no financial analysis of the MWVF was conducted</u>, and that the decision to invest in these projects is based on system reliability, replacement of legacy bare steel and system reinforcement. (See Staff/1107; Company response to Staff DR 216(b)(5). Consequently, Staff is uncertain on what basis the Company decided that the MWVF is cost-effective with respect to their perceived benefits and the beneficiaries. Furthermore, there is additional concern arising with respect to how the MWVF was modeled in the modified 2011 IRP if no financial analysis was conducted, and when the Corvallis Loop Project was not modeled. The Company stated that it did not include the Corvallis Loop project in the IRP because it is not within the scope of the IRP. (Also, see Staff/1107; Company response to Staff DR 216.) This statement does not align with Mr. Yoshihara's testimony that the first segment of the Corvallis Loop project will become a segment of the MWVF. (See Yoshihara/4, NWN/600, lines 1-5.)

Q. WHAT IS THE RELEVANCE OF THE PVRR ANALYSIS?

A. The PVRR analysis is a fundamental measure in analyzing and evaluating future resources required by the Commission's IRP guidelines:

> *"The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.*[7]

[7] We sometimes refer to this portfolio as the "best cost/risk portfolio."

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases." (*Order No. 07-047; Substantive Requirements, Item 1(c), second bullet.)

Q. DID THE COMPANY PROVIDE ADDITIONAL INFORMATION WITH RESPECT TO JUSTIFYING THE NEED FOR THE CORVALLIS LOOP PROJECT?

A. The Company provided an analysis of the required capacity (under design peak demand criteria) in order to meet the additional firm demand (hourly load in therms/hour) that is the result of migration of several large customers from interruptible to firm service.[8] (Staff/1114 Company response to Staff DR 302.) This information is subject to the Commission's Protective Order No. 12-001. (See Staff/1115: subject to protective order No. 12-001). Also, the Company projects a net loss of 951 residential customers at an annual estimated usage of 636 therms per customer, while projecting 28 additional commercial customers and one additional industrial customer. (Staff/1114; Company response to Staff DR 302.) This information was provided with respect to the

[8] See confidential attachments which were provided by the Company in response to Staff DR 302. Confidential information is subject to Protective Order No. 12-001

Corvallis Loop project, which the Company ties with the MWVF project.[9] Further, it is not clear whether the Company took into account the projected reduction in residential load in the Albany area in the IRP modeling. This could result in lower demand due to reduction in residential sales that offset the projected growth in the industrial load. It is possible that the need for the MWVF project may be further delayed.

Q. DID THE COMPANY CONDUCT A FINANCIAL ANALYSIS FOR THE CORVALLIS LOOP PROJECT?

A. The Company provided a document described as a "Financial Analysis of the Corvallis Loop project" in a supplemental to Staff DR 216.[10]

Q. PLEASE DESCRIBE THIS DOCUMENT.

A. The document shows the incremental revenue requirements and incremental revenues resulting from switching some industrial customers from interruptible to firm service.

Q. ARE THERE OTHER ISSUES RELATED TO THIS PROJECT?

A. Yes. In accordance with ORS 757.355, this project must be in service by November 1, 2012, in order to be allowed in rate base. This issue is addressed by Staff's Witness Ken Zimmerman.

Q. DID THE COMPANY PROVIDE EVIDENCE THAT A SIGNIFICANT UNSERVED DEMAND IS FORECASTED IN THE ALBANY-CORVALLIS AREA IN THE NEAR OR MIDTERM?

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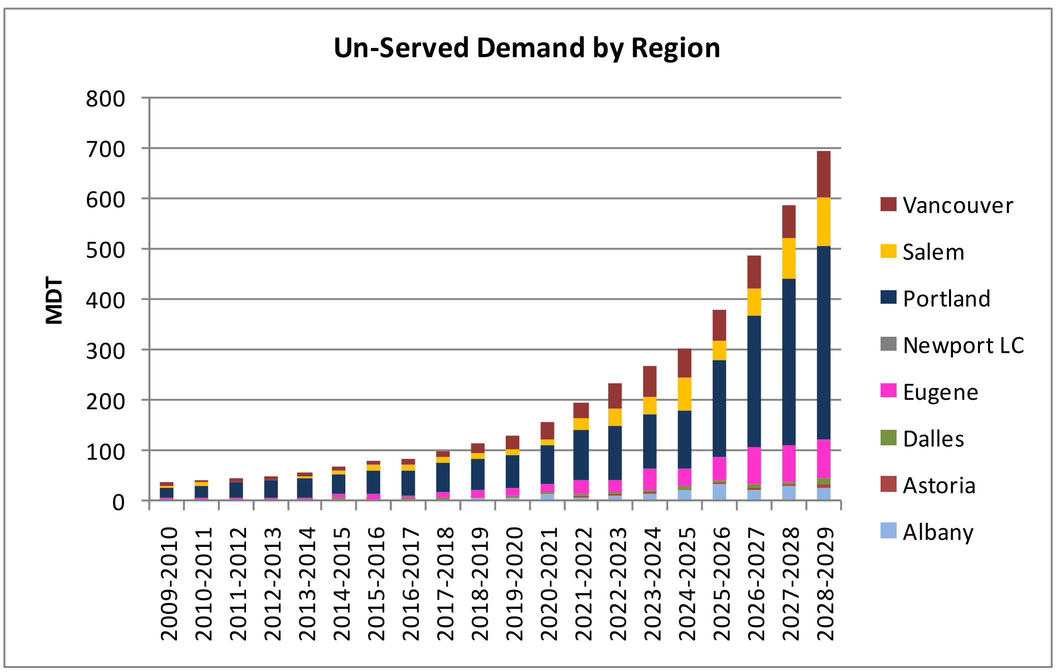
[9] See response to Staff DR 340. The Company also projected the addition of 28 commercial customers and one industrial customer with no further details.
[10] Exhibit Staff/1107.

A. No. To the contrary, the Company's 2011 IRP information does not indicate such shortage in the Albany-Corvallis area (except in the instance of service outage on the interstate pipeline as previously discussed) will be experienced in the near and midterm. The figure below is from chapter one of the Company's modified 2011 IRP (Figure 1.2), and is based on a moderate growth rate, i.e. does not reflect the sales reduction projected in the test year. This figure displays the forecasted design peak demand by region. As shown, there is no indication that the Albany area will begin experiencing increased unserved demand before 2020/2021. Finally, if unserved demand were to occur in the future, the evidence suggests that the primary cause for this deficiency will be due to the increase in large customers and industrial demand. (See Staff/1116).



Q. WHAT IS THE CONCLUSION OF YOUR ANALYSIS?

A. There is no sufficient information to justify the recovery of the MWVF project through rates in this proceeding. Recovery of the Corvallis Loop project through rates may be allowed in this proceeding subject to: Compliance with the in-service date requirement per ORS 757.355, and allocating the project cost among the rate classes according to the cost causation principle.

SECTION 3: THE INDUSTRIAL DSM PROGRAM

Q. PLEASE EXPLAIN YOUR PROPOSAL WITH RESPECT TO THE RECOVERY MECHANISM OF THE INDUSTRIAL DSM PROGRAM.

A. The current deferral mechanism was adopted and implemented when the Industrial DSM program was offered as a pilot program. As of March 2011, the Industrial DSM program is being offered on a permanent basis. Therefore, a permanent tariff rate is consistent with this change. Second, the permanent tariff rate will provide savings to the customers since the only applicable interest rate to be recovered through rates will be the blended treasury rate.[11] Under the current deferral mechanism, the applicable interest rate during the deferral period is the effective (authorized) rate of return.[12] The proposed mechanism will be subject to a balancing account, i.e. recovery or refund of overage. The funding of the program will remain consistent with the budget requirements of the program's administrator, i.e., the Energy Trust of Oregon, which is subject to the Commission review.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[11] Currently 2.24%.
[12] Currently, the authorized rate of return on new deferrals is 8.618%: See Order No. 03-507.

CASE: UG 221
WITNESS: Moshrek Sobhy

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME:	Moshrek Sobhy
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	Senior Utility Analyst Natural Gas Rates and Planning
ADDRESS:	550 CAPITOL STREET NE SUITE 215, SALEM, OREGON 97301-2115.
EDUCATION:	I received a Bachelor of Science degree in Chemical Engineering in 1991 from Alexandria University, Egypt. I received the Certificate of Public Management (CPM) from Willamette University, Oregon in June 2011.
EXPERIENCE:	In September 1997, I began my employment with the Indiana Department of Natural Resources as engineering assistant. In October 1998, I was promoted to Utility Engineer with the Indiana Utility Regulatory Commission (IURC). Following reorganization of the IURC, from 1998 to 2006 my duties as a Principal Utility Analyst with the Gas/Water/Sewer Division included advising and assisting the Commission on numerous proceedings involving rate cases, acquisitions, rulemaking, investigations, and customer complaints. In November 2006, I accepted the position of Senior Rates Analyst with the Northern Indiana Public Utility Corporation (NIPSCO), a subsidiary of NiSource, where I worked primarily on the cost of service study for the electric utility, in addition to energy efficiency and decoupling issues for the gas utility. From April 200 7 to February 2009, I held the position of Senior Rates and Regulatory Affairs Analyst with Citizens Energy Group, a natural gas and steam utility serving Marion and Hamilton Counties in Indiana. In July 2009, I joined the Public Utility Commission of Oregon as a Senior Utility Analyst.

CASE: UG 221
WITNESS: Moshrek Sobhy

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1102

Exhibits in Support Of Opening Testimony

May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 171:
Note: DRs 171-177 correspond to the Mid-Willamette Valley Feeder (MWVF) excluding the bare steel replacement portion of the project.

Explain in more details why and how the Mid-Willamette Valley Feeder (MWVF) project is/will be tied with the Corvallis Loop Project from physical/ operational, and service perspectives. Please supplement your response with an illustrative map.

Response: 1/30/2012

The southern end of the Mid-Willamette Valley Feeder (MWVF) project will be physically tied to the northeastern end of the Corvallis Loop at the Albany-Corvallis Feeder east of Corvallis near Riverside Drive as stated in UG 221 Exhibit 600. Operationally as stated in the 2011 modified IRP:

> "Mid and South Willamette Valley Feeder – A new pipeline could move natural gas from the Mist underground storage facility south down the valley. The mid-section would link Salem with Albany, and the south section would link Albany with Eugene. The project is a viable alternative to NWPL's Grants Pass Lateral and would improve reliability of the system." (2011 Modified IRP)

An illustrative map is provided. See OPUC-DR-171_Attachment -1.

This page is confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

CASE: UG 221
WITNESS: Moshrek Sobhy

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1103

Exhibits in Support
Of Opening Testimony

May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 267:
See pages 4-7 of testimony by witness Yoshihara.
a. Explain how the Mid-Willamette Valley Feeder Project is included in the projects listed on the "Capital Projects Timeline" document provided by NWN.
b. Explain how the forecasted costs of the Mid-Willamette Valley Feeder Project are divided among the projects listed on the "Capital Projects Timeline" document.
c. For the Mid-Willamette Valley Feeder Project provide the following:
i. Request for bids issued.
ii. All bids received in response to the request for bids issued by NWN.
iii. The bids sheets or tables where NWN compared and evaluated the bids received.
iv. The winning bid for the work, including the reasons the bid was selected as winner.
v. The construction budget for the project developed by the winning bidder and approved by NWN.
vi. The construction schedule for the project developed by the winning bidder and approved by NWN.
vii. All changes to the initial construction budget, with explanations.
viii. All changes to the initial construction schedule, with explanations.
d. For the Mid-Willamette Valley Feeder Project, provide the basis for the "in service" date provided by NWN, including full documentation (invoices, construction schedules, etc.)
e. Please explain why the capital cost for the Corvallis Loop Project ($12.8 million) differs from the projected capital cost for this project in the "Capital Projects Timeline" document ($9.3 million).

Response: 2/9/2012

a) The Mid-Willamette Valley Feeder Project is broken down into four phases. The first two phases are scheduled for completion in 2012 and are listed as "Perrydale to Monmouth" and "Monmouth Reinforcement" on the "Capital Projects Timeline" document. The second two phases are scheduled for completion in 2013 and are not listed on the "Capital Projects Timeline". They are "South of Monmouth Bare Replacement" and "Willamette River Crossing near Corvallis". The phases being completed in 2013 are not included in the

"Capital Projects Timeline" due to the in-service dates being projected as October 2013.

b) The forecasted costs of the Mid-Willamette Valley Feeder Project is as follows:

Perrydale to Monmouth $13,500,000

Monmouth Reinforcement $8,100,000

South of Monmouth Bare Replacement $14,300,000

Willamette Crossing near Corvallis $11,000,000

Note: Some expenses have occurred in 2011 on the MWVF.

c) Please see the Company's response to OPUC DR 165.

d) Please see the Company's response to OPUC DR 158.

e) The estimated capital cost of the Corvallis Loop Project is $ 12.8 million. Approximately $3.5 million of expense occurred in 2011. The remaining $9.3 million is forecast to be spent in 2012 as stated in the "Capital Projects Timeline".

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STAFF EXHIBIT 1104

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NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 177:
Note: DRs 171-177 correspond to the Mid-Willamette Valley Feeder (MWVF) excluding the bare steel replacement portion of the project.

According to the Company's pending Integrated Resource Plan (IRP) in Docket No. LC-51, the MWVF is not utilized in any of the models in the Modified IRP:

i. Why does the Company need this pipeline?

ii. Does the Company believe this project is/will be used and useful during the test year given the results from the IRP analysis? Please explain and provide supporting information.

iii. Please reconcile the statements in Yoshihara/4-7 that the MWVF is needed to improve service reliability, reduce risk of service interruption, and meeting peak demand with the results from the modified IRP analysis that this project is not selected in any of the modified resource portfolio cases.

Response: 1/30/2012

i. The need for the MWVF is explained in the Company's modified IRP, Docket LC-51 ("IRP"). See Chapter 1, page 1.9 and Chapter 3, pages 3.12 through 3.19, and in iii below.

ii. Yes, the Company does expect the MWVF to be used and useful during the test year. The construction schedule and other supporting documentation for the MWVF will be included with the Company's response to DR 166 (in progress) which is due February 6, 2012. Once in service, the MWVF will provide additional system reliability and reduce risk of service disruption should an outage on NWPL's Grants Pass Lateral occur in the test year.

iii. Scenarios 1348 and 1350 (*See LC 51, Appendix 5 for Scenario Results*) of the original IRP model scenarios of service disruptions, and the SENDOUT model does select the MWVF in the least cost portfolio. These two scenarios demonstrate that if a service disruption were to occur, the MWVF can help serve demand south of Salem, and therefore improve system reliability. The MWVF was not selected in any of the modified resource portfolio cases because none of the modified scenarios were designed to model service disruptions.

The SENDOUT model cannot explicitly model some of the advantages of the MWVF due to their qualitative nature. The Company discusses these advantages in its IRP. Specifically, from the LC-51 IRP:

> *"The Willamette Valley Feeder project offers three advantages that are qualitative in nature and so could not be explicitly modeled in SENDOUT, the linear programming software that optimizes resources into portfolios for the IRP. These advantages are: 1. Risk management. By providing gas deliveries through pipelines following different routes, NW Natural will be less susceptible to disruptions affecting NWPL's system. 2. New service opportunities. By following new routes, homes and businesses that previously may have been too distant may now be able to access gas service. 3. Lower impact. Further expansion of NWPL's Grants Pass Lateral would necessitate expansion of existing distribution lines emanating from the NWPL gate stations. Prior customer growth along these corridors may make those lines more difficult to expand as compared to the Willamette Valley Feeder, which would approach those communities using alternate routes."* (LC51, Page 3.19)

> *"The Mid-WVF has additional benefits, which are not incorporated into the model, including the replacement of a significant portion of the remaining bare steel on NW Natural's system, and the fact that the Mid-WVF will add system reliability that may be even more important given the delay in cross-Cascade pipeline and other projects. When an outage is modeled on the Northwest Pipeline Lateral, the SENDOUT model does select the Mid-WVF as a resource in the least-cost portfolio to meet load. NW Natural believes that these considerations are important in determining which resource will be relied on to meet load in the Willamette Valley and in determining a reliable operation of its system."* (LC51, Page 5.32)

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B. Recent Resource Decisions

1. Mist Storage Recall

   A portion of the capacity at the Mist Storage Facility is under contract to interstate customers. "Mist Recall" is the general term given when the Company recalls storage capacity at Miller Station in order to serve core customers. The 2008 IRP called for a recall of 10 MDT/day in 2008/2009 and an additional 30 MDT/day in 2009/2010. The Company did recall 10 MDT/day in 2008. Due to a reduction in the demand forecast, the 2009 Washington IRP only required 10 MDT/day for 2009/2010, which was recalled in 2009, and in 2011, an additional 100,000 therms per day of deliverability was recalled, along with related annual storage capacity,

2. Harrisburg River Crossing

   This small project allows an additional 8 MDT/day of supply to serve Eugene and is a key resource for meeting peak day demand in the southern Willamette Valley. This link was selected in both the 2008 and 2009 IRPs, and the project was completed in November of 2010.

3. Willamette Valley Feeder (WVF)

   This project can move supplies south from the Mist Storage facility to Salem, and eventually to Albany and Eugene, if necessary. This project was selected in the 2008 IRP. Due to a recent evaluation of Newport LNG capabilities, additional peak day resources are required for Salem, and the North section of this project, from Aurora to Brooks, is expected to be in service by November 2011.

C. Future Resource Alternatives

In this Plan, NW Natural has considered the following incremental resource additions:

1. Interstate Pipeline Capacity Additions
   a. New NWPL Grants Pass Lateral capacity serving Salem, Albany and Eugene,
   b. New capacity upstream of NWPL mainline capacity providing access to the Rockies and Alberta supply areas,
   c. New Palomar East/Blue Bridge pipeline capacity from Madras to Molalla
   d. New GTN pipeline capacity from Malin to Madras
   e. New capacity on the proposed Pacific Connector Pipeline to access re-gasified LNG from the proposed Jordan Cove LNG project at Coos Bay, Oregon.
   f. New capacity on the proposed Oregon Pipeline to access re-gasified LNG from the proposed Oregon LNG project at Warrenton Oregon.

2. NW Natural Infrastructure Enhancements
   a. Newport LNG Compressor Project - The daily deliverability of gas from NW Natural's Newport liquefied natural gas plant could be increased from 60 MDT/day to 100 MDT/day by the addition of a compressor station at Perrydale. The cost of the infrastructure addition would be about $12 million and would allow additional supply to reach Salem to serve peak day demand.

b. Mid and South Willamette Valley Feeder – A new pipeline could move natural gas from the Mist underground storage facility south down the valley. The mid section would link Salem with Albany, and the south section would link Albany with Eugene. The project is a viable alternative to NWPL's Grants Pass Lateral and would improve reliability of the system.

c. Satellite Storage – Small-scale LNG storage and vaporization facilities are used as peaking resources because they provide only a few days of deliverability. Where peaking demands are sharpest, the addition of satellite storage could defer significant pipeline infrastructure investments. In this IRP, NW Natural has evaluated satellite storage in three locations in the Willamette Valley (Salem, Albany and Eugene) as interim resources that might delay more expensive pipeline projects such as additions to the NWPL Grants Pass Lateral or construction of the Mid and South WVF.

3. Mist Recall: Additional storage capacity can be recalled as necessary for the core utility through time as interstate contracts roll off.

4. Imported LNG - The Company is evaluating the impact of two LNG import terminals proposed to be sited in Oregon. The Oregon LNG project proposed for Warrenton would connect to NW Natural's system at Molalla. The Jordon Cove project near Coos Bay would connect to the proposed Pacific Connector Gas Pipeline. Neither project has been constructed, and, while NW Natural included them for analysis purposes, imported LNG does not currently appear imminent given recent developments in shale gas supply. In fact, sponsors of the Jordan Cove project have proposed re-permitting their project as an export facility. Neither project is included in the base case planning portfolio.

5. The Company has come to the following principal conclusions with regard to supply-side resources:

    a. The Company's existing supplies are not sufficient to satisfy 100% of projected peak day demand. In the near term, completion of the North section of the Willamette Valley Feeder along with Mist Storage recall will help to resolve that shortfall in the northern reaches of the service area, and completion of the Harrisburg River Crossing project will help to solve supply shortages to the south.

    b. The Newport LNG facility is over 30 years old and may need to be brought down for service for an unknown period of time. NW Natural is assessing a likely timeline for taking the facility offline without disrupting peak day capacity. Once the facility is back in service, the Newport LNG Compressor project is a cost effective way to further serve peak day demand.

    c. In the longer term, additional resources will be required further down the valley. The demand requirements could be met by additional Grants Pass Lateral capacity, the Company's Satellite Storage and/or Willamette Valley Feeder pipeline, or possibly a targeted DSM approach.

    d. The Company continues to pursue strategies to improve supply path diversity, including pursuing the opportunity to take capacity on the proposed Palomar/Blue Bridge Pipeline.

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C. NW NATURAL INFRASTRUCTURE ADDITIONS

System expansions or reinforcements accompany the need to increase resources to meet load growth, regardless of whether supplies come from Mist or from the Company's numerous gate station interconnections with NWPL. The Company's Engineering Department, in close collaboration with the Construction and Marketing departments, and using input from outside economic development and planning agencies, plans for the expansion, reinforcement and replacement of the distribution system.

The Company uses the Synergy software package[10] to evaluate infrastructure requirements. Synergy provides the platform for digital computer simulation of transient gas flow behavior in any arbitrarily configured piping system. The analysis procedure calculates the time-varying flows, pressures, horsepower and other variables under scenarios that reflect actual service conditions. Studies are conducted to determine the response of the gas distribution system due to load changes, pressure set point changes, compressor performance changes, etc. The software is also sophisticated enough to enable the modeling of high-speed transient conditions, such as instantaneous valve closure and pipeline rupture.

The Company has constructed models based on the Synergy software that are designed to evaluate distribution system capacity constraints, inter-related flow characteristics, and pressure stabilization aspects of distribution system planning that are evaluated under steady-state and transient conditions. Over time the process was streamlined through the integration of geographically referenced system map information and Company data sources. This enhancement enabled Engineering to avoid the formerly tedious and time-consuming effort of manually constructing nodal networks and linking data. System maps from the Geographic Information System provide the physical distribution system data required for basic model construction, and the Customer Information System provides load data.

The Synergy models and software provide the Company the opportunity to evaluate performance of the distribution system under a variety of conditions. Typically the analysis focuses on meeting growing peak day customer demands while maintaining system stability. Gas requirements at delivery nodes are projected based on observed flow rates during recent cold weather episodes. These flow rates are then adjusted to match design peak weather conditions and the effects of customer growth. Alternative system expansion and reinforcement strategies are then evaluated in terms of system stability, cost, and the ability to meet future gas delivery requirements. This computer simulation capability allows the Company to efficiently evaluate distribution system performance in terms of stability, reliability, and safety under varying boundary conditions ranging from peak-day delivery requirements to temporary service interruptions, both planned and unplanned.

System planning takes place continuously, integrating new customer growth requirements into the Company's construction forecasts. Computer simulation testing is used to help validate the need for and timing of specific system expansion, reinforcement, and replacement projects. <u>Near-term (one to two-year) projects are highly likely to occur as specified to meet customer delivery requirements. Mid-term (three to five-year) projects are subject to time slippage based on adjustments to the rate and geographic direction of customer growth. Long-term (beyond five years) will tend to be general</u>

10 This software was formerly known as the Stoner Workstation Service (SWS).

projections based on expected economic development of the region and gas supply resource acquisitions, and thus, subject to change.

With SMPE completed in 2004, future internal infrastructure decisions revolve around two key considerations:

1. The impact on the Company's pipeline system design, reinforcement and replacement projects from the 2002 federally-mandated Integrity Management Program (IMP) and other similar state approved programs regarding bare steel pipeline and geo-hazard mitigation. IMP and similar programs continue to evolve, but compliance is likely to require significant infrastructure investment over the next ten years. Those programs have been and will continue to be the subject of separate proceedings with state regulators and will not be further discussed here, but any infrastructure conclusions reached in the IRP will require further analysis to ensure congruence with the various integrity programs.

2. Alternatives for moving Mist and Newport storage gas to customers outside the current confines of the Portland-area and northern Willamette Valley distribution systems, respectively. The focus of the next three sections will be options for moving storage gas to areas traditionally beyond their reach.

D. Enhancement of Pipeline from Newport

The daily deliverability of the Newport LNG plant is modeled at 60,000 Dth/day due to load and infrastructure limitations. That is, the market areas served by the Newport plant (from the town of Newport north to Lincoln City and then east to Salem) have peak loads ranging up to about 60,000 Dth/day. However, the Newport plant has all the equipment necessary to vaporize and deliver up to 100,000 Dth/day. To reach the 100,000 Dth/day capability, infrastructure additions would be needed on the Newport to Salem pipeline to deliver an incremental 40,000 Dth/day (see Appendix 3-1). In addition, to connect more load centers (*e.g.*, Corvallis/Albany, Eugene) to the Newport plant, NW Natural would need to invest in some or all of the Willamette Valley Feeder project pipeline segments (see below). The additional piping and upgrading required to reach new load centers could be quite costly due to geographical constraints. This cost, though, could be competitive as compared to a subscription to additional upstream pipeline capacity, which also would need to be accompanied by Willamette Valley Feeder project investments to serve customers increasingly distant from NWPL's gate stations.

E. Brownsville to Eugene

To access approximately 8,000 Dth/day of Grants Pass Lateral capacity available at the Brownsville/Halsey gate station, the Company needed a Willamette River crossing near the town of Harrisburg in order to bring that capacity to the Eugene market. The Company completed this project in late 2010.

F. Willamette Valley Feeder

The Willamette Valley Feeder project involves new piping to move Mist gas or other incremental gas supplies delivered to Molalla south to Salem, Albany, and potentially even the Eugene area. This project

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Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 216:
Regarding Exhibit NWN/1100 Feingold/16, lines 11-22:
"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."

a) Please identify the new distribution-classified investments referenced above.

b) For each new distribution-classified investment referenced above, please provide:

(1) A description of the investment;

(2) The specific location of the investment;

(3) A one-line diagram (single-line or unifilar diagram), which shall include such investment;

(4) A detailed breakdown of capital costs for each listed capital cost category (e.g., Labor, Materials, Vehicles, Other), including a description of each category, in electronic spreadsheet format with all formulae and cell references intact;

(5) The financial analysis of the investment conducted by the Company, including all underlying assumptions and the present value of revenue requirement (PVRR) in electronic spreadsheet format with all formulae and cell references intact;

(6) Has the Public Utility Commission of Oregon acknowledged this investment/project in any Integrated Resource Plan? If "yes," please identify the docket and order indicating such acknowledgment.

(7) As of today, what is the anticipated in-service date of the investment?

(8) Assuming the investment comes into service as projected above, would the investment also be considered by the company as used and useful from an Oregon regulatory perspective? If not, please explain.

c) Identify the southern portions of NW Natural's gas system that will benefit from the new distribution-classified investments and, separately, those portions of the Company's system that will not benefit from these investments.

d) Provide a diagram showing the southern portions within NW Natural's gas system that will benefit from the new distribution-classified investments and, separately, those portions of the Company's system that will not benefit from these investments.

Response: 2/9/2012

a) The new distribution-classified investments referenced above include the four phases of the Mid-Willamette Valley Feeder and the Corvallis Loop Project.

b) For the Mid-Willamette Valley Feeder Project:
   (1) Refer to Exhibit NWN/600 Yoshihara pages 2-7
   (2) Refer to Exhibit NWN/600 Yoshihara pages 2-7
   (3) Refer to OPUC-DR-171_Attachment -1
   (4) The detailed estimate of costs for each phase is as follows:
      i. Perrydale to Monmouth – Refer to OPUC-DR-165
      ii. Monmouth Reinforcement - Refer to OPUC-DR-165
      iii. South of Monmouth Bare Replacement - Detailed Estimate not available
      iv. Willamette Crossing near Corvallis - Detailed Estimate not available
   (5) A financial analysis of the investment was not conducted by the Company on these projects. The decision to invest in these projects is based on system reliability, replacement of legacy bare steel and system reinforcement.
   (6) Yes, The need for the MWVF is modeled in the Company's 2011 Modified IRP filed in LC 51, and the Company's 2008 IRP filed in LC 45 and acknowledged by the Commission in Order 09-005, issued on January 1, 2009.
   (7) At this time, the anticipated in-service dates for each of the four phases of the MWVF are as follows:
      i. Perrydale to Monmouth – October 31, 2012
      ii. Monmouth Reinforcement - August 31, 2012
      iii. South of Monmouth Bare Replacement September 30, 2013
      iv. Willamette Crossing near Corvallis - September 30, 2013
   (8) Yes

c) From a systems stand point, the areas that will benefit from the MWVF are the systems serving Salem and areas south of Salem including the Central Coast system. The areas that would not see any substantial benefit from these expansions are the areas north of Salem including the North Coast and Columbia Gorge Systems.

d) See diagram at OPUC-DR-216_Attachment-1.

b) For the Corvallis Loop Project:

   (1) Refer to Exhibit NWN/600 Yoshihara pages 2-7
   (2) Refer to Exhibit NWN/600 Yoshihara pages 2-7
   (3) Refer to OPUC-DR-171_Attachment -1
   (4) For the detailed Estimate of Cost please refer to OPUC-DR-165
   (5) A financial analysis of the investment was not conducted by the Company on this project. The decision to invest in this project is based on system reliability and reinforcement.
   (6) No, this project is outside the scope of the IRP as it is a system reinforcement that is being undertaken to maintain reliability in the system. It is not within the scope of the IRP because it does not relate to our acquisition of supply resources to meet load in a least cost manner.

(7) At this time, the anticipated in-service date for the Corvallis Loop is October 31st, 2012.

(8) Yes

c) From a systems stand point, the areas that will benefit from the Corvallis Loop Project are the systems serving Corvallis and Philomath. The areas that would not see a substantial benefit from this expansion are all the areas north, south, east and west of Benton County.

d) See diagram at OPUC-DR-216_Attachment-2.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response
SUPPLEMENTAL

Request No. GR1-OPUC-DR 216:
Regarding Exhibit NWN/1100 Feingold/16, lines 11-22:
"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."

a) Please identify the new distribution-classified investments referenced above.
b) For each new distribution-classified investment referenced above, please provide:
(1) A description of the investment;
(2) The specific location of the investment;
(3) A one-line diagram (single-line or unifilar diagram), which shall include such investment;
(4) A detailed breakdown of capital costs for each listed capital cost category (e.g., Labor, Materials, Vehicles, Other), including a description of each category, in electronic spreadsheet format with all formulae and cell references intact;
(5) The financial analysis of the investment conducted by the Company, including all underlying assumptions and the present value of revenue requirement (PVRR) in electronic spreadsheet format with all formulae and cell references intact;
(6) Has the Public Utility Commission of Oregon acknowledged this investment/project in any Integrated Resource Plan? If "yes," please identify the docket and order indicating such acknowledgment.
(7) As of today, what is the anticipated in-service date of the investment?
(8) Assuming the investment comes into service as projected above, would the investment also be considered by the company as used and useful from an Oregon regulatory perspective? If not, please explain.
c) Identify the southern portions of NW Natural's gas system that will benefit from the new distribution-classified investments and, separately, those portions of the Company's system that will not benefit from these investments.
d) Provide a diagram showing the southern portions within NW Natural's gas system that will benefit from the new distribution-classified investments and, separately, those portions of the Company's system that will not benefit from these investments.

Response: Supplemented 2/28/2012

The Company is supplementing its response to amend subsection (5) relating to financial analyses of the investment. In the course of compiling documentation in response to OPUC Data Request 302, the Company identified a financial analysis that was performed on the Corvallis Loop project in January 2011. The Company considers portions of this analysis to be confidential subject to protective order and has posted the worksheet OPUC DR 216 Attachment-3 CONFIDENTIAL on the Company's FTP site in the folder titled CONFIDENTIAL SUBJECT TO PROTECTIVE ORDER 12-001. A redacted file is provided as OPUC DR 216 Attachment-3 REDACTED.

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This page is confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

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STAFF EXHIBIT 1108

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D. Base Case and Preferred Path

Run # 1 - 1411-2011 IRP Mod Base Case represents the planning base case for the modification phase of the IRP. This is the least cost plan with base case demand inputs and assumes that the Palomar/Blue Bridge Cross-Cascades pipeline is not built. The plan primarily relies on DSM and Mist Storage recall to serve demand growth in the earlier years. Later, in the 2025/2026 time frame, additional resources are required down the Willamette Valley when the Newport LNG Compressor project and Satellite Storage options are selected. The model NPV cost ($000) for this plan is $6,772,580.

Run # 11 - 1392-2011 IRP Mod PAL 100 represents the low bracket for resource planning that includes capacity on Palomar/Blue Bridge under base case conditions. This case assumes NW Natural takes 100 MDTH/day of firm capacity on the project at the estimated Palomar rate only, beginning in November of 2017. Prior to that date, the resource selections are the same as for the 1411-2011 IRP Mod Base Case. In the later years, additional resources are still required in the Willamette Valley. In this case, the Newport LNG Compressor project is selected, along with expansion of the Grants Pass Lateral. There is less reliance on Mist Storage for this case. The model NPV cost ($000) for this plan over the 20 year horizon is $6,792,363, which is $19.8 million more than the 1411 Base Case – a 0.3% increase.

Run # 10 - 1391-2011 IRP Mod PAL BB 50 represents the high bracket for a resource plan that includes Palomar/Blue Bridge. This case assumes NW Natural takes 100 MDTH/day of firm capacity on the project with 50% at the Palomar rate and 50% at the Blue Bridge rate. The resource selection is the same as the low bracket, run 1392. The model NPV cost ($000) for this plan is $6,813,487. This is $40.9 million more than the Base Case 1411 – a 0.6% increase.

Together, these three plans comprise a potential resource planning pathway for NW Natural's future. Figure 5.14 outlines the pathway, along with the delta in NPV costs.

- 1411-2011 IRP Mod Base Case: Palomar/Blue Bridge is not an option
- 1392-2011 IRP Mod PAL 100: Capacity on Palomar/Blue Bridge starting in 2017 – low cost bracket
- 1391-2011 IRP Mod PAL BB 50: Capacity on Palomar/Blue Bridge starting in 2017 – high cost bracket

demand with pipeline CD at 35% and recall making up the rest. Then on a normal spring day, pipeline CD is back up to 90%, with storage at roughly 10% as the withdrawal season winds down.

VI. Key Findings

- Resource modeling produced a least cost Base Case resource plan to meet current and future demand. The plan's key future resource addition in the near term includes incremental Mist Storage Recall. Energy savings from DSM programs are also important.
- Modeling also generated a preferred path for resource planning that includes future capacity on the proposed Palomar/Blue Bridge project. Modeling has shown that a new Cross-Cascades Pipeline could improve service reliability and open up supply diversity options. However, there is an increased cost for such infrastructure, ranging from 0.3% to 0.6% over the base case for the 20-year planning period.
- Demand Side Management (DSM) is expected to play an increasingly important role in serving future demand.
- Modeling indicates that the Newport LNG Storage facility could be brought down for repairs at a future date without severely limiting service.
- Some sort of new resource is expected to be required down in the Willamette Valley, but not until the 2024/2025 time frame. This requirement could be filled by an expansion of the Grants Pass Lateral, building small Satellite Storage facilities, or building the Willamette Valley Feeder (WVF).

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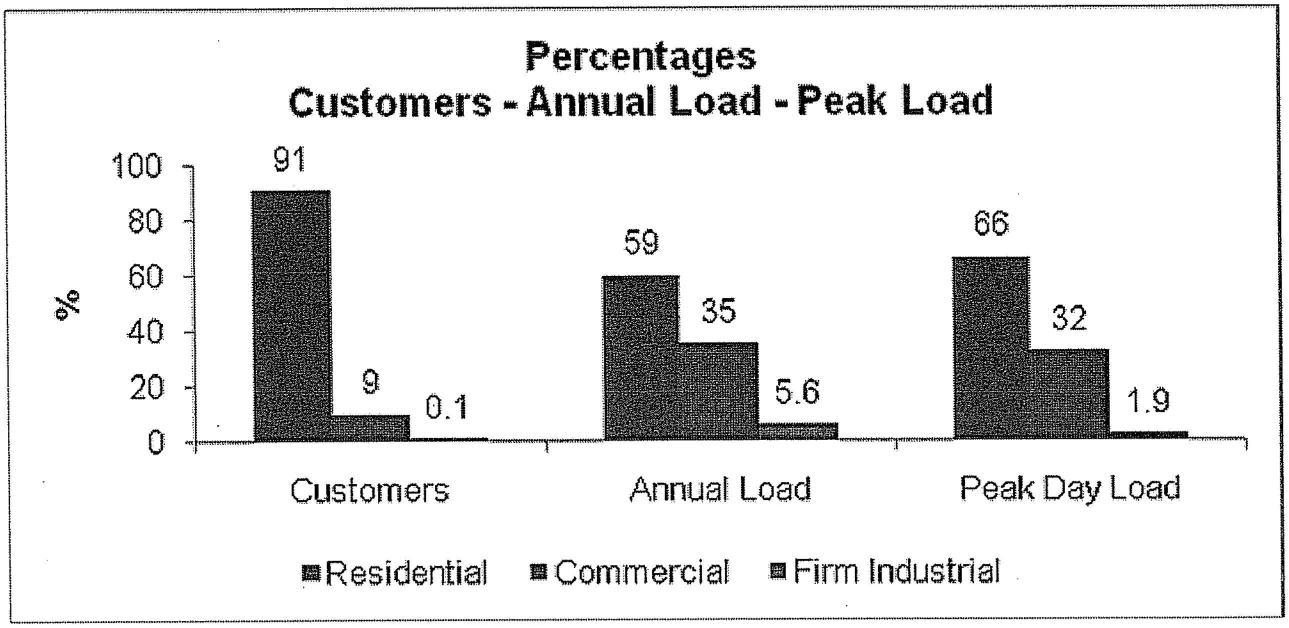
Figure 2.15 - Demand Percentages



Peak day demand is the primary driver of the resource plan. High peaking demand puts a premium on storage, while large base line volumes may drive more pipeline capacity. A typical daily forecast load value for a winter day in gas year 2009/2010 is 355 MDT. The forecast peak day for that gas year is 944 MDT. This is 2.75 times the load for a typical winter day. Clearly, meeting peak day load is of primary consideration for the resource plan. Figure 2.16 shows the daily forecast demand for gas year 2009/2010, along with two recent historic cold winter events. NW Natural served its highest daily firm demand ever (718 MDT) on January 5, 2004. The system weighted average temperature that day was 22 ° F, which corresponds to a HDD value of 43. The cold temperature was accompanied by strong winds, fog, rain and snow. More recently, on December 9, 2009, the region experienced a 44 HDD peak with calm and sunny conditions. Firm demand that day registered 698 MDT. In relation, NW Natural plans for a peak day of 53 HDD.

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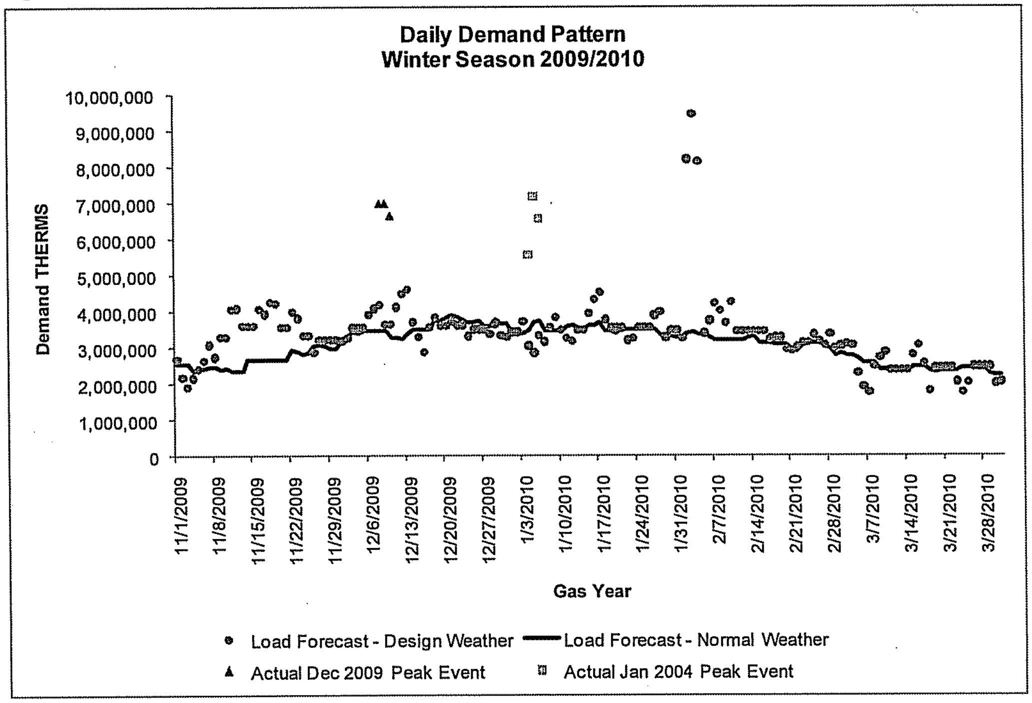
Figure 2.16 - Demand Forecast Pattern



B. Demand Scenarios

Several demand scenarios were developed around the base case. There are three main forecast ingredients to each demand scenario:

1. Customer Forecast
2. Customer Usage
3. Gas Price Forecast

For the base case, each component is derived from NW Natural's best estimate at the time the forecast was generated. Demand scenarios and "world views" can be generated by mixing and matching forecast cases and run through the SENDOUT® resource model to generate and evaluate resource plans. Table 2.4 presents the demand scenarios and the components that were prepared for this IRP.

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OF
OREGON

STAFF EXHIBIT 1110

Exhibits in Support
Of Opening Testimony

May 3, 2012

CASE: UG 221
WITNESS: Moshrek Sobhy

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1111

Exhibits in Support Of Opening Testimony

May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 359:
In reference to the Company's response to Staff DRs 171-177 and the proposed Capital Projects in NWN/600:

i. Describe each specific service reliability issue and/or incident that affected NW Natural's firm customers in the Albany-Corvallis, which was caused by a disruption of service on NWPL's Grants Pass Lateral in the past five years.

ii. Provide specific details for each of these incidents such as number of customers affected, customer class, service area (e.g. Corvallis, Philomath, Albany) the volume involved, and the incident duration.

iii. Was the Company able to meet firm customers demand in each of the reported incidents? Describe the specific measures taken and the associated cost incurred with each measure.

iv. How does the Company justify the decision to make the investment in the MWVF project from a cost effectiveness perspective as opposed to purchasing additional capacity on the Grants Pass Lateral?

Response: 3/1/2012

i. There has been one instance of disruption of service on NWPL's Grants Pass Lateral in the past five years. On December 9, 2009, NWPL experienced a compressor failure at Jackson Prairie facility, which resulted in reduced pressure on the Grants Pass Lateral.

ii. This disruption did not impact any of the Company's firm customers. However, the incident affected all interruptible sales service customers in the Company's Oregon service territory over a four-day period, consisting of two full days and two partial days. See the Company's response to OPUC DR 275, OPUC DR 275 Attachment-1 at rows 91-94 for details on the duration of the incident and the number of customers affected. The Company has no means in which to identify the volumes associated with non-usage as a result of a curtailment.

iii. Yes. The Company was able to meet all Oregon firm customers' demands during this incident by taking the following measures:

- The full curtailment of all Oregon interruptible sales services customers over a period of four days (see response to ii above), and
- The issuance of a Stage 1 Entitlement for all transportation customers for the period December 9 through December 12.

iv. Please see the Company's responses to:

OPUC DR 173	OPUC DR 274
OPUC DR 175	OPUC DR 302
OPUC DR 177	OPUC DR 340

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PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1112

Exhibits in Support Of Opening Testimony

May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 275:
Please provide, in electronic spreadsheet format with cell references and formulae intact, information on a system-wide basis regarding interruptible customers, as requested in the attachment to this data request (i.e., "Attachment - Interruptible Customers Information"). Please also:
a) Identify each customer and their rate schedule/service type though a numbering system if the Company believes the name of the Company is confidential;
b) Provide the length of time each customer experienced partial/total interruption (in Hours); and
c) Provide each customer's foregone purchases of gas (Dth).
If the information was derived or obtained from other sources, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format indicating the specific page, section, etc. of the relevant source document.

Response: 2/13/2012

NW Natural objects to this request because the Company does not have the data in the format requested in the data request attachment "Attachment – Interruptible Customer Information", and for the Company to provide such data in that format would be unduly burdensome and would not provide more relevant information than the information presented in the format attached to this data request. Further, all of the data required to populate the requested attachment is either provided here, or provided in other data request responses such that Staff would be able to compile the information in the manner that Staff deems useful for purposes of its analysis. Without waiving this objection, NW Natural provides the following response in an effort to assist Staff with the analyses it understands Staff would like to perform.

a) See OPUC DR 275 Attachment-1. This attachment is confidential because it contains customer-specific information. See OPUC OPUC DR 275 Attachment-1 REDACTED. The non-redacted information is in the folder on the Company's FTP site titled CONFIDENTIAL SUBJECT TO PROTECTIVE ORDER 12-001 in the subfolder Confidential Data Responses, and is titled OPUC DR 175 Attachment-1 CONFIDENTIAL.
b) See OPUC DR 275 Attachment-1.
c) The Company cannot provide this information as we have no method of determining how much gas customers would have used had their service not been interrupted.

Customer-specific usage data for the Oregon customers represented in OPUC DR 275 Attachment-1 has been previously provided. See the Company's response to OPUC DR 193.

CASE: UG 221
WITNESS: Moshrek Sobhy

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1113

Exhibits in Support Of Opening Testimony

May 3, 2012

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

NWN/303
McVay-Siores/1

Staff/1113
Sobhy/1

CASE: UG 221
WITNESS: Moshrek Sobhy

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1114

Exhibits in Support
Of Opening Testimony

May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 302:
Regarding the following projects represented in NW Natural's Exhibit NWN/600 Yoshihara/2, Lines 6-17:

- Corvallis Loop project
- Mid-Willamette Valley Feeder project

For each project or group of projects as combined by the Company, please:
a) Discuss how the Company identified the specific need (e.g., reliability, reducing curtailment of service to customers, compliance, meeting growth needs, reducing congestion, etc.) of the project;
b) Provide the Company's analysis supporting the need for the project, including but not limited to investment appraisals, planning documents (not limited to integrated resource plans), studies, reports, etc.
c) Provide copies of all internal correspondence and presentations leading to and with regards to the final decision to go forward with these projects.
d) In the event the above referenced projects involve Bare Steel replacement, provide your response to a, b, and c for the Bare Steel portion and the non-Bare Steel replacement portion separately.

Response: 2/23/2012

As discussed in Exhibit NWN/600 Yoshihara/3, Lines 4-18, 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, in order to maintain service to firm customers, interruptible customers in this area have experienced partial curtailment as temperatures in the area drop below 42 degrees Fahrenheit -- typically, the Company would not expect to curtail interruptible customers until the temperature was below freezing. For all of the reasons described above, the Company determined that the appropriate action was to increase capacity to this service area with a planned completion in the fourth quarter of 2012.

Also as discussed in Exhibit NWN/600 Yoshihara/5, Lines 19-23 and 6, Lines 1-11, the Mid-Willamette Valley Feeder Project will achieve multiple objectives. First, similar to the Corvallis Loop Project, the Mid-Willamette Valley Feeder Project will increase winter delivery capability to address existing system limitations in serving customers through the Albany-Corvallis Feeder. Second, it will bring us significantly closer to reaching the safety goal of replacing the remaining bare steel in 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 today 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.

The Company has provided specific documentation and further discussion of these projects in other data requests. Please see the Company's responses to:

OPUC DR 156	OPUC DR 173	OPUC DR 216	OPUC DR 274
OPUC DR 165	OPUC DR 174	OPUC DR 227	OPUC DR 340
OPUC DR 168	OPUC DR 175	OPUC DR 228	
OPUC DR 171	OPUC DR 177	OPUC DR 267	

See the two subfolders titled OPUC DR 302 CLP and OPUC DR 302 MWVF for the information requested in item c). Please note that a number of the internal communications provided in response to this data request contain attachments that the Company considers confidential subject to protective order, and has posted these documents in their entirety on the Company's FTP site in the folder CONFIDENTIAL SUBJECT TO PROTECTIVE ORDER 12-001, in the subfolder OPUC DR 302, within the subfolders named OPUC DR 302 CLP and OPUC DR 302 MWVF, respectively.

Pages 3 through 9 are confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

CASE: UG 221
WITNESS: Moshrek Sobhy

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1115

Exhibits in Support
Of Opening Testimony

May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 340:
In reference to the Company's response to Staff DRs 171-177 and the proposed Capital Projects in NWN/600:

i. Did the Company conduct an analysis to determine whether the MWVF project and Corvallis Loop project provide benefits to the ratepayers from a cost effectiveness perspective when compared to purchasing additional capacity on the Grants Pass Lateral or to other alternatives? Please provide the analysis or studies performed to support this conclusion. If none was performed, explain how the Company concluded that these projects were found cost effective from a ratepayer perspective?

ii. With regard to reducing the impact of an outage on the Grants Pass Lateral: Did the Company conduct a cost-benefit analysis from a risk mitigation perspective to its ratepayers of the proposed projects vs. purchasing additional capacity on the Grants Pass Lateral or vs. other alternatives?

iii. Provide a map showing the NWPL's Grants Pass Lateral in the Company's territory and identify the facilities with specifications where the two systems interconnect.

iv. What are the average demand (annually) and the peak demand in the last five years by customer class in the Albany region?

v. What is the Company's projected growth in the number of customers and the associated load during the test year in the Albany area?

Response: 2/23/2012

i) There is no additional capacity available on the Grants Pass Lateral and the Company is not aware of any plans by Northwest Pipeline (NWP) to expand or reinforce the Grants Pass Lateral. And, for other reasons, some of which are described in part ii below, the Company believes that the MWVF project offers advantages that would not be available through an expansion of the Grants Pass lateral. The Company's IRP contains additional analysis and discussion about the Grants Pass lateral and MWVF. See the Company's IRP at Docket LC-51 Chapter 1, page 1.9 and Chapter 3, pages 3.12 through 3.19. See also the Company's response to OPUC DR 177.

With respect to the Corvallis Loop Project, regardless of the fact that there is no expected expansion of the Grants Pass Lateral, a purchase of additional firm capacity on the Grants Pass Lateral is not a viable alternative because it does not address the pipeline restrictions downstream of the Grants Pass Lateral between the Albany Gate Station and the Albany and Corvallis service territories.

ii) With regard to the MWVF Project, please refer to the Company's IRP and the Company's response to OPUC DR 177. Purchasing additional capacity on the Grants Pass Lateral does not reduce the impact of an outage on the Grants Pass Lateral. See OPUC DR 340 Attachment-1, which is a copy of a system reliability study that was produced in 2008. The study priority ranks single feed systems within NW Natural's territory based on potential customer outages due to a system failure. Upon completion of the MWVF, Albany, the highest ranked system would no longer be a single feed system.

iii) See OPUC DR 340 Attachment-2, which is the requested map which shows the NWN interconnects with the Grants Pass Lateral in zones 12, 9 and 8 of the NW Pipeline System. See OPUC DR 340 Attachment-3, which provides the Maximum Daily Delivery Obligation (MDDO) and NW Pipeline's published Meter Capacity for each of the delivery points within these zones.

iv) The average annual demand for the Company's Albany District by customer class for 2007 through 2011 is provided at OPUC DR 340 Attachment-4.

Peak demand in therms per-hour as measured at the three gate stations in the Albany district is provided in OPUC DR 340 Attachment-5. Gas send-out at the gate stations represents all customers, including interruptible transportation customers, and cannot be reported by customer class.

v) Due to adjustments made to account for customer losses related to rate design and heat pumps, the projected change in Albany residential customer counts is a net loss of 951 customers.

The net decrease in load associated with those residential customers is 1,871 therms during the test year. Projected growth in commercial customer counts is 28, with an associated load of 76,384 therms during the test year.

Projected growth in industrial customer counts is 1, with expected additional therm usage of 2,507,333 based on the new customer add and usage changes of existing customers in the test year.

Pages 3 through 6 are confidential.

You must have signed the Modified Protective Order No: 12-0058 in this docket to view this page.

CASE: UG 221
WITNESS: Moshrek Sobhy

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1116

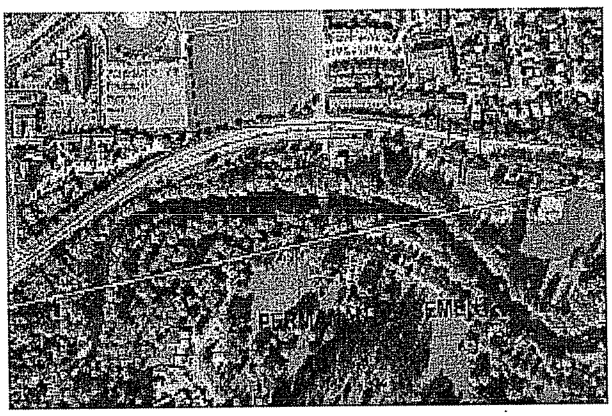
Exhibits in Support Of Opening Testimony

May 3, 2012

NW Natural will tunnel, dig new, nine-mile gas line under Corvallis

Corvallis Gazette-Times democratherald.com | Posted: Wednesday, March 28, 2012 5:45 am

Read more: http://democratherald.com/news/local/nw-natural-will-tunnel-dig-new-nine-mile-gas-line/article_ef67e53c-788f-11e1-bc64-001871e3ce6c.html#ixzz1qR8kKEiR



NW Natural is going to use cutting-edge technology to tunnel a new high-efficiency gas line in a nine-mile loop through Corvallis. The work is to start sometime this summer.

Valerie White, a Portland-based spokeswoman for the company, said this week that the entire $15 million project is 39 meandering miles long, stretching from Monmouth through Albany and Corvallis.

However, the most visible part of the project in Corvallis will be the equipment that will be staged at Alan Berg Park on the Linn County side of the Willamette River, and little disruption is expected to traffic or the environment.

Using the same kind of high-efficiency borer used to build enormous tunnels, the pipeline will be laid 60 feet under the Marys River and perhaps 30 feet under the tree roots at Avery Park.

Not all of the pipeline will be buried so deep, White said. Most of the regular line will be four to five feet underground and some will be laid into a regular trench that is dug rather than through the process using a borer.

The project will replace a bare steel main pipe with a higher-pressure 12-inch coated steel, replacing inadequate pipe that is more than 50 years old.

"When it got really cold, the pressure gets so low in that (Corvallis) part of the system that we have 'interruptible customers' that we have to pull off the system,'" White said.

While she declined to identify who those customers are, White said they are typically large industrial-type clients who voluntarily agree to go off-line in times of low pressure so that residential customers can stay warm.

That happened just last week, White said, so it is not unusual.

One large natural gas consumer that no longer will have to worry about capacity will be Oregon State University, which is where the new pipeline will end.

The route begins at the Orleans Natural Area on the east side of the Willamette River in Alan Berg Park, then crosses — 60 feet under under the river — into Corvallis near the Highway 20/34 Bypass.

The line will run under Pioneer Park, beneath the Marys River and 1,500 feet through Avery Park, then continues west before turning north along 35th Street and ending at the Oregon State University Energy Center at Western Boulevard and 36th Street.

Initially, citizen concerns about the pipeline centered on environmental damage and danger, but the deep-underground boring and relative lack of disruption prompted the Corvallis City Council to green-light the plan at its March 19 meeting, 7-0.

"It's definitely going to add more reliability to that area," White said. "It's a good thing for customers."

However, those customers likely will pay for the improvement.

NW Natural has asked Oregon's Public Utility Commission to approve a 6 percent rate hike.

Although no specific date for the start of work has been identified, the Monmouth portion began in January, and it is expected to reach Corvallis this summer.

"Our goal is to complete the project before winter," White said.

CASE: UG 221
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Matt Muldoon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/1201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review Northwest Natural Gas Company's (NWN or Company) Cost of Long-Term Debt (Cost of LT Debt).

Q. DID YOU PREPARE ANY EXHIBITS FOR THIS DOCKET?

A. Yes. I have prepared the following four exhibits:

1. Exhibit Staff /1201 consisting of 1 page.
2. **Confidential** Exhibit Staff /1202 consisting of 1 page.
3. **Confidential** Exhibit Staff /1203 consisting of 4 pages.
4. **Confidential** Exhibit Staff /1204 consisting of 2 pages.

Q. HAS STAFF PROVIDED A UNIFYING EXHIBIT?

A. Yes. Exhibit Staff/1202 illustrates Staff recommended adjustments.

Q. WHY IS THIS EXHIBIT CONFIDENTIAL?

A. Exhibit Staff/1202 incorporates confidential information provided in numerous confidential responses to Staff's standard and other data requests.

Q. WHAT INFORMATION DID STAFF RELY ON IN PREPARING THIS TESTIMONY?

A. In conducting its review, Staff referred to the Company's initial filing and to the Company's responses to approximately 56 standard and 59 other Staff multi-part data requests (DR) pertaining to Cost of LT Debt, many following up on a phone workshop on Cost of LT Debt, held February 23, 2012.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as shown below:

SUMMARY

Q. HAVE YOU PREPARED A SUMMARY TABLE THAT SUCCINTLY SUMMARIZES STAFF'S RECOMMENDED COST OF LT DEBT[1]?

A. Yes Table 1 below summarizes the Company-proposed, and Staff recommended cost of LT Debt for NWN:

Table 1

Cost of LT Debt		
Company Proposed	**Staff Recommended**	**Adjustment**
6.265 %	**5.924 %**	**(0.341%)**

Q. BRIEFLY, HOW MANY CHANGES DOES STAFF PROPOSE TO THE COMPANY'S CALCULATION OF ITS COST OF LT DEBT?

A. Staff proposes three adjustments regarding cost of LT Debt:

Q WHAT IS THE FIRST CHANGE YOU PROPOSE?

1 Pursuant to Docket UE-116, "The Commission has defined long-term debt as any debt with a maturity of more than one year. Concomitantly, the definition of short-term debt is a debt with a maturity of one year or less."

A. First, the portion of test-year LT Debt that is maturing within one year of the test period is replaced with a Pro Forma 10-year issue of the same aggregate principal size, preserving bond portfolio integrity.

Q WHAT IS THE SECOND CHANGE YOU PROPOSE?

A. Second, Staff enlarges the third quarter, 2012 $25 million issues to $50 million at costs reflective of currently expected market conditions. The choice of larger-sized issuance is within the Company's Board of Directors' finance need projections.[2] Staff also uses a lower interest rate for the debt issuance than that assumed by NWN.

Q WHAT IS THE THIRD CHANGE YOU PROPOSE?

A. Third, Staff proposes that ratepayers and the Company share equally a financial hedging loss, removing half that amount from the Company's cost of LT Debt. Authorization in Order 07-032 deferred consideration of prudence regarding actions taken until rate recovery was requested. The hedge was imprudent because the Company did not conduct independent, unbiased analysis and due diligence prior to the Company's decision to execute the hedge.

[2] Confidential Attachment 2, in response to Staff DR 299, provides the Company's Finance Committee December, 2011 recommendations to NWN's Board of Directors.

ISSUE 1, REPLACING THE CURRENT PORTION OF LONG-TERM DEBT

Q. WHAT PREVIOUSLY CLASSIFIED LT DEBT MATURES WITHIN ONE YEAR OF THE TEST YEAR?

A. NWN/401Feltz/1, and spreadsheets provided by the Company in response to additional data requests depict two series of bonds on lines 1 and 2 that reach this status within the test year.[3]

Q. WHY DOES STAFF PROPOSE PRO-FORMA 10-YEAR REPLACEMENT FOR $50 MILLION OF FIVE-YEAR DEBT, ORIGINALLY ISSUED IN JULY OF 2009, RATHER THAN A LIKE MATURITY REPLACEMENT?

A. Using a ten-year replacement avoids adding to concentration in debt maturing in five to eight years. An additional advantage is that while a ten year maturity has a higher interest rate than a five year (and thus tends to raise the cost of debt); a ten-year maturity takes advantage of historically low 10-year bond coupon rates. At this time no other LT Debt matures in 2022.

Q. WHY DOES STAFF ALSO PROPOSE PRO FORMA 10-YEAR REPLACEMENT FOR $10 MILLION OF 20-YEAR DEBT, ORIGINALLY ISSUED IN SEPTEMBER OF 1994?

A. Using a ten-year debt also avoids concentration of maturities twenty years from the test period.

Q. IS THE PRO FORMA REPLACEMENT OF THE CURRENT PORTION OF LT DEBT A WELL ESTABLISHED COMMISSION PRACTICE?

---

[3] Line 1 of Feltz/1 describes a $10 million bond series maturing in September of 2014, while Line 2 of the same spreadsheet describes a $50 million bond series maturing in July of 2014.

A. Yes. For example, this practice is reflected in the recent Order 12-055 for the UE 233, Idaho Power general rate case.

ISSUE 2, Q-3, 2012 BOND ISSUANCE

Q. PLEASE COMPARE THE COMPANY'S PROPOSED THIRD QUARTER LT DEBT ISSUANCE WITH STAFF'S RECOMMENDATIONS REGARDING ISSUANCE SIZE AND COST.

A. The following table summarizes the company's proposal contrasted against Staff's recommendations:

	Company Proposed	Staff Recommended
Q3 2012 LT Debt Issuance	$25 Million	$50 Million
Maturity	30-Years	30-Years
Coupon (Interest) Rate	4.70%	4.34%
All-in Cost of Money (Includes Costs Shown Below)	4.795%	4.394%
Make Whole Provision (Flexibility of Early Retirement)	Not Addressed	20 Basis Points
Credit Rating (Bloomberg Aggregate)	A+	A+
Agent's Commission	$125,000 to $187,500	$250,000 or Less, Includes Delayed Settlement
Other Expenses (Including Legal Expenses)	$150,000 to $250,000	$200,000 or Less, Includes All Legal Expenses

Q. DOES STAFF FIND THE INTEREST RATE ASSUMED BY NWN FOR ITS THRITY-YEAR DEBT ISSUANCE FOR 2012 TO BE OVERSTATED?

A. Yes.

Q. WHAT IS THE BASIS OF STAFF'S OPINION?

A. Staff has frequently monitored its Bloomberg resources since January 17, 2012. According to the Bloomberg resources, the implied forward yield for a 30-year U.S. Treasury bond is periodically twenty basis points lower than the Company projects in NWN / 400 Feltz/11.

Q. WHY DOES STAFF'S ALL-IN COST[4] OF MONEY INCLUDE COMPONENT COSTS HIGHER THAN THE COMPANY'S ESTIMATES?

A. The main reason that Staff's estimates are higher in an absolute sense is because Staff's estimates are based on a $50 million issuance while NWN's estimates are for $25 million. Staff monitors eight components which comprise "Other Expenses." Staff's assumptions for each component cost on a $50 million third quarter issuance shown below are reflective of other recent jurisdictional issuances, adjusted proportionally upward because Northwest Natural issues long-term debt less frequently:

Staff's Recommended Other Expenses for $50 Million Issuance	
Registration Fee	$ 5,500
Legal Fees and Expenses	$ 65,000
Accounting Fees & Expenses	$ 50,000
Trustee Fees	$ 2,500
Rating Agency Fees	$ 60,000
Indenture Recording Fees	$ 10,000
Printing and Delivery of Registration Statement, Prospectus & Certifications	$ 5,000
Miscellaneous Expenses	$ 2,000
Total Other Expenses	$ 200,000

Staff's estimate of legal costs[5] is proportionally lower than the Company's; however, the $50,000 difference between the Company's projections and Staff's recommendations will not make a material difference to Cost of LT Debt.

4 All-in Cost includes all expenses associated with issuance, the coupon rate, and any discount or premium from par value at issuance. Technically, it is the percentage internal rate of return when all costs, such as any original issue discount, floatation, and insurance costs, as well as the actual cash flows of the security, are included. See pages 746 through 747 of "Futures, Options, and Swaps," Fifth Edition; by Robert W. Kolb and James A. Overdahl; Blackwell Publishing, Ltd; 2007.

5 Staff's basis for estimate for legal expense in a Northwest Natural current bond issue of $50 million is the legal expense for PacifiCorp to issue $100 million on March 6, 2012. Staff accessed PacifiCorp's Form 8-K Current Report of March 6, 2012 on April 20, 2012 under

Q. DID THE DIFFERENCES IN OTHER EXPENSES BETWEEN NWN AND STAFF APPRECIABLY AFFECT THE ALL-IN COST DIFFERENCE?

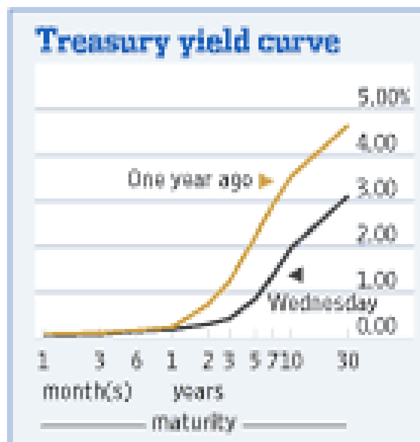
A. No. The all-in cost differences do not appreciably affect the respective effective interest rate projected by NWN or by Staff.

Q. THE COMPANY ESTIMATES A SPREAD OF 150 BASIS POINTS FOR A PLANNED THIRD QUARTER 2012 BOND ISSUANCE OVER LIKE MATURITY U.S. TREASURIES. IS THAT A GOOD ESTIMATE?

A. No.

Q. WHAT IS THE BASIS FOR THIS PERSPECTIVE?

A. Staff finds that current forward cost expectations reflect two trends. First there has been a dramatic drop in the yields on both 10-year and 30-year U.S. Treasuries (UST) which are the foundation for pricing of utility first mortgage bond issues. As shown to the right in the Thursday, March 8, 2012, Wall Street Journal, 10-year UST yields have dropped to just 1.970 percent – down a full percent from a year earlier.[6]



Security and Exchange Commission File No. 1-5152, and identified “Legal Expense” in Section 4, “Other Expenses of Issuance and Distribution”.

6 Staff accessed the article, “Treasury Prices Retreat” by Mig Zeng, published in the print Wall Street Journal on April 21, 2012, to confirm that 10-year treasuries were still under two percent yield while 30-year treasuries were under 3.13 percent yield for the prior week.

Q. WHAT IS THE SECOND MATERIAL TREND?

A. In highly volatile larger aggregate financial markets, there has been investor flight to quality.[7] The Company's Bloomberg aggregated utility, A+ rated, first mortgage bonds are likely to be oversubscribed and able to be issued at much lower coupon and all-in-cost than the majority of the Company's outstanding LT Debt.

Q. WHAT EVIDENCE IS THERE THAT THIS TREND IMPACTS NORTHWEST INVESTOR OWNED UTILITIES?

A. For example, PacifiCorp, which has a lower credit rating than NW Natural, arranged with J.P. Morgan Securities LLC:

2.95% Series settled January 6, 2012, 10-year maturity bonds

2.95% Series settled March 6, 2012, 10-year maturity bonds; and,

4.10% Series settled January 6, 2012, 30-year maturity bonds

Q. IN GENERAL HOW DO PACIFICORP AND NORTHWEST NATURAL BONDS COMPARE?

A. While PacifiCorp enjoys Berkshire Hathaway association and is larger, Northwest Natural has higher credit ratings.

Q. WHAT DID YOU FIND WITH RESPECT TO OTHER UTILITIES?

A. Idaho Power Company issued $75 million each of 2.95 percent 10 year bonds, and 4.3 percent 30 year bonds, also arranged with J.P. Morgan Securities LLC as a primary underwriter and book manager. These April, 2012 issuances

[7] For example, Staff accessed the article "Spooked Investors Make a Run for Safety" by Tom Lauricella published in the Wall Street Journal on October 3, 2011.. The term "flight-to-quality" means a shifting from the volatility of higher-risk, lower-rated investments into highly rated bonds offering certainty of return and preservation of capital.

corroborate both the cost and short-term durability of investor interest in high quality regulated utility LT Debt series.[8]

Q. CAN THE SIZE OF THE BOND ISSUANCE ITSELF AFFECT THE INTEREST RATE REQUIRED?

A. Yes, on February 14, 2012, the Wall Street Journal article "For Bond Investors, Bigger is Better" by Katy Burne noted that historically there was no size premium for smaller bond issues. However, in the current period due to regulatory uncertainty there is a 0.03 to 0.14 percent small issue size premium reflecting relative liquidity as measured in frequency of after-market trading.

Q. DID THE RECENT PACIFICORP LIKE-MATURITY, LOWER-RATED ISSUE HAVE A 60 BASIS POINT LOWER COUPON, A 25 BASIS POINT LOWER AGENT'S COMMISSION AND LOWER COST OF ISSUANCE THAN PROJECTED IN NWN/400?

A. Yes.

Q. DO STAFF'S PROPOSED CHANGES REFLECT A 14 BASIS POINT COUPON RATE SMALL ISSUANCE SIZE PREMIUM FOR THE COMPANY'S PLANNED SECOND QUARTER 30-YEAR BOND ISSUANCE?

A. Yes. Staff finds the recent PacifiCorp issue data plus up to a 14 basis point small issuance size premium to be a more targeted validation reference than the Company's NWN/400 Feltz/11 older, lower rated transactions cited.

[8] Staff accessed both Bloomberg and SNL data to confirm bond issuance detail the second week after each issuance to preclude reliance on any issuance day errata.

Q. WERE IDAHO POWER RECENT $75 MILLION ISSUANCES HEAVILY PENALIZED FOR SMALL BOND ISSUANCE SIZE?

A. No. Idaho Power paid no liquidity premium on 10-year bonds, and only a small liquidity premium on 30-year bonds, in sharp contrast to testimony provided in NWN/400 Feltz/11.

ISSUE 3, FINANCIAL HEDGE LOSS

Q. PLEASE DESCRIBE THE TRANSACTION DISCUSSED HERE.

A. The Company entered into a cancellable swap transaction (hedge) wherein the Company would pay a [redacted] per annum on a notional amount of [redacted] in exchange for [redacted] based on [redacted] with a notional maturity of [redacted] of like principle amount of senior secured notes. Herein, neither party [redacted] as noted in Confidential Exhibit Staff/1203[9].

Q. WHAT AUTHORIZATION DID THE COMPANY HAVE TO ENTER INTO THIS TRANSACTION?

A. Commission Order No. 07-032 authorized the Company to utilize hedging tools provided among other provisions that:

> "Northwest Natural shall demonstrate that each hedge transaction was prudent, providing market data and correspondence with agents and counterparties as well as risk analysis, in support of that demonstration."

Q. WHAT WERE THE RESULTS OF THIS TRANSACTION AND HOW DID THE COMPANY RECORD THE FINANCIAL EFFECTS?

A. The Company and UBS [redacted], with the Company paying UBS AG the sum of [redacted] as shown in Confidential

[9] This confidential exhibit is provided in response to Staff DR 292.

Exhibit Staff/1204[10]. This sum was assigned to the Company's March, 2009 issuance of $75 million of 5.370 percent first mortgage bonds (FMB) to be amortized over the life of the series as an addition to issuance costs.

The Company lost approximately [redacted] on a notional amount of [redacted] dollars to protect against [redacted] movements in FMB interest rates.

Q. WHAT ARE STAFFS RECOMMENDATIONS?

A. Staff recommends that the Commission order the Company to modify its financial hedging policy to address three concerns:

1. That the Company will perform either its own probabilistic risk analysis in the future, considering both likely outcomes and high-impact less-frequent outcomes, before executing financial hedging contracts, or in the alternative, hire an independent third party (not affiliated with the hedge seller(s), bidders and counterparties) to conduct such analysis;
2. That the Company will restrict its accounting of financial hedging activity to FASB methods and subsequent generally accepted replacements thereto; and
3. That the Company will revisit how it defines "highly effective" in its financial hedging policy.

Further Staff recommends that the cost of issuance of the 5.370 percent series due in February of 2020 be [redacted] (half the hedge loss amount) for rate making purposes.

Q. WHAT IS THE BASIS FOR STAFF'S RECOMMENDATIONS?

A. Staff believes the swap hedge was imprudent for four primary reasons:

[10] This confidential exhibit is provided in response to Staff DR 395.

Q. WHAT IS THE FIRST REASON?

A. The Company's did not perform its own probabilistic risk analysis or use an independent third party to conduct the risk analysis. Instead, NW Natural relied on the sellers of the hedge product for the financial analysis. As a general matter, the Company should not solely rely on risk analysis from those bidding to sell the Company a product.

Q. DID STAFF ASK FOR THE COMPANY'S OWN ANALYSIS?

A. Yes, Staff issued multiple DRs asking for the Company's own probabilistic risk analysis, but received marketing materials from investment banks bidding to be the counterparty in this hedging transaction.

Q. DID THE INVESTMENT BANKS' ANALYSIS EMPHASIZE POSITIVE GENERAL OUTCOMES AND NOTE SUCH RESULTS MAY NOT BE INDICIATIVE OF FUTURE RESULTS?

A. [redacted].

Q. WHAT IS THE SECOND BASIS FOR STAFF'S RECOMMENDATIONS?

A. The Company failed to deliver price and timing certainty at a cost proportional to the interest rate risk. It is reasonable that there should be some bounds on gains or losses proportional to the investment size and risk averted. [redacted].

Q. WHAT IS THE THIRD BASIS FOR STAFF'S RECOMMENDATIONS?

A. The Company's financial hedging policy allows for less stringent accounting methods than FASB and tests for "highly effective" hedging by applying tests such as: a) The bank counterparty is highly rated, and b) Terms of the hedge do not change.

Q. WHAT IF THE COMPANY HAD LOST THE ENTIRETY OF THE NOTIONAL AMOUNT, WOULD THE HEDGE STILL HAVE BEEN DEEMED "HIGHLY EFFECTIVE" BY THE COMPANY BASED ON THE COMPANY'S EVALUATION CRITERIA?

A. It appears so. Loss of the entire notional [redacted] under the criteria applied would still have been deemed "highly effective". The Company's financial hedging policy can benefit from a reexamination of term definitions and financial hedge evaluation criteria.

Q. WHAT WAS THE FOURTH REASON?

A. There appears to be limited transparency regarding the hedge transaction and accounting treatment.

Q. WAS THE HEDGE LOSS VISIBLE TO INVESTORS AND RATEPAYERS?

A. No. Deemed a highly effective hedge; the loss was entirely amortized over the life of the assigned FMB series as additional issuance cost.[11]

Q. DO TIGHTER TESTS FOR EFFECTIVENESS AND MORE STRINGENT ACCOUNTING METHODS IMPACT TRANSPARENCY?

A. Yes, the ineffective portion of a failed hedge is explained under FASB accounting in the Company's annual report financial statements under the heading 'Other Comprehensive Income".

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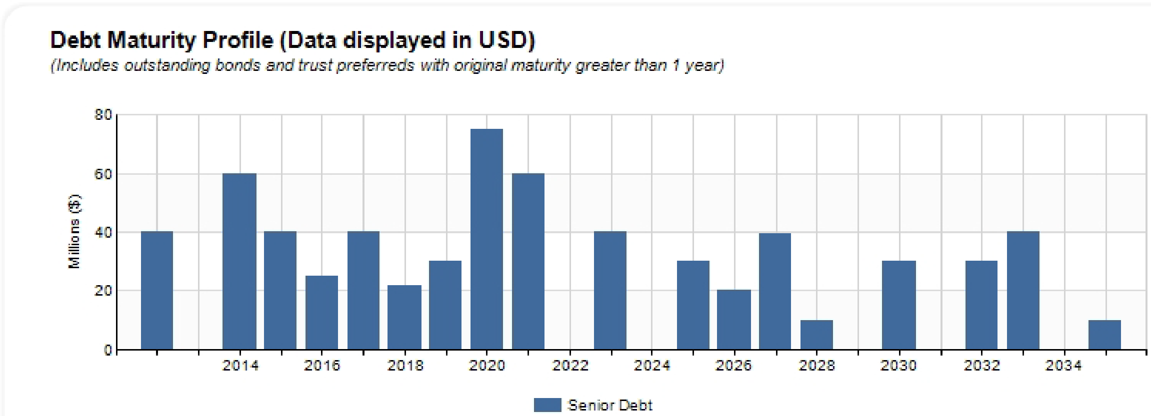
[11] The Company's response to DR 417 shows straight line hedge loss amortization over the life of the designated bond series.

DEBT MATURITY PROFILE

Q. DID STAFF EXAMINE NORTHWEST NATURAL'S DEBT MATURITY PROFILE TO LOOK FOR CONCENTRATIONS OF DEBT MATURITY?

A. Yes. Staff accessed the following Northwest Natural Debt maturity on SNL.[12]



Q. HOW DOES THIS PROFILE COMPARE WITH THE COMPANY'S PROFORMA EMBEDDED COST OF LONG-TERM DEBT CAPITAL PROVIDED IN NWN/401 FELTZ/1 (FELTZ/1)?

A. The Company plans to retire $40 million short-term portion of long term debt in 2012 and to issue $25 million long-term debt in the third quarter of 2012 with a maturity of 30 years. Otherwise FELTZ/1 matches the SNL debt profile above.

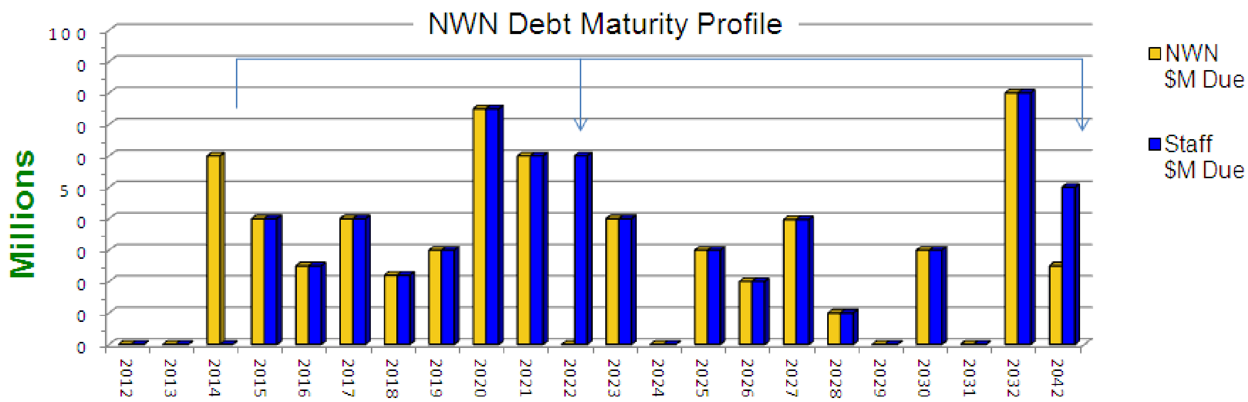
Q. WHAT PATTERNS DOES STAFF DETECT IN THIS PROFILE?

A. The Company's portfolio of long-term debt now has no outstanding series with a maturity of 23 years to maturity or greater. Considering the SNL debt maturity profile, 11 of the 24 bond series reflected therein were issued with a 30-year maturity. However, the Company plans a new 30-year Medium Term Notes (MTN) issuance in the test year.

[12] Staff accessed the Company's historical debt profile on SNL Financial, on February 6, 2012

Q. PLEASE SHOW THE DEBT MATURITY PROFILE FOR NORTHWEST NATURAL REFLECTING ALL OF STAFF'S PROPOSED CHANGES.

A. Please see Staff's adjusted profile below:



Q. DOES ANY CHANGE PROPOSED BY STAFF STRESS THE COMPANY'S DEBT MATURITY PROFILE?

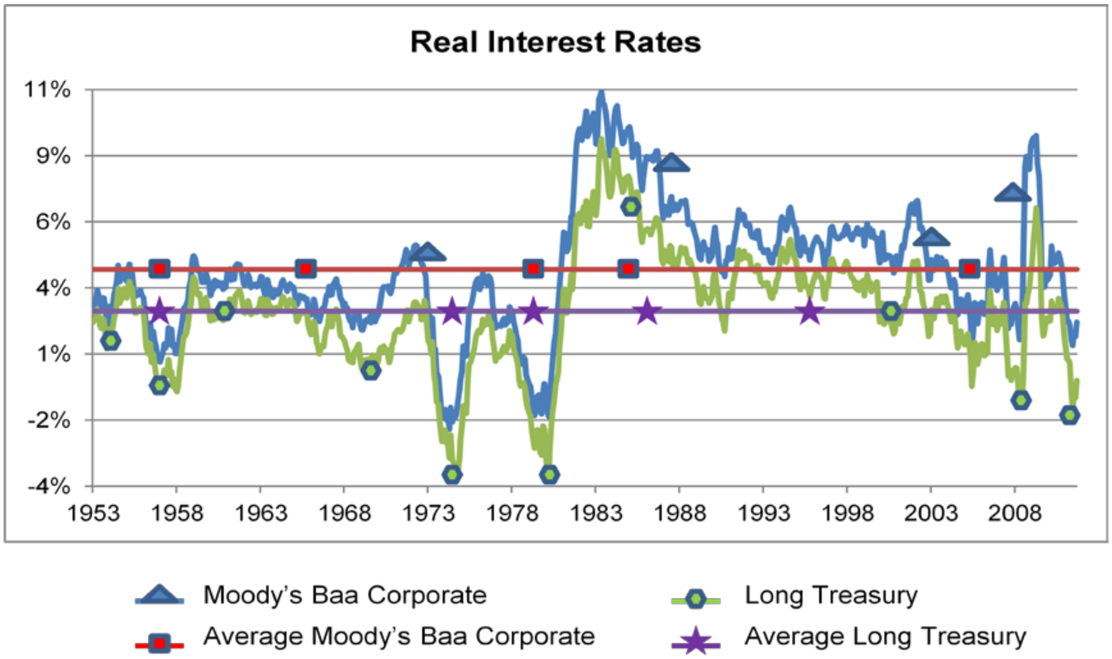
A. No. No concerning concentrations of debt maturity would result from Staff's changes.

Q. DOES STAFF'S ADJUSTMENT OF THE SIZE OF THIRD QUARTER, 2012 30-YEAR DEBT CONFLICT WITH COMPANY BOARD OF DIRECTORS FINANCE COMMITTEE ADVICE?

A. No.

Q. DO CURRENT INTEREST RATE TRENDS SUPPORT ISSUANCE OF AN ADDITIONAL $25 MILLION LONG TERM BONDS AT THIS TIME?

A. Yes. As of February 8, 2012, Moody's Investment Services data shows that current corporate bonds are much lower than the long run average from 1953 to present, as depicted next.



Q. DID STAFF INVESTIGATE THE COST OF EARLY REDEMPTION OF OUTSTANDING HIGH COUPON BOND SERIES?

A. Yes. Unfortunately, outstanding bond series either had negative net present value effectiveness tests for early redemption or are not callable. Other market methods for early redemption such as tender offers or repurchase through an investment bank agent were investigated, but did not prove cost effective with acceptable risks at this time.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME:	Matthew (Matt) Muldoon
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	Senior Economist Economic Research & Financial Analysis Division Economic & Policy Analysis Program
ADDRESS:	550 CAPITOL STREET NE SUITE 215, SALEM, OREGON 97301-2115.
EDUCATION:	In 1981, I received a Bachelors of Arts Degree from the University of Chicago. Then in 2007, I received a Masters of Business Administration from Portland State University with a certificate in Finance.
EXPERIENCE:	From April of 2008 to the present, I have been employed by the OPUC. My current responsibilities include financial and rate analysis in the Economic Research and Financial Analysis Division of the OPUC's Utility Program. I have also participated in regional and sub-regional planning including activities with Western Electricity Coordinating Council, Variable Generation Subcommittee, Columbia Grid, Northern Tier Transmission Group (NTTG) and other regional and sub-regional forums focused on transmission and wind integration. From 2002 to 2008 I was Executive Director of the Acceleration Transportation Rate Bureau, Inc. where I developed new rate structures for surface transportation and created metrics to insure program success within regulated processes. I was the Vice President of Operations for Willamette Traffic Bureau, Inc. from 1993 to 2002. There I managed tariff rate compilation and analysis. I also developed new information systems and did sensitivity analysis for rate modeling.
OTHER EXPERIENCE:	I have prepared, and defended formal testimony in contested hearings before the ICC, STB, WUTC and ODOT. I have also prepared OPUC Staff testimony in BPA and utility rate cases.

CASE: UG 221
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1202

Exhibits in Support
Of Opening Testimony

May 3, 2012

STAFF EXHIBIT 1202

IS CONFIDENTIAL AND SUBJECT TO MODIFIED PROTECTIVE ORDER NO. 12-058. YOU MUST HAVE SIGNED APPENDIX B OF THE MODIFIED PROTECTIVE ORDER IN DOCKET UG 221 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UG 221
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1203

[NWN Confidential Attachment 1 in Response to Staff DR 292]

Exhibits in Support Of Opening Testimony

May 3, 2012

STAFF EXHIBIT 1203

IS CONFIDENTIAL AND SUBJECT TO MODIFIED PROTECTIVE ORDER NO. 12-058. YOU MUST HAVE SIGNED APPENDIX B OF THE MODIFIED PROTECTIVE ORDER IN DOCKET UG 221 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UG 221
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1204

[NWN Confidential Attachment A in Response to Staff DR 395]

Exhibits in Support Of Opening Testimony

May 3, 2012

STAFF EXHIBIT 1204

IS CONFIDENTIAL AND SUBJECT TO MODIFIED PROTECTIVE ORDER NO. 12-058. YOU MUST HAVE SIGNED APPENDIX B OF THE MODIFIED PROTECTIVE ORDER IN DOCKET UG 221 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UG 221
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Steve Storm. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement can be found in Exhibit Staff/1301.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss Northwest Natural's existing Schedule 190 Distribution Margin Normalization decoupling mechanism and the Company's proposed changes to the mechanism. I describe the impetus for and specific changes to the mechanism, which I present as recommendations to Commission.

I discuss the Company's requested 10.3 Return on Equity (ROE) and requested capital structure, describe my analysis of the Company's cost of equity capital, and provide my assessment of the analysis performed by the Company's cost of capital witness Dr. Hadaway.

I include a table identifying the individual effects of updated prices and dividends, choice of peer utilities, choice of long-term growth rate, and an adjustment for the individual capital structures of peer utilities from that of Northwest Natural have in explaining the 80 basis point difference between the multistage DCF model employed by Dr. Hadaway (10.0 percent ROE) and the multistage DCF models I use (9.2 percent ROE).

I provide recommendations for the Commission's consideration regarding authorized levels of the Company's ROE and capital structure.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/1301, consisting of one page; Exhibit Staff/1302, consisting of one page; Exhibit Staff/1303, consisting of eight pages; Exhibit Staff/1304, consisting of six pages; and Exhibit Staff/1305, consisting of five pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Q. WHAT ARE YOUR SUMMARY DECOUPLING RECOMMENDATIONS FOR THE COMMISSION'S CONSIDERATION?

A. I recommend the Commission:

- Adopt the Company's proposal to maintain the existing distinction between Residential and Commercial customers for purpose of the decoupling mechanism;
- Adopt the Company's proposal to remove the price elasticity adjustment in the current mechanism;
- Change the benchmark from use per customer to total use (weather-normalized therms);
- Incorporate a "New Service Rate" as a regulatory construct to be applied to cumulative values of new meters in new service locations for purposes associated with determining levels of decoupling credits or charges;

- Fix the value of the margin rate per therm in this rate case, to be updated in future rate cases; and
- Change the deferral period to August through July.

Q. WHAT ARE YOUR SUMMARY COST OF EQUITY AND CAPITAL STRUCTURE RECOMMENDATIONS FOR THE COMMISSION'S CONSIDERATION?

A. I recommend the Commission:

- Authorize a Return on Equity (ROE) rate of 9.2 percent for Northwest Natural, which is within my 8.8 to 9.5 percent range of recommended ROEs; and
- Adopt the Company's recommended capital structure of 50 percent long-term debt and 50 percent common equity.

Q. PLEASE SUMMARIZE YOUR DECOUPLING TESTIMONY.

A. My decoupling testimony discusses the concept of decoupling; how the current Northwest Natural decoupling mechanism works and its effect on the Company's incentives; the actual results produced by the current mechanism since it was implemented; the changes to the mechanism proposed by the Company, including identification of those I support and why; and the benefit to Northwest Natural's ratepayers of decoupling.

I discuss certain aspects of a natural gas local distribution utility's fixed costs, including reference to relevant portions of the Company's Exhibits NW/1100 and NWN/1101. I point out that revenue or use per customer mechanisms inherently assume fixed costs, which are believed not to vary with volumes, are believed to vary directly (and completely) with the number of customers, and why this assumption is suspect.

I recommend several changes to the existing mechanism and include my objectives for doing so. Those changes are to:

- Remove the price elasticity adjustment component of the current mechanism;
- Replace the existing weather-normalized use per customer with total weather-normalized use;
- Include a "New Service Rate," to incorporate into decoupling charges amounts sufficient to cover relevant changes in fixed costs attributable to the addition of a customer at a service address not previously served;
- Establish the margin rate per therm as an outcome in general rate case proceedings which does not change between rate cases; and
- Change the deferral period from the current November through October to August through July of each year.

I discuss the rationale for each of these recommendations and include analysis based on modeling the actual experience since implementation of decoupling for Northwest Natural as well as analysis based on using values from the Company's most recently filed Integrated Resource Plan.

Q. WHAT IS "DECOUPLING?"

A. Decoupling is a regulatory rate mechanism designed to remove a rate-regulated energy utility's incentive to increase profits by increasing volumes of delivered energy. The objective underlying the removal of such an incentive is to make the utility indifferent as to the volumes of energy it sells, thereby removing the parallel incentive to oppose energy efficiency efforts serving to reduce the use of energy provided by the utility. The Commission described decoupling in Order No.02-634 of Docket No. UG 143[1] as

> "…a regulatory tool designed to break the link between a utility's earnings and the energy consumption of its customers. While such mechanisms take several forms, the basic approach consists of defining a target for revenues and placing over- and under-collections relative to that target in a deferred account for recovery in a later period. Under such mechanisms, a utility cannot increase its earnings by increasing its sales, because additional sales margins are returned to customers.

Order No. 02-634 includes a passage from Order No. 92-1673 in Docket No. UM 409 as the Commission's earlier acknowledgment of the "need to change regulatory policy to encourage the efficient use of energy resources:"

> "We are persuaded that the connection between profits and sales should be severed. As long as the regulatory system provides that increased sales may lead to increased profits, a conflict will exist between the motivation to sell energy and the motivation to promote reduction in energy consumption."

Q. PLEASE DISCUSS THE NATURE OF AN ENERGY UTILITY'S INCENTIVE TO INCREASE PROFITS BY INCREASING THE VOLUMES OF ENERGY IT SELLS.

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[1] *See* page 2 of the Order. Order No. 02-634 authorized implementation of Northwest Natural's Distribution Margin Normalization mechanism, which is the current decoupling mechanism.

A. Energy utility rate designs under traditional regulation typically include a monthly customer charge that neither varies between customers in a given rate schedule nor with changes in the monthly level of energy used by a specific customer over time. This fixed dollar monthly charge is not, in conventional rate designs, intended to cover all of the utility's fixed costs. If the customer charge is less than total fixed costs on a per customer basis, with the volumetric charge[2] more than covering costs that vary with volume, the utility's profits increase with higher volumes. Beyond some level of sales, all fixed costs are covered and that portion of the volumetric charge intended to cover fixed costs is available to the utility as additional return. This is the "thoughput incentive" of the utility: profits increase if sales volumes and resulting revenues increase; an incentive to increase profits leads directly to an incentive to increase sales volumes or, alternatively, to minimize reductions in sales volumes. In particular, the throughput incentive is mirrored as a disincentive for an energy utility to support or facilitate energy efficiency activities, which result in reduced sales volumes.

Q. PLEASE DESCRIBE NORTHWEST NATURAL'S DECOUPLING MECHANISM.

A. The mechanism applies to Residential customers and smaller Commercial customers. It is a revenue per customer (RPC) type of decoupling mechanism, with a couple of twists. RPC decoupling mechanisms measure actual revenues per customer against an established benchmark, with the

[2] Volumetric charge as used here is the product of the volumetric rate and the volume.

revenue difference per customer multiplied by the number of actual customers, and the result deferred for later collection (actual less than benchmark) or crediting (actual greater than benchmark). Revenue variances are calculated and charged or credited separately for Residential class and for Commercial class customers. An important characteristic of revenue per customer decoupling mechanisms is that they serve to provide an assured amount of revenue per customer.[3]

Q. WHAT ARE THE "TWISTS" TO THE NORTHWEST NATURAL DECOUPLING MECHANISM?

A. The first is fairly simple. Northwest Natural's mechanism separates revenue per customer into two component parts: rate per quantity, termed the "margin rate per therm," and quantity (therms) per customer, which, when multiplied together, determine revenue per customer.

The second variation is separation of the amounts to be recovered from or credited to customers into two different sets of calculations or adjustments.[4] The first, called the price elasticity adjustment, updates baseline monthly therms per customer from the benchmark level established in a rate case due to the expected change in use associated with a change in price as experienced by the customer. A price increase results in a downward adjustment to the monthly baseline therms per customer and a price decrease results in an upward adjustment to the monthly baseline therms per

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[3] If actual volumes are weather-normalized, this assurance is with respect to normal weather; i.e., revenue risk due to other than normal weather remains present.

[4] *See* also Exhibit NWN/1200 Siores/3 line 5 through Siores/4 line 2.

customer. The amount of adjustment to the baseline therms per customer results from the percent price change and the price elasticity coefficients agreed upon in Docket No. UG 143. These price elasticity coefficients are -0.172 for Residential customers and -0.110 for Commercial customers.[5]

Q. WHAT ROLE DO THESE PRICE ELASTICITY COEFFICIENTS PLAY IN CALCULATING THE PRICE ELASTICITY ADJUSTMENT?

A. A price elasticity coefficient is a measure of the responsiveness of quantity changes to changes in price. A coefficient of -0.172 means that, if prices <u>increase</u> by 10 percent, quantities (therms) are expected, all else being equal, to <u>decrease</u> by 1.72 percent. Analogously, if prices <u>decrease</u> by 10 percent, quantities (therms) are expected to <u>increase</u> by 1.72 percent. The role of the price elasticity coefficients is presumably to separate the estimated effects of changes in prices on usage from other causes of changes in usage when calculating the decoupling adjustment.

Q. WHAT IS THE IMPACT OF ESTABLISHING NEW BASELINE MONTHLY THERMS PER CUSTOMER?

A. The first impact is an adjustment to the margin rate per therm, to maintain the levels of revenue necessary to cover fixed costs,[6] which are assumed to not change with volumes. If overall rates increase, the baseline therms per customer are reduced. This lower level of baseline monthly therms implies a

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[5] *See* page 4 of Appendix A to Order No. 02-634.

[6] There is a certain logically-appearing symmetry to the notion that, if revenue is measured on a per customer basis, fixed costs should also be measured on the same fixed cost per customer basis. I discuss this notion and its implications later in my testimony.

higher margin rate per therm is necessary in order to recover the same dollar margin per customer. Another way of saying this is that the Company adjusts the margin rate per therm so that the product of baseline therms per customer and the margin rate per therm is a fixed dollar value per customer.[7] Recall that I described Northwest Natural's decoupling mechanism as a variant of the revenue per customer form of decoupling mechanisms.

Q. WHAT IS THE SECOND IMPACT OF ESTABLISHING NEW MONTHLY BASELINE THERMS?

A. The new monthly baseline therms are used going forward as the comparative values against which to measure actual usage per customer on a monthly basis. The Company calls the adjustment resulting from this set of calculations the monthly decoupling deferral.[8]

Q. PLEASE DESCRIBE THE MONTHLY DECOUPLING DEFERRAL ADJUSTMENT.

A. This adjustment compares the current baseline therms per customer value for the current month to the actual weather-normalized therms per customer. The difference is multiplied by the current margin rate per therm and then by the actual number of customers in the current month to determine the amount to be deferred for the current month. If the actual therms per customer are greater than the baseline value, the amount deferred represents a future

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7 *See*, in Docket No. UG 163, Exhibit NWN/201 pages 2 and 3.

8 *See* Exhibit NWN/1200 Siores/3.

credit to customers; if actual therms per customer are less than the baseline value, the amount deferred represents a future charge to customers.

Q. WHEN DO ALL THESE CALCULATIONS TAKE PLACE?

A. The Company calculates the decoupling deferral amount on a monthly basis, with the result deferred until rates from the Purchased Gas Adjustment (PGA) are effective; i.e., the Company calculates this adjustment monthly, and the rate for the charge or credit to customers is updated annually.

The Company calculates the price elasticity adjustment whenever rates change, most typically as a result of an annual PGA filing.[9]

Q. WHAT IS MOST IMPORTANT TO KNOW ABOUT THE CALCULATIONS ASSOCIATED WITH THE EXISTING DECOUPLING MECHANISM?

A. It is important to know that the actual therms used in the monthly decoupling deferral calculations are weather-normalized, which means that Northwest Natural's revenues from customers covered by the decoupling mechanism have risk associated with weather. It is also important to understand that separating the decoupling calculations into two sets of calculations only affects the timing of calculating the amounts credited or charged to customers. Northwest Natural witness Ms. Siores has it right in saying "[r]emoval of the elasticity adjustment does not change the overall collection of costs from customers under the decoupling mechanism; it merely changes how much of the decoupling impact is recovered or refunded through the

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9 *Ibid*.

monthly deferral versus how much is recovered or refunded through the elasticity adjustment."[10]

Northwest Natural implemented the decoupling mechanism through Schedule 190, with an effective date of September 1, 2003. Measurement of monthly variances from the baseline therms per customer began Fall 2002.

Q. WHAT DOES THE COMPANY'S TESTIMONY SAY WITH RESPECT TO THE WORKINGS OF ITS DECOUPLING MECHANISM?

A. The Company's filing contains several representations as to its decoupling mechanism, including that the mechanism addresses the issue of declining use per customer "in part."[11] The mechanism "…provide[s] partial mitigation for the increasing volatility in the natural gas industry…"[12] the "overall effects…are beneficial";[13] together with the WARM mechanism, decoupling "…may solve the revenue stability issue";[14] "Northwest Natural's WARM and decoupling mechanism…" [*sic*] achieve benefits of "…improved revenue stability and certainty relative to its approved level of revenue, and [eliminates] the disincentive for NW Natural to actively support and pursue energy efficiency initiatives";[15] and "[g]enerally, the [WARM and decoupling]

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[10] *See* Exhibit NWN/1200 Siores/10 line 21 through Siores/11 line 3. Note that I challenge the use of the word "costs" as I perceive its use in this statement, preferring what I consider to be the more accurate term "revenue per customer variance." At the same time, it is obviously a cost to customers. See also the Company's response to Staff Data Request 471.

[11] Exhibit NWN/100 Kantor/5.

[12] Exhibit NWN/500 Hadaway/15.

[13] Exhibit NWN/500 Hadaway/16.

[14] Exhibit NWN/1100 Feingold/47.

[15] Exhibit NWN/1100 Feingold/66.

mechanisms have operated as expected and have provided the benefits expected to both customers and the Company."[16] The Company includes that:

> "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 [Energy Trust of Oregon]. NW Natural believes that balancing the interests of customers and the Company in this way has been mutually beneficial."[17]

Q. DOES THE COMPANY PROPOSE ANY CHANGES TO THE DECOUPLING MECHANISM IN THIS PROCEEDING?

A. Yes, and, most obvious, the Company proposes a three-year phase-out of the decoupling mechanism and a simultaneous phase-in of the Company's proposed Fixed/Variable rate design. Exhibit Staff/1500 includes discussion of the Company's proposed Fixed/Variable rate design.

[16] Exhibit NWN/1200 Siores/5.

[17] Exhibit NWN/1200 Siores/5 line 8 through line 14.

The Company proposes several "adjustments" to the decoupling mechanism, stating that "…certain adjustments to the mechanism[s]…would improve the mechanism[s] for both customers and the Company…"[18]

Q. WHAT CHANGES TO THE CURRENT DECOUPLING MECHANISM DOES THE COMPANY PROPOSE?

A. First, the Company proposes that, if the proposed Fixed/Variable rate design is not adopted by the Commission, the current decoupling mechanism "…remain in place, covering the same rate schedules [it] cover[s] today."[19]

The Company proposes the following changes[20] to the existing decoupling mechanism:

- Update the load forecast, normalized use-per-customer, normal heating degree days (HDDs) and HDD coefficients used to weather-normalize;
- Remove the price elasticity adjustment;
- Change the decoupling deferral period to November through October; and
- Normalize usage in the month of May by the actual WARM effect attributable to May.

Q. DO YOU SUPPORT ALL OF THE CHANGES PROPOSED BY THE COMPANY?

A. No. Staff does not support changing the decoupling deferral period to November through October. Doing so reduces the time Staff has for analysis and review of the Company's annual filing. The deferral calculations require

[18] *See* Exhibit NWN/1200 Siores/5 line 15 through line 18.

[19] Exhibit NWN/1200 Siores/9 lines 13 and 14.

[20] *See* Exhibit NWN/1200 Siores/10 line 4 through Siores/11 line18.

reconciling actual sales versus estimated sales as described in Provision 1.5 of the Settlement Agreement adopted in its entirety in Order No. 02-634. Since the effective date of updated decoupling rates is November 1 of each year, the Company's proposed deferral period would not allow comparing actual sales with estimated sales. Instead, the Company-proposed deferral period would necessitate reconciling estimates with prior estimates. Staff believes this may result in unnecessary and essentially continuous updates to the PGA filing, reducing the review time Staff and other interested parties require for verifying the Company's calculations.

Staff alternatively proposes basing the deferral calculations on actual weather-normalized monthly volumes of the twelve months ending July 31st of each year. This change will reduce the number of calculations Staff and Parties must make in reviewing the annual filing.

Q. DO YOU SUPPORT THE REMAINING COMPANY-PROPOSED CHANGES LISTED ABOVE?

A. Yes, as to the first—on a qualified basis, second, and fourth bullet points above. Related to the first bullet point and as it applies to decoupling, I support an updating using values adopted by the Commission resulting from this proceeding, and do not support the use of updates the Company developed in preparing their filing.[21] Please see Exhibit Staff/400 for discussion related to the first and fourth bullet point and to the WARM

[21] *See* the Company's specific proposal at Exhibit NWN/1200 Siores/10 lines 4 through 16.

mechanism, and Exhibit Staff/1500 for discussion of the Company's proposed Fixed/Variable rate design.

I support the Company's proposal to remove the price elasticity adjustment component of the mechanism. While I believe prices matter, this part of the existing mechanism does not change the amount collected from ratepayers,[22] nor does it involve an issue of price transparency in that it is not apparent to customers as a price signal.

I recommend changes to the current decoupling mechanism and Schedule 190; therefore I do not support retaining the current mechanism, regardless of whether the Commission adopts the Fixed/Variable rate design proposed by the Company. I discuss these recommendations later in this testimony.

Q. DID YOU ANALYZE THE CURRENT MECHANISM AND THE RESULTS IT HAS PRODUCED SINCE IMPLEMENTED?

A. Yes. I first discuss relevant outcome values and then discuss incentives. I begin with sales volumes.

Volumes for Residential customers, while varying considerably year-to-year even on a weather-normalized basis,[23] have trended upward[24] over the period from usage year October 2002 through September 2003 through usage year October 2010 through September 2011, as depicted in Figure 1.

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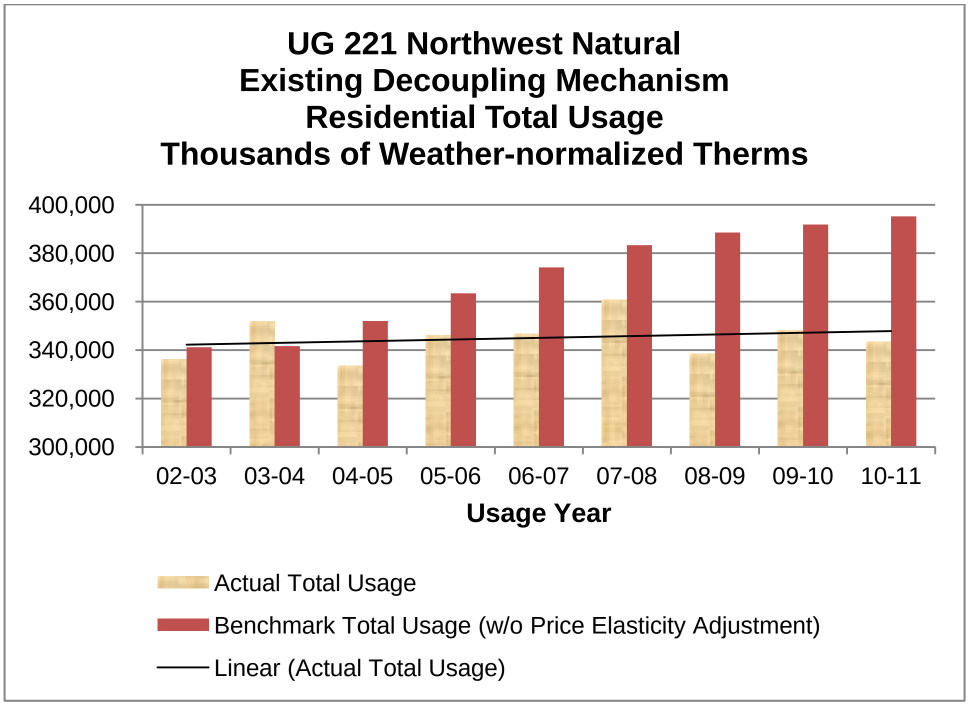
[22] *See* my testimony above regarding this point.

[23] All actual usage volumes in this testimony are weather-normalized unless described or labeled otherwise.

[24] Note, in Figure 1, the upward slope of the black "trend line" in Residential actual total therms since decoupling was implemented.

Figure 1



Residential customers' actual weather-normalized total usage for the 2002 – 2003 usage year was 336.3 million therms, while actual weather-normalized total usage for the 2010 – 2011 years was 343.4 million therms; i.e., actual weather-normalized total usage increased about 2.1 percent over the period since decoupling was implemented. To put it plainly, Residential volumes <u>have</u> <u>not</u> <u>declined</u> since implementation of decoupling. Use per Residential customer has declined, and, without considering potential reasons, has declined materially. Actual use was 731.0 therms per Residential customer in usage year 2002 - 2003 and 629.1 therms per Residential customer in usage year 2010 - 2011,[25] reflecting an average annual rate

[25] *See* also Exhibit NWN/1200 Siores/7 Table 2.

of decline of 1.9 percent[26] in weather-normalized actual therms per Residential customer.

Q. YOU ARE SAYING RESIDENTIAL TOTAL THERMS HAVE NOT DECLINED, AS GROWTH IN THE NUMBER OF CUSTOMERS HAS MORE THAN OFFSET THE DECLINE IN USE PER CUSTOMER?

A. Yes, that is true for Residential customers over the period since implementation of Northwest Natural's decoupling mechanism.[27]

Q. WHAT HAS BEEN THE EXPERIENCE OF COMMERCIAL CUSTOMERS' SINCE IMPLEMENTATION OF DECOUPLING?

A. Decoupling currently applies to Commercial Firm Sales customers in Schedules 1, 3, and 31 and also to Interruptible Sales and Firm Transport customers in Schedule 31.[28] The results of Commercial customers are somewhat different than those of Residential customers. Commercial customers' actual weather-normalized use has, like that of Residential customers, varied considerably on a year-to-year basis since implementation of decoupling, as can be seen in Figure 2. Total weather-normalized use has declined at an average annual rate of 0.9 percent, with two-thirds of that rate resulting from the decline between usage year 2002 – 2003 and usage year 2003 – 2004; i.e., since 2003 – 2004, the average annual rate of decline is 0.3 percent.

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26 This is $\left({}^{629.1}/_{731.0}\right)^{\left({}^{1}/_{8}\right)} - 1$, or -1.9%.

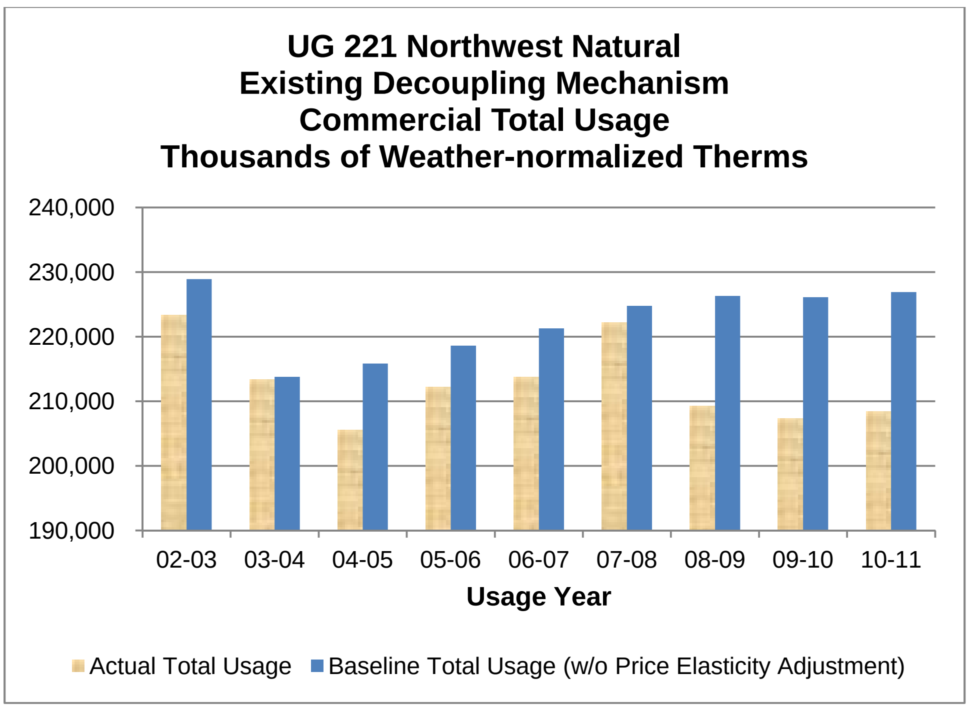
27 I provided testimony on this aspect of revenue (usage) per customer decoupling mechanisms in Docket No. UE 197. See Exhibit Staff/600 Storm/17 line 12 through Storm/21 line 19.

28 *See Eleven Revision of [Tariff] Sheet 190-1*, effective November 1, 2010.

Q. IF RESIDENTIAL TOTAL USE HAS INCREASED, AND COMMERCIAL TOTAL USE HAS DECLINED, WHAT IS THE CHANGE IN ACTUAL TOTAL USE FOR THE DECOUPLED RATE SCHEDULES COLLECTIVELY?

A. Total weather-normalized use by Residential and Commercial customers is essentially flat over the time since implementation of decoupling, at 560 million therms in usage year 2002 – 2003 and 552 million therms in usage year 2010 – 2011, which is an average annual rate of decline of 0.2 percent.

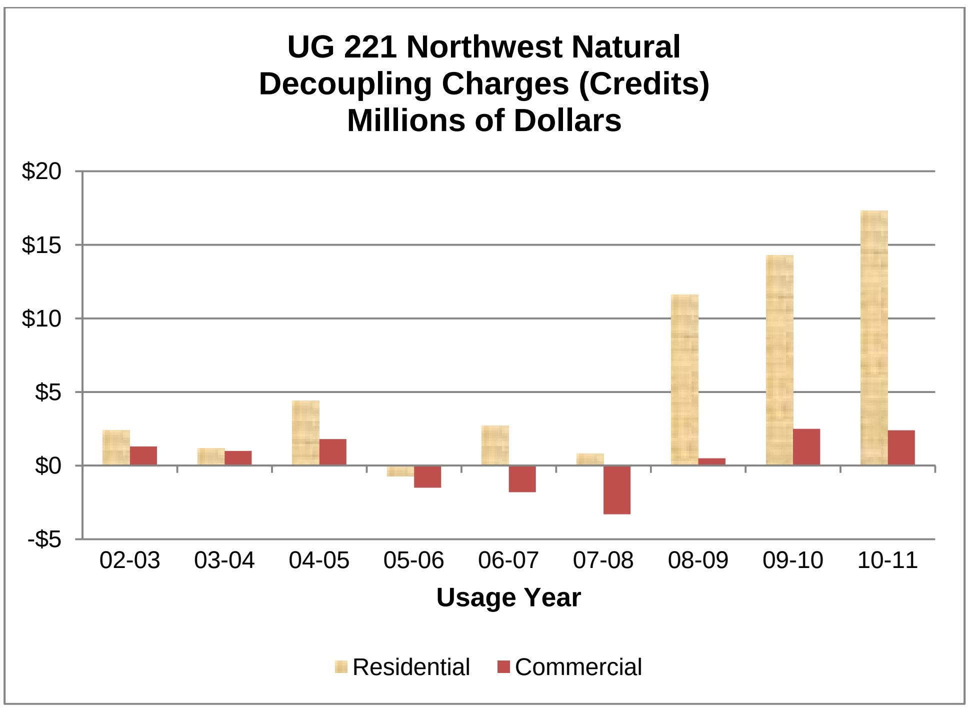
Figure 2



Q. PLEASE DISCUSS THE AMOUNTS COLLECTED FROM RATEPAYERS AS A RESULT OF THE DECOUPLING MECHANISM.

A. Total net surcharges collected or to be collected from implementation through usage year 2010 - 2011 totals $54.0 million from Residential customers and $2.9 million from Commercial customers, with the combined net surcharge collected totaling $56.7 million.[29] Figure 3 illustrates decoupling charges and credits on a usage year basis. Notably, 86 percent of the total $56.7 million in decoupling charges since the mechanism's implementation, or $48.6 million, resulted from the last three usage years through September 2011.

Figure 3



Q. WHY DID DECOUPLING CHARGES DRAMATICALLY INCREASE IN THE LAST THREE USAGE YEARS IN FIGURE 3?

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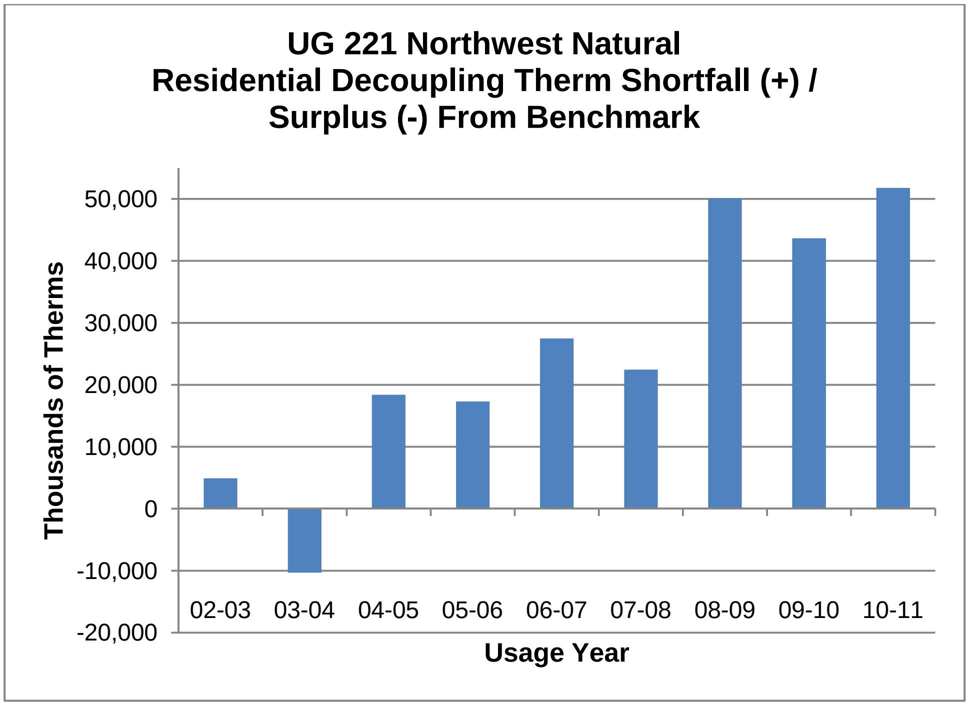
[29] *See* the response to Staff Data Request 460, which includes that the totals ($54.0 million Residential; $2.9 million Commercial) may not cross-foot due to rounding. This presumably accounts for the $0.2 million difference between the sum of the two parts ($56.9 million) and the whole ($57.7 million).

A. This outcome resulted from a large reduction in use per customer in usage years 2008 – 2009 through 2010 – 2011. The average shortfall in actual total Residential therms versus the benchmark (before cumulative price elasticity adjustments) almost quadrupled for the later period—with an average annual shortfall of 48.5 million therms per usage year—as compared with the former period, with an average annual shortfall of 13.4 million therms per usage year.[30] Figure 4 depicts actual total Residential therm shortfalls from the total therm benchmark, which is the 12-month sum of the monthly use per customer values multiplied by the actual number of customers in each of the 12 months, by usage year.

The average Commercial shortfall for usage years 2008 – 2009 through 2010 – 2011 was 18.1 million therms per year versus the earlier period's average of 5.5 million therms per year.

[30] I calculated values of total therm shortfalls from information supplied in response to Staff Data Request 459.

Figure 4



Q. DOES YOUR ANALYSIS INDENTIFY ANY REASONS FOR THE LARGE CHANGE BETWEEN THESE TWO TIME PERIODS?

A. The decline in the annual use per Residential customer was in the heating season. Table 1 shows this, where Columns A and C are the average therm per Residential customer monthly variances for usage years 2002 – 2003 through 2007 – 2008 and usage years 2008 – 2009 through 2010 – 2011, respectively. Note first the change in the average annual shortfall in therms per customer, from an average of negative 28.9 therms per customer in the former period (Column A) to an average of negative 89.6 therms per customer in the later period (Column C). By comparing the Heating and Non-heating season subtotals at the bottom of Column A with their counterparts in Column C, you can see that almost all (57.0 therms versus 60.7 therms) of the change in average variation from the benchmark use per Residential customer between these two time periods was in the November through May heating season.

Table 1
Weather-normalized Use per Residential Customer
Monthly Averages of Two Periods

Usage Year Month	2002 - 2003 through 2007 - 2008 Therm Variance (A)	Variance Composition (B)	2008 - 2009 through 2010 - 2011 Therm Variance (C)	Variance Composition (D)
Jan	-5.2	17.8%	-14.4	16.0%
Feb	-8.4	29.2%	-17.0	19.0%
Mar	-3.3	11.6%	-10.8	12.1%
Apr	-4.1	14.1%	-10.0	11.2%
May	1.1	-3.8%	-4.0	4.5%
Jun	2.6	-8.9%	3.5	-3.9%
Jul	0.0	0.2%	1.2	-1.3%
Aug	0.0	0.1%	0.1	-0.1%
Sep	0.3	-1.0%	-0.9	1.0%
Oct	1.1	-3.8%	-3.7	4.2%
Nov	-6.9	23.9%	-16.3	18.2%
Dec	-6.0	20.6%	-17.2	19.2%
Total	-28.9	100.0%	-89.6	100.0%
Heating	-32.7		-89.7	
Non-heating	3.9		0.1	

Q. DO YOU HAVE ANY THOUGHTS OR CONCLUSIONS WITH RESPECT TO THIS ANALYSIS?

A. The much higher shortfalls in therms per Residential customer in the November through May Heating season during recent years could be, if only in part, related to the weather-normalizing adjustment coefficients and methods.[31] I think the larger impact results from one or both of two dynamics. The first is lower average use per customer for all Residential customers. The second, and not exclusive of the first, is lower average use per customer for new Residential customers than for existing Residential customers. The second dynamic seems unlikely to, by itself, account for the large decline between these two periods: if the number of customers increases one percent, and the new customers have no usage, use per customer declines by that same one percent.

Q. DOES THE RECESSION DURING THE LATTER PART OF THE LAST DECADE POTENTIALLY ACCOUNT FOR THE DECLINE IN USE PER RESIDENTIAL CUSTOMER BETWEEN THESE TWO TIME PERIODS?

A. Perhaps. Figure 5 depicts the weather-normalized therms per Residential customer and Oregon's per capital income[32] since implementation of decoupling. The National Bureau of Economic Research has the recent recession as beginning in December 2007 ("peak") and ending in June 2009 ("trough").[33]

Q. IF I UNDERSTAND CORRECTLY, YOU DO NOT KNOW WHY AVERAGE USAGE PER RESIDENTIAL CUSTOMER DECLINED IN THE USAGE YEARS BEGINNING 2008 THROUGH 2010 VERSUS THE AVERAGE OF USAGE YEARS BEGINNING 2002 THROUGH 2007.

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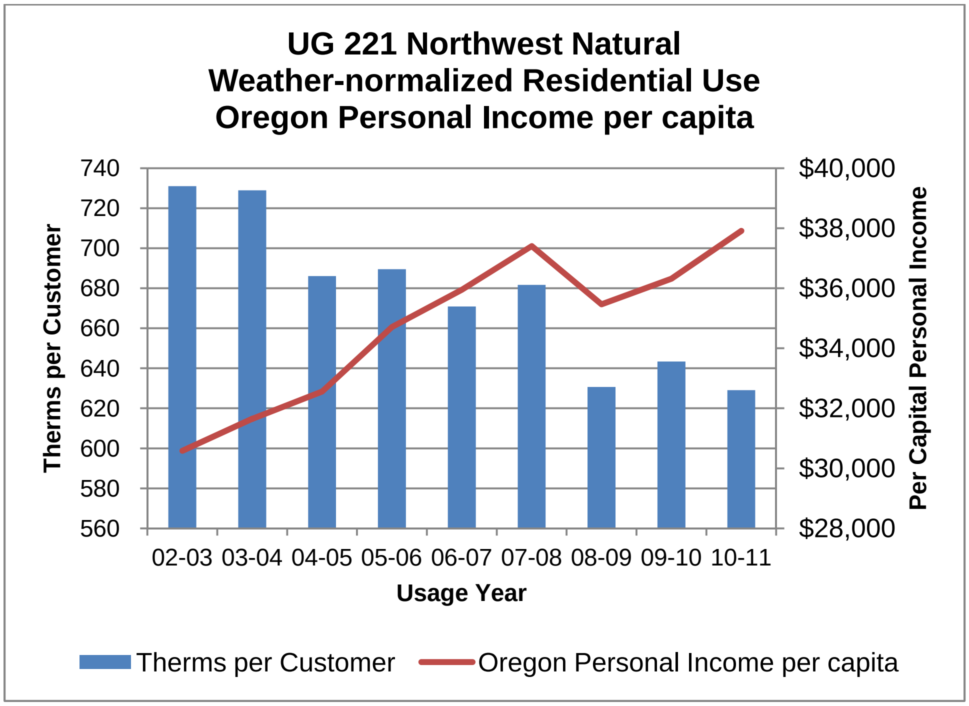
31 *See* Exhibit Staff/400 for discussion of Northwest Natural's weather-normalization methods.

32 Source of Oregon per capital Personal Income was the U.S. Bureau of Economic Analysis. The values are in current dollars and timed such that the value for 2003 is represented as concurrent with usage year 2002 – 2003.

33 *See* at http://www.nber.org/ ; accessed April 21, 2012.

A. Yes; that is correct. I do not know the underlying causes of the reduction in use per Residential customer between these two time periods.

Figure 5



Q. PLEASE DISCUSS THE PRIMARY BENEFIT TO NORTHWEST NATURAL'S RATEPAYERS FROM DECOUPLING.

A. The primary ratepayer benefits are energy efficiencies achieved through the transfers to the ETO of Public Purpose charges to increase investment in energy efficiency programs. The Company has calculated the total amount transferred since 2003 through August 2011 (inclusive) as $97.1 million.[34]

Q. DOES ADDING THE CUMULATIVE NET DECOUPLING SURCHARGES OF $56.7 MILLION TO THE $97.1 MILLION TRANSFERRED TO THE ETO

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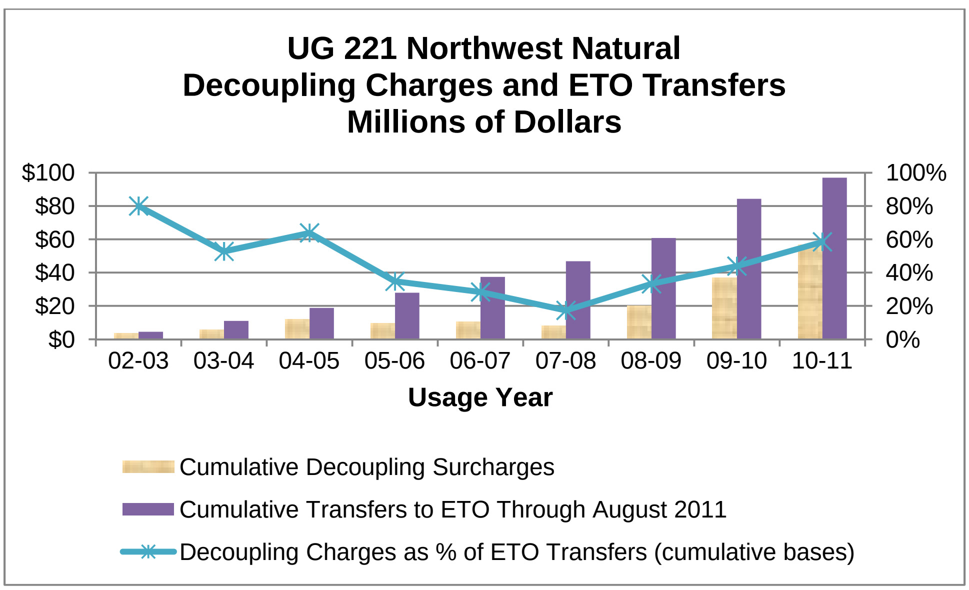
[34] *See* Exhibit NWN/1200 Siores/8 Table 4.

REFLECT THE TOTAL COLLECTED FROM NORTHWEST NATURAL'S RATEPAYERS TO PROVIDE THE LATTER VALUE TO ETO IN SUPPORT OF ENERGY EFFICIENCY PROGRAMS?

A. It does. Please note that, if the Company had filed a general rate case prior to the current filing, some portion of the decoupling charges paid downstream from the date of that hypothetical filing would presumably have been incorporated into base rates, and the decoupling charges would therefore be less. Figure 6 illustrates the cumulative values of decoupling charges and transfers to the ETO from Northwest Natural ratepayers through their Northwest Natural bill. On cumulative bases, the decoupling charges correspond with approximately 60 percent of the dollar amount transferred to the ETO.

Figure 6



Q. WHAT DO YOU THINK ABOUT THIS OUTCOME—OF COLLECTING AN ADDITIONAL $56.7 MILLION IN DECOUPLING SURCHARGES TO TRANSFER $97.1 MILLION TO THE ETO?

A. We can do better. By implementing my recommended changes to the Company's Schedule 190 decoupling mechanism, Northwest Natural has no throughput incentive associated with the decoupled rate schedules and decoupling surcharges are reduced versus the current mechanism under conditions similar to those experienced since implementation of decoupling.

Q. PLEASE CHARACTERIZE THESE CONDITIONS.

A. Such conditions include a declining use per customer and non-negative customer growth.

Q. IS THERE ANY INDICATION FROM THE COMPANY REGARDING ANY REQUIREMENTS FOR ITS CONTINUED FUNDING OF THE ETO THROUGH PUBLIC PURPOSE CHARGES COLLECTED FROM NORTHWEST NATURAL'S CUSTOMERS?

A. Yes. I rely on the statement "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 remove the financial disincentive to the Company of encouraging increased energy efficiency for our customers."[35] The Company enhanced this statement in response to Staff Data Request 472, including that "…the purpose of the [decoupling] deferral is two-fold: (1) To make the Company indifferent to the consumption patterns

[35] *See* Exhibit NWN/1200 Siores/9 line 18 through Siores/10 line 2,

and energy efficiency activities of its residential and commercial customers through a decoupling mechanism; and (2) To provide funding for public purposes to be administered by the Energy Trust of Oregon." Additionally, Order No. 05-934 in Docket No. UG 163 includes that "Second, the parties agree that as long as Schedule 190 remains in effect, none of the parties will seek termination of NWN Schedule 301 (Public Purposes Funding Surcharge), Schedule 310 (Oregon Low-Income Gas Assistance , also known as OLGA), and Schedule 320 (Oregon Low-Income Energy Efficiency Program)" [emphasis added].[36]

Q. PLEASE DISCUSS CHANGES TO THE COMPANY'S SCHEDULE 190 DECOUPLING MECHANISM YOU BELIEVE REMOVE NORTHWEST NATURAL'S THROUGHPUT INCENTIVE AND POTENTIALLY REDUCE THE LEVEL OF DECOUPLING CHARGES TO RATEPAYERS.

A. I first want to discuss the nature of Northwest Natural's fixed costs. The Company contends these do not vary with volume of therms delivered and, for the most part and in the short-run, Staff agrees.[37]

At the highest level of disaggregation, the Company's long-run incremental costs (LRIC) fall into the categories of Storage, Transmission, and Distribution.[38] The Company disaggregates Distribution costs into the categories of Customer-related and Design Day-related. In Exhibit NWN/1101

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[36] *See* page 3 of Appendix A to the Order. Docket No. UG 163 considered the issue of continuing Northwest Natural's decoupling mechanism.

[37] *See* Exhibit Staff/1400.

[38] *See*, as an example, Exhibit NWN/1101 Feingold/1.

Feingold/9, the Company disaggregates the Customer-related Distribution costs into the following subcategories: Mains, Services, Meters and Regulators, and Accounting.

Table 2

Categorization of Northwest Natural Fixed Costs

Category	Subcategory	Vary with Number of Customers	Do Not Vary with Number of Customers
Storage			✓
Transmission			✓
Distribution: Design Day			✓
Distribution: Customer-related			
	Mains	See discussion in text	
	Services	✓	
	Meters & Regulators	✓	
	Accounting	✓	

Northwest Natural contends, in the context of discussing the Residential customer charge for Schedules 1 and 2, that the “out of pocket” costs per Residential customer are for “customer service, the meter, regulator, and service line…” and that these costs, on an annual basis, total “…on average approximately $366.00…”[39] This value[40] includes customer-related distribution costs, on both forward-looking and long-run bases.

39 *See* Exhibit NWN/1100 Feingold/38 line 9 through line 21.

40 I see, at Exhibit NWN/1101 Feingold/9 Column N Line 3, and calculate the annual dollar cost as $378 annually for schedule 2. When I aggregate schedules 1R and 2, my result remains $378 annually.

Q. WHAT ABOUT THE COSTS FOR DISTRIBUTION MAINS?

A. First, the Company represents that "[i]n the long run, main costs vary with either growing design day demand or a growing number of customers."[41] The Company also states that the Company's LRIC study[42] has four primary components, one of which is "[t]he costs to install distribution mains in order to connect new customers and to provide additional capacity to both new and existing customers…"[43] These statements imply, in the context of low or negative growth in Residential load (and presumably in Design Day demand as well[44]) and declining use per Residential customer, that the cost of distribution mains does not change when a Residential customer begins service at a location to which service was previously available or at a location which can be served by an existing main. Therefore, the only new Residential customer that potentially impacts the cost of distribution mains is one receiving service at a hithertofor unserved address at a location not servable by an existing main.

Q. THE COMPANY SAYS ITS FIXED COSTS DO NOT VARY BY VOLUME AND YOU ARE SAYING THAT SEVERAL CATEGORIES AND SUBCATEGORIES OF THOSE SAME FIXED COSTS DO NOT VARY BY CUSTOMER?

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[41] Exhibit NWN/1100 Feingold/7 lines 1 through 7.

[42] *See* Exhibit NWN/1100.

[43] Exhibit NWN/1100 Feingold/15 lines 15 through 20.

[44] The only way this is not the case is if new customers are, on average, "peakier" on a design day basis than existing customers. This seems unlikely.

A. On a long-run incremental cost basis, that is correct. I recommend caution in assessing whether categories of fixed costs vary with usage or with customers. What can appear to vary by customer might actually vary as a result of the additional usage associated with additional customers, which is different.

Q. WHY IS THIS IMPORTANT?

A. The existing use per customer decoupling mechanism assumes, in essence, that all fixed costs[45] vary directly with the number of customers.

Q. DO YOU HAVE A SIMPLIFIED EXAMPLE OF HOW THE CURRENT DECOUPLING MECHANISM WORKS WITH RESPECT TO THIS "ALL COSTS VARY DIRECTLY WITH THE NUMBER OF CUSTOMERS" NOTION THAT IS EMBEDDED IN THE CURRENT MECHANISM?

A. Exhibit Staff/1302 is a simplified model illustrating the workings of the Company's current mechanism. The model is of the mechanism as it applies to Residential customers and only to volumetric rates and revenues other than those related to commodity. The box at the top of the page contains assumed parameters and certain values driven by the assumed parameters. The assumed 636 annual therms per Residential customer is from the Company's filing, as is the rate per therm value of $0.38, which I have rounded from the $0.38228 rate per therm requested in the Company's

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[45] I am speaking here of costs other than commodity costs and those costs associated with commodity costs; i.e., the Company's fixed costs.

filing.[46] My example starts with 500 customers in Year 1 and increases by six to 506 in Year 2—a 1.2 percent annual growth rate.[47] I assume use per existing customer declines by 0.75 percent and new customers use an average of 495 therms. These values result in a decline in use per customer of 1.0 percent, which is the Company's projected future annual rate of decline.[48, 49]

Q. WHAT DOES THIS EXHIBIT SHOW?

A. It illustrates the incentive the Company has under the existing mechanism to increase customers. By adding six new customers, whose average use per customer is less than that of existing customers, the following occurs:

- Use per customer declines by 1.0% (Line 6);
- Total therms <u>increase</u> by 0.2% (Line 8);
- Revenue produced by volumetric base rates <u>increases</u> by 0.2% (Line 9);
- The decoupling adjustment results in a $1,228 dollar charge to new and existing customers (Line 10);
- Total volumetric revenue increases by 1.2%, equaling the rate of increase in the number of customers (Line 11);

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46 *See*, in the Company's application, Schedule 2 Residential Sales Service and Schedule 190 Partial Decoupling Mechanism.

47 I calculate the average annual future growth rate of Oregon residential customers as 1.2 percent using values from the Company's 2011 IRP as filed (see Appendix 2.2). Using information in the Company's response to Staff Data Request 459, I calculate the average annual rate of growth in Residential customers since implementation of decoupling as 2.1 percent.

48 *See* Exhibit NWN/1200 Siores/7 table 2, where the Residential use per customer was 729 therms in 2003-2004 and 636 in the Schedule 190 file in this proceeding. This average annual rate of growth (decline) is $\left({}^{636}/_{729}\right)^{\left({}^{1}/_{9}\right)} - 1$, or -1.5 percent; i.e., the average annual rate of decline in use per Residential customer since usage year 2003 – 2004 is 1.5 percent.

49 The 1.0 percent annual rate of decline in Residential use per customer is from the Company's 2011 IRP as filed. See page 2.12.

- The revenue produced by volumetric rates, on a per customer basis (Lines 25 – 27) is $242 annually for each existing customer, for each new customer, per customer in Year 1, and per customer in Year 2.

It is important to understand the relationships between changes in total use, use per customer, and customer growth (decline). Use per customer is declining, but growth in the number of customers more than offsets this, so total therms increase. Therefore, the total number of therms on which to recover fixed costs has increased, not decreased. This is the situation I described earlier for Northwest Natural and its Residential customers since implementation of decoupling: actual weather-normalized therms have increased and revenues to cover fixed costs have therefore increased, yet Residential customers paid a cumulative $54.0 million in decoupling charges.

Q. WHAT OTHER RESULT FROM THE SIMPLIFIED MODEL DO YOU THINK IS IMPORTANT?

A. The assumption behind decoupling mechanisms is that fixed costs do not vary with volumes. The assumptions behind revenue or use per customer decoupling mechanisms are that fixed costs do not vary with volumes *and* that fixed costs vary directly and on a pro rata basis with the number of customers.[50] This second assumption is directly implied by the way in which revenue or use per customer decoupling mechanisms work.

[50] By "vary directly and on a pro rata basis" I mean the following: if total fixed costs are $X and the number of customers is Y, then adding one customer increases fixed costs by $X/Y.

Table 2 shows this is not the reality of Northwest Natural's natural gas utility distribution costs. Using the Company's use per Residential customer in its filing of 636 therms for the test year, and a $0.38 per therm margin rate, the Company's revenue in the simplified model increases by $242 on an annual basis for each new customer.[51] Fixed costs increase by something less.

Q. WHAT DO YOU CONCLUDE FROM THESE RESULTS?

A. An energy utility having a revenue or use per customer decoupling mechanism is highly incented to increase its number of customers. If the rate of customer growth exceeds the (absolute value of the) rate of decline in use per customer, total therms increase, as do total revenues. This is the outcome of the current Northwest Natural decoupling mechanism as applied to Residential customers since implementation of decoupling.

Q. DOES NORTHWEST NATURAL'S CURRENT MECHANISM, WITH OR WITHOUT THE CHANGES PROPOSED BY THE COMPANY, PROVIDE AN INCENTIVE TO INCREASE ENERGY SALES?

A. Yes, if only indirectly. All regulation is, in one sense, an incentive structure. Regulation establishes the "rules of the game," allowing ratepayers and the utility to transact business under known rules, established through a known process. Change in regulations can transform the utility's incentives, sometimes in unanticipated ways.

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[51] This value does not include revenues produced by the monthly customer charge for each new customer, which is designed to cover some portion of the fixed costs.

The existing decoupling mechanism, whether considered with or without the Company's proposed changes, is a form of revenue per customer decoupling. This type of decoupling mechanism works to ensure a specific level of revenue on a per customer basis by comparing actual use per customer versus a benchmark level of use per customer, with the difference multiplied by the margin rate per therm.[52] In Northwest Natural's decoupling mechanism, the margin rate per therm changes year to year with overall price changes, so the assured revenue per customer varies directly with this rate. Northwest Natural's revenues, under either the existing mechanism or with changes proposed by the Company, increase with additional customers and additional customers increase the total volume of therms sold, all else being equal. As the margin rate per therm includes a profit component, increasing revenues by increasing therms serves to increase profits over the level that would otherwise prevail. Hence, the current Northwest Natural decoupling mechanism has what I consider to be an incentive to increase customers, which results in an increase in total usage by customers, all else being equal.

Q. WHY DOES NORTHWEST NATURAL'S DECOUPLING MECHANISM HAVE THIS INCENTIVE?

A. The end goal or *raison d'être* of decoupling mechanisms is sometimes stated as increased conservation and decreased consumption. If Northwest Natural

[52] *See* the Company's response to Staff Data Request 459.

has an incentive to increase profits,[53] the existing decoupling mechanism incents the Company to increase customers. Assuming positive usage by any additional customer, increasing customers under the current decoupling mechanism serves to, in and of itself, increase consumption. I note that the Company may have countervailing incentives regarding customer growth as well.

Q. WHAT IF THE ADDITIONAL CUSTOMERS HAVE LOWER USAGE THAN THE BENCHMARK VALUE?

A. First, note that this is the situation depicted in my simplified model example. The Company's average usage per customer declines with the addition of such customers, so actual usage per customer measured against the benchmark is less than what would otherwise be the case. All else being equal, this serves to <u>increase</u> the dollar amount of the decoupling charge to ratepayers.

Q. DO ALL REVENUE (OR USE) PER CUSTOMER DECOUPLING MECHANISMS PROVIDE THIS INCENTIVE TO INCREASE CUSTOMERS AND THEREBY INCREASE SALES?

A. I cannot speak to all such mechanisms, but apparently it is common. The National Association of Regulatory Utility Commissioners' (NARUC) "Decoupling For Electric & Gas Utilities: Frequently Asked Questions" on

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[53] This would seem to be an intuitively plausible assumption. I believe Northwest Natural's executive management team has strong incentives to increase profits.

page nine poses the question “Can a utility increase its profitability with decoupling?” NARUC’s response to this question follows:

> “Yes. With a per-customer form of decoupling, utilities receive their revenue from customers that cover the fixed costs of service, and that cost of service includes a rate of return that contributes to profits. In other words, instead of making more money by selling more kilowatt hours or therms, utilities would make more money when they increase their customer base, regardless of whether there is a corresponding increase in sales. Alternatively, if the utility can find a way to improve its efficiency and thereby lower its cost of service without decreasing its number of customers, it has an opportunity to improve its bottom line. **Under decoupling, the primary driver for profitability growth is the addition of new customers, especially in areas where the addition of new customers does not carry high infrastructure addition costs. In these cases, the customers who would bring the greatest potential profitability to a utility are those who are the most energy efficient, since they can be added with the lowest addition to the utility’s cost of service.**”[54]

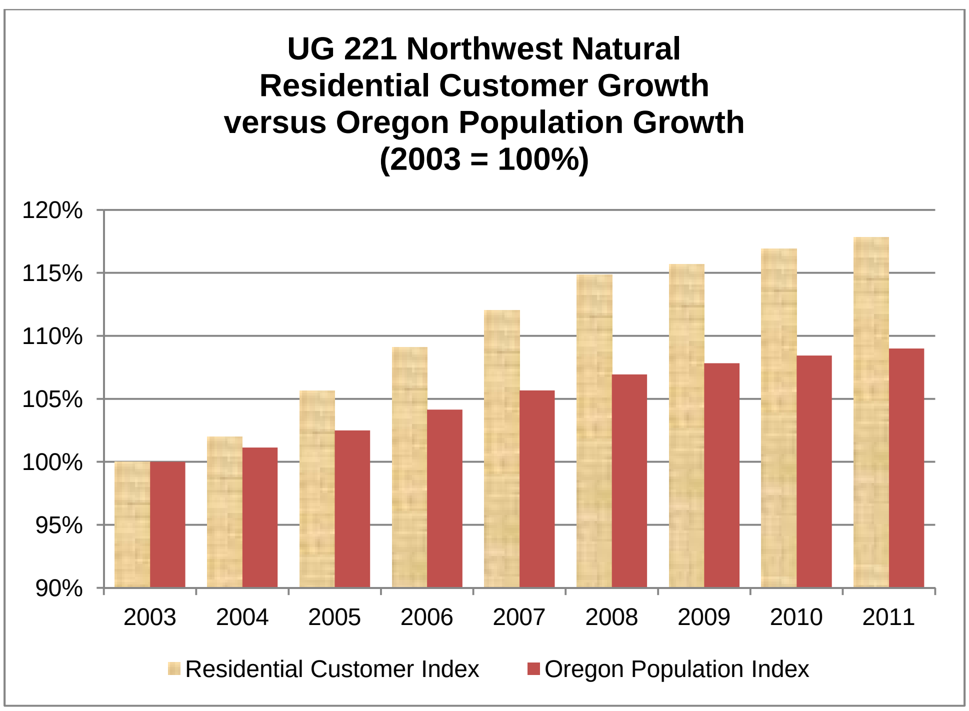
[54] *See* page 9 of “Decoupling For Electric & Gas Utilities: Frequently Asked Questions,” 2007, The National Association of Regulatory Utility Commissioners. The emphasis in the original was replaced with the emphasis shown here.

I note again that adding customers at any level of positive usage serves to increase total usage. Based on the emphasized language in the NARUC statement, profitability would increase the most when customer growth includes a component of what I think of as "in-fill," where most, if not all, infrastructure required to serve the new customer already exists.

Q. HOW DOES NORTHWEST NATURAL'S RESIDENTIAL CUSTOMER GROWTH COMPARE WITH GROWTH IN OREGON'S POPULATION?

A. It was twice the growth rate of Oregon's population from 2003 through 2011. The number of Residential customers grew at an annual average rate of 2.1 percent[55] and the Oregon's population grew at an annual average rate of 1.1 percent. See Figure 7.

FIGURE 7



55 This calculation uses information supplied in response to Staff Data Request 459.

Q. WHAT OTHER INFORMATION RELATED TO NORTHWEST NATURAL'S CUSTOMER GROWTH DID YOU REVIEW?

A. The Company has represented in presentations to investor groups that "conversion opportunities exist due to gas coming late to the Northwest (in the mid-1950s)."[56] The Company's response to Staff Data Request 458 defined "residential conversions" as "[n]ew meter sets associated with existing residential dwellings where natural gas equipment was not previously in use." Table 3 contains information from the Company presentation at the American Gas Association Financial Forum on May 18, 2010.[57]

Table 3
Northwest Natural-estimated Market Potential

	Single-Family	Multi-Family	Non-Residential	Total
On-main and Near-main prospects (0-150ft from main)	169,841	8,060	16,087	193,988
Near-main prospects (150-600ft from main)	112,290	25,945	19,166	157,401
Off-main prospects (>600ft from main)	109,385	8,.770	22,124	140,279
Total	391,516	42,775	57,377	491,668

56 *See* page 19 of the Investor Presentation on March 22, 2012 at the West Coast Energy Seminar in Las Vegas, Nevada. I accessed the presentation through the Company's website on April 22, 2012 at http://www.snl.com/irweblinkx/presentations.aspx?iid=4057132 .

57 I accessed the presentation through the Company's website at http://www.snl.com/irweblinkx/presentations.aspx?iid=4057132 on April 23, 2012. See page 19.

Obviously the Company sees potential growth in Residential customers on what I think of as an "in-fill" basis. The Company's presentation identifies 177,901 potential Residential customers as being either on or within 150 feet of an existing main.

Q. WHAT CHANGES DO YOU PROPOSE FOR NORTHWEST NATURAL'S SCHEDULE 190 DECOUPLING MECHANISM?

A. I list the objectives associated with my recommended changes as a whole before discussing the individual changes I recommend. These objectives are:

- Remove the throughput incentive;
- Reduce the dollar impact on ratepayers under expected future conditions as compared with the current mechanism;
- Stabilize margin revenues;
- Allow for recovery of fixed costs independent of actual levels of weather-normalized volumes;
- Make the mechanism and related calculations more transparent;
- Make it less difficult for Staff and Parties to review filings;
- Remove the incentive to add customers irrespective of the expected economic viability; and
- Retain the flow-through of monies from Northwest Natural's decoupled customers to support energy efficiency and ETO activities.

I start with the most important change. I recommend replacing the current metric of therms per customer with a metric of total therms, based on values the Commission adopts in this proceeding. As in the current decoupling mechanism, there should continue to be one benchmark value for Residential customers and another for the applicable Commercial schedules' customers.

Q. DID YOU COMPARE THE USE OF YOUR PROPOSED BENCHMARK AGAINST THE USE PER CUSTOMER BENCHMARK IN THE CURRENT AND COMPANY-PROPOSED MECHANISM?

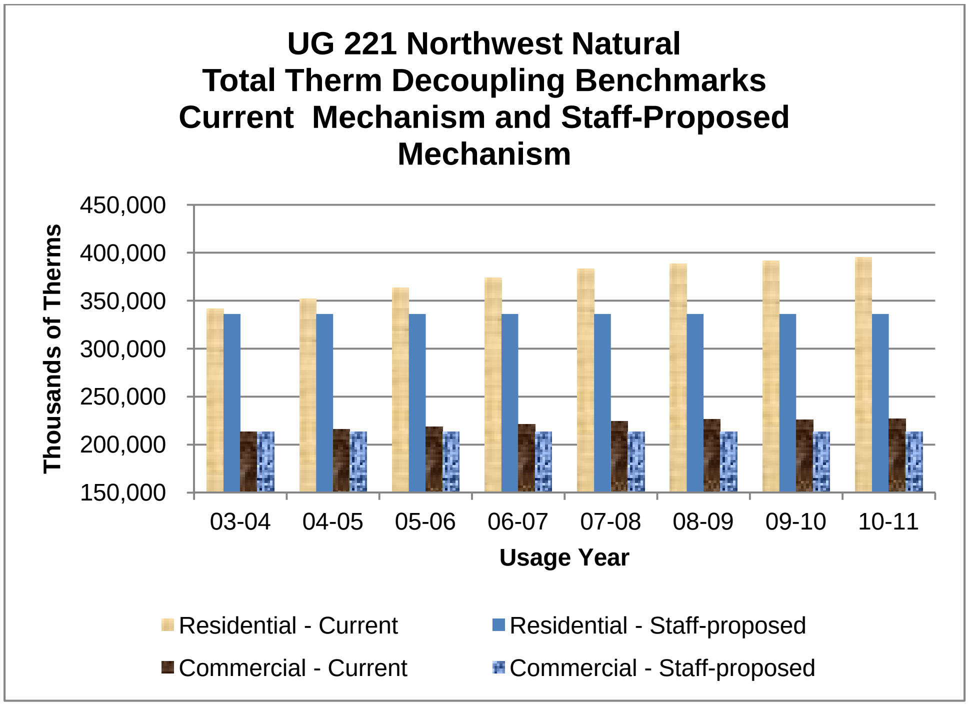
A. Yes. I modeled my proposed benchmark against the current mechanism's benchmark using actual data since implementation time of the current mechanism. As can be seen in Figure 8, the differences between the two are relatively small for the Commercial customers and much larger for Residential customers. The current mechanism's benchmark reflects the fact that, while Residential total volumes did not change a great deal, the strong growth in the number of Residential customers resulted in a use per Residential customer benchmark translated into a total therms benchmark that increased markedly over the period.[58]

Q. DOES THE DECOUPLING MECHANISM WITH YOUR RECOMMENDED CHANGES MEET THE REQUIREMENT OF REMOVING THE FINANCIAL DISINCENTIVE TO THE COMPANY OF ENCOURAGING INCREASED ENERGY EFFICIENCY FOR ITS CUSTOMERS?

A. Yes; it does. Use per customer may continue to decline, but it is not, under a decoupling mechanism incorporating my recommended changes, relevant to coverage of the Company's fixed costs. A total weather-normalized therm volume metric "nets out" changes in both the use per customer and the number of customers.

[58] I have omitted usage year 2002 – 2003, as this year had different use per customer benchmarks.

Figure 8



If actual weather-normalized therms exceed the benchmark, this part of the mechanism results in a credit to customers. If actual weather-normalized therms are less than the benchmark, the result is a charge to customers. The Company has no incentive to increase throughput.[59]

Q. WHAT ABOUT CHANGES IN THE NUMBER OF CUSTOMERS? TABLE 2 IDENTIFIES COSTS WHICH DO VARY WITH THE NUMBER OF CUSTOMERS (OR AT LEAST WITH NEW CUSTOMERS IN CERTAIN SITUATIONS).

A. First, I offer a reminder that, in the absence of decoupling and under traditional rate design, a utility has no assurance regarding coverage of

[59] Additionally and symmetrically, the Company also has no incentive to decrease throughput.

incremental fixed costs associated with serving an additional customer. Under the current decoupling mechanism, with a monthly Residential customer charge at the current $6.00 level,[60] the Company's proposed monthly margin rate of $0.38 (rounded), and the 636 therms per year benchmark use per Residential customer proposed by the Company, the level of margin revenue assuredness per Residential customer is $313.68 annually and $26.14 monthly.[61] These values hold regardless of whether the Company-proposed changes to the existing decoupling mechanism are adopted.

I recommend adopting a monthly rate per cumulative new meters/new service locations.[62] This monthly "new service rate" is determined based on costs that do vary with the number of new customers served at new service addresses. Such a rate clearly follows the principles of cost causation more closely than does the current mechanism, as I explained earlier in my testimony.

Q. WHAT IS THE LEVEL OF THIS MONTHLY RATE AND HOW IS IT DETERMINED?

A. The monthly New Service Rate is calculated, as an outcome of this proceeding, by adding the annual customer-related long-run incremental costs other than mains on a per customer basis, dividing by 12, and

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[60] For Schedule 2.

[61] This is 636 therms benchmark average Residential use per customer X $0.38 per therm + 12 months X $6.00 per month for the customer charge. Note that this analysis assumes the additional customer's use is not greater than the benchmark. This assumption appears to be, based on history and on average across many new customers, highly plausible.

[62] For lack of a better term, I will refer to this as the "New Service Rate."

subtracting the monthly customer charge from the result. This calculation need only be performed once until outcomes of a future rate case are available.

The monthly New Service Rate, when multiplied by the cumulative new meters/new service locations and combined with the monthly customer charge, allows the Company to recover the long-run incremental costs it incurs associated with providing service to a new customer at a new service location. If the monthly customer charge resulting from this proceeding for a Schedule exceeds the New Service Rate, the rate does not apply, as the monthly customer charge covers relevant fixed costs.

Q. PLEASE PROVIDE EXAMPLES OF THE NEW SERVICE RATE AND ITS CALCULATION.

A. Using information in Exhibit NWN/1101 Feingold/9 and based on the number of customers and volumes in the Company's filing, the monthly rates are as in Table 4.[63] This rate depends on outcomes in rate cases associated with the monthly customer charge, loads, numbers of customers, and inputs to and changes in the LRIC model used to calculate the costs.

[63] The actual rate will be calculated after updating the Company's LRIC model based on the outcomes of this proceeding as well as to incorporate certain modifications proposed by Staff. Please see Exhibit Staff/1400.

Table 4
Rate per Cumulative New Meter in New Service Location
(New Service Rate)

Rate Schedule	Monthly Customer-related LRIC	NWN-proposed Monthly Customer Charge	Staff-proposed Monthly Customer Charge[64]	Monthly Rate per "New Meter"
2	$22.28		$10.00	$12.28
1C	$22.75	Frozen		N/A
3CFS	$46.01	$15.00		$31.01
31CFS	$149.91	$260.00		N/A
31CTF	$220.22	$260.00		N/A

Q. YOU SAID "CUMULATIVE" WITH RESPECT TO "NEW METER/NEW SERVICE LOCATION." WHAT DOES THIS LANGUAGE MEAN?

A. First "cumulative:" a cumulative count of "new meters/new service locations" is necessary as these LRIC costs are on an annual basis and are based on cost recovery over multiple years; i.e., the LRIC values are ongoing costs. I divided the annual value by 12 to get a monthly equivalent. Think of the "cumulative" aspect as analogous with customers. There are a number of new customers added every month, but the existing mechanism uses total customer counts, which is the cumulative value of new customers over time. The accumulation of the "new meters/new service locations" counts should begin with the effective date of rates resulting from this proceeding.

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64 Staff recommends consolidating Schedule 1R into Schedule 2; see Exhibit Staff/1500.

I use the term "new meters/new service locations" because I want to be clear that the monthly New Service Rate does not apply to customers newly taking service in a location where there is an existing meter. It also does not apply to those service locations which have a new meter and a new customer, but the new meter replaced an existing meter.

Assuming one of the 177,901 potential Residential conversion opportunities identified by the Company in Table 3 is "converted," by the Company's definition of "conversion" as supplied in response to Staff Data Request 458, each such customer added would increment the "new meters/new service locations" count by one. In other words, if the Company, by its definition of "residential conversion," must install a new meter should any one of these 177,901 potential Residential customers be "converted," the decoupling mechanism with my proposed changes would result in transfers from ratepayers through the decoupling charge to cover customer-related costs, other than those associated with the main, that are not covered by the monthly customer charge. Note that there may be no main cost associated with this conversion.

Q. ARE THERE MORE NEW CUSTOMERS OR MORE NEW METERS/NEW SERVICE LOCATIONS?

A. Historically there are more new meters/new service locations than new customers.[65] For Residential customers, the ratio of new meters installed where no meter previously existed to the increase in the number of

[65] The following analysis uses information in the redacted versions of responses to Staff Data Requests 456 and 457 and the response to Staff Data Request 459 (Attachment-2).

Residential customers as of the month of December for 2003 through 2011 varied on an annual basis from a high of 127 percent in 2003 to a low of 107 percent in 2006, with an aggregate ratio of 115 percent over this timeframe.

Commercial customers in decoupled schedules varied much more year-to-year and had an aggregate ratio of 180 percent over this timeframe. I note that the Commercial values are much smaller than those of Residential customers; i.e., a total of nine thousand plus new meters installed versus over 105 thousand for Residential customers over the same timeframe.

Should overall customer numbers decline, the Company will certainly be providing service to new customers at new service locations. This means the cumulative “new meter/new service location” value will continue growing in spite of this hypothetical decline in the number of customers. This is an example of how my recommended changes result in a decoupling mechanism that more closely follows cost causation than does the current mechanism. Alternatively stated, incorporating my recommended changes into the Northwest Natural decoupling mechanism results in a mechanism that provides the Company with “decoupling revenues” with which to cover existing fixed costs and additional “decoupling revenues” when those fixed costs actually change. It does not provide the Company with “decoupling revenues” when total volumes and total revenues from base rates increase.[66]

[66] The New Service Rate component may result in decoupling revenues even though total volumes increase. Note that this would reduce the amount of the customer credit resulting from the volume increase.

Q. WHAT ELSE IS IMPORTANT TO KNOW ABOUT THE NEW SERVICE RATE?

A. It is important to remember this rate is a regulatory construct; it is part of the decoupling mechanism: *it is not a rate directly charged to customers.*

Q. HOW WILL DECOUPLING CHARGES TO CUSTOMERS BE LOWER WITH IMPLEMENTATION OF YOUR RECOMMEND CHANGES TO NORTHWEST NATURAL'S DECOUPLING MECHANISM?

A. Decoupling surcharges paid by ratepayers will be lower due to the "netting-out" of new customers and declines in use per customer under the future conditions used by the Company in the "Base Case" Integrated Resource Plan (IRP) analysis. These conditions include an average annual growth rate in the number of Northwest Natural's Oregon Residential customers of 1.2 percent[67] and an average annual rate of decline in use per Oregon Residential customer of 1.0 percent.[68] I point out that these values produce an average annual rate of growth in actual Residential weather-normalized therms of 0.19 percent—very low, but positive load growth.

Consider a period where use per customer has declined, yet the number of customers is growing. With respect to the "load" part of the monthly decoupling calculation, what is relevant is the total load versus the load benchmark for the month. If a decline in average use per customer does not fully offset an increase in the number of customers (total load declines)

[67] *See* page 2.12 of Northwest Natural's 2011 Integrated Resource Plan.

[68] *See* Appendix 2.2 of Northwest Natural's 2011 Integrated Resource Plan.

versus the benchmark, this part of the calculation results in a charge to customers. Conversely, if a decline in average use per customer is more than fully offset by an increase in the number of customers (total load increases), this part of the calculation results in a credit to customers.[69]

Q. DID YOU MODEL NORTHWEST NATURAL'S DECOUPLING MECHANISM WITH AND WITHOUT YOUR RECOMMENDED CHANGES?

A. I compiled four scenarios, which I provide as Exhibit Staff/1303. I focused on Residential customers and used values based in part on Northwest Natural's history since implementation of the decoupling mechanism (Scenarios A, B, and C).

Scenarios A, B, and C in Exhibit Staff/1303 differ only in the assumed rate of customer growth. Scenario A assumes a 2.1 percent annual rate of growth, the average annual rate of Residential customer growth experienced by the Company since implementation of decoupling. Scenario B assumes no customer growth and Scenario C assumes a 1.0 percent annual rate of decline in the number of customers. Scenario D uses input values for the annual rate of decline in use per Residential customer (1.0 percent) and the annual rate of growth in Residential customers (1.2 percent) from the Company's 2011 IRP, as filed.

[69] Please note that average use per customer is not a value required in order to calculate the monthly decoupling charges or credits for the mechanism with my proposed change. I only use this measure to draw parallels with the existing mechanism.

I use a five year horizon for each scenario based on the premise that this amount of time appears to be towards the outside of the expected interval between general rate case filings.

Q. WHAT IS IMPORTANT TO KNOW BASED ON THE RESULTS OF THESE FOUR SCENARIOS?

A. In an environment of strong customer growth and positive load growth, the current mechanism results in substantially higher decoupling charges relative to the mechanism with my recommended changes. Scenario A illustrates outcomes ($47.9 million over five years versus $36.5 million) in these conditions, which was the experience since implementation of decoupling.

In an environment of no customer growth and declining load, the current mechanism results in somewhat higher decoupling charges ($44.3 million versus $41.4 million) relative to the mechanism with my recommended changes. Scenario B illustrates this situation.

With negative customer growth and strongly negative load growth, (-2.88 percent annually), and all other relevant parameters as in Scenario A, the mechanism with my recommended changes provides the Company substantially more from decoupling charges ($61.9 million versus $42.7 million) than does the existing mechanism. Scenario C illustrates this situation.

Q. WHAT DOES SCENARIO D ILLUSTRATE?

A. Scenario A depicts decoupling charges for the two mechanisms (current and Staff-proposed) based on the actual experience since Northwest Natural implemented the current mechanism. In Scenario D, I replace this history, which I characterize as strong growth in the number of Residential customers and strong declines in use per Residential customer, with “Base Case” values from the Company’s 2011 IRP filing. These are more moderate, with Residential customer growth of 1.2 percent annually (versus 2.1 percent) and the rate of growth (decline) in use per Residential customer at -1.0 percent annually (versus -1.9 percent). Note that load still increases at a 0.19 percent annual rate.

Scenario D illustrates that, under future conditions the Company presumably believes to be “most likely,” both mechanisms have much smaller levels of decoupling charges to ratepayers than in Scenario A and the mechanism with my proposed changes produces smaller levels of decoupling charges than does the current mechanism: $18.9 million over five years versus $22.0 million over five years.

Q. AFTER REVIEWING AND DISCUSSING PERFORMANCE OF THE DECOUPLING MECHANISM WITH YOUR PROPOSED CHANGES VERSUS THE EXISTING MECHANISM, WHAT SUMMARY THOUGHTS DO YOU HAVE?

A. The mechanism with my proposed changes provides the Company with decoupling charges when total weather-normalized therms decline. Assuming normal weather, it is actual total therms billed at base rates that produce revenues with which to cover fixed costs.

The mechanism with my proposed changes provides what I believe to be a reasonable level of decoupling charges associated with actual growth in infrastructure and the Company's resulting increases in fixed costs.

The mechanism with my proposed changes does not provide the Company with $242 annually through decoupling charges for each additional Residential customer when actual total weather-normalized therms and base rates produce revenues that cover fixed costs; i.e., when total actual load increases.

Q. WHAT OTHER CHANGES DO YOU RECOMMEND TO THE DECOUPLING MECHANISM?

A. I recommend determining the margin rate per therm as a value established in rate cases, to be updated only with outcomes in future rate cases. One result of this is to make the mechanism more transparent and consistent with the establishing of many other regulatory values; i.e., the margin rate is established in a rate case, along with the benchmark load for decoupling, base rates, rate base, rate of return, et cetera. Additionally, this is one less series of calculations for the Company to make and for Staff and Parties to review on a periodic basis.

I also recommend basing the deferral calculations on actual weather-normalized monthly volumes of the twelve months ending July 31st of each year. Doing so provides sufficient time for Staff and interested parties to verify the actual versus estimated sales volumes.

Q. PLEASE SUMMARIZE YOUR RECOMMENDED CHANGES TO NORTHWEST NATURAL'S SCHEDULE 190 DECOUPLING MECHANISM.

A. I recommend the following:

- Maintain the existing distinction between Residential and Commercial customers for purpose of the decoupling mechanism;
- Remove the price elasticity adjustment in the current mechanism;
- Change the benchmark from use per customer to total use (weather-normalized therms);
- Incorporate a New Service Rate to be applied to cumulative values of new meters in new service locations;
- Fix the value of the margin rate per therm in this rate case, to be updated in future rate cases;
- Change the annual deferral period to August through July; and
- Update relevant parameters with values resulting from this proceeding.

Q. DO YOU HAVE ANY ADDITIONAL TESTIMONY REGARDING DECOUPLING?

A. Yes. The $15.1 million labeled as "decoupling" in various locations in the Company's filing[70] is not a decoupling deferral. Instead, and as included in the Company's response to Staff Data Request 343, this amount "…represents an estimate of the impact of re-setting the residential and commercial use-per-customer baselines in the rate case." This amount relates to changes in sales volumes and is incorporated into Staff's discussion in Exhibit Staff/400.

[70] *See*, as examples, page 1 of the Executive Summary in the Company's filing and Exhibit NWN/100 Kantor/2 at line 8.

COST OF EQUITY AND CAPITAL STRUCTURE

Q. WHAT IS YOUR SUMMARY RECOMMENDATION REGARDING RETURN ON COMMON EQUITY AND REGARDING CAPITAL STRUCTURE?

A. Table 5 illustrates returns on long-term debt and common stock, as well as capital structure, as currently authorized, as proposed in Northwest Natural's direct testimony, and as recommended by Staff in testimony.[71]

I recommend a range of return on equity (ROE) for the Commission's consideration of 8.8 to 9.5 percent, along with a point estimate of 9.2 percent, with both range and point estimate associated with a capital structure as proposed in the Company's testimony, which is one of 50 percent long-term debt and 50 percent common stock. This results in a recommended rate of return (ROR) of 7.562 percent inclusive of Staff's recommended cost of long-term debt. The 9.2 percent ROE and 7.562 percent ROR I recommend meet the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statue (ORS) 756.040. My recommendations are consistent with establishing "fair and reasonable rates" that are both "commensurate with the return on investments in other enterprises having corresponding risks" and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[72]

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[71] *See* Exhibit Staff/1200 for Staff's recommended cost of long-term debt.

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

Table 5

Capital Costs and Capital Structure

Currently Authorized (UG 152; Order No. 03-507)

Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	49.82%	7.066%	3.520%	
Preferred Stock	0.68%	7.160%	0.049%	
Common Stock	49.50%	10.200%	5.049%	
	100.00%		8.618%	

Northwest Natural Proposed

Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	50.000%	6.265%	3.133%	
Preferred Stock	0.00%		0.000%	
Common Stock	50.00%	10.300%	5.150%	
	100.00%		8.283%	-0.335%

Staff Recommendation

Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	50.00%	5.924%	2.962%	
Preferred Stock	0.00%		0.000%	
Common Stock	50.00%	9.200%	4.600%	
	100.00%		7.562%	-1.056%

Q. NORTHWEST NATURAL IS REQUESTING AN ROE OF 10.3 PERCENT AND THE COMPANY'S RETURN ON EQUITY WITNESS DR. HADAWAY PROVIDES A MULTISTAGE DCF MODEL ESTIMATING A 10.0 PERCENT ROE. WHY THE DIFFERENCE FROM YOUR RECOMMENDED 9.2 PERCENT ROE?

A. There are several reasons, which I discuss in my testimony below. Table 6 lists several differences between Dr. Hadaway's multistage DCF model and my multistage DCF models, as well as tracing the path of estimated ROE changes from his model's 10.0 percent result to my model's 9.2 percent result.

Table 6
ROE Changes
From Exhibit NWN/504 Hadaway/4 (10.0%)
To Exhibit Staff/1304 Storm/3 (9.2%)

Change	ROE
Exhibit NWN/504 with 5.8% long-term growth rate	10.0%
Update Prices and Dividends	9.6%
Staff/1304 Storm/5 (Hadaway peer utilities - 5.8% LT growth)	9.6%
Use Staff peer utilities	9.1%
Use Staff's 5.43% long-term growth rate (Staff/1304 Storm/3)	8.8%
Adjust for divergent capital structures (Hamada equation)	9.2%

Q. DO YOU USE VALUES FROM COMPARABLE COMPANIES TO ESTIMATE NORTHWEST NATURAL'S COST OF EQUITY?

A. I use companies that meet the following criteria as peer utilities to the regulated natural gas utility activities of Northwest Natural:

1. Covered by either Value Line or SNL as a gas utility;
2. Followed by Value Line;
3. Long-term Issuer credit rating from S&P of "A+," "A," or "A-";
4. No decline in annual dividend in last five years based on SNL information as of January 31, 2012; and
5. No recent merger and acquisition activity.

Q. WHAT COMPANIES RESULTED FROM THIS SCREEN?

A. Table 7 lists my peer utilities as well as those used by Dr. Hadaway in Exhibit NWN/500.

Table 7
Peer Utilities to Northwest Natural

Company[73]	Staff Peer Utility	NWN Peer Utility
Alliant Energy*#		✓
Black Hills*#		✓
Consolidated Edison*		✓
DTE Energy*#		✓
Laclede Group	✓	
Northwest Natural Gas	✓	✓
NiSource#		✓
Piedmont Natural Gas	✓	✓
Pepco Holdings*#		✓
Questar	✓	
SCANA*#		✓
Sempra Energy*#		✓
Southwest Gas#		✓
Vectren*#		✓
WGL Holdings	✓	
Wisconsin Energy*#		✓
Xcel Energy*		✓

Q. NORTHWEST NATURAL HAS A DECOUPLING MECHANISM FOR ITS RESIDENTIAL AND SOME COMMERCIAL CUSTOMERS. DO YOUR PEER UTILITIES ALSO HAVE DECOUPLING MECHANISMS?

A. All have decoupling or a Fixed/Variable rate design in at least one of the jurisdictions in which they operate as a regulated gas utility. Laclede operates in Missouri with a “flat” Fixed/Variable rate design; Piedmont has decoupling

73 An asterisk following the company name indicates Value Line categorizes the company as an electric utility. The “number” or “pound” (“#”) sign indicates the company has an S&P Long-term Issuer rating less than “A-.”

in North Carolina; Questar in Utah and Wyoming; and WGL Holdings in Maryland.[74] Piedmont operates in South Carolina "…under a rate stabilization mechanism that achieves the objectives of margin decoupling for residential and commercial customers with a one year lag."[75]

Q. WHAT TYPES OF MODELS DID YOU USE TO DEVELOP YOUR RECOMMENDED RETURN ON EQUITY FOR NORTHWEST NATURAL?

A. I rely on two different multistage discounted cash flow (DCF) models[76] for estimating the expected return on common equity required by Northwest Natural investors. I also update values for certain input parameters in some of the models used by Dr. Hadaway and contrast the analytic results with both his results and those from my two DCF models.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THESE TWO DCF MODELS.

A. Each model has three stages, in the first of which I use Value Line's dividend per share[77] estimates. In the second stage the value of each company's dividend at the end of the first stage is increased by a rate that converges

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74 *See* "Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List As of March 2012" from the American Gas Association, accessed April 26, 2012 at http://www.aga.org/our-issues/RatesRegulatoryIssues/ratesregpolicy/Documents/Innovative%20Rates%20Current%20Status%20-%202012%20Mar.pdf .

75 See Piedmont's Form 10-K accessed online at http://www.gurufocus.com/news/156606/piedmont-natural-gas-company-inc-reports-operating-results-10k , accessed April 26, 2012.

76 *See*, in Docket No. UE 115, the Commission's discussion of multistage versus single stage DCF models in Order No. 01-777 at page 27.

77 Hereafter "dividends."

from a first stage growth rate, which I calculate based on Value Line's estimated dividends, to the growth rate in the third stage.

Each model uses two sets of calculations, which differ in the assumed timing of dividend receipt. One set of calculations uses the standard assumption that the investor receives dividends at the end of each period. The second set of calculations assumes the investor receives dividends at the beginning of each period. Each model averages the unadjusted ROE values[78] produced with each set of calculations for each peer utility. This approach more closely replicates the "real world" quarterly receipt of dividends by investors; i.e., it takes into account the time value of money.

Each model uses the Hamada equation to adjust for differences in capital structure between each peer utility and the Staff-recommended capital structure for Northwest Natural.[79]

Q. WHAT PRICES DO YOU USE FOR EACH PEER UTILITY'S STOCK?

A. I use the average of closing prices from the first trading day of each of the past three months; i.e., February 1st, March 1st, and April 2nd.[80]

Q. DID YOU REVIEW THE IMPACT OF USING PRICES FROM ANY OTHER DAY OF THESE MONTHS?

A. No.

Q. HOW DO THESE TWO DCF MODELS DIFFER?

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[78] The technical term for each of these estimates is the "internal rate of return," or IRR.

[79] I described this adjustment in recent cost of capital testimony. See, as an example, my description in Docket No. UE 233 Exhibit Staff/800 Storm/54 through Storm/57.

[80] I have used this approach in recent cost of capital testimony. See, in Docket No. UE 233, Exhibit Staff/800 Storm/29 line 10 through Storm/31 line 7.

A. One model uses the calculation of a growing perpetuity as part of the terminal valuation in 2042. This may be the most common approach used in multistage DCF models.

The second model uses the current price-earnings (P/E) ratio[81] multiplied by the estimated earnings per share (EPS) in 2042, which establishes the stock's "selling price" in 2042 for terminal valuation. I estimate the 2042 EPS analogously with methods used to estimate the 2042 dividend in both models; i.e., based on Value Line estimates to which multiple growth rates are sequentially applied.

Q. WHAT IS THE PURPOSE OF THIS SECOND MODEL?

A. I developed this model as a method by which to incorporate the fact that most companies have estimates of future EPS and future dividends growing at different rates. While it is only dividends the investor receives until he or she sells the stock, using EPS growing on a separate trajectory than dividends provides the foundation for an alternative means of terminal valuation.[82]

Q. FOR PURPOSES OF THIS TESTIMONY, HOW CAN WE DISTINGUISH BETWEEN THE TWO MODELS?

A. I use as presumably descriptive terms "30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity" for the first model ("Model 1") and "30-year Three-stage Discounted Dividend Model

[81] "Current" in this context means the price obtained, as previously described, divided by Value Line's estimated 2012 earnings per share (EPS); i.e., it is a forward P/E, not an historical P/E.

[82] Please note that the approach used in this second model is not the same as using a singular estimate of the growth rate in EPS as the growth rate in dividends.

with Terminal Valuation Based on P/E Ratio" for the second model ("Model 2").

Q. AFTER POSSIBLY THE CHOICE OF PEER UTILITIES, WHAT IS THE SINGLE MOST IMPORTANT ATTRIBUTE OF DISCOUNTED DIVIDEND OR DISCOUNTED CASH FLOW MODELS FOR USE IN ESTIMATING INVESTORS' REQUIRED RETURN ON EQUITY?

A. It is the estimated rate of growth of future dividends. I refer here to the singular growth rate for constant growth DCF models and the long-term growth rate for multistage DCF models such as those I use.

Q. WHAT LONG-TERM GROWTH RATES DO YOU USE IN THE TWO DCF MODELS?

A. I use estimated growth rates in U.S. Gross Domestic Product (GDP) for the third stage period of 2023 through 2042. I used three different long-term growth rates, with different methods employed in developing each.

Q. PLEASE DESCRIBE EACH OF THESE LONG-TERM GROWTH RATES.[83]

A. The first uses a 50 percent weight applied to the average annual growth rate resulting from estimates of long-term GDP by the EIA, the OMB, and the CBO, which each receiving one-third of the 50 percent weight.[84] The

[83] Methods used here related to GDP-based growth rates are similar, if not identical to methods I have used in past proceedings. See, as an example, my discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, at Exhibit Staff/800 Storm/46 line through Storm/52 line 14.

[84] The EIA is the Energy Information Administration within the U.S. Department of Energy, OMB is the Office of Management and Budget, and CBO is the Congressional Budget Office. EIA and OMB's estimates are of nominal GDP. I applied to CBO's estimate of real GDP an inflation rate for the relevant timeframe developed using the Treasury Inflation-Protected Securities (TIPS) method I described in testimony in multiple recent general rate case proceedings. See, as an example, in Docket No. UE 233, Exhibit Staff/800 Storm/50 line 4

remaining 50 percent is the average annual historical real GDP growth rate, established using regression analysis, for the period 1980 through 2011,[85] to which I apply the TIPS inflation forecast.

The second long-term growth rate for Stage 3 dividends is the average annual historical real GDP growth rate, established using regression analysis, for the period 1980 through 2011, to which I apply the TIPS inflation forecast.

The third Stage 3 annual growth rate, which I use primarily for illustrative purposes, is the 5.8 percent annual growth rate used by Dr. Hadaway in his DCF models.[86]

Q. WHAT ARE THESE THREE ANNUAL GROWTH RATES YOU APPLY TO STAGE 3 DIVIDENDS IN YOUR DCF MODELS?

A. Table 8 depicts these values.

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through Storm/51 line 3. The TIPS forecast of annual inflation over the relevant Stage 3 timeframe is 2.44 percent, based on an averages of interest rates for each of the months of December 2011, January 2012, and February 2012. I believe it is useful to think of the TIPS inflation rate forecast as a forward curve of dollars; i.e., market-based estimates of what a dollar will be worth in the future.

[85] I discussed this approach in recent Staff cost of equity testimony in several rate case proceedings. See, as an example, in Docket No. UE 233, Exhibits Staff/800 Storm/46 line 15 through Storm/50 line 3.

[86] *See* Exhibit NWN/500 Hadaway/35 lines 11 through 22.

Table 8

Construction of Stage 3 Annual Dividend Growth Rates

Stage 3 Annual Dividend Growth Rate	Component	Real Rate	TIPs Inflation Forecast	Nominal Rate[87]	Weight	Weighted Rate
	EIA			4.52%	16.7%	0.75%
	OMB			4.30%	16.7%	0.72%
	CBO			4.63%	16.7%	0.77%
	Historical 1980-2011	2.91%	2.44%	5.43%	50.0%	2.71%
Composite Rate						4.96%
Historical 1980 – 2011		2.91%	2.44%	5.43%	100.0%	5.43%
NWN/500 (Hadaway)				5.80%	100.0%	5.80%

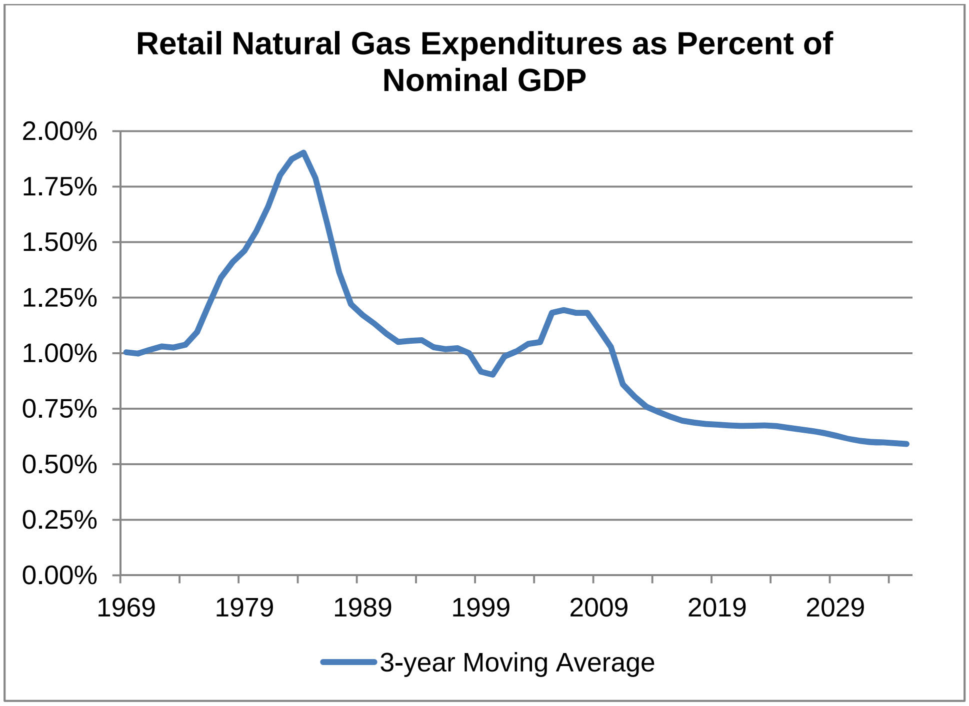
Q. IS IT APPROPRIATE TO USE ESTIMATES OF LONG-TERM GDP GROWTH RATES TO ESTIMATE FUTURE DIVIDENDS?

A. I have questioned this approach in previous testimony in the context of discussing the ROE of regulated electric utilities.[88] Based on information from the EIA, retail natural gas expenditures as a percent of nominal GDP have declined over the past 30-plus years and the EIA expects continued decline over the next 30 years; the natural gas retail distribution industry will grow at a slower rate than does GDP. See Figure 9.

[87] I calculate the nominal rate as $(1 + Real\ Rate) \times (1 + TIPs\ Inflation\ Rate) - 1$; i.e., the rates are multiplicative, not additive.

[88] *See*, for example, in Docket No. 233, Exhibit Staff/800 Storm/35 line 15 through Storm/46 line 7.

Figure 9[89]



Q. DO YOU USE AN ANNUAL RATE OF LONG-TERM GROWTH LESS THAN THAT ESTIMATED FOR GDP, GIVEN THE ENERGY INFORMATION ADMINISTRATION'S OUTLOOK FOR THE INDUSTRY, AS ILLUSTRATED IN FIGURE 9?

A. I do not, which is one of the reasons my recommended ROE is conservative.

Q. WHAT ARE THE RESULTS OF YOUR MULTISTAGE DCF MODELS?

A. Please see Table 9 as well as Exhibit Staff/1304.

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89 Historical retail expenditures result from retail prices in the EIA's Annual Energy Review's Table 6.8 and quantities in Table 6.5. Estimated future retail expenditures are based on EIA's 2012 Annual Energy Outlook's (early release) "Natural Gas Supply, Disposition, and Prices." Historical GDP is from the U.S. Bureau of Economic Analysis and future GDP is from EIA's 2012 AEOer Macro Table.

Table 9
Estimated ROEs of Multistage DCF Models
with Alternative Stage 3 Annual Growth Rates

	Composite Rate: 4.96%		Historical Rate: 5.43%		NWN/500 Rate: 5.80%	
Company	Model 1	Model 2	Model 1	Model 2	Model 1	Model 2
Laclede Group	9.0%	8.8%	9.4%	9.1%	9.7%	9.4%
Northwest Natural	8.5%	8.9%	8.9%	9.2%	9.2%	9.5%
Piedmont Natural Gas	8.7%	8.6%	9.1%	9.0%	9.4%	9.2%
Questar	8.7%	9.4%	9.1%	9.7%	9.4%	10.0%
WGL Holdings	9.1%	8.9%	9.4%	9.2%	9.7%	9.5%
Average	8.8%	8.9%	9.2%	9.2%	9.5%	9.5%

Q. HOW DO THESE ESTIMATED ROE VALUES COMPARE WITH HISTORICAL NATURAL GAS UTILITIES' AUTHORIZED ROE VALUES?

A. These estimated ROEs are low compared with regulated utilities' authorized return on equity capital in some prior periods. At the same time, the bond market is forecasting, through nominal Treasury bond yields versus TIPS bond yields, an annual inflation rate of 2.44 percent over the 20 year period beginning in 2023, the first year in Stage 3 of the DCF models, through 2042 and, based on relative yields on 10-year Treasury bonds, 2.2 percent for the 10-year period between today and 2023.

Exhibit Staff/1305 is the *Major Rate Case Decisions* report dated April 5, 2012 from SNL's Regulatory Research Associates division. Table 9 lists the average authorized Gas Utility ROE (AROE) by year from this report. On the "outside," Northwest Natural's current AROE of 10.2 percent, authorized in

Order No. 03-507 in Docket No. UG 152 and entered on August 22, 2003, was 79 basis points (bps) below the average gas utility AROE awarded that year. Using the first quarter 2012 result of 9.63 percent, and considering nothing else, a comparable AROE for Northwest Natural today is 8.8 percent. On the "inside," using the 2004 average authorized ROE of 10.59 percent, the 2011 full year value of 9.92 percent, and considering nothing else, a comparable AROE for the Company today is 9.5 percent.

Table 10
Northwest Natural's UG 152 Authorized ROE versus Average Authorized Gas Utility ROEs[90]

Year	# Rate Cases	Average Authorized ROE	Northwest Natural UG 152 Authorized ROE	Difference
2003	25	10.99%	10.20%	-0.79%
2004	20	10.59%	10.20%	-0.39%
2005	26	10.46%	10.20%	-0.26%
2006	16	10.43%	10.20%	-0.23%
2007	37	10.24%	10.20%	-0.04%
2008	30	10.37%	10.20%	-0.17%
2009	29	10.19%	10.20%	0.01%
2010	37	10.08%	10.20%	0.12%
2011	16	9.92%	10.20%	0.28%
2012 Q1	5	9.63%	10.20%	0.57%

90 Source: *Major Rate Case Decisions—January-March 2012*; Dennis Sperduto; Regulatory Research Associates; April 5, 2012. See Exhibit Staff/1305.

Q. WHAT IS YOUR RECOMMENDED RETURN ON EQUITY FOR NORTHWEST NATURAL?

A. I recommend an ROE of 9.2 percent and provide the Commission a recommended range for consideration of 8.8 percent to 9.5 percent.

Q. WHAT DO YOU RECOMMEND AS AN AUTHORIZED CAPITAL STRUCTURE FOR NORTHWEST NATURAL?

A. The Company proposed in its filing a capital structure of 50 percent long-term debt and 50 percent common equity. This structure is materially less weighted towards equity than that in some recent Northwest Natural Securities and Exchange Commission (SEC) filings. This directional shift is appropriate, as the Company is more than its regulated utility operations. I recommend the Commission consider authorizing the requested capital structure of 50 percent long-term debt and 50 percent common equity.

Q. WHAT IS THE COMPANY'S REQUESTED ROE?

A. The Company's filing requests an authorized ROE of 10.3 percent.

Q. HAVE YOU REVIEWED DR. HADAWAY'S DISCUSSION AND RECOMMENDATIONS RELATED TO THE COMPANY'S REQUESTED ROE IN EXHIBIT NWN/500?

A. I have. Dr. Hadaway's analysis includes two estimated ROE results from a constant growth (single stage; Gordon growth) DCF model, one result from a multistage DCF model, and two ROE estimates based on his risk premium approach.[91] I note that the 10.3 percent requested ROE appears as a result in

[91] *See* Table 4 in Exhibit NWN/500 Hadaway/41.

only one version of his constant growth DCF model, the version using his forecasted annual rate of future GDP growth of 5.8 percent.

Q. WHAT IS YOUR ASSESSMENT OF DR. HADAWAY'S ANALYSIS AND RESULTS?

A. The first issue I have is regarding the choice of peer utilities. Dr. Hadaway includes in his group of 14 comparable companies 10 utilities or utility holding companies considered by Value Line to be electric utilities. I have indicated the electric utilities in Table 7 with an asterisk. Per values in Dr. Hadaway's electronic spreadsheet workpaper titled "NWN 500-506 Hadaway WP-1," these 10 electric utilities have "gas" revenues that constitute, on average, 21.8 percent of their total revenue when weighted by the latter and a simple average of 25.2 percent. By Dr. Hadaway's calculations, individual company values range from a low of 2.7 percent (Pepco Holdings) to a high of 48.5 percent (Sempra Energy). By way of contrast, the five companies I use as peer utilities to Northwest Natural average over 80 percent of 2011 total revenue as <u>regulated</u> gas revenue, with a low of 46.8 percent (WGL Holdings) and three of the five exceeding 90 percent on this basis.[92]

Calculated using the same information extracted from SNL on the same date, Dr. Hadaway's peer utilities as a group average 38.3 percent of total 2011 revenue as <u>regulated</u> gas revenue. Fully one-half of his 14 peer utilities have less than 30 percent of their 2011 total revenue as regulated gas

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[92] I extracted information used to calculate these values from SNL's Peer Analytics on March 22, 2012. SNL uses information included in FERC filings as well as SEC filings as sources of data.

revenue (Pepco Holdings, Alliant Energy, Consolidated Edison, DTE Energy, Xcel Energy, SCANA Corp., and Wisconsin Energy Group) including a low of 3.1 percent for Pepco Holdings. Comparing with Table 7, these companies are seven of the 10 classified by Value Line as electric utilities. The remaining three electric utilities in his group and their 2011 regulated gas revenues as a percent of total 2011 revenues are Vectren (35.8 percent), Sempra Energy (41.4 percent), and Black Hills Corp. (44.1 percent).

Q. IS IT IMPORTANT THAT 10 OF DR. HADAWAY'S 14 PEER UTILITIES ARE ELECTRIC UTILITIES?

A. It is. As an example and using my first DCF model with a long-term growth rate of 5.43 percent,[93] his 10 electric utilities have an ROE averaging 9.6 percent versus the 8.8 percent average of his four peer utilities considered by Value Line to be natural gas utilities, an 80 basis point difference.

An alternative look, using information in Exhibit NWN/504 Hadaway/4, affirms this difference in that, using Dr. Hadaway's multistage DCF model with which he obtained an average ROE of 10.0 percent, with no changes or updates, the 10 electric utilities have an average ROE of 10.3 percent and the four natural gas utilities have an average ROE of 9.3 percent, a 100 bps difference.

I think the differences between natural gas and electric utilities are important and, for these 14 utilities, whether using Dr. Hadaway's multistage

[93] *See* totals and subtotals of Column O in Exhibit Staff/1304 Storm/3.

DCF model or my multistage DCF models, the market apparently thinks so as well.

Q. ARE THERE OTHER ISSUES WITH DR. HADAWAY'S PEER UTILITIES?

A. Northwest Natural has an S&P long-term Issuer credit rating of A+. Only six of the 14 peer utilities used by Dr. Hadaway have an S&P long-term Issuer credit rating that is not at least one full step below that of Northwest Natural. One of these six IS Northwest Natural. Table 11 lists Dr. Hadaway's peer utilities, the S&P credit rating in his Exhibit NWN/501, and the S&P long-term issuer credit rating from S&P I accessed on April 24, 2012.[94] The companies in **bold** type are at least one full rating (A+ to BBB+) lower than Northwest Natural's S&P "A+" long-term issuer credit rating. As it is unlikely the ratings of this many companies changed in less than six months in Dr. Hadaway's group of 14, the differences are presumably due to the use of different sources or perhaps to the use of ratings of entities other than the publicly traded companies. I identify my source in the footnote. Exhibit NWN/501 identifies "AUS Utility Reports Nov 2011" as the source of credit ratings used by Dr. Hadaway. I note that it is the publicly traded companies' prices and dividends that both Dr. Hadaway and I use in our DCF models.

[94] I accessed the publicly traded companies' credit ratings on April 24, 2012 at S&P's site http://www.standardandpoors.com/ratings/en/us/ .

Table 11
S&P Credit Ratings

	Exhibit NWN/501	Long-term Issuer
Alliant Energy Co.	**A-/BBB+**	**BBB+**
Black Hills Corp	**BBB+**	**BBB-**
Con. Edison	A-	A-
DTE Energy Co.	**A**	**BBB+**
N.W. Nat'l Gas	A+	A+
NiSource Inc.	**BBB-**	**BBB-**
Piedmont Nat'l	A	A
Pepco Holdings	**A**	**BBB+**
SCANA Corp.	**A-**	**BBB+**
Sempra Energy	**A+**	**BBB+**
Southwest Gas	**BBB**	**BBB+**
Vectren Corp.	A-	A-
Wisconsin Energy	A-	A-
Xcel Energy Inc.	A	A-

Q. ARE CREDIT RATINGS IMPORTANT TO THE COST OF EQUITY CAPITAL?

A. Please refer to Exhibit Staff/1304 Storm/3 and the totals and subtotals of Column O. Using my Model 1 with a long-term growth rate of 5.43 percent for Dr. Hadaway's peer utilities results in an average ROE of 9.3 percent. The average of his 10 peer utilities with an S&P long-term issuer credit rating below "A-" is 9.4 percent and the average of the four peer utilities with an S&P long-term issuer credit rating above "BBB+" is 9.2 percent. While there are different thoughts on the impact of credit ratings on costs of equity, the market appears to be communicating a 20 basis point difference for these two groups of companies, with the market requiring the "theoretically consistent" higher expected ROE of the lower-rated utilities. I encourage caution with this interpretation however, as Value Line considers seven of these 10 lower-rated utilities to be electric utilities, as discussed above. Additionally the notion of "theoretical consistency" is valid in a context of "all else being equal," which may not be the case here, and assumes credit ratings measure equity risk.

Q. TURNING NOW TO DR. HADAWAY'S DCF MODELS' RESULTS, WHAT OBSERVATIONS DO YOU OFFER?

A. I updated Dr. Hadaway's constant growth models to include the prices and dividends[95] I use in my DCF models. I illustrate these updates, as well as values from his Exhibit NWN/504 Hadaway/1, in Table 12.

Q. WHAT INFORMATION DOES TABLE 12 PROVIDE?

A. Dr. Hadaway's constant growth DCF models producing his average ROE estimates of 10.0 percent and 10.3 percent, when updated with more recent price and dividend information, produce average ROE estimates of 9.5 percent and 9.9 percent, respectively. In other words, to the extent one considers the constant growth DCF model a valid representation and Dr. Hadaway's 10.0 percent and 10.3 percent results credible, those credible results are, with updated information, 9.5 percent and 9.9 percent, respectively.

95 Prices changed; dividends not so much. See Exhibit NWN/504 Hadaway/2 or Hadaway/3, in which the average dividend for his 14 peer utilities is $1.56. My update changed this average to $1.57.

Table 12
Exhibit NWN/504
with Updated Dividend Estimates, Prices, and Estimated ROEs

Company	With Analysts' Growth Rates		With Long-term GDP Growth Rate	
	Exhibit NWN/504-2	Staff Update	Exhibit NWN/504-3	Staff Update
Alliant Energy Co.	11.2%	10.7%	10.5%	10.0%
Black Hills Corp	11.1%	10.6%	10.7%	10.2%
Con. Edison	7.6%	7.4%	10.1%	9.9%
DTE Energy Co.	9.2%	8.8%	10.7%	10.3%
N.W. Nat'l Gas	8.2%	8.0%	9.9%	9.6%
NiSource Inc.	14.1%	13.6%	10.2%	9.6%
Piedmont Nat'l	8.3%	7.9%	9.8%	9.5%
Pepco Holdings	10.6%	10.3%	11.6%	11.4%
SCANA Corp.	8.9%	8.3%	10.8%	10.2%
Sempra Energy	9.9%	9.3%	9.9%	9.3%
Southwest Gas	8.8%	8.5%	8.8%	8.6%
Vectren Corp.	10.6%	10.2%	11.1%	10.6%
Wisconsin Energy	11.5%	11.2%	9.5%	9.3%
Xcel Energy Inc.	9.4%	9.0%	10.2%	9.8%
Average	10.0%	9.5%	10.3%	9.9%

Q. WHAT DO YOU RECOMMEND TO THE COMMISSION REGARDING DR. HADAWAY'S RESULTS FROM HIS CONSTANT GROWTH DCF MODEL?

A. I believe the primary value of the constant growth DCF model is to represent the key variables involved in DCF modeling and their impact on DCF results.

The Commission rejected consideration of parties' constant growth DCF models in Docket No. UE 115.[96]

I recommend the Commission give little weight to the results of Dr. Hadaway's constant growth DCF model.

Q. DID YOU REVIEW DR. HADAWAY'S TWO-STAGE GROWTH DCF MODEL?

A. I did. I first note that, according to the electronic worksheet supplied in support of Exhibit NWN/504 Hadaway/4, changing the 5.80 percent annual long-term growth rate to the 5.43 percent annual long-term growth rate, which in my DCF models produces the 9.2 percent ROE for my peer utilities, produces a 9.7 percent ROE from his two-stage model, with no other changes. As the change in the long-term growth rate is -0.37 percent and the resulting ROE declines by a rounded 0.3 percent, this underscores the importance of long-term growth rates in multistage DCF models.

I also note that Dr. Hadaway's long-term growth rate of 5.8 percent has full effect in 2016 and seemingly contradicts the statement in Exhibit NWN/200 Anderson/21, made in the context of discussing risks faced by the Company, that "[m]ost economists are forecasting little to no growth until late this decade due to the financial nature of this crisis and associated recession."[97] A zero ("little to no") percent to 5.8 percent annual growth rate establishes a wide

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[96] *See* page 27 of Order No. 01-777. See also page 24 of Order No. 01-787 in Docket No. UE 116.

[97] Exhibit NWN/200 Anderson/21 line 4 through line 6.

range of outcomes as applicable to Dr. Hadaway's multistage DCF model for 2016 and thereafter.

Q. DID YOU UPDATE DR. HADAWAY'S MULTISTAGE DCF?

A. Yes. Table 13, which is the same as Table 6 above, has a progression from Dr. Hadaway's multistage DCF result of 10.0 percent in Exhibit NWN/504 to my recommended 9.2 percent. Other paths or path orderings between the two values might produce different results at different steps.

Table 13
ROE Changes
Exhibit NWN/504 Hadaway/4 (10.0%)
to Exhibit Staff/1304 Storm/3 (9.2%)

Change	ROE
Exhibit NWN/504 with 5.8% long-term growth rate	10.0%
Update Prices and Dividends	9.6%
Staff/1304 Storm/5 (Hadaway peer utilities - 5.80% LT growth)	9.6%
Use Staff peer utilities	9.1%
Use Staff's 5.43% long-term growth rate (Staff/1304 Storm/3)	8.8%
Adjust for divergent capital structures (Hamada equation)	9.2%

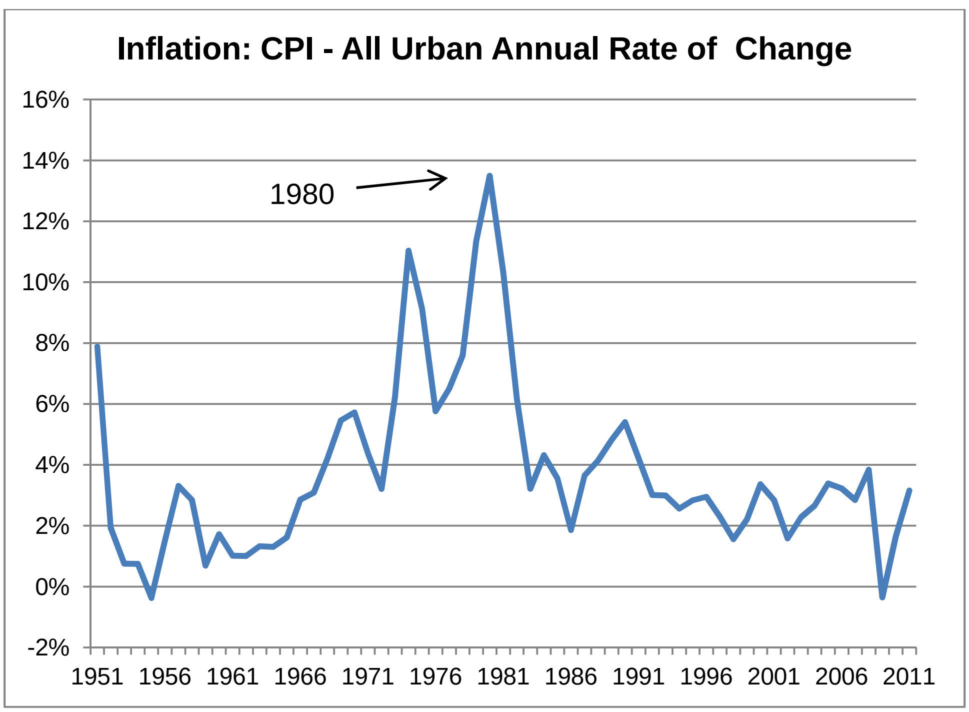
Q. WHAT DO YOU RECOMMEND TO THE COMMISSION REGARDING DR. HADAWAY'S RESULTS FROM HIS TWO-STAGE DCF MODEL?

A. I recommend the Commission consider his 10.0 and 10.1 percent results in light of the companies he used as peer utilities to Northwest Natural, the impact of changes in the stock prices of his peer utilities since the time of his analysis, and his use of a long-term annual growth rate of 5.8 percent. I note that, since 1981, the number of times the annual rate of growth in nominal GDP exceeded 5.8 percent for three consecutive calendar years is four: 1985, 1989, 1990, and 2006 (out of 30 possible). The average annual growth rate is 5.4 percent for 1982 through 2011, inclusive.

Q. HAVE YOU REVIEWED DR. HADAWAY'S RISK PREMIUM ANALYSES?

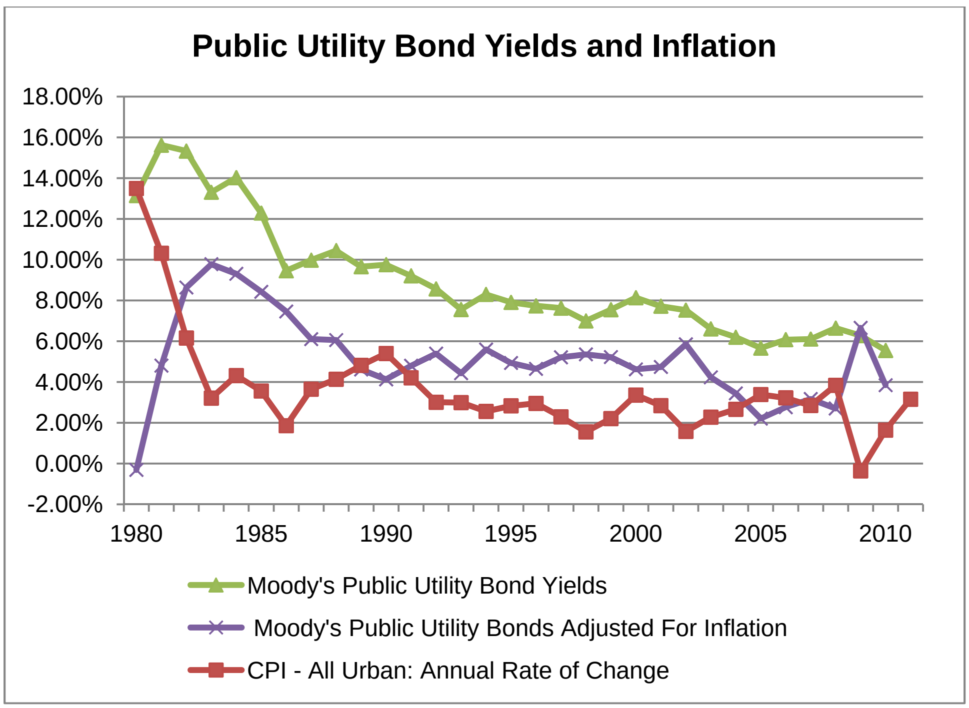
A. I have. The annual rate of inflation as measured by the Consumer Price Index – All Urban (CPI) accelerated in the late 1970's; peaked in 1980 at an annual rate I calculate at 13.5 percent on a year-over-year basis; and declined to an annual rate of 3.2 percent in 1983. The highest annual rate since 1983 to date, on the same year-over-year basis, is the 5.4 percent rate in 1990. See Figure 10.

Figure 10



Bond yields reflect investors' expectation of future inflation. My own belief is that bond investors found the Federal Reserve's inflation-fighting stance in the early 1980s less than completely credible until the inflation rate decelerated over the course of a few years. This belief appears to be supported by the data. Figure 11 depicts the annual rate of change in the CPI, yields on Moody's Public Utility Bond index, and the bond yields deflated by the current year annual rate of change in the CPI. Note that on this latter basis, real yields on public utility bonds increased from a negative yield in 1980 to a high of 9.8 percent in 1983. After this point real yields declined.

Figure 11

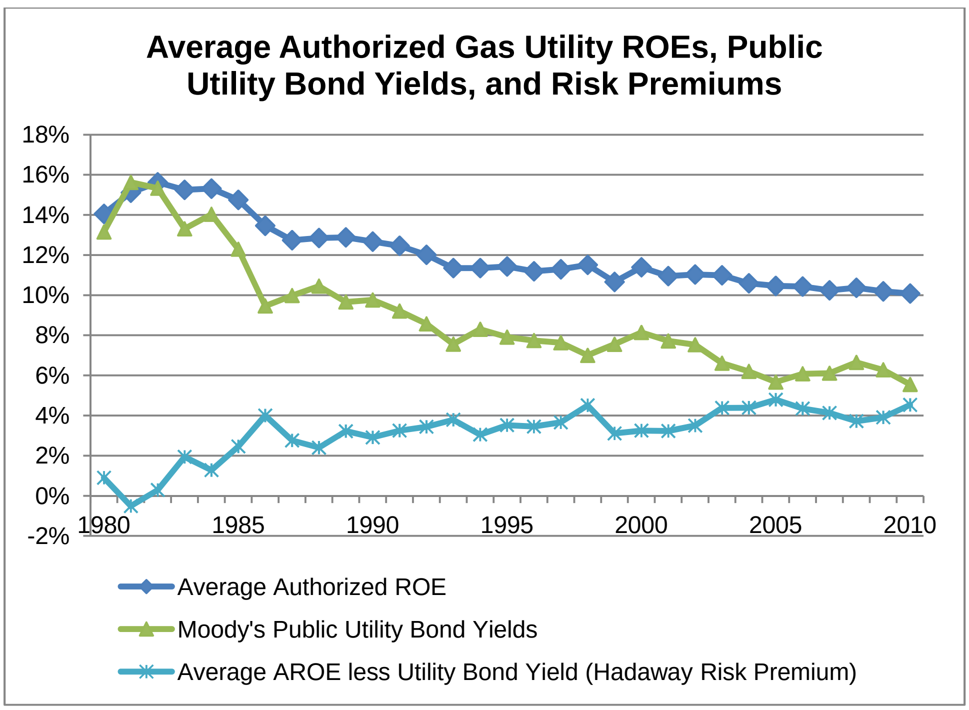


Q. WHAT DOES THIS IMPLY FOR DR. HADAWAY'S RISK PREMIUM ANALYSES?

A. Dr. Hadaway's results are due in part to the timeframe he used to model his risk premium versus the yield on public utility bonds. While 1980 might be the first year for which average gas utility AROE decisions are readily available, it also is the year of the "peak" in the annual rate of inflation over the past 60 years.

Figure 12 depicts gas utilities' average AROE, Moody's Public Utility Bond yields, and Dr. Hadaway's risk premium of AROE less the yield on Moody's Public Utility Bond index.

Figure 12



Q. IT APPEARS A GOOD DEAL OF THE INCREASE IN THE RISK PREMIUM FROM 1980 TO THE LEVEL OF 2010 OCCURRED IN THE FIRST SEVERAL YEARS OF THE 1980S. DID YOU LOOK MORE CLOSELY AT THIS?

A. I performed the same regression of risk premia on utility bond yields as Dr. Hadaway,[98] and extended his analysis by examining regression results using time periods with starting years from 1980 through 1986. The regression "slope" coefficient in each regression, including the regression involving the period starting with 1980, is negative and statistically significant, and the "intercept" coefficient in each regression is positive and also statistically significant. The (negative) coefficient between risk premium and utility bond yield ranges from a high of the 41.7 percent in the 1980 – 2010 regression used by Dr. Hadaway to a low of 33.2 percent in the 1985 – 2010 regression. I appreciate that, while beginning the analysis with 1980 data may serve to use all readily available AROE data, the coefficient of (negative) 41.7 percent, for the reasons discussed above, appears overstated. Dr. Hadaway's risk premium values for 1980 of 0.90 percent, 1981 of -0.51 percent, and 1982 of 0.29 percent are the three lowest in Exhibit NWN/505; i.e., the three lowest in the 31 year period 1980 through 2010. The next lowest value is 1.28 percent in 1984 and the only remaining value under 2.00 percent, in the 1980 through 2010 timeframe, is the 1983 value of 1.94 percent. Dr. Hadaway's use of data from years 1980 through 1982,

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[98] *See* Dr. Hadaway's discussion at Exhibit NWN/500 Hadaway/38 line 5 through line 16.

which years were, as discussed above, atypical of the period 1980 through 2010,[99] results in a higher estimated coefficient value than the 34.0[100] percent obtained using a period of 1983 through 2010 or the 35.0 percent average of regression "slope" coefficients obtained using starting years of 1982 through 1986.

Q. IS THE HISTORICAL GDP-BASED GROWTH RATE YOU USE AND DISCUSSED PREVIOUSLY NOT BASED ON A PERIOD BEGINNING IN 1980?

A. It is. Recall that I used real GDP values however, and not nominal.

Q. WHAT ROE RESULTS DO YOU OBTAIN USING THE 34.0 PERCENT AND DR. HADAWAY'S OTHER PARAMETERS?

A. Using the results of the 1983 through 2010 period and Dr. Hadaway's current (Exhibit NWN/505 Hadaway/2) and future (Exhibit NWN/505 Hadaway/1) bond yield input values, I obtain ROE estimates of 9.30 percent and 9.29 percent, respectively.[101] These results appear to support my recommended point estimate of ROE for Northwest Natural of 9.2 percent.

Q. WHAT DO YOU RECOMMEND TO THE COMMISSION WITH RESPECT TO DR. HADAWAY'S RISK PREMIUM RESULTS AND YOUR ALTERNATIVE RESULTS?

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99 *See* especially Figure 11.

100 The actual value from the regression used in the calculations, to four decimal places, is 34.99 percent. I note that the R^2 value from this regression of 0.8303 is similar to the 0.8952.obtained in Dr. Hadaway's regression.

101 Note that removing years 1980 – 1982 from the regression had the effect of <u>increasing</u> the average risk premium from the 3.15 percent in Exhibits NWN/505 Hadaway/1 and Hadaway/2 to 3.46 percent.

A. I recommend that, to no less extent than the Commission finds Dr. Hadaway's risk premium models' results supportive of Northwest Natural's requested ROE of 10.3 percent, the Commission view my results using his risk premium approach as supportive of my recommended ROE for Northwest Natural of 9.2 percent.

Q. WHAT SUMMARY THOUGHTS DO YOU HAVE REGARDING NORTHWEST NATURAL'S REQUESTED 10.3 PERCENT ROE?

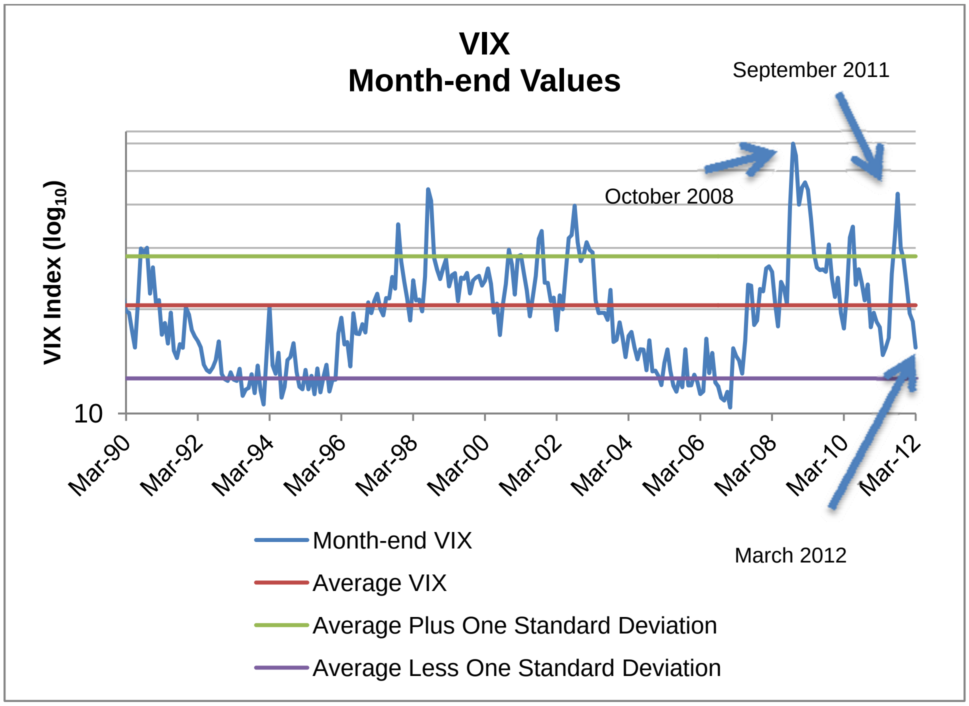
A. The Company chose to request the highest value obtained in Dr. Hadaway's analysis, the 10.3 percent ROE estimate resulting from his constant growth DCF model. The Company requested this level of ROE based on the belief that a 10.3 percent ROE "…adequately reflects the risks faced by NW Natural and also recognizes the uncertainty in the economy and financial markets given that rates will not go into effect for 10 months, and that the decision on ROE will not be made until then."[102] I agree uncertainty exists and investors are widely believed to be risk averse. At the same time, and acknowledging that much change can occur between now and the date on which the Commission determines Northwest Natural's authorized ROE, there are indications that risk aversion and uncertainty are "going the other way" than might be inferred from the Company's testimony.[103] The risk aversion of equity investors, as measured by the Chicago Board Options Exchange's (CBOE) Volatility Index, or VIX, is <u>below</u> its 20-plus year average level as of

[102] *See* Exhibit NWN/200 Anderson/21 line 16 through line 20.

[103] *See*, as examples, Exhibit NWN/500 Hadaway/10 line 21 and NWN/200 Anderson/22 line 16 ("…great uncertainty existing in the markets at the time of filing…").

March 30, 2012 and has declined on a month-end basis since September, 2011. See Figure 13.[104]

Figure 13



With respect to the requested 10.3 percent ROE in the Company's filing versus my recommended 9.2 percent ROE: updating with more recent price information, using multistage DCF models, using as comparable companies natural gas utilities having credit ratings similar to that of Northwest Natural, and reducing the annual rate of long-term dividend growth from the 5.8 percent annual rate used by Dr. Hadaway to a more conservative 5.43 percent annual rate of long-term dividend growth provides the 9.2 percent estimated ROE I recommend to the Commission as my point

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104 I use a log_{10} base for the index as this allows examining the VIX time series in greater detail.

estimate of ROE required at this time by investors in Northwest Natural's common stock.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME	Steven T. Storm
EMPLOYER	Public Utility Commission of Oregon
TITLE	Program Manager Economic Research and Financial Analysis Division
ADDRESS	550 Capitol Street NE Suite 215 Salem, Oregon 97301-2115
EDUCATION	MBA; University of Oregon; Eugene, Oregon AB (Economics); Harvard; Cambridge, Massachusetts
EXPERIENCE	I began employment with the Public Utility Commission of Oregon in October 2007, and have been Program Manager of the Economic and Policy Analysis section since September, 2008. My responsibilities include leading a team of analysts engaged in economic and financial research and providing technical support on a wide range of policy issues involving electric, natural gas, and telecommunications utilities. I have testified before the Commission on policy and technical issues in multiple dockets. Prior regulatory experience includes four years in which my responsibilities included developing responses to data requests regarding the financial analysis of new products and services at US WEST Communications.
OTHER EXPERIENCE	I was a self-employed financial planner for eight years following an 18 year career in management positions engaged in pricing and cost analysis; financial analysis, planning and management; and strategic planning in the publishing and telecommunications industries. I managed the pricing and cost accounting functions in the Directory department of Pacific Northwest Bell and its successor company, US WEST Direct for five years. I was responsible for departmental budgeting and management reporting functions for three years at US West Direct and was responsible for corporate financial planning, analysis, and management reporting for one year at Electric Lightwave. I have seven years management experience in capital budgeting, financial analysis, and strategic planning functions at US West Communications.

CASE: UG 221
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support
Of Opening Testimony

May 3, 2012

UG 221 Northwest Natural
Existing and Company-proposed Decoupling Mechanism
Simplified Model Example

Line No.		Year 1	Change	Year 2	Percent Change
		(A)	(B)	(C)	(D)
1	Number of Customers	500	6	506	1.2%
2	Annual Use per Customer (therms)				
3	Benchmark	636.0		636.0	
4	Actual per Existing	636.0	-4.8	631.2	-0.75%
5	Actual per New			495.0	
6	Actual per Each (all)			629.6	-1.00%
7	Rate per Therm	$0.38		$0.38	0.0%
8	Total Therms	318,000	585	318,585	0.2%
9	Volumetric Revenue - Base Rates[1]	$120,840	$222	$121,062	0.2%
10	Decoupling Adjustment			$1,228	
11	Total Volumetric Revenue	$120,840	$1,450	$122,290	1.2%
12	Volumetric Revenue from Existing Customers				
13	Base Rates	$120,840	-$906	$119,934	
14	Decoupling Adjustment		$906	$906	
15	Total Volumetric Revenue	$120,840	$0	$120,840	0.0%
16	Volumetric Revenue from New Customers				
17	Base Rates		$1,129	$1,129	
18	Decoupling Adjustment		$321	$321	
19	Total Revenue		$1,450	$1,450	
20	Total Volumetric Revenue				
21	Base Rates	$120,840	$222	$121,062	
22	Decoupling Adjustment		$1,228	$1,228	
23	Total	$120,840	$1,450	$122,290	1.2%
24	Volumetric Revenue per Customer				
25	Existing	$242	$0	$242	
26	New			$242	
27	Volumetric Revenue per Customer	$242		$242	
28	Benchmark Revenue per Customer: 636 therms @ $0.38			$242	

Note 1. Volumetric in this context does not include commodity rates or revenues.

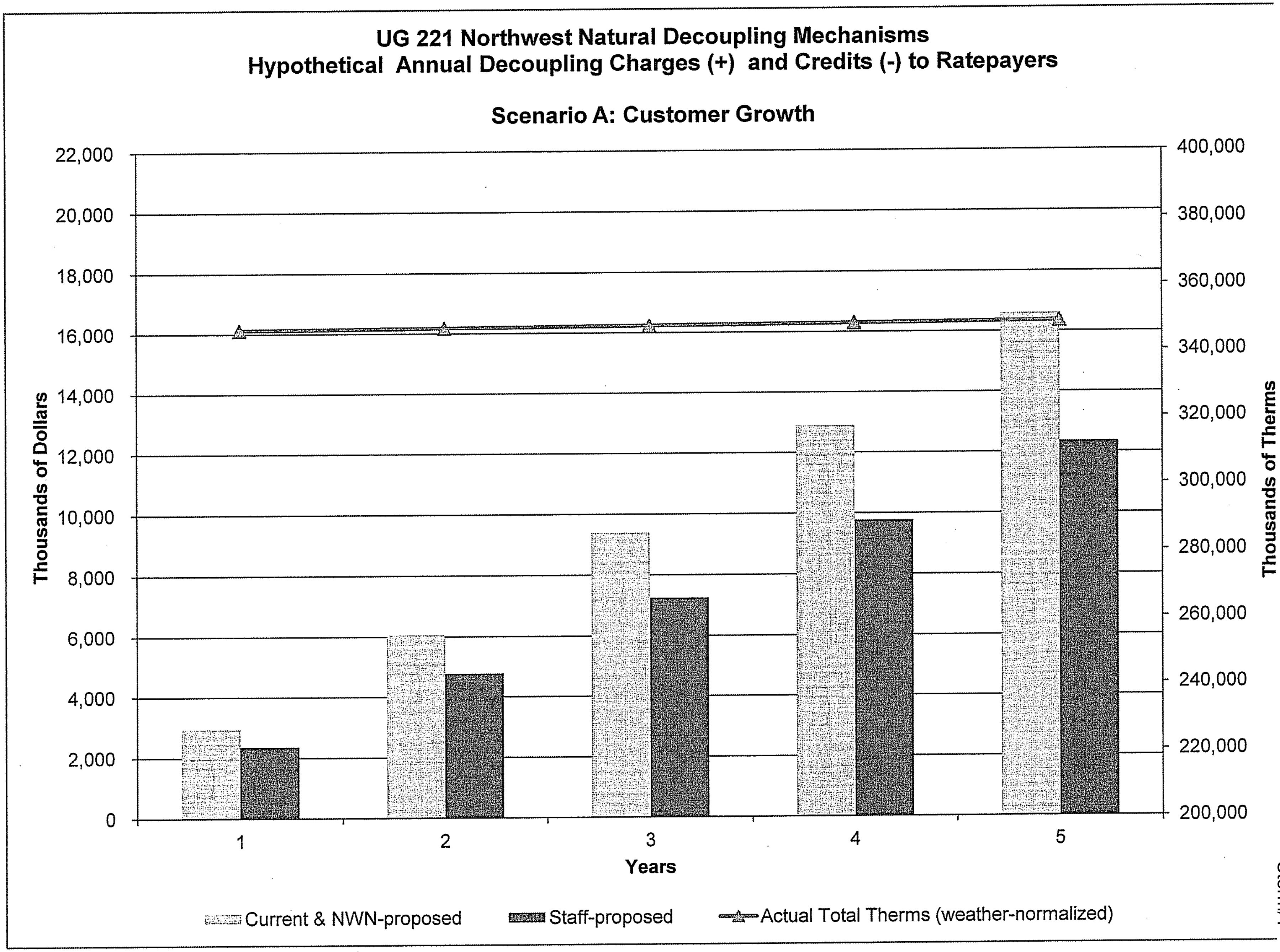
CASE: UG 221
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1303

Exhibits in Support Of Opening Testimony

May 3, 2012


UG 221 Northwest Natural Decoupling Mechanisms
Hypothetical Annual Decoupling Charges (+) and Credits (-) to Ratepayers
Scenario A: Customer Growth
Thousands of Dollars
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Thousands of Therms
400,000
380,000
360,000
340,000
320,000
300,000
280,000
260,000
240,000
220,000
200,000
1
2
3
4
5
Years
Current & NWN-proposed
Staff-proposed
Actual Total Therms (weather-normalized)

UG 221 Northwest Natural
Hypothetical Results of Current/Company-proposed Mechanism and Staff-proposed Mechanism

Scenario A

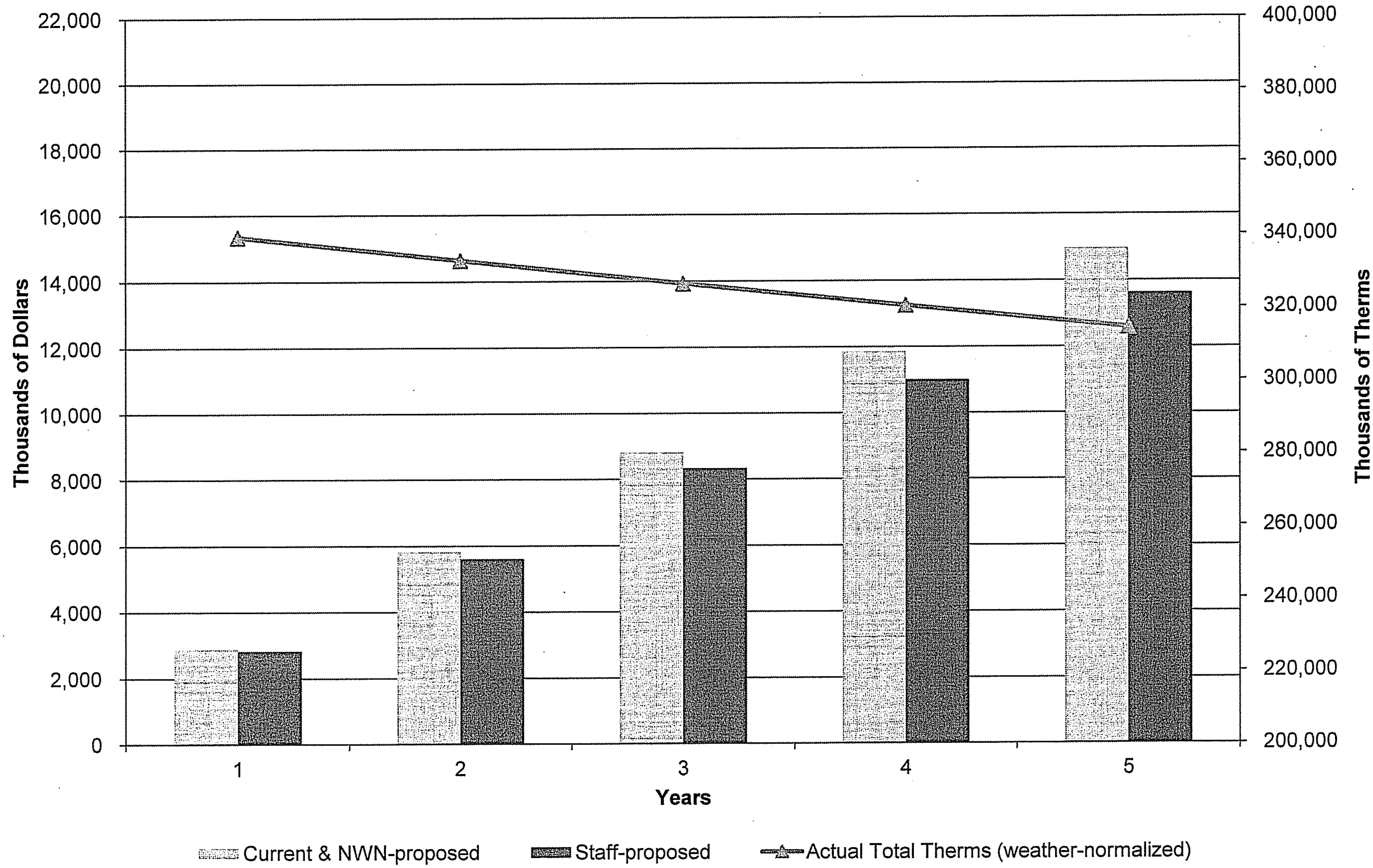
	Benchmark Values	Usage Year 1	2	3	4	5	5 Year Total
Annual Usage per Customer							
Company - Current & Proposed	629.1	617.1	605.4	593.9	582.6	571.6	
Staff Proposed	N/A						
Actual Customers							
Company - Current & Proposed	550,000	561,550	573,343	585,383	597,676	610,227	
Staff Proposed	N/A						
Total Therm Benchmark							
Company - Current & Proposed (000's)	346,005	353,271	360,690	368,264	375,998	383,894	
Staff Proposed (000's)	346,005			→			
Actual Therms (weather-normalized)							
Company - Current & Proposed (000's)		346,559	347,114	347,670	348,226	348,784	
Staff Proposed (000's)		346,559	347,114	347,670	348,226	348,784	
Therm Variance from Benchmark							
Company - Current & Proposed (000's)		(6,712)	(13,576)	(20,595)	(27,772)	(35,110)	
Staff Proposed (000's)		554	1,109	1,665	2,221	2,779	
New Meters/New Service Location-Cumulative							
Company - Current & Proposed	N/A						
Staff Proposed		13,283	26,844	40,690	54,827	69,261	
Margin Rate per Therm							
Company - Current & Proposed	$ 0.43044	$ 0.43862	$ 0.44695	$ 0.45544	$ 0.46410	$ 0.47292	
Staff Proposed	$ 0.43044			→			
Decoupling Charge (Credit) to Ratepayers ($000's)							
Company - Current & Proposed							
Due to Variance in Usage per Customer		$ 2,889	$ 5,844	$ 8,865	$ 11,954	$ 15,113	$ 44,664
Due to Change in Margin Rate per Therm		$ 55	$ 224	$ 515	$ 935	$ 1,491	$ 3,220
Total Company Current & Proposed		$ 2,944	$ 6,068	$ 9,380	$ 12,889	$ 16,604	$ 47,885
Staff Proposed							
Due to Variance in Total Weather-normalized Therms		$ (238)	$ (477)	$ (716)	$ (956)	$ (1,196)	$ (3,584)
Due to New Meters at New Service Locations		$ 2,598	$ 5,251	$ 7,959	$ 10,724	$ 13,547	$ 40,079
Total Staff Proposed		$ 2,360	$ 4,773	$ 7,243	$ 9,768	$ 12,351	$ 36,495

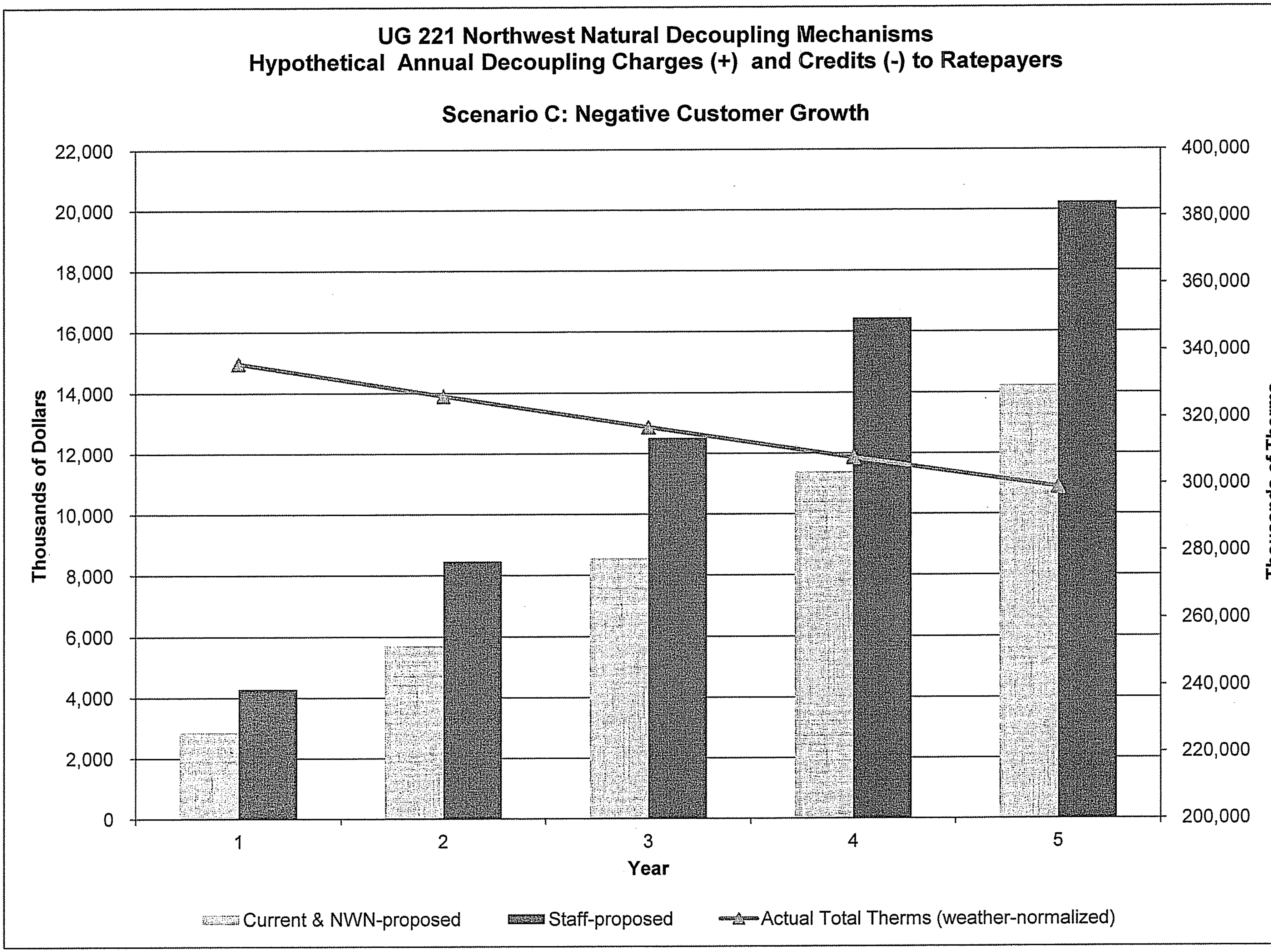
Assumptions

Common Benchmark Values		
Number of Customers	550,000	Average annual number of Residential customers from last full year for which actuals are available (10-11) was 546 thousand (Response to Staff DR 459)
Usage per Customer (therms per year)	629.1	Annual Residential Usage per Customer from last year for which actuals are available (10-11) was 629.1 (Response to Staff DR 459)
Total Therm Benchmark (000's)	346,005	
Margin Rate per Therm	$ 0.43044	Residential Distribution Margin Rate was $0.43044 in year 09-10 (Response to Staff DR 459)
Common Annual Rate of Growth (Decline)		
Annual Rate of Customer Growth (Decline)	2.10%	Residential customers (average of year) averaged 2.1% per year growth over period 02-03 through 10-11 (Response to Staff DR 459)
Actual Total Therms	0.16%	Derived from annual growth rate assumptions for customers and usage per customer
Northwest Natural Current & Proposed		
Annual Rate of Usage per Customer Growth (Decline)	-1.90%	Residential Usage per Customer averaged a 1.9% per year decline over period 02-03 through 10-11 (Response to Staff DR 459)
Margin Rate per Therm	1.90%	Residential rate increased at an annual average rate of 1.9% (Response to Staff DR 459)
Staff-proposed		
Ratio of the Number of New Meters at New Service Locations to the Number of New Customers	115.00%	Residential Average 2004 - 2011 was 115%
Monthly Relevant LRIC Customer-related Costs per Customer	$ 22.30	$22.30 per information in Exhibit Feingold/1101 for customers in Schedule 2.
Monthly Customer Charge	$ 6.00	Current

UG 221 Northwest Natural Decoupling Mechanisms
Hypothetical Annual Decoupling Charges (+) and Credits (-) to Ratepayers

Scenario B: No Customer Growth



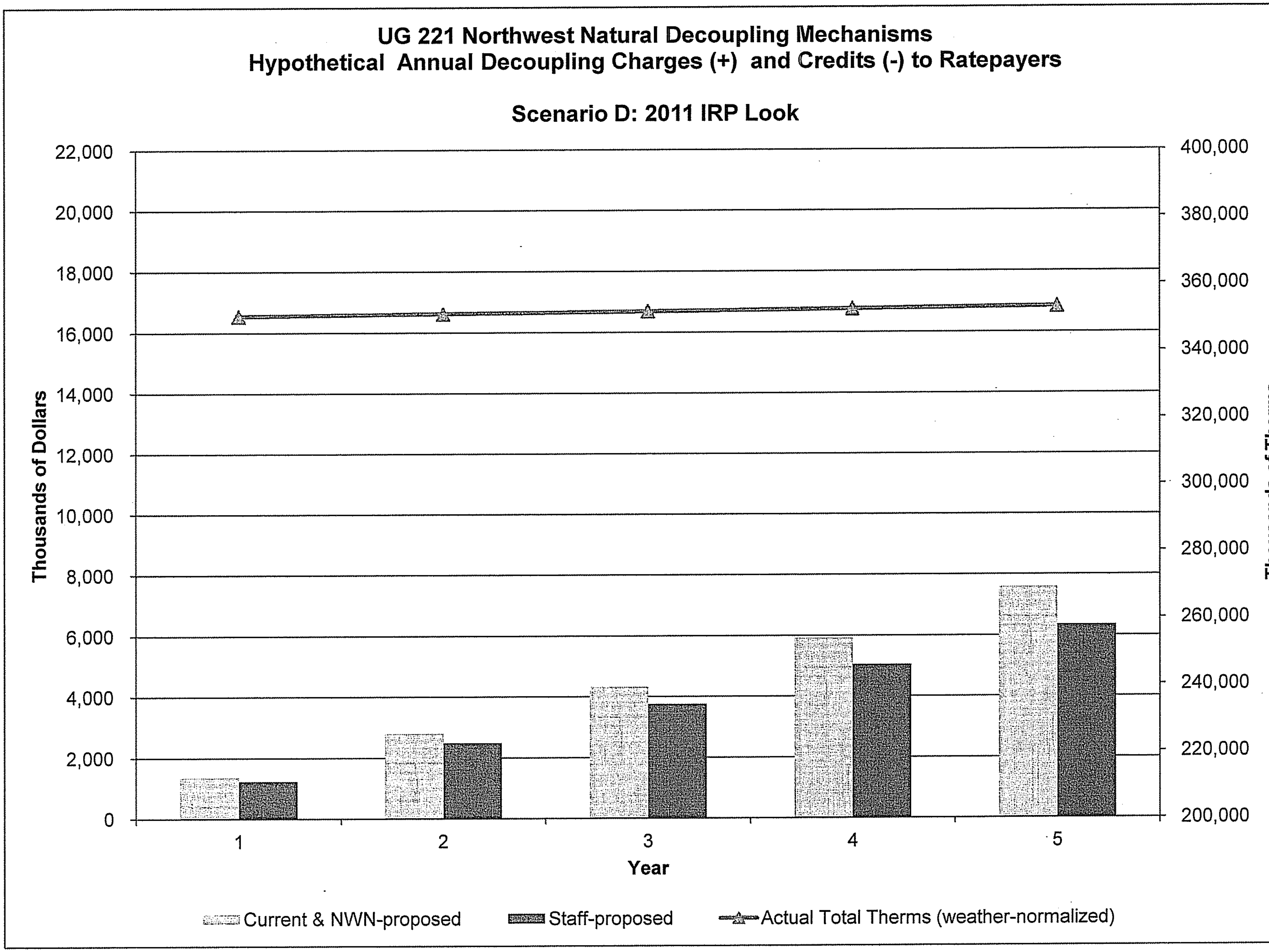

UG 221 Northwest Natural Decoupling Mechanisms
Hypothetical Annual Decoupling Charges (+) and Credits (-) to Ratepayers
Scenario C: Negative Customer Growth
Thousands of Dollars
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Thousands of Therms
400,000
380,000
360,000
340,000
320,000
300,000
280,000
260,000
240,000
220,000
200,000
1
2
3
4
5
Year
Current & NWN-proposed
Staff-proposed
Actual Total Therms (weather-normalized)

UG 221 Northwest Natural
Hypothetical Results of Current/Company-proposed Mechanism and Staff-proposed Mechanism

Scenario C	Benchmark Values	Usage Year 1	2	3	4	5	5 Year Total
Annual Usage per Customer							
Company - Current & Proposed	629.1	617.1	605.4	593.9	582.6	571.6	
Staff Proposed	N/A						
Actual Customers							
Company - Current & Proposed	550,000	544,500	539,055	533,664	528,328	523,045	
Staff Proposed	N/A						
Total Therm Benchmark							
Company - Current & Proposed (000's)	346,005	342,545	339,120	335,728	332,371	329,047	
Staff Proposed (000's)	346,005			→			
Actual Therms (weather-normalized)							
Company - Current & Proposed (000's)		336,037	326,355	316,953	307,822	298,953	
Staff Proposed (000's)		336,037	326,355	316,953	307,822	298,953	
Therm Variance from Benchmark							
Company - Current & Proposed (000's)		(6,508)	(12,764)	(18,775)	(24,549)	(30,094)	
Staff Proposed (000's)		(9,968)	(19,650)	(29,052)	(38,183)	(47,052)	
New Meters/New Service Location-Cumulative							
Company - Current & Proposed	N/A						
Staff Proposed		-	-	-	-	-	
Margin Rate per Therm							
Company - Current & Proposed	$ 0.43044	$ 0.43862	$ 0.44695	$ 0.45544	$ 0.46410	$ 0.47292	
Staff Proposed	$ 0.43044			→			
Decoupling Charge (Credit) to Ratepayers ($000's)							
Company - Current & Proposed							
Due to Variance in Usage per Customer		$ 2,801	$ 5,494	$ 8,082	$ 10,567	$ 12,954	$ 39,898
Due to Change in Margin Rate per Therm		$ 53	$ 211	$ 469	$ 826	$ 1,278	$ 2,838
Total Company Current & Proposed		$ 2,855	$ 5,705	$ 8,551	$ 11,393	$ 14,232	$ 42,736
Staff Proposed							
Due to Variance in Total Weather-normalized Therms		$ 4,291	$ 8,458	$ 12,505	$ 16,436	$ 20,253	$ 61,942
Due to New Meters at New Service Locations		$ -	$ -	$ -	$ -	$ -	$ -
Total Staff Proposed		$ 4,291	$ 8,458	$ 12,505	$ 16,436	$ 20,253	$ 61,942

Assumptions

Common Benchmark Values		
Number of Customers	550,000	Average annual number of Residential customers from last full year for which actuals are available (10-11) was 546 thousand (Response to Staff DR 459)
Usage per Customer (therms per year)	629.1	Annual Residential Usage per Customer from last year for which actuals are available (10-11) was 629.1 (Response to Staff DR 459)
Total Therm Benchmark (000's)	346,005	
Margin Rate per Therm	$ 0.43044	Residential Distribution Margin Rate was $0.43044 in year 09-10 (Response to Staff DR 459)
Common Annual Rate of Growth (Decline)		
Annual Rate of Customer Growth (Decline)	-1.00%	Residential customers (average of year) averaged 2.1% per year growth over period 02-03 through 10-11 (Response to Staff DR 459)
Actual Total Therms	-2.88%	Derived from annual growth rate assumptions for customers and usage per customer
Northwest Natural Current & Proposed		
Annual Rate of Usage per Customer Growth (Decline)	-1.90%	Residential Usage per Customer averaged a 1.9% per year decline over period 02-03 through 10-11 (Response to Staff DR 459)
Margin Rate per Therm	1.90%	Residential rate increased at an annual average rate of 1.9% (Response to Staff DR 459)
Staff-proposed		
Ratio of the Number of New Meters at New Service Locations to the Number of New Customers	115.00%	Residential Average 2004 - 2011 was 115%
Monthly Relevant LRIC Customer-related Costs per Customer	$ 22.30	$22.30 per information in Exhibit Feingold/1101 for customers in Schedule 2.
Monthly Customer Charge	$ 6.00	Current


UG 221 Northwest Natural Decoupling Mechanisms
Hypothetical Annual Decoupling Charges (+) and Credits (-) to Ratepayers
Scenario D: 2011 IRP Look
Thousands of Dollars
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Thousands of Therms
400,000
380,000
360,000
340,000
320,000
300,000
280,000
260,000
240,000
220,000
200,000
1
2
3
4
5
Year
Current & NWN-proposed
Staff-proposed
Actual Total Therms (weather-normalized)

UG 221 Northwest Natural
Hypothetical Results of Current/Company-proposed Mechanism and Staff-proposed Mechanism

Scenario D

	Benchmark Values	Usage Year 1	2	3	4	5	5 Year Total
Annual Usage per Customer							
Company - Current & Proposed	636.0	629.6	623.3	617.1	610.9	604.8	
Staff Proposed	N/A						
Actual Customers							
Company - Current & Proposed	550,000	556,600	563,279	570,039	576,879	583,802	
Staff Proposed	N/A						
Total Therm Benchmark							
Company - Current & Proposed (000's)	349,800	353,998	358,246	362,545	366,895	371,298	
Staff Proposed (000's)	349,800			→			
Actual Therms (weather-normalized)							
Company - Current & Proposed (000's)		350,458	351,116	351,777	352,438	353,101	
Staff Proposed (000's)		350,458	351,116	351,777	352,438	353,101	
Therm Variance from Benchmark							
Company - Current & Proposed (000's)		(3,540)	(7,129)	(10,768)	(14,457)	(18,197)	
Staff Proposed (000's)		658	1,316	1,977	2,638	3,301	
New Meters/New Service Location-Cumulative							
Company - Current & Proposed	N/A						
Staff Proposed		7,590	15,271	23,044	30,911	38,872	
Margin Rate per Therm							
Company - Current & Proposed	$ 0.38000	$ 0.38722	$ 0.39458	$ 0.40207	$ 0.40971	$ 0.41750	
Staff Proposed	$ 0.38000			→			
Decoupling Charge (Credit) to Ratepayers ($000's)							
Company - Current & Proposed							
Due to Variance in Usage per Customer		$ 1,345	$ 2,709	$ 4,092	$ 5,494	$ 6,915	$ 20,555
Due to Change in Margin Rate per Therm		$ 26	$ 104	$ 238	$ 430	$ 682	$ 1,479
Total Company Current & Proposed		$ 1,371	$ 2,813	$ 4,330	$ 5,923	$ 7,597	$ 22,034
Staff Proposed							
Due to Variance in Total Weather-normalized Therms		$ (250)	$ (500)	$ (751)	$ (1,002)	$ (1,254)	$ (3,758)
Due to New Meters at New Service Locations		$ 1,485	$ 2,987	$ 4,507	$ 6,046	$ 7,603	$ 22,629
Total Staff Proposed		$ 1,235	$ 2,487	$ 3,756	$ 5,044	$ 6,349	$ 18,871

Assumptions

	Value	Comment
Common Benchmark Values		
Number of Customers	550,000	Average annual number of Residential customers from last full year for which actuals are available (10-11) was 546 thousand (Response to Staff DR 459)
Usage per Customer (therms per year)	636.0	Annual Residential Usage per Customer from last year for which actuals are available (10-11) was 629.1 (Response to Staff DR 459)
Total Therm Benchmark (000's)	349,800	
Margin Rate per Therm	$ 0.38000	Residential Distribution Margin Rate was $0.43044 in year 09-10 (Response to Staff DR 459)
Common Annual Rate of Growth (Decline)		
Annual Rate of Customer Growth (Decline)	1.20%	Residential customers (average of year) averaged 2.1% per year growth over period 02-03 through 10-11 (Response to Staff DR 459)
Actual Total Therms	0.19%	Derived from annual growth rate assumptions for customers and usage per customer
Northwest Natural Current & Proposed		
Annual Rate of Usage per Customer Growth (Decline)	-1.00%	Residential Usage per Customer averaged a 1.9% per year decline over period 02-03 through 10-11 (Response to Staff DR 459)
Margin Rate per Therm	1.90%	Residential rate increased at an annual average rate of 1.9% (Response to Staff DR 459)
Staff-proposed		
Ratio of the Number of New Meters at New Service Locations to the Number of New Customers	115.00%	Residential Average 2004 - 2011 was 115%
Monthly Relevant LRIC Customer-related Costs per Customer	$ 22.30	$22.30 per information in Exhibit Feingold/1101 for customers in Schedule 2.
Monthly Customer Charge	$ 6.00	Current

CASE: UG 221
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1304

Exhibits in Support
Of Opening Testimony

May 3, 2012

Staff/1304
Storm/1

UG 221 Northwest Natural

30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity Stage 3 Annual Growth Rate of 4.96 Percent

		Unadjusted ROE[1] (IRR) (A)	Average Recent Share Price (B)	Dividend Yield @ Average Recent Share Price[2] (C)	2012-17 Annual Dividend Growth Rate[3] (D)	2018-22 Annual Dividend Growth Rate[3] (E)	2023-42 Annual Dividend Growth Rate[3] (F)	Terminal Value as % of Total Valuation[1] (G)	2012 Common Equity % of Capital Structure (H)	Test Year Common Equity % of Capital Structure (I)	Value Line Beta[4] (J)	Unlevered Beta[5] (Business Risk) (K)	Beta Relevered to Test Year Capital Structure[5] (L)	ROE Adjustment (Hamada Equation) (M)	ROE[1] Adjusted for Divergent Capital Structures (O)
Staff's Peer Utilities															
1	Laclede Group	8.5%	$41.02	4.0%	2.2%	3.8%	4.96%	37.7%	63.0%	50.0%	0.60	0.43	0.72	0.5%	9.0%
2	Northwest Natural	8.3%	$46.55	3.8%	2.1%	3.8%	4.96%	39.7%	55.0%	50.0%	0.60	0.38	0.65	0.2%	8.5%
3	Piedmont Natural Gas	8.4%	$32.27	3.7%	3.2%	4.2%	4.96%	39.1%	57.0%	50.0%	0.70	0.46	0.78	0.3%	8.7%
4	Questar	8.6%	$19.39	3.4%	5.7%	5.2%	4.96%	37.6%	52.5%	50.0%	NMF	0.40	0.66	0.1%	8.7%
5	WGL Holdings	8.4%	$41.54	3.8%	2.4%	3.9%	4.96%	39.2%	67.5%	50.0%	0.65	0.50	0.81	0.7%	9.1%
	Group Average	8.5%		3.8%	3.1%	4.2%	4.96%	38.7%	59.0%	50.0%	0.64	0.44	0.72	0.4%	8.8%
Northwest Natural's Peer Utilities															
1	Alliant Energy*#	9.4%	$42.96	4.2%	5.2%	5.0%	4.96%	30.5%	49.0%	50.0%	0.75	0.41	0.74	-0.1%	9.3%
2	Black Hills*#	8.7%	$33.71	4.4%	1.5%	3.6%	4.96%	35.5%	54.0%	50.0%	0.85	0.54	0.90	0.2%	8.9%
3	Consolidated Edison*	8.4%	$58.62	4.1%	1.2%	3.5%	4.96%	38.5%	51.5%	50.0%	0.60	0.37	0.61	0.1%	8.5%
4	DTE Energy*#	9.3%	$54.35	4.5%	3.8%	4.4%	4.96%	30.9%	51.0%	50.0%	0.75	0.46	0.76	0.0%	9.3%
5	Northwest Natural Gas	8.3%	$46.55	3.8%	2.1%	3.8%	4.96%	39.7%	55.0%	50.0%	0.60	0.38	0.65	0.2%	8.5%
6	NiSource#	7.9%	$23.94	3.8%	0.0%	2.9%	4.96%	43.9%	45.0%	50.0%	0.85	0.49	0.78	-0.3%	7.6%
7	Piedmont Natural Gas	8.4%	$32.27	3.7%	3.2%	4.2%	4.96%	39.1%	57.0%	50.0%	0.70	0.46	0.78	0.3%	8.7%
8	Pepco Holdings*#	9.8%	$19.37	5.6%	1.4%	3.4%	4.96%	26.0%	51.0%	50.0%	0.80	0.48	0.81	0.1%	9.9%
9	SCANA*#	8.8%	$45.18	4.4%	2.1%	3.8%	4.96%	34.5%	46.0%	50.0%	0.70	0.39	0.65	-0.2%	8.6%
10	Sempra Energy*#	8.9%	$59.41	3.5%	6.6%	5.5%	4.96%	35.1%	50.5%	50.0%	0.80	0.46	0.81	0.0%	8.9%
11	Southwest Gas#	8.3%	$42.77	2.8%	8.3%	5.8%	4.96%	41.6%	55.5%	50.0%	0.75	0.49	0.81	0.3%	8.6%
12	Vectren*#	9.6%	$29.22	4.8%	3.0%	4.5%	4.96%	28.4%	48.0%	50.0%	0.70	0.41	0.68	-0.1%	9.5%
13	Wisconsin Energy*#	9.8%	$34.59	3.5%	11.1%	6.8%	4.96%	28.2%	46.0%	50.0%	0.65	0.37	0.61	-0.2%	9.6%
14	Xcel Energy*	9.6%	$26.52	4.0%	6.3%	5.7%	4.96%	28.9%	46.5%	50.0%	0.65	0.37	0.61	-0.2%	9.5%
	Group Average	9.0%		4.1%	4.0%	4.5%	4.96%	34.4%	50.4%	50.0%	0.73	0.43	0.73	0.0%	9.0%
	Average of 10 Utilities classified by Value Line as Electric Utilities *	9.2%		4.3%	4.2%	4.6%	4.96%	31.7%	49.4%	50.0%	0.73	0.43	0.72	0.0%	9.2%
	Average of 4 Utilities classified by Value Line as Natural Gas Utilities	8.2%		3.5%	3.4%	4.2%	4.96%	41.1%	53.1%	50.0%	0.73	0.46	0.76	0.1%	8.4%
	Average of 10 Utilities with an S&P Issuer or Long-term Credit Rating <u>below</u> "A-" #	9.1%		4.1%	4.3%	4.6%	4.96%	33.5%	49.6%	50.0%	0.71	0.42	0.71	0.0%	9.0%
	Average of 4 Utilities with an S&P Issuer or Long-term Credit Rating <u>above</u> "BBB+"	8.7%		3.9%	3.2%	4.3%	4.96%	36.6%	52.5%	50.0%	0.75	0.45	0.76	0.1%	8.8%

Notes

1. Based on average of Beginning of Year values and End of Year values.
2. Based on Value Line's estimated 2012 dividends.
3. Based on calendar year dividends.
4. Value Line reports Questar's beta as "NMF" (not meaningful). Questar's unlevered beta is average of remaining members of peer group.
5. Calculations of the unlevered beta and the relevered beta use the Hamada Equation.

Displayed values have not been rounded.

UG 221 Northwest Natural

30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio Stage 3 Annual Growth Rate of 4.96 Percent

	Unadjusted ROE[1] (IRR) (A)	Average Recent Share Price (B)	Dividend Yield @ Average Recent Share Price[2] (C)	2013-17 Average Annual Dividend Growth Rate[3] (D)	2013-17 Average Annual EPS[4] Growth Rate[3] (E)	2018-22 Average Annual Dividend Growth Rate[3] (F)	2018-22 Average Annual EPS[4] Growth Rate[3] (G)	2023-42 Average Annual Dividend & EPS[4] Growth Rates[3] (H)	Terminal Value as % of Total Valuation[1] (I)	2012 Common Equity % of Capital Structure (J)	Test Year Common Equity % of Capital Structure (K)	Value Line Beta[5] (L)	Unlevered Beta[5] (Business Risk) (M)	Beta Relevered to Test Year Capital Structure[6] (N)	ROE Adjustment (Hamada Equation) (O)	ROE[1] Adjusted for Divergent Capital Structures (P)
Staff's Peer Utilities																
1 Laclede Group	8.3%	$41.02	4.0%	2.2%	3.0%	3.8%	4.1%	4.96%	35.9%	63.0%	50.0%	0.60	0.43	0.72	0.5%	8.8%
2 Northwest Natural	8.7%	$46.55	3.8%	2.2%	7.7%	3.8%	5.7%	4.96%	42.4%	55.0%	50.0%	0.60	0.38	0.65	0.2%	8.9%
3 Piedmont Natural Gas	8.3%	$32.27	3.7%	3.2%	3.6%	4.2%	4.5%	4.96%	38.0%	57.0%	50.0%	0.70	0.46	0.78	0.3%	8.6%
4 Questar	9.3%	$19.39	3.4%	5.5%	9.6%	5.2%	7.2%	4.96%	43.1%	52.5%	50.0%	NMF	0.40	0.66	0.1%	9.4%
5 WGL Holdings	8.2%	$41.54	3.8%	2.4%	2.9%	3.9%	4.2%	4.96%	37.5%	67.5%	50.0%	0.65	0.50	0.81	0.7%	8.9%
Group Average	8.5%		3.8%	3.1%	5.4%	4.2%	5.1%	4.96%	39.4%	59.0%	50.0%	0.64	0.44	0.72	0.4%	8.9%
Northwest Natural's Peer Utilities																
1 Alliant Energy*#	9.4%	$42.96	4.2%	5.1%	5.4%	5.0%	5.0%	4.96%	30.8%	49.0%	50.0%	0.75	0.41	0.74	-0.1%	9.3%
2 Black Hills*#	8.7%	$33.71	4.4%	1.5%	4.0%	3.6%	4.6%	4.96%	34.9%	54.0%	50.0%	0.85	0.54	0.90	0.2%	8.9%
3 Consolidated Edison*	8.1%	$58.62	4.1%	1.2%	2.2%	3.5%	3.8%	4.96%	36.0%	51.5%	50.0%	0.60	0.37	0.61	0.1%	8.2%
4 DTE Energy*#	9.3%	$54.35	4.5%	3.7%	4.6%	4.4%	4.7%	4.96%	30.6%	51.0%	50.0%	0.75	0.46	0.76	0.0%	9.3%
5 Northwest Natural Gas	8.7%	$46.55	3.8%	2.2%	7.7%	3.8%	5.7%	4.96%	42.4%	55.0%	50.0%	0.60	0.38	0.65	0.2%	8.9%
6 NiSource#	8.3%	$23.94	3.8%	0.0%	6.4%	2.9%	5.8%	4.96%	46.6%	45.0%	50.0%	0.85	0.49	0.78	-0.3%	8.0%
7 Piedmont Natural Gas	8.3%	$32.27	3.7%	3.2%	3.6%	4.2%	4.5%	4.96%	38.0%	57.0%	50.0%	0.70	0.46	0.78	0.3%	8.6%
8 Pepco Holdings*#	10.0%	$19.37	5.6%	1.7%	6.8%	3.4%	5.6%	4.96%	28.2%	51.0%	50.0%	0.80	0.48	0.81	0.1%	10.1%
9 SCANA*#	8.9%	$45.18	4.4%	2.1%	4.5%	3.8%	4.9%	4.96%	34.7%	46.0%	50.0%	0.70	0.39	0.65	-0.2%	8.7%
10 Sempra Energy*#	9.2%	$59.41	3.5%	6.2%	7.6%	5.5%	6.0%	4.96%	37.8%	50.5%	50.0%	0.80	0.46	0.81	0.0%	9.2%
11 Southwest Gas#	8.8%	$42.77	2.8%	7.7%	9.3%	5.8%	6.6%	4.96%	46.0%	55.5%	50.0%	0.75	0.49	0.81	0.3%	9.1%
12 Vectren*#	9.9%	$29.22	4.8%	3.3%	7.7%	4.5%	6.0%	4.96%	31.2%	48.0%	50.0%	0.70	0.41	0.68	-0.1%	9.8%
13 Wisconsin Energy*#	9.7%	$34.59	3.5%	10.3%	5.0%	6.8%	4.8%	4.96%	27.3%	46.0%	50.0%	0.65	0.37	0.61	-0.2%	9.6%
14 Xcel Energy*	9.4%	$26.52	4.0%	6.9%	2.6%	5.7%	4.0%	4.96%	26.3%	46.5%	50.0%	0.65	0.37	0.61	-0.2%	9.2%
Group Average	9.0%		4.1%	3.9%	5.5%	4.5%	5.1%	4.96%	35.1%	50.4%	50.0%	0.73	0.43	0.73	0.0%	9.1%
Average of 10 Utilities classified by Value Line as Electric Utilities *	9.3%		4.3%	4.2%	5.0%	4.6%	4.9%	4.96%	31.8%	0.49	0.50	0.73	0.43	0.72	0.0%	9.2%
Average of 4 Utilities classified by Value Line as Natural Gas Utilities	8.5%		3.5%	3.2%	6.7%	4.2%	5.6%	4.96%	43.3%	0.53	0.50	0.73	0.46	0.76	0.1%	8.6%
Average of 10 Utilities with an S&P Issuer or Long-term Credit Rating <u>below</u> "A-" #	9.2%		4.1%	4.2%	6.1%	4.6%	5.4%	4.96%	34.8%	0.50	0.50	0.76	0.45	0.76	0.0%	9.2%
Average of 4 Utilities with an S&P Issuer or Long-term Credit Rating <u>above</u> "BBB+"	8.6%		3.9%	3.4%	4.0%	4.3%	4.5%	4.96%	35.7%	0.53	0.50	0.64	0.40	0.66	0.1%	8.7%

Notes

1. Based on average of Beginning of Year values and End of Year values. ROE is unadjusted for divergent capital structures.
2. Based on Value Line's estimated 2012 dividends.
3. Based on calendar year dividends and Earnings per Share (EPS).
4. Earnings per Share
5. Value Line reports Questar's beta as "NMF" (not meaningful). Questar's unlevered beta is average of remaining members of peer group.
6. Calculations of the unlevered beta and the relevered beta use the Hamada Equation.

Displayed values have not been rounded.

UG 221 Northwest Natural

30-year Three-stage Discounted Dividend Model
with Terminal Valuation based on Growing Perpetuity
Stage 3 Annual Growth Rate of 5.43 Percent

	Unadjusted ROE[1] (IRR) (A)	Average Recent Share Price (B)	Dividend Yield @ Average Recent Share Price[2] (C)	2012-17 Annual Dividend Growth Rate[3] (D)	2018-22 Annual Dividend Growth Rate[3] (E)	2023-42 Annual Dividend Growth Rate[3] (F)	Terminal Value as % of Total Valuation[1] (G)	2012 Common Equity % of Capital Structure (H)	Test Year Common Equity % of Capital Structure (I)	Value Line Beta[4] (J)	Unlevered Beta[5] (Business Risk) (K)	Beta Relevered to Test Year Capital Structure[5] (L)	ROE Adjustment (Hamada Equation) (M)	ROE[1] Adjusted for Divergent Capital Structures (O)
Staff's Peer Utilities														
1 Laclede Group	8.9%	$41.02	4.0%	2.2%	4.1%	5.43%	38.9%	63.0%	50.0%	0.60	0.43	0.72	0.5%	9.4%
2 Northwest Natural	8.7%	$46.55	3.8%	2.1%	4.1%	5.43%	40.9%	55.0%	50.0%	0.60	0.38	0.65	0.2%	8.9%
3 Piedmont Natural Gas	8.8%	$32.27	3.7%	3.2%	4.5%	5.43%	40.3%	57.0%	50.0%	0.70	0.46	0.78	0.3%	9.1%
4 Questar	9.0%	$19.39	3.4%	5.7%	5.5%	5.43%	38.8%	52.5%	50.0%	NMF	0.40	0.66	0.1%	9.1%
5 WGL Holdings	8.8%	$41.54	3.8%	2.4%	4.2%	5.43%	40.4%	67.5%	50.0%	0.65	0.50	0.81	0.7%	9.4%
Group Average	8.8%		3.8%	3.1%	4.5%	5.43%	39.9%	59.0%	50.0%	0.64	0.44	0.72	0.4%	9.2%
Northwest Natural's Peer Utilities														
1 Alliant Energy*#	9.7%	$42.96	4.2%	5.2%	5.2%	5.43%	31.7%	49.0%	50.0%	0.75	0.41	0.74	-0.1%	9.7%
2 Black Hills*#	9.1%	$33.71	4.4%	1.5%	3.9%	5.43%	36.7%	54.0%	50.0%	0.85	0.54	0.90	0.2%	9.3%
3 Consolidated Edison*	8.8%	$58.62	4.1%	1.2%	3.8%	5.43%	39.7%	51.5%	50.0%	0.60	0.37	0.61	0.1%	8.9%
4 DTE Energy*#	9.6%	$54.35	4.5%	3.8%	4.7%	5.43%	32.0%	51.0%	50.0%	0.75	0.46	0.76	0.0%	9.7%
5 Northwest Natural Gas	8.7%	$46.55	3.8%	2.1%	4.1%	5.43%	40.9%	55.0%	50.0%	0.60	0.38	0.65	0.2%	8.9%
6 NiSource#	8.3%	$23.94	3.8%	0.0%	3.2%	5.43%	45.1%	45.0%	50.0%	0.85	0.49	0.78	-0.3%	8.0%
7 Piedmont Natural Gas	8.8%	$32.27	3.7%	3.2%	4.5%	5.43%	40.3%	57.0%	50.0%	0.70	0.46	0.78	0.3%	9.1%
8 Pepco Holdings*#	10.2%	$19.37	5.6%	1.4%	3.7%	5.43%	27.1%	51.0%	50.0%	0.80	0.48	0.81	0.1%	10.2%
9 SCANA*#	9.2%	$45.18	4.4%	2.1%	4.1%	5.43%	35.7%	46.0%	50.0%	0.70	0.39	0.65	-0.2%	9.0%
10 Sempra Energy*#	9.3%	$59.41	3.5%	6.6%	5.7%	5.43%	36.3%	50.5%	50.0%	0.80	0.46	0.81	0.0%	9.3%
11 Southwest Gas#	8.7%	$42.77	2.8%	8.3%	6.1%	5.43%	42.8%	55.5%	50.0%	0.75	0.49	0.81	0.3%	9.0%
12 Vectren*#	10.0%	$29.22	4.8%	3.0%	4.8%	5.43%	29.5%	48.0%	50.0%	0.70	0.41	0.68	-0.1%	9.9%
13 Wisconsin Energy*#	10.2%	$34.59	3.5%	11.1%	7.1%	5.43%	29.3%	46.0%	50.0%	0.65	0.37	0.61	-0.2%	10.0%
14 Xcel Energy*	10.0%	$26.52	4.0%	6.3%	6.0%	5.43%	30.0%	46.5%	50.0%	0.65	0.37	0.61	-0.2%	9.8%
Group Average	9.3%		4.1%	4.0%	4.8%	5.43%	35.5%	50.4%	50.0%	0.73	0.43	0.73	0.0%	9.3%
Average of 10 Utilities classified by Value Line as Electric Utilities *	9.6%		4.3%	4.2%	4.9%	5.43%	32.8%	49.4%	50.0%	0.73	0.43	0.72	0.0%	9.6%
Average of 4 Utilities classified by Value Line as Natural Gas Utilities	8.6%		3.5%	3.4%	4.5%	5.43%	42.3%	53.1%	50.0%	0.73	0.46	0.76	0.1%	8.8%
Average of 10 Utilities with an S&P Issuer or Long-term Credit Rating <u>below</u> "A-" #	9.4%		4.1%	4.3%	4.8%	5.43%	34.6%	49.6%	50.0%	0.71	0.42	0.71	0.0%	9.4%
Average of 4 Utilities with an S&P Issuer or Long-term Credit Rating <u>above</u> "BBB+"	9.1%		3.9%	3.2%	4.6%	5.43%	37.7%	52.5%	50.0%	0.75	0.45	0.76	0.1%	9.2%

Notes

1. Based on average of Beginning of Year values and End of Year values.
2. Based on Value Line's estimated 2012 dividends.
3. Based on calendar year dividends.
4. Value Line reports Questar's beta as "NMF" (not meaningful). Questar's unlevered beta is average of remaining members of peer group.
5. Calculations of the unlevered beta and the relevered beta use the Hamada Equation.

Displayed values have not been rounded.

Staff/1304
Storm/3

UG 221 Northwest Natural

30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio Stage 3 Annual Growth Rate of 5.43 Percent

	Unadjusted ROE[1] (IRR) (A)	Average Recent Share Price (B)	Dividend Yield @ Average Recent Share Price[2] (C)	2013-17 Average Annual Dividend Growth Rate[3] (D)	2013-17 Average Annual EPS[4] Growth Rate[3] (E)	2018-22 Average Annual Dividend Growth Rate[3] (F)	2018-22 Average Annual EPS[4] Growth Rate[3] (G)	2023-42 Average Annual Dividend & EPS[4] Growth Rates[3] (H)	Terminal Value as % of Total Valuation[1] (I)	2012 Common Equity % of Capital Structure (J)	Test Year Common Equity % of Capital Structure (K)	Value Line Beta[5] (L)	Unlevered Beta[5] (Business Risk) (M)	Beta Relevered to Test Year Capital Structure[6] (N)	ROE Adjustment (Hamada Equation) (O)	ROE[1] Adjusted for Divergent Capital Structures (P)
Staff's Peer Utilities																
1 Laclede Group	8.6%	$41.02	4.0%	2.2%	3.0%	4.1%	4.4%	5.43%	36.6%	63.0%	50.0%	0.60	0.43	0.72	0.5%	9.1%
2 Northwest Natural	9.0%	$46.55	3.8%	2.2%	7.7%	4.1%	6.0%	5.43%	43.2%	55.0%	50.0%	0.60	0.38	0.65	0.2%	9.2%
3 Piedmont Natural Gas	8.6%	$32.27	3.7%	3.2%	3.6%	4.5%	4.8%	5.43%	38.7%	57.0%	50.0%	0.70	0.46	0.78	0.3%	9.0%
4 Questar	9.6%	$19.39	3.4%	5.5%	9.6%	5.5%	7.4%	5.43%	43.9%	52.5%	50.0%	NMF	0.40	0.66	0.1%	9.7%
5 WGL Holdings	8.5%	$41.54	3.8%	2.4%	2.9%	4.2%	4.5%	5.43%	38.2%	67.5%	50.0%	0.65	0.50	0.81	0.7%	9.2%
Group Average	8.9%		3.8%	3.1%	5.4%	4.5%	5.4%	5.43%	40.1%	59.0%	50.0%	0.64	0.44	0.72	0.4%	9.2%
Northwest Natural's Peer Utilities																
1 Alliant Energy*#	9.7%	$42.96	4.2%	5.1%	5.4%	5.2%	5.3%	5.43%	31.5%	49.0%	50.0%	0.75	0.41	0.74	-0.1%	9.7%
2 Black Hills*#	9.0%	$33.71	4.4%	1.5%	4.0%	3.9%	4.8%	5.43%	35.7%	54.0%	50.0%	0.85	0.54	0.90	0.2%	9.2%
3 Consolidated Edison*	8.5%	$58.62	4.1%	1.2%	2.2%	3.8%	4.1%	5.43%	36.7%	51.5%	50.0%	0.60	0.37	0.61	0.1%	8.5%
4 DTE Energy*#	9.6%	$54.35	4.5%	3.7%	4.6%	4.7%	5.0%	5.43%	31.3%	51.0%	50.0%	0.75	0.46	0.76	0.0%	9.6%
5 Northwest Natural Gas	9.0%	$46.55	3.8%	2.2%	7.7%	4.1%	6.0%	5.43%	43.2%	55.0%	50.0%	0.60	0.38	0.65	0.2%	9.2%
6 NiSource#	8.6%	$23.94	3.8%	0.0%	6.4%	3.2%	6.1%	5.43%	47.3%	45.0%	50.0%	0.85	0.49	0.78	-0.3%	8.3%
7 Piedmont Natural Gas	8.6%	$32.27	3.7%	3.2%	3.6%	4.5%	4.8%	5.43%	38.7%	57.0%	50.0%	0.70	0.46	0.78	0.3%	9.0%
8 Pepco Holdings*#	10.4%	$19.37	5.6%	1.7%	6.8%	3.7%	5.9%	5.43%	28.9%	51.0%	50.0%	0.80	0.48	0.81	0.1%	10.4%
9 SCANA*#	9.2%	$45.18	4.4%	2.1%	4.5%	4.1%	5.2%	5.43%	35.4%	46.0%	50.0%	0.70	0.39	0.65	-0.2%	9.0%
10 Sempra Energy*#	9.5%	$59.41	3.5%	6.2%	7.6%	5.7%	6.3%	5.43%	38.5%	50.5%	50.0%	0.80	0.46	0.81	0.0%	9.5%
11 Southwest Gas#	9.2%	$42.77	2.8%	7.7%	9.3%	6.1%	6.9%	5.43%	46.8%	55.5%	50.0%	0.75	0.49	0.81	0.3%	9.4%
12 Vectren*#	10.2%	$29.22	4.8%	3.3%	7.7%	4.8%	6.3%	5.43%	31.9%	48.0%	50.0%	0.70	0.41	0.68	-0.1%	10.1%
13 Wisconsin Energy*#	10.0%	$34.59	3.5%	10.3%	5.0%	7.1%	5.1%	5.43%	28.0%	46.0%	50.0%	0.65	0.37	0.61	-0.2%	9.9%
14 Xcel Energy*	9.7%	$26.52	4.0%	6.9%	2.6%	6.0%	4.3%	5.43%	26.9%	46.5%	50.0%	0.65	0.37	0.61	-0.2%	9.5%
Group Average	9.4%		4.1%	3.9%	5.5%	4.8%	5.4%	5.43%	35.8%	50.4%	50.0%	0.73	0.43	0.73	0.0%	9.4%
Average of 10 Utilities classified by Value Line as Electric Utilities *	9.6%		4.3%	4.2%	5.0%	4.9%	5.2%	5.43%	32.5%	0.49	0.50	0.73	0.43	0.72	0.0%	9.5%
Average of 4 Utilities classified by Value Line as Natural Gas Utilities	8.8%		3.5%	3.2%	6.7%	4.5%	5.9%	5.43%	44.0%	0.53	0.50	0.73	0.46	0.76	0.1%	9.0%
Average of 10 Utilities with an S&P Issuer or Long-term Credit Rating <u>below</u> "A-" #	9.5%		4.1%	4.2%	6.1%	4.8%	5.7%	5.43%	35.5%	0.50	0.50	0.76	0.45	0.76	0.0%	9.5%
Average of 4 Utilities with an S&P Issuer or Long-term Credit Rating <u>above</u> "BBB+"	8.9%		3.9%	3.4%	4.0%	4.6%	4.8%	5.43%	36.4%	0.53	0.50	0.64	0.40	0.66	0.1%	9.1%

Notes

1. Based on average of Beginning of Year values and End of Year values. ROE is unadjusted for divergent capital structures.
2. Based on Value Line's estimated 2012 dividends.
3. Based on calendar year dividends and Earnings per Share (EPS).
4. Earnings per Share
5. Value Line reports Questar's beta as "NMF" (not meaningful). Questar's unlevered beta is average of remaining members of peer group.
6. Calculations of the unlevered beta and the relevered beta use the Hamada Equation.

Displayed values have not been rounded.

UG 221 Northwest Natural

30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity Stage 3 Annual Growth Rate of 5.8 Percent

	Unadjusted ROE[1] (IRR) (A)	Average Recent Share Price (B)	Dividend Yield @ Average Recent Share Price[2] (C)	2012-17 Annual Dividend Growth Rate[3] (D)	2018-22 Annual Dividend Growth Rate[3] (E)	2023-42 Annual Dividend Growth Rate[3] (F)	Terminal Value as % of Total Valuation[1] (G)	2012 Common Equity % of Capital Structure (H)	Test Year Common Equity % of Capital Structure (I)	Value Line Beta[4] (J)	Unlevered Beta[5] (Business Risk) (K)	Beta Relevered to Test Year Capital Structure[5] (L)	ROE Adjustment (Hamada Equation) (M)	ROE[1] Adjusted for Divergent Capital Structures (O)
Staff's Peer Utilities														
1 Laclede Group	9.2%	$41.02	4.0%	2.2%	4.3%	5.80%	39.8%	63.0%	50.0%	0.60	0.43	0.72	0.5%	9.7%
2 Northwest Natural	9.0%	$46.55	3.8%	2.1%	4.3%	5.80%	41.9%	55.0%	50.0%	0.60	0.38	0.65	0.2%	9.2%
3 Piedmont Natural Gas	9.1%	$32.27	3.7%	3.2%	4.7%	5.80%	41.3%	57.0%	50.0%	0.70	0.46	0.78	0.3%	9.4%
4 Questar	9.3%	$19.39	3.4%	5.7%	5.7%	5.80%	39.7%	52.5%	50.0%	NMF	0.40	0.66	0.1%	9.4%
5 WGL Holdings	9.1%	$41.54	3.8%	2.4%	4.4%	5.80%	41.3%	67.5%	50.0%	0.65	0.50	0.81	0.7%	9.7%
Group Average	9.1%		3.8%	3.1%	4.7%	5.80%	40.8%	59.0%	50.0%	0.64	0.44	0.72	0.4%	9.5%
Northwest Natural's Peer Utilities														
1 Alliant Energy*#	10.0%	$42.96	4.2%	5.2%	5.5%	5.80%	32.5%	49.0%	50.0%	0.75	0.41	0.74	-0.1%	10.0%
2 Black Hills*#	9.4%	$33.71	4.4%	1.5%	4.1%	5.80%	37.6%	54.0%	50.0%	0.85	0.54	0.90	0.2%	9.6%
3 Consolidated Edison*	9.1%	$58.62	4.1%	1.2%	4.0%	5.80%	40.7%	51.5%	50.0%	0.60	0.37	0.61	0.1%	9.2%
4 DTE Energy*#	9.9%	$54.35	4.5%	3.8%	4.9%	5.80%	32.9%	51.0%	50.0%	0.75	0.46	0.76	0.0%	10.0%
5 Northwest Natural Gas	9.0%	$46.55	3.8%	2.1%	4.3%	5.80%	41.9%	55.0%	50.0%	0.60	0.38	0.65	0.2%	9.2%
6 NiSource#	8.6%	$23.94	3.8%	0.0%	3.4%	5.80%	46.1%	45.0%	50.0%	0.85	0.49	0.78	-0.3%	8.4%
7 Piedmont Natural Gas	9.1%	$32.27	3.7%	3.2%	4.7%	5.80%	41.3%	57.0%	50.0%	0.70	0.46	0.78	0.3%	9.4%
8 Pepco Holdings*#	10.4%	$19.37	5.6%	1.4%	3.9%	5.80%	27.9%	51.0%	50.0%	0.80	0.48	0.81	0.1%	10.5%
9 SCANA*#	9.5%	$45.18	4.4%	2.1%	4.3%	5.80%	36.6%	46.0%	50.0%	0.70	0.39	0.65	-0.2%	9.3%
10 Sempra Energy*#	9.6%	$59.41	3.5%	6.6%	6.0%	5.80%	37.2%	50.5%	50.0%	0.80	0.46	0.81	0.0%	9.6%
11 Southwest Gas#	9.0%	$42.77	2.8%	8.3%	6.3%	5.80%	43.8%	55.5%	50.0%	0.75	0.49	0.81	0.3%	9.3%
12 Vectren*#	10.2%	$29.22	4.8%	3.0%	5.0%	5.80%	30.3%	48.0%	50.0%	0.70	0.41	0.68	-0.1%	10.1%
13 Wisconsin Energy*#	10.5%	$34.59	3.5%	11.1%	7.3%	5.80%	30.1%	46.0%	50.0%	0.65	0.37	0.61	-0.2%	10.3%
14 Xcel Energy*	10.3%	$26.52	4.0%	6.3%	6.2%	5.80%	30.8%	46.5%	50.0%	0.65	0.37	0.61	-0.2%	10.1%
Group Average	9.6%		4.1%	4.0%	5.0%	5.80%	36.4%	50.4%	50.0%	0.73	0.43	0.73	0.0%	9.6%
Average of 10 Utilities classified by Value Line as Electric Utilities *	9.9%		4.3%	4.2%	5.1%	5.80%	33.7%	49.4%	50.0%	0.73	0.43	0.72	0.0%	9.9%
Average of 4 Utilities classified by Value Line as Natural Gas Utilities	8.9%		3.5%	3.4%	4.7%	5.80%	43.2%	53.1%	50.0%	0.73	0.46	0.76	0.1%	9.1%
Average of 10 Utilities with an S&P Issuer or Long-term Credit Rating below "A-" #	9.7%		4.1%	4.3%	5.1%	5.80%	35.5%	49.6%	50.0%	0.71	0.42	0.71	0.0%	9.7%
Average of 4 Utilities with an S&P Issuer or Long-term Credit Rating above "BBB+"	9.4%		3.9%	3.2%	4.8%	5.80%	38.6%	52.5%	50.0%	0.75	0.45	0.76	0.1%	9.5%

Notes

1. Based on average of Beginning of Year values and End of Year values.
2. Based on Value Line's estimated 2012 dividends.
3. Based on calendar year dividends.
4. Value Line reports Questar's beta as "NMF" (not meaningful). Questar's unlevered beta is average of remaining members of peer group.
5. Calculations of the unlevered beta and the relevered beta use the Hamada Equation.

Displayed values have not been rounded.

Staff/1304
Storm/5

Staff/1304
Storm/6

UG 221 Northwest Natural

30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio Stage 3 Annual Growth Rate of 5.8 Percent

		Unadjusted ROE[1] (IRR) (A)	Average Recent Share Price (B)	Dividend Yield @ Average Recent Share Price[2] (C)	2013-17 Average Annual Dividend Growth Rate[3] (D)	2013-17 Average Annual EPS[4] Growth Rate[3] (E)	2018-22 Average Annual Dividend Growth Rate[3] (F)	2018-22 Average Annual EPS[4] Growth Rate[3] (G)	2023-42 Average Annual Dividend & EPS[4] Growth Rates[3] (H)	Terminal Value as % of Total Valuation[1] (I)	2012 Common Equity % of Capital Structure (J)	Test Year Common Equity % of Capital Structure (K)	Value Line Beta[5] (L)	Unlevered Beta[5] (Business Risk) (M)	Beta Relevered to Test Year Capital Structure[6] (N)	ROE Adjustment (Hamada Equation) (O)	ROE[1] Adjusted for Divergent Capital Structures (P)
Staff's Peer Utilities																	
1	Laclede Group	8.9%	$41.02	4.0%	2.2%	3.0%	4.3%	4.6%	5.80%	37.2%	63.0%	50.0%	0.60	0.43	0.72	0.5%	9.4%
2	Northwest Natural	9.3%	$46.55	3.8%	2.2%	7.7%	4.3%	6.2%	5.80%	43.7%	55.0%	50.0%	0.60	0.38	0.65	0.2%	9.5%
3	Piedmont Natural Gas	8.9%	$32.27	3.7%	3.2%	3.6%	4.7%	5.0%	5.80%	39.3%	57.0%	50.0%	0.70	0.46	0.78	0.3%	9.2%
4	Questar	9.9%	$19.39	3.4%	5.5%	9.6%	5.7%	7.7%	5.80%	44.5%	52.5%	50.0%	NMF	0.40	0.66	0.1%	10.0%
5	WGL Holdings	8.8%	$41.54	3.8%	2.4%	2.9%	4.4%	4.7%	5.80%	38.7%	67.5%	50.0%	0.65	0.50	0.81	0.7%	9.5%
	Group Average	9.1%		3.8%	3.1%	5.4%	4.7%	5.6%	5.80%	40.7%	59.0%	50.0%	0.64	0.44	0.72	0.4%	9.5%
Northwest Natural's Peer Utilities																	
1	Alliant Energy*#	10.0%	$42.96	4.2%	5.1%	5.4%	5.5%	5.5%	5.80%	32.0%	49.0%	50.0%	0.75	0.41	0.74	-0.1%	9.9%
2	Black Hills*#	9.2%	$33.71	4.4%	1.5%	4.0%	4.1%	5.1%	5.80%	36.2%	54.0%	50.0%	0.85	0.54	0.90	0.2%	9.5%
3	Consolidated Edison*	8.7%	$58.62	4.1%	1.2%	2.2%	4.0%	4.3%	5.80%	37.2%	51.5%	50.0%	0.60	0.37	0.61	0.1%	8.8%
4	DTE Energy*#	9.8%	$54.35	4.5%	3.7%	4.6%	4.9%	5.2%	5.80%	31.8%	51.0%	50.0%	0.75	0.46	0.76	0.0%	9.9%
5	Northwest Natural Gas	9.3%	$46.55	3.8%	2.2%	7.7%	4.3%	6.2%	5.80%	43.7%	55.0%	50.0%	0.60	0.38	0.65	0.2%	9.5%
6	NiSource#	8.9%	$23.94	3.8%	0.0%	6.4%	3.4%	6.3%	5.80%	47.9%	45.0%	50.0%	0.85	0.49	0.78	-0.3%	8.6%
7	Piedmont Natural Gas	8.9%	$32.27	3.7%	3.2%	3.6%	4.7%	5.0%	5.80%	39.3%	57.0%	50.0%	0.70	0.46	0.78	0.3%	9.2%
8	Pepco Holdings*#	10.6%	$19.37	5.6%	1.7%	6.8%	3.9%	6.1%	5.80%	29.4%	51.0%	50.0%	0.80	0.48	0.81	0.1%	10.7%
9	SCANA*#	9.4%	$45.18	4.4%	2.1%	4.5%	4.3%	5.4%	5.80%	35.9%	46.0%	50.0%	0.70	0.39	0.65	-0.2%	9.2%
10	Sempra Energy*#	9.8%	$59.41	3.5%	6.2%	7.6%	6.0%	6.5%	5.80%	39.1%	50.5%	50.0%	0.80	0.46	0.81	0.0%	9.8%
11	Southwest Gas#	9.4%	$42.77	2.8%	7.7%	9.3%	6.3%	7.2%	5.80%	47.4%	55.5%	50.0%	0.75	0.49	0.81	0.3%	9.7%
12	Vectren*#	10.5%	$29.22	4.8%	3.3%	7.7%	5.0%	6.5%	5.80%	32.5%	48.0%	50.0%	0.70	0.41	0.68	-0.1%	10.4%
13	Wisconsin Energy*#	10.3%	$34.59	3.5%	10.3%	5.0%	7.3%	5.3%	5.80%	28.5%	46.0%	50.0%	0.65	0.37	0.61	-0.2%	10.1%
14	Xcel Energy*	9.9%	$26.52	4.0%	6.9%	2.6%	6.2%	4.5%	5.80%	27.5%	46.5%	50.0%	0.65	0.37	0.61	-0.2%	9.8%
	Group Average	9.6%		4.1%	3.9%	5.5%	5.0%	5.7%	5.80%	36.3%	50.4%	50.0%	0.73	0.43	0.73	0.0%	9.6%
	Average of 10 Utilities classified by Value Line as Electric Utilities *	9.8%		4.3%	4.2%	5.0%	5.1%	5.4%	5.80%	33.0%	0.49	0.50	0.73	0.43	0.72	0.0%	9.8%
	Average of 4 Utilities classified by Value Line as Natural Gas Utilities	9.1%		3.5%	3.2%	6.7%	4.7%	6.2%	5.80%	44.6%	0.53	0.50	0.73	0.46	0.76	0.1%	9.2%
	Average of 10 Utilities with an S&P Issuer or Long-term Credit Rating <u>below</u> "A-" #	9.8%		4.1%	4.2%	6.1%	5.1%	5.9%	5.80%	36.1%	0.50	0.50	0.76	0.45	0.76	0.0%	9.8%
	Average of 4 Utilities with an S&P Issuer or Long-term Credit Rating <u>above</u> "BBB+"	9.2%		3.9%	3.4%	4.0%	4.8%	5.0%	5.80%	36.9%	0.53	0.50	0.64	0.40	0.66	0.1%	9.3%

Notes

1. Based on average of Beginning of Year values and End of Year values. ROE is unadjusted for divergent capital structures.
2. Based on Value Line's estimated 2012 dividends.
3. Based on calendar year dividends and Earnings per Share (EPS).
4. Earnings per Share
5. Value Line reports Questar's beta as "NMF" (not meaningful). Questar's unlevered beta is average of remaining members of peer group.
6. Calculations of the unlevered beta and the relevered beta use the Hamada Equation.

Displayed values have not been rounded.

CASE: UG 221
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1305

Exhibits in Support Of Opening Testimony

May 3, 2012

Regulatory Research Associates

REGULATORY FOCUS

Staff/1305
Storm/1

April 5, 2012

MAJOR RATE CASE DECISIONS--JANUARY-MARCH 2012

The average return on equity (ROE) authorized electric utilities in the first quarter of 2012 was 10.84% (12 observations), significantly higher than 10.22% in calendar-2011. This increase was largely driven by several surcharge/rider generation cases in Virginia that incorporate ROE premiums. Virginia statutes authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects (see the Virginia Commission Profile). Excluding these Virginia surcharge/rider generation cases from the data, the average authorized electric ROE approximated 10.3% for the first quarter of 2012. The average ROE authorized gas utilities for the first three months of 2012 was 9.63% (five observations), slightly lower than the 9.92% in calendar-2011. We note that this report utilizes the simple mean for the return averages.

After reaching a low in the early-2000's, the number of rate case decisions for energy companies has generally increased over the last several years, although the number of decisions declined in 2011. There were 84 electric and gas rate decisions in 2011, versus 126 in 2010, 95 in 2009, and only 32 back in 2001. Increased costs, including environmental compliance expenditures, the need for generation and delivery infrastructure upgrades and expansion, renewable generation mandates, and higher employee benefit expenses argue for the continuation of an active rate case schedule over the next few years.

As a result of electric industry restructuring, certain states have unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction over the revenue requirement and return parameters for delivery operations only (which we footnote in our chronology beginning on page 5), thus complicating historical data comparability. We also note that while the heightened business risk associated with the sluggish economy may have increased corporate capital costs, average authorized ROEs have declined slightly since 2008. In fact, some state commissions have cited customer hardship as a significant factor influencing their equity return authorizations.

The table on page 2 shows the average ROE authorized in major electric and gas rate decisions annually since 1990, and by quarter since 2006, followed by the number of observations in each period. The tables on page 3 show the composite electric and gas industry data for all major cases summarized annually since 1998 and by quarter for the past nine quarters. The individual electric and gas cases decided in the first quarter of 2012 are listed on pages 4-5, with the decision date (generally the date on which the final order was issued) shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return (ROR), return on equity (ROE), and percentage of common equity in the adopted capital structure. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study. We note that the cases and averages included in this study may be slightly different from those in our on-line Rate Case History database, with any differences reflecting, for example, this study's inclusion of ROE determinations that are rendered in cost-of-capital-only proceedings in California.

Dennis Sperduto

Average Equity Returns Authorized January 1990 - March 2012

Year	Period	Electric Utilities ROE %	(# Cases)	Gas Utilities ROE %	(# Cases)
1990	Full Year	12.70	(44)	12.67	(31)
1991	Full Year	12.55	(45)	12.46	(35)
1992	Full Year	12.09	(48)	12.01	(29)
1993	Full Year	11.41	(32)	11.35	(45)
1994	Full Year	11.34	(31)	11.35	(28)
1995	Full Year	11.55	(33)	11.43	(16)
1996	Full Year	11.39	(22)	11.19	(20)
1997	Full Year	11.40	(11)	11.29	(13)
1998	Full Year	11.66	(10)	11.51	(10)
1999	Full Year	10.77	(20)	10.66	(9)
2000	Full Year	11.43	(12)	11.39	(12)
2001	Full Year	11.09	(18)	10.95	(7)
2002	Full Year	11.16	(22)	11.03	(21)
2003	Full Year	10.97	(22)	10.99	(25)
2004	Full Year	10.75	(19)	10.59	(20)
2005	Full Year	10.54	(29)	10.46	(26)
	1st Quarter	10.38	(3)	10.63	(6)
	2nd Quarter	10.68	(6)	10.50	(2)
	3rd Quarter	10.06	(7)	10.45	(3)
	4th Quarter	10.39	(10)	10.14	(5)
2006	**Full Year**	**10.36**	(26)	**10.43**	(16)
	1st Quarter	10.27	(8)	10.44	(10)
	2nd Quarter	10.27	(11)	10.12	(4)
	3rd Quarter	10.02	(4)	10.03	(8)
	4th Quarter	10.56	(16)	10.27	(15)
2007	**Full Year**	**10.36**	(39)	**10.24**	(37)
	1st Quarter	10.45	(10)	10.38	(7)
	2nd Quarter	10.57	(8)	10.17	(3)
	3rd Quarter	10.47	(11)	10.49	(7)
	4th Quarter	10.33	(8)	10.34	(13)
2008	**Full Year**	**10.46**	(37)	**10.37**	(30)
	1st Quarter	10.29	(9)	10.24	(4)
	2nd Quarter	10.55	(10)	10.11	(8)
	3rd Quarter	10.46	(3)	9.88	(2)
	4th Quarter	10.54	(17)	10.27	(15)
2009	**Full Year**	**10.48**	(39)	**10.19**	(29)
	1st Quarter	10.66	(17)	10.24	(9)
	2nd Quarter	10.08	(14)	9.99	(11)
	3rd Quarter	10.26	(11)	9.93	(4)
	4th Quarter	10.30	(17)	10.09	(12)
2010	**Full Year**	**10.34**	(59)	**10.08**	(37)
	1st Quarter	10.32	(13)	10.10	(5)
	2nd Quarter	10.12	(10)	9.88	(5)
	3rd Quarter	10.00	(7)	9.65	(2)
	4th Quarter	10.34	(11)	9.88	(4)
2011	**Full Year**	**10.22**	(41)	**9.92**	(16)
2012	**1st Quarter**	**10.84**	(12)	**9.63**	(5)

Electric Utilities--Summary Table*

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Eq. as % Cap. Struc.	(# Cases)	Amt. $ Mil.	(# Cases)
1998	Full Year	9.44	(9)	11.66	(10)	46.14	(8)	-429.3	(31)
1999	Full Year	8.81	(18)	10.77	(20)	45.08	(17)	-1,683.8	(30)
2000	Full Year	9.20	(12)	11.43	(12)	48.85	(12)	-291.4	(34)
2001	Full Year	8.93	(15)	11.09	(18)	47.20	(13)	14.2	(21)
2002	Full Year	8.72	(20)	11.16	(22)	46.27	(19)	-475.4	(24)
2003	Full Year	8.86	(20)	10.97	(22)	49.41	(19)	313.8	(12)
2004	Full Year	8.44	(18)	10.75	(19)	46.84	(17)	1,091.5	(30)
2005	Full Year	8.30	(26)	10.54	(29)	46.73	(27)	1,373.7	(36)
2006	Full Year	8.24	(24)	10.36	(26)	48.67	(23)	1,465.0	(42)
2007	Full Year	8.22	(38)	10.36	(39)	48.01	(37)	1,401.9	(46)
2008	Full Year	8.25	(35)	10.46	(37)	48.41	(33)	2,899.4	(42)
2009	Full Year	8.23	(38)	10.48	(39)	48.61	(37)	4,192.3	(58)
	1st Quarter	7.95	(17)	10.66	(17)	48.36	(16)	2,010.0	(19)
	2nd Quarter	7.95	(15)	10.08	(14)	47.07	(13)	937.5	(19)
	3rd Quarter	8.16	(12)	10.26	(11)	49.52	(11)	730.6	(18)
	4th Quarter	7.95	(15)	10.30	(17)	49.00	(14)	1,889.6	(21)
2010	**Full Year**	**7.99**	**(59)**	**10.34**	**(59)**	**48.45**	**(54)**	**5,567.7**	**(77)**
	1st Quarter	8.12	(13)	10.32	(13)	49.05	(13)	610.5	(15)
	2nd Quarter	8.01	(10)	10.12	(10)	46.36	(10)	1,055.9	(12)
	3rd Quarter	8.09	(7)	10.00	(7)	48.33	(7)	642.4	(11)
	4th Quarter	7.61	(11)	10.34	(11)	47.91	(10)	544.7	(15)
2011	**Full Year**	**7.95**	**(41)**	**10.22**	**(41)**	**47.97**	**(40)**	**2,853.5**	**(53)**
2012	**1st Quarter**	**8.00**	**(11)**	**10.84**	**(12)**	**50.20**	**(10)**	**970.6**	**(16)**

Gas Utilities--Summary Table*

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Eq. as % Cap. Struc.	(# Cases)	Amt. $ Mil.	(# Cases)
1998	Full Year	9.46	(10)	11.51	(10)	49.50	(10)	93.9	(20)
1999	Full Year	8.86	(9)	10.66	(9)	49.06	(9)	51.0	(14)
2000	Full Year	9.33	(13)	11.39	(12)	48.59	(12)	135.9	(20)
2001	Full Year	8.51	(6)	10.95	(7)	43.96	(5)	114.0	(11)
2002	Full Year	8.80	(20)	11.03	(21)	48.29	(18)	303.6	(26)
2003	Full Year	8.75	(22)	10.99	(25)	49.93	(22)	260.1	(30)
2004	Full Year	8.34	(21)	10.59	(20)	45.90	(20)	303.5	(31)
2005	Full Year	8.25	(29)	10.46	(26)	48.66	(24)	458.4	(34)
2006	Full Year	8.51	(16)	10.43	(16)	47.43	(16)	444.0	(25)
2007	Full Year	8.12	(32)	10.24	(37)	48.37	(30)	813.4	(48)
2008	Full Year	8.48	(30)	10.37	(30)	50.47	(30)	884.8	(41)
2009	Full Year	8.15	(28)	10.19	(29)	48.72	(28)	475.0	(37)
	1st Quarter	8.20	(10)	10.24	(9)	50.27	(9)	177.3	(11)
	2nd Quarter	7.80	(11)	9.99	(11)	46.31	(11)	230.2	(12)
	3rd Quarter	8.13	(4)	9.93	(4)	49.00	(4)	290.5	(10)
	4th Quarter	7.84	(13)	10.09	(13)	49.11	(14)	118.7	(16)
2010	**Full Year**	**7.95**	**(38)**	**10.08**	**(37)**	**48.56**	**(38)**	**816.7**	**(49)**
	1st Quarter	8.07	(6)	10.10	(5)	52.47	(4)	48.3	(9)
	2nd Quarter	8.05	(4)	9.88	(5)	54.45	(3)	234.0	(7)
	3rd Quarter	8.09	(2)	9.65	(2)	49.44	(2)	26.5	(4)
	4th Quarter	8.07	(5)	9.88	(4)	52.03	(4)	127.5	(11)
2011	**Full Year**	**8.57**	**(16)**	**9.92**	**(16)**	**48.04**	**(13)**	**436.3**	**(31)**
2012	**1st Quarter**	**7.63**	**(5)**	**9.63**	**(5)**	**51.40**	**(5)**	**125.3**	**(5)**

ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
2011	***FULL-YEAR: AVERAGES/TOTAL***	**7.95**	**10.22**	**47.97**		**2,853.5**
	MEDIAN	**8.11**	**10.15**	**47.87**		**---**
	OBSERVATIONS	**41**	**41**	**40**		**53**
1/3/12	Appalachian Power (VA)	---	11.40	---	2/13-YE	26.1 (B,1)
1/10/12	PacifiCorp (ID)	---	---	---	12/10	34.0 (B,Z)
1/25/12	Duke Energy Carolinas (SC)	8.10	10.50	53.00	12/10-YE	92.8 (B)
1/27/12	Duke Energy Carolinas (NC)	8.11	10.50	53.00	12/10-YE	368.0 (B,2)
2/2/12	Virginia Electric and Power (VA)	8.77	11.40	53.25	3/13-A	34.1 (3)
2/15/12	Indiana Michigan Power (MI)	6.84	10.20	42.07 *	12/12-A	14.6 (B)
2/23/12	Idaho Power (OR)	7.76	9.90	49.90	12/11-A	1.8 (B)
2/22/12	Florida Power (FL)	---	---	---	---	150.0 (B,4)
2/27/12	Gulf Power (FL)	6.39	10.25	38.50 *	12/12-A	68.1 (I,Z)
2/29/12	Northern States Power-Minnesota (ND)	---	10.40	---	12/11	15.7 (B,I,Z)
3/16/12	Virginia Electric and Power (VA)	9.03	12.40	53.25	3/13-A	6.4 (5)
3/20/12	Virginia Electric and Power (VA)	8.48	11.40	53.25	3/13-A	-4.3 (6)
3/21/12	NorthWestern Corp. (MT)	---	---	---	A	39.1 (I,Z,7)
3/23/12	Virginia Electric and Power (VA)	8.48	11.40	53.25	3/13-A	46.8 (8)
3/29/12	Northern States Power-Minnesota (MN)	8.32	10.37	52.56	12/11-A	72.9 (B,I,Z)
3/30/12	PacifiCorp (WA)	7.74	---	---	12/10	4.5 (B)
2012	***1ST QUARTER: AVERAGES/TOTAL***	**8.00**	**10.84**	**50.20**		**970.6**
	MEDIAN	**8.11**	**10.50**	**53.00**		**---**
	OBSERVATIONS	**11**	**12**	**10**		**16**

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
2011	***FULL-YEAR: AVERAGES/TOTAL***	**8.57**	**9.92**	**48.04**		**436.3**
	MEDIAN	**8.09**	**10.03**	**52.30**		**---**
	OBSERVATIONS	**16**	**16**	**13**		**31**
1/10/12	Ameren Illinois (IL)	8.33	9.06	53.27	12/12-A	32.2
1/10/12	North Shore Gas (IL)	7.43	9.45	50.00 (9)	12/12-A	1.9
1/10/12	Peoples Gas Light & Coke (IL)	6.94	9.45	49.00 (9)	12/12-A	57.8
1/23/12	Piedmont Natural Gas (TN)	7.98	10.20	52.71	2/13-A	11.9 (B)
1/31/12	New Mexico Gas (NM)	7.48	10.00	52.00	9/10-YE	21.5 (B)
2012	***1ST QUARTER: AVERAGES/TOTAL***	**7.63**	**9.63**	**51.40**		**125.3**
	MEDIAN	**7.48**	**9.45**	**52.00**		**---**
	OBSERVATIONS	**5**	**5**	**5**		**5**

FOOTNOTES

A- Average
B- Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
D- Applies to electric delivery only
E- Estimated
I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
YE- Year-end
Z- Rate change implemented in multiple steps.
* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Rate increase authorized through a generation rider/adjustment clause.
(2) The approved/stipulated $368 million base rate increase includes $51 million that the company is to defer until its next rate case, representing a cash return on construction work in progress.
(3) Increase authorized through a surcharge, Rider W, which reflects in rates the investment in the Warren County Power Station and associated transmission facilities.
(4) PSC adopted a settlement that addresses base rates and issues related to the company's nuclear plants. Effective January 2013, the company is to increase base rates by $150 million, and base rates would then be frozen through 2016, except as otherwise provide for by the settlement.
(5) Increase authorized through a surcharge (Rider B) related to generation conversion project investments.
(6) Rate change approved through surcharge (Rider R) related to the Bear Garden Generating Station.
(7) Case is a limited-issue rate proceeding, covering NorthWestern's incremental investment in the Dave Gates (formerly Mill Creek) generating facility.
(8) Increase authorized through a surcharge, Rider S, associated with the Virginia City Hybrid Energy Center.
(9) Component of an "imputed" capital structure.

Dennis Sperduto

CASE: UG 221
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1400

Opening Testimony

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Jorge Ordonez. I am employed by the Oregon Public Utility Commission (OPUC) as the Senior Financial Economist in the Economic and Policy Analysis Section. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualifications Statement is found in Exhibit Staff/1401 Ordonez /1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to propose the spread (Rate Spread) of Northwest Natural Gas Company's ("NW Natural" or "Company") revenue requirement, including the review of the Company's Long-Run Incremental Cost (LRIC) Study.

In thoroughly conducting the aforementioned review, Staff referred to the Company's initial filing and approximately 76 data requests pertaining to LRIC Study and Rate Spread.

Q. WHICH STAFF MEMBER IS REVIEWING AND PROPOSING CHANGES TO THE COMPANY'S RATE DESIGN?

A. In Exhibit Staff/1500 with supporting exhibits, Dr. George Compton is reviewing and proposing changes to the Company's rate design, including the merger of some customer schedules.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes, I have prepared Staff Exhibit/1401 consisting of one page (Witness Qualification Statement), Staff Exhibit/1402 consisting of four pages (Staff Cost of Service and Rate Spread), Staff Exhibit/1403 consisting of four pages (NW Natural's Updated LRIC), Staff Exhibit/1404 consisting of six pages (Exhibits related to the LRIC of Gas Storage), Staff Exhibit/1405 consisting of two pages (Exhibits Related to the LRIC of Gas Transmission), Staff Exhibit/1406 consisting of 18 pages (Exhibits Related to the LRIC of Distribution), and Staff Exhibit/1407 consisting of six pages (other Exhibits related to Rate Spread).

SUMMARY RECOMMENDATION

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS?

A. As for the Company's LRIC, I recommend that the Commission conclude that NW Natural's LRIC study is reasonable, with the exception of NW Natural's LRIC of Distribution Mains, [1] for which I recommend that the Commission require NW Natural to provide a study that relates the existing length of distribution mains as a function of customer schedules.

Regarding the Company's rate spread, for illustrative purposes and based on a hypothetical overall rate increase of approximately 15.20% (approximately $43.68 million), I propose the rate increases represented in column "D" of Table 1. As shown in the highlighted part of Table 1, the main differences

[1] The Company's LRIC Study covers the functions of storage, transmission, and distribution. The distribution function, in turn, comprises the following sub-functions: distribution mains, distribution services, distribution meters & regulators, and distribution accounting.

between Staff's and the Company's rate spread are in three schedules: Schedules "3C Firm Sales," "3I Firm Sales," and "31C Firm Sales.

Table 1

Schedule	Cost of Service (Cost) Versus Revenues Collected Under Current Rates (Revenue) Cost > Revenue (+) Cost < Revenue (-)		Proposed Increase (+)/Decrease (-) from Current Rates	
	NW Natural[2]	Staff[3]	NW Natural[4, 5]	Staff[6]
	(A)	(B)	(C)	(D)
1R	**145.9%**	**134.1%**	**19.0%**	**N/A**[7]
1C	30.3%	24.6%	14.9%	20.9%
2R	36.0%	31.4%	17.7%	20.9%
3C Firm Sales	**-1.6%**	**9.5%**	**15.2%**	**6.8%**
3I Firm Sales	**-21.6%**	**-0.3%**	**15.2%**	**3.0%**
31C Firm Sales	**-44.6%**	**-45.5%**	**7.6%**	**0.0%**
31C Firm Transmission	-74.8%	-68.4%	0.0%	0.0%
31C Interruptible Sales	-88.6%	-83.7%	0.0%	0.0%
31I Firm Sales	-59.6%	-50.7%	0.0%	0.0%
31I Firm Transmission	-76.2%	-71.0%	0.0%	0.0%
31I Interruptible Sales	-58.8%	-42.3%	0.0%	0.0%
32C Firm Sales	-37.3%	-40.8%	0.0%	0.0%
32I Firm Sales	-79.1%	-75.1%	0.0%	0.0%
32 Firm Transmission	-82.3%	-78.5%	0.0%	0.0%
32C Interruptible Sales	-84.1%	-74.1%	0.0%	0.0%
32I Interruptible Sales	-82.2%	-71.6%	0.0%	0.0%
32 Interruptible Transmission	-77.0%	-58.5%	0.0%	0.0%
Total	15.2%	15.2%	15.2%	15.2%

2 See Exhibit Staff/1402 Ordonez/1-2, line 45.
3 See Exhibit Staff/1402 Ordonez/1-2, line 54.
4 See Exhibit NWN/1102 Feingold/1-2, line 13.
5 See Exhibit Staff/1402 Ordonez/1-2, line 62.
6 See Exhibit Staff/1402 Ordonez/1-2, line 66.
7 In Exhibit Staff/1500, Dr. George Compton is proposing to terminate the 1R schedule, and include all of its customers with Schedule 2R.

If the overall increase from the revenues collected under current rates is significantly lower than the approximately $43.68 million requested, or if there is a decrease from revenues collected under current rates, I will likely recommend that the Commission modestly decrease rates for customers schedules "31C Firm Transmission" through "32 Interruptible Transmission" and increase rates for customer schedules "1R," "1C," and "2R."[8] Staff intends to work with NW Natural to obtain either the Company's functionalized revenue requirement after Staff adjustments or the tools necessary for Staff to perform such functionalization.

Nevertheless, this position should not be perceived as setting precedent for future rate cases, in which Staff may review specific parts of the Company's LRIC Study and may propose changes based on contemporaneous facts, methodologies, trends, etc. Additionally, as noted by the Commission in Order No. 98-374 of Docket No. UM 827, calculating the marginal cost is as much an art as it is a science.

[8] Any increase or decrease from the revenues collected under current rates may impact my recommendation based on the function (e.g., storage, transmission, distribution, etc.) affected by such an increase or decrease.

NW NATURAL'S LRIC STUDY

Q. DID NW NATURAL PROVIDE AN LRIC STUDY AS SUPPORT FOR THE COMPANY'S RATE SPREAD AND RATE DESIGN?

A. Yes. In Exhibits NWN/1100-1102, NW Natural presented, among other things,[9] an LRIC study (Initial LRIC Study) in support of the allocation of its proposed revenue requirement among rate schedules.

The Company's LRIC Study covers the functions of storage, transmission, and distribution.[10, 11, 12]

LRIC OF GAS STORAGE

Q. PLEASE EXPLAIN NW NATURAL'S LRIC OF GAS STORAGE.

A. The Company asserts that: "[its] 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."[13]

NW Natural also asserts that: "[t]herefore, 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)."[14]

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[9] Exhibits NWN/1100-1102 cover NW Natural's LRIC Study, rate spread and rate design.
[10] The distribution function, in turn, comprises the following sub-functions: distribution mains, distribution services, distribution meters & regulators, and distribution accounting.
[11] See Exhibit NWN/1101 Feingold/1-2 for the results of the Company's LRIC Study.
[12] Also see Exhibit Staff/1402 Ordonez/3-4 and Staff Data Request 225 attached to this testimony as Exhibit Staff/1403 Ordonez/1-4 for the Company's Updated LRIC.
[13] See Exhibit NWN/1100 Feingold/16, lines 4-6.
[14] See Exhibit NWN/1100 Feingold/16, lines 6-9.

The Company further indicates that: "[s]torage service reflects the physical structure used to store the natural gas underground [(Gas Storage Capacity Cost, Energy Portion of Gas Storage Cost, or Commodity Portion of Gas Storage Cost)], the ability to withdraw that gas when needed on a design day [(Gas Deliverability Portion of Gas Storage Cost or Demand Portion of Gas Storage Cost)], 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." [15]

Q. WHAT IS NW NATURAL'S LRIC OF GAS STORAGE?

A. In its Initial LRIC Study, the Company represented an LRIC of Gas Storage of approximately $55 million,[16] which was broken down into an LRIC of Gas Storage Capacity (LRIC of Gas Storage Energy or LRIC of Gas Storage Commodity) of approximately $8 million[17, 18] and an LRIC of Gas Storage Deliverability (LRIC of Gas Storage Demand) of approximately $47 million.[19, 20]

Q. HOW DID THE COMPANY BREAK DOWN THE LRIC OF GAS STORAGE OF $55 MILLION INTO AN LRIC OF GAS STORAGE CAPACITY OF $8 MILLION AND AN LRIC OF GAS STORAGE DELIVERABILITY OF $47 MILLION?

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15 See Exhibit NWN/1100 Feingold/16, lines 11-15.
16 $55 million is approximately the sum of $46,697,054 (row 13, column A) and $8,265,500 (row 14, column A) of Exhibit NWN/1101 Feingold/1.
17 The number represented by the Company is $8,265,500.
18 See Exhibit NWN/1101 Feingold/1, line 14, column A.
19 The number represented by the Company is $46,697,054
20 See Exhibit NWN/1101 Feingold/1, line 13, column A.

A. $8 million is approximately 15 percent of $55 million and $47 million is approximately 85 percent[21] of $55 million. 15 percent is the proportion of the test-year gross storage plant for "Wells Equipment" of approximately $39 million[22, 23, 24] of the test-year "Total Gross Storage Plant" of approximately of $252 million.[25, 26, 27] The remaining test-year "Total Gross Storage Plant" of approximately $212 million[28, 29] ($252 million - $39 million) divided by $252 million results in approximately 85 percent.

Per the Company's response to Staff Data Request 221,[30] the Company represented that all components of the Total Gross Storage Plant were considered demand-related (deliverability-related) except the Gross Storage Plant for "Wells Equipment,"[31, 32] which was considered capacity-related (energy- or commodity-related).

Q. PLEASE COMMENT ON NW NATURAL'S LRIC OF GAS STORAGE?

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21 85 percent is approximately the quotient obtained by dividing $212 million by $251 million.
22 The exact number is $39,340,908.
23 See Exhibit NWN/1101 Feingold/3, row "Storage - Energy," column A.
24 See NW Natural's response to Staff Data Request 220, attached to this testimony as Exhibit Staff/1404 Ordonez/1-2. (Staff/1404 Ordonez/2, sum of FERC Accounts 352 through 362.12).
25 The exact number is $251,757,033.
26 See Exhibit NWN/1101 Feingold/3, row "Total," column A.
27 See NW Natural's response to Staff Data Request 220, attached to this testimony as Exhibit Staff/1404 Ordonez/1-2 (Staff/1404 Ordonez/2, row "Total on Feingold LRIC").
28 The exact number is $212,416,125.
29 See Exhibit NWN/1101 Feingold/3, row "Storage - Demand," column A.
30 See NW Natural's response to Staff Data Request 221 (initial and supplemental), attached to this testimony as Exhibit Staff/1404 Ordonez/3-6.
31 See NW Natural's supplemental response to Staff Data Request 221, attached to this testimony as Exhibit Staff/1404 Ordonez/4-5.
32 See Exhibit Staff/1404 Ordonez/4, Account No. "352, 362".

A. Staff has no comments at this time[33] besides noting that the Company updated its LRIC Study (Update LRIC) in response to Staff Data Request 225,[34] filed on February 8, 2012. This Updated LRIC Study provides an updated LRIC of Gas Storage of approximately $32 million, which comprises an updated LRIC of Storage Gas Deliverability (LRIC of Gas Storage Demand) of approximately $27 million[35, 36] and an updated LRIC of Gas Storage Capacity (LRIC of Gas Storage Energy or LRIC of Gas Storage Commodity) of approximately $5 million.[37, 38]

Q. HOW DID THE COMPANY ALLOCATE THE LRIC OF GAS STORAGE AMONG CUSTOMERS CLASSES AND SCHEDULES?

A. In the Company's Updated LRIC Study,[39] NW Natural allocated its LRIC of Gas Deliverability (LRIC of Gas Storage Demand) of approximately $27 million (approximately 85 percent) based on "Design Day Sales,"[40] and the LRIC of Storage Capacity (LRIC of Gas Storage Energy or LRIC of Gas Storage Commodity) of approximately $5 million (approximately 15 percent) based on "Winter-4 Storage Volume-Sales,"[41] which is defined as the firm sales volumes for each of NW Natural's rate classes in the four winter months of December

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33 This position should not be seen as setting a precedent for future rate cases, in which Staff may review specific parts of the Company's LRIC of Gas Storage and may propose changes based on contemporaneous facts, methodologies, trends, etc.

34 See NW Natural's response to Staff Data Request 225 attached to this testimony as Exhibit Staff/1403 Ordonez/1-4.

35 The number represented by the Company is $27,725,825.

36 See Exhibit Staff/1403, Ordonez/3, line 13, column A.

37 The number represented by the Company is $4,751,900.

38 See Exhibit Staff/1403, Ordonez/3, line 14, column A.

39 See NW Natural's response to Staff Data Request 225 attached to this testimony as Exhibit Staff/1403 Ordonez/1-4.

40 See Exhibit Staff/1403 Ordonez/3, line 6.

41 See Exhibit Staff/1403 Ordonez/3, line 4.

through March in excess of the average monthly sales volumes in the months of April through November.

LRIC OF GAS TRANSMISSION

Q. PLEASE EXPLAIN NW NATURAL'S LRIC OF GAS TRANSMISSION.

A. To estimate NW Natural's LRIC of Gas Transmission of approximately $2 million, [42, 43] the Company used a proxy transmission investment of approximately $45 million,[44, 45] which comprises the Mid-Willamette Valley Feeder (MWVF) project of approximately $32 million[46, 47] and the Corvallis Loop project of approximately $13 million.[48, 49]

The value of $1,107[50] per Dth/day was estimated by dividing the proxy transmission investment of approximately $45 million by the provided "Total Additional Design Day Capacity" of 41,000[51] Dth/Day.

Then, the Company multiplied the $1,107 per Dth/day by an Economic Carrying Charge Rate (ECCR) of 8.68%[52] to arrive at the annual incremental cost of transmission per design day Dth ("Annual Cost per Dth/Design Day"[53])

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42 The number represented by the Company is $1,681,326.
43 See Exhibit Staff/1403 Ordonez/3, line 18, column A.
44 The number represented by the Company is $45,400,000.
45 See Exhibit NWN/1101 Feingold/5, line 3, column (A).
46 The number represented by the Company is $32,600,000.
47 See Exhibit NWN/1101 Feingold/5, line 2, column (A).
48 The number represented by the Company is $12,800,000.
49 See Exhibit NWN/1101 Feingold/5, line 1, column (A).
50 See Exhibit NWN/1101 Feingold/5, line 8.
51 See Exhibit NWN/1101 Feingold/5, line 5.
52 See Exhibit NWN/1101 Feingold/4, column (B).
53 See header of column (C) in Exhibit NWN/1101 Feingold/4.

of $96.11 per Dth/day[54] for all rate schedules except the rate schedules for interruptible customers.[55, 56]

Q. WHY DID THE COMPANY NOT ASSUME ANY INCREMENTAL COST OF GAS TRANSMISSION FOR INTERRUPTIBLE CUSTOMERS?

A. In NW Natural's response to Staff Data Request 274,[57] the Company represented that: "a gas utility such as NW Natural does not install firm pipeline capacity to serve its interruptible customers. The existence of interruptible customers enables the gas utility to serve the full capacity requirements of its firm service customers. Therefore, within the context of NW Natural's LRIC Study, an increase in interruptible service does not cause NW Natural to incur incremental firm capacity costs to serve this interruptible load because it does not design and expand its gas pipeline system over time to serve interruptible customers." [58]

Q. DO YOU AGREE WITH THE COMPANY'S REPRESENTATION?

A. No. The effects of the chosen timing of facitliy reinforcements on interruptible customers and the history of actual service interruptions of interruptible customers, leads me to disagree with the Company's representation.

Q. DO YOU HAVE ANY EVIDENCE TO SUPPORT YOUR OBSERVATIONS?

A. Yes.

As represented by the Company in Exhibit NWN/600 Yoshihara/3, lines 4-20:

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54 See Exhibit NWN/1101 Feingold/4, column (C).
55 The Company assumed an annual cost for interruptible customers of $0 per Dth/day.
56 See Exhibit NWN/1101 Feingold/4, column (C), lines 8,11,15,16, and 17.
57 See NW Natural's response to Staff Data Request 274 attached to this testimony as Exhibit Staff/1405.
58 See Exhibit Staff/1405 Ordonez/2.

> 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 consist 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 winder already exceeds normal design requirement. <u>For the past several years, interruptible customers in this area have experienced partial curtailment as temperatures in the area drop below 32 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</u> [emphasis added] [(with the Corvallis Loop Project)], and also begin to move forward on the Mid-Willamette Valley Feeder Project that will increase peak day delivery capability in the west end of the Albany-Corvallis corridor".

Also, in NW Natural's response to Staff Data Request 275,[59] the Company provided the amount of time (approximately 0.40%[60]) that interruptible customers experienced curtailment in the five-year period beginning in 2007 through 2011.

Therefore, it is not unreasonable for interruptible customers to share some of the gas transmission revenue requirement (embedded gas transmission costs), as I will describe later in the Gas Transmission Cost of Service part of my testimony.

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[59] See the text of NW Natural's response to Staff Data Request 275 attached to this testimony as Exhibit Staff/1407 Ordonez/6.

[60] See MS Excel spreadsheet: "Workpaper from OPUC DR 275 Attachment -1 REDACTED (Interruptible Customers)".

Q. HOW DID THE COMPANY ALLOCATE THE LRIC OF GAS TRANSMISSION AMONG CUSTOMERS CLASSES AND SCHEDULES?

A. In the Company's Updated LRIC[61] the Company allocated its LRIC of Gas Transmission of approximately $2 million[62, 63] based on Incremental Firm Design Day Sales.[64] In this allocation, Interruptible rate schedules have no costs assigned.[65, 66]

LRIC OF GAS DISTRIBUTION

Q. PLEASE EXPLAIN NW NATURAL'S LRIC OF GAS DISTRIBUTION.

A. NW Natural broke down its LRIC of Gas Distribution into two parts: demand-related distribution costs (Demand-Related LRIC of Gas Distribution)[67, 68] and customer-related distribution costs (Non-Demand-Related or Customer-Related LRIC of Gas Distribution).[69, 70, 71]

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61 See NW Natural's response to Staff Data Request 225 attached to this testimony as Exhibit Staff/1403.

62 The number represented by the Company is $1,681,326.

63 See Exhibit Staff/1403 Ordonez/3, line 18, column A.

64 See Exhibit Staff/1403 Ordonez/3-4, line 7.

65 See Exhibit Staff/1403 Ordonez/3 line 18, column: 31C Interr Sales (I); and Exhibit Staff/1403 Ordonez/4 line 18, columns: 31I Interr Sales (L), 32C Interr Sales (P), 32I Interr Sales (Q), and 32 Interr Trans (R).

66 Also see Exhibit Staff/1402 Ordonez/3 line 18, column: 31C Interr Sales (I); and Exhibit Staff/1402 Ordonez/4 line 18, columns: 31I Interr Sales (L), 32C Interr Sales (P), 32I Interr Sales (Q), and 32 Interr Trans (R).

67 See Exhibit NWN/1101 Feingold/6.

68 The Demand-Related LRIC of Gas Distribution comprises solely the demand portion of the distribution mains.

69 See Exhibit NWN/1101 Feingold/9.

70 For a description of customer-related gas distribution costs, refer to NW Natural's response to Staff Data Request 246 attached to this testimony as Exhibit Staff/1406 Ordonez/1.

71 The Customer-Related LRIC of Gas Distribution comprises: the distribution mains cost per customer (except the demand portion), the distribution services cost per customer, the cost of distribution meters & regulators per customer, and the distribution accounting cost per customer.

For estimating NW Natural's LRIC of Distribution, (i.e., Demand-Related and Non-Demand Related), the Company used as an input the "cost associated with the installation of distribution mains [(Distribution Mains)] to connect new customers and to provide additional capacity to both new and existing customers."[72]

"[Distribution] Mains costs that served those two functions [(i.e., Demand-Related and Non-Demand-Related Costs)] were extracted from NW Natural's current capital budget and separated into customer and demand components."[73]

The Distribution Mains Non-Demand-Related Costs estimation is based on a Distribution Main cost per foot (Distribution Main Cost per Foot) of $14.56[74] and an installed Distribution Main length per new customer (Installed Distribution Main Length per Customer) of 77 feet.[75]

Q. PLEASE EXPLAIN HOW NW NATURAL ESTIMATED THE DISTRIBUTION MAIN COST PER FOOT OF $14.56.

A. In response to Staff Data Request 237,[76] NW Natural represented that: "[t]he Cost per Foot value of $14.56 [was] derived from the Forecast Capital Expenditure for residential [customers] in 2011 of $843,243[77] divided by the

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72 See Exhibit NWN/1100 Feingold/18, lines 9-10.
73 See Exhibit NWN/1100 Feingold/18, lines 10-12.
74 See Exhibit NWN/1101 Feingold/7, line 24.
75 See Exhibit NWN/1101 Feingold/7, line 25.
76 See NW Natural's response to Staff Data Request 237 attached to this testimony as Exhibit Staff/1406 Ordonez/2.
77 See Exhibit NWN/1101 Feingold/7, line 20.

number of installed feet of distribution main for the residential category"[78] of 57,932 feet.[79, 80]

Q. PLEASE EXPLAIN HOW NW NATURAL ESTIMATED THE INSTALLED DISTRIBUTION MAIN LENGTH PER CUSTOMER OF 77 FEET.

A. In response to Staff Data Request 238,[81] NW Natural represented that: "the referenced Average Main per Service worksheet[82] contains the installed feet of main from 2004-2010 (5,990,199 feet)[83, 84] and the total number of meters installed from 2004-2010 (77,816 new customers sets)".[85, 86]

Q. DOES STAFF HAVE ANY COMMENT ON THE COMPANY-DERIVED $14.56 MAIN COST PER FOOT AND THE 77 DISTRIBUTION MAIN LENGTH PER CUSTOMER?

A. Yes. Staff thinks that using such values is not reliable because the information is used inconsistently.

As for the Distribution Main Cost per Foot of $14.56, the Company arrived at this figure based on residential class information (i.e., residential main capital expenditure and number of installed fee of distribution main for residential

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[78] See Exhibit Staff/1406 Ordonez/2.
[79] See Exhibit Staff/1406 Ordonez/3.
[80] Also see NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "MainCap," sum of cells I19, I20 and I21.
[81] See NW Natural's response to Staff Data Request 238 attached to this testimony as Exhibit Staff/1406, Ordonez/4.
[82] NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "Average Main per Service" attached to this testimony as Exhibit Staff/1406, Ordonez/5.
[83] See NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "Average Main per Service," cell I11.
[84] See Exhibit Staff/1406, Ordonez/5.
[85] See NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "Average Main per Service," cell I17.
[86] See Exhibit Staff/1406, Ordonez/5.

class), but used the figure for additional customers classes (i.e., commercial and industrial customer classes). Also, as represented in the Company's workpapers,[87] there is clearly a distinction among customer classes consider the cost per foot value for commercial customers of $25.07,[88, 89] as represented by the Company. $25.07 is approximately 1.72 times the $14.56 cost per foot for the residential customer class.

Regarding the 77 feet per customer, the Company arrived at the 77 feet figure based on information applied to the residential class[90] (i.e., residential installed feet of main and total number of residential meters); however, the Company used this value for other customer classes (i.e., commercial and industrial customer classes) as well. Furthermore, in response to Staff Data Request 307,[91] the Company represents that the "average footage for commercial and industrial segments combined is 85 ft*."*[92, 93] Additionally, even though NW Natural represents in the same response that the Company-wide length of 77 feet[94] coincides with the residential cost of 77 feet, as shown above, there is a clear distinction of distribution main length among customer classes.

[87] See NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "MainCap".
[88] See NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "MainCap," cell B72.
[89] Also see Exhibit Staff/1406 Ordonez/6.
[90] See Exhibit Staff/1406 Ordonez/5.
[91] See NW Natural's response to Staff Data Request 307, attached to this testimony as Exhibit Staff/1406 Ordonez/7-10.
[92] See highlighted part of Exhibit Staff/1406 Ordonez/7.
[93] Also see Exhibit Staff/1406 Ordonez/9.
[94] See Exhibit Staff/1406 Ordonez/10.

Q. WHAT IS STAFF'S RECOMMENDATION TO ADDRESS YOUR COMMENTS ABOUT THE COMPANY'S ESTIMATION OF NON-DEMAND-RELATED COSTS FOR DISTRIBUTION MAINS? (I.E., THE INSTALLED DISTRIBUTION MAIN LENGTH PER CUSTOMER OF 77 FEET)?

A. I recommend that the Commission require NW Natural to provide a study of its Oregon service and customer locations that explores whether, and to what extent, there is a correlation between the existing length of distribution mains as a function of customer schedules. If Staff's assumption is correct, then the next cost study can differentiate distribution mains by customer class.

Q. WHAT OTHER CUSTOMER-RELATED LRIC OF GAS DISTRIBUTION[95] DID THE COMPANY PROVIDE IN ITS LRIC STUDY?

A. In addition to the customer-related LRIC of distribution mains, NW Natural provided customer-related LRIC of Services, customer-related LRIC of Meters & Regulators, and customer-related LRIC of Accounting.[96]

The LRIC of Services per customer for different schedules was estimated based on three years of historical costs[97] (i.e., 2008, 2009 and 2010) escalated to the test-year, resulting in the test-year investment costs provided in Exhibit NWN/1101 Feingold/9, column "D," which were multiplied by an ECCR of

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[95] The Customer-Related LRIC of Gas Distribution comprises: the distribution mains cost per customer (except the demand portion), the distribution services cost per customer, the cost of distribution meters & regulators per customers, and the distribution accounting cost per customer.

[96] For a description of customer-related gas distribution costs, refer to NW Natural's response to Staff Data Request 246, attached to this testimony as Exhibit Staff/1406 Ordonez/1.

[97] See NW Natural's response to Staff Data Request 248, attached to this testimony as Exhibit Staff/1406 Ordonez/11.

8.19%[98] resulting in the annual cost of services per customer for each customer schedule represented in Exhibit NWN/1101 Feingold/9, column “F”.

As for the LRIC of Meters & Regulators, the information of “Meters & Regulators Investment” per customer in Exhibit NWN/1101 Feingold/9, column “G” for each customer class (e.g., 1R, 1C, 2R…32 Interr Trans) was derived by escalating the 2009 Weighted Average Meter Costs[99] to the test-year. Subsequently, the values in column “G” were multiplied by an ECCR of 13.50%[100] resulting in the annual cost of meters and regulators per customer for each customer as represented in Exhibit NWN/1101 Feingold/9, column “I”.

Finally, regarding the LRIC of Accounting, as stated in Staff Data Request 251:[101] “[o]n the worksheet entitled ‘Accounting,’[102] NW Natural provided a detailed listing of costs by FERC account for certain sub accounts. An analysis was performed to identify costs that could be specifically associated with a particular revenue class. If a cost was specifically associated with a revenue class, that cost was directly assigned to that revenue class. Other costs were allocated to the revenue classes based on the average number of customers in each revenue class. The resulting allocation of costs were summed by revenue class and used to create a percentage-based allocator to allocate the total

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98 See Exhibit NWN/1101 Feingold/9, column E.

99 See NW Natural’s response to Staff Data Request 249, attached to this testimony as Exhibit Staff/1406 Ordonez/12-17.

100 See Exhibit NWN/1101 Feingold/9, column H.

101 See NW Natural’s response to Staff Data Request 251, attached to this testimony as Exhibit Staff/1406 Ordonez/18.

102 See NW Natural’s workpapers, workbook “1101 - Feingold Workpaper – 1,” worksheet “Accounting.”

customer costs included in NW Natural's test year. The resulting allocation of test year costs was then divided by the average number of customers to derive the average 'Accounting' test year costs by revenue class presented in Column (L) of NWN/1101 Feingold/9".[103]

Q. DOES STAFF HAVE ANY OTHER COMMENT ON NW NATURAL'S CUSTOMER-RELATED (NON-DEMAND-RELATED) LRIC OF GAS DISTRIBUTION[104]?

A. No. However, this position should not be perceived as setting a precedent for future rate cases, in which Staff may review specific parts of the Company's other customer-related LRIC of Gas Distribution and may propose changes based on contemporaneous facts, methodologies, trends, etc.

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[103] See NW Natural's response to Staff Data Request 251, attached to this testimony as Exhibit Staff/1406, Ordonez/18.

[104] The Customer-Related LRIC of Gas Distribution comprises: the distribution mains cost per customer (except the demand portion), the distribution services cost per customer, the cost of distribution meters & regulators per customers, and the distribution accounting cost per customer.

STAFF COST OF SERVICE

Q. DID NW NATURAL PROVIDE A COST OF SERVICE?

A. Yes. In its initial filing (Initial Filing), NW Natural provided an LRIC-based Cost of Service.[105] In response to Staff Data Request 225,[106] the Company provided an Updated LRIC Study and noted that the results of NW Natural's LRIC have not change materially from its Initial Filing LRIC.[107]

Q. WHAT REVENUE REQUIREMENT IS TO BE COLLECTED FROM CUSTOMERS?

A. In Exhibit NWN/1101, NW Natural represents a revenue requirement (Embedded Costs) of approximately $331 million, [108, 109, 110] which excludes gas purchased and other costs.[111]

Q. HOW DID THE COMPANY ALLOCATE THE REVENUE REQUIREMENT OF APPROXIMATELY $331 MILLION AMONG CUSTOMER SCHEDULES?

A. First, NW Natural obtained the "incremental" revenue requirement of approximately $310 million,[112, 113] which is the sum of the LRIC of Storage, Transmission and Distribution.,[114]

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105 See Exhibit NWN/1101 Feingold/1-2, line 28: "Total Revenue Requirement – Allocated Based on LRIC."
106 See NW Natural's response to Staff Data Request 225, attached to this testimony as Exhibit Staff/1403 Ordonez/1-4.
107 For comparison purposes, see lines 28 and 35 of Exhibit Staff/1403 Ordonez/3-4.
108 The number represented by the Company is $331,087,253.
109 See Exhibit NWN/1101 Feingold/1, column "A," lines 10 and 28.
110 Also see column "A," lines 10, 28 and 35 of Exhibit Staff/1403 Ordonez/3.
111 See NW Natural's response to Staff Data Request 330, attached to this testimony as Exhibit Staff/1407, Ordonez/1-2.
112 The number represented by the Company is $310,156,482.
113 See Exhibit NWN/1101 Feingold/1, line 25.

Then, the Company grossed-up the $310 million of "incremental" revenue requirement to obtain the $331 million[115] of revenue requirement (embedded costs) using a factor of approximately 94%. [116, 117, 118]

Q. DOES STAFF PROPOSE A DIFFERENT APPROACH FOR ALLOCATING THE REVENUE REQUIREMENT OF APPROXIMATELY $331 MILLION AMONG CUSTOMER SCHEDULES?

A. Yes. The revenue requirement of approximately $331 million can be better allocated by breaking ("functionalizing") it into the same functions as in the Company's LRIC Study (i.e., Storage, Transmission, Distribution Mains, Distribution Services, Distribution Meters & Regulators, and Distribution Accounting). From there, the allocation of embedded costs of a particular cost function can be based on the respective LRIC allocations.

Q. WHY IS FUNCTIONALIZING THE REVENUE REQUIREMENT IMPORTANT FOR ALLOCATING EMBEDDED COSTS?

A. Functionalizing the revenue requirement avoids distortions when there is a significant mismatch between a function's "incremental" and "embedded" costs, recognizing that certain customer classes have costs that are weighted more heavily in some functions than in others.

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[114] The LRIC of Distribution, in turn, comprises the the LRIC of the following sub-functions: distribution mains, distribution services, distribution meters & regulators, and distribution accounting.

[115] See Exhibit NWN/1101 Feingold/1, column "A," line 10.

[116] The percentage value with three decimal figures is 93.678%.

[117] See Exhibit NWN/1101 Feingold/1, column "A," line 27.

[118] 94 percent is the approximately quotient obtained by dividing the "incremental" revenue requirement of approximately $310 million by the revenue requirement of $331 million.

Oregon-regulated electric Investor Owned Utilities are required to functionalize their revenue requirement pursuant to ORS 757.642 and OAR 860-038-0200 where the revenue requirement should be unbundled into functions.

Q. DID STAFF ASK THE COMPANY TO FUNCTIONALIZE ITS REVENUE REQUIREMENT?

A. Yes. In NW Natural's response to Staff Data Request 306,[119] the Company provided the following functionalized revenue requirement:

Table 2

Function	**$ Million**
Storage	34
Transmission	6
Distribution Mains	113
Distribution Services	61
Distribution Meters & Regulators	35
Distribution Accounting	44
Prod-Dist Other	37
Total Revenue Requirement in Test-Year	**331**

Q. DID STAFF DEPART MATERIALLY FROM THE COMPANY-PROPOSED COST OF SERVICE?

A. No. Staff's proposed cost of service presented in Exhibit Staff/1402 Ordonez/1-2 is mostly based on the Company's Updated LRIC presented in Exhibit Staff/1402 Ordonez/3-4 and does not represent a material change from the Company's cost of service. The contrast of Staff's and the Company's cost of service is represented in Exhibit Staff/1402 Ordonez/1-2, lines 39-57.

[119] See NW Natural's response to Staff Data Request 306, attached to this testimony as Exhibit Staff/1407 Ordonez/3-5.

Q. PLEASE EXPLAIN STAFF'S ALLOCATION OF GAS STORAGE EMBEDDED COSTS AMONG CUSTOMER SCHEDULES.

A. The gas storage embedded cost of approximately $34 million[120, 121] was disaggregated into approximately $29 million[122] (≈85%) for demand (deliverability) and $5 million[123] (≈15%) for capacity (energy or commodity). These amounts are based on the proportion of demand ($27,725,825)[124, 125] and capacity ($4,751,900)[126, 127] of the LRIC of Gas Storage ($32,477,725)[128,129] as provided by the Company in its Updated LRIC Study submitted in response to Staff Data Request 225.[130]

The demand (deliverability) portion of the storage revenue requirement of approximately $29 million[131] was allocated among rate schedules based on the Company's incremental revenue requirement of demand (deliverability) storage,[132] which, in turn, was based on "Design Day Sales."[133]

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120 The number represented by the Company is $34,332,770. See Staff/1407 Ordonez/5, line 327, column (F).
121 Also see Exhibit Staff/1402 Ordonez/1, line 6, column A.
122 See Exhibit Staff/1402 Ordonez/1, line 4, column A.
123 See Exhibit Staff/1402 Ordonez/1, line 5, column A.
124 See Exhibit Staff/1402 Ordonez/3, line 13, column A.
125 See Exhibit Staff/1403 Ordonez/3, line 13, column A.
126 See Exhibit Staff/1402 Ordonez/3, line 14, column A.
127 See Exhibit Staff/1403 Ordonez/3, line 14, column A.
128 $32,477,725 equals the sum of $27,725,825 and $4,751,900.
129 See Exhibit Staff/1402 Ordonez/3, line 14b, column A.
130 See NW Natural's response to Staff Data Request 225, attached to this testimony as Exhibit Staff/1403 Ordonez/1-4.
131 See Exhibit Staff/1402 Ordonez/1, line 4, column A.
132 See Exhibit Staff/1402 Ordonez/3, line 13a.
133 See Exhibit Staff/1402 Ordonez/3, line 6a.

The capacity (energy or commodity) portion of the storage revenue requirement of approximately $5 million[134] was allocated among rate schedules based on the Company's incremental revenue requirement of capacity (energy or commodity) storage,[135] which in turn, was based on "Winter-4-month Storage Volumes-Sales."[136, 137] The point is that the benefit of storage is that it allows for hedging of gas purchases by substituting lower off-peak season gas costs for on-peak season gas costs. Additionally, gas storage lowers the required transmission capacity needed during peak periods as peak periods can be met with a portion of gas stored.

Q. PLEASE EXPLAIN STAFF'S ALLOCATION OF THE COMPANY'S EMBEDDED COSTS OF GAS TRANSMISSION AMONG CUSTOMER SCHEDULES.

A. Staff allocated the gas transmission embedded cost of approximately $6.30 million[138, 139] among customer schedules as follows:

- 75% (≈$4.70 million) [140] to all rate schedules, except interruptible customer schedules based on "Firm Design Day Throughput (i.e., Sales

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134 See Exhibit Staff/1402 Ordonez/1, line 5, column A.
135 See Exhibit Staff/1402 Ordonez/3, line 14a.
136 See Exhibit Staff/1402 Ordonez/3, line 4a.
137 The "Winter-4-month Storage Volumes-Sales" term is the firm sales volumes for each of NW Natural's rate classes in the four winter months (December through March) in excess of the average monthly sales volumes in the months of April through November.
138 The number represented by the Company is $6,265,911. See Staff/1407 Ordonez/5, line 327, column (E).
139 Also see Exhibit Staff/1402 Ordonez/1, line 12, column A.
140 See Exhibit Staff/1402 Ordonez/1, line 10, column A.

and Transport)."[141] This approach is similar to that of the Company, which did not include interruptible customers; [142] and

- 25% (≈$1.60 million) [143] to all rate schedules based on "Annual Throughput (i.e., Sales and Transport)".[144]

Q. WHAT IS STAFF'S RATIONALE FOR PROPOSING A 25 PERCENT SHARE OF THE TRANSMISSION REVENUE REQUIREMENT AMONG ALL CUSTOMER CLASSES?

A. As I stated in the LRIC of Gas Transmission section of my testimony, in NW Natural's response to Staff Data Request 275,[145] the Company provided the amount of time (approximately 0.40%[146]) that interruptible customers experienced curtailment in the five-year period beginning in 2007 through 2011. Furthermore, in Exhibit NWN/600 Yoshihara/3, lines 4-20, the Company notes that system reinforcements include consideration of interruptions of interruptible customers. Based on that information, Staff estimated that a 25% share of the transmission costs by all customers (i.e., non-interruptible and interruptible customers) is not unreasonable.

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141 See Exhibit Staff/1402 Ordonez/3, lines 5 and 5a.

142 See Exhibit Staff/1402 Ordonez/1 line 10, column: 31C Interr Sales (I); and Exhibit Staff/1402 Ordonez/1 line 10, columns: 31I Interr Sales (L), 32C Interr Sales (P), 32I Interr Sales (Q), and 32 Interr Trans (R).

143 See Exhibit Staff/1402 Ordonez/1, line 11, column A.

144 See Exhibit Staff/1402 Ordonez/3, lines 7a and 7b

145 See the text of NW Natural response to Staff Data Request 275 attached to this testimony as Exhibit Staff/1407 Ordonez/6.

146 See MS Excel spreadsheet: "Workpaper from OPUC DR 275 Attachment -1 REDACTED (Interruptible Customers)"

Q. PLEASE EXPLAIN STAFF'S ALLOCATION OF THE COMPANY'S EMBEDDED COSTS OF GAS DISTRIBUTION AMONG CUSTOMER SCHEDULES.

A. The Company's distribution function comprises the following four sub-functions:

1. Distribution Mains;
2. Distribution Services;
3. Distribution Meters & Regulators; and
4. Distribution Accounting.

Q. THEN EXPLAIN STAFF'S ALLOCATION OF THE COMPANY'S EMBEDDED COSTS OF DISTRIBUTION MAINS AMONG CUSTOMER SCHEDULES.

A. As explained in the LRIC section of my testimony, the Company used information for one customer class (main costs per foot and installed main length per new customer) and applied to other classes. Staff used an alternative approach by disaggregating the Company's Distribution Mains embedded costs of approximately $113 million[147, 148] into approximately $107 million[149, 150] (≈94 percent) of non-demand-related costs and $6 million[151, 152] (≈6 percent) of demand-related costs; then Staff allocated the $107 million among customer schedules using the same proportions as the LRIC of

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[147] The number represented by the Company is $113,387,169. See Staff/1407 Ordonez/5, line 327, column (G).

[148] Also see Exhibit Staff/1402 Ordonez/1, line 19, column A.

[149] The exact number is $107,104,392.

[150] See Exhibit Staff/1402 Ordonez/1, line 17, column A.

[151] The exact number is $6,282,778.

[152] See Exhibit Staff/1402 Ordonez/1, line 18, column A.

Services[153] and the $6 million using "Design Day Sales, Excluding Residential"[154] customers.

Q. HOW DID STAFF ARRIVE AT THE 94 PERCENT AND 6 PERCENT PROPORTIONS?

A. Staff based its estimation on the Company's provided non-demand-related (customer-related) LRIC of Distribution Mains of approximately $66 million[155] (approximately 94 percent of $70 million[156]) and on the demand-related LRIC of Distribution Mains of approximately $4 million[157] (6 percent of approximately $70 million).

Q. PLEASE EXPLAIN THE RATIONALE FOR ALLOCATING THE APPROXIMATELY $107 MILLION (NON-DEMAND-RELATED COSTS) BASED ON THE LRIC OF SERVICES AND THE APPROXIMATELY $6 MILLION (DEMAND-RELATED COSTS) BASED ON "DESIGN DAY SALES, EXCLUDING RESIDENTIAL" CUSTOMERS.

A. Staff's rationale for allocating approximately $107 million is based on the assumption that the frontage of length of distribution mains is proportional to the length of setback from the distribution mains for different classes of customers. (The length of setback establishes the cost of services).

The rationale for allocating approximately $11 million, whereby residential schedules were excluded, was inspired by the Company's approach that: "[t]he

[153] See Exhibit Staff/1402 Ordonez/3, line 20l.
[154] See Exhibit Staff/1402 Ordonez/3, line 6c.
[155] See Exhibit Staff/1402 Ordonez/3, line 20c, column A.
[156] $70 million is the sum of approximately $66 million of customer-related LRIC of Distribution Mains and approximately $4 million of demand-related LRIC of Distribution Mains.
[157] See Exhibit Staff/1402 Ordonez/3, line 20g, column A.

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 [emphasis added] of all residential customers served by NW Natural, there is no capacity-related distribution LRIC that is separately computed for residential customers [emphasis added]."[158] Therefore, Staff's approach was to allocate the $11 million based on "Design Day Sales, Excluding Residential"[159] customers.

Q. PLEASE EXPLAIN HOW STAFF SPREAD THE OTHER SUB-FUNCTIONS OF THE DISTRIBUTION FUNCTION OF EMBEDDED COSTS, SUCH AS SERVICES, METERS & REGULATORS, AND ACCOUNTING.

A. The revenue requirement of Distribution Services of approximately $61 million[160, 161] was allocated based on the Company's LRIC of Distribution Services.[162, 163] The revenue requirement of Distribution Meters & Regulators of approximately $35 million[164, 165] was allocated based on the Company's LRIC of Distribution Meters & Regulators.[166, 167] Finally, the revenue

[158] See Exhibit NWN/1100 Feingold/19, lines 15-20.
[159] See Exhibit Staff/1402 Ordonez/3, line 6c.
[160] The number represented by the Company is $61,109,690. See Staff/1407 Ordonez/5, line 327, column (H).
[161] Also see Exhibit Staff/1402 Ordonez/1, line 21, column A.
[162] See Exhibit Staff/1402 Ordonez/1-2, line 21, columns B to R.
[163] See Exhibit Staff/1402 Ordonez/3-4 line 20l.
[164] The number represented by the Company is $34,939,372. See Staff/1407 Ordonez/5, line 327, column (I).
[165] Also see Exhibit Staff/1402 Ordonez/1, line 23, column A.
[166] See Exhibit Staff/1402 Ordonez/1-2, line 23, columns B to R.
[167] See Exhibit Staff/1402 Ordonez/3-4 line 20p.

requirement of Distribution Accounting of approximately $44 million[168, 169] was allocated based on the Company's LRIC of Distribution Accounting.[170, 171]

All allocation approaches are the same as those used by the Company in its LRIC Study.

Q. PLEASE EXPLAIN HOW STAFF ALLOCATED THE "PRODUCTION-DISTRIBUTION OTHER" (PROD-DIST OTHER) PORTION OF THE EMBEDDED COSTS AMONG RATE SCHEDULES

A. First, Staff broke down the Prod-Dist Other revenue requirement of approximately $37 million[172, 173] into three portions:

- Approximately $13 million[174, 175] (approximately 36 percent of $37 million),[176] where allocated based on the embedded cost Distribution Services allocation.[177, 178]
- Approximately $16 million[179, 180] (approximately 44 percent of $37 million),[181] were allocated based on the embedded costs of Distribution except Distribution Accounting allocation.[182, 183]

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[168] The number represented by the Company is $43,842,341, which is the sum of the values line 327 of Staff/1407 Ordonez/5, columns: "Cust Acct Plant," "Cust Acct O&M Direct," and "Cust Acct O&M by Cust".
[169] Also see Exhibit Staff/1402 Ordonez/1, line 25, column A.
[170] See Exhibit Staff/1402 Ordonez/1-2, line 25, columns B to R.
[171] See Exhibit Staff/1402 Ordonez/3-4 line 20t.
[172] The number represented by the Company is $37,210,000. See Staff/1407 Ordonez/5, line 327, column (D).
[173] Also see Exhibit Staff/1402 Ordonez/1, line 33, column A.
[174] The exact number is $13,395,600.
[175] See Exhibit Staff/1402 Ordonez/1, line 30, column A.
[176] Staff estimated the 36 percent based on the rationale that the "Customer Installation Expenses" (FERC Account 879) portion of the Company's "Prod-Dist Other" embedded costs is approximately 36 percent.
[177] See Exhibit Staff/1402 Ordonez/1-2, line 30, columns B to R.
[178] See Exhibit Staff/1402 Ordonez/1-2, line 21.

- The remaining approximately $7 million,[184, 185] were allocated based on overall embedded revenue requirement allocation. [186, 187]

Q. PLEASE SUMMARIZE STAFF'S AND NW NATURAL'S REVENUE REQUIREMENT INCREASES FROM CURRENT RATES FOR EACH CUSTOMER SCHEDULE FROM THE PERSPECTIVE OF COSTS OF SERVICE.

A. As shown in columns (A) and (B) of Table 1 presented in the Summary Recommendation section of my testimony, Staff's results for most customer schedules do not materially differ in magnitude from the Company's results. For example, for the first three customer schedules (i.e., Schedule "1R," Schedule "1C," and Schedule 2R) the costs exceed the revenues collected under current rates (positive value percentages). Also for other customer schedules (i.e., Schedule "31C Firm Sales" thought Schedule "32 Interr Trans" costs are lower than revenues collected under current rates (negative numbers).

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179 The exact value is $16,372,400.
180 See Exhibit Staff/1402 Ordonez/1, line 31, column A.
181 Staff estimated the 44 percent based on the rationale that is the "Other Distribution Expenses" portion of the Company's "Prod-Dist Other" embedded costs is approximately 44 percent.
182 See Exhibit Staff/1402 Ordonez/1-2, line 31, columns B to R.
183 The aggregated embedded revenue requirement of Distribution Mains (Exhibit Staff/1402 Ordonez/1-2, line 19), Distribution Services (Exhibit Staff/1402 Ordonez/1-2, line 21), and Distribution Meters & Regulators (Exhibit Staff/1402 Ordonez/1-2, line 23).
184 The exact number is $7,442,000.
185 See Exhibit Staff/1402 Ordonez/1, line 32, column A.
186 See Exhibit Staff/1402 Ordonez/1-2, line 32, columns B to R.
187 The aggregated embedded revenue requirement of Storage (Exhibit Staff/1402 Ordonez/1-2, line 6), Transmission (Exhibit Staff/1402 Ordonez/1-2, line 13), and Distribution (Exhibit Staff/1402 Ordonez/1-2, line 26).

The differences arise in Schedule “3I Firm Sales” and Schedule “31C Firm Sales,” where, the Company’s results of costs lower than revenues collected under current rates, are the opposite to Staff’s.

RATE SPREAD

Q. PLEASE SUMMARIZE STAFF'S PROPOSED INCREASE/DECREASE OF RATES FROM THE REVENUES COLLECTED UNDER CURRENT RATES.

A. Column (D) of Table 1 presented in the Summary Recommendation section of my testimony shows Staff's recommended increases, assuming the Company's revenue request were approved, from rates collected under current rates. Staff's first step was to increase rates (to different degrees) for all the rate schedules for which costs exceed revenues collected under current rates. The second step was to estimate the magnitude of increases as follows:

- Add only the positive numbers in Exhibit Staff/1402 Ordonez/1-2, line 53, columns (B) to (R) resulting in the information represented Exhibit Staff/1402 Ordonez/1, line 55.
- Spread the revenue deficiency of approximately $43 million[188] among rate schedules based on the proportion of the values in Exhibit Staff/1402 Ordonez/1, line 55, columns (B) to (F) from the approximately $66 million,[189] arriving at the values represented in Exhibit Staff/1402 Ordonez/1, line 56, columns (B) to (F).
- For each customer schedule, divide the values in Exhibit Staff/1402 Ordonez/1, line 56 by the values in Exhibit Staff/1402 Ordonez/1, line 51 yielding the percentages represented in Exhibit Staff/1402 Ordonez/1, line 57.

[188] See Exhibit Staff/1402 Ordonez/1, line 56, column A.
[189] See Exhibit Staff/1402 Ordonez/1, line 55, column A.

- Maintain the 20.9 percent[190] obtained for Schedule 2R[191] and assign it to Schedule 1C.[192]
- Manually input the 31.3 percent for Schedule 1R[193] and 3 percent for Schedule 3I Firm Sales.[194]

By following the steps described above, Staff estimated the rate increases represented in Table 1, Column (D) presented in the Summary Recommendation section of this testimony.

Q. PLEASE EXPLAIN THE MAIN DIFFERENCES BETWEENS STAFF'S AND THE COMPANY'S RATE SPREAD.

A. As shown in the highlighted part of Table 1 presented in the Summary Recommendation section of my testimony, the main differences between Staff's and the Company's rate spread lie in three schedules: Schedules "3C Firm Sales," "3I Firm Sales," and "31C Firm Sales. For example, the Company recommends increasing rates for the "31 Firm Sales" schedule by 7.6 percent while the cost of service for this schedule is approximately 44 percent below this schedule's revenue collected under current rates. In contrast, Staff recommendation is no change in rates collected under current rates.

Q. DO YOU HAVE ANYTHING ELSE TO ADD?

A. Yes. The rate spread above proposed and presented in Table 1, Column (D) of this testimony, is for illustrative purposes and based on a hypothetical overall

190 See Exhibit Staff/1402 Ordonez/1, line 57, column D.
191 See Exhibit Staff/1402 Ordonez/1, line 66, column D.
192 See Exhibit Staff/1402 Ordonez/1, line 66, column C.
193 See Exhibit Staff/1402 Ordonez/1, line 66, column B.
194 See Exhibit Staff/1402 Ordonez/1, line 66, column F.

rate increase of approximately 15.20% (increase of approximately $43.68 million from the revenues collected under current rates).

If the overall increase from the revenues collected under current rates is significantly lower than the approximately $43.68 million requested, or if there is a decrease from revenues collected under current rates, I will likely recommend that the Commission modestly decrease rates for customers schedules "31C Firm Transmission" through "32 Interruptible Transmission" and increase rates for customer schedules "1R," "1C," and "2R."[195] However, at this point, I do not expect any increase or decrease from current revenues may change materially the Cost of Service results in column "B" of Table 1.

Nevertheless, this position should not be perceived as setting precedent for future rate cases, in which Staff may review specific parts of the Company's LRIC Study and may propose changes based on contemporaneous facts, methodologies, trends, etc. Additionally, as noted by the Commission in Order No. 98-374 of Docket No. UM 827, calculating the marginal cost is as much an art as it is a science.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[195] Any increase or decrease from the revenues collected under current rates may impact my recommendation based on the function (e.g., storage, transmission, distribution, etc.) affected by such an increase or decrease.

CASE: UG 221
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1401

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME	Jorge D. Ordonez
EMPLOYER	Public Utility Commission of Oregon
TITLE	Senior Financial Economist, Economic and Policy Analysis Section
ADDRESS	550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2115
EDUCATION AND TRAINING	Utility Management Certificate Willamette University, Oregon, 2008 Certificate in Management of Hydropower Development Swedish International Development Cooperation Agency, Sweden, 2006 & South Africa, 2007 Fulbright Scholar, MBA, concentration in finance Willamette University, Oregon, 2005 Certificate in Project Appraisal and Management Maastricht School of Management, Netherlands, 2002 BS, Mechanical Engineering, thermal power efficiency Electrical & Mechanical Engineering School San Antonio Abad University, Peru, 1998
EXPERIENCE	I received a Bachelors of Science degree in Mechanical Engineering from San Antonio Abad University in Cusco, Peru in 1998. Subsequently, as a Fulbright Scholar, I received an MBA with an emphasis in finance from Willamette University in 2005. From 1999 to 2008, I worked for a Peruvian power generation company and was promoted many times, working as an Engineer, Resource Scheduler, Manager of Economic Planning and Vice-President of Generation, Commercial and Trading. Since January 2009, I have been employed by the Public Utility Commission of Oregon as a Senior Financial Economist in the Economic Research and Financial Analysis Division, evaluating utilities' issuance of securities, cost of capital, cost studies, mergers and acquisitions, and integrated resource plans.

CASE: UG 221
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1402

May 3, 2012

UG 221 NW Natural - Rate Spread including LRIC Study
Based on NW Natural's Respose to Staff Data Request 225 (Updated LRIC)

STAFF'S ESTIMATIONS

				Units	Total (A)	1R (B)	1C (C)	2R (D)	3C Firm Sales (E)	3I Firm Sales (F)	31C Firm Sales (G)	31C Firm Trans (H)	31C Interr Sales (I)
1	**STAFF COST OF SERVICE**												
2													
3	**Embedded Storage Costs**	**Allocation Criterion**											
4	Deliverability (demand) [Allocated based on Company's LRIC of Deliverability Storage]	Same as Company		$	29,309,453	29,025	4,574	19,378,968	6,704,601	52,986	2,456,966	0	0
5	Capacity (energy or commodity) [Allocated based on Company's LRIC of Capacity Storage]	Same as Company		$	5,023,316	4,804	953	3,265,934	1,214,882	14,040	405,510	0	0
6	**Total Embedded Storage Costs**			$	**34,332,770**	33,829	5,527	22,644,901	7,919,483	67,026	2,862,476	0	0
7	**%**				100.00%	0.10%	0.02%	65.96%	23.07%	0.20%	8.34%	0.00%	0.00%
8													
9	**Embedded Transmission Costs**	**Allocation Criterion**											
10	75% (versus Company's 100%) [Allocated based on the Company's Firm Design Day Throughput (i.e., Sales and Transport)]	Staff proposed	75%	$	4,699,433	4,592	724	3,065,694	1,060,648	8,382	388,685	966	0
11	25% (versus Company's 0%) [Allocated based throughput]	Staff proposed	25%	$	1,566,478	1,181	182	585,008	251,628	6,995	101,330	389	2,296
12	**Total Embedded Transmission Costs**		100%	$	**6,265,911**	5,772	906	3,650,702	1,312,275	15,377	490,014	1,355	2,296
13	**%**				100.00%	0.09%	0.01%	58.26%	20.94%	0.25%	7.82%	0.02%	0.04%
14													
15	**Embedded Distribution Costs**	**Allocation Criterion**											
16	Distribution Mains												
17	Non-Demand-Related Costs (94%) [Allocation based on the Company's LRIC of Distribution Services]	Staff proposed	94%	$	107,104,392	461,227	21,775	81,865,803	20,727,837	202,443	1,296,071	10,534	18,927
18	Demand-Related (6%) [Allocation based on Design Day-Sales, Excluding Residential]	Staff proposed	6%	$	6,282,778	0	2,902	0	4,254,273	33,621	1,559,020	0	0
19	Total Distribution - Mains		100%	$	**113,387,169**	461,227	24,678	81,865,803	24,982,109	236,064	2,855,090	10,534	18,927
20	Distribution Services												
21	Distribution - Services [Allocation based on the Company's LRIC of Distribution Services]	Same as Company		$	**61,109,690**	263,159	12,424	46,709,512	11,826,515	115,506	739,489	6,010	10,799
22	Distribution Meters & Regulators												
23	Distribution - Meters & Regulators [Allocation based on the Company's LRIC of Meters & Regulators]	Same as Company		$	**34,939,372**	168,777	12,779	28,021,169	5,600,445	116,051	630,518	3,823	7,349
24	Distribution Accounting												
25	Distribution - Accounting (Allocation based on the Company's "LRIC of Accounting)	Same as Company		$	**43,842,341**	260,560	12,559	37,279,621	4,210,082	714,796	89,015	446	892
26	**Total Embedded Distribution Costs**			$	**253,278,572**	1,153,723	62,440	193,876,105	46,619,151	1,182,417	4,314,112	20,814	37,967
27	**%**				**100.00%**	0.46%	0.02%	76.55%	18.41%	0.47%	1.70%	0.01%	0.01%
28													
29	**Embedded Production-Distribution Other Costs**	**Allocation Criterion**											
30	36% [based on the allocation of the Company's Embedded Distribution Services costs]	Staff proposed	36%	$	13,395,600	57,686	2,723	10,238,997	2,592,441	25,320	162,100	1,318	2,367
31	44% [based on the allocation of the Company's Embedded Distribution costs except Distribution Accounting	Staff proposed	44%	$	16,372,400	69,822	3,899	12,241,723	3,315,273	36,556	330,291	1,592	2,898
32	20% (remaining) [based on the allocation of the Company's Embedded costs except Prod-Dist Other]	Staff proposed	20%	$	7,442,000	30,219	1,744	5,575,518	1,414,340	32,030	194,145	561	1,020
33	**Total Embedded Production - Distribution Other Costs**		100%	$	**37,210,000**	157,727	8,367	28,056,238	7,322,054	93,905	686,537	3,471	6,285
34	**%**				**100.00%**	0.42%	0.02%	75.40%	19.68%	0.25%	1.85%	0.01%	0.02%
35													
36	**TOTAL EMBEDDED COSTS**			**$**	**331,087,253**	**1,351,050**	**77,240**	**248,227,946**	**63,172,963**	**1,358,726**	**8,353,138**	**25,641**	**46,548**
37	**%**			**%**	**100.00%**	**0.41%**	**0.02%**	**74.97%**	**19.08%**	**0.41%**	**2.52%**	**0.01%**	**0.01%**
38													
39	**COST OF SERVICE VERSUS CURRENT REVENUES**												
40													
41	**Company**												
42	Revenue requirement collected under current rates			$	287,404,942	577,125	62,009	188,891,594	57,697,369	1,362,237	15,322,004	81,269	285,292
43	Revenue requirement requested by the Company allocated based on Company's cost of service			$	331,087,253	1,418,944	80,769	256,951,964	56,762,228	1,067,346	8,493,124	20,518	32,467
44	$ Increase/decrease from revenue requirement collected under current rates			$	43,682,312	841,820	18,760	68,060,371	(935,140)	(294,892)	(6,828,880)	(60,751)	(252,824)
45	% Increase/decrease from current revenue			%	15.2%	145.9%	30.3%	36.0%	-1.6%	-21.6%	-44.6%	-74.8%	-88.6%
49													
50	**Staff**												
51	Revenue requirement collected under current rates (X)			$	287,404,942	577,125	62,009	188,891,594	57,697,369	1,362,237	15,322,004	81,269	285,292
52	Revenue requirement requested by the Company allocated based on Staff's cost of service			$	331,087,253	1,351,050	77,240	248,227,946	63,172,963	1,358,726	8,353,138	25,641	46,548
53	$ Increase/decrease from current revenue			$	43,682,312	773,926	15,231	59,336,353	5,475,594	(3,511)	(6,968,866)	(55,628)	(238,743)
54	% Increase/decrease from current revenue			%	15.2%	134.1%	24.6%	31.4%	9.5%	-0.3%	-45.5%	-68.4%	-83.7%
55	Increase from current revenue (only positive $ numbers)			$	65,601,104	773,926	15,231	59,336,353	5,475,594	-	-	-	-
56	Revenue deficiency allocated in proportion to positive items (Y)			$	43,682,312	515,340	10,142	39,510,754	3,646,076	-	-	-	-
57	Y/X %			%	15.2%	89.3%	16.4%	20.9%	6.3%	0.0%	0.0%	0.0%	0.0%
58													
59	**PROPOSED RATE SPREAD**												
60													
61	**Company**												
62	% Increase/decrease from current revenue (From Exhibit NWN/1102 Feingold/1, line 13)			%	15.2%	19.0%	14.9%	17.7%	15.2%	15.2%	7.6%	0.0%	0.0%
63	$ Increase/decrease from current revenue (From Exhibit NWN/1102 Feingold/1, line 12)			$	43,682,312	109,654	9,215	33,421,911	8,770,000	207,060	1,164,472	-	-
64													
65	**Staff**												
66	% Increase/decrease from current revenue			%	15.2%	31.3%	20.9%	20.9%	6.8%	3.0%	0.0%	0.0%	0.0%
67	$ Increase/decrease from current revenue			$	43,682,312	180,640	12,971	39,510,754	3,937,080	40,867	-	-	-

NW Natural - Rate Spread including LRIC Study

Based on NW Natural's Respose to Staff Data Request 225 (Updated LRIC)

STAFF'S ESTIMATIONS

Line				Units	31I Firm Sales (J)	31I Firm Trans (K)	31I Interr Sales (L)	32C Firm Sales (M)	32I Firm Sales (N)	32 Firm Trans (O)	32C Interr Sales (P)	32I Interr Sales (Q)	32 Interr Trans (R)
1	**STAFF COST OF SERVICE**												
2													
3	**Embedded Storage Costs**	**Allocation Criterion**											
4	Deliverability (demand) [Allocated based on Company's LRIC of Deliverability Storage]	Same as Company		$	151,371	0	0	459,819	71,144	0	0	0	0
5	Capacity (energy or commodity) [Allocated based on Company's LRIC of Capacity Storage]	Same as Company		$	46,271	0	0	57,979	12,943	0	0	0	0
6	**Total Embedded Storage Costs**			$	197,643	0	0	517,799	84,086	0	0	0	0
7	**%**				0.58%	0.00%	0.00%	1.51%	0.24%	0.00%	0.00%	0.00%	0.00%
8													
9	**Embedded Transmission Costs**	**Allocation Criterion**											
10	75% (versus Company's 100%) [Allocated based on the Company's Firm Design Day Throughput (i.e., Sales and Transport)]	Staff proposed	75%	$	23,946	1,950	0	72,742	11,255	59,849	0	0	0
11	25% (versus Company's 0%) [Allocated based throughput]	Staff proposed	25%	$	28,610	1,384	516	19,165	19,737	99,134	35,157	56,039	357,727
12	**Total Embedded Transmission Costs**		100%	$	52,557	3,334	516	91,907	30,991	158,983	35,157	56,039	357,727
13	**%**				0.84%	0.05%	0.01%	1.47%	0.49%	2.54%	0.56%	0.89%	5.71%
14													
15	**Embedded Distribution Costs**	**Allocation Criterion**											
16	Distribution Mains												
17	Non-Demand-Related Costs (94%) [Allocation based on the Company's LRIC of Distribution Services]	Staff proposed	94%	$	354,881	12,618	11,041	125,557	106,605	253,686	202,949	257,589	1,174,847
18	Demand-Related (6%) [Allocation based on Design Day-Sales, Excluding Residential]	Staff proposed	6%	$	96,050	0	0	291,769	45,143	0	0	0	0
19	Total Distribution - Mains		100%	$	450,931	12,618	11,041	417,326	151,748	253,686	202,949	257,589	1,174,847
20	Distribution Services												
21	Distribution - Services [Allocation based on the Company's LRIC of Distribution Services]	Same as Company		$	202,482	7,199	6,299	71,638	60,825	144,744	115,795	146,971	670,323
22	Distribution Meters & Regulators												
23	Distribution - Meters & Regulators [Allocation based on the Company's LRIC of Meters & Regulators]	Same as Company		$	139,225	4,950	4,372	32,768	27,822	40,649	32,149	41,501	55,025
24	Distribution Accounting												
25	Distribution - Accounting (Allocation based on the Company's "LRIC of Accounting)	Same as Company		$	564,312	20,064	17,556	3,939	112,862	163,024	3,864	165,532	223,217
26	**Total Embedded Distribution Costs**			$	1,356,950	44,832	39,269	525,671	353,257	602,103	354,758	611,592	2,123,412
27	**%**				0.54%	0.02%	0.02%	0.21%	0.14%	0.24%	0.14%	0.24%	0.84%
28													
29	**Embedded Production-Distribution Other Costs**	**Allocation Criterion**											
30	36% [based on the allocation of the Company's Embedded Distribution Services costs]	Staff proposed	36%	$	44,385	1,578	1,381	15,703	13,333	31,729	25,383	32,217	146,939
31	44% [based on the allocation of the Company's Embedded Distribution costs except Distribution Accounting]	Staff proposed	44%	$	61,963	1,936	1,697	40,786	18,793	34,324	27,431	34,870	148,545
32	20% (remaining) [based on the allocation of the Company's Embedded costs except Prod-Dist Other]	Staff proposed	20%	$	40,699	1,220	1,007	28,752	11,860	19,273	9,874	16,907	62,831
33	**Total Embedded Production - Distribution Other Costs**		100%	$	147,047	4,734	4,086	85,241	43,986	85,326	62,688	83,994	358,315
34	**%**				0.40%	0.01%	0.01%	0.23%	0.12%	0.23%	0.17%	0.23%	0.96%
35													
36	**TOTAL EMBEDDED COSTS**			**$**	**1,754,197**	**52,900**	**43,870**	**1,220,617**	**512,320**	**846,413**	**452,602**	**751,625**	**2,839,454**
37	**%**			**%**	**0.53%**	**0.02%**	**0.01%**	**0.37%**	**0.15%**	**0.26%**	**0.14%**	**0.23%**	**0.86%**
38													
39	**COST OF SERVICE VERSUS CURRENT REVENUES**												
40													
41	**Company**												
42	Revenue requirement collected under current rates			$	3,561,584	182,560	75,970	2,060,560	2,056,408	3,945,752	1,749,021	2,647,371	6,846,817
43	Revenue requirement requested by the Company allocated based on Company's cost of service			$	1,438,680	43,450	31,327	1,292,694	429,796	699,457	278,731	470,447	1,575,311
44	$ Increase/decrease from revenue requirement collected under current rates			$	(2,122,904)	(139,110)	(44,643)	(767,866)	(1,626,613)	(3,246,295)	(1,470,290)	(2,176,925)	(5,271,506)
45	% Increase/decrease from current revenue			%	-59.6%	-76.2%	-58.8%	-37.3%	-79.1%	-82.3%	-84.1%	-82.2%	-77.0%
49													
50	**Staff**												
51	Revenue requirement collected under current rates (X)			$	3,561,584	182,560	75,970	2,060,560	2,056,408	3,945,752	1,749,021	2,647,371	6,846,817
52	Revenue requirement requested by the Company allocated based on Staff's cost of service			$	1,754,197	52,900	43,870	1,220,617	512,320	846,413	452,602	751,625	2,839,454
53	$ Increase/decrease from current revenue			$	(1,807,387)	(129,660)	(32,099)	(839,943)	(1,544,088)	(3,099,339)	(1,296,419)	(1,895,746)	(4,007,363)
54	% Increase/decrease from current revenue			%	-50.7%	-71.0%	-42.3%	-40.8%	-75.1%	-78.5%	-74.1%	-71.6%	-58.5%
55	Increase from current revenue (only positive $ numbers)			$	-	-	-	-	-	-	-	-	-
56	Revenue deficiency allocated in proportion to positive items (Y)			$	-	-	-	-	-	-	-	-	-
57	Y/X %			%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
58													
59	**PROPOSED RATE SPREAD**												
60													
61	**Company**												
62	% Increase/decrease from current revenue (From Exhibit NWN/1102 Feingold/1, line 13)			%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
63	$ Increase/decrease from current revenue (From Exhibit NWN/1102 Feingold/1, line 12)			$	-	-	-	-	-	-	-	-	-
64													
65	**Staff**												
66	% Increase/decrease from current revenue			%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
67	$ Increase/decrease from current revenue			$	-	-	-	-	-	-	-	-	-

UG 221 NW Natural - Rate Spread including LRIC Study

Based on NW Natural's Respose to Staff Data Request 225 (Updated LRIC)

COMPANY'S ESTIMATIONS

			Units	Total (A)	1R (B)	1C (C)	2R (D)	3C Firm Sales (E)	3I Firm Sales (F)	31C Firm Sales (G)	31C Firm Trans (H)	31C Interr Sales (I)
	TEST YEAR FORECAST INFORMATION											
1	Number Customers		Customers	601,298	3,764	169	538,601	56,653	285	1,198	6	12
2	MDDV Volumes		Dth									
3	Winter 4-month 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	
4	Winter 4-month Storage Volumes-Sales		Dth	203,768,706	194,861	38,670	132,481,223	49,281,181	569,537	16,449,324		
4a	% Winter 4-month Storage Volumes-Sales		%	100.00%	0.10%	0.02%	65.02%	24.18%	0.28%	8.07%		
5	Firm Design Day Throughput (i.e., Sales and Transport)		Dth/day	849,990	830	131	554,495	191,840	1,516	70,302	175	
5a	% Firm Design Day Throughput (i.e., Sales and Transport)		%	100.00%	0.10%	0.02%	65.24%	22.57%	0.18%	8.27%	0.02%	0.00%
6	DesignDay-Sales		Dth/day	838,638	830	131	554,495	191,840	1,516	70,302		
6a	% DesignDay-Sales		%	100.00%	0.10%	0.02%	66.12%	22.88%	0.18%	8.38%		
6b	DesignDay-Sales, Excluding Residential		Dth/day	283,313	0	131	0	191,840	1,516	70,302	0	0
6c	% DesignDay-Sales, Excluding Residential		%	100.00%	0.00%	0.05%	0.00%	67.71%	0.54%	24.81%	0.00%	0.00%
7	Incremental Firm DesignDay		Dth/day	17,459	14	3	9,496	4,531	115	1,660	4	0
7a	Annual Throughput (i.e., Sales and Transport)		Dth	936,983,484	706,257	109,077	349,920,397	150,510,301	4,184,174	60,610,071	232,814	1,373,459
7b	% Annual Throughput (i.e., Sales and Transport)		%	100.00%	0.08%	0.01%	37.35%	16.06%	0.45%	6.47%	0.02%	0.15%
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
9												
10	Total Revenue Requirement		$	331,087,253								
11												
11a	**COMPANY LONG-RUN INCREMENTAL COST STUDY**											
11b												
12	**Incremental Storage Costs**											
13	Storage Revenue Requirement - Daily Deliverability (Demand)	85%	$	$27,725,825	$27,457	$4,327	$18,331,897	$6,342,342	$50,123	$2,324,213	$0	$0
13a	%		%	100.00%	0.10%	0.02%	66.12%	22.88%	0.18%	8.38%	0.00%	0.00%
14	Storage Revenue Requirement - Capacity (Energy or Commodity)	15%	$	$4,751,900	$4,544	$902	$3,089,471	$1,149,240	$13,282	$383,599	$0	$0
14a	%		%	100.00%	0.10%	0.02%	65.02%	24.18%	0.28%	8.07%	0.00%	0.00%
14b	**Total Incremental Storage Costs**		**$**	**32,477,726**	32,001	5,228	21,421,368	7,491,583	63,405	2,707,812	0	0
14c	**%**			**100.00%**	0.10%	0.02%	65.96%	23.07%	0.20%	8.34%	0.00%	0.00%
15					≈ 94% [≈ $66.4 million/(66.4 million + $3.8 million)]							
16	**Incremental Transmission Costs**											
17	Incremental Transmission Costs per Dth/Design Day		$ per Dth/Design Day		$96	$96	$96	$96	$96	$96	$96	$0
18	Incremental Transmission Revenue Requirement		$	$1,681,326	1,370	298	914,482	436,328	11,027	159,896	397	
18a	**Total Incremental Transmission Costs**		**$**	**$1,681,326**	$1,370	$298	$914,482	$436,328	$11,027	$159,896	$397	$0
18b	**%**			**100.00%**	0.08%	0.02%	54.39%	25.95%	0.66%	9.51%	0.02%	0.00%
19					≈ 6% [≈ $3.8 million/(66.4 million + $3.8 million)]							
20	**Incremental Distribution Costs**											
20a	Mains (Customer-related)											
20b	Incremental Mains Annual Cost per customer		$/Customer		$110	$110	$110	$110	$110	$110	$110	$110
20c	Incremental Mains (Customer-related) Annual Cost per schedule	########	$	**$66,441,772**	$415,963	$18,674	$59,513,894	$6,260,001	$31,492	$132,356	$663	$1,326
20d	% Incremental Mains (Customer-related) Annual Cost per schedule		%	100.00%	0.63%	0.03%	89.57%	9.42%	0.05%	0.20%	0.00%	0.00%
20e	Mains (Demand-related)				$0							
20f	Incremental Distribution Costs per Dth/Design Day		$	$0	$0	$13	$0	$13	$13	$13	$13	$0
20g	Incremental Mains (Demand-related)	6%	$	**$3,897,495**	$0	$1,731	$0	$2,537,444	$20,053	$929,871	$2,311	$0
20h	% Incremental Mains (Demand-related) Annual Cost per schedule		%	100.00%	0.00%	0.04%	0.00%	65.10%	0.51%	23.86%	0.06%	0.00%
20i	Services											
20j	Incremental Services Annual Cost per customer		$/Customer		$130	$136	$161	$387	$751	$1,144	$1,857	$1,668
20k	Incremental Services Annual Cost per schedule		$	**$113,274,155**	$487,796	$23,030	$86,581,694	$21,921,867	$214,105	$1,370,731	$11,141	$20,017
20l	% Incremental Services Annual Cost per schedule		%	100.00%	0.43%	0.02%	76.44%	19.35%	0.19%	1.21%	0.01%	0.02%
20m	Meters & Regulators											
20n	Incremental Meters & Regulators Annual Cost per customer		$/Customer		$50	$85	$58	$111	$457	$591	$716	$688
20o	Incremental Meters & Regulators Annual Cost per schedule		$	**$39,243,303**	$189,567	$14,354	$31,472,896	$6,290,323	$130,346	$708,187	$4,294	$8,255
20p	% Incremental Meters & Regulators Annual Cost per schedule		%	100.00%	0.48%	0.04%	80.20%	16.03%	0.33%	1.80%	0.01%	0.02%
20q	Accounting											
20r	Incremental Accounting Annual Cost per customer		$/Customer		$47	$50	$47	$50	$1,696	$50	$50	$50
20s	Incremental Accounting Annual Cost per schedule		$	**$29,641,747**	$176,164	$8,491	$25,204,701	$2,846,431	$483,272	$60,183	$301	$603
20t	% Incremental Accounting Annual Cost per schedule		%	100.00%	0.59%	0.03%	85.03%	9.60%	1.63%	0.20%	0.00%	0.00%
20u	**Total Incremental Distribution Costs**		**$**	**252,498,472**	1,269,490	66,280	202,773,185	39,856,066	879,268	3,201,328	18,711	30,201
20v	**%**			**100.00%**	0.50%	0.03%	80.31%	15.78%	0.35%	1.27%	0.01%	0.01%
20w												
20x	**TOTAL INCREMENTAL COSTS**		**$**	**286,657,524**	**1,302,861**	**71,806**	**225,109,036**	**47,783,976**	**953,700**	**6,069,037**	**19,109**	**30,201**
20y	**%**		**%**	**100.00%**	**0.45%**	**0.03%**	**78.53%**	**16.67%**	**0.33%**	**2.12%**	**0.01%**	**0.01%**
20z												
25	Total Incremental Revenue Requirement		$	286,657,523	1,302,861	71,806	225,109,035	47,783,976	953,700	6,069,037	19,109	30,201
26												
27	Ratio of Incremental Rev Req to Rev Req			87%								
28	**Total Revenue Requirement - Allocated based on LRIC**		$	$331,087,253	$1,504,794	$82,935	$259,999,219	$55,190,128	$1,101,516	$7,009,691	$22,070	$34,882
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
31	Revenue to Cost Ratio			0.87	0.38	0.75	0.73	1.05	1.24	2.19	3.68	8.18
32	Unitized Revenue to Cost Ratio			1.00	0.44	0.86	0.84	1.20	1.42	2.52	4.24	9.42
33												
34	**As-Filed**											
35	**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
36	Revenue to Cost Ratio			0.87	0.41	0.77	0.74	1.02	1.28	1.80	3.96	8.79
37	Unitized Revenue to Cost Ratio			1.00	0.47	0.88	0.85	1.17	1.47	2.08	4.56	10.12

NW Natural - Rate Spread including LRIC Study

Based on NW Natural's Respose to Staff Data Request 225 (Updated LRIC)

COMPANY'S ESTIMATIONS

			Units	31I Firm Sales (J)	31I Firm Trans (K)	31I Interr Sales (L)	32C Firm Sales (M)	32I Firm Sales (N)	32 Firm Trans (O)	32C Interr Sales (P)	32I Interr Sales (Q)	32 Interr Trans (R)
	TEST YEAR FORECAST INFORMATION											
1	Number Customers		Customers	225	8	7	53	45	65	52	66	89
2	MDDV Volumes		Dth				1,708,764	1,888,634	3,150,048			
3	Winter 4-month Storage Volumes-Sales & Transport		Dth	1,876,983	157,702		2,351,912	525,017	3,427,811			
4	Winter 4-month Storage Volumes-Sales		Dth	1,876,983			2,351,912	525,017				
4a	% Winter 4-month Storage Volumes-Sales		%	0.92%			1.15%	0.26%				
5	Firm Design Day Throughput (i.e., Sales and Transport)		Dth/day	4,331	353		13,157	2,036	10,825			
5a	% Firm Design Day Throughput (i.e., Sales and Transport)		%	0.51%	0.04%	0.00%	1.55%	0.24%	1.27%	0.00%	0.00%	0.00%
6	DesignDay-Sales		Dth/day	4,331			13,157	2,036				
6a	% DesignDay-Sales		%	0.52%			1.57%	0.24%				
6b	DesignDay-Sales, Excluding Residential		Dth/day	4,331	0	0	13,157	2,036	0	0	0	0
6c	% DesignDay-Sales, Excluding Residential		%	1.53%	0.00%	0.00%	4.64%	0.72%	0.00%	0.00%	0.00%	0.00%
7	Incremental Firm DesignDay		Dth/day	327	27	0	311	154	818	0	0	0
7a	Annual Throughput (i.e., Sales and Transport)		Dth	17,113,089	827,715	308,711	11,463,285	11,805,390	59,296,740	21,028,927	33,519,721	213,973,355
7b	% Annual Throughput (i.e., Sales and Transport)		%	1.83%	0.09%	0.03%	1.22%	1.26%	6.33%	2.24%	3.58%	22.84%
8	Revenues		$	$3,561,584	$182,560	$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												
11a	**COMPANY LONG-RUN INCREMENTAL COST STUDY**											
11b												
12	**Incremental Storage Costs**											
13	Storage Revenue Requirement - Daily Deliverability (Demand)	85%	$	$143,193	$0	$0	$434,974	$67,300	$0	$0	$0	$0
13a	%		%	0.52%	0.00%	0.00%	1.57%	0.24%	0.00%	0.00%	0.00%	0.00%
14	Storage Revenue Requirement - Capacity (Energy or Commodity)	15%	$	$43,771	$0	$0	$54,847	$12,243	$0	$0	$0	$0
14a	%		%	0.92%	0.00%	0.00%	1.15%	0.26%	0.00%	0.00%	0.00%	0.00%
14b	**Total Incremental Storage Costs**		**$**	186,964	0	0	489,821	79,543	0	0	0	0
14c	**%**			0.58%	0.00%	0.00%	1.51%	0.24%	0.00%	0.00%	0.00%	0.00%
15					**≈ 94% [≈ $66.4 million/(66.4 million + $3.8 million)]**							
16	**Incremental Transmission Costs**											
17	Incremental Transmission Costs per Dth/Design Day		$ per Dth/De	$96	$96	$0	$96	$96	$96	$0	$0	$0
18	Incremental Transmission Revenue Requirement		$	31,501	2,566		29,924	14,805	78,731			
18a	**Total Incremental Transmission Costs**		**$**	$31,501	$2,566	$0	$29,924	$14,805	$78,731	$0	$0	$0
18b	**%**			1.87%	0.15%	0.00%	1.78%	0.88%	4.68%	0.00%	0.00%	0.00%
19					**≈ 6% [≈ $3.8 million/(66.4 million + $3.8 million)]**							
20	**Incremental Distribution Costs**											
20a	Mains (Customer-related)											
20b	Incremental Mains Annual Cost per customer		$/Customer	$110	$110	$110	$110	$110	$110	$110	$110	$110
20c	Incremental Mains (Customer-related) Annual Cost per schedule	########	$	$24,862	$884	$773	$5,856	$4,972	$7,182	$5,746	$7,293	$9,834
20d	% Incremental Mains (Customer-related) Annual Cost per schedule		%	0.04%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
20e	Mains (Demand-related)											
20f	Incremental Distribution Costs per Dth/Design Day		$	$13	$13	$0	$13	$13	$13	$0	$0	$0
20g	Incremental Mains (Demand-related)	6%	$	$57,288	$4,666	$0	$174,025	$26,925	$143,181	$0	$0	$0
20h	% Incremental Mains (Demand-related) Annual Cost per schedule		%	1.47%	0.12%	0.00%	4.47%	0.69%	3.67%	0.00%	0.00%	0.00%
20i	Services											
20j	Incremental Services Annual Cost per customer		$/Customer	$1,668	$1,668	$1,668	$2,505	$2,505	$4,128	$4,128	$4,128	$13,961
20k	Incremental Services Annual Cost per schedule		$	$375,324	$13,345	$11,677	$132,790	$112,746	$268,300	$214,640	$272,428	$1,242,524
20l	% Incremental Services Annual Cost per schedule		%	0.33%	0.01%	0.01%	0.12%	0.10%	0.24%	0.19%	0.24%	1.10%
20m	Meters & Regulators											
20n	Incremental Meters & Regulators Annual Cost per customer		$/Customer	$695	$695	$702	$694	$694	$702	$694	$706	$694
20o	Incremental Meters & Regulators Annual Cost per schedule		$	$156,375	$5,560	$4,911	$36,804	$31,249	$45,657	$36,110	$46,613	$61,803
20p	% Incremental Meters & Regulators Annual Cost per schedule		%	0.40%	0.01%	0.01%	0.09%	0.08%	0.12%	0.09%	0.12%	0.16%
20q	Accounting											
20r	Incremental Accounting Annual Cost per customer		$/Customer	$1,696	$1,696	$1,696	$50	$1,696	$1,696	$50	$1,696	$1,696
20s	Incremental Accounting Annual Cost per schedule		$	$381,531	$13,566	$11,870	$2,663	$76,306	$110,220	$2,613	$111,916	$150,917
20t	% Incremental Accounting Annual Cost per schedule		%	1.29%	0.05%	0.04%	0.01%	0.26%	0.37%	0.01%	0.38%	0.51%
20u	**Total Incremental Distribution Costs**		**$**	995,381	38,020	29,231	352,138	252,199	574,540	259,108	438,249	1,465,078
20v	**%**			0.39%	0.02%	0.01%	0.14%	0.10%	0.23%	0.10%	0.17%	0.58%
20w												
20x	**TOTAL INCREMENTAL COSTS**		**$**	**1,213,846**	**40,586**	**29,231**	**871,883**	**346,547**	**653,271**	**259,108**	**438,249**	**1,465,078**
20y	**%**		**%**	**0.42%**	**0.01%**	**0.01%**	**0.30%**	**0.12%**	**0.23%**	**0.09%**	**0.15%**	**0.51%**
20z												
25	Total Incremental Revenue Requirement		$	1,213,846	40,586	29,231	871,883	346,547	653,271	259,108	438,249	1,465,078
26												
27	Ratio of Incremental Rev Req to Rev Req											
28	**Total Revenue Requirement - Allocated based on LRIC**		$	$1,401,983	$46,877	$33,761	$1,007,019	$400,259	$754,523	$299,268	$506,174	$1,692,154
29												
30	**Test Year Revenues**		$	$3,561,584	$182,560	$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			2.54	3.89	2.25	2.05	5.14	5.23	5.84	5.23	4.05
32	Unitized Revenue to Cost Ratio			2.93	4.49	2.59	2.36	5.92	6.02	6.73	6.03	4.66
33												
34	**As-Filed**											
35	**Total Revenue Requirement - Allocated based on LRIC**		$	$1,438,680	$43,450	$31,327	$1,292,694	$429,796	$699,457	$278,731	$470,447	$1,575,311
36	Revenue to Cost Ratio			2.48	4.20	2.43	1.59	4.78	5.64	6.27	5.63	4.35
37	Unitized Revenue to Cost Ratio			2.85	4.84	2.79	1.84	5.51	6.50	7.23	6.48	5.01

CASE: UG 221
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1403

May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 225:
Regarding NW Natural's Exhibit NWN/1101 Feingold/3, where the Company provided the Storage-Demand Direct Revenue Requirement of $46,697,054 and Storage-Energy Direct Revenue Requirement of $8,265,500, which were derived by assuming a "Storage Rate Base" of $356,493,283 as provided in NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "Input," column "G," lines 129 and 133, please:

a) Is it appropriate to calculate the "Storage Rate Base" of $356,493,283 , by summing the "Total Utility Plant" of $259,196,538 and the "Depreciation Reserve" of $97,260,892? Please explain the Company's response.

b) If the response to the preceding sub-question is not, please update Exhibit NWN/1101 Feingold/3.

c) Please explain if it would be appropriate to calculate the "Storage Rate Base" by subtracting the Depreciation Reserve" of $97,260,892 from the "Total Utility Plant" of $259,196,538.

d) Is it correct NW Natural's representation that the Company rate base is $3,200,714,942 as in NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "Input," cell D129?

Response: 2/8/2012

a) Storage Rate Base was miscalculated in NW Natural's original filing. Exhibit NWN/1101 (See OPUC DR 225 Attachment - 1) has been revised to reflect the appropriate calculations for this item by deducting Depreciation Reserve from Total Utility Plant to derive Storage Rate Base, and that revision is included in response to this data request. Mr. Feingold believes that this version is the appropriate one for parties to review. However, it should be noted that the results of NW Natural's LRIC Study have not changed materially due to this recalculation for purposes of allocating NW Natural's proposed revenue increase to its rate classes or establishing the level of full cost-based Customer Charges under Rate Schedules 1 and 2. See OPUC DR 225 Attachment – 2 for the updated Exhibit NWN/1101 Work Papers.

b) See the response to part a.

c) Yes, see the response to part a.

d) No, Exhibit NWN/1101 has been revised to reflect the appropriate calculations.

NW Natural
Long-Run Incremental Cost Study – OPUC Staff Data Response 225
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) Tax Rates	(E)
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	27,725,825
Storage-Energy	4,751,900

NW Natural
Long-Run Incremental Cost Study – OPUC Staff Data Response 225
Incremental Distribution Revenue Requirements

		Units	Total (A)	1R (B)	1C (C)	2R (D)	3C Firm Sales (E)	3I Firm Sales (F)	31C Firm Sales (G)	31C Firm Trans (H)	31C Interr Sales (I)	31I Firm Sales (J)	31I Firm Trans (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	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	$	$27,725,825	$27,457	$4,327	$18,331,897	$6,342,342	$50,123	$2,324,213	$0	$0	$143,193	$0
14	Storage Revenue Requirement - Capacity	$	$4,751,900	$4,544	$902	$3,089,471	$1,149,240	$13,282	$383,599	$0	$0	$43,771	$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	$	$1,681,326	1,370	298	914,482	436,328	11,027	159,896	397	0	31,501	2,566
19													
20	Incremental Distribution Costs												
21	Incremental Distribution Costs per Customer	$		$337	$382	$376	$659	$3,015	$1,896	$2,733	$2,517	$4,169	$4,169
22	Incremental Distribution Costs per Dth/Design Day	$		$0	$13	$0	$13	$13	$13	$13	$0	$13	$13
23	Incremental Distribution Revenue Requirement	$	$252,498,472	$1,269,490	$66,280	$202,773,185	$39,856,066	$879,268	$3,201,328	$18,711	$30,201	$995,381	$38,020
24													
25	Total Incremental Revenue Requirement	$	$286,657,523										
26													
27	Ratio of Incremental Rev Req to Rev Req		87%										
28	Total Revenue Requirement - Allocated based on LRIC	$	$331,087,253	$1,504,794	$82,935	$259,999,219	$55,190,128	$1,101,516	$7,009,691	$22,070	$34,882	$1,401,983	$46,877
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	0.38	0.75	0.73	1.05	1.24	2.19	3.68	8.18	2.54	3.89
32	Unitized Revenue to Cost Ratio		1.00	0.44	0.86	0.84	1.20	1.42	2.52	4.24	9.42	2.93	4.49
33													
34	As-Filed												
35	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
36	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
37	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

Staff/1403
Ordonez/3

NW Natural
Long-Run Incremental Cost Study – OPUC Staff Data Response 225
Incremental Distribution Revenue Requirements

		31I Interr Sales (L)	32C Firm Sales (M)	32I Firm Sales (N)	32 Firm Trans (O)	32C Interr Sales (P)	32I Interr Sales (Q)	32 Interr Trans (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	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	$434,974	$67,300	$0	$0	$0	$0
14	Storage Revenue Requirement - Capacity	$0	$54,847	$12,243	$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	29,924	14,805	78,731	0	0	0
19								
20	Incremental Distribution Costs							
21	Incremental Distribution Costs per Customer	$4,176	$3,361	$5,006	$6,636	$4,983	$6,640	$16,462
22	Incremental Distribution Costs per Dth/Design Day	$0	$13	$13	$13	$0	$0	.$0
23	Incremental Distribution Revenue Requirement	$29,231	$352,138	$252,199	$574,540	$259,108	$438,249	$1,465,078
24								
25	Total Incremental Revenue Requirement							
26								
27	Ratio of Incremental Rev Req to Rev Req							
28	Total Revenue Requirement - Allocated based on LRIC	$33,761	$1,007,019	$400,259	$754,523	$299,268	$506,174	$1,692,154
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	2.25	2.05	5.14	5.23	5.84	5.23	4.05
32	Unitized Revenue to Cost Ratio	2.59	2.36	5.92	6.02	6.73	6.03	4.66
33								
34	As-Filed							
35	Total Revenue Requirement - Allocated based on LRIC	$31,327	$1,292,694	$429,796	$699,457	$278,731	$470,447	$1,575,311
36	Revenue to Cost Ratio	2.43	1.59	4.78	5.64	6.27	5.63	4.35
37	Unitized Revenue to Cost Ratio	2.79	1.84	5.51	6.50	7.23	6.48	5.01

CASE: UG 221
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1404

May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 220**:**
Regarding NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "Input," range B36:D45 (NATURAL GAS STORAGE PLANT & PROD PLANT), where the Company estimated the $251,757,033 value for Storage Plant, please:

a) Explain the source of this information including the specific timeframe(s) to which it belongs (historical, forecasted, etc.)

b) Explain how it was derived (in electronic spreadsheet format with cell references and formulae intact).

If the information was derived or obtained from other sources to NW Natural, in whole or in part, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format, indicating the specific page, section, etc. of the relevant source document(s).

Response: 2/10/2012

a) The source of this information is the 2010 NW Natural utility plant balances plus the 2011, 2012 & 2013 (Jan. – Oct.) additions.

b) The source of the information is the Rate Case Documents / 300 Revenue Requirements / Line by line explanations and workpapers / Line 16 Utility Plant in Service / WP-310-01.xls.

   The calculation of the $251,757,033 is shown in the table below:

DR 220 - Derivation of Oregon Storage & Production Plant

		Plant Balance Test Year	Oregon %	Oregon Portion	
350.1	**Land**	$ 106,549	0.9015	$ 96,054	
350.2	**Rights-of-way**	109,625	0.9015	98,827	
360.11	**Land - LNG Linnton**	83,598	0.9015	75,364	
360.12	**Land - LNG Newport**	536,675	0.9015	483,813	
360.2	**Land - Other**	128,860	0.9015	116,167	
					870,224
351	**Structures & Improvements**	6,555,425	0.9015	5,909,716	
361.11	**Structures & Improvements - LNG Linnton**	4,247,918	0.9015	3,829,498	
361.12	**Structures & Improvements - LNG Newport**	4,511,163	0.9015	4,066,813	
361.2	**Structures & Improvements - Other**	28,357	0.9015	25,564	
					13,831,591
352	**Wells**	20,047,076	0.9015	18,072,439	
352.1	**Storage Leaseholds & Rights**	3,538,491	0.9015	3,189,950	
352.2	**Reservoirs**	5,130,395	0.9015	4,625,051	
352.3	**Non-Recoverable Natural Gas**	6,440,890	0.9015	5,806,462	
362.11	**Gas Holders - LNG Linnton**	2,690,579	0.9015	2,425,557	
362.12	**Gas Holders - LNG Newport**	5,791,957	0.9015	5,221,449	
					39,340,908
353	**Lines**	6,705,058	0.9015	6,044,610	
363.11	**Liquefaction Equipment - Linnton**	4,776,213	0.9015	4,305,756	
363.12	**Liquefaction Equipment - Newport**	6,951,260	0.9015	6,266,561	
363.21	**Vaporizing Equipment - Linnton**	2,629,836	0.9015	2,370,797	
363.22	**Vaporizing Equipment - Newport**	2,481,000	0.9015	2,236,622	
363.31	**Compressor Equipment - Linnton**	180,903	0.9015	163,084	
363.32	**Compressor Equipment - Newport**	300,951	0.9015	271,307	
363.41	**Measuring & Regulating Equipment Linnton**	737,149	0.9015	664,540	
363.42	**Measuring & Regulating Equipment Newport**	113,414	0.9015	102,243	
363.5	**CNG Refueling Facilities**	1,828,161	0.901	1,647,173	
363.6	**LNG Refueling Facilities**	739,473	0.901	666,265	
					24,738,958
354	**Compressor Station Equipment**	27,957,660	0.9015	25,203,830	
					25,203,830
355	**Measuring & Regulating Equipment**	6,318,797	0.9015	5,696,395	
356	**Purification Equipment**	297,363	0.9015	268,073	
					5,964,468
357	**Other Equipment**	1,331,924	0.9015	1,200,729	
367.21	**North Mist Transmission Lines**	1,563,157	0.9015	1,409,186	
367.22	**South Mist Transmission Lines**	14,949,264	0.9015	13,476,761	
367.23	**South Mist Feeder Loop**	34,007,331	0.9015	30,657,609	
367.24	**South Mist Feeder Loop**	17,466,182	0.9015	15,745,763	
367.25	**South Mist Feeder Loop**	18,530,259	0.9015	16,705,028	
367.26	**South Mist Feeder Loop**	68,232,676	0.9015	61,511,757	
367.XX	**Adjustment ***			1,100,218	
					141,807,053
				Total on Feingold LRIC	**$ 251,757,033**

* A $1.1 million adjustment was required to make the LRIC study match the 13 month average in the revenue requirement testimony

R:\Financial Planning and Analysis\Rate Case\Plant Forecast\Data Requests\DR 220\[DR 220 supporting calculation.xlsx]DR220 Response

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 221**:**
Regarding NW Natural's Exhibit NWN/1101 Feingold/3, Storage-Energy plant of $39,340,908, please explain the rationale underlying the assumption(s) that this value was the "Wells-Well Equipment" value of $39,340,908 as provided in NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "Input," line 40.

Response: 2/10/2012

The rationale underlying the value of the "Wells-Well Equipment" is as follows:

- The forecasted system total at year-end 2011& October 31, 2012 for plant accounts 352 & 362 is $43,639,388.
- The appropriate allocation method for these plant accounts between Oregon and Washington is the Firm Volumes percentage of 90.15%.
- Multiplying the asset balance by the allocation percentage generates the Oregon allocation of $39,340,908.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response
SUPPLEMENTAL

Request No. GR1-OPUC-DR 221**:**
Regarding NW Natural's Exhibit NWN/1101 Feingold/3, Storage-Energy plant of $39,340,908, please explain the rationale underlying the assumption(s) that this value was the "Wells-Well Equipment" value of $39,340,908 as provided in NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "Input," line 40.

Response: Supplemented 2/23/2012

Based on discussions between NW Natural and the OPUC Staff on February 13, 2012 during the Company's Rate Design Workshop, the information requested by the OPUC Staff was expanded to include all plant in service accounts that are included under the Company's gas storage function.

The table below presents a description of each of the Company's storage-related plant accounts and the basis upon which each account was classified in its LRIC Study.

Account No.	Account Name	Account Balance	Description	Basis for Cost Classification in NW Natural's LRIC Study
350,360	Land and Land Rights	$870,224	This account includes the cost of lands held in fee on which underground storage wells are located, and other lands held in fee within an area utilized for the underground storage of gas.	This account was treated as demand-related to recognize that land and land rights support the plant assets that are sized to provide the maximum daily deliverability of gas from the Company's Mist Storage Facility.
351,361	Structures and Improvements	$13,831,591	This account includes the cost in place of structures and improvements used wholly or predominantly in connection with underground storage of natural gas.	This account was treated as demand-related to recognize that structures and improvements support the plant assets that are sized to provide the maximum daily deliverability of gas from the Company's Mist Storage Facility.
352,362	Wells-Wells Equipment	$39,340,908	This account includes the drilling cost of wells used for injection and withdrawal of gas from underground storage projects,	This account was treated as capacity-related to recognize that storage wells and gas holders support the creation of capacity in

			including wells kept open and used for observation. This account also includes the installed cost of holders and associated appliances used in the storage of gas above ground, or in underground receptacles.	an underground gas storage field. Gas storage capacity is defined as the maximum volume of natural gas that can be stored at the particular storage facility. The wells and wells equipment enable the injection and withdrawal of natural gas throughout the year from the Company's Mist Storage Facility.
353,363	Lines	$24,738,958	This account includes the cost installed of gas pipe lines used wholly or predominantly for conveying gas from point of connection with transmission or field lines to underground storage wells and from underground storage wells to the point where the gas enters the transmission or distribution system.	This account was treated as demand-related to recognize that storage lines are sized to support the maximum deliverability of gas from an underground storage field. Deliverability is a measure of the amount of gas that can be delivered (withdrawn) from a storage facility on a daily basis. It is also referred to as the deliverability rate, withdrawal rate, or withdrawal capacity.
354	Compressor Station Equipment – Other	$25,203,830	This account includes the installed cost of compressor station equipment used wholly or predominantly for the purpose of raising the pressure of gas for delivery to underground storage or to raise the pressure of gas withdrawn from underground storage for delivery to the transmission or distribution system.	This account was treated as demand-related to recognize that compressor station equipment is sized to support the maximum daily deliverability of gas from the Company's Mist Storage Facility.
355, 356	M&R Equipment – Meters and Gauges	$5,964,468	This account includes the installed cost of equipment used wholly or predominantly for the purpose of measuring and regulating deliveries of gas to underground storage and withdrawals of gas from underground storage and the installed cost of apparatus used wholly or predominantly for the removal of impurities from and the conditioning of, gas delivered to or removed from underground storage fields.	This account was treated as demand-related to recognize that M&R equipment is sized to support the maximum daily deliverability of gas from the Company's Mist Storage Facility.

357	Other Equipment	$141,807,053	This account includes the installed cost of equipment used wholly or predominantly in connection with underground storage of gas, when not assignable to any of the foregoing accounts.	This account was treated as demand-related to recognize that over 99% of the costs reflected in this account consisted of storage-related transmission lines that are associated with the North and South Mist underground storage facilities which are sized to support the maximum daily deliverability of gas from the Company's Mist Storage Facility.

The Company's initial response reads:

The rationale underlying the value of the "Wells-Well Equipment" is as follows:

- The forecasted system total at year-end 2011& October 31, 2012 for plant accounts 352 & 362 is $43,639,388.
- The appropriate allocation method for these plant accounts between Oregon and Washington is the Firm Volumes percentage of 90.15%.
- Multiplying the asset balance by the allocation percentage generates the Oregon allocation of $39,340,908.

CASE: UG 221
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1405

May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 274**:**
INCREMENTAL TRANSMISSION COSTS

Regarding Northwest Natural's Exhibit NWN/600 Yoshihara/3, lines 4-20:
"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 consist 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 winder already exceeds normal design requirement. For the past several years, interruptible customers in this area have experienced partial curtailment as temperatures in the area drop below 32 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 [(with the Corvallis Loop Project)], and also begin to move forward on the Mid-Willamette Valley Feeder Project that will increase peak day delivery capability in the west end of the Albany-Corvallis corridor" [emphasis added].
and
Regarding Northwest Natural's Exhibit NWN/1101 Feingold/5, where the Company provided the "Forecasted Transmission Investment per Design Day Dth" of $1,107, which was derived by dividing the Total Investment of $45,400,000 by the "Total Additional Design Day Capacity for both Projects" of 41,000 Dth/day,
Please explain why the Company assumed an Annual Cost of "$0" for interruptible service customers as represented in Exhibit NWN/1101 Feingold/4, since one of the stated reasons the Company has proposed the Corvallis Loop and the Mid-Willamette Valley Feeder projects is because interruptible customers have experienced curtailment.

Response: 2/13/2012

NW Natural has not proposed to construct the Corvallis Loop and Mid-Willamette Valley Feeder projects based on the fact that its interruptible service customers have been curtailed for the past several years. Instead, this situation is an operational outcome which indicates that insufficient firm capacity currently exists on NW Natural's gas pipeline system to accommodate all of its firm demand requirements. As a result, it is inappropriate to view interruptible service as the cause of this incremental firm pipeline capacity need.

By definition, a gas utility such as NW Natural does not install firm pipeline capacity to serve its interruptible customers. The existence of interruptible customers enables the gas utility to serve the full capacity requirements of its firm service customers. Therefore, within the context of NW Natural's LRIC Study, an increase in interruptible service does not cause NW Natural to incur incremental firm capacity costs to serve this interruptible load because it does not design and expand its gas pipeline system over time to serve interruptible customers.

Exhibit NWN/600 points out with regard to the Corvallis Loop Project that there is inadequate firm delivery capacity to meet its current firm capacity requirements as evidenced by pressure drops along this feeder during the winter that exceed normal design requirements. OPUC DR 274 Attachment-1 shows a graphic that depicts the relationship between pipeline pressure and heating degree days at the Corvallis and Philomath primary regulator stations using firm customer load requirements only. The analysis shows that the pressure drop occurring on the existing system will begin to exceed the design pressure drop standard at 35 heating degree days for Philomath and 45 heating degree days for Corvallis.

The investment in firm capacity from these pipeline projects is lumpy and designed to meet firm capacity requirements over the life of the assets. While it is true that NW Natural's customers will receive an ancillary benefit in the form of reduced exposure to service interruptions in the early years of the projects, this is an outgrowth of the addition of firm capacity to serve future firm demands rather than a strict design objective of these pipeline projects.

CASE: UG 221
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1406

May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 246**:**
Regarding Exhibit NWN/1101 Feingold/9, where NW Natural provided the "Incremental Customer-Related Distribution Costs (Test Year $)," for the following customer cost categories:
- Mains
- Services
- Meters & Regulators
- Accounting

For each customer cost category above, please:
a) Describe the cost category; and
b) Provide examples of the types of costs (e.g., labor, materials, vehicles, etc.) included in the cost category.

Response: 2/9/2012

a) Mains are the distribution pipes used to provide gas to NW Natural's Service Territory. Services are the distribution pipes used to connect a distribution main to a customer's premises. Meter & Regulators are the measuring equipment at a customer's premises used to identify the amount of gas provided to the customer. Accounting, (i.e. account services) are the activities necessary to read a customer's meter, to provide a customer with a bill, and to handle a customer's account information.

b) Mains, Services, and Meters and Regulators are all capital costs which are composed of material costs and the cost to install. Accounting includes meter reading expenses, billing expenses and customer account maintenance expenses, which are comprised of labor costs, postage, vehicle fuel, and other costs.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 237**:**
Regarding NW Natural's Exhibit NWN/1101 Feingold/7, where the Company provided a Cost per Foot value of $14.56, please explain how the Company arrived at this value. Please provide the specific assumptions underlying the estimation/calculation of this value; i.e., do not limit the response to pointing out that these values were calculated in NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "MainCap."

Response: 2/8/2012

The Cost per Foot value of $14.56 is derived from the Forecast Capital Expenditure for residential in 2011 of $843,243 divided by the number of installed feet of distribution main for the residential category. The number of installed feet for the residential category is located on the MainCap Sheet Column I, rows 19-21.

LRIC Study Requests

Last Updated 10/20/2011

Objective: **2011 - 2013 Average main per foot and average installation per job by pipe size/type**

Special Notes: **The capital expenditure forecast was driven by the meter sets forecast as well as our in house expertise. We forecast volume at a very high level; therefore, to get down to the pipe size/type detail level, an allocation based on 2 years of historical completed work was used. Again these unit cost and average installation cost do not include construction overhead. Currently, the Construction Overhead for New Mains is 112% and New Service is 79%.**
**** Please note that these unit costs do not include meter installation**

Work type	Pipe Size and Type	Based on completed Mains during Aug/2009 to Jul/2011						2011					
		Number of Jobs	Actual Installed Footage (ft)	Total Cost Without COH (Dollars)	Average Installation Cost w/o COH (Dollars)	Feet/Jobs (ft)	% Allocation (based on historical installed footage)	Installed Footage (ft)	Total Cost Without COH (Dollars)	Unit Cost per Foot w/o COH and w/o Contribution and Permit (Dollars)	Unit Cost per Foot w/o COH and with Contribution and Permit (Dollars)	Average Installation Cost w/o COH (Dollars)	Average Installation Cost w/o COH with Contribution and Permit (Dollars)
MX COMMERCIAL & INDUSTRIAL MAIN	P-0200	47	27,005	$ 385,813	$ 8,209	575	60%	29,020	$ 785,893	$ 27.08		$ 15,560	
	P-0400	13	15,306	$ 327,646	$ 25,204	1,177	34%	16,448	$ 445,432	$ 27.08		$ 31,885	
	P-0600	3	2,197	$ 360,678	$ 120,226	732	5%	2,361	$ 63,937	$ 27.08		$ 19,832	
	S-0200	4	861	$ 101,878	$ 25,470	215	2%	925	$ 25,057	$ 27.08		$ 5,829	
Total		67	45,369	$ 1,176,016	$ 17,552	677	100%	48,754	$ 1,320,318	$ 27.08	$ 25.86	$ 18,338	$ 17,509
MX RESIDENTIAL MAIN	P-0100	20	3,948	$ 52,669	$ 2,633	197	15%	3,163	$ 72,639	$ 22.97		$ 4,534	
	P-0200	97	21,813	$ 548,260	$ 5,652	225	85%	17,473	$ 401,336	$ 22.97		$ 5,165	
Total		117	25,761	$ 600,929	$ 5,136	220	100%	20,636	$ 473,975	$ 22.97	$ 21.93	$ 5,057	$ 4,829
MX SYSTEM EXPANSION	P-0100	23	4,132	$ 25,959	$ 1,129	180	3%	1,280	$ 14,079	11.00		$ 1,976	
	P-0200	189	116,238	$ 807,447	$ 4,272	615	90%	36,016	$ 396,051	11.00		$ 6,763	
	P-0400	5	8,727	$ 72,156	$ 14,431	1,745	7%	2,704	$ 29,735	11.00		$ 19,193	
Total		217	129,097	$ 905,562	$ 4,173	595	100%	40,000	$ 439,864	$ 11.00	$ 10.50	$ 6,542	$ 6,246

= 57,932 feet

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 238**:**
Regarding NW Natural's Exhibit NWN/1101 Feingold/7, where the Company provided the Installed Mains Length per New Customer of 77 feet, please, explain how the Company arrived at this value. Please provide the specific assumptions underlying the calculation/estimation of this value; i.e., do not limit the response to pointing out that these values were calculated in NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "Average Main per Service."

Response: 2/8/2012

The referenced Average Main per Service worksheet contains the installed feet of main from 2004-2010 (5,990,199 feet) and the total number of meters installed from 2004-2010 (77,816 new customer meter sets without idle and add sets[1]). The Installed Mains Length per New Customer of 77 feet is equal to (5,990,199 divided by 77,816).

[1] Idle and add sets are new customers that currently have meter and service connections

Average Main Length per Service

Last Updated 9/14/2011

Note: Assume in 2004 to 2008, System Expansion were all Residential until 2009 when SAP started to differentiate commercial and residential market in System Expansion.
To be consistent with the OPUC request, the footage and meter counts down below are based from the same Oregon data file. Therefore, Washington data is excluded from this analysis.

Installed Footages

	2004	2005	2006	2007	2008	2009	2010	Total
MX Residential	162,559	95,440	141,678	108,875	14647	6919	27489	557,607
System Expansion	1,075,700	1,022,980	1,618,492	1,348,642	84806	56191	225781	5,432,592
Total	1,238,259	1,118,420	1,760,170	1,457,517	99,453	63,110	253,270	5,990,199

# of Meters (w/o idle and addset)

	2004	2005	2006	2007	2008	2009	2010	Total
Conversion Service	3,964	3,909	1,911	3,256	3,521	2,245	2,351	21,157
New Residential Service	11,192	12,759	11,927	9,556	5,231	2,850	3,144	56,659
Total	15,156	16,668	13,838	12,812	8,752	5,095	5,495	77,816
Average Main Addition Length	82	67	127	114	11	12	46	77

2004

Grouping	SumOfQUANTITY
MX Residential Main	162559
System Expansion	1075700

2005

Grouping	SumOfQUANTITY
MX Residential Main	95440
System Expansion	1022980

2006

Grouping	SumOfQUANTITY
MX Residential Main	141678
System Expansion	1618492

2007

Grouping	SumOfQUANTITY
MX Residential Main	108875
System Expansion	1348642

2008

Grouping	SumOfQUANTITY
MX Residential Main	14647
System Expansion	84806

2009

ZBUCKET	SumOfQty
MX RESIDENTIAL MAIN	6919
MX SYSTEM EXPANSION	56191

2010

ZBUCKET	SumOfTotal
MX RESIDENTIAL MAIN	27489
MX SYSTEM EXPANSION	225781

LRIC Study Requests

Last Updated 10/20/2011

Objective: **2011 - 2013 Average main per foot and average installation per job by pipe size/type**

Special Notes: **The capital expenditure forecast was driven by the meter sets forecast as well as our in house expertise. We forecast volume at a very high level; therefore, to get down to the pipe size/type detail level, an allocation based on 2 years of historical completed work was used. Again these unit cost and average installation cost do not include construction overhead. Currently, the Construction Overhead for New Mains is 112% and New Service is 79%.**
**** Please note that these unit costs do not include meter installation**

	Q3 2011 (F)				2012 (F)				2013 (F)				
	Amount	% Cost Allocation	Permit Cost	Retained Contribution	Amount	% Cost Allocation	Permit Cost	Retained Contribution	Amount	% Cost Allocation	Permit Cost	Retained Contribution	Weighted Permit Cost
MX Residential	$ 473,975	21%	$ 25,791	$ (47,221)	$ 495,916	35%	$ 26,613	$ (15,968)	$ 304,775	21%	$ 14,369	$ (8,621)	
MX Com & Ind	$ 1,320,318	59%	$ 71,843	$ (131,541)	$ 423,096	30%	$ 22,705	$ (13,623)	$ 539,447	37%	$ 25,432	$ (15,259)	
System Expansion	$ 439,864	20%	$ 23,935	$ (43,823)	$ 489,219	35%	$ 26,253	$ (15,752)	$ 598,729	41%	$ 28,227	$ (16,936)	
TOTAL MAIN	$ 2,234,157	23%	$ 121,569	$ (222,585)	$ 1,408,231	15%	$ 75,571	$ (45,343)	$ 1,442,952	14%	$ 68,028	$ (40,817)	
	Amount	% Cost Allocation	Permit Cost	Retained Contribution	Amount	% Cost Allocation	Permit Cost	Retained Contribution	Amount	% Cost Allocation	Permit Cost	Retained Contribution	
New Construction Services	$ 1,965,583	27%	$ 106,955	$ (195,828)	$ 2,129,800	27%	$ 114,293	$ (68,576)	$ 2,951,318	32%	$ 139,139	$ (83,484)	
Conversion Services	$ 3,866,210	53%	$ 210,375	$ (385,184)	$ 4,132,128	52%	$ 221,746	$ (133,047)	$ 4,374,613	48%	$ 206,241	$ (123,744)	
Commercial Services	$ 1,508,841	21%	$ 82,102	$ (150,323)	$ 1,647,112	21%	$ 88,390	$ (53,034)	$ 1,836,726	20%	$ 86,592	$ (51,955)	
TOTAL SERVICE	$ 7,340,634	77%	$ 399,431	$ (731,335)	$ 7,909,040	85%	$ 424,429	$ (254,657)	$ 9,162,657	86%	$ 431,972	$ (259,183)	
Average Permit Cost			$ 73				$ 71				$ 60		$ 67
Grand Total	$ 9,574,791		$ 521,000	$ (953,920)	$ 9,317,270		$ 500,000	$ (300,000)	$ 10,605,608		$ 500,000	$ (300,000)	

	Cost per Foot		
Residential Totals	$ 14.56	$ 15	$ 14
Commercial Totals	$ 25.07	$ 20	$ 21
	Permit and Retained Contribution		
Residential Totals	$ (19,430)	$ 10,259	$ 11,031
Commercial Totals	$ (458)	$ 242	$ 260
2011 Dollars			
Residential Totals	$ 843,244	$ 972,968	$ 879,808
Commercial Totals	$ 1,289,897	$ 465,491	$ 590,355

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 307**:**
307. Tab "Average Main per Service" from Feingold.1101 Workpapers depicts what is employed as an average "Installed Mains Length per New Customer" (see line 25 of NWN/1101 Feingold/7). Does Northwest Natural (or NWN or Company) possess average main lengths by schedule (preferably) or by customer category (i.e., residential, commercial, industrial) on either an imbedded or a new-customer basis (or both)? Please provide all averages available to you and identify whether they are based upon published industry figures, Northwest Natural's own empirical records, or sample extrapolations.

Response: 2/21/2012

NW Natural does not classify mains by rate schedule. The "Installed Mains Length per New Customer" in tab "Average Main per Service" from NWN/1011 Feingold/7 work paper depicts figures for the average main length for residential segments. NW Natural classifies industrial and commercial mains together. By applying the same methodology used to estimate the average main length for residential segments, it was possible to estimate that the average footage for commercial and industrial segments combined is 85 ft. See OPUC DR 307 Attachment-1 for this calculation. If all classes are combined, the result is an average length of 77 feet. See OPUC DR 307 Attachment-2.

Because a single main may serve more than one customer class, the data on a customer class basis may not be totally accurate in terms of identifying classes of customers served by that main. For example, if a main is installed because of a request for service by a commercial customer and several residential customers are able to connect to that main as well, the main will most likely be classified as commercial – associating it with the customer class that initiated the service installation.

At the recent workshop with Staff and parties on LRIC/Rate design, Staff asked us to clarify the note that appears at the top of the "Average Main per Service" tab in "1100 – Feingold – Workpaper -1.xls". That note refers to the fact that before the Company implemented SAP, system expansion was not differentiated by customer classes, and all system expansion was assumed to be residential. In fact, most system expansion is typically related to new residential subdivisions. After implementation of SAP, however, the system allowed for system expansion to be differentiated between Residential and C&I System Expansion. While most of the footage in System Expansion continues to be linked to residential new subdivisions, there were a handful work requests identified as

System Expansion Commercial, with minimal volume. The note was intended to clarify that the SAP numbers reported in the worksheet exclude anything classified as C&I after implementation of SAP. C&I System Expansion was instead added to MX C&I (main extension C&I). In summary, this means that to the best of NW Natural's knowledge, the mains reported and classified by customer class are appropriately classified.

Also, to follow-up on a discussion at the recent workshop with respect to the use of 77 feet for the minimum system component and the resulting cost of a 2-inch main of $1,120 in 2011 dollars, there is no reason to change this analysis in the Company's LRIC Study. The $1,120 value is considered to be the customer component of distribution mains for all rate classes (see Column (A) of NWN/1101 Feingold/9 in which the incremental customer-related mains investment is the same for each rate class). The residential class only receives a customer component equal to $1,120 per customer and the remaining mains investment amount is allocated on a demand basis to the other non-residential rate classes. In this way, there is no double counting of costs and the demand component is attributed only to customers with generally higher design day demands than the residential classes.

Average Commercial and Industrial Main Length per Service

Last Updated 02/08/2012

Note: The figures down below include both Commercial (big and small commercial) and Industrial.
To be consistent with the OPUC request, the footage and meter counts down below are based from the same Oregon data file. Therefore, Washington data is excluded from this analysis.

Installed Footages

	2004	2005	2006	2007	2008	2009	2010	Total
MX Commercial and Industrial	76,755	52,116	97,662	77,573	4,138	21,292	23,399	352,935
Total	76,755	52,116	97,662	77,573	4,138	21,292	23,399	352,935

# of Meters (w/o idle and addset)

	2004	2005	2006	2007	2008	2009	2010	Total
Commercial & Industrial Service	655	730	658	670	688	423	311	4,135
Total	655	730	658	670	688	423	311	4,135

Average Main Addition Length	117	71	148	116	6	50	75	85

Average Company Main Length per Service

Last Updated 02/14/2012

Note: The figures down below include Commercial (big and small commercial), Industrial, and Residential
To be consistent with the OPUC request, the footage and meter counts down below are based from the same Oregon data file. Therefore, Washington data is excluded from this analysis.

Installed Footages

	2004	2005	2006	2007	2008	2009	2010	Total
Total Company Installed FT	1,315,014	1,170,536	1,857,832	1,535,090	103,591	84,402	276,669	6,343,134
	1,315,014	1,170,536	1,857,832	1,535,090	103,591	84,402	276,669	6,343,134

# of Meters (w/o idle and addset)

	2004	2005	2006	2007	2008	2009	2010	Total
Total Company # of Meter Sets	15,811	17,398	14,496	13,482	9,440	5,518	5,806	81,951
	15,811	17,398	14,496	13,482	9,440	5,518	5,806	81,951

Average Main Addition Length	83	67	128	114	11	15	48	77

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Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 248**:**
Regarding Exhibit NWN/1101 Feingold/9, column (D), where the Company provided the test year "Services Investment" per customer of each customer class (e.g., 1R, 1C, 2R…32 Interr Trans), which were derived by escalating the 2009 service costs provided in range K7:K23 of NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "MainsMeterServ," please explain and provide any supporting documentation regarding how the Company arrived at the 2009 service costs values. In your response, please include the specific assumptions underlying the estimation/calculation of this values; i.e., do not limit the response to pointing out that these values were calculated in NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "Service Average by Rate Class."

Response: 2/9/2012

Service costs provided in range K7:K23 of NW Natural's workpapers, workbook "1101-Feingold Workpaper -1" worksheet "MainsMeterServ" were based on three years of historical actual costs: 2008, 2009, and 2010. The service cost in range K7:K23 was calculated by taking the average actual cost (Column C in worksheet "Service Average by Rate Class") minus retained contributions (column D in worksheet "Service Average by Rate Class"), and plus weighted forecast permit cost (column E in worksheet "Service Average by Rate Class").

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Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 249**:**
Regarding Exhibit NWN/1101 Feingold/9, column (G), where the Company provided the test year "Meters & Regulators" investment per customer for each customer class (e.g., 1R, 1C, 2R…32 Interr Trans), which were derived by escalating the 2009 "Wt. Avg Meter Cost[s]" provided in range F7:F23 in NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "MainsMeterServ," please explain and provide any supporting documentation regarding how the Company arrived at the 2009 "Wt. Avg Meter Cost[s]" values.
In your response, please provide the specific assumptions underlying the estimation/calculation of this values; i.e., do not limit the response to pointing out that these values were calculated in NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "FreqTable."

Response: 2/9/2012

See OPUC DR 249 Attachment-1 for the source of the cost data. The LRIC Study weights the cost and count of each type of meter by rate class to determine the average meter costs in each rate class.

See also the Company's response to OPUC DR 250.

Staff/1406
Ordonez/13

NW Natural

Section: Construction Cost Estimating Preparation Procedures

Subject: Cost Estimating Guide, Fixed Construction Costs

Revision: 04 (supersedes Rev 03, 4/22/05) Effective Date: 11/29/10

Approved:	K. F. Shampine, 11/29/10		Reviewed:		
	Name	Date		Name	Date

Purpose

The tables in this section are to be used when estimating the fixed construction costs for new construction and conversion services, meter set assemblies, and district/service regulator assemblies and relief's in conjunction with the policy set forth by Oregon and Washington tariffs (P.U.C. Or. 24, Schedule X, and WN U-6, Schedule E, respectively). This data is to be used unless site-specific costing is required.

Fixed Cost Estimating Tables

- Table 1 identifies costs associated with installing new services based on market segment.
- Table 2 identifies costs associated with installing residential & 2 psig delivery meter sets.
- Table 3 identifies costs associated with installing 5 psig (or greater) delivery meter sets.
- Table 4 identifies costs associated with installing district regulators, relief's, and service regulators.

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Table 1: Costs for New Services Based on Market Segment	
Market Segment	**Cost**
Residential Conversion SF on EM and Residential Conversion MF less than 4 units on EM	$2042 [1] $3624 [2] Site Specific Estimate [3]
Residential Conversion SF on MX	Site Specific Estimate
Residential Conversion MF 4 units or greater on EM	Site Specific Estimate
Residential Conversion MF on MX	Site Specific Estimate
Residential New Construction SF on EM This is the same cost for Unity, Open Pathway, Closed Pathway	$625 [4]
Residential New Construction SF on MX	Site Specific Estimate
Residential New Construction Spot lot on EM	Site Specific Estimate
Residential New Construction Spot lot on MX	Site Specific Estimate
Residential New Construction MF 4 units or greater on EM	Site Specific Estimate
Residential New Construction MF less than 4 units on EM	$625 [4]
Residential New Construction MF on MX	Site Specific Estimate
Commercial on EM and MX	Site Specific Estimate
Industrial on EM and MX	Site Specific Estimate

[1] System average cost for normal installation with no extraordinary construction conditions. Cost includes meter and COH at 10.4%.

[2] System average cost for installation with one or more of these extraordinary construction conditions: (1) Major arterial; (2) excess rock; (3) service line greater than 300 feet. Cost includes meter and COH at 10.4%.

[3] Installation with extraordinary construction conditions other than set forth in note [2].

[4] System average cost for normal installation. Cost includes meter and COH at 10.4%. Add costs as set forth by Oregon and Washington tariffs (P.U.C. Or. 24, Schedule C, and WN U-6, Schedule C, respectively) for company-provided pathway.

Glossary of Terms

EM = Existing Main
MX = Main Extension
SF= Single Family
MF = Multi Family (Note: Less than 4 units default cost is used, 4 units or greater the site is measured for cost)
COH = Construction Overhead

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Table 2: Costs for Residential & 2 psig Delivery Meter Sets

Drawing Number	Nominal Meter Size	Main Pressure	Delivery Pressure (psig)	Capacity (SCFH)	Capacity (Therms)	Installed Cost WO/COH ($)*	Rate Schedule
250 METER SETS							
D-03-46-A-1-12	250	B	STANDARD	250	3	212	1R
D-03-46-A-2-14							
D-05-35-A-1-10	250-RESIDENTIAL	B	2	602	6	213	1R / 2R
D-05-38-A-1	250-COMMERCIAL	B	STANDARD & 2	602	6	311	1C
630 METER SETS							
D-05-37-A-3	630-RESIDENTIAL	B	2	1,516	16	612	1R / 2R
D-05-39-A-1	630-COMMERCIAL	B	STANDARD & 2	1,516	16	647	3C / 3I
1000 METER SETS							
D-05-46-A-5	1000-COMMERCIAL	B	STANDARD & 2	2,407	25	1100	3C / 3I / 31C / 31I
ROTARY METER SETS							
D-05-52-A-1	8C175TQM	B	2	864	9	1825	3C / 3I / 31C / 31I
D-05-54-B-4	15C175TQM	B	2	1,729	18	1866	3C / 3I / 31C / 31I
D-05-53-B-3	3M175TQM	B	2	3,361	35	2188	3C / 3I / 31C / 31I
D-05-48-B-1	5M175TQM	B	2	5,666	59	3803	3C / 3I / 31C / 31I
D-05-50-B-1	5M175TQM	B	2	5,666	59	3788	3C / 3I / 31C / 31I
D-05-49-B-1	7M175TQM	B	2	7,875	82	3979	3C / 3I / 31C / 31I
D-05-51-B-1	7M175TQM	B	2	7,875	82	3965	3C / 3I / 31C / 31I
D-05-61-B-2	11M175TQM	B	2	12,478	129	3902	3C / 3I / 31C / 31I
D-05-62-B-2	11M175TQM	B	2	12,478	129	3836	3C / 3I / 31C / 31I
SPECIALTY ASSEMBLIES							
D-05-40-A-2	250-RESIDENTIAL	B	2	602	6	235	1R / 2R
D-05-41-A-3	630-RESIDENTIAL	B	2	1,516	16	600	1R / 2R

*Installed Cost WO/COH includes the installation of a Meter Set WITHOUT Construction Overhead, and the Meter Shop Technician and Weld Shop labor required to build the assembly.

Staff/1406
Ordonez/16

NW Natural

Table 3: Costs for 5 psig (or Greater) Delivery Meter Sets							
Drawing Number	**Nominal Meter Size**	**Main Pressure**	**Delivery Pressure (psig)**	**Capacity (SCFH)**	**Capacity (Therms)**	**Assembly Cost WO/COH ($)***	**Rate Schedule**
D-07-68-B-16	11M175TQM	B	5	14,716	152	8,125	32C / 32I
D-07-68-B-16	16M175TQM	B	5	21,405	221	8,582	32C / 32I
D-07-68-B-16	23M232TQM	B	5	30,769	318	10,163	32C / 32I
D-07-69-B-16	11M175TQM	B	FLOATING	37,092	383	10,477	32C / 32I
D-07-69-B-16	16M175TQM	B	FLOATING	53,951	557	10,934	32C / 32I
D-07-69-B-16	23M232TQM	B	FLOATING	77,555	800	12,515	32C / 32I
D-07-72-B-16	5M175TQM	B	5	6,689	69	3,801	3C / 3I / 32C / 32I
D-07-73-B-15	7M175TQM	B	5	9,365	97	3,977	3C / 3I / 32C / 32I
D-07-77-B-11	8C175TQM	B	5	1,050	11	2,313	3C / 3I / 32C / 32I
D-07-77-B-11	15C175TQM	B	5	2,000	21	2,317	3C / 3I / 32C / 32I
D-07-77-B-11	3M175TQM	B	5	4,013	41	2,372	3C / 3I / 32C / 32I
D-07-80-B-12	5M175TQM	B	5	6,689	69	3,671	3C / 3I / 32C / 32I
D-07-81-B-12	7M175TQM	B	5	9,365	97	3,847	3C / 3I / 32C / 32I
D-07-82-B-12	11M175TQM	B	5	14,716	152	4,161	32C / 32I
D-07-82-B-12	16M175TQM	B	5	21,405	221	4,618	32C / 32I
D-07-83-B-12	11M175TQM	B	5	14,716	152	8,457	32C / 32I
D-07-83-B-12	11M175TQM	B	5	14,716	152	8,844	32C / 32I
D-07-83-B-12	16M175TQM	B	5	21,405	221	8,914	32C / 32I
D-07-83-B-12	16M175TQM	B	5	21,405	221	9,301	32C / 32I
D-07-83-B-12	23M232TQM	B	5	30,769	318	10,495	32C / 32I
D-07-83-B-12	23M232TQM	B	5	30,769	318	10,882	32C / 32I
D-07-84-B-17	23M125TQM	B	FLOATING	77,555	800	16,284	32C / 32I
D-07-86-B-8	38M125TQM	B	FLOATING	128,134	1,322	20,474	32C / 32I
*****ALL FLOATING METER SETS THAT REQUIRE INSTRUMENTATION, NERTEC AND LABOR ADD = $1845*****							
*****FIXED FACTOR METER SETS THAT REQUIRE PULSAR, NERTEC AND LABOR ADD = $548*****							
*Assembly Cost WO/COH includes the installation of a Meter Set WITHOUT Construction Overhead, the ERT installation on meters, the constituent components, the sub-assemblies that make up the meter set, and the Meter Shop Technician and Weld Shop labor required to build the assembly.							

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Table 4: Costs for District Regulators, Relief's, and Service Regulators		
Description	Drawing No.	Assembly Cost WO/COH ($)*
DISTRICT REGULATOR STANDARD DRAWINGS		
1" District Reg. (below ground installation) 61-720 inlet MAOP	F-02-20-B-11	2638
1" District Reg. (above ground installation) 61-720 inlet MAOP	F-02-21-B-12	2196
1" District Reg. (below ground installation) 721-1000 inlet MAOP	F-02-26-B-2	3254
1" District Reg. (above ground installation) 721-1000 inlet MAOP	F-02-27-B-2	2817
2" District Reg. Vert. (above ground installation) 61-600 inlet MAOP	F-03-31-B-14	3698
2" District Reg. Vert. Double Run (above ground installation) 61-600 inlet MAOP	F-03-32-B-14	7402
2" District Reg. Vert. (above ground installation) 721-1000 inlet MAOP	F-03-35-B-9	5714
2" District Reg. Vert. Double Run (above ground installation) 721-1000 inlet MAOP	F-03-36-B-7	11242
2" District Reg. (below ground installation) 61-600 inlet MAOP	F-03-40-B-2	4555
DISTRICT REGULATOR RELIEF STANDARD DRAWINGS		
4" Axial Flow Relief Installation (below ground) inlet MAOP up to 60 PSIG	F-09-35-B-6	4230
6" Axial Flow Relief Installation (below ground) inlet MAOP up to 60 PSIG	F-09-36-B-6	7024
4" Axial Flow Relief Installation (above ground) inlet MAOP up to 275 PSIG	F-09-43-B-14	3415
6" Axial Flow Relief Installation (above ground) inlet MAOP up to 275 PSIG	F-09-46-B-11	5659
2" 1805P-6358 Relief Installation (above ground) inlet MAOP up to 60 PSIG	F-09-47-B-8	2320
2" Axial Flow Relief Installation (above ground) inlet MAOP up to 60 PSIG	F-09-48-B-9	2075
PRIMARY SERVICE REGULATOR STANDARD DRAWINGS		
1" Primary Service Regulator (below ground installation) 61-720 inlet MAOP	G-01-21-B-17	1728
1" Primary Service Regulator (above ground installation) 61-720 inlet MAOP	G-01-22-B-16	1870
1" Primary Service Regulator (below ground installation) 721-1000 inlet MAOP	G-01-29-B-2	1797
1" Primary Service Regulator (above ground installation) 721-1000 inlet MAOP	G-01-30-B-2	1938
*Assembly Cost WO/COH includes the installation of a Meter Set WITHOUT Construction Overhead, the constituent components and sub-assemblies that make up the district regulator, relief, or service regulator, and the Meter Shop Technician and Weld Shop labor required to build the assembly.		

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 251**:**
Regarding Exhibit NWN/1101 Feingold/9, column (L), where the Company provided the test year "Accounting Annual Cost" per customer," for each customer class (e.g., 1R, 1C, 2R…32 Interr Trans), which were derived from NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "Accounting," please explain how the Company arrived at such values.
In your response, please provide the specific assumptions underlying the estimation/calculation of this values; i.e., do not limit the response to pointing out that these values were calculated in NW Natural's workpapers, workbook "1101 - Feingold Workpaper – 1," worksheet "Accounting."

Response: 2/9/2012

On the worksheet entitled, "Accounting," NW Natural provided a detailed listing of costs by FERC account for certain sub accounts. An analysis was performed to identify costs that could be specifically associated with a particular revenue class. If a cost was specifically associated with a revenue class, that cost was directly assigned to that revenue class. Other costs were allocated to the revenue classes based on the average number of customers in each revenue class. The resulting allocation of costs were summed by revenue class and used to create a percentage-based allocator to allocate the total customer costs included in NW Natural's test year. The resulting allocation of test year costs was then divided by the average number of customers to derive the average "Accounting" test year costs by revenue class presented in Column (L) of NWN/1101 Feingold/9.

CASE: UG 221
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1407

May 3, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 330**:**
Regarding Exhibit NWN/302 McVay-Siores/1 column "e," in which column "e" Proposed Total" line 4 "Total Operating Revenues" has a value of $742,978 thousand and the line 5 "Gas Purchased" has a value of $395,039, with a difference between the two of $347,939 thousand;
and
Line 10 of Exhibit NWN/1101 Feingold/1, where the "Total Revenue Requirement" value is $331,087,253;
please explain the difference between the $347,939 thousand derived from Exhibit NWN/302 and the $331,087 thousand in Exhibit NWN/1101, and provide a detailed reconciliation of such values, in electronic spreadsheet format with cell references and formulae intact.

Response: 2/20/2012

The difference between the two numbers referenced in this data request is due to miscellaneous revenues, revenues from special contracts and the revenue sensitive gross up on gas costs. See OPUC DR 330 Attachment-1.

Revenue sensitive costs are those costs and fees that are charged on the basis of revenues and include franchise tax, regulatory fees and uncollectible expense. The Company updates the revenue sensitive rate each year as part of its Purchased Gas Adjustment (PGA) filing.

NW Natural
Oregon Jurisdictional Rate Case - UG 221

Staff/1407
Ordonez/2

Staff DR 330

Reconciliation of revenue requirement and total test year revenues less cost of gas expense ($000's)

Line	Description	Amount	Exhibit / Reference
3	Total Proposed Operating Revenue	$742,978	Exhibit NWN/302, line 4 column e
5	Gas Purchased	$395,039	Exhibit NWN/302, line 5 column e
7	Total Revenue less Gas Purchased	$347,939	line 3 less line 5
9	Total Revenue Requirement	$331,087	Exhibit NWN/1101, line 10 column a
11	**Variance**	**$16,852**	
14	Reconciliation		
15	Revenue sensitive gross up on gas costs	$11,609	see lines 28-38 below
17	Miscellaneous Revenues	$3,429	Exhibit NWN/302, line 3 column e
19	Revenues from Special Contracts	$1,814	Exhibit NWN/303, line 10 & 11, column f
21	**Variance reconciled**	**$16,852**	
28	Calculation of gas cost gross-up [a]:		
29	Gas costs collected (includes revenue sensitive)	$406,648	Workpaper 303, "Oregon Rev & Cost Model Test Year.xls", tab "Normal Revs by RS w MDDV Demand', line 68, columns j+k+l
31	Gas cost expense (excludes revenue sensitive)	$395,039	Exhibit NWN/302, line 5 column e; also at Workpaper 303, "Oregon Rev & Cost Model Test Year.xls", tab "Normal Revs by RS w MDDV Demand', line 68, column p
33	Revenue sensitive gross up on gas costs	$11,609	

[a] Revenue sensitive costs are those costs and fees that are charged on the basis of revenues and include franchise tax, regulatory fees and uncollectible expense. The revenue sensitive rate is updated each year during the Purchased Gas Adjustment (PGA) filing. Schedule P, at sheets P-2 and P-3, reflect the tariff rates for weighted average cost of gas (WACOG) and non-commodity costs both with and without the revenue sensitive gross-up. The rates with revenue sensitive were used to derive gas costs on line 29 and rates without revenue sensitive were used to derive gas costs on line 31. These rates were also reflected in the Workpaper 303 file mentioned above, on the tab "Other inputs & calcs".

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 306**:**
Column A, line 28 of NWN/1101 Feingold shows a "Total [Net] Revenue Requirement…" of $331,087,253. Please "functionalize," or de-compose, that amount (i.e., so that the parts add up to the total revenue requirement) into the following categories: Transmission (per se), Storage, Mains, Services, Meters & Regulators, Customer Accounts – Plant Related, Non-Plant Related Customer Accounts – Directly Assigned (i.e., per the Accounting tab of the Feingold.1101 Workpapers), Non-Plant Related Customer Accounts – Other (i.e., allocated in proportion to customer count), All Other.

a. The revenue requirement associated with Customer Accounts – Plant Related includes the return on the net rate base (i.e., related plant less accumulated depreciation), current depreciation expense, property-related taxes, and income tax.

b. Please supply the FERC Account Numbers and descriptions for the accounts underlying the just listed "All Other" category.

Response: 2/21/2012

a) A precise and detailed response to this question requires the completion of an embedded cost of service study. Although NW Natural was not required to perform such a study, Mr. Feingold has undertaken to provide a reasonable approximation of the requested data by modifying the cost of service data contained in1101-Feingold Workpaper-1 (under the Input tab). The "Input" spreadsheet contains plant balances and expense amounts by FERC account, with each account originally functionalized according to the following categories: Prod-Dist Other, Storage, Mains, Services, Meters & Regulators, and Customer Accounts. This "Input" spreadsheet was modified to also include a Transmission function and three Customer Accounts categories based on the functional categories specified in the question (see the attached file named, OPUC Staff Data Request 306.xlsx). The amounts by FERC account in the above-described file were totaled to derive a total embedded cost of service composed of a tax adjusted return on net rate base, depreciation expense, taxes other than income taxes, and operating expenses. This total on Line 323 formed the basis for an allocator which was applied to the Company's Total (Net) Revenue Requirement of $331,087,253 on Line 327 to derive the Total (Net) Revenue Requirement by function. This approach was utilized because NW Natural's proposed rate request was derived using various adjustments that were not available to Mr. Feingold by FERC account.

The specific assumptions made by Mr. Feingold to functionalize certain plant and expense amounts are listed below:

- Intangible Plant – Total Utility Plant excluding Intangible Plant (Line 95)
- General Plant – Total Labor-Related Expenses (Line 261)
- Depreciation Reserve – Associated plant accounts
- Materials & Supplies – Total Utility Plant excluding Intangible Plant (Line 95)
- Deferred Income Taxes - Total Utility Plant excluding Intangible Plant (Line 95)
- Operation Supervision & Engineering (Account No. 870) – All other Operating Expenses (Line 231)
- Maintenance Supervision & Engineering (Account No. 885) – All other Operating Expenses (Line 231)
- Administrative & General Expenses (Labor-Related) – Total Labor-Related Expenses (Line 261)
- Administrative & General Expenses (Plant-Related) – Total Utility Plant excluding Intangible Plant (Line 95)
- Administrative & General Expenses (Other) – Total Utility Plant excluding Intangible Plant (Line 95), Total Rate Base (Line 134), and Total Labor-Related Expenses (Line 261).
- Depreciation Expense – Associated plant accounts
- Taxes Other Than Income Taxes (General Taxes) – Total Rate Base (Line 134) and Total Labor-Related Expenses (Line 261)
- Revenue-Related Taxes – Total Rate Base (Line 134)

b) See OPUC DR 306 Attachment-1, for the requested information. The “All Other” category consists of any FERC account with a balance in column (D) - Prod-Dist Other.

NW NATURAL
Long-Run Incremental Cost Study – Response to OPUC Staff Data Request 306

Line No.	Account Description	Account Code	Account Balance	Prod-Dist Other	Transmission	Storage	Mains	Service	Meters	Cust Acct Plant	Cust Acct O&M Direct	Cust Acct O&M by Cust
1	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)			(J)
325	Percentage allocator		100.00%	11.24%	1.89%	10.37%	34.25%	18.46%	10.55%	1.91%	4.91%	6.43%
326												
327	Total Revenue Requirement		331,087,253	37,210,000	6,265,911	34,332,770	113,387,169	61,109,690	34,939,372	6,326,842	16,240,488	21,275,010

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 275**:**
Please provide, in electronic spreadsheet format with cell references and formulae intact, information on a system-wide basis regarding interruptible customers, as requested in the attachment to this data request (i.e., "Attachment - Interruptible Customers Information"). Please also:
a) Identify each customer and their rate schedule/service type though a numbering system if the Company believes the name of the Company is confidential;
b) Provide the length of time each customer experienced partial/total interruption (in Hours); and
c) Provide each customer's foregone purchases of gas (Dth).
If the information was derived or obtained from other sources, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format indicating the specific page, section, etc. of the relevant source document.

Response: 2/13/2012

NW Natural objects to this request because the Company does not have the data in the format requested in the data request attachment "Attachment – Interruptible Customer Information", and for the Company to provide such data in that format would be unduly burdensome and would not provide more relevant information than the information presented in the format attached to this data request. Further, all of the data required to populate the requested attachment is either provided here, or provided in other data request responses such that Staff would be able to compile the information in the manner that Staff deems useful for purposes of its analysis. Without waiving this objection, NW Natural provides the following response in an effort to assist Staff with the analyses it understands Staff would like to perform.

a) See OPUC DR 275 Attachment-1. This attachment is confidential because it contains customer-specific information. See OPUC OPUC DR 275 Attachment-1 REDACTED. The non-redacted information is in the folder on the Company's FTP site titled CONFIDENTIAL SUBJECT TO PROTECTIVE ORDER 12-001 in the subfolder Confidential Data Responses, and is titled OPUC DR 175 Attachment-1 CONFIDENTIAL.
b) See OPUC DR 275 Attachment-1.
c) The Company cannot provide this information as we have no method of determining how much gas customers would have used had their service not been interrupted.

Customer-specific usage data for the Oregon customers represented in OPUC DR 275 Attachment-1 has been previously provided. See the Company's response to OPUC DR 193.

CASE: UG 221
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1500

Opening Testimony
Residential Rate Design

May 3, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is George R. Compton. I am a Senior Economist employed by the Economic Research and Financial Analysis Division (ERFA) of the Public Utility Commission of Oregon (OPUC). My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is included as Exhibit Staff/1501.

Q. PLEASE CONVEY THE ESSENCE OF YOUR TESTIMONY.

A. I am proposing to move the residential rate structure for the Northwest Natural Gas Company (NW Natural or Company) onto a much firmer cost-causation basis. This entails: a) increasing the monthly customer charge to include broadly acknowledged customer-cost elements; and, b) the introduction of a winter-summer volumetric price differential in order to properly incorporate peak-seasonal cost elements. Staff opposes the Company's proposal to recover all of the distribution costs that are allocated to the residential class through a customer charge that would reach $29 per month by latter 2014. Staff concurs with NW Natural's recommendation that in the event of an overall revenue requirement increase in the neighborhood of 1% that the revenue requirements for the commercial and industrial classes remain largely unchanged from what are produced by the current rate structures for those classes. In that same spirit, and taking into consideration whatever revenue requirement adjustments for those classes are ultimately deemed appropriate, Staff on the occasion of this Opening Testimony remains neutral regarding the rate design modifications proposed by the Company for this docket.[1]

In preparing this testimony, the Company's filed application was reviewed along with responses to the twenty-one data requests which I submitted.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Topic 1 – Major Points and Recommendations of this Testimony

Topic 2 – A Brief General Rate Design Discussion

Topic 3 – Proposed, Cost-Based Reforms to NW Natural's Residential Rates

Topic 4 – The Pros and Cons of Straight-Fixed/Variable Pricing, and Why the Cons Outweigh the Pros

Q. DID YOU PREPARE EXHIBITS FOR THIS CASE?

A. Yes, they are listed as follows:

1501 – Witness Qualification Statement

1502 – Three Residential Rate Designs: Status Quo, Straight-Fixed/ Variable, Staff-Proposed.

1503 – Computations Supporting Staff's Proposed Rate Design

1504 – Monthly and Annual Residential Billing Comparisons

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[1] As of this writing, there are three outstanding data requests from Staff which seek information regarding proposed alterations to Schedule 31 customer charges and the Company's intent to eliminate interruptible sales under Schedule 31.

TOPIC 1 – MAJOR POINTS AND RECOMMENDATIONS OF THIS TESTIMONY

Q. WHAT ARE THE MAIN POINTS OF YOUR TESTIMONY?

A. They are as follows:

- The "Rate, or Revenue, Spread" process establishes the portions of the overall revenue requirement that are assigned to each customer schedule in the tariff.[2] The first requirement of the "Rate Design" process is to construct pricing elements for each schedule which produce its assigned level of revenues (i.e., assuming the accuracy of the test period sales projections). Beyond that, and typically receiving much greater attention, are the twin rate design goals of fostering both economic efficiency and social equity or fairness.
  - As a general rule, prices based upon underlying costs promote both economic efficiency and fairness.
    - Current circumstances relating primarily to wholesale gas cost trends require some compromise in the simultaneous pursuit of the two rate design objectives.
- While some argue that the customer charge should be more expansive, few argue against the inclusion of the following cost elements: Meters, meter reading, billing, and the service line which connects the meter with the gas mains that are typically in the

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[2] Staff's rate spread testimony in this case is Staff/1400, sponsored by Jorge Ordonez.

street.[3] Staff opposes placing in the fixed customer charge the costs of resources whose usage is shared – notably mains. Staff particularly opposes placing in a fixed customer charge the costs of resources that are not only shared, but whose costs are in fact *not* fixed. Examples of these latter costs are the gas utility's storage and transmission costs, which increase as peak loads increase.

- o Staff is recommending a ten dollar monthly customer charge for all residential customers. (The current Schedule 2R customer charge is six dollars.[4])
- o Largely to avoid rate shock from more than doubling the customer charge, Staff has chosen in this case to include only a portion of the average cost of service lines in its recommended residential customer charge.

- Gas storage costs are incurred to enable the utility to efficiently meet winter peak demands and to allow some purchases of gas to occur during the lower-cost summer season, thereby reducing the average cost of gas sold in the winter. Gas storage can also be used to avoid peak transmission costs by using storage to meet some of the peak

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[3] The electricity equivalent of the service line is the service "drop," which connects the electric meter with the nearby transformer (which, in turn, either hangs on a power pole or is mounted on an underground serving pad).

[4] The Schedule 1R amount is $5. Only 0.7% of residential customers are included in Schedule 1R. The Company is proposing to not allow any more customers to enter that schedule. Staff is proposing to terminate the 1R schedule, and include all of its customers with Schedule 2R. That would leave Schedule 1 as only serving commercial customers.

loads instead of having to purchase all of the gas needs during peak periods. Similarly, pipeline capacity costs, i.e., the charges imposed by the transmission companies who deliver gas to NW Natural, are a direct function of the peak level of delivery to that utility. Some of NW Natural's own transmission costs are also peak-delivery determined. Staff believes strongly that the costs incurred directly for the benefit of, or to meet, winter loads should be charged to winter loads via a winter-time per-therm volumetric charge rather than being spread throughout the entire year.

  - The winter-summer differential proposed by Staff would be in the neighborhood of 25 cents per therm.
  - Because of the shift of some costs from the status quo volumetric charge over to the customer charge, Staff's proposed *winter* rate for residential customers would still be about the same, or even slightly below, the current year-round rate of $1.05 per therm.

- It is generally recognized that much of a distribution gas utility's own costs[5] are fixed, at least in the short run if not the long run. However, for pricing purposes at least, NWN overstates the level of costs that are fixed. For example, Company witness Russell Feingold would place *all* of that utility's *own* costs that are assigned

[5] By definition, a *distribution* gas utility (as opposed to an integrated gas utility) does not own the sources of its gas supply. Accordingly, a distribution utility's *own* costs do not include what it pays to its pipeline suppliers and other wholesale gas sources.

to the residential class in the "fixed" portion of the Company's proposed straight fixed-variable rate design. For Residential Schedule 2 that fixed charge would be approximately $29 per month, or about three times the level recommended by Staff.

- The rectitude of a simple straight fixed-variable (SFV) rate design depends on the accuracy of the assumption that the costs incorporated in the customer charge are indeed uniform across the customers within the class. That assumption can't be sustained. There is a range of underlying distribution costs associated with every customer schedule.
- By far the single largest cost component of a distribution gas utility pertains to the mains, i.e., the gas lines that go down the streets to deliver gas to the customers. The large differences among neighborhoods in the density of their domiciles translate to large differences in the costs of mains required to serve those neighborhoods. The greater the customer density, the less footage of mains is required to serve each customer.

- A "perfect" residential customer charge[6] would relate the customer charge to the length of main "dedicated" to each customer.[7]
    - In point of fact, lengths of main are not "dedicated" to individual customers because unless a customer is at the end of the line he effectively shares "his" length of main with all the customers downstream from him. It is Staff's position that when a resource is shared, it is reasonable to recover the costs of that resource from customers in consideration of their levels of use of the resource and the timing of their usage in relation to peak demands. Such is achieved through a volumetric price rather than a through a uniform fixed monthly charge.
- The fact that residential gas consumption tends to be inversely related to domicile density (i.e., high-density apartment and town-house dwellers use less gas than is used in large, single family residences), means that a

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[6] That is, in some narrow sense – for example disregarding the high implementation costs of such an approach and the conservation implications of shifting cost recovery from a volumetric, or per-therm, charge to a fixed customer charge.

[7] The cost of the service line to serve that customer would also be factored into the "perfect" customer charge.

rough justice in terms of cost-causation would be served by collecting the costs of mains through a per-therm volumetric charge whereby those who use more gas will pay more of the costs of the mains.

- Tariff Schedule X embodies a traditional mechanism by which up-front payments are received from new customers who are unlikely to produce sufficient volumes of sales over time to allow the Company to recover its fixed investments in connecting those customers to the system. The specific numerics that go into Schedule X will depend upon the ultimately established customer charge and whether or not Schedule 1R is consolidated with Schedule 2R. Decoupling, whereby the Company is assured of cost recovery in the presence of lower-than-average consumption also has implications vis a vis Schedule X.

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<u>TOPIC 2 – A BRIEF, GENERAL, RATE DESIGN DISCUSSION</u>

Q. WHAT IS THE CONNECTION BETWEEN RATE DESIGN AND RATE, OR REVENUE, SPREAD?

A. Rate Spread refers to the exercise of dividing the utility's overall revenue requirement among the rate classes or tariff schedules. Rate design consists of the service price elements that principally constitute those tariffs. If the test-year-projected sales volumes are achieved, revenues produced by the designed prices will precisely equal the respective schedules' revenue targets as they were spelled out in the revenue spread process.

Q. A HOST OF DIFFERENT PRICES COULD BE COMBINED TO YIELD A PARTICULAR REVENUE TARGET. WHAT GUIDELINES ARE THERE FOR ESTABLISHING SPECIFIC PRICES?

A. Generally speaking, there is a two-fold objective of rate design as applied to each customer class – it is to promote both equity and economic efficiency. Fortunately, both values tend to be achieved by basing prices on costs.

Q. IN SIMPLE ECONOMIC EFFICIENCY TERMS, WHAT ARE THE ADVANTAGES OF HAVING PRICES REFLECT RESPECTIVE MARGINAL COSTS?

A. If the price of a good or service is too high relative to its cost on the margin, that good or service will tend to be under-consumed in the sense that the cost of its production will be less than the relative value that would have been achieved had it been produced and consumed. Conversely, if the price of a good or service is too low relative to its cost on the margin, that good or service will tend to be over-consumed in the sense that the cost of its production will be greater than the relative value that is yielded by its consumption.

Q. YOU HAVE JUST PUT FORTH THE ECONOMIC EFFICIENCY ARGUMENT FOR HAVING PRICES ACCURATELY REFLECT COSTS. WHAT IS THE EQUITY ARGUMENT FOR THAT SAME KIND OF ACCURACY?

A. Equity in ratemaking usually refers to having those who cause the costs being those who bear the costs through the rates that are charged. In general rate cases the matter of equity is addressed most prominently in the context of the cost-of-service/rate-spread regulatory objective of avoiding some customer classes being subsidized by other classes by virtue of the latter's revenue requirement allocations exceeding their fair shares of costs while the former's allocations are beneath their shares of costs. However, there can also be a problem of customers' subsidizing other customers *within* the same schedule. For example, if gas prices are the same year-round even though costs are greater in the winter, the upshot is for customers who are consuming gas more heavily in the winter season to be subsidized by customers whose use does not fall so heavily in that high-cost season.[8]

Q. HAVING OBSERVED LITTLE OR NO RESPONSIVENESS BY MANY CUSTOMERS TO PRICES THAT REFLECT COSTS (I.E., THEIR CONSUMPTION IS RELATIVELY FIXED, WHATEVER THE PRICE), SOME HAVE ARGUED THAT UTILITY REGULATION SHOULD DE-EMPHASIZE COST-BASED PRICING IN FAVOR OF OTHER CONSIDERATIONS. PLEASE COMMENT.

A. Equity in this context can be viewed as having primacy over economic efficiency in the sense that even if (improbably) customers are totally

[8] Preponderant winter gas-use customers are those who use natural gas mostly, or even entirely, for space heating. The greater load-factor customers use gas year-round for such purposes as water heating, clothes drying, and cooking.

unresponsive to prices (meaning that there would be no economic efficiency benefits from cost-based pricing), there remains an equity benefit from cost-based pricing in having customers pay for the costs they impose on the system.

But I agree that efficiency and cost-based equity are not the sole utility rate design considerations. For example, “gradualism” (i.e., minimizing “rate shock” by not precipitously moving rates closer to costs) is a well-established pricing criterion. Other grounds put forth for resisting cost-based rates are less compelling. For example, some in their opposition to seasonal rates argue that the status quo should be preserved because it serves to stabilize bills over the course of the year and better protects customers who are somehow vulnerable. With regard to the first argument: Much more complete bill stabilization can be achieved by participating in voluntary equal-pay plans. The second argument is particularly tenuous for two reasons: 1. As regards seasonal rates, while raising rates in some season(s) may impose some pain – at that time – to some vulnerable cohorts, the offsetting reduction of rates in the rest of the year will not only assist other vulnerable cohorts which have a different seasonal load profile but may actually entirely offset the larger bills experienced by the former group in the high-cost season. 2. Orthodox regulatory economic wisdom holds that palliative measures to assist the vulnerable should be administered on a targeted basis -- focusing on those in need rather than introducing price distortions that would be applied to all customers within a particular class.[9]

Q. THE COMMISSION'S COMMENTS IN THE UM 1415 DOCKET PLACED A LOT OF EMPHASIS ON THE POTENTIAL FOR SYSTEM COST SAVINGS DUE TO CUSTOMERS' SHIFTING THEIR LOADS AWAY FROM THE PEAK PERIODS IN RESPONSE TO PRICE SIGNALS. WHAT MIGHT BE THE RELEVANCE OF SEASONAL RATES IN A UM 1415 CONTEXT?

A. Higher winter gas prices certainly won't cause gas heating loads to shift to the non-winter in the same manner that high daily peak-period electricity rates might cause customers to shift some of their discretionary electrical loads to the lower-priced periods of the day. But some gas system cost savings can still be expected to occur owing to the kind of winter-season rates advocated by the Staff. In the short and long run, the basic price elasticity effect of the higher-than-otherwise rate will encourage some reduction in consumption. The longer run effect has to do with the type of customer-conservation-responsiveness that is either carried out individually or through the Energy Trust of Oregon. Higher gas prices encourage more intensive housing weatherization and increases the attractiveness of the more efficient gas space heating and other appliances that have higher front-end costs. And pertaining to the subsequent discussion of long-run

[9] That is not to say that regulators should be insensitive regarding placing burdens upon the less fortunate when careful cost analyses would lead to the contrary.

and short-run "fixed costs," reduced winter loads enable the utility a) to delay adding to its storage capacity, and b) to reduce its pipeline capacity charge/obligations.

TOPIC 3 – STAFF'S PROPOSED, COST-BASED REFORMS TO NW NATURAL'S RESIDENTIAL RATES

Q. PLEASE DESCRIBE THE CURRENT RESIDENTIAL RATE STRUCTURE, FOCUSING UPON RESIDENTIAL SALES SERVICE RATE SCHEDULE 2.

A. There is a monthly $6 customer charge, a $0.42899 per-therm Base Rate,[10] a $0.48994 per-therm Commodity charge, and a $0.13472 per-therm Pipeline Capacity charge. They are shown, respectively, on lines 9, 11, 7, and 8 of Staff/1502 Compton/1. The Base Rate serves to recover NW Natural's own costs that are not otherwise recovered through the $6 customer charge. The Commodity and Pipeline Capacity charges are, respectively, to recover what the utility pays for the gas it purchases and for the interstate pipeline transportation of that gas from its sources. The revenue requirements associated with those latter two charges are outside the scope of this general rate case.

Q. NW NATURAL IS ASKING THAT THE MONTHLY RESIDENTIAL CUSTOMER CHARGE BE ELEVATED TO $13.70 FOR THE TEST

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[10] That figure includes the "Base Rate Adjustment." The separate "Temporary Adjustment" is ignored since it will go away with the completion of this rate case.

PERIOD (ON THE WAY TO $29.09 AFTER TWO MORE YEARS). DOES STAFF HAVE AN ALTERNATIVE PROPOSAL?

A. Yes. It is to raise the monthly charge to $10, which would be in place indefinitely. (For reasons to be discussed below, Staff rejects the straight fixed/variable notions that underlie the $29 rate.)

Q. WHAT PRINCIPLES HAS THE STAFF EMPLOYED IN OBTAINING ITS $10 CUSTOMER CHARGE PROPOSAL?

A. The primary motivating philosophy is that the customer charge should cover only those costs which each customer, unambiguously, imposes on the system. That philosophy would suggest the inclusion of the following customer-cost elements: meters, meter reading, billing, and the service lines which connect the individual customers' meters with the *shared* gas mains.

The industry generally classifies costs as either energy-related or demand-related, with what's left over being categorized as customer-related costs. The inclination of many utilities, including NW Natural in the current docket, is to lump into the customer charge all of costs that are deemed as customer-related. Staff rejects this broad, "catch-all" approach to customer-charge inclusion. The upshot is to recover many of the generic, not easily classified costs through volumetric charges rather than through fixed monthly customer charges.

Q. I NOTICE THAT YOU DID NOT INCLUDE MAINS (WHICH IS THE SINGLE LARGEST COST ITEM OF NW NATURAL) WITH YOUR LIST

OF ITEMS FOR COST RECOVERY THROUGH THE CUSTOMER CHARGE. CONTRARILY, MR. RUSSELL FEINGOLD CLASSIFIES THE LARGE BULK OF THE COST OF MAINS AS CUSTOMER-RELATED AND INCLUDES THE ENTIRE COST OF MAINS THAT IS ALLOCATED TO THE RESIDENTIAL CLASS AS PART OF HIS $29 RESIDENTIAL CUSTOMER CHARGE.[11] ON WHAT GROUNDS WOULD STAFF EXCLUDE MAINS COST RECOVERY FROM THE RESIDENTIAL CUSTOMER CHARGE?

A. Having observed that standard-diameter mains are not sized to reflect the levels of demand they are expected to accommodate, Mr. Feingold classifies the bulk of main costs as "customer-related,"[12] and allocates those costs accordingly. Staff acknowledges as a general matter that the costs of mains, once installed, are indeed fixed and are neither demand- nor energy-driven. But just because costs are neither demand- nor energy-driven in the conventional engineering-economics sense does not constitute a sufficient justification for recovering those costs through a fixed customer charge. As I have previously argued,[13] when explicit cost causation for

[11] Mr. Feingold does not advocate that approach for the commercial and industrial schedules.

[12] To avoid the tendency to place expansively-defined "customer-related costs" into the customer charge, Staff prefers in this context to label what are non-demand-related costs as "non-demand-related" rather than as "customer-related."

[13] *See* Staff/1100 Compton/24-26 in the 2009 PacifiCorp Docket No. UE 210.

some resource cannot be established,[14] then some form of volumetric charge satisfies the fairness notion that revenues paid for a service should correlate with benefits received, which in turn are most conveniently measured by some form or level of usage.

Q. IN YOUR PREVIOUS ANSWER YOU REFERRED TO COSTS THAT ARE NEITHER DEMAND- NOR ENERGY-DRIVEN *IN THE CONVENTIONAL ENGINEERING-ECONOMICS SENSE*. DO YOU HAVE SOMETHING IN MIND THAT WOULD TIE THE COST OF MAINS TO DEMAND OR ENERGY USAGE IN SOME *NON-* CONVENTIONAL ENGINEERING-ECONOMICS SENSE?

A. I do. There is evidence of a significant relationship between the cost of mains and gas usage. That evidence points to customer density being inversely related to *per-customer* gas usage. The implication is that customers who tend to impose smaller main costs burdens (due to high-density housing occupancy) also tend to use less gas than the average: therefore having mains' cost recovery through a volumetric charge (whereby less usage translates to smaller bills) is a reasonable way of connecting gas rates with the underlying costs.

[14] As with much of the electric distribution infrastructure, explicit cost-causation for mains is elusive at best. Who causes the cost of the main in front of my house? Is it I, who might not even be a gas customer? Is it my across-the-street neighbor who happens to be a gas customer? "Is it the twenty customers located between my house and where the pipe ends, and who depend on the portion of main in front of my house for its role in transporting gas to their houses? The best answer is that both the costs and the benefits of the main in front of my house are shared, and attempting to isolate cost responsibility to a particular customer is a fool's errand.

Q. HAVE YOU A READY EXAMPLE OF CATEGORIES OF RESIDENTIAL CUSTOMERS WITH GREATER LOCATIONAL DENSITIES, AND THEREFORE LOWER MAINS COSTS?

A. Yes. Apartments, townhomes, and duplexes have much greater density than do single-family dwellings. That means that the length of main attributable to each multi-family-dwelling customer is well under the 77 feet assumption that underlies the single largest cost component of the "fixed" portion of Mr. Feingold's fixed-variable rate design.

Q. OKAY, APARTMENTS AND THE LIKE WILL ENTAIL LOWER-THAN-AVERAGE MAINS COSTS. WHAT INFORMATION DO YOU POSSESS REGARDING THEIR USAGE?

A. The response to Staff Data Request No. 204[15] stated that "the Company estimates that the average annual consumption of Schedule 2 [i.e., residential] customers who are occupants of multi-metered, multi-family dwellings in Oregon is 269.8 therms." That figure compares to a projected test-period average for Schedule 2 of 650 therms.

It is intuitively obvious that multi-family dwellings will be expected to have lower-than-average heating usage for the following reasons:

- Less floor space means less area to heat.
- Common walls between dwellings mean less heat-losing outer-wall footage per area of floor space.

[15] This Data Request and Response is replicated as Exhibit Staff/1503 Compton/2.

- A greater likelihood of multiple stories/levels means less heat-losing roof area per area of floor space.

Q. WOULD NOT THE GREATER CUSTOMER DENSITY ASSOCIATED WITH APARTMENT HOUSING REQUIRE LARGER DIAMETER MAINS TO SERVE THEM – MEANING GREATER COSTS?

A. NW Natural's witness Russell Feingold discusses at some length the scale economies of gas distribution.[16] His main point was that a lot of additional design day capacity can be obtained at surprisingly little incremental cost, if any.

Q. YOU HAVE DISCUSSED MULTI-FAMILY DWELLINGS, HOW ABOUT UNATTACHED, SINGLE-FAMILY DWELLINGS?

A. The same principles hold. All else equal, larger homes tend to have larger lots and deeper set-backs – translating to greater main and service costs – and they tend to require more gas for their heating. They also tend to have more occupants, which translates to more hot-water usage and clothes drying and the associated gas consumption if the respective appliances are gas-fired rather than electrical. So again, usage bears a positive relationship with mains cost causation.

Q. WHAT KIND OF RATE MECHANISM WILL ALLOW THE LOWER-COST/ LOWER-USE CUSTOMERS AND HIGHER-COST/HIGHER-USE CUSTOMERS TO HAVE BILLS THAT ACCORD WITH THOSE DUAL CORRESPONDENCES?

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[16] *See* NWN/1100 Feingold/12-14.

A. Because there is some (inverse) correlation between usage and customer density, rough justice can be achieved through the conventional volumetric charge applied to usage – as proposed by Staff. The rate mechanism that does *not* “accord with that correspondence” is to recover the mains costs through a uniform customer charge that applies to all customers regardless of their level of service.[17]

Q. YOU JUST USED THE EXPRESSION, “ROUGH JUSTICE,” IMPLYING THAT YOU RECOGNIZE THAT SOME APARTMENT OR TOWNHOME DWELLERS WILL BE LARGE USERS OF GAS AND SOME SINGLE FAMILY DWELLINGS ON LARGE LOTS WILL BE SMALL USERS. BY EMPLOYING A VOLUMETRIC CHARGE TO RECOVER MAINS COSTS, WILL NOT THE FORMER CUSTOMERS BE OVER-CHARGED AND THE LATTER UNDER-CHARGED FROM THE POINT OF VIEW OF COST CAUSATION?

A. Utility ratemaking is far from an exact science: for example, much cost averaging is inevitable. However, there is a broad sense of perceived justice that makes palatable what you just described. By its light, bills should track consumption fairly closely. So if, for example, an energy-*in*efficient apartment uses twice as much gas as an energy-efficient, large-lot-occupying single family residence, it is normally regarded as quite appropriate for the former’s bill to be roughly twice the level of the latter’s.

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[17] An alternative cost-based approach *a propos* to mains and used by some gas utilities is to have different tariffs for different residential demographics.

Obviously that will not happen with the kind of fixed-variable residential pricing proposed by NW Natural.

Q. YOU HAVE DISCUSSED WHETHER OR NOT THE COSTS OF METERS, METER READING, BILLING, SERVICE LINES, AND MAINS SHOULD BE INCLUDED IN THE RESIDENTIAL CUSTOMER CHARGE. HOW ABOUT THE COSTS OF STORAGE AND TRANSMISSION – WHICH MR. FEINGOLD ALSO INCLUDES IN HIS $29 CUSTOMER CHARGE?

A. I will first note that for marginal cost-of-service purposes Mr. Feingold attributes 100 percent of incremental transmission cost causation to the winter design day *demands*, and allocates all of incremental storage costs to customer schedules on the basis of a combination of the schedules' design day *demands* and winter-season *sales*. Because design day demand and winter-season sales have increased over time due to customer growth, storage and transmission costs certainly are not fixed in a marginal cost sense and are classified – including by Mr. Feingold – as demand- or winter-load-related and not as customer-related. It is Staff's strongly held opinion that even though storage and transmission costs may be fixed in the short run, they are variable in the long run – and, accordingly, the costs of storage and transmission should be recovered through a volumetric charge rather than a fixed customer charge.[18]

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[18] While changes in the loads of existing customers will *not* affect the costs of the mains *serving those customers*, changes in those same loads *will* affect the degree to which the utility must add storage or transmission capacity to its system. That is why Staff regards the costs of mains as, in an economics sense, "fixed" over the long- (and short-) run.

Q. NOW THAT WE HAVE SETTLED WHAT DOES AND DOES NOT ENTER STAFF'S CONCEPTION OF THE PROPER CUSTOMER CHARGE, HAVE YOU PREPARED AN EXHIBIT THAT SHOWS THE DEVELOPMENT OF YOUR $10 RESIDENTIAL FIGURE?

A. Yes. Staff/1502 Compton/1 shows the derivation of something in excess of $12 per month. Doubling the customer charge (i.e., from $6 to $12) would violate the principle of gradualism: a $10 customer charge would be more appropriate at this time.

I would add that some of the same principles discussed just above in this testimony about connecting usage levels with the costs of mains (and therefore justifying cost recovery through a volumetric charge) would apply to service lines. Duplexes and townhouses tend to have shorter setbacks from the street (and, therefore, shorter service lines) than do single-family dwellings that are typically on larger lots. Apartments may have longer setbacks, but scale economies relating to their service lines (i.e., one larger service line can serve multiple meters) also produces lower service costs per customer. So with the smaller gas usage tied to those higher-density customers, they can claim to appropriately pay a smaller customer charge, where that charge includes cost recovery for service lines.

Q. ARE YOU CONCERNED THAT ELEVATING THE CUSTOMER CHARGE AS YOU HAVE PROPOSED WILL INDUCE A NUMBER OF

(From an accounting point of view, the costs of mains are also "variable" insofar as the mains accounts values change over time with the addition of new subdivisions and new customers who occupy them.)

CUSTOMERS TO TEMPORARILY (E.G., FOR THE SUMMER SEASON) DISCONNECT THEIR SERVICE IN ORDER TO AVOID PAYING THE CUSTOMER CHARGE OVER THE MONTHS WHERE THEY DON'T RECEIVE SERVICE?

A. No. The following "Special Provision" that is proposed (and supported by Staff) for inclusion in Residential Rate Schedule 2 should be dispositive: "A Customer that requests reconnection of service at the same address following a Temporary Disconnection of Service shall pay the minimum bill [i.e., the Customer Charge] due under this Rate Schedule *for each month* [emphasis added] of the Temporary Disconnection, in addition to the reconnection charge set forth in Schedule C…." In other words, trying to avoid costs through the disconnect/re-connect process would, fittingly, be futile. After all, the costs of his meter and service line do not go away just because a customer decides to disconnect for a few months.

Q. LET US NOW RETURN TO THE VOLUMETRIC PORTION(S) OF THE RESIDENTIAL PRICE STRUCTURE. YOUR HAVING SAID NOTHING TO THE CONTRARY, CAN I ASSUME THAT THE COMPANY'S PRICES YOU LISTED ABOVE ARE DESIGNED TO BE IN PLACE THROUGHOUT THE ENTIRE YEAR?

A. You can. The tariff makes no distinctions regarding seasonality.

Q. IN THE PACIFIC NORTHWEST, AND WITH REGARD TO ELECTRICITY, WE EXPERIENCE TWO PEAK SEASONS EACH YEAR – MID-SUMMER AND MID-WINTER. DOES THE FACT THAT IN THE REALM OF GAS

UTILITIES WE EXPERIENCE A SINGLE PEAK – IN THE WINTER – HAVE IMPLICATIONS REGARDING COST CAUSATION?

A. It certainly does. There is no ambiguity about what season's loads are adding costs to the system.

Q. EARLIER YOU REFERRED TO TRANSMISSION AND STORAGE COSTS AS BEING DEMAND OR WINTER LOAD-RELATED. IN WHAT SENSE DO WINTER LOADS "DRIVE" TRANSMISSION AND SYSTEM STORAGE COSTS?

A. Unlike the case with service lines and residential area mains[19], transmission and storage capacity are sized to meet winter peak or winter season demands.

Q. ARE THERE OTHER GAS UTILITY COSTS THAT ARE ALSO DRIVEN BY SYSTEM PEAK DEMAND?

A. Yes, what are referred to as "Pipeline Capacity" costs are purely demand driven. As stated by the Company in its response to Staff's Data Request No. 437, the amount charged to NW Natural by its interstate pipeline suppliers is entirely a function of the utility's peak demand.[20]

Q. RESIDENTIAL GAS METERS DO NOT MEASURE DEMAND, PER SE, SO HOW MIGHT RESIDENTIAL PRICES BE STRUCTURED SO AS TO CAPTURE WINTER-PEAK COST CAUSATION?

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[19] Staff joins Mr. Feingold in recognizing the role – albeit not large – played by demand in the cost and sizing of mains in commercial and industrial areas.

[20] *See* Staff/1503 Compton/3.

A. The cheapest and most direct way is for the winter-time volumetric charge to be elevated to incorporate the season-specific costs.

Q. HAVE YOU PREPARED AN EXHIBIT THAT SHOWS HOW STAFF WOULD INCORPORATE SEASON-SPECIFIC COST CAUSATION IN ITS VOLUMETRIC CHARGES?

A. Yes. Staff/1503 Compton/1 shows the derivations of the volumetric surcharges; lines 36 and 37 of Staff/1502 Compton/1 show the final volumetric rates. At this point I would alert you to the fact that my rates development is based upon Company load projections and a residential revenue requirement that is unchanged from what is produced by the prices in the current tariff. I held things constant for purposes of ease of comparability. The specific values will ultimately be modified slightly on the basis of alterations of load projections and the final revenue requirement determination and spread.[21]

Q. WHAT IF THE AUTHORIZED OVERALL REVENUE REQUIREMENT IS SOMEWHAT GREATER OR SOMEWHAT BELOW THE REVENUES PRODUCED BY THE CURRENT TARIFF? MORE PRECISELY, HOW WILL SUCH AFFECT YOUR SUGGESTED CUSTOMER CHARGE AND VOLUMETRIC RATES?

A. Because our $10 customer charge does not match Staff's recognized customer costs in any event, the $10 recommendation will remain in effect

[21] Because the number of residential customers in Schedule 1 is so small, folding those customers and their loads into the Schedule 2 rates calculation has virtually no effect.

whatever the revenue requirement outcome. The winter volumetric surcharges have a rather sound cost basis and also would not be expected to change from our recommendation. That means that the "moving" rate will be the year-round volumetric distribution charge. I would also note that the primary Staff rate spread model assumes an overall revenue requirement increase of 15%. Should the increase be something substantially less than that figure, Staff is recommending slight revenue requirement decreases for commercial and industrial schedules. Such would be offset by a revenue requirement increase to the residential schedule, which, again, would translate to an increase in the year-round volumetric distribution charge.

Q. I NOTICE THAT YOUR WINTER SEASON EXTENDS FROM NOVEMBER THROUGH APRIL. ISN'T THAT RATHER LONG, ESPECIALLY ON THE SPRING END?

A. It is, but I have two reasons for making that six-month determination: 1) That period better matches the WARM billing adjustment period; 2) it leads to bills that more closely emulate those of the status quo (i.e., recognizing that this consideration is more meritorious for some than for others).

Q. HAVE YOU PREPARED AN EXHIBIT THAT COMPARES BILLINGS UNDER STAFF'S PROPOSED RESIDENTIAL RATE DESIGN WITH BILLINGS UNDER THE STATUS QUO AND WITH A PURE, STRAIGHT FIXED/VARIABLE DESIGN?

A. Yes. Staff/1504 Compton/1 shows the monthly and annual billing under those three alternatives for an average customer, for a customer with substantially greater than average usage, and for a customer with substantially lower than average usage. Compton/2 of that same exhibit shows the winter and summer billings under the status quo and under Staff's proposal over a large range of monthly usage levels.

Q. NW NATURAL HAS PROPOSED TO FREEZE RESIDENTIAL SCHEDULE 1R, A SCHEDULE WITH FEWER THAN ONE PERCENT OF THE RESIDENTIAL CLASS AND WHOSE USAGE IS BUT A FRACTION OF THAT OF THE MEMBERS OF THE DOMINANT SCHEDULE, 2R. WHAT IS STAFF'S RECOMMENDATION IN THIS REGARD?

A. Staff is in accord with allowing no new customers to enter Schedule 1R. We believe that a properly constituted Schedule X will assure the Company of cost recovery in the cases of customers whose low level of usage would have previously placed them in Schedule 1R. But in the interest of tariff simplicity and administrative ease, Staff would go beyond the freeze idea. It is Staff's recommendation that 1R be removed from Schedule 1 (retaining that schedule for commercial customers only), with existing and otherwise future 1R customers placed onto Schedule 2R.

Q. HAVE YOU PREPARED AN EXHIBIT WHICH INDICATES THE IMPACT ON SCHEDULE 1R CUSTOMERS OF BEING ABSORBED IN SCHEDULE 2R?

A. Yes. Compton/3 of exhibit Staff/1504 compares Schedule 1R monthly bills with winter and summer billings under Staff's rate design proposal over a range of monthly usage levels. Note that the increase seen be the average 1R customer is modest compared to what Staff's cost-of-service analysis would have justified were Schedule 1R to be preserved as a stand-alone schedule.[22]

TOPIC 4 – STRAIGHT FIXED/VARIABLE PRICING FOR RESIDENTIAL CUSTOMERS: PROS AND CONS

Q. IN DEVELOPING STAFF'S RESIDENTIAL RATE DESIGN PROPOSAL, YOU PRESENTED THE FOLLOWING ARGUMENTS AGAINST PLACING COST RECOVERY EXCLUSIVELY IN THE CUSTOMER CHARGE:

- CUSTOMER LOADS CAN HAVE A DIRECT AFFECT ON SYSTEM STORAGE AND TRANSMISSION COSTS[23]: VARIABLE COSTS SHOULD NOT BE RECOVERED THROUGH A FIXED CHARGE THAT HAS NO RELATION TO LOADS.
- THE FIXED CHARGE DOES NOT CAPTURE SEASONAL COST CAUSATION – AGAIN RELATED TO STORAGE AND TRANSMISSION COSTS.

[22] *See* line 54 of Staff/1402 Ordonez/1.

[23] By contrast, changing loads has no affect on the metering, billing, service line, and mains costs associated with the customer.

- UNDERLYING THE JUSTIFICATION FOR CHARGING ALL CUSTOMERS THE SAME FIXED AMOUNT FOR THE COST RECOVERY OF MAINS ARE THE ASSUMPTIONS THAT THE SAME LEVEL OF MAINS COSTS CAN BE ATTRIBUTED TO ALL CUSTOMERS AND THAT A VOLUMETRIC CHARGE WOULD NOT BETTER CAPTURE DIFFERENT LEVELS OF MAINS COST ATTRIBUTION. EVIDENCE PREVIOUSLY SHOWN IN THIS TESTIMONY DEFIES BOTH ASSUMPTIONS.
- FIXED COST RECOVERY OF MAINS AND OTHER SHARED RESOURCES VIOLATES THE COMMON FAIRNESS EXPECTATION THAT MONTHLY BILLINGS SHOULD BE DIRECTLY PROPORTIONAL TO GAS USAGE.

IS THERE A LEGITIMATE, ECONOMICS BASED ARGUMENT IN SUPPORT OF MINIMIZING THE VOLUMETRIC CHARGE AS PER THE STRAIGHT FIXED-VARIABLE APPROACH?

A. There is. It is the standard notion of marginal-cost-based pricing. Due primarily to fracking, the marginal cost of producing natural gas has fallen to a level well below even the volumetric rate that remains if all the Company's own costs were recovered through fixed charges. Gone are the days when increasing marginal production costs could justify the high volumetric rates that also could readily incorporate environmental/conservation considerations. Having said that, I would re-affirm the natural gas industry's observation regarding the greater efficiency of using gas directly in home appliances as opposed to burning a greater amount of gas required to produce the electricity that would operate the equivalent home appliances.[24] The efficiency of encouraging a greater penetration of natural gas-fired appliances is fostered through low volumetric gas prices.

Q. YOU HAVE JUST DESCRIBED AN ECONOMIC EFFICIENCY VIRTUE OF MARGINAL COST PRICING. CAN THERE BE AN EQUITY THREAT ASSOCIATED WITH MARGINAL COST PRICING, PARTICULARLY WHEN MARGINAL COSTS ARE BENEATH AVERAGE COSTS?

A. There definitely will be such a threat. If all units of consumption were priced at the lower, marginal cost level, the utility would not come close to achieving full cost recovery. So the question becomes what units of consumption, and, therefore, which array of customers, are to bear what degrees of responsibility for covering the utility's revenue requirement. In a very real sense we cannot escape embracing some form of embedded-cost (as opposed to marginal-cost) based pricing. As we do so, fairness in allocating and pricing the utility's embedded costs assumes a prominent guiding role.

Q. ONE LAST QUESTION ON THIS SUBJECT: IS THERE AN ECONOMIC EFFICIENCY HAZARD THAT WOULD BE PRODUCED BY RESIDENTIAL

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[24] It is argued that more electricity is produced in America by a combination of hydro, coal, and nuclear facilities than by natural-gas-fired plants. But due to the unavailability, environmental, or prohibitive new-facilities cost associated with the historic alternatives, on the margin virtually all new electric generating plants are gas-fired.

FIXED-VARIABLE PRICING AND ITS ASSOCIATE $29 CUSTOMER CHARGE?

A. There is. It is twofold. 1) The Company estimates a loss of about fourteen thousand residential customers who would permanently drop of the system rather than pay that large charge. That wasteful loss would idle perfectly good meters and service lines that would still be in the rate base, with their cost recovery falling on the remaining customers. As Mr. Feingold himself has argued, all other customers benefit by keeping customers on the system as long as they are paying their marginal costs.[25] Staff's proposed ten-dollar customer charge plus its partial distribution cost recovery through the volumetric rate would allow the *existing*, but marginal, customers to recover far more than their true *marginal* costs, which boil down to meter-reading and billing.[26]

2) Those who would be vacating the system have benefited from their modest levels of gas consumption in the past and would continue to benefit in the future – *but not to the tune of a flat-loaded $29 customer charge.* Insofar as those benefits would exceed the marginal cost of those customers' retention, their departure would constitute an economic welfare loss.

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[25] *See* NWN/1100 Feingold/8 Lines 11-21.

[26] The meters and service lines are "sunk," not marginal, costs

Q. TO CONCLUDE, DOES STAFF HAVE OTHER RECOMMENDATIONS TO THE COMMISSION IN THIS AREA BESIDES THE ADOPTION OF STAFF'S PROPOSED RESIDENTIAL RATE DESIGN?

A. There are two recommended instructions to NW Natural that Staff would like to see as part of the Final Order in this docket. They are:

1) The Company should examine its existing customer demographics to obtain a better understanding of a) how mains costs and per-customer average lengths of mains vary among customer schedules or classes, and b) the depth of the relationship within customer schedules between the costs of mains and the levels of customer usage.

2) The Company should coordinate with Staff and other interested parties in its efforts to refine Schedule X to account for whatever residential rate design and residential decoupling are put into place.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1501

Witness Qualification Statement

May 3, 2012

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist (1/2), Economic Research & Financial Analysis Division (ERFA)

ADDRESS: 550 Capital Street NE, Suite 215
Salem, OR 97301-2551

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah I also taught economics part-time for about ten years at BYU. Prior to my utility regulatory career I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California. I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), an AVISTA General Rate Case (UG 181), the 2008 and 2008 PGE General Rate Cases (UE 197 and UE 215), the 2009 PacifiCorp General Rate Case (UE210), and the 2011 Idaho Power General Rate Case (UE 233).

CASE: UG 221
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1502

Three Residential Rate Designs: Status Quo, Straight Fixed-Variable, Staff Proposed

May 3, 2012

The Development of Three Residential Schedule (2R) Rate Designs

1	**Target Test Year "Distribution" (i.e., exclusive of "Cost of Gas") Revenues**	$	$188,891,594	For comparison convenience it is assumed that the revenue requirement does not change.			
2							
3	**Current Residential (2R) Tariff Amounts and Resulting Revenues**						
4	Test Year Distribution Revenues From Current Rates	$	188,891,594		Line 30 of NWN/1101 Feingold/1		
5	Average Number of Customers		538,601		Line 1 of NWN/1101 Feingold/1		
6	Annual Sales	Th	349,920,397		Line 14 of Staff/1503 Compton/1		
7	Cost of Gas - "Commodity" - per Therm of Sales	$/Th	0.48994		Current Tariff		
8	Cost of Gas - "Pipeline Capacity" - per Therm of Sales	$/Th	0.13472		Current Tariff		
9	**Current Residential (2R) Monthly Customer Charge**	$/Mo.	6.00		Current Tariff		
10	Revenues from Current $6 Customer Charge	$	38,779,242		Line 5 x Line 9 x 12		
11	Charge to Produce Distribution Revenues Net of Customer Charge Revenues	$/Th	0.42899		(Line 4 - Line 10) / Line 6		
12	Volumetric Charge Components			Yr-Round Dist. Charge	Commodity Charge	Pipeline Capacity Charge	
13	**Residential Total Volumetric Charge and its Components**	$/Th	1.05365	0.42899	0.48994	0.13472	
14							
15	**Simplified Straight Fixed-Variable (SFV) Option**						
16	Cost of Gas - "Commodity" - per Therm of Sales	$/Th	0.48994		Current Tariff		
17	Cost of Gas - "Pipeline Capacity" - per Therm of Sales	$/Th	0.13472		Current Tariff		
18	**Monthly Customer Charge to Collect Total Target Test Year Distribution Revenues**	$/Mo.	29.23		Line 1 / Line 5 / 12		
19	Revenues Collected from SFV Customer Charge	$	188,891,594		Line 18 x Line 5 x 12		
20	Volumetric Charge Components			Commodity Charge	Pipeline Capacity Charge		
21	**Residential Total Volumetric Charge and its Components**	$/Th	0.62466	0.48994	0.13472		
22							
23	**Staff-Recommended Residential (2R) Tarrif Amounts With a Winter Surcharge**						
24	**Incorporating Storage, Transmission (Design-Day), and Pipeline Capacity/Demand Costs**						
25	Schedule's Winter Sales (November through April)	Th	275,147,012		Line 12 of Staff/1503 Compton/1		
26	**Cost of Gas - "Commodity" - per Therm of Annual Sales**	$/Th	0.48994		Current Tariff		
28	**Cost of Gas - "Pipeline Capacity" - per Therm of Winter (six months) Sales**	$/Th	0.17133		Current Tariff		
29	**Volumetric Winter Distribution-Related Surcharge (per Therm)**	$/Th	0.09344		Line 11 of Staff/1503 Compton/1		
30	Revenues from Target Volumetric Winter Distribution-Related Margin Surcharge	$	25,710,595		Line 29 x Line 25		
31	**Target Customer Charge**	$/Mo.	10.00		Staff Recommendation		
32	Revenues from Target Customer Charge	$	64,632,070		Line 31 x Line 5 x 12		
33	**Year-round Charge to Recover Balance of Target "Distribution" Revenues**	$/Th	0.28163		(Line 4 - Line 30 - Line 32) / Line 6		
34	Revenue from Year-round Volumetric Charge	$	98,548,928		Line 33 x Line 6		
35	Volumetric Charge Components			Yr-Round Dist. Charge	Winter Dist. Surcharge	Commodity Charge	Pipeline Capacity Charge
36	**Summer (May - October) Total Volumetric Charge and its Components**	$/Th	0.77157	0.28163	N.A.	0.48994	N.A.
37	**Winter (November - April) Total Volumetric Charge and its Components**	$/Th	1.03635	0.28163	0.09344	0.48994	0.17133

CASE: UG 221
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 1503

Computations Underlying Staff's Proposed Residential Rate Design

May 3, 2012

Derivations of Miscellaneous Elements of Staff's Proposed Residential (Schedule 2R) Rate Design

Line	Customer Costs Development	Annual Cost/Allocation	Per Customer-Month
1	Meters and Regulators (LRIC), Per Customer:	$59	
2	Embedded Factor = 34.9/39.2:	$ 52.53	$ 4.38
3	Services (LRIC), Per Customer:	$162	
4	Embedded Factor = 61.1/113.3:	$ 87.36	$ 7.28
5	Billing (All Oregon Customers):	$ 5,090,617	$ 0.71
6	Meter Reading (All Oregon Customers):	$ 571,001	$ 0.08
7	**SUM (Monthly Customer Costs):**		**$ 12.44**
8	Total Number of Oregon Customers:	601,298	

Line	Winter Storage and Transmission Cost Surcharge Development	Residential Allocation	Per Winter Therm
9	Storage Costs:	$ 22,644,901	$ 0.08230
10	Transmission (Design-Day):	$ 3,065,694	$ 0.01114
11	**SUM (Winter Storage/Transmission Surcharge):**		**$ 0.09344**
12	Winter (six month) Sales (Th):	275,147,012	

Line	Conversion of a Year-Round Pipeline Capacity Charge to a Winter-Only Charge	
13	Cost of Gas - "Pipeline Capacity" - per Therm of Sales	$ 0.13472
14	Annual Residential (2R) Sales (Th):	349,920,397
15	"Pipeline Capacity" - Residential Allocation	$ 47,141,276
16	"Demand" Allocation Share:	100%
17	**Winter (six months) volumetric rate ($/Th)**	**$ 0.17133**

Input Sources

Line 1: $59 per residential customer -- Line 3 of NWN/1101 Feingold/9.
Line 2: $34.9MM -- Line 23 of Staff/1402 Ordonez/1; $39.2MM -- Line 20o of Staff/1402 Ordonez/3; $52.34 = $59 x (34.9/39.2); $4.36 = $52.34/12.
Line 3: $162 per residential customer -- Line 3 of NWN/1101 Feingold/9.
Line 4: $61.1MM -- Line 21 of Staff/1402 Ordonez/1; $113.3MM -- Line 20k of Staff/1402 Ordonez/3; $87.36 = $162 x (61.1/113.3); $7.28 = $87.36/12.
Line 5: $5,090,617 -- Company response to Staff DR 202 (Staff/1503 Compton/4); $0.71 = $5,090,617/601,298.
Line 6: $571,001 -- NWN/306 McVay-Siores/1; $0.08 = $571,001/$601,298 (from Line 8).
Line 8: Line 1 of NWN/1101 Feingold/1.
Line 9: $22,644,901 -- Line 6 of Staff/1402 Ordonez/1; $0.08230 = $5,090,617/275,147,012 (Line 12).
Line 10: $3,065,694 -- Line 10 of Staff/1402 Ordonez/1; $0.01114 = $3,065,694/275,147,012 (Line 12).
Line 12: Developed from "Volumes New" Tab of Feingold's 1101 Workpapers.
Line 13: Rate Schedule 2 (Fifteenth Revision of Sheet 2-1)
Line 14: Line 7a of Staff/1402 Ordonez/3.
Line 15: Line 13 x Line 14.
Line 16: From Company response to Staff DR 437 (Staff/1503 Compton/3).
Line 17: Line 15 / Line 12.

Staff/1503
Compton/1

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 204:
~~If the average annual consumption for Schedule 2 customers is 246 Dth (see Exhibit NWN/1101 Feingold/1), what is the Company's estimate of the average annual consumption of Schedule 2 customers who are occupants of multi-metered, multi-family dwellings?~~If the average annual consumption for Schedule 2 customers is 650 therms, what is the Company's estimate of the average annual consumption of Schedule 2 customers who are occupants of multi-metered, multi-family dwellings?

Response: 2/8/2012

The average annual consumption for Schedule 2 customers is not 246 Dth. The volumes used to derive 246 represent just 4 months of sales and does not represent annual volumes. The correct unit reference for the 246 figure is therms.

Based on actual 2011 records from the Company's Customer Information System (CIS) the Company estimates that the average annual consumption of Schedule 2 customers who are occupants of multi-metered, multi-family dwellings in Oregon is 269.8 therms.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 437:
The current (and proposed) "Pipeline Capacity Volumetric Charge (per therm)" that appears in all of the gas sales schedules is $0.13472. On average, what portion of that amount represents maximum daily deliverability payments (i.e., the fixed/reservation demand component) and what portion represents volumetric annual throughput payments (i.e., the variable component)?

Response: 3/15/2012

The entire $0.13472 charge per therm is related to the fixed/reservation/demand component of the demand charges paid to third party pipelines.

This charge is updated and calculated annually in the Company's Purchased Gas Adjustment (PGA) filing. This charge represents demand costs paid to third party pipelines to move gas to NW Natural's system.

Any expected volumetric payments based on throughput (the variable component) are estimated at the time of the PGA and are included in the Company's commodity component, also referred known as the Weighted Average Cost of Gas (WACOG).

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 202:
What are the annual billing costs (exclusive of overheads, etc.) for Northwest Natural?

Response: 2/8/2012

Before preparing this response, the Company confirmed with George Compton of OPUC staff that this data request relates to the test year.

NW Natural's annual billing costs, exclusive of overheads, for the test year is $5,090,617.

CASE: UG 221
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1504

Monthly Residential Billing Comparisons

May 3, 2012

Annual and Monthly Residential Customer (2R) Billings Under Three Rate Design Approaches

"Cost of Gas" 2R Revenue Requirement = $218,581,275   Target NWN's "Distribution" 2R Revenue Requirement = $188,891,594 I.e., what is produced by the current rates.

Average Monthly Residential Customer Billings Under Current Rates, Under Simplified Straight-Fixed-Variable Rates, and Under the Staff-Recommended Option -- Assuming No Schedule Revenue Increase

		Annual Total	November	December	January	February	March	April	May	June	July	August	September	October
Residential (2R) Schedule Total Monthly Consumption	Th	349,920,397	41,831,081	59,803,033	57,727,713	47,041,944	40,388,258	28,354,983	17,376,017	9,566,876	8,360,076	8,332,732	9,045,289	22,092,395
Per-Customer Average Monthly Consumption	Th	650	77.7	111.0	107.2	87.3	75.0	52.6	32.3	17.8	15.5	15.5	16.8	41.0
Billings Given Current Rates	$	$ 756.54	$ 87.83	$ 122.99	$ 118.93	$ 98.03	$ 85.01	$ 61.47	$ 39.99	$ 24.72	$ 22.35	$ 22.30	$ 23.70	$ 49.22
Billings Under Simplified Full Fixed-Variable (FFV)	$	$ 756.54	$ 77.74	$ 98.58	$ 96.18	$ 83.78	$ 76.07	$ 62.11	$ 49.38	$ 40.32	$ 38.92	$ 38.89	$ 39.72	$ 54.85
Billings Given Staff-Recommended Rates	$	$ 756.54	$ 90.49	$ 125.07	$ 121.08	$ 100.52	$ 87.71	$ 64.56	$ 34.89	$ 23.71	$ 21.98	$ 21.94	$ 22.96	$ 41.65

Monthly Residential Customer Billings Under the Above Three Rate Design Options Given *Below-Average** Consumption -- Assuming No Schedule Revenue Increase

		Total	November	December	January	February	March	April	May	June	July	August	September	October
Per-Customer Average Monthly Consumption	Th	348	38.8	55.5	53.6	43.7	37.5	26.3	21.5	11.8	10.3	10.3	11.2	27.3
Billings Given Current Rates	$	$ 438.65	$ 46.92	$ 64.50	$ 62.47	$ 52.01	$ 45.51	$ 33.74	$ 28.66	$ 18.48	$ 16.90	$ 16.87	$ 17.80	$ 34.81
Billings Under Simplified Full Fixed-Variable (FFV)	$	$ 568.08	$ 53.48	$ 63.90	$ 62.70	$ 56.50	$ 52.65	$ 45.67	$ 42.66	$ 36.62	$ 35.69	$ 35.67	$ 36.22	$ 46.31
Billings Given Staff-Recommended Rates	$	$ 456.12	$ 50.24	$ 67.53	$ 65.54	$ 55.26	$ 48.86	$ 37.28	$ 26.59	$ 19.14	$ 17.98	$ 17.96	$ 18.64	$ 31.10

*NOTE: "Below-Average" in this example is defined as one-half the schedule average level of consumption in the winter six months (Nov -April) and two-thirds the average in the rest of the year.

Monthly Residential Customer Billings Under the Above Three Rate Design Options Given *Above-Average** Consumption -- Assuming No Schedule Revenue Increase

		Total	November	December	January	February	March	April	May	June	July	August	September	October
Per-Customer Average Monthly Consumption	Th	951	116.5	166.6	160.8	131.0	112.5	79.0	43.0	23.7	20.7	20.6	22.4	54.7
Billings Given Current Rates	$	$ 1,074.43	$ 128.75	$ 181.49	$ 175.40	$ 144.04	$ 124.52	$ 89.21	$ 51.32	$ 30.95	$ 27.81	$ 27.73	$ 29.59	$ 63.63
Billings Under Simplified Full Fixed-Variable (FFV)	$	$ 945.00	$ 102.00	$ 133.26	$ 129.65	$ 111.06	$ 99.49	$ 78.55	$ 56.10	$ 44.02	$ 42.15	$ 42.11	$ 43.21	$ 63.39
Billings Given Staff-Recommended Rates	$	$ 1,056.96	$ 130.73	$ 182.60	$ 176.61	$ 145.77	$ 126.57	$ 91.84	$ 43.19	$ 28.27	$ 25.97	$ 25.92	$ 27.28	$ 52.20

*NOTE: "Above-Average" in this example is defined as three-halves the schedule average level of consumption in the winter six months (Nov -April) and four-thirds the average in the rest of the year.

NOTE: Tariff prices for the above three approaches are displayed in Staff/1502 Compton/1.

Staff/1504
Compton/1

Billing Impacts of Converting the Current Schedule 2R Rates to Staff's Proposed

Therms	Current Monthly 2R Bill	Staff-Proposed 2R Monthly Bills			
		Summer		Winter	
		Bill	% Increase	Bill	% Increase
0	6.00	10.00	67%	10.00	67%
20	27.07	25.49	-6%	30.71	13%
23	30.23	27.81	-8%	33.82	12%
40	48.15	40.97	-15%	51.42	7%
60	69.22	56.46	-18%	72.14	4%
80	90.29	71.94	-20%	92.85	3%
85	95.56	75.81	-21%	98.03	3%
100	111.37	87.43	-21%	113.56	2%
120	132.44	102.91	-22%	134.27	1%
140	153.51	118.40	-23%	154.99	1%
160	174.58	133.88	-23%	175.70	1%
180	195.66	149.37	-24%	196.41	0%
200	216.73	164.86	-24%	217.12	0%
220	237.80	180.34	-24%	237.83	0%
240	258.88	195.83	-24%	258.55	0%
260	279.95	211.31	-25%	279.26	0%
280	301.02	226.80	-25%	299.97	0%
300	322.10	242.28	-25%	320.68	0%
320	343.17	257.77	-25%	341.40	-1%
340	364.24	273.26	-25%	362.11	-1%
360	385.31	288.74	-25%	382.82	-1%
380	406.39	304.23	-25%	403.53	-1%
400	427.46	319.71	-25%	424.24	-1%

NOTE: The reason the Staff-proposed billings should appear to be so favorable to ratepayers is because monthly average summer consumption for a 2R customer is only 23 therms while the winter average is 85 therms.

CAUTION: The 2R rates in this exhibit are designed to collect the same revenues as would be collected by the 2R rates currently in effect.

The Impact on Schedule 1R Bills of Moving to Schedule 2R

Therms	Current Monthly 1R Bill	Staff-Proposed 2R Monthly Bills			
		Summer		Winter	
		Bill	% Increase	Bill	% Increase
0	5.00	10.00	100%	10.00	100%
10	16.59	17.72	7%	20.36	23%
15.6	23.07	22.04	-4%	26.17	13%
20	28.17	25.43	-10%	30.73	9%
30	39.76	33.15	-17%	41.09	3%
40	51.34	40.86	-20%	51.45	0%
50	62.93	48.58	-23%	61.82	-2%

NOTE: The monthly average consumption for a 1R customer is 15.6 therms.
CAUTION: The 2R rates in this exhibit are designed to collect the same revenues as would be collected by the 2R rates currently in effect.