Oregon
John A. Kitzhaber. MD. Governor

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July 20, 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 Rebuttal 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)

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

STAFF REBUTTAL TESTIMONY OF

Fred Goodwin
Brian Bahr & Linnea Wittekind
Deborah Garcia
Kenneth R. Zimmerman
Lisa Gorsuch
Nick Cimmiyotti
Steve Storm
Matt Muldoon
Jorge Ordonez
George Compton

In the Matter of
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,
Request for a General Rate Revision

JULY 20, 2012

CASE: UG 221
WITNESS: FRED GOODWIN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1600

Rebuttal Testimony

July 20, 2012

Q. ARE YOU THE SAME FRED GOODWIN WHO PREVIOUSLY TESTIFIED IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to: (1) introduce Staff's Rebuttal witnesses and the issues they address; and (2) present the new revenue requirement that resulted from a partial settlement between the parties and changes in Staff's adjustments related to issues for which the parties were not able to reach a settlement.

Q. HAVE YOU PREPARED EXHIBITS FOR THIS PROCEEDING?

A. Yes. I have prepared Exhibit Staff/1601 that supports the revenue requirement presented in my rebuttal testimony.

Q. PLEASE SUMMARIZE STAFF'S REBUTTAL WITNESSES AND THE ISSUES THEY ADDRESS.

A. The following table lists Staff's rebuttal witnesses and issues:

Rebuttal Witness	**Exhibit**	**Issue(s)**
Goodwin	1600	Revenue requirements
Bahr & Wittekind	1700	Medical benefits and incentive compensation
Garcia	1800	Response to NWN witnesses Sohl, Doolittle, and Siores on miscellaneous labor and revenue – taxes
Zimmerman	1900	Response to NWN witnesses Siores, White and Yoshihara on working gas inventory, storage operations, prudency and SIP
Gorsuch	2000	Response to NWN witness King on service appointment windows and reconnect charges
Cimmiyotti	2100	Pensions
Storm	2200	Decoupling, return on equity and capital structure
Muldoon	2300	Cost of long-term debt
Ordoñez	2400	Long-run incremental cost and rate spread

Compton	2500	Response to NWN witness Feingold on volumetric rates to recover fixed distribution costs

Q. WHAT IS STAFF'S PROPOSED REVENUE REQUIREMENT ON REBUTTAL?

A. Staff Exhibit/1601/Goodwin is a set of spreadsheets that summarizes Staff's rebuttal position on the revenue requirement adjustments for UG 221. As I did in my opening testimony, I represent all dollar figures in the spreadsheets and in my rebuttal testimony in thousands (000).

The table below provides an item number for each Staff Adjustment, the initials of the Staff witness sponsoring rebuttal testimony for the adjustment, a description of the adjustment and the revenue requirement effect of the adjustment, where the adjustments were revised by Staff to account for the partial settlement or other factors as discussed in the rebuttal testimony of each witness:

Item	Staff	Issue	Requirement Effect
			$43,682
S-0	**SS/MM**	**Rate of Return** Based on 50% Debt, 50% Equity-6.022% cost of debt and 9.4% cost of equity	**(8,826)**
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	**(3,942)**
S-2	**KZ**	**Corvallis Reinforcement** Settled	**(934)**
S-3	**KZ**	**Monmouth Reinforcement** Insufficient information to support that the project is prudent; see MS testi-mony.	**(902)**
S-4	**KZ**	**Nertec Replacement** Settled	**(95)**
S-5	**KZ**	**Parkrose Retrofit**	**(0)**

		Settled	
S-6	**KZ**	**Perrydale to Monmouth** ORS 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	**(2,024)**
S-7	**KZ**	**Tualatin replacement, training facility & land** Settled	**(0)**
S-8	**KZ**	**Unified Communication Phase 1 (PBX Switch)** Settled.	**(0)**
S-9	**KZ**	**Westside Transmission Re-Rate** Settled	**(200)**
S-10	**BB**	**Directors and Officers Insurance** Settled	**(279)**
S-11	**BB**	**Incentive Compensation** Partially settled	**(2,588)**
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.	**(1,578)**
S-13	**BB**	**Various Customer Service, A&G Expenses** Settled	**(1,249)**
S-14	**NC**	**Pensions** Removes $21.9 million from rate base for the Company's "out of test-period" cash contributions. Removes $4.6 million from amortizable expenses, representing one-eighth of the $36.5 million prior period cash contributions.	**(6,120)**
S-15	**NC**	**Research & Development** Settled	**(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.	**(4,736)**
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-19	**LG**	**Advertising** Settled	**(393)**
S-21		**Miscellaneous Revenue** Settled	**(508)**
S-24		**Revenue Adjustments** Pending Commission decision	**(0)**
S*		**Rounding**	**(0)**
		Total Staff-Proposed Adjustments (Base Rates):	(35,304)
		Staff-Calculated Revenue Requirements Change (Base Rates):	**$8,378**

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: FRED GOODWIN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1601

Exhibits in Support
Of Rebuttal Testimony

July 20, 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, 6.022% cost of debt and 9.4% cost of equity	(8,826)
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	(3,942)
S-2	KZ	Corvallis Reinforcement Settled	(934)
S-3	KZ	Monmouth Reinforcement Insufficient information to support that the project is prudent; see MS testimony.	(902)
S-4	KZ	Nertec Replacement Settled	(95)
S-5	KZ	Parkrose Retrofit Settled	0
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	(2,024)
S-7	KZ	Tualatin replacement, training facility & land Settled	0
S-8	KZ	Unified Communication Phase 1 (PBX Switch) Settled	0
S-9	KZ	Westside Transmission Re-Rate Settled	(200)
S-10	BB	Directors and Officers Insurance Settled	(279)

S-11	BB	Incentive Compensation Partially settled	(2,588)
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.	(1,578)
S-13	BB	Various Customer Service, General & Administrative Expenses Settled	(1,249)
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.	(6,120)
S-15	NC	Research & Development Settled	(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.	(4,736)
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 Settled	(393)
S-20		blank	0
S-21	PR	Miscellaneous Revenue Settled	(508)

S-22		blank	0
S-23		blank	0
S-24	IP	Revenue Adjustments Pending Commission decision	0
			0
S*		Rounding	0
		Total Staff-Proposed Adjustments (Base Rates):	(35,304)
		Staff-Calculated Revenue Requirements Change (Base Rates):	**$8,378**

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	$0	$682,996	$8,378	$691,374
3		Transportation	12,871	0	12,871	0	12,871
4		Other Revenues	3,429	1,390	4,819	0	4,819
5		**Total Operating Revenues**	$699,296	$1,390	$700,686	$8,378	$709,064
6		**Operating Expenses**					
7		Gas Purchased	$395,039	$0	$395,039	$0	$395,039
8		Uncollectible Accrual for Gas Sales	2,110	0	2,110	121	2,231
9		Other O & M Expenses	118,219	(9,975)	108,244	0	108,244
10		**Total Operation & Maintenance**	$515,368	($9,975)	$505,393	$121	$505,514
11							
12		Depreciation & Amortization	60,094	(4,618)	55,476	0	55,476
13		PENSIONS	0	0	0	0	0
14		Taxes Other than Income	42,927	(297)	42,630	219	42,849
15		Income Taxes	22,719	7,552	30,271	3,211	33,482
16		Miscellaneous Revenue and Expense	0	0	0	0	0
17		**Total Operating Expenses**	$641,108	($7,338)	$633,770	$3,551	$637,321
18		**Net Operating Revenues**	$58,188	$8,728	$66,916	$2,227	$69,143
19		**Average Rate Base**					
20		Gas Plant in Service	$2,227,108	($39,029)	$2,188,079	$0	$2,188,079
21	Less:	Accumulated Depreciation & Amortization	(990,862)	0	(990,862)	0	(990,862)
22		Accumulated Deferred Income Taxes	(329,082)	9,266	(319,816)	0	(319,816)
23		Accumulated Deferred Inv. Tax Credit		0	0	0	0
24		**Net Utility Plant**	$907,164	($29,763)	$877,401	$0	$877,401
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	($87,011)	$896,674	$0	$896,674
36		**Rate of Return**	5.92%		7.46%		**7.71%**
37		**Implied Return on Equity**	5.81%		8.90%		0.094

		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	$1,390	$700,686	$8,378	$709,064
2		Book Expenses Other than Depreciation	558,295	(10,272)	548,023	340	548,363
3		State Tax Depreciation	60,094	(4,618)	55,476	0	55,476
4		Interest	29,619	(2,620)	26,999	0	26,999
5	PLUS:	Schedule M Differences (Perm)	6,084	0	6,084	0	6,084
6		State Taxable Income	$57,372	$18,900	$76,272	$8,038	$84,311
7		Add OR Depletion Adjustment	$0				
8		Total State Taxable Income	$57,372			$8,038	
9		State Income Tax @ 7.60%	$4,360	$1,436	$5,796	$611	$6,407
10		State Tax Credits	0	0	0	0	0
11		Net State Income Tax	$4,360	$1,436	$5,796	$611	$6,407
12		Additional Tax Depreciation	0	0	0	0	0
13	Plus:	Other Schedule M Differences	0	0	0	0	0
14		Federal Taxable Income	$53,012	$17,464	$70,476	$7,427	$77,904
15		Federal Tax @ 35%	18,554	6,116	24,670	2,600	27,270
16		Federal Tax Credits	0	0	0	0	0
17		Current Federal Tax	$18,554	$6,116	$24,670	$2,600	$27,270
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	$22,719	$7,552	$30,271	$3,211	$33,482

INPUT ASSUMPTIONS

COST OF CAPITAL - STAFF	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	50.00%	6.022%	3.011%
Preferred Stock	0.00%		0.000%
Common Equity	50.00%	9.400%	4.700%
OVERALL RATE OF RETURN	100.00%		**7.711%**

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**	unchanged	settlement	unchanged	settlement	settlement	unchanged	settlement	settlement	settlement	settlement	p. settlement
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)	(2,513)
10	**Total Operation & Maintenance**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**($272)**	**($2,513)**
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	425	101	98	10	0	218	0	0	22	109	1,004
16	Miscellaneous Revenue and Expense											
17	**Total Operating Expenses**	$425	$101	$98	$10	$0	$218	$0	$0	$22	($163)	($1,509)
18	**Net Operating Revenues**	**($425)**	**($101)**	**($98)**	**($10)**	**$0**	**($218)**	**$0**	**$0**	**($22)**	**$163**	**$1,509**
19	**Average Rate Base**											
20	Gas Plant in Service	0	(8,370)	(8,087)	(844)	0	(18,131)	0	0	(1,800)	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	($8,370)	($8,087)	($844)	$0	($18,131)	$0	$0	($1,800)	$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)**	**($8,370)**	**($8,087)**	**($844)**	**$0**	**($18,131)**	**$0**	**$0**	**($1,800)**	**$0**	**$0**
36	**Revenue Requirement Effect**	**($3,942)**	**($934)**	**($902)**	**($95)**	**$0**	**($2,024)**	**$0**	**$0**	**($200)**	**($279)**	**($2,588)**

	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**	staff position	settlement	unchanged	settlement	staff position	unchanged		settlement		settlement	
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	494	0
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$0**	**$896**	**$0**	**$0**	**$0**	**$494**	**$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	(1,532)	(1,212)	0	(6)	(4,058)	0	0	(382)	0	0	0
10	**Total Operation & Maintenance**	**($1,532)**	**($1,212)**	**$0**	**($6)**	**($4,058)**	**$0**	**$0**	**($382)**	**$0**	**$0**	**$0**
11												
12	Depreciation and Amortization	0	0	(4,569)	0	(49)	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	(297)	0	0	0	0	0	0
15	Income Taxes	612	484	1,977	2	1,781	358	0	153	0	198	0
16	Miscellaneous Revenue and Expense											
17	**Total Operating Expenses**	($920)	($728)	($2,592)	($4)	($2,623)	$358	$0	($229)	$0	$198	$0
18	**Net Operating Revenues**	**$920**	**$728**	**$2,592**	**$4**	**$2,623**	**$538**	**$0**	**$229**	**$0**	**$296**	**$0**
19	**Average Rate Base**											
20	Gas Plant in Service	0	0	0	0	(1,797)	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	9,266	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	$9,266	$0	($1,797)	$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**	**($12,664)**	**$0**	**($1,797)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
36	**Revenue Requirement Effect**	**($1,578)**	**($1,249)**	**($6,120)**	**($7)**	**($4,736)**	**($923)**	**$0**	**($393)**	**$0**	**($508)**	**$0**

	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**		pending PUC								
2	General Business	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Transportation	0	0	0	0	0	0	0	0	0	$0
4	Other Revenues	0	0	0	0	0	0	0	0	0	$1,390
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,390**
6	**Operating Expenses**										
7	Gas Purchased	$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
9	Other O & M Expenses	0	0	0	0	0	0	0	0	0	($9,975)
10	**Total Operation & Maintenance**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**($9,975)**
11											$0
12	Depreciation and Amortization	0	0	0	0	0	0	0	0	0	($4,618)
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	($297)
15	Income Taxes	0	0	0	0	0	0	0	0	0	$7,552
16	Miscellaneous Revenue and Expense										$0
17	**Total Operating Expenses**	$0	$0	$0	$0	$0	$0	$0	$0	$0	($7,338)
18	**Net Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$8,728**
19	**Average Rate Base**										
20	Gas Plant in Service	0	0	0	0	0	0	0	0	0	($39,029)
21	Accumulated Depreciation & Amortization			0	0	0	0	0	0	0	$0
22	Accumulated Deferred Income Taxes		0	0	0	0	0	0	0	0	$9,266
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	($29,763)
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
35	**Total Average Rate Base**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**($87,011)**
36	**Revenue Requirement Effect**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**($26,478)**

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	(1,063)	(252)	(244)	(25)	0	(546)	0	0
5	Schedule M Differences	0	0	0	0	0	0	0	0
6	State Taxable Income	$1,063	$252	$244	$25	$0	$546	$0	$0
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0
8	Total State Taxable Income	$1,063	$252	$244	$25	$0	$546	$0	$0
9	State Income Tax	$81	$19	$19	$2	$0	$41	$0	$0
10	State Tax Credits	0	0	0	0	0	0	0	0
11	Net State Income Tax	$81	$19	$19	$2	$0	$41	$0	$0
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	$982	$233	$225	$23	$0	$505	$0	$0
15	Federal Tax @ 35%	344	82	79	8	0	177	0	0
16	Federal Tax Credits	0	0	0	0	0	0	0	0
17	Current Federal Tax	$344	$82	$79	$8	$0	$177	$0	$0
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	$425	$101	$98	$10	$0	$218	$0	$0

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	$729	$173	$168	$17	$0	$374	$0	$0
Rate Base	(4671)	(1107)	(1070)	(112)	0	(2398)	0	0
Total	($3,942)	($934)	($902)	($95)	$0	($2,024)	$0	$0

Income Tax Calculations for Adjustments

	Income Tax Calculations	Westside Transmission Rerate (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)	(2,513)	(1,532)	(1,212)	0	(6)	(4,355)	0
3	State Tax Depreciation	0	0	0	0	0	(4,569)	0	(49)	0
4	Interest	(54)	0	0	0	0	(381)	0	(54)	0
5	Schedule M Differences	0	0	0	0	0	0	0	0	0
6	State Taxable Income	$54	$272	$2,513	$1,532	$1,212	$4,950	$6	$4,458	$896
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0	0
8	Total State Taxable Income	$54	$272	$2,513	$1,532	$1,212	$4,950	$6	$4,458	$896
9	State Income Tax	$4	$21	$191	$116	$92	$376	$0	$339	$68
10	State Tax Credits	0	0	0	0	0	0	0	0	0
11	Net State Income Tax	$4	$21	$191	$116	$92	$376	$0	$339	$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	$50	$251	$2,322	$1,416	$1,120	$4,574	$6	$4,119	$828
15	Federal Tax @ 35%	18	88	813	496	392	1,601	2	1,442	290
16	Federal Tax Credits	0	0	0	0	0	0	0	0	0
17	Current Federal Tax	$18	$88	$813	$496	$392	$1,601	$2	$1,442	$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	$22	$109	$1,004	$612	$484	$1,977	$2	$1,781	$358

REVENUE REQUIREMENTS
EFFECTS OF ADJUSTMENTS

	Westside Transmission Rerate (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	$38	($279)	($2,588)	($1,578)	($1,249)	($4,445)	($7)	($4,498)	($923)
Rate Base	(238)	0	0	0	0	(1675)	0	(238)	0
Total	($200)	($279)	($2,588)	($1,578)	($1,249)	($6,120)	($7)	($4,736)	($923)

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	$494	$0	$0
2	Book Expenses Other than Depreciation	0	(382)	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	$382	$0	$494	$0	$0
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	
8	Total State Taxable Income	$0	$382	$0	$494	$0	$0
9	State Income Tax	$0	$29	$0	$38	$0	$0
10	State Tax Credits	0	0	0	0	0	0
11	Net State Income Tax	$0	$29	$0	$38	$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	$353	$0	$456	$0	$0
15	Federal Tax @ 35%	0	124	0	160	0	0
16	Federal Tax Credits	0	0	0	0	0	0
17	Current Federal Tax	$0	$124	$0	$160	$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	$153	$0	$198	$0	$0

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	($393)	$0	($508)	$0	$0
Rate Base	0	0	0	0	0	0
Total	$0	($393)	$0	($508)	$0	$0

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	$0	$0	$0	$0	$0	$0	$0	$0	$1,390
2	Book Expenses Other than Depreciation	0	0	0	0	0	0	0	0	($10,272)
3	State Tax Depreciation	0	0	0	0	0	0	0	0	($4,618)
4	Interest	0	0	0	0					($2,620)
5	Schedule M Differences	0	0	0	0	0	0	0	0	$0
6	State Taxable Income	$0	$0	$0	$0	$0	$0	$0	$0	$18,900
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0	$0
8	Total State Taxable Income	$0	$0	$0	$0	$0	$0	$0	$0	$18,900
9	State Income Tax	$0		$0	$0	$0	$0	$0	$0	$1,436
10	State Tax Credits	0	0	0	0	0	0	0	0	$0
11	Net State Income Tax	$0	$0	$0	$0	$0	$0	$0	$0	$1,436
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	$0	$0	$0	$0	$0	$0	$0	$0	$17,464
15	Federal Tax @ 35%	0		0	0	0	0	0	0	$6,116
16	Federal Tax Credits	0	0	0	0	0	0	0	0	$0
17	Current Federal Tax	$0	$0	$0	$0	$0	$0	$0	$0	$6,116
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	$0	$0	$0	$0	$0	$0	$0	$0	$7,552

REVENUE REQUIREMENTS
EFFECTS OF ADJUSTMENTS

	Revenue	0	0	0	0	0	0	0	0	Total
	Adjustment	0	0	0	0	0	0	0	0	Adjustments
	0	0	0	0	0	0	0	0	0	(Base Rates)
	(S-24)	(S-25)	(S-26)	(S-27)	(P-1)	(S-31,I-5)	(I-7,C-1)	(I-8)	0	0
Revenues and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	##	($14,969)
Rate Base	0	0	0	0	0	0	0	0	0	($11,509)
Total	$0	$0	$0	$0	$0	$0	$0	$0		($26,478)

CASE: UG 221
WITNESS: BRIAN BAHR & LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

JOINT STAFF EXHIBIT 1700

Rebuttal Testimony

July 20, 2012

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

A. Our names are Brian Bahr and Linnea Wittekind. We are employed within the Corporate Analysis and Water Regulation Section of the Oregon Public Utility Commission. Our business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. ARE YOU THE SAME BRIAN BAHR WHO PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDNG?

A. Yes. I have filed testimony previously in this case, found in Exhibit Staff/800.

Q. LINNEA WITTEKIND, DID YOU PREVIOUSLY FILE TESTIMONY IN THIS DOCKET?

A. No. My qualification statement is found in Exhibit/1701, Wittekind/1.

Q. DID YOU PREPARE ANY EXHIBITS FOR THIS TESTIMONY?

A. Yes. Exhibit/1701 is Linnea Wittekind's qualification statement. Exhibit/1702 is a worksheet on medical benefits and workers compensation. Exhibit/1703 is a worksheet on incentive compensation.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of this testimony is to present an amended recommendation for our adjustments to medical benefits, workers compensation, and incentive compensation. Second, we respond to NW Natural's reply testimony concerning medical benefits and workers compensation expense found in Exhibit NWN/2300.

Q. PLEASE SUMMARIZE THE COMPANY'S REPLY TESTIMONY REGARDING YOUR ADJUSTMENT TO MEDICAL BENEFITS AND WORKERS COMPENSATION EXPENSE?

A. The Company states that the direct testimony proposed adjustment is incorrect because it uses an unreasonable level of full time employees (FTE) and because the Company's application already includes removal of 1.78 percent of payroll expense to reflect unregulated labor expense.[1]

Q. DO YOU HAVE ANY COMMENT ON THE COMPANY'S REPLY TESTIMONY REGARDING THE ADJUSTMENT TO MEDICAL BENEFITS AND WORKERS COMPENSATION EXPENSE?

A. Yes. The direct testimony proposed adjustment reduces the Company's requested expense based on Staff Garcia's proposed adjustments to FTE and labor expense. The Company has not stated opposition to the method used in calculating the adjustment, but rather to the inputs of the calculation. In calculating this adjustment, reliance was placed on Staff Garcia's proposed adjustments to the Company's FTE levels. The Company was able to provide verification that the 1.78 percent of payroll expense was removed in its original application. Staff Garcia's analysis regarding FTE and labor expense can be found in Exhibit Staff/500 and Exhibit Staff/1800.

Q. BASED ON STAFF GARCIA'S PROPOSED ADJUSTMENTS TO FTE AND LABOR EXPENSE, WHAT IS YOUR UPDATED ADJUSTMENT TO MEDICAL BENEFITS AND WORKERS COMPENSATION EXPENSE?

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[1] *See* Exhibit NWN/2300, Sohl/11-12.

A. Based on Staff's Garcia's proposed FTE level of 1,020, the updated adjustment is $1,532,370. In regards to the removal of 1.78 percent of payroll expense to reflect unregulated labor expense, our adjustment has been updated to remove this portion of the adjustment. The updated calculation for this adjustment can be found in Exhibit Staff/1702, Bahr-Wittekind/1-2.

Q. ARE ANY OF YOUR OTHER ADJUSTMENTS PREVIOUSLY FILED IN TESTIMONY AFFECTED BY STAFF GARCIA'S ANALYSIS OF FTE AND LABOR EXPENSE?

A. Yes. Although not mentioned in the Company's reply testimony as being affected by the FTE and labor expense issues, the adjustment to incentive compensation also takes into account Staff Garcia's adjustments to FTE and labor expense. Based on Staff's Garcia's proposed FTE level of 1,020, the updated adjustment is $3,350,113. The updated calculation for this proposed adjustment can be found in Exhibit Staff/1703, Bahr-Wittekind/1-2.

Q. DOES THE COMPANY'S REPLY TESTIMONY ADDRESS REVENUE REQUIREMENT REDUCTION ADJUSTMENTS IN GENERAL?

A. Yes. On page 12 of Exhibit NWN/1800, Anderson states:

> First, many of the 'typical' ratemaking adjustments remove from rates costs that cannot be avoided by a utility like NW Natural. For instance, Commission precedent disallows significant portions of employee incentive pay and other labor costs that are required to match market compensation—yet no one would argue that NW Natural

> could effectively run the Company without offering compensation at the market level.

Anderson also states that these revenue requirement adjustments have a larger impact on NW Natural than on other companies because NW Natural is an independent company rather than a subsidiary of a larger company, and NW Natural does not have a generation function as do electric utilities.

Q. DOES THE COMPANY'S REPLY TESTIMONY PROPOSE AN ALTERNATIVE TO YOUR PROPOSED ADJUSTMENTS?

A. No, the Company's reply testimony does not propose any alternatives to my proposed adjustments to these expenses.

Q. DO YOU HAVE ANY COMMENT ON THESE ADJUSTMENTS?

A. Yes. It is noted that the Company essentially argues that while the proposed adjustments are consistent with Commission precedent, they should not be applied to NW Natural in this case.[2] We disagree with this assertion. The adjustments being proposed in this rate case are not based on Commission precedent alone, but based on the same logic on which Commission precedent on these issues was set. It is appropriate that certain expenses of public utilities should be shared between shareholders and ratepayers. The logic used in Commission precedent and in the proposed adjustments in this rate case is found in Exhibit Staff/800.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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[2] *See* Exhibit NWN/1800, Anderson/12.

CASE: UG 221
WITNESS: BRIAN BAHR & LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

JOINT STAFF EXHIBIT 1701

WITNESS QUALIFICATIONS STATEMENT

July 20, 2012

WITNESS QUALIFICATION STATEMENT

NAME: Linnea Wittekind

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Financial Analyst,
Economic Research & Financial Analysis Division

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

EDUCATION: B.S. Western Oregon University
Major: Business with focus in Accounting
Minor: Entrepreneurship

EXPERIENCE: Since November 2009, I have been employed by the Public Utility Commission of Oregon. Responsibilities include research, analysis and recommendations on a wide range of cost, revenue and policy issues for electric and natural gas utilities. I have provided testimony in UE 215, UE 233, UE 246 and have filed comments in LC 50 and UI 314, UP 280, and UP 281. I have also reviewed and analyzed a number of energy efficiency tariff filings, filed by Idaho Power Company. I've written several public meeting memos summarizing my analysis of the energy efficiency tariff filings. I have performed an operational audit of NW Natural and Cascade Natural Gas and am currently performing an operational audit of Portland General Electric.

From July 2005 to November 2009, I worked as a Tax Auditor for the Oregon Department of Revenue. In enforcement of tax laws, rules and regulations, I performed income tax audits of individual tax payers and small businesses. Additionally I prepared cost analysis of tax credits and measures. I also represented the department before the Oregon Tax Court for tax deficiency appeals.

CASE: UG 221
WITNESS: BRIAN BAHR & LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

JOINT STAFF EXHIBIT 1702

Exhibits in Support
Of Rebuttal Testimony

July 20, 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	$15,032	($1,533)

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)	Per Staff	Adjustment
Medical Benefits						
Bargaining Unit Health - Active Employees	$ 8,455,751	90.1%	$ 7,618,632	90.27%	$ 6,876,995	$ 741,637
Bargaining Unit Health - Retirees	$ 913,387	90.1%	$ 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	90.27%	$ 6,170,118	$ 665,405
	$ 16,955,734		$ 15,277,117			**$ 1,407,042**

	TY per NWN (DR 384c)	3 factor allocation (per NWN/312)	included in OR test year	FTE % allowance (see box A)		Adjustment
Workers Comp	$ 1,428,928	90.1%	$ 1,287,464	90.27%	$ 1,162,136	**$ 125,328**
			Total OR allocated		Total Per Staff	**Total Adjustment**
			$ 16,564,581		$ 15,032,211	**$ 1,532,370**

* 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 1800

FTE per NWN	1130
FTE per Staff	1020
%	90.27%

CASE: UG 221
WITNESS: BRIAN BAHR & LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

JOINT STAFF EXHIBIT 1703

Exhibits in Support
Of Rebuttal Testimony

July 20, 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	$2,147	($3,350)

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)		Sharing % allowance		Adjustment (OR)
officers	$ 339,000	90.10%	$ 305,439	90.27%	$ 275,706	0%	$ -	$ 305,439
NBU non-officers based on employee merit	$ 3,781,000	90.10%	$ 3,406,681	90.27%	$ 3,075,057	50%	$ 1,537,529	$ 1,869,152
NBU non-officers based on Company performance	$ 558,000	90.10%	$ 502,758	90.27%	$ 453,817	25%	$ 113,454	$ 389,304
BU non-officers based on employee merit	$ 1,016,000	90.10%	$ 915,416	90.27%	$ 826,305	50%	$ 413,152	$ 502,264
BU non-officers based on Company performance	$ 407,000	90.10%	$ 366,707	90.27%	$ 331,010	25%	$ 82,752	$ 283,955
	$ 6,101,000		$ 5,497,001		$ 4,961,895		$ 2,146,888	**$ 3,350,113**

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 1800

FTE per NWN	1130
FTE per Staff	1020
%	90.27%

CASE: UG 221
WITNESS: DEBORAH GARCIA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1800

Rebuttal Testimony

July 20, 2012

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

A. My name is Deborah Garcia. I am a senior revenue requirements analyst. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon.

Q. ARE YOU THE SAME DEBORAH GARCIA WHO PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony can be found at Staff/500.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to update my recommendation for an adjustment to Miscellaneous Labor. Second, I respond to issues raised in Northwest Natural Gas Company's (NWN or Company) reply testimony related to issues in my direct testimony.[1]. Specifically, I address the appropriate test year levels for number of full-time equivalent employees (FTE), wages and salaries, overtime, payroll tax, and depreciation expense. I also respond to NWN/Siores/1900 regarding my proposed increase to test year revenues that eliminates recovery of an out-of- period increase to income tax expense.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Staff Exhibit/1801, consisting of 13 pages and Staff Exhibit/1802 consisting of 15 pages that are copies of NWN's responses to Staff Data Requests Nos. 504 and 507, and the supplemental response to Data Request No. 508.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

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[1] *See generally* NWN/Sohl/2300 and NWN/Doolittle/2400.

A. My testimony is organized as follows:

ISSUE 1, MISCELLANEOUS LABOR ADJUSTMENT

Q. PLEASE PROVIDE A SUMMARY OF YOUR UPDATED RECOMMENDATION TO ADJUST MISCELLANEOUS LABOR.

A. I have revised my Miscellaneous Labor adjustment to reflect new information provided by NWN regarding its number of test year FTE and associated expense related to its regulated operations.[2]

Q. WHAT IS THE RESULT TO THE MISCELLANEOUS LABOR ADJUSTMENT FROM UTILIZING THIS NEW INFORMATION?

A. The following table illustrates my updated proposed adjustment.

Miscellaneous Labor Adjustment Oregon-Allocated ($000s)		
	(O&M)	Rate Base
Wages & Salaries	(19)	(8)
FTE Adjustment	(4,036)	(1,788)
Overtime	(3)	(1)
Payroll Taxes	(297)	
Depreciation Expense	(49)	
Totals	($4,404)	($1,797)

Q. WHY WAS IT NECESSARY TO UPDATE YOUR PROPOSED ADJUSTMENT TO MISCELLANEOUS LABOR?

A. In its direct testimony and exhibits, NWN included in its proposed test year a number of FTE that included FTE whose associated expense should be

[2] New information provided in Supplemental Response to Staff Data Request No. 508.

allocated to below-the-line or non-regulated activities (Non-regulated FTE), which should not be included in rates.

Furthermore, NWN's response to the Commission's Standard Data Request (SDR) No. 95, which requested test year miscellaneous labor information, included both the number of Non-Regulated FTE and the associated expense. Finally, in NWN response to SDR No. 96, which requests test year labor allocation factors, it included allocation factors related to Non-regulated FTE.[3]

Based on the above information, my direct testimony adjusted the calculations of the Miscellaneous Labor adjustment to ensure that they included only the number of FTE and related expense that are associated with regulated operations and properly includible in rates.

Q. WHY IS IT IMPORTANT THAT BOTH THE TEST YEAR FTE COUNT AND ASSOCIATED EXPENSE ONLY INCLUDE REGULATED OPERATIONS?

A. The primary reason is to ensure that only the expense related to regulated operations is included in rates. Staff's 3-year wage and salary model (Staff's Model) relies on the exclusion of both Non-regulated FTE and the associated expense or rate base. The total number of test year FTE also impacts the calculation of loading costs that are included in rates for expenses such as insurance benefits, bonuses, and incentives.

Q. DID YOU EXPECT NWN TO INCLUDE NON-REGULATED INFORMATION IN RESPONSE TO A DATA REQUEST?

[3] See Staff Exhibit 1802 for a copy of those data responses.

A. No. I assumed that as is typical for most regulated utilities that when information is requested on a total company basis or test year information that the response would only include information for regulated operations.

Q. DOES THERE APPEAR TO BE A DISCREPANCY BETWEEN NWN'S REPLY TESTIMONY AND ITS RESPONSES TO DR NOS. 507 AND 508?

A. Yes, it appears so. In NWN/2400/Doolittle/2 at lines17-20 and NWN/2400/Doolittle/3 lines 1-2, NWN states that it is amending its number of test year FTE from 1,130 to 1,114. I sent DR 507 to ascertain if the 1,114 FTE included the 19.2 Non-regulated FTE listed at NWN/2300/Sohl/3. According to NWN response to DR 507, they are included. By my calculations the new regulated FTE level that the Company is requesting is 1,094.8 (1,114-19.2). However, in Supplemental DR response No. 508, the Company shows its regulated test year FTE count at 1,110.8.

Q. DO THERE APPEAR TO BE INCONSISTENCIES IN THE NUMBER OF FTE AND THE TOTAL WAGES & SALARIES BETWEEN SUPPLEMENTAL DR RESPONSE NO. 508 AND NWN/2304/SOHL/1?

A. Yes, it appears so. In the supplemental response to DR No. 508, the total number of regulated test year FTE is reported at 1,110.8, with wages and salaries totaling $79,553,496. In NWN/2304/Sohl/1 the amounts are 1,114 and $79,934,460, respectively.

Q. MR. SOHL ASSERTS THAT STAFF'S CALCULATION TO ADJUST TEST YEAR FTE LEVELS CONTAINS THREE PROBLEMS.[4] CAN YOU RESPOND TO THESE THREE ASSERTIONS?

A. Yes.

Q. IS IT APPROPRIATE TO BEGIN THE CALCULATION WITH THE 2011 AVERAGE FTES?

A. Yes. It is appropriate to begin the calculation with the 2011 average FTEs to determine the appropriate number of regulated FTE that should be in the test period. Staff's responsibility is to estimate the appropriate level of expense for inclusion into rates. As demonstrated in Staff Exhibit 1801/10 at Table 1, line 1, the 2011 average actual FTE of 1,006.1 is very close to the 2008-2011 actual average FTE of 1,007.9. NWN's latest estimate of regulated FTE for the test year is 1,094.8 or 1,110.8 (depending on which source is correct). An FTE level of 1,094.8 equals a 2-year increase of 88.7 FTE or 8.82 percent. An FTE level at 1,110.8 equals an increase of 104.7 FTE or a 10.4 percent increase. It is difficult to justify increases at either of these levels considering that the request is for a period when growth is relatively flat, NWN's automatic meter reading program is complete, and the Company has outsourced its meter installation work.

Furthermore, the level of expense associated with a specific number of regulated FTE that is granted in a general rate case does not guarantee that a utility will actually employ that number of FTE. For example, in UG 152,

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[4] NWN/2300/Sohl/4 line 18.

NWN's last general rate case, the Commission approved miscellaneous labor costs (including loading costs) for approximately 1,294 FTE. NWN exercised its operational discretion as found in Mr. Anderson's direct testimony at NWN/Anderson/13/ at 11-12, where he testifies that, "Overall, from 2005 to 2010, the Company went from a level of 1,275 FTE to 1,015 FTE." In Supplemental DR response No. 508, the Company estimates there were 966 regulated FTE for 2010. Based on Mr. Anderson's testimony, this is a reduction of approximately 279 FTE from the FTE levels approved in UG 152, or 328 FTE based on the supplemental response to DR No. 508. Meanwhile, the annual expense for the UG 152-approved FTE, including loading costs, continued to be included in customer's rates.

Finally, the 2011 level of 1,006.1 FTE reflects an approximate 40 FTE increase over the 2010 level of 966.0 FTE. Beginning with the 2011-estimated regulated FTE number of 1,006.1 FTE plus the 14 FTE related to service windows gives an overall increase of 54 FTE from the estimated regulated 2010 FTE level.

Q. IN NWIGU-CUB/100/LARKIN/41-44, MR. LARKIN USES A DIFFERENT METHOD TO CALCULATE AN APPROPRIATE LEVEL OF TEST YEAR FTE. DO YOU AGREE WITH HIS APPROACH?

A. In large part, but not entirely. Mr. Larkin makes a valid point that including a forecasted number of test period FTE does not produce reliable results. I do not agree with his determination to begin his calculation to amend FTE based on the number of FTE level at a specific point in time. First, by NWN's own testimony and DR responses, the FTE numbers it provides include Non-regulated FTE, except in response to DRs that specifically ask for regulated FTE numbers. Second and more importantly, it appears that NWN is increasing FTE levels in anticipation of the outcome of the general rate case. If not, it is unclear why else NWN would propose such a large increase in FTE when it appears that NWN has been providing adequate service with the number of actual average FTE employees for the 2011 period. NWN states in testimony that increased safety standards are one of the major drivers in this case. If that is the case then it is suspicious why NWN has requested increases to its 2011 regulated FTE levels at only an 8% increase in its union force, the FTE presumably ensuring NWN meets safety standards, while simultaneously requesting a 16 percent increase in Exempt FTEs and a 9 percent increase in Officer FTEs.[5]

Q. PLEASE COMMENT ON THE NUMBER OF NON-REGULATED FTE THAT SHOULD BE REMOVED.

A. As stated previously, I amended the calculation of proposed test year FTE based upon the new information provided in the Company's reply testimony. One of those changes was to remove the adjustment for 42.6 FTE related to non-regulated activities. Upon review of DR Nos.504 and 508, I agree that the 19.2 Non-regulated FTE the Company removed from its test period FTE level is sufficient when taking into consideration the FTE level I am proposing. Therefore, I have updated my recommendation to reflect the removal of 19.2

[5] See Table No. 5, Staff 1801/10.

Non-regulated FTE instead of the 42.6 Non-regulated FTE proposed in my direct testimony.

Q. DO YOU AGREE WITH MR. SOHL THAT STAFF'S MODEL DISREGARDS UNION CONTRACT AMOUNTS IN THE CALCULATION OF THE FACTOR APPLIED TO INCREASE UNION WAGES AND SALARIES TO A REASONABLE TEST YEAR LEVEL?[6]

A. No. As shown in Staff's workpaper, Staff accurately calculated the factor to capture the *actual* weighted increases for union employees as shown in Exhibit 1801 at6-8. While a union contract may specify a specific overall percent increase, the actual annual increase realized by union employees can be determined by utilizing a series of calculations to weight the actual increases the employees have received or will be receiving. NWN provided this information in response to SDR No. 97.

Q. DO YOU AGREE WITH MR. SOHL'S ASSESSMENT THAT NO ADJUSTMENT TO PAYROLL IS WARRANTED?[7]

A. No. As discussed earlier in this testimony, using the corrected test year information provided by NWN, which includes the elimination of a 1.78 reduction to overall labor expense, Staff's Miscellaneous Labor adjustment is consistent with Commission precedent.

Q. DO YOU AGREE WITH MR. SOHL'S STATEMENT THAT STAFF DID NOT PROVIDE A REBUTTAL TO MS. DOOLITTLE'S DIRECT TESTIMONY

[6] See NWN/2300/Sohl/9 at 11-16.
[7] See NWN/1300/Sohl/10 at 5-7.

THAT MARKET BASED INCREASES APPROPRIATELY ESCALATE WAGES AND SALARIES?[8]

A. No. In Staff /500/Garcia/3 at 1-17, I discuss why the Company's approach to escalate wages and salaries at market rates does not constitute a reasonable approach.

[8] See NWN/2300/Sohl/10 at 16.

ISSUE 2, -MISCELLANEOUS REVENUES – TAXES

Q. NWN DESCRIBES ITS ATTEMPT TO COLLECT THIS EXPENSE FROM A PRIOR PERIOD AS SEEKING TO RECOVER A CHANGE TO ITS DEFERRED TAX BALANCES.[9] PLEASE EXPLAIN WHY THIS IS MISLEADING.

A. There is no direct relationship between the amount of tax expense a utility may or may not collect from customers between rate cases for any given year and the requirements of GAAP accounting to amend a utility's deferred tax balance in specific situations.

The tax expense the Company is seeking to collect is an expense that occurred between rate cases. That this is a tax expense does not qualify it for a status that is any different from other expense the utility might incur between rate cases.

Q. DID NWN HAVE THE OPTION TO FILE A DEFERRAL TO COLLECT THE TAX INCREASE?

A. Yes.

Q. HAD NWN FILED A TIMELY DEFERRAL, WOULD THE COMMISSION BE EXPECTED TO AUTOMATICALLY GRANT AMORTIZATION OF THE DEFERRED AMOUNT?

A. No. Amortization of such a deferral would be subject to the same statutory earnings review as any other deferral. Amortization would be dependent on

[9] See NWN/1900/Siores/23 at 19-23.

whether the Commission determined that the Company's earnings were sufficient to absorb the expense.

Q. DO YOU AGREE WITH NWN'S CHARACTERIZATION THAT STAFF APPEARS TO BE CONCERNED THAT IF "NW NATURAL'S UPDATED DEFERRED TAX BALANCES WERE TO BE RECOVERED IN RATES, THEN THE COMPANY WOULD BE RECOVERING COSTS IN EXCESS OF ITS CURRENT OR FUTURE EXPENSES."?[10]

A. Absolutely not. Staff's concern is that NWN is inappropriately attempting to recover an expense that occurred between rate cases. Tax expense is like any other expense a utility may incur. Absent specific Commission approval, such as a deferral, there is no mechanism in place for an automatic true up to reconcile the difference between amounts collected in rates and actual revenues or expenses.

Q. NWN SEEMS TO REFER TO THIS TAX EXPENSE THAT OCCURRED BETWEEN RATE CASES AND ITS DEFERRED TAX BALANCE AS IF THEY ARE INTERCHANGEABLE, RATHER THAN RELATED.[11] DO YOU AGREE?

A. No. The utility's deferred tax balance is the cumulative result of timing differences between the taxes a utility has collected over time in rates and the amount of taxes the utility has paid. The change to NWN's deferred tax balance that resulted from the change to state income tax rate is governed by GAAP accounting that requires a utility to amend its deferred tax balances

[10] See NWN/1900/Siores/27 at 3-5.
[11] See NWN/1900/Siores/27 at 7-9.

under certain circumstances. The amendment to deferred tax balances is independent of whether a utility over or under recovers the expense associated with the change.

Q. NWN IMPLIES THAT IT SHOULD BE ENTITLED TO RECOVER THE TAXES IN QUESTION BECAUSE IT WILL BE REQUIRED TO PAY FUTURE TAXES FOR WHICH IT WOULD NEVER HAVE ANY RECOVERY.[12] DO YOU AGREE?

A. No. A utility's deferred tax balance does not represent a strict reconciliation between tax expense amounts recovered in rates and the future obligations of the Company. Between rate cases there is no guarantee that the amounts in deferred taxes will absolutely represent the amount of taxes collected from customers. Senate Bill 408, which has since been repealed, was in effect during the 2009 tax year. It was the only automatic mechanism that attempted to reconcile the recovery of taxes in rates with the amount of taxes paid to the taxing authority. NWN's 2009 tax year (Docket No. UG 170) was reconciled in that process pursuant to Commission Order No. 11-117.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[12] See NWN/1900/Siores/27 at 1-3.

CASE: UG 221
WITNESS: DEBORAH GARCIA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1801

Exhibits in Support
Of Rebuttal Testimony

July 20, 2012

Northwest Natural UG 221
Test Year Ending 10/31/2013
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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 REGULATED 2011 FTE (Company provided in its Supplemental DR No. 508) that is adjusted to ADD 14 FTE related to 4-hour service windows. 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.

	Company-Wide				OR- Allocated	
Description/ Account No.	**Company Filing**	**Staff**	**O&M Adjustment**	**Capital Adjustment**	**O&M Adjustment**	**Capital Adjustment**
Wages & Salaries	$ 79,553	$ 79,523	$ (21)	$ (9)	$ (19)	$ (8)
FTE Adjustment	* $ 79,523	$ 73,029	$ (4,500)	$ (1,993)	$ (4,036)	$ (1,788)
Overtime	$ 3,026	$ 3,022	$ (3)	$ (1)	$ (3)	$ (1)

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

Total OR - Allocated Adjustments					**$ (4,058)**	**$ (1,797)** *

	Oregon Only			
Payroll Taxes associated w/ W&S and OT	$ 3,763	$3,466	$ (297)	**$ (297)**

Depreciation O&M Adjustment Associated with Capital Adjustment	**$ (49)**

Staff Initiator:
Deborah Garcia

* Adj. for rounding (1 off)

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	Supplemental Data Response 508	Base Year W&S (12 months ending 10/31/2010)	**$2,428,443**	**$28,524,292**	**$1,746,601**	**$32,970,252**	**$65,669,588**
2	Supplemental Data Response 508	Average. # of FTE (12 months ending 10/31/2010)	10	342	31	599	**981**
3	(1)/(2)	Average Salary	$254,714	$83,504	$56,470	$55,087	
4	Actual/Forecast CPI Index*	Allowable % Increase	1.063 [1]	1.063 [1]	1.063 [1]	1.34 [2]	
5	Supplemental Data Response 508	Ave. # of FTE (2013 Test Year)	10	435	29	638	**1111**
6	(3)*(4)*(5)	Projected W&S	**$2,679,845**	**$38,584,865**	**$1,710,332**	**$46,963,221**	**$89,938,264**
7	Supplemental Data Response 508	Test Year W&S (12 months ending 10/31/2013)	**$2,741,418**	**$37,560,734**	**$1,699,422**	**$37,551,922**	**$79,553,496**
8	(7)-(6)	Total Difference eligible for Sharing	$61,573	$0	$0	$0	**$61,573**
9	(6)*.10	10% Band - Allowable	$267,985	$0	$0	$0	**$267,985**
10	[(8) or (9)] *0.5	50% Sharing of Lesser of Difference or Band	$30,786	$0	$0	$0	**$30,786**
11	(6)+(10)	Staff Proposed Level	**$2,710,632**	**$37,560,734**	**$1,699,422**	**$37,551,922**	**$79,522,710**
12	(11)-(7)	Net W&S Adjustment	**($30,786)**	**$0**	**$0**	**$0**	**($30,786)**
13	NWN/2300/Sohl/14/14	O&M Expense as % of W&S Adjustment	69.30%	69.30%	69.30%	69.30%	69.30%
14	(12)*(13)	O&M Expense Adjustment - Systemwide	($21,335)	$0	$0	$0	($21,335)
15		Oregon Allocation Factor [5]	0.897	0.897	0.897	0.897	0.897
16	(12)*(15)	**O&M Expense Adjustment - Oregon**	**($19,137)**	**$0**	**$0**	**$0**	**($19,137)**
17	100%-69.30%	Rate Base as % of W&S Adjustment	30.70%	30.70%	30.70%	30.70%	30.70%
18	(12)*(17)	Rate Base Adjustment - Systemwide	($9,451)	$0	$0	$0	**($9,451)**
19	(18)*(15)	**Rate Base Adjustment - Oregon**	**($8,478)**	**$0**	**$0**	**$0**	**($8,478)**

[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 1801/6-9)

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

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 1,111 to the actual 2011 regulated FTE level of 1006 plus 14 FTE related to 4-hour service windows. The Staff-proposed FTE levels for each of the categories, Officers, Exempt, Non Exempt, and Union are calculated using the weighted averages established by NWN's test year numbers.

Line No.	Source		Officers	Exempt	Non Exempt	Union	Total
1	Supplemental DR 508	Test Year W&S	$2,741,418	$37,560,734	$1,699,422	$37,551,922	**$79,553,496**
2	Staff Exhibit 1801/1 PUC 3-year W&S Adj, line 12	Less Staff Adj to Test Year W&S[1]	$30,786 [1]	$0	$0	$0	**$30,787**
3	(1)-(2)	Adjusted W&S	$2,710,632	$37,560,734	$1,699,422	$37,551,922	**$79,522,710**
4	Supplemental DR 508	Average # of FTE Test Year	10	435	29	638	1,111
5	(3)/(5)	Adjusted Average Salary	273,801	86,386	59,629	58,896	
6	See Explanation above	Staff Proposed FTE	9	399	26	586	1020
7	(5)*(6)	Staff Proposed Test Year W&S	**$2,489,301**	**$34,493,793**	**$1,560,659**	**$34,485,700**	**$73,029,453**
8	(7)-(3)	**Net Payroll Adjustment**	**($221,331)**	**($3,066,941)**	**($138,763)**	**($3,066,222)**	**($6,493,257)**
9	Staff Exhibit 1801/1 PUC 3-year W&S Adj, line 13	O&M Expense as % of Payroll Expense					69.30%
10	(8)*(9)	O&M Expense Adjustment - Systemwide					($4,499,827)
11	Staff Exhibit 1801/1 PUC 3-year W&S Adj, line 15	Oregon Allocation Factor					0.897
12	(10)*(11)	**O&M Adjustment - Oregon**					**($4,036,345)**
13	Staff Exhibit 1801/1 PUC 3-year W&S Adj, line 17	Capitalized Labor as % of Payroll Expense					30.70%
14	(8)*(13)	Rate Base Adjustment - Systemwide					($1,993,430)
15	(14)*(11)	**Rate Base Adjustment - Oregon**					**($1,788,107)**

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, if the Company's test period overtime exceeds Staff's projected overtime, 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.

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Line No.	Source		Officers	Exempt	Non Exempt	Union	**Total**
1	Supplemental DR 508	Base Period Overtime (12 months ending 10/31/2010)	**$0**	**$0**	**$18,443**	**$3,318,705**	**$3,337,148**
2	Supplemental DR 508	Base Period # of FTE (12 months ending 10/31/2010)	10	342	31	599	
3	(1)/(2)	Average Overtime per FTE	$0	$0	$596	$5,545	
4	Staff Exhibit 1801/1 PUC 3-year W&S Adj, line 4	Allowable % Increase	0	0	1.063	1.337	
5	Staff Exhibit 1801/2 at line 6	Staff Proposed FTE for Test Period	9	399	26	586	1,020
6	(3)*(4)*(5)	Projected Overtime	**$0**	**$0**	**$16,586**	**$4,341,196**	**$4,357,781**
7	Supplemental DR 508	Test Period Overtime	**$0**	**$0**	**$21,452**	**$3,004,154**	**$3,025,606**
8	If (7)>(6), then (7)-(6)	Total Difference	$0	$0	$4,866	$0	**$4,866**
9	If (7)>(6), then (6)*.10	10% Band - Allowable	$0	$0	$1,659	$0	**$1,659**
10	[(8) or (9)] *0.5	50% Sharing of Lesser of Difference or Band	$0	$0	$829	$0	**$829**
11	(6)+(10)	Staff Proposed Level	**$0**	**$0**	**$17,415**	**$3,004,154**	**$3,021,569**
12	(11)-(7)	Net Payroll Adjustment	**$0**	**$0**	**($4,037)**	**$0**	**($4,037)**
13	Staff Exhibit 1801/1 PUC 3-year W&S Adj, line 13	O&M Expense as % of Payroll Exp	69.30%	69.30%	69.30%	69.30%	69.30%
14	(12)*(13)	O&M Expense Adjustment - Systemwide	$0	$0	($2,798)	$0	($2,798)
15	Staff Exhibit 1801/1 PUC 3-year W&S Adj, line 15	Oregon Allocation Factor	0.897	0.897	0.897	0.897	0.897
16	(14)*(15)	**O&M Expense Adjustment**	**$0**	**$0**	**($2,509)**	**$0**	**($2,509)**
17	Staff Exhibit 1801/1 PUC 3-year W&S Adj, line 17	Rate Base as % of Payroll Exp	30.70%	30.70%	30.70%	30.70%	30.70%
18	(12)*(17)	Rate Base Adjustment - Systemwide	$0	$0	($1,239)	$0	**($1,239)**
19	(18)*(15)	**Rate Base Adjustment - Oregon**	**$0**	**$0**	**($1,112)**	**$0**	**($1,112)**

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		$82,579,102	$74,073,454
Staff Proposed W&S and Overtime		$76,051,022	$68,217,767
Difference	(4)-(5)	$6,528,080	$5,855,688
Payroll Taxes factor from above			5.080%
Payroll Taxes associated with Staff's Adjustment	(6)*(7)		$ 297,479
NW Natural UG 221 Payroll Taxes associated with W&S and Overtime	(4)*(7)		$ 3,763,060
Staff Adjusted Payroll Taxes	(5)*(7)		$ 3,465,580
Payroll Tax Adjustment	(10)-(9)		**$ (297,479)**

* OR Allocation factor from Exhibit 1801.1, PUC 3-year W&S, line 15

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	($21,335)	(19,137)	(4,499,827)	($4,036,345)	($2,798)	($2,509)	($4,523,959)	($4,057,992)	($4,524)	($4,058)
Rate Base	($9,451)	(8,478)	(1,993,430)	($1,788,107)	($1,239)	($1,112)	($2,004,121)	($1,797,696)	($2,004)	($1,798)
							($6,528,080)	**($5,855,688)**	**($6,528)**	**($5,856)**

O&M Depreciation associated with Capital Adjustments			$ (48,507)
* 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)

			Year Ending 12/31/2010					
Union	Grade	Position	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				Experienced			
# of Entry FTE	% of Entry FTE	% inc.	Weighted Increase	# 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

Excerpt From EXHIBIT M97

UNION SALARY INFORMATION (2009-2013)

			Year Ending 12/31/2011					
Union	Grade	Position	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				Experienced			
# of Entry FTE	% of Entry FTE	% inc.	Weighted Increase	# 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

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**

*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.

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

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**

*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

TABLE No. 1

Line		Alternative #1 Adjusted 2011	Alternative #2 Adjusted 3-yr average (2009-2011)
1	Beginning FTE	1006.1	1,007.9
2	Add 14 Union FTE related to 4-hr service windows	14.0	14.0
3	Staff Prop. FTE	1020.1	1021.9
4	UG 221 FTE (Revised)	1110.8	1110.8
5	Staff FTE Adj.	(90.7)	(88.9)

TABLE No. 2

Staff Proposed FTE: Categories @ Test Year Percentages					
Line	Categories	UG 221	% of Test Yr Total	Alt. # 1	Alt. # 2
1	Officers	9.9	0.89%	9.1	9.1
2	Exempt	434.8	39.14%	399.3	400.0
3	Non-exempt	28.5	2.57%	26.2	26.2
4	Union	637.6	57.40%	585.5	586.6
5	Total	1,110.8	100.00%	1,020.1	1,021.9

TABLE No. 3

Customers per FTE				
	NWN Test Period Customers[2]		679,721	
Line		UG 221	Alternative 1	Alternative 2
1	FTE	1130	1020.1	1021.9
2	No of customers per FTE	602	666	665

[2] See NWN/902/Williams/1

TABLE No. 4

Excerpt DR 508: NWN Supplemental Response to SDR 95Standard Data Request M95

Line	Category	2009 Total Co FTE	2010 Total Co FTE	2011* Total Co FTE	Test Year Total Co FTE	Original Test YR Total Co FTE	2009-2011 3-Year Avg Total Co FTE
1	Officers	9.7	9.5	9.1	9.9	10.0	9.4
2	Exempt	352.3	339.4	373.3	434.8	448.8	355.0
3	Non-exempt	30.1	31.1	30.7	28.5	28.5	30.6
4	Union	659.6	586.0	593.0	637.6	642.7	612.9
5	Total	1,051.7	966.0	1,006.1	1110.8	1,130.0	1,007.9

Table No. 5

Line		Percent increase between NWN's test year and 2011 FTE
1	Officers	9%
2	Exempt	16%
3	Non-exempt	-7%
4	Union	8%

Excerpt from NWN Data Response M 95

Year: 2009	Actual (unadjusted) Paid Cash Compensation				
Category	Total Co FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	9.9	$ 2,490,442	$ -	$ 1,900,368	$ 4,390,810
Exempt	371.2	$ 30,692,710	$ -	$ 3,956,788	$ 34,649,498
Nonexempt	30.1	$ 1,606,075	$ 21,924	$ 109,355	$ 1,737,353
Union	664.7	$ 36,048,676	$ 3,363,596	$ 1,471,016	$ 40,883,287
Total	1,075.9	$ 70,837,902	$ 3,385,519	$ 7,437,526	$ 81,660,948

Year: 2010	Actual (unadjusted) Paid Cash Compensation				
Category	Total Co FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	10.0	$ 2,568,475	$ -	$ 2,230,919	$ 4,799,394
Exempt	365.5	$ 30,584,270	$ -	$ 5,870,093	$ 36,454,364
Nonexempt	31.1	$ 1,775,383	$ 17,730	$ 122,157	$ 1,915,270
Union	591.1	$ 32,678,330	$ 3,343,646	$ 1,695,059	$ 37,717,035
Total	997.7	$ 67,606,459	$ 3,361,376	$ 9,918,227	$ 80,886,062

Year: 2011	Actual/Forecasted (unadjusted) Paid Cash Compensation				
Category	Total Co FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	10.0	$ 2,638,538	$ -	$ 1,505,534	$ 4,144,072
Exempt	391.0	$ 33,287,679	$ -	$ 6,389,092	$ 39,676,771
Nonexempt	30.7	$ 1,713,797	$ 17,850	$ 181,736	$ 1,913,383
Union	598.1	$ 33,603,046	$ 2,814,223	$ 2,183,957	$ 38,601,226
Total	1,029.8	$ 71,243,060	$ 2,832,073	$ 10,260,319	$ 84,335,452

Test Year	Forecasted (unadjusted) Paid Cash Compensation				
Category	Total Co FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	10.0	$ 2,777,472	$ -	$ 1,260,025	$ 4,037,497
Exempt	448.8	$ 38,767,484	$ -	$ 4,004,303	$ 42,771,787
Nonexempt	28.5	$ 1,699,422	$ 21,452	$ 91,701	$ 1,812,575
Union	642.7	$ 37,852,290	$ 3,028,183	$ 1,344,021	$ 42,224,494
Total	1,130.0	$ 81,096,668	$ 3,049,635	$ 6,700,050	$ 90,846,353

Excerpt from DR 508: Supplemental Response to SDR 95 for 2009, 2010, 2011 & Test Year FTEs and Compensation Excluding Below the Line Reductions

Year: 2009	Actual (unadjusted) Paid Cash Compensation				
Category	Estimated Regulated FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	9.7	$ 2,432,937	$ -	$ 1,856,488	$ 4,289,425
Exempt	352.3	$ 29,126,502	$ -	$ 3,754,878	$ 32,881,380
Nonexempt	30.1	$ 1,606,075	$ 21,924	$ 109,355	$ 1,737,353
Union	659.6	$ 35,772,087	$ 3,337,788	$ 1,459,729	$ 40,569,605
Total	1,051.6	$ 68,937,601	$ 3,359,712	$ 7,180,450	$ 79,477,763

Year: 2010	Actual (unadjusted) Paid Cash Compensation				
Category	Estimated Regulated FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	9.5	$ 2,427,523	$ -	$ 2,108,491	$ 4,536,013
Exempt	339.4	$ 28,400,948	$ -	$ 5,451,044	$ 33,851,993
Nonexempt	31.1	$ 1,775,383	$ 17,730	$ 122,157	$ 1,915,270
Union	586.0	$ 32,396,382	$ 3,314,797	$ 1,680,434	$ 37,391,613
Total	966.0	$ 65,000,236	$ 3,332,527	$ 9,362,125	$ 77,694,889

Year: 2011	Actual (unadjusted) Paid Cash Compensation				
Category	Estimated Regulated FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	9.1	$ 2,395,551	$ -	$ 1,366,887	$ 3,762,439
Exempt	373.3	$ 31,781,807	$ -	$ 6,100,061	$ 37,881,868
Nonexempt	30.7	$ 1,713,797	$ 17,850	$ 181,736	$ 1,913,383
Union	593.0	$ 33,316,513	$ 2,790,226	$ 2,165,334	$ 38,272,073
Total	1,006.1	$ 69,207,668	$ 2,808,076	$ 9,814,019	$ 81,829,763

Test Year	Forecasted (unadjusted) Paid Cash Compensation				
Category	Regulated FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	9.9	$ 2,741,418	$ -	$ 1,243,669	$ 3,985,087
Exempt	434.8	$ 37,560,734	$ -	$ 3,879,658	$ 41,440,392
Nonexempt	28.5	$ 1,699,422	$ 21,452	$ 91,701	$ 1,812,575
Union	637.6	$ 37,551,922	$ 3,004,154	$ 1,333,356	$ 41,889,431
Total	1,110.8	$ 79,553,496	$ 3,025,606	$ 6,548,383	$ 89,127,485

TABLE A.1

Dec 2011 - Other Economic Indicators

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
GDP (Bil of 2005 $),												
Chain Weight (in billions of $	12,703.1	13,088.0	13,308.0	13,491.4	13,810.0	14,298.3	14,778.8	15,200.1	15,586.0	15,950.7	16,344.7	16,769.6
% Ch	(3.5)	3.0	1.7	1.4	2.4	3.5	3.4	2.9	2.5	2.3	2.5	2.6
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2005=1C	109.7	111.0	113.4	115.0	116.4	118.5	120.7	123.0	125.2	127.3	129.4	131.5
% Ch	1.1	1.2	2.2	1.4	1.2	1.8	1.9	1.8	1.8	1.7	1.6	1.6
Personal Consumption Deflator,												
Chain Weight U.S., 2005=10(	109.2	111.1	113.7	115.1	117.1	119.5	121.9	124.2	126.4	128.7	130.9	133.1
% Ch	0.2	1.8	2.4	1.2	1.7	2.1	2.0	1.8	1.8	1.8	1.7	1.7
CPI, Urban Consumers,												
1982-84=100												
Portland-Salem, OR-WA	215.6	218.3	224.7	227.6	231.8	236.6	241.4	246.0	250.9	255.8	261.1	266.4
% Ch	0.1	1.3	2.9	1.3	1.8	2.1	2.0	1.9	2.0	1.9	2.1	2.0
U.S.	214.5	218.1	224.7	227.6	232.0	237.3	242.4	246.9	251.2	255.6	260.0	264.2
% Ch	(0.3)	1.6	3.0	1.3	1.9	2.3	2.1	1.9	1.7	1.8	1.7	1.6
Oregon Average Wage												
Rate (Thous $)	43.0	44.0	44.9	46.4	47.8	49.3	50.8	52.2	53.9	55.4	57.1	58.8
% Ch	0.9	2.4	2.1	3.3	3.0	3.2	3.1	2.8	3.1	2.8	3.1	3.1
U.S. Average Wage												
Wage Rate (Thous $)	47.9	49.4	50.9	52.1	53.4	55.0	56.6	58.2	60.0	61.8	63.8	65.8
% Ch	0.1	3.0	3.0	2.4	2.7	2.9	2.9	2.8	3.0	3.1	3.2	3.2
Housing Indicators												
FHFA Oregon Housing Price Index												
Housing Index 1987 Q1=100	410.3	383.5	347.1	323.9	322.4	331.5	346.0	355.6	368.1	380.2	391.8	404.8
% Ch	(7.7)	(6.5)	(9.5)	(6.7)	(0.5)	2.8	4.4	2.8	3.5	3.3	3.1	3.3
FHFA National Housing Price Index												
(1980Q1=100)	344.4	332.3	314.9	301.5	307.7	322.5	340.4	351.1	364.1	375.9	387.0	399.8
% Ch	(4.6)	(3.5)	(5.2)	(4.3)	2.1	4.8	5.6	3.1	3.7	3.2	3.0	3.3
Housing Starts												
Oregon (Thous)	7.6	7.6	7.7	8.1	10.5	13.9	18.8	22.6	25.2	25.3	25.3	25.2
% Ch	(40.6)	0.7	0.7	5.0	29.8	33.1	34.8	20.0	11.6	0.7	(0.2)	(0.2)
U.S. (Millions)	0.6	0.6	0.6	0.7	0.9	1.3	1.6	1.7	1.8	1.8	1.7	1.7
% Ch	(38.4)	5.6	0.4	13.3	41.8	41.0	21.2	7.6	2.5	(1.5)	(1.1)	(0.9)
Other Indicators												
Industrial Production Index												
U.S, 2002 = 100	85.5	90.1	93.4	94.8	97.8	102.3	106.2	109.1	111.4	113.9	116.8	120.0
% Ch	(11.2)	5.3	3.6	1.6	3.2	4.6	3.8	2.7	2.2	2.2	2.5	2.7
Prime Rate (Percent)	3.3	3.3	3.3	3.3	3.2	4.2	6.3	7.0	7.0	7.0	7.0	7.0
% Ch	(36.1)	0.0	0.0	0.0	(0.0)	30.3	48.1	11.6	0.0	0.0	0.0	0.0
Population (Millions)												
Oregon	3.82	3.84	3.86	3.89	3.92	3.97	4.01	4.06	4.11	4.16	4.22	4.27
% Ch	0.8	0.6	0.5	0.8	0.9	1.1	1.2	1.2	1.2	1.3	1.3	1.3
U.S.	307.8	310.8	313.8	316.9	319.9	323.0	326.2	329.3	332.5	335.6	338.8	342.0
% Ch	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9
Timber Harvest (Mil Bd Ft)												
Oregon	2,820.0	3,210.0	3,189.2	3,385.4	3,841.9	4,036.2	4,106.5	4,138.2	4,219.5	4,291.1	4,367.1	4,404.7
% Ch	(18.0)	13.8	(0.6)	6.2	13.5	5.1	1.7	0.8	2.0	1.7	1.8	0.9

CASE: UG 221
WITNESS: DEBORAH GARICA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1802

Exhibits in Support
Of Rebuttal Testimony

July 20, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 504**:**
Regarding NWN/2303/Sohl/1: Please provide a copy of the complete position description, that is on file and provided to an employee, for each of the FTE that are listed in the last column of the table as being included in NW Natural's Rev Req. On each position description please note to which FERC account(s) the associated labor expense is assigned.

Response: 6/29/2012

Below are the FERC accounts for the associated labor expense for each position.

DR 504: FERC Account Assignments	
Cost Center Position Focus	FERC ACCTS
Business Development Business Development Consultant - OPUC DR 504 Attachment-1 Business Development Director - OPUC DR 504 Attachment-2	921
Customer Choice Program Admin. Positions Sales Specialist - OPUC DR 504 Attachment-3	921
Marketing Strategy Marketing Manager - OPUC DR 504 Attachment-4	921
Dir., Acquire Customers Process Director - OPUC DR 504 Attachment-5	908
Marketing Marketing Program Manager - OPUC DR 504 Attachment-6	912
Conversion Sales Account Manager - OPUC DR 504 Attachment-7 Sales Supervisor - OPUC DR 504 Attachment-8 Sales Representative - OPUC DR 504 Attachment-9	908, 912

Consultant Profile

General Purpose
Provides advice and counsel to management and client organizations. Conducts special studies and analyses, develops alternatives, presents recommendations to management and influences management decisions. Researches, analyzes, develops and implements new strategies, programs, and/or processes in response to changing internal and external conditions.

Competencies

- Research and analysis skills including ability to obtain relevant data, evaluate complex situations, develop creative alternatives, provide recommendations, and negotiate and influence outcomes.
- Program design skills including development of interventions, processes, or new or modified programs to meet customer needs.
- Communication and interpersonal skills involving the ability to establish trust, maintain confidence, and understand social behavior and interactions. Ability to work with all organizational levels, to influence actions and negotiate outcomes. Ability to listen and communicate effectively through oral and written means.
- Use of personal computer to gather, analyze, and summarize data.
- Project management and leadership skills, including ability to work as a team member, to maintain project timelines, budgets, and deliver on commitments.
- Knowledge of research, analysis and consulting techniques, Company policies, procedures, practices, and applicable federal, state, and local governmental laws and regulations.

Decision Making/Impact

- Provide alternatives and recommendations regarding development or enhancement of programs or processes.
- Provide advice and counsel, and negotiate and influence outcomes.

Education/Experience
Bachelor's degree in Business Administration, Marketing, Finance, Human Resource Management, or other applicable fields or an equivalent combination of education and experience resulting in proven consulting skills.

Special Requirements
May require advanced degrees or travel.

Levels
Non-Engineering:

1. Under close/general supervision, performs work requiring the application of standard techniques, procedures and criteria. Receives training to enhance proficiency and productivity.
2. Under general supervision performs moderately complex assignments requiring analysis, integration and creativity.
3. Under general guidance performs complex assignments lacking precedent and requiring creativity. Serves as an expert in the discipline, provides advice or functional direction, and/or assumes a lead role in the work group.

Disciplines:

Business Development
Business development activities including business plans, formation of strategic alliances, distributed energy applications and value-added services. Also includes responsibility for Interstate Gas Storage (commercial development), special non-tariff contracts and strategic market analysis.

Director Profile

General Purpose

Manages one or more large geographic territories, regions, locations and/or major function that have a major impact on corporate objectives and performance. Leads development of business objectives, strategies, and plans in support of Company strategic goals. Regularly participates on corporate senior management teams and committees. Approves policy for area of responsibility. Provides input to, implements and supports Company programs and policies. Typically reports to an Officer.

Competencies

- Management skills including ability to initiate and establish objectives, develop and execute policy, direct and monitor extensive resources, and recommend and oversee development or implementation of systems, programs, or processes.
- Leadership and teamwork skills to negotiate with and influence peers and senior officers on policy and strategic issues.
- Communication and interpersonal skills including ability to manage and motivate employees, use oral and written communication to create a vision, communicate strategy, and effectively interface with other Company leaders.
- Knowledge of Company's strategic plan, regulatory and political environment, as well as the Company's policies, procedures and practices, and applicable federal, state, and local laws and regulations.

Decision Making/Impact

- Initiates, recommends and implements plans and approaches to support overall business strategies and performance.
- Decisions regularly impact the achievement of corporate objectives and performance.

Education/Experience

Bachelor's degree in applicable field or combination of experience and education resulting in the proven ability to provide leadership to a significant entity in implementing the Company's strategic plans.

Special Requirements

Advanced degree and travel may be required.

Levels

No levels apply to this role.

Disciplines:

Business Development

Business development activities including business plans, formation of strategic

alliances, distributed energy applications and value-added services. Also includes responsibility for Interstate Gas Storage (commercial development), special non-tariff contracts and strategic market analysis.

Specialist

General Purpose
Facilitates activities in an effective sequence by monitoring tasks and expenditures, compiling data, tracking and reporting results, and maintaining reference information and databases. Determines schedules and availability of resources/materials. Ensures activities are performed in accordance with contract, Corporate, and regulatory agency requirements.

Competencies

- Compiles, organizes, and summarizes data from multiple sources.
- Monitors/tracks processes to ensure their execution within defined parameters.
- Communication and interpersonal skills including the ability to work with all organizational levels as a team member, to ensure that key information on schedules, requirements, and resources is communicated to management in a clear and timely manner.
- Uses PC including spreadsheet, database, word processing and presentation applications to compile, maintain, and present information.
- Knowledge of Company and departmental policies, procedures, and practices as well as applicable federal, state, and local governmental laws and regulations.

Decision Making/Impact

- Determines appropriate activities to support organizational or departmental processes.
- Provides management with information on departmental operations, and informs management of deviations from established processes or schedules which may impact business outcomes.

Education/Experience
High school education and additional courses or equivalent combination of education and experience resulting in proven skills in monitoring and tracking departmental operations.

Special Requirements
None

Levels
Non-Engineering:

1. Under close/general supervision, performs work requiring the application of standard techniques, procedures and criteria. Receives training to enhance proficiency and productivity.
2. Under general supervision performs moderately complex assignments requiring analysis, integration and creativity.
3. Under general guidance performs complex assignments lacking precedent and requiring creativity. Serves as an expert in the discipline, provides advice or functional direction, and/or assumes a lead role in the work group.

Disciplines:

Sales/Marketing
Activities related to the performance and/or management of sales and service transactions, marketing programs, and business relationships. Includes measuring sales/marketing performance, conducting consumer research activities and developing/delivering advertising and information delivery requirements.

Manager Profile

General Purpose
Manages a single geographic territory, region, location or functional unit that has a significant impact on corporate, business unit, or organizational objectives. Assists in developing and implementing policy recommendations. Develops or assists in developing and implementing policy recommendations. Implements and supports Company strategic plans, programs and policies. Manages resources, people and/or budget. Typically reports to a Director or Officer (on exception to Manager).

Competencies

- Management skills including the ability to establish objectives, execute policy, monitor resources, and manage the development or implementation of a system, program or process.
- Leadership and teamwork skills to provide input into policy decisions, and to mobilize resources to produce desired business results.
- Communication and interpersonal skills to manage and motivate employees, use oral and written communication to communicate objectives and action plans.
- Knowledge of the Company's strategic plan, objectives for specific area, as well as Company policies, procedures, and practices and federal, state, and local governmental laws and regulations.

Decision Making/Impact

- Provides alternatives and recommendations to management on action plans for achieving objectives.
- Recommends and implements action plans for achieving objectives.

Education/Experience
Bachelor's degree in applicable field or combination of experience and education contributing to the development of proven ability to manage a significant entity.

Special Requirements
May require advanced degree or travel.

Levels
No levels apply to this role.

Disciplines:

Marketing
Activities related to development, implementation and performance of short and long-range marketing programs.

Director Profile

General Purpose

Manages one or more large geographic territories, regions, locations and/or major function that have a major impact on corporate objectives and performance. Leads development of business objectives, strategies, and plans in support of Company strategic goals. Regularly participates on corporate senior management teams and committees. Approves policy for area of responsibility. Provides input to, implements and supports Company programs and policies. Typically reports to an Officer.

Competencies

- Management skills including ability to initiate and establish objectives, develop and execute policy, direct and monitor extensive resources, and recommend and oversee development or implementation of systems, programs, or processes.
- Leadership and teamwork skills to negotiate with and influence peers and senior officers on policy and strategic issues.
- Communication and interpersonal skills including ability to manage and motivate employees, use oral and written communication to create a vision, communicate strategy, and effectively interface with other Company leaders.
- Knowledge of Company's strategic plan, regulatory and political environment, as well as the Company's policies, procedures and practices, and applicable federal, state, and local laws and regulations.

Decision Making/Impact

- Initiates, recommends and implements plans and approaches to support overall business strategies and performance.
- Decisions regularly impact the achievement of corporate objectives and performance.

Education/Experience

Bachelor's degree in applicable field or combination of experience and education resulting in the proven ability to provide leadership to a significant entity in implementing the Company's strategic plans.

Special Requirements

Advanced degree and travel may be required.

Levels

No levels apply to this role.

Disciplines:

Process

Activities related to the review, study, analysis, redesign and implementation of business processes.

Program Manager

General Purpose

Manages a market program through the development and implementation of program plans that coordinate the positions, products, pricing, schedules, promotions and distribution channels. Assesses effectiveness of program plans and recommends revised strategies and tactics to achieve goals.

Competencies

- Research, analysis, and development skills to obtain relevant data on market segment, to investigate and understand complex characteristics of market segment, to project future directions and trends, and to develop effective program strategies.

- Project management skills to identify necessary tasks, timelines, budgets, and measurement systems for program plans, and to monitor the implementation of plans.

- Communication and interpersonal skills including ability to interface effectively with all organizational levels as a team member and to establish positive relationships and elicit feedback from customers. Oral and written communication skills to package, present, and report on program plans.

- Leadership and teamwork skills to build cooperative working relationships and effectively coordinate the efforts of multiple functions in support of the program plan.

- PC skills for using automated tools to support analysis, tracking, and reporting activity.

- Knowledge of sales and marketing principles and practices including financial modeling, pricing, competitive assessment, proposal development. Knowledge of gas business, competitive environment, assigned market segment, products, distribution channels, competitors, and business environment. Knowledge of Company policies, procedures, and practices, and relevant federal, state, and local laws and regulations.

Decision Making/Impact

- Makes recommendations to management on effective strategies and specific tactics for achieving sales and market share objectives in assigned market programs.

- Impacts the achievement of sales, gross margin, and customer satisfaction goals in assigned market program.

Education/Experience

Bachelor's degree in Business, Economics, Marketing, Engineering, or related discipline, or a combination of education and experience resulting in demonstrated skills in market segment planning and management.

Special Requirements

Travel may be required.

Levels

Non-Engineering:

1. Under close/general supervision, performs work requiring the application of standard techniques, procedures and criteria. Receives training to enhance proficiency and productivity.
2. Under general supervision performs moderately complex assignments requiring analysis, integration and creativity.

3. Under general guidance performs complex assignments lacking precedent and requiring creativity. Serves as an expert in the discipline, provides advice or functional direction, and/or assumes a lead role in the work group.

Disciplines:

Marketing

Activities related to development, implementation and performance of short and long range marketing programs.

Account Manager

General Purpose
Represents NW Natural to new and existing customers to initiate and close promotion of services utilizing knowledge of the customer's investment strategy and NW Natural's service offerings. Develops, executes and maintains account plans and strategies utilizing technological tools, market information and leads.

Competencies

- Marketing skills including account planning, research, and account management skills.
- Communication and interpersonal skills including ability to establish trust and maintain confidence; understand concepts and causes for behaviors in diverse social and/or business situations; ability to work with all levels of an organization including people with different styles and backgrounds; able to influence others to modify their positions and/or negotiate to an acceptable solution.
- Oral presentation, listening and written communication skills, including the ability to present to different audiences.
- Project management, teamwork and leadership skills to produce desired business results.
- Knowledge of the Company's business, regulatory and political environment.

Decision Making / Impact

- Provides alternatives and recommendations to customers and influences their decisions to select NW Natural as their provider of services.
- Provides input and recommendations regarding new and existing services in order to meet customer's needs, increase market share and revenues.

Education / Experience
Education and/or experience which have contributed to the development of proven sales, problem solving, analytical and strategizing skills, typically achieved with 5 or more years experience performing various sales and marketing functions including sales of products and services, market research, account planning, product development, and sales strategy functions.

Special Requirements
Travel may be required.

Levels
Non-Engineering:

1. Under close/general supervision, performs work requiring the application of standard techniques, procedures and criteria. Receives training to enhance proficiency and productivity.
2. Under general supervision performs moderately complex assignments requiring analysis, integration and creativity.
3. Under general guidance performs complex assignments lacking precedent and requiring creativity. Serves as an expert in the discipline, provides advice or functional direction, and/or assumes a lead role in the work group.

Disciplines:

Sales/Marketing
Activities related to the performance and/or management of sales and service transactions, marketing programs, and business relationships. Includes measuring sales/marketing performance, conducting consumer research activities and developing/delivering advertising and information delivery requirements.

Supervisor Profile

General Purpose
Supervises a location or functional unit. Implements business objectives, and plans and oversees daily work functions. Responsible for selecting, coaching, and developing employees. Implements and supports Company programs and policies. Must have full supervisory responsibility for three or more employees. Typically reports to a Manager (on exception to a Director or Officer).

Competencies

- Management skills including the ability to implement action plans for achieving objectives, and to oversee daily operations.
- Leadership and teamwork skills to develop and promote cooperative working relationships within and among departments.
- Communication and interpersonal skills to communicate expectations, coach employees, provide feedback, and work collaboratively with other departments.
- Knowledge of strategic plan and objectives for area, day-to-day operations of specific area, Company policies, procedures and practices, and federal, state, and local laws and regulations.

Decision Making/Impact

- Makes hiring and pay decisions for employees in assigned area.
- Oversees and monitors departmental operations and employee activity in support of business objectives.

Education/Experience
Bachelor's degree or equivalent education and experience in a specific location or functional unit, resulting in the ability to effectively oversee the day-to-day operations of that area.

Special Requirements
Some travel may be required.

Levels
No levels apply to this role.

Disciplines:

Outside Sales
Activities relating to the direct sale of natural gas service and equipment to new and existing residential, commercial, and small industrial customers.

Sales Representative

General Purpose

Conducts technical sales activities directed toward the efficient utilization of gas products and service. Educates the general public on comparisons and advantages of gas, including appliance features, installation requirements and equipment operations.

Competencies

- Selling skills including developing leads, prospecting and account management.
- Customer service skills and experience.
- Requires high-level communication, interpersonal and negotiation skills.
- Knowledge of marketing concepts, theories and approaches, including sales promotions and contacts.
- Utilize personal computers including spreadsheet, database, word processing, and presentation applications.
- Knowledge of advertising practices and methodologies.

Decision Making/Impact

- Resolves customer concerns and negotiates sales within established Company guidelines and policy.

Education/Experience

High school diploma with specialized training or business course, or an equivalent combination of education and experience.

Special Requirements

Ability to manage items up to a maximum of 50#. Requires a valid Oregon/Washington Driver's License and a satisfactory driving record.

Levels

Non-Engineering:

1. Under close/general supervision, performs work requiring the application of standard techniques, procedures and criteria. Receives training to enhance proficiency and productivity.
2. Under general supervision performs moderately complex assignments requiring analysis, integration and creativity.
3. Under general guidance performs complex assignments lacking precedent and requiring creativity. Serves as an expert in the discipline, provides advice or functional direction, and/or assumes a lead role in the work group.

Disciplines

No disciplines apply to this role.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 504**:**
Regarding NWN/2303/Sohl/1: Please provide a copy of the complete position description, that is on file and provided to an employee, for each of the FTE that are listed in the last column of the table as being included in NW Natural's Rev Req. On each position description please note to which FERC account(s) the associated labor expense is assigned.

Response: 6/26/2012

Please refer to page 4, lines 1-12 of John Sohl's reply testimony (NWN 2300, Sohl). Of the total Company 1,114 FTEs, 19.2 FTEs should be considered below the line, because the costs associated with 19.2 FTEs that are associated with unregulated activities have not been included in the Company's test year revenue requirement.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 504**:**
Regarding NWN/2303/Sohl/1: Please provide a copy of the complete position description, that is on file and provided to an employee, for each of the FTE that are listed in the last column of the table as being included in NW Natural's Rev Req. On each position description please note to which FERC account(s) the associated labor expense is assigned.

Response: 6/29/2012

See OPUC DR 508 Attachment-1, which provides a supplemental response that restates 2009, 2010, and the test year as requested.

DR 508: Supplemental Response to SDR 95 for 2009, 2010, & Test Year					
FTEs and Compensation Excluding Below the Line Reductions					
Year: 2009	**Actual (unadjusted) Paid Cash Compensation**				
Category	**Estimated Regulated FTE**	**Base Wages or Salaries**	**Overtime**	**Incentive or Bonus**	**Total**
Officers	9.7	$ 2,432,937	$ -	$ 1,856,488	$ 4,289,425
Exempt	352.3	$ 29,126,502	$ -	$ 3,754,878	$ 32,881,380
Nonexempt	30.1	$ 1,606,075	$ 21,924	$ 109,355	$ 1,737,353
Union	659.6	$ 35,772,087	$ 3,337,788	$ 1,459,729	$ 40,569,605
Total	1,051.6	$ 68,937,601	$ 3,359,712	$ 7,180,450	$ 79,477,763
Year: 2010	**Actual (unadjusted) Paid Cash Compensation**				
Category	**Estimated Regulated FTE**	**Base Wages or Salaries**	**Overtime**	**Incentive or Bonus**	**Total**
Officers	9.5	$ 2,427,523	$ -	$ 2,108,491	$ 4,536,013
Exempt	339.4	$ 28,400,948	$ -	$ 5,451,044	$ 33,851,993
Nonexempt	31.1	$ 1,775,383	$ 17,730	$ 122,157	$ 1,915,270
Union	586.0	$ 32,396,382	$ 3,314,797	$ 1,680,434	$ 37,391,613
Total	966.0	$ 65,000,236	$ 3,332,527	$ 9,362,125	$ 77,694,889
Test Year	**Forecasted (unadjusted) Paid Cash Compensation**				
Category	**Regulated FTE**	**Base Wages or Salaries**	**Overtime**	**Incentive or Bonus**	**Total**
Officers	9.9	$ 2,741,418	$ -	$ 1,243,669	$ 3,985,087
Exempt	434.8	$ 37,560,734	$ -	$ 3,879,658	$ 41,440,392
Nonexempt	28.5	$ 1,699,422	$ 21,452	$ 91,701	$ 1,812,575
Union	637.6	$ 37,551,922	$ 3,004,154	$ 1,333,356	$ 41,889,431
Total	1,110.8	$ 79,553,496	$ 3,025,606	$ 6,548,383	$ 89,127,485

CASE: UG 221
WITNESS: Kenneth R. Zimmerman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1900

Rebuttal Testimony

July 20, 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/1902.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony has three purposes:

1. To respond to Northwest Natural Gas Company's (NWN or Company) reply testimony (NWN/1900), regarding Working Gas Inventory included in rate base.
2. To respond NWN's reply testimony (NWN/2200), regarding the Mid-Willamette Valley Feeder capital addition and the System Integrity Program (SIP).
3. To respond to NWN's reply testimony (NWN/2700), regarding storage and pipeline optimization in Schedules 185 and 186.

I. WORKING GAS INVENTORY IN RATEBASE

Q. DO YOU AGREE WITH THE COMPANY'S REPLY TESTIMONY THAT WORKING GAS INVENTORY SHOULD BE INCLUDED IN RATEBASE?

A. No.

Q. CAN YOU PLEASE RESPOND TO NWN'S REPLY TESTIMONY (NWN/1900) RELATED TO THIS ISSUE?

A. Yes.

Q. ARE YOU RECOMMENDING THAT NWN NOT BE ALLOWED TO COLLECT CARRYING COSTS ON WORKING GAS INVENTORY?

A. Yes, that is correct as relates to this general rate case. States treat working gas inventory differently. For example, some states allow inclusion of working gas inventory in rate base through a working capital adjustment. On the other hand, some states allow recovery of carrying costs of working gas inventory through annual purchased gas adjustment-like mechanisms. Still other states do not allow recovery of carrying costs at all.

My recommendation is that it is better regulatory policy to allow the carrying costs of working gas inventory to occur through NWN's annual Purchased Gas Adjustment (PGA) mechanism. Embedding an average working gas inventory into rate base and allowing the Commission-approved authorized return on equity on that inventory is less accurate than updating working gas inventory in NWN's annual PGA, with an allowance for the carrying costs of what then becomes a short term asset, i.e. because working gas inventory is reviewed annually the carrying costs of such an asset would never be more than one year.

Q. WHY ARE CARRYING CHARGES ON WORKING GAS INVENTORY MORE APPROPRIATELY HANDLED THROUGH THE ANNUAL PGA PROCESS?

A. Ratepayers fund both cushion and inventory gas in storage. However, only working gas inventory is withdrawn during each year to serve ratepayers. The annual PGA review process – which looks at gas injections and withdrawals on an annual basis – is a more appropriate place to review the accuracy, reasonableness, and prudence of all annual gas costs paid by ratepayers, including the carrying costs of working gas inventory. Relatedly, reviewing carrying costs through NWN's annual PGA allows the Commission to establish the actual carrying costs of a short term asset versus estimating those costs as the average inventory times authorized return on equity. The Company's proposed method increases the potential likelihood that ratepayers will pay inaccurate carrying costs for working gas inventory because it assumes that the carrying costs of a short term asset is the average working gas inventory times authorized return on equity instead of establishing the actual carrying costs through an annual PGA.

Q. WHAT ARE THE PRIMARY RISKS TO RATEPAYERS OF NWN INCLUDING WORKING GAS INVENTORY IN RATE BASE?

A. The primary risk of NWN including average working gas inventory in rate base is that ratepayers will not pay the accurate and actual costs of working gas inventory. Table 1, below, demonstrates through a simplistic example how NWN's proposal could lead to inaccurate recovery of carrying costs.

Table 1

	Market value of working inventory gas
UG 221	$35,325,888
After 2012 injection season	$26,903,302
After 2013 injection season	$25,185,587

This table illustrates what would happen to the market value of NWN's working gas inventory in a rate case if current forecasts for natural gas prices over the next two years are relatively accurate and half of the volume of working gas inventory is replaced in each of those two years. After the 2012 injection season, the market value of working gas inventory in rate base would be $26,903,301 and after the 2013 injection season the value of working gas inventory in rate base would be $25,185,587. However, ratepayers would still be paying the Commission authorized return on equity on the value of working gas inventory requested in this proceeding of $35,325,888. In this simplified example, NWN customers would pay around two million dollars more than the actual costs incurred by NWN to maintain working gas inventory.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE RECOVERY OF THE COST OF AND THE RETURN ON WORKING GAS INVENTORY HELD BY NWN FOR ITS UTILITY RATEPAYERS?

A. My recommendation is that the Commission deny NWN's request to include the cost of storage working gas inventory in rate base. Instead, I recommend that the Commission order the cost of the working gas inventory to meet the needs of ratepayers and any carrying costs associated with that inventory be reviewed for accuracy, reasonableness, and prudence during the annual PGA where all parties will have an opportunity to make recommendations regarding recovery of both gas costs (storage and flowing) and storage carrying charges.

II. Mid-Willamette Feeder Capital Addition

Q. DO YOU ADOPT THE OPENING TESTIMONY OF STAFF WITNESS MOSHREK SOBHY (STAFF EXHIBIT 1100) PREVIOULY FILED IN THIS DOCKET?

A. Yes.

Q. SHOULD NWN'S INTEGRATED RESOURCE PLAN (IRP) EXAMINE THE NEED FOR DISTRIBUTION AND SAFETY RELATED RESOURCES?

A. Yes. In fact, NWN's recently acknowledged Modified IRP explicitly considered the Mid-Willamette Valley Feeder (MWVF). NWN admits that the earliest date that the IRP would select the MWVF would be 2019 based upon reliability and 2025/2026 based upon load growth.[1]

Q. DESPITE THE INCONSISTENCY WITH THE 2011 MODIFIED IRP, NWN ASSERTS THAT IT IS PRUDENT TO INCLUDE COSTS FOR TWO PORTIONS OF THE MWVF IN THIS PROCEEDING (PERRYDALE TO MONMOUTH AND MONMOUTH REINFORCEMENT). DO YOU AGREE?

A. No. NWN fails to offer an explanation of why these two portions of the MWVF were not included in the recently acknowledged Modified IRP. Without an explanation of why the Modified IRP is incorrect or providing quantitative analysis in this general rate case, it would be inappropriate to ignore the IRP process results. While NWN attempts to offer some after-the-fact qualitative justifications for the prudency of building projects inconsistent with the results of the Modified IRP, it offers no evidence to contradict the actual results of the Modified IRP. NWN should not be rewarded for its failure to follow the Modified IRP or provide quantitative analysis supporting its departure from the results of the Modified IRP.

Q. WHAT DO YOU RECOMMEND FOR THESE TWO PORTIONS OF THE MWVF?

A. I continue to recommend that the Commission deny NWN's request to include the costs for these two portions of the MWVF into rates. NWN's request is not supported by the results of NWN's most recently acknowledged Modified IRP and NWN has provided no quantitative analysis to demonstrate that the Modified IRP is incorrect.

[1] NWN/2200,Yoshihara/6 at lines 3-14.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?

A. Yes. One issue with these two projects is related to the evidence of when the projects are needed. Furthermore, even for projects where a need has been demonstrated, it also must be demonstrated that they are "used and useful" at the time they enter ratepayer rates. The issue of whether these projects are used and useful by the effective date of rates has been settled through an attestation process that is part of a partial stipulation entered into in this docket.[2] The issue of the prudence of the projects remains unaddressed by NWN, particularly in light the fact that NWN's recently acknowledged Modified IRP demonstrates they are not needed any time soon. My alternative recommendation is that the projects be found not prudent at this time, but reserve the right of NWN to ask for inclusion of these projects at a later time when IRP results or quantitative analysis convince the Commission that the projects are needed and will be used and useful when placed into rates.

III. System Integrity Program (SIP)

Q. WHAT DO YOU RECOMMEND FOR THE SIP PROGRAM?

A. I continue my recommendation from my opening testimony that the current SIP balances for 2012 are allowed into rate base, but that the SIP is discontinued going forward.

Q. WHY DO YOU RECOMMEND THAT THE SIP SHOULD BE DISCONTINUED?

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[2] The Partial Stipulation at Para. 11 provides:
"To remove any continuing concerns, however, the Company agrees that by October 1, 2012 it will file an attestation from senior management confirming that these projects either are or will be used and useful by the rate effective date. The attestation filing will also confirm the amount that the Company has invested in each of those projects as of the date of the filing, and, if the project is not yet complete, the Company's reasonable expectation of costs that will be incurred up to the rate effective date."

A. The question of the continuation or elimination of the SIP program, or some portion thereof, is one of regulatory policy. The SIP is an exception to normal ratemaking in that it reduces regulatory lag for a subset of categories, while not allowing for a holistic and simultaneous review of all expenses and revenues.

As a general matter, I am concerned about several regulatory policy issues. First, the SIP started out as a narrow program to recover the costs of bare steel replacement. However, the SIP program has expanded and may expand more based upon future safety requirements. While I understand that safety is of the utmost importance, the appropriate level of safety investments can be thoroughly analyzed in a general rate case. Furthermore, NWN could employ deferred accounting applications for new safety requirements that require large expenditures. These potential deferred accounting applications have the regulatory benefit of requiring an earnings test. Therefore, at a minimum, regulatory policy of general rates cases and deferred accounting allow some review of overall earnings and does not isolate one cost category while ignoring the overall reasonableness of rates.

Second, the SIP programs and its expansion are the result of stipulations. The SIP stipulations entered into for bargained-for-consideration should not create an expectation that the SIP program will be continued indefinitely. Certainly, continuation of the SIP program reduces regulatory lag and makes it less likely NWN will file regular general rates cases. Furthermore, NWN has an annual PGA clause, it is requesting continuation of a decoupling mechanism, it desires a balancing account for environment remediation costs with no sharing, it wants a way to recover pensions costs, including a return on and of cash contributions, and it requests more full-time equivalent employees than it has currently employed or has employed in a number of years, and the SIP. These types of regulatory treatments substantially reduce the risk to NWN and make it less likely that the Company will use traditional ratemaking procedures to establish the overall reasonableness of rates.

In summary, the existing regulatory mechanisms of general rate cases and deferred accounting allow NWN to recover its prudently incurred costs of operation. The SIP is another mechanism to lower the risk profile of the Company and reduce regulatory lag. My opinion is that it is better regulatory policy to review these costs holistically in regular general rate cases or through deferred accounting subject to an earnings test, both of which would allow a more thorough look than the automatic inclusion of some costs and expenses without the normal benefits of traditional ratemaking and regulatory lag.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS REGARDING THE SIP?

Yes, I have several alternatives that are not mutually exclusive. First, the SIP could be shrunk to its original purpose – the replacement of bare steel. Second, the SIP could be attached to a two or three year sunset provision so as not to continue indefinitely. Third, the portion of expenses that the Company must absorb as regulatory lag, currently 3.25 million, could be increased to 5 million in the newly constituted SIP. To be clear, I recommend that the Commission terminate the SIP going forward and rely on general rate cases and deferred accounting, but offer these as alternatives that would improve the status quo.

IV. INTERSTATE STORAGE – SCHEDULES 185 AND 186

Q. WHAT IS THE OVERRIDING GOAL OF YOUR RECOMMENDATION ON APPROPRIATE SHARING PERCENTAGES IN SCHEDULES 185 AND 186?

A. The goal of my recommendation on these two schedules is that the sharing should reflect the share of the costs and risks, i.e. benefits and burdens, to perform off-system sales and optimization that are borne by NWN shareholders versus its ratepayers.

Q. DO YOU AGREE WITH NWN THAT ONE RESULT OF STAFF'S PROPOSED CHANGES TO SCHEDULES 185 AND 186 WOULD BE TO PROVIDE CREDITS TO INTERRUPTIBLE CUSTOMERS WHO DO NOT HAVE THE COSTS FOR MIST STORAGE INCLUDED IN THEIR SCHEDULES?

A. I agree that Staff's proposal in its opening testimony inadvertently resulted in some benefits flowing to interruptible customers. I have updated my recommendation and remedied that issue in this rebuttal testimony.

Q. IN ADDITION TO CHANGES TO THE SHARING PERCENTAGES IN THESE SCHEDULES, DO YOU CONTINUE TO RECOMMEND A NEW STUDY BE COMPLETED RELATED TO THE MIST STORAGE ISSUES?

A. Yes. The Company's basic reply (NWN/2700) to my recommendation for altering the sharing arrangements in Schedules 185 and 186 to more closely align the benefits and the burdens of shareholder versus ratepayer funded assets is to suggest that Staff does not understand the background, investment, and operations of the Mist storage facility.

While I disagree with NWN that aligning the sharing percentages to be consistent with the benefits and burdens of shareholders versus ratepayers demonstrates a lack of understanding of the background, investment and operations of the Mist storage facility, it would seem that NWN would desire to complete a new study to demonstrate that all is well with the Mist facility. Particularly since the last operational study (no financial analysis) of the Mist facility was completed more than five years ago. Instead, NWN does not agree with my sharing percentages based upon benefits and burdens, argues that I do not understand why the sharing percentages are what they are, but argues against having an independent study completed to review these issues.[3]

Q. PLEASE SUMMARIZE YOUR UPDATED RECOMMENDATION ON THE SHARING PERCENTAGES IN SCHEDULES 185 AND 186.

A. Table 2, below, summarizes the existing and proposed changes to the contents and sharing percentages of schedules 185 and 186.

Table 2

Activity	Schedule	Sharing – Current	Sharing – Staff Opening Testimony	Sharing – NWN Witness White Responsive Testimony	Sharing – Staff Rebuttal Testimony
Off-System Sales of Mist Storage Deliverability and Capacity[4]	185	80/20 (80% retained by NWN; 20% shared with ratepayers)	50/50 (50% retained by NWN; 50% shared with ratepayers)	90/10 (90% retained by NWN; 10% shared with ratepayers)	50/50 (50% retained by NWN; 50% shared with ratepayers)
Optimization of	185	33/67	10/90	25/75	20/80

[3] NWN relies on an Altos report from 2007 and suggests that no new study is warranted. See NWN/2700, White/11, lines 11-12. That report is five years stale and does not provide answers to all of the accounting and investment background of the Mist storage facility.
[4] Interstate and intrastate.

Activity	Schedule	Sharing – Current	Sharing – Staff Opening Testimony	Sharing – NWN Witness White Responsive Testimony	Sharing – Staff Rebuttal Testimony
core customer storage and related transportation services		(33% retained by NWN; 67% shared with ratepayers)	(10% retained by NWN; 90% shared with ratepayers)	(25% retained by NWN; 75% shared with ratepayers	(20% retained by NWN; 80% shared with ratepayers)
Optimization of core customer Pipeline and Storage capacity	186	33/67 (33% retained by NWN; 67% shared with ratepayers)	10/90 (10% retained by NWN; 90% shared with ratepayers)	25/75 (25% retained by NWN; 75% shared with ratepayers	20/80 (20% retained by NWN; 80% shared with ratepayers)
Optimization of interstate storage capacity	Not in current Schedule 185 or Schedule 186[5]	Not in current Schedule 185 or Schedule 186	Not included in Staff's Opening Testimony	90/10 (90% retained by NWN; 10% shared with ratepayers)	Since this is not included in current Schedules 185 or 186, Staff does not address this optimization work and related sharing.
Upstream optimization not related to Mist	Not in current Schedule 185 or Schedule 186[6]	Not in current Schedule 185 or Schedule 186	Not included in Staff's Opening Testimony	25/75 (25% retained by NWN; 75% shared with ratepayers	Since this is not included in current Schedules 185 or 186, Staff does not address this optimization work and related sharing.

My recommendation on the appropriate sharing percentages in Schedules 185 and 186 has changed slightly. For off-system sales of Mist storage capacity and deliverability, I based my sharing recommendation on the portions of Mist deliverability used to provide utility vs. non-utility storage service. This division is

[5] Mr. White appears to conclude that this sharing is embedded in the current 80/20 sharing of off-system Sales of Mist Storage Deliverability and Capacity in Schedule 185.
[6] Mr. White appears to conclude that this sharing is embedded in the current 33/67 sharing of core customer storage and related transportation services in Schedule 185 or core customer Pipeline and Storage capacity in Schedule 186. Each has a 33/67 sharing currently associated it; this is the benchmark Mr. White cites in his testimony for these two categories of optimization. See NWN/2700, White/21 at lines 3-24 and White/22 at lines1-23.

roughly 50/50. For revenues from optimization of core customer storage and related transportation services and optimization core customer pipeline and storage capacity, I recommend a 20/80 sharing, with NWN retaining 20 percent of the revenues. This sharing recommendation is based upon the proportion of utility and non-utility investments in the Mist storage facility. Since 2000, this investment division has averaged 20/80, 20 percent in non-utility investment and 80 percent in utility investment. Because ratepayers have paid for 80 percent of the investment in Mist, it matches benefits and burdens that they should receive 80 percent of the revenues from optimization of the physical facilities and operations of Mist, including related transportation services, pipelines, and storage capacity.

Q. WHAT FINANCIAL IMPACT WOULD STAFF'S PROPOSED CHANGES TO THE SHARING PERCENTAGES HAVE ON THE ANNUAL REVENUES RECEIVED BY NWN FROM SCHEDULES 185 AND 186 AND THE RETURN NWN EARNS ON ITS STORAGE INVESTMENT?

A. The answer to this question is summarized in Table 3, below.

Table 3

NWN Schedule 185 and 186 Annual Sharing and Return on Mist Storage Investment		
Sharing Proposal	Total Annual Revenue	Return on Mist Storage Investment
Current	$16,200,800	17.74%
Staff Opening Testimony	$6,804,354	13.48%
NWN Witness White Reply Testimony	$14,193,795	17.00%
Staff Rebuttal Testimony	$8,474,012	14.27%

This table is based on three-year averages for 2009-2011. These values are estimates based on historical data, but should be representative of the range of possible revenues and return for NWN on its Mist storage investments from Schedules 185 and 186 in the future.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING SCHEDULES 185 AND 186?

A. My recommendations regarding Schedule 185 and Schedule 186 are:

1. I propose the following sharing percentages:
    a. Off-System Sales of Mist Storage Deliverability and Capacity 50/50, with NWN and ratepayers each receiving 50 percent of net revenues.
    b. Optimization of core customer storage and related transportation services 20/80, with NWN receiving 20 percent and ratepayers receiving 80 percent of the net revenues.
    c. Optimization of core customer Pipeline and Storage capacity 20/80, with NWN receiving 20 percent and ratepayers receiving 80 percent of the net revenues.
2. I recommend NWN be ordered to conduct an independent study of Mist storage and related issues. The Commission should get to approve the parameters of the study and the selection of an independent party to carry out the work. I recommend that the study occur in 2013 and that at the conclusion of the study any interested party can raise challenges at the Commission that changes should be made to the sharing structure based upon the new study.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: LISA GORSUCH

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2000

Rebuttal Testimony

July 20, 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 filed with my opening testimony, Staff/700.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present Staff's rebuttal to NWN's testimony in exhibit 2800 regarding the following two issues:

I. Customer Service – Service Appointment Windows

II. Tariffs – Schedule C Reconnect Charges

I. CUSTOMER SERVICE

Q. HAS STAFF INCREASED THE NUMBER OF FTE ASSOCIATED WITH NWN OFFERING SERVICE APPOINTMENT WINDOWS TO ALIGN WITH THE DISCREPANCY, A SHORFALL OF 1 FTE, DESCRIBED BY THE COMPANY IN NWN/2800?

A. Yes. Staff proposes to increase the number of FTE from 13 to 14 that were specifically requested for the implementation of service appointment windows. The additional FTE is accounted for in rebuttal testimony of Deborah Garcia, Staff/1800.

Q. DOES STAFF SUPPORT ALLOWANCE OF THE EXPENSE ASSOCIATED WITH THE IMPLEMENTATION OF SERVICE APPOINTMENT WINDOWS, AS DESCRIBED IN NWN/900, WITHOUT ACCOUNTABILITY IN THE FORM OF A SERVICE GUARANTEE PROGRAM?

A. No. The expense associated with the implementation of service appointment windows should be disallowed if NWN does not agree to initiate a service guarantee program. As stated in my opening testimony, Staff/700, if ratepayers are paying for the costs of the service appointment windows, there should be an accountability metric to ensure that 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, MODIFIED FROM OPENING TESTIMONY IN STAFF/700, BASED ON CONCERNS RAISED IN NWN/2800.

A. Staff maintains that a $100.00 service guarantee[1], for service appointment windows that NWN fails to meet is just and appropriate. This calculation would be completed once a year and would be assessed on ninety-eight percent of the missed service appointment windows, which allows NWN to miss two percent of the service windows without a penalty to account for such things as unexpected or unforeseeable circumstances and safety issues that need to be

[1]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 Staff/704.

prioritized. To allow the Company time to prepare and ramp up the program, the service guarantee would be implemented six months after rates go into effect and would be ongoing, as the rates will be ongoing. Funds collected for missed service appointment windows would go into an account to be distributed to the customer base during the annual Purchased Gas Adjustment.

Q. DOES STAFF PROPOSE AN ALTERNATIVE SERVICE GUARANTEE ASSOCIATED WITH THE IMPLEMENTATION OF SERVICE APPOINTMENT WINDOWS?

A. Yes. As an alternative to the service guarantee program described above, Staff proposes assessing a $25.00 service guarantee on every service appointment window NWN fails to meet. The $25.00 fee assessed would be provided directly to the impacted customer following the missed commitment. This program would be implemented six months after rates go into effect and would be ongoing.

II. TARIFFS

Q. HAVE STAFF-PROPOSED REVISIONS TO SCHEDUE C, MISCELLANEOUS CHARGES, CHANGED FROM OPENING TESTIMONY, STAFF/700, ILLUSTRATED IN EXHIBIT STAFF/704?

A. No. Staff sustains its proposal[2] to increase NWN's service reconnection charges from $25.00 to $30.00 for reconnections scheduled from 8:00 – 5:00, Monday – Friday (except Holidays), an increase from $75.00 to $80.00 for reconnection the same day or after 5:00 pm, Monday – Friday. In addition,

[2] A redlined version of Staff-proposed revisions to Schedule C, Miscellaneous Charges, can be found in Staff/704.

Staff continues to support 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.

Q. DOES STAFF VIEW COSTS ASSOCIATED WITH NWN SERVICE RECONNECTION AS 100 PERCENT INCREMENTAL TO EXISTING REVENUE REQUIREMENT?

A. No. NWN confirmed in its response to DR 512 that some of the costs associated with service reconnection are included in its revenue requirement. However, the Company reported that same-day after hours reconnections are completely incremental as they are completed on a “call out” basis.

Q. DOES STAFF AGREE WITH NWN THAT SERVICE RECONNECTION COSTS SHOULD BE PAID IN FULL BY THE CUSTOMERS CAUSING THE COSTS[3] VERSUS BEING PARTIALLY SUBSIDIZED BY THE ENTIRE CUSTOMER BASE?

A. No. As stated in opening testimony, Staff/700, costs associated with tariffed miscellaneous charges often exceed the amount charged to an individual customer. This spreads the difference to all rate payers to avoid imposing a hardship on low-income customers. Service reconnection charges serve as a deterrent to customer’s actions or inactions.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[3] NWN indicated in its response to DR 512 that a goal of the increased reconnection charge is to ensure that all ratepayers are not paying for the costs associated with reconnections caused by other customers.

CASE: UG 221
WITNESS: NICK CIMMIYOTTI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2100

Rebuttal Testimony

July 2, 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 a 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. ARE YOU THE SAME NICK CIMMIYOTTI THAT PREVIOUSLY PRESENTED TESTIMONY ON BEHALF OF STAFF?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to correct NW Natural's (NWN or Company) representation of my previously filed testimony. Specifically, I disagree with the view expressed by the Company in NWN/1800, Anderson/13, regarding my, and perhaps other parties', position on the recovery in rates of the Company's FAS-87 net periodic pension expenses (NPPC).

Q. WHAT IS THE COMPANY'S STATEMENT THAT YOU REGARD AS INACCURATE?

A. Mr. Anderson's testimony in NWN/1800, Anderson/13, states that "the parties' proposals to remove pension cost recovery would lock in under-recovery of expenses for the long-term."

Q. IS STAFF RECOMMENDING THE REMOVAL OF FUTURE "PENSION COST RECOVERY" IN THIS RATE CASE PROCEEDING?

A. No. Staff is recommending recovery, based on 2013 test year levels, of the Company's actuarially calculated FAS-87 net periodic pension expenses.

Q. IS STAFF RECOMMENDING THE ELIMINATION OF THE FAS-87 NET PERIODIC PENSION EXPENSE/(COST) BALANCING ACCOUNT, ESTABLISHED IN 2011, FOR THE COMPANY THROUGH COMMISSION ORGER 11-051?

A. No. The Commission's Order 11-051, in Docket UM 1475, set up a balancing account for NPPC. Under the balancing account mechanism approved in the order, any NPPC in excess of the amount agreed to in UG 152 of $3,796,055, is then captured in a balancing account that earns the Company's rate-of-return. Therefore, with the institution in 2011 of the NPPC balancing account, Staff is recommending recovery of the Company's FAS-87 expense, in this case, of $12,900,000 (NWN/409, Feltz/1).

Q. BEYOND BEING IN COMPLIANCE WITH BOTH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES AND THE FEDERAL ACCOUNTING STANDARDS BOARD'S DIRECTIVE, WHY IS USING THE FAS-87 NET PERIODIC PENSION EXPENSE CALCULATION MORE ACCURATE AN ESTIMATE OF A COMPANY'S CURRENT PERIOD PENSION EXPENSE THAN USING THE COMPANY'S CASH CONTRIBUTIONS?

A. Unlike using the Company's cash contributions to its qualified defined pension benefit plan as their pension expense, the NPPC pension expense calculation incorporates the impacts that other variables have on a Company's accrued pension obligation and period expense.

Q. CAN YOU PROVIDE SOME EXAMPLES OF VARIABLES AFFECTING PENSION OBLIGATIONS, WHICH ARE NOT ACCOUNTED FOR USING CASH CONTRIBUTIONS AS A PROXY FOR PENSION EXPENSE, AND ARE ACCOUNTED FOR IN CALCULATING THE COMPANY'S FAS-87 NPPC?

A. Yes. The NPPC calculation incorporates the concept of time-value-of-money by discounting the Company's accrued pension obligation by the Company's discount rate. The NPPC calculation adjusts the Company's obligation for changes in mortality table rates. Calculating the pension expense using the Company's cash contribution ignores unrealized gains and losses of the plans assets. They are captured in the NPPC. These unrealized gains and losses are also smoothed in the NPPC calculation to reduce volatility in pension expense associated with the equity markets. Given that NW Natural's plan is closed to newly hired employees, as pension plan qualified employees leave, the replacement employee would not qualify and overall, annual associated accruals would decrease. That is reflected in the NPPC calculation. Changes to the Company's estimated rate-of-return earned on pension plan assets impacts a Company's pension obligation and is reflected in the NPPC calculation.

Q. IS STAFF RECOMMENDING THAT THE COMPANY'S CASH CONTRIBUTIONS, MADE PRIOR TO THE TEST YEAR, BE RECOVERED IN THIS CASE?

A. No. Consistent with my initial testimony in this case and because the Company made the expenditures to the pension plan prior to the test period in this case, they should not be included for recovery in this case. As of the initial filing, Oregon's allocation of the difference in 2011 between the UE 152 NPPC of $3,796,055 established in UE 152 was $5,557,481. Under this mechanism, the Company will earn a return equal to the Company's authorized rate of return on any positive balances in the balancing account established by Commission Order 10-051 in Docket UM 1475 on March 15, 2010.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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CASE: UG 221
WITNESS: STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2200

Rebuttal Testimony

July 20, 2012

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

A. My name is Steve Storm. The Public Utility Commission of Oregon employs me as Program Manager of the Economic and Policy Analysis section. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. ARE YOU THE SAME STEVE STORM WHO TESTIFIED IN STAFF'S OPENING TESTIMONY IN THIS PROCEEDING?

A. Yes. I sponsored Exhibits Staff/1300 through Staff/1305 in Staff's opening testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My rebuttal testimony discusses capital structure, return on equity, and decoupling, all as applicable to Northwest Natural Gas Company ("NW Natural" or "Company") in this proceeding.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/2201 consisting of eight pages, and Exhibit Staff/2202, consisting of two pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I organized my testimony as follows:

I include an appendix discussing additional details of and findings related to the Company's existing decoupling mechanism.

SUMMARY RECOMMENDATIONS

Q. WHAT IS YOUR RECOMMENDATION REGARDING NW NATURAL'S CAPITAL STRUCTURE?

A. I recommend the Commission authorized the capital structure requested by the Company, which is one of 50 percent long-term debt and 50 percent common equity.

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS REGARDING NW NATURAL'S RETURN ON COMMON EQUITY (ROE)?

A. I recommend the following:

- The Commission adopt a 9.4 percent ROE from within my recommended range of 8.8 to 9.5 percent;
- The Commission disregard Dr. Hadaway's apparent 20 to 60 basis point "outboard" upward adjustment in his recommended point estimate of ROE for NW Natural for risks perceived by Dr. Hadaway, which are risks he assumes to not be reflected in the prices of the peer utilities to NW Natural used by either myself or Dr. Hadaway;
- The Commission disregard results of Dr. Hadaway's risk premium models, as they involve "circular reasoning" in that they are based on ROEs primarily authorized in other jurisdictions; and
- The Commission give little weight to the 9.8 to 9.9 percent estimated ROE of Dr. Hadaway's multistage DCF model due to his singularly high and insufficiently supported 5.7 percent estimated long-term annual growth rate in nominal GDP.

Q. WHAT RATE OF RETURN (ROR) RESULTS FROM STAFF'S RECOMMENDED COST OF LONG-TERM DEBT, ROE, AND CAPITAL STRUCTURE?

A. Staff's recommended component values for NW Natural's cost of capital result in a rate of return of 7.711 percent. However, as discussed in Staff witness Muldoon's testimony, the rate of return number will change as the estimates of the interest rates for debt issuances in 2012 are replaced with actual results.

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS IN THIS TESTIMONY REGARDING DECOUPLING?

A. I recommend the Commission consider the mechanism in light of my finding that the mechanism is provides an expected contribution to earnings of $374 thousand per year. In the event the Commission adopts NW Natural's structure (existing or proposed) of the decoupling mechanism, the Commission should reduce the Company's ROE by no less than five basis points[1] (bps) in recognition of this over-compensation.

I understand the practical difficulties the Commission faces with respect to adopting the changes to NW Natural's decoupling mechanism, which are opposed by the Company. For example, the Commission may be unable to

[1] Five (5) basis points reduces the Company's "Total Operating Revenue," per Staff's revenue requirement model and beginning at an ROE of 9.7 percent, by $386 thousand. In other words, this level of ROE reduction "covers" one year between (the test years of) rate cases. To "cover" two years, the reduction in "Total Operating Revenue" must average $561 thousand, which implies an ROE reduction of approximately eight (8) basis points. To "cover" three years between rate cases, the revenue reduction must average $748 thousand, which implies an ROE reduction of approximately 10 basis points.

impose such changes on the Company. Secondly, the decoupling mechanism represents a “quid pro quo’ for obtaining NW Natural’s agreement to collect public purpose charges to fund energy efficiency through the Energy Trust of Oregon. Finally, the decoupling mechanism in effect has not caused any major problems that clearly require correction.

Issue 1, Capital Structure

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND THE COMMISSION AUTHORIZE IN THIS PROCEEDING?

A. I continue to recommend a 50 percent long-term debt, 50 percent common equity capital structure recommended by both Staff[2] and the Company.[3]

ISSUE 2, COST OF COMMON EQUITY

Q. WHAT ARE STAFF'S RECOMMENDED VALUES FOR EACH COMPONENT OF NW NATURAL'S COST OF CAPITAL?

A. Staff's recommended values for capital cost components are in Table 1 following. See Exhibit Staff/2300 for Staff's rebuttal testimony regarding NW Natural's cost of long-term debt. Please note that the cost of long-term debt values will change as the results of the Company's additional debt issuances for 2012 replace the estimated values for those issuances.

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[2] See; e.g., Exhibit Staff/1300 Storm/53.

[3] See; e.g., Exhibit NWN/400 Feltz/2.

Table 1

Staff's Recommended Costs of Capital and Capital Structure for NW Natural

Component	Percent of Total	Cost	Weighted Average
Long Term Debt	50.0%	6.022%	3.011%
Preferred Stock	0.0%		0.000%
Common Stock	50.0%	9.400%	4.700%
	100.0%		7.711%

Q. WHAT IS THE "SHORT STORY" BEHIND YOUR ROE ESTIMATES AND THE REASONS THEY DIFFER CONSIDERABLY FROM THE 10.2 PERCENT ROE REQUESTED BY NW NATURAL?

A. While both NW Natural and Staff use multistage DCF models with conceptually similar structures, I obtain my results using published sources for critical assumptions. The Company bases its recommendations on outboard adjustments and critical assumptions not supported by mainstream sources. To be clear, my models replicate Dr. Hadaway's multistage DCF model's results when I use Dr. Hadaway's assumptions.

My recommended range of ROEs result from using long-term growth rates for GDP that are: a) based on the average of forecasts by four Federal agencies and Blue Chip Consensus Forecasts; b) based on my analysis of historical data; and c) based on a combination of the two. My point estimate and recommended ROE is within the range of ROE values I recommend the Commission consider, although near the top of the range.

I have several issues with the results of the Company's rate of return on equity witness Dr. Samuel C. Hadaway, with his recommended range of reasonable ROEs for NW Natural, and with the Company's requested 10.2 percent ROE,. These issues include the "circular reasoning" incorporated within Dr. Hadaway's risk premium methodologies and his use of an extremely high (and rare!) estimate of the long-term annual rate of growth in nominal GDP, which represents the long-term growth rate in two of his three DCF models.

I take issue with the apparent 20 to 60 basis point "outboard" upward adjustment Dr. Hadaway makes to the estimated ROE results of his DCF models. This adjustment appears to stem from his belief that recent stock prices for the peer utilities to NW Natural, whether the companies he uses in his reply testimony, or those I use in my testimony, do not reflect either all of or the appropriate risks to investors, as perceived by Dr. Hadaway, on a contemporaneous basis.

Q. WHAT DO YOU RECOMMEND AND WHAT DOES DR. HADAWAY AND THE COMPANY RECOMMEND?

A. Please see the recommended ROE values in Table 2 following.

TABLE 2

Company-recommended and Staff-recommended ROEs[4]

Model	Hadaway	Storm (Low Growth)	Storm (Moderate Growth)	Storm (High Growth)
DCF Constant Growth 1	9.7%			
DCF Constant Growth 2	10.0%			
Multistage DCF 1	9.8%	8.8%	9.1%	9.3%
Multistage DCF 2		8.9%	9.1%	9.4%
Risk Premium 1	9.43%			
Risk Premium 2	9.44%			
Recommended Range	9.43% - 10.2%	8.8% - 9.5%		
Recommended Point Estimate	10.2%			9.4%

Q. BRIEFLY, WHY ARE THERE LARGE DIFFERENCES BETWEEN YOUR RECOMMENDATION AND THE COMPANY'S REQUESTED ROE?

A. My DCF models, using the 5.7 percent long-term growth rate used by Dr. Hadaway, provides exactly the same 9.8 – 9.9 percent result as his multistage DCF model; i.e., the difference between these results is entirely due to his use of an unsupportable growth rate of 5.7 percent. See Table 3 following.

The 5.7 percent growth rate used by Dr. Hadaway embeds an inflation rate of 3.0 percent. My research shows that this rate is entirely unsupported

[4] Specific values above for DCF models represent the averages (means) of ROE values for the individual peer companies. Median values outside the specified averages above were, for Dr. Hadaway's "Constant Growth 1" model, 9.6 percent and, for my "Multistage DCF 2" model, 9.5 percent.

and exceeds estimates for the relevant period from credible institutions and estimates derived from the financial markets by almost 90 basis points.

The 40 basis point difference between the Company's requested 10.2 percent ROE and the 9.8 percent result from either my or Dr. Hadaway's multistage DCF models is due to an "outboard" upward adjustment for risks perceived by Dr. Hadaway and the Company. These risks are unforeseen by both me and by the market at this time.

I discuss both Dr. Hadaway's use of the 5.7 percent growth rate and the "outboard" upward adjustment in this testimony.

Q. DID YOU UPDATE THE ANALYSIS YOU PERFORMED ON NW NATURAL'S COST OF COMMON EQUITY, AS DOCUMENTED IN YOUR OPENING TESTIMONY?

A. Yes. While I continue to rely on two multistage DCF models, I made several methodological changes. One was to use discounted cash flow models based on calendar quarters versus the prior use of annual periods. This allows for greater precision as to the timing of dividend increases and more closely represents the timing of an investor's receipt of stock dividends on a quarterly basis.

My opening testimony included a description of each model (Model 1 and Model 2).[5] In these models, "period 0" is second quarter 2012 with the models incorporating long-run growth through second quarter 2052; i.e., the models are of 40 years duration. Each model has a first stage in which values

[5] See Exhibit Staff/1300 Storm/57 line 14 through Storm/58 line 13.

(dividends or earnings per share) derived from Value Line forecasts through 2017Q4 are used, has a five-year transition stage from 2018Q1 through 2022Q4, and grows dividends (Model 1) or earnings per share (EPS) (Model 2) at the estimated long-term real GDP growth rate for 2023 forward. Each model includes a terminal valuation as of 2052Q2.

Another change in methodology results from reviewing Dr. Hadaway's testimony as it pertained to the estimation of future inflation using the TIPS break-even rate approach.

Treasury Inflation-Protected Securities, or TIPS, provide investors protection against inflation. The principal of a TIPS increases with inflation and decreases with deflation, where inflation is measured by the Consumer Price Index (CPI). When a TIPS matures, the investor is paid the adjusted principal or original principal, whichever is greater.[6] I used TIPS break-even inflation rates in my opening testimony as well as in prior proceedings to develop an estimate of the forward inflation rate expected by investors.

As indicated above, the TIPS inflation adjustment is based on the CPI. As I use the estimate of forward inflation to translate estimated growth rates in real GDP into estimated growth rates in nominal GDP, a question arises as to the comparability of the two; i.e., is inflation as measured by the CPI identical to, similar to, or very different from inflation as measured by the GDP Price Inflator index?

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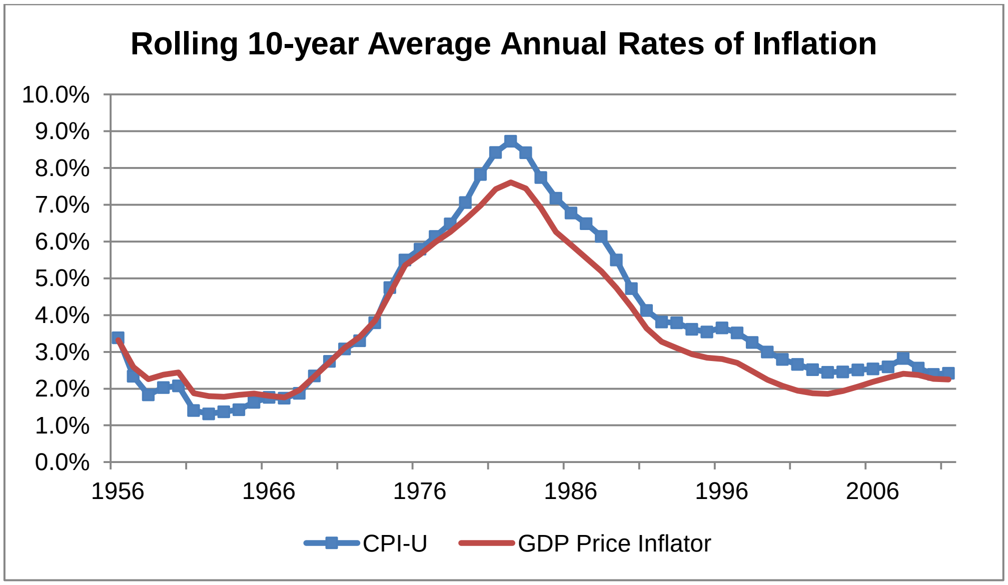
6 Per information from the U.S. Treasury, accessed July 16, 2012 at http://www.treasurydirect.gov/indiv/products/prod_tips_glance.htm .

Q. HOW DID YOU ANSWER THIS QUESTION?

A. I compared the average of the 10-year moving average of annual rates of change for the CPI – All Urban (CPI-U) and the GDP Price Inflator for the period 1956 through 2011; i.e., the first pair of data points reflect inflation over the 10-year period 1947 – 1956. Figure 1 depicts values of the 10-year moving average for each index. Over this timeframe the average value for the 10-year moving average of the GDP Price Inflator was 91.3 percent of the average value for the 10-year moving average of the CPI-U. Therefore, I multiplied the estimated annual rate of CPI inflation obtained through the TIPS break-even analysis by 91.3 percent to estimate the annual rate of change in the GDP Price Inflator.

Figure 1



Q. WHAT OTHER METHODOLOGICAL CHANGES DID YOU MAKE?

A. I made a number of changes in how I estimated long-term growth rates in addition to the CPI to GDP Price Inflator conversion discussed above. Whereas my opening testimony included use of the average of the estimated nominal GDP long-term growth rate from EIA, OMB, and the CBO, in this testimony my "Agencies plus Blue Chip" growth rate is derived by using equally-weighted growth rates from Blue Chip, CBO, EIA, OMB, and the Social Security Administration (SSA).

Q. TO WHAT TIME PERIODS DO THESE FORECASTS APPLY?

A. The Blue Chip Consensus forecast is the value for 2022 and is identical with the rate forecast for 2018 through 2022. The CBO forecast is from the June 2012 Long-term Budget Outlook, and pertains to the years 2023 – 2042. The EIA forecast is for the years 2023 – 2035. OMB's forecast matches with Blue Chip's; i.e., it is for 2022 and it is identical with OMB's estimate for 2020 through 2022. The Social Security Administration's forecast is from the 2012 OASDI Trustees Report and pertains to the years beyond 2021 for the real GDP rate forecast, and to the years 2022 – 2086 for the GDP Price Inflator forecast.

Q. TO WHAT YEARS DO YOU APPLY THESE RATES?

A. I use the average of these forecasts as annual rates of growth in dividends and EPS for the first quarter of 2022 through the second quarter of 2052 and in the calculation of terminal value in my DCF Model 1. Additionally, the average is the growth rate used at the 2022 end of the 2018 – 2022 second stage transition period, while the estimates of dividends and EPS based on Value Line for 2017 provide values for the last year (2017) prior to this stage.

Q. IS IT ACCURATE TO SAY YOU ARE USING CREDIBLE FORECASTS OF FUTURE GDP GROWTH FOR THE THIRD STAGE OF YOUR DCF MODELS; I.E., FOR THE PERIOD 2022 THROUGH 2052?

A. Yes, that is accurate.

Q. WHAT METHODOLOGY CHANGES RELATE TO THE HISTORICAL GROWTH RATE ESTIMATE?

I incorporated into the development of my historical real GDP growth rate the results of research indicating that there was a structural break in U.S. real GDP in 1973, with a resultant change in the slope of the trend line of real GDP.[7] Researchers used January, 1973 as the "point date" for the structural change.

Q. HOW DID YOU USE THIS INFORMATION?

A. I developed a simple ordinary least squares (OLS) regression trend model using EViews software and quarterly values of real U.S. GDP[8] for the period 1951Q1 through 2011Q4, which is the period used by Dr. Hadaway to develop his estimate of nominal GDP growth. My trend model incorporates a change in the value of the intercept and slope in 1973Q1.[9] Based on values of the Schwarz (or Bayesian) Information Criterion (BIC), this model

7 See "Let's take a break: Trends and cycles in US real GDP" by Perron and Wada; *Journal of Monetary Economics* 56 (2009) pages 749 – 765.

8 Quarterly values were log transformed.

9 Estimating both different intercept and slope coefficients allows the trend line to "pivot" or articulate at 1973Q1.

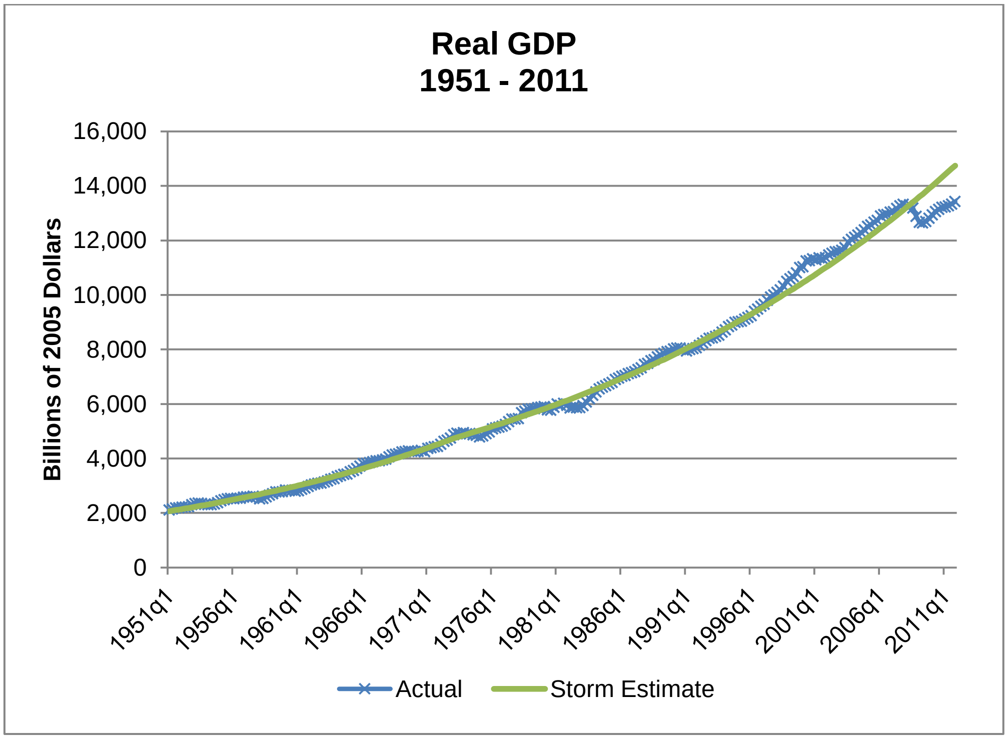
"outperformed" models having trend only; having trend plus an dummy indicator (intercept change) for post-1972; and having trend plus a "slope" change for post-1972. All t-statistics for the model I used exceed critical values at all conventional levels and the adjusted R^2 is 99.63 percent. Figure 2 following plots actual real GDP and real GDP estimated by this model.

Q. WHAT ANNUAL GROWTH RATE FOR REAL GDP RESULTED FROM THIS MODEL?

A. The estimated annual long-term growth rate in real GDP is 2.96 percent. I performed a trend regression in Excel for the 1973Q1 – 2012Q1 period with a resulting annual average growth rate of 2.95 percent, serving to confirm the value of the growth rate estimated using EViews software.

Figure 2

Staff Real GDP Trend Model with 1973Q1 Structural Change



Q. WHAT OTHER CHANGES DID YOU MAKE REGARDING LONG-TERM GROWTH RATES?

A. For the “historical” rate, I averaged the result obtained using the 2.96 percent real GDP long-term growth rate with the 2.13 percent estimated GDP Price Inflator rate discussed above (5.15 percent) and the result obtained using the 2.96 percent rate with the 2.11 percent average of the long-term GDP Price Inflator rates forecast by Blue Chip, CBO, EIA, OMB, and SSA (5.13 percent) for a 5.14 percent average annual long-term growth rate in nominal GDP based on history.

Q. WHY DO YOU DEVELOP OR REVIEW REAL GROWTH RATES AND INFLATION RATES SEPARATELY?

A. Disaggregating nominal GDP growth rates into an inflation rate component and a real growth rate component facilitates understanding regarding whether it is the real growth rate or the inflation rate responsible for an anomalous-appearing nominal rate. Additionally, disaggregating allows using values of future inflation expected by participants in financial markets; i.e., the use of an inflation rate forecast based on the TIPS break-even rate methodology.

Q. DID YOU REVIEW YOUR NATURAL GAS UTILITY COMPANIES FOR INCLUSION OR EXCLUSION AS A PEER UTILITY TO NORTHWEST NATURAL FOR YOUR REBUTTAL TESTIMONY?

A. I reviewed all publicly-traded U.S. companies considered to be local distribution natural gas utilities. My review did not result in any additions or deletions.

Q. DID YOU UPDATE THE STOCK PRICES OF YOUR PEER UTILITIES?

A. Yes. The prices I use reflect a change in methodology. Previously I used closing prices of the first trading day of each of the prior three calendar months. In this rebuttal testimony, I use, for each peer utility, the average of closing prices for each trading day[10] in the prior three calendar months; i.e., the average of each trading day's closing price over the months of April, May, and June, 2012.

[10] These are available from Yahoo at; e.g., http://finance.yahoo.com/q/hp?a=&b=&c=&d=6&e=16&f=2012&g=d&s=lg&ql=1 .

Q. DID YOU UPDATE ESTIMATES OF DIVIDENDS AND EARNINGS PER SHARE FROM VALUE LINE?

A. Yes, using the Value Line reports for my peer utilities dated June 8, 2012.

Q. WHAT ARE THE RESULTS OF YOUR DCF MODELS?

A. I rely on two multistage discounted cash flow models, which are very similar to those described in my opening testimony, but are of quarterly and not annual periodicity.[11] The values of estimated ROE for my peer utilities from these models are in Table 3. See also Exhibit Staff/2201.

Table 3

Estimated ROEs Using Staff DCF Models

	Long-term Annual Growth Rate	Estimated ROE			
		Model 1		Model 2	
		Mean	Median	Mean	Median
Agencies + Blue Chip	4.51%	8.8%	8.9%	8.9%	9.0%
Composite	4.83%	9.1%	9.1%	9.1%	9.2%
Historical	5.14%	9.3%	9.4%	9.4%	9.5%
Average		9.1%	9.1%	9.1%	9.2%
Hadaway growth rate	5.7%	9.8%	9.8%	9.8%	9.9%

Q. WHAT RETURN ON EQUITY DO YOU RECOMMEND THE COMMISSION AUTHORIZE FOR NW NATURAL?

A. Based on my updated results, I continue to recommend a range of 8.8 to 9.5 percent, with a recommended point estimate of 9.4 percent. I base the recommended range on the results of my DCF models using the first three growth rates above and the recommended point estimate using these results

[11] See Exhibit Staff/1300 Storm/57ff.

and incorporating that the models using the historical growth rate in my opening testimony now provide estimated ROEs ranging from 9.3 percent to 9.5 percent. I believe my 9.4 percent recommended point estimate of ROE for NW Natural is reasonably comparable with the 9.2 percent point estimate recommended in my opening testimony.

Q. HAVE YOU REVIEWED DR. HADAWAY'S REBUTTAL TESTIMONY?

A. Yes. I begin discussion of his testimony by focusing on growth rates and, more specifically, his estimate of the inflation component of GDP growth rates because that is what drives the difference between our analytic results. Dr. Hadaway's long-term growth rate used in two of his three DCF models is his estimate of nominal GDP growth based on his weighted average of historical growth in nominal GDP over the period 1951 through 2011.[12] Dr. Hadaway's rate can be decomposed into a real GDP growth rate and an inflation rate, based on values he provides in Exhibit NWN/2105.

Q. WHAT ARE THESE VALUES AND HOW DO THEY COMPARE WITH THE RATES YOU USE?

A. Table 4 depicts the real GDP growth rates used in Dr. Hadaway's reply testimony and my rebuttal testimony.

[12] See Exhibit NWN/2105.

Table 4

Annual Long-term "Horizon" Rates of Growth or Change

Real GDP, GDP Price Inflator, Nominal GDP

Source	Real GDP	GDP Price Inflator	Nominal GDP
Blue Chip Consensus	2.5%	2.1%	4.65%
CBO	2.15%	2.2%	4.4%
EIA	2.56%	2.06%	4.67%
OMB	2.46%	1.8%	4.3%
SSA	2.1%	2.4%	4.55%
Historical (Staff)	2.96%	2.13%	5.15%
Average of estimates used by Staff	2.45%	2.11%	4.62%
Hadaway (UG 221 Rebuttal)	2.62%	3.0%	5.7%
Hadaway vs. average of other estimates	+0.17%	+0.89%	+1.08%

Q. WHAT IN TABLE 4 IS IMPORTANT TO KNOW?

A. First note that the independent real GDP forecasts, including my historical rate of 2.96 percent, average 2.45 percent. Dr. Hadaway's implied value of 2.62 percent is somewhat higher than this average and *materially less than* (34 basis points) the 2.96 percent in my historical rate. It is not his forecast of growth in economic activity as measured by real GDP with which I take issue.

Q. DO YOU TAKE ISSUE WITH THE 3.0 PERCENT ANNUAL RATE OF GDP INFLATION EMBEDDED IN DR. HADAWAY'S NOMINAL GROWTH RATE OF 5.7 PERCENT?

A. Yes. Note first the range of estimated annual rates of inflation in Table 4 other than Dr. Hadaway's, from OMB's 1.8 percent to SSA's 2.4 percent, and averaging 2.11 percent, which value is almost identical with my adjusted TIPS break-even rate of 2.13 percent discussed above. The GDP Price Inflator rate embedded in Dr. Hadaway's 5.7 percent nominal GDP average annual growth rate is 89 basis points (bps) higher than the 2.11 percent average, at 3.0 percent. This represents a view of future inflation at a rate fully 42 percent higher than the average of the other estimates.[13] It appears Dr. Hadaway's view on future inflation, as incorporated within his nominal GDP growth rate, is very much above the long-term inflation rates forecast by several credible institutions, including the 2.33 percent CPI inflation investors comprising the market for Treasury bonds are "forecasting," which value underlies the 2.13 percent annual rate of change in the GDP Price Inflator incorporated into my 5.15 percent historical rate.

Federal Reserve Chairman Bernanke's July 17, 2012 *Semiannual Monetary Policy Report to the Congress* included a re-confirmation of the Fed's recently articulated policy interpretation of the bank's dual mandates (employment and price stability), that the Fed target a 2.0 percent annual rate of inflation; i.e., "[t]he central tendency of the [Federal Open Market]

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13 This is (0.03 – 0.0211) / 0.0211.

Committee's projections is that inflation will be 1.2 to 1.7 percent this year, and at or below *the 2 percent level that the Committee judges to be consistent with its statutory mandate* in 2013 and 2014."[14]

I note that Dr. Hadaway's 5.7 percent rate applies to 2013 forward in one of his constant growth DCF models; i.e., it is used, in this model, for the near-term as well as the long-term. This is obviously and grossly out of line with expected near-term conditions.

Q. DR. HADAWAY SEEMS TO HAVE TWO ISSUES WITH THE HISTORICAL RATE OF 5.43 PERCENT YOU USED IN YOUR OPENING TESTIMONY. PLEASE DESCRIBE HIS ISSUES WITH THIS VALUE.

A. Dr. Hadaway, as I read his testimony, seems to imply I should have used Morningstar's growth rate of 3.3 percent[15] rather than the 2.91 percent developed using historical data from 1980 forward, presumably because this is what Morningstar did. Exhibit NWN/2103 indicates the Morningstar value results from data over the period 1929 – 2010. This implication seems curiously at odds with the much lower 2.62 percent rate embedded in the 5.7 percent annual growth rate in nominal GDP Dr. Hadaway calculates. In other words and according to Dr. Hadaway, 2.91 percent is "too low," 3.3 percent is "better," and apparently 2.62 percent is "just right."

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[14] Accessed July 19, 2012 at http://www.federalreserve.gov/newsevents/testimony/bernanke20120717a.htm . Emphasis added.

[15] See NWN/2100 Hadaway/16 lines 8 – 13 and Hadaway/17 line 10 through Hadaway/18 line 5.

Q. DR. HADAWAY CLAIMS THE USE OF THE TIPS BREAK-EVEN RATE MAY UNDERSTATE EXPECTED INFLATION. WHAT THOUGHTS DO YOU HAVE REGARDING THIS CLAIM?

A. I have several thoughts regarding his claim. TIPS are a smaller market than that for nominal Treasury bonds, as of September 30, 2011 comprising approximately 8.7 percent of the value of Treasury notes and bonds and totaling over $705 billion as being held by the public.[16] This equates to somewhat less than three times the market capitalization of Microsoft, reported as $249 billion as of July 17, 2012.[17]

The research cited by Dr. Hadaway[18] includes the following:

- The TIPS liquidity premium has declined since TIPS introduction in 1997; and
- Nominal bonds incorporate an inflation risk premium, which is the extra compensation investors in nominal bonds demand for bearing the inflation risk they do not bear with TIPS.[19]

Note that a liquidity premium on TIPS not present on nominal Treasury notes and bonds, all else being equal, reduces the calculated rate of expected inflation while risk premiums on nominal Treasuries not present on TIPS, all else being equal, increase the calculated rate of expected inflation.

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16 See page 24 of GAO's 2011 Financial Audit of the Bureau of the Public Debt, accessed July 17, 2012 at http://www.treasurydirect.gov/govt/reports/pd/feddebt/feddebt_ann2011.pdf .

17 Accessed on July 17, 2012 at Yahoo Finance at http://finance.yahoo.com/q/ks?s=MSFT+Key+Statistics .

18 " "Tips from TIPS: the informational content of Treasury Inflation-Protected Security prices;" by D'Amico, et al; Federal Reserve Board; 2010.

19 "Inflation risk" can be thought of in this context as deviations from expected inflation.

More recent research, using data through December 2009, concludes that "[t]he liquidity premium on TIPS was large in the early 2000s, but declined steadily during the decade, with the exception of a pronounced spike during the financial crisis in the fall of 2008."[20] This research suggested the liquidity premium might be as much as 106 bps.

Other researchers estimated the unconditional inflation risk premium embedded in nominal Treasury bonds with a five-year term averaged 114 bps.[21] As these values largely offset one another, in the absence of having specified values of the time-varying nature of both the TIPS liquidity premium and the inflation risk premium in nominal bonds, a reasonable assumption is to assume they *do* offset one another. This results in the TIPS break-even rate estimate of expected inflation as measured by the CPI being a reasonable as well as market-based estimate of future inflation. I add that TIPS break-even rates of inflation are in obvious use as a measure of inflationary expectations at the Federal Reserve.[22]

Q. DO YOU BELIEVE EITHER OF THESE PREMIUMS IS CURRENTLY AT THE LEVELS YOU MENTION ABOVE?

A. No.

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[20] "An Empirical Decomposition of Risk and Liquidity in Nominal and Inflation-indexed Government Bonds;" Pflueger and Viceira; March 2011; National Bureau of Economic Research.

[21] "The Term Structure of Real Rates and Expected Inflation;" Ang, et al; 2008; *Journal of Finance*.

[22] See; e.g., the text of Ben S. Bernanke's July 10, 2007 speech on "Inflationary Expectations and Inflation Forecasting."

Q. DO YOU HAVE ANY ADDITIONAL INFORMATION, OTHER THAN THE 2.11 PERCENT AVERAGE OF FORECASTS FROM FOUR FEDERAL AGENCIES AND BLUE CHIP, TO SUPPORT YOUR ADJUSTED TIPS BREAK-EVEN INFLATION RATE OF 2.13 PERCENT?

A. The Second Quarter 2012 *Survey of Professional Forecasters*[23] has an average (mean) rate of inflation as measured by the Personal Consumption Expenditures (PCE) Index for 2017 through 2021 of 2.23 percent. This estimate is 10 bps lower than the TIPS break-even forecast prior to adjustment of 2.33 percent. This rate of change in the PCE index, which is more similar to the CPI than to the GDP Price Inflator, multiplied by the 91.25 percent adjustment factor I use to translate CPI inflation rates into GDP Price Inflator rates, results in an estimated GDP Price Inflator rate of 2.0 percent.

Q. DR. HADAWAY REFERS TO "CURRENT, ABERRANT, MARKET CONDITIONS,"[24] "INCREASE[D] INVESTOR RISK AVERSION,"[25] ETC. AT MULTIPLE POINTS IN HIS REPLY TESTIMONY. WHAT THOUGHTS DO YOU HAVE REGARDING THESE AND SIMILAR STATEMENTS MADE BY DR. HADAWAY IN HIS REPLY TESTIMONY?

A. I first point out that it is not clear what level of "outboard" adjustment to his DCF model results Dr. Hadaway thinks is appropriate for those things he mentions. As his DCF models produce results ranging from 9.6 percent to

[23] The *Survey* was released May 11, 2012.

[24] Exhibit NWN/2100 Hadaway/3 lines 5 – 6.

[25] Exhibit NWN/2100 Hadaway/6 line 17 through Hadaway/7 line 2.

10.0 percent,[26] and he claims to "…believe the Company's revised ROE request of 10.2 percent is reasonable,"[27] I conclude this outboard adjustment must range from 20 to 60 basis points. I cannot locate anywhere in his testimony any quantitative bases for this adjustment.

Dr. Hadaway believes the following:

- Low interest rates have resulted in utility stocks becoming sought after by income-seeking investors;
- Which resulted in higher prices for utility stocks;
- Which reduced dividend yields;
- Which leads to historically low DCF estimates of ROE;[28] and that
- Current low interest rates are unsustainable.[29]

Q. ON WHICH OF THESE POINTS DO YOU AGREE WITH DR. HADAWAY AND ON WHICH DO YOU DISAGREE?

A. I agree with most of these five points, albeit with some qualification. I am not sure about the "historically low" DCF estimates, and "unsustainable" does not mean the phenomena could not continue for an extended time *a la* Japan's "lost decade" which gives some appearance of becoming a "lost generation."

I first note that, in saying "income investors have reduced dividend yields" on utility stocks, Dr. Hadaway is directly implying that he believes that stock prices of utilities are "too high," or perhaps "unsustainably high." As

[26] See Exhibit NWN/2106 Hadaway/1.

[27] Exhibit NWN/2100 Hadaway/21 lines 10 – 11.

[28] Exhibit NWN/2100 Hadaway/6 lines 5 – 8.

[29] See; e.g., Exhibit/2100 Hadaway/6 lines 13 – 17.

utility dividends are relatively stable, and dividend yields are dividends divided by stock price, you cannot have it any other way. In other words, he is indirectly saying his DCF models would produce higher ROE estimates if there was a broad and material price decline in utility stocks.

Q. DO YOU DISAGREE WITH THAT LINE OF REASONING?

A. No; it makes perfect sense to me. Conceptually related to the "outboard" risk adjustment he makes, Dr. Hadaway appears to have a different understanding than do I regarding the relationship of asset prices and risk. If he believes dividend yields are "low," it must be because he believes prices are "high."

The requested 10.2 percent ROE is in essence asking that the Commission impute a general price decline that he apparently expects to occur by November 1, 2012.[30] While such a price decline could and may occur, for me it would result in higher estimated ROEs whereas *it has to happen* for Dr. Hadaway and the Company's position to make sense.

Q. WHAT LEVEL OF DECLINE IN STOCK PRICES IS NECESSARY FOR THE COMPANY'S REQUESTED 10.2 PERCENT ROE TO MAKE SENSE?

A. Recall that I use the average closing price for the months of April, May, and June of 2012. Therefore, such a price decline would reasonably have to apply to a similar average of closing prices.

[30] See; e.g., Exhibit NWN/2100 Hadaway/3 lines 6 – 8; including that "…I do not believe that [his] updated model results provide the best information *about NW Natural's cost of equity in the rate effective period beginning in November 2012…*" (emphasis added).

My analysis, using my peer utilities, and the "high" (5.14 percent) growth rate, indicate an 18 percent across-the-board price decline provides this result. At this lower level of stock prices, my Model 1 estimates an average ROE of 10.2 percent (median also 10.2 percent) and my Model 2 estimates an average ROE of 10.2 percent (median 10.4 percent). These results are based on no change in the dividend or EPS estimates; any downward revision to these estimates between "now" and the time of such a price decline requires a larger than 18 percent decline in prices in order to provide a 10.2 percent average ROE estimate.

I believe it is a reasonable expectation that Dr. Hadaway provide, in his surrebuttal testimony, quantitative information justifying this "outboard" upward adjustment, or, alternatively or in combination, supporting the 10.2 percent requested ROE vis-à-vis his multistage DCF model results.

Q. RELATED TO THE BULLET POINTS ABOVE, ON WHAT DO YOU DISAGREE WITH DR. HADAWAY.

A. The results of his and my DCF models—given the value of parameter inputs used, which materially differ between him and me as discussed above—are not *unduly low*: they reflect the current cost of equity capital for his peer utilities and for my peer utilities.[31] He believes current ROE estimates "…do not capture investors' requirements for a long-term equity return."[32] I believe

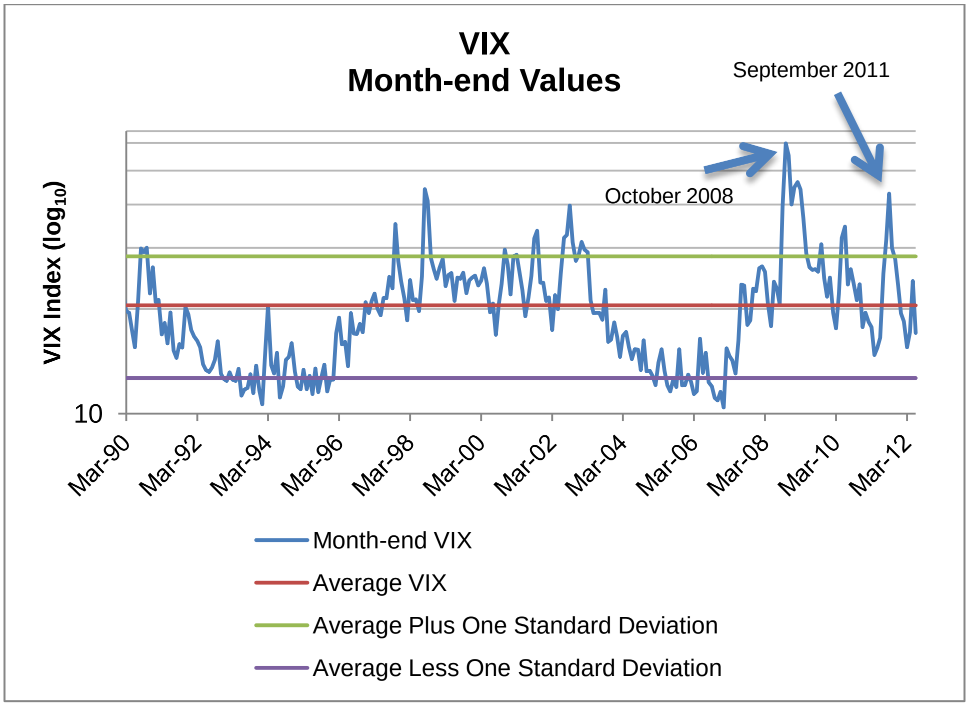
[31] This is not to be interpreted as an endorsement of Dr. Hadaway's models, methods, parameter inputs, peer utility selections, conclusions, recommendations, etc.

[32] Exhibit NWN/2100 Hadaway/6 lines 14 – 15.

prices reflect investors' requirements, which are lower rates of expected return than Dr. Hadaway wants to believe.

Dr. Hadaway evidently believes risks in the equity market are "high" and I believe the risks perceived by investors vary day to day, week to week, and so forth, but are essentially "normal" as of the July 17th 2012 date I write this. Additionally, I believe current equity prices fully reflect the risks perceived by investors and specifically by investors in the companies used by either of us as peer utilities to NW Natural. Figure 3 following illustrates the VIX closing price on a month-end basis from early 1990 through June, 2012. I have indicated the average value over this timeframe and the ± one standard deviation values. The June, 2012 month-ending value of 17.08 was well under the historical average of 20.5.

Figure 3



I think it is reasonable to anticipate that negative news (or, more precisely, negative news as perceived by investors in U.S. stocks) regarding European fiscal issues could increase the level of the VIX, at least temporarily. I think it is highly likely that, should the U.S. government enter into a protracted "budget battle" such as occurred a year ago, the level of the VIX will increase, at least temporarily.

I encourage examination, given the above, of Dr. Hadaway's statement that "[o]ngoing market volatility continues to increase investor risk aversion…"[33] It is not clear to me which measure used by Dr. Hadaway indicates "ongoing market volatility;" over which timeframe such volatility

[33] Exhibit NWN/2100 Hadaway/6 line 17 through Hadaway/7 line 2.

"continues;" or, and perhaps most importantly, why he believes the "increase[d] investor risk aversion…" is fully not reflected in the stock prices of the peer utilities he uses and those I use.

Figure 4 following plots closing values of the VIX for 2012 through July 17th. Note that the closing daily high this year of 26.66 is far less than one-half the 72.76 closing value on November 20, 2008, in the height of the financial crisis, when investors' risk aversion was decidedly higher than at any point this year[34] through at least July 17th.

On June 20, 2012 and subsequent to the Company's filing of reply testimony, the Federal Reserve's Federal Open Market Committee (FOMC) issued a press release announcing that "inflation has declined…and longer-term inflation expectations have remained stable."[35] A main point of the press release was to communicate that the Federal Reserve would continue through the end of the year its so-called "Operation Twist,"[36] in which the Fed purchases Treasury notes and bonds having six- to 30-year maturities. This has and will continue to put downward pressure on interest rates through at least the end of the year.

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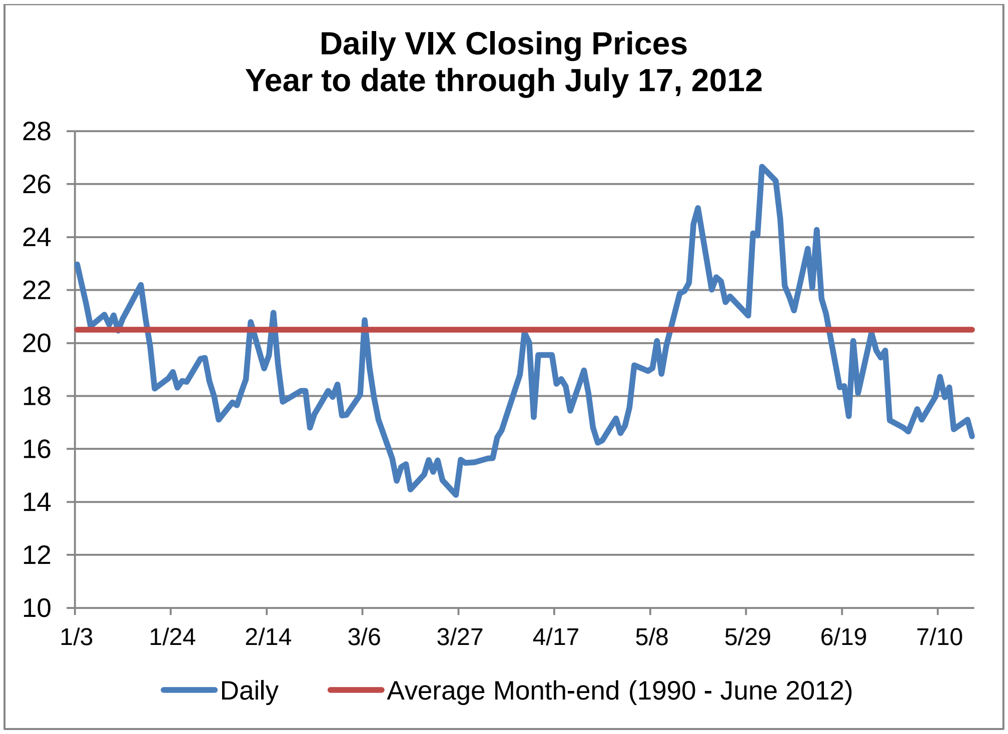
[34] As reflected in daily closing prices.

[35] Accessed July 17, 2012 at http://federalreserve.gov/newsevents/press/monetary/20120620a.htm .

[36] The Fed refers to this program as the "Maturity Extension Program," or "MEP."

Figure 4



Q. DR. HADAWAY INCLUDED HIS DIRECT TESTIMONY, AS EXHIBIT NWN/502 HADAWAY/3, MATERIALS WHICH INCLUDED A FORECAST OF INTEREST RATES. WHAT WAS THE FORECAST FOR 10-YEAR TREASURY BONDS IN THIS EXHIBIT?

A. The forecast was for 10-year Treasury bonds to yield 2.3 percent, 2.4 percent, and 2.5 percent in, respectively, the second, third, and fourth quarters of 2012.

Q. WHAT ARE RECENT AVERAGE YIELDS FOR 10-YEAR TREASURY BONDS?

A. Per information from the Federal Reserve, the average yield in June, 2012 for the 10-year Treasury was 1.62 percent and the average for the months of

April through June was 1.82 percent. The rate for July 17, 2012 was 1.50 percent.[37]

Q. DR. HADAWAY INCLUDED IN HIS REPLY TESTIMONY, AS EXHIBIT NWN/2102 HADAWAY/2, MATERIALS WHICH INCLUDED A FORECAST OF INTEREST RATES. WHAT WAS THE FORECAST FOR 10-YEAR TREASURY BONDS IN THIS EXHIBIT?

A. The forecast was for 10-year Treasury bonds to yield 2.0 percent, 2.1 percent, and 2.2 percent in, respectively, the second, third, and fourth quarters of 2012. This forecast also included estimated yields for the first and second quarter of 2013, which were, respectively, 2.3 percent and 2.6 percent.

Q. THESE TWO FORECASTS INDICATE ESTIMATES OF FUTURE YIELDS ON 10-YEAR TREASURY BONDS DECLINED BY 30 BASIS POINTS FOR EACH OF THE SECOND, THIRD, AND FOURTH QUARTERS OF 2012. WHAT THOUGHTS DO YOU HAVE REGARDING THESE LOWERED FORECASTS?

A. Both forecasts were from Standard and Poors, with the second forecast dated May, 2012 and therefore not reflecting the certainty of the Federal Reserve's continuance of "Operation Twist" through at least year-end 2012, which was announced in June. It seems reasonable to assume a Standard & Poors' forecast prepared subsequent to the Fed's June announcement will either

[37] Accessed from the Federal Reserve on July 18, 2012 at http://federalreserve.gov/releases/h15/update/default.htm .

push increases in Treasury bond yields out from the earlier forecast or, alternatively, have yields increasing, but from a materially lower starting level.

I note that Standard and Poors' May, 2012 forecast[38] for the second quarter of 2012, at 2.0 percent for the 10-year Treasury, exceeded the June 2012 average yield by 38 basis points and that the third quarter estimate of 2.1 percent exceeds the July 17th yield by fully 60 basis points. I also note that Dr. Hadaway's reply testimony includes a footnote quoting a January 25, 2012 statement from the Federal Reserve that it "…currently anticipates that economic conditions—including low rates of resource utilization and <u>a subdued outlook for inflation over the medium run</u>—are likely to warrant exceptionally low levels for the federal funds rate at least through late 2014."[39]

Interest rates are notoriously difficult to forecast with accuracy and considerable sums of money have been lost in recent years by investors taking positions requiring that interest rates rise in order to realize a gain on the investment.[40]

Q. WHAT DO YOU RECOMMEND TO THE COMMISSION REGARDING THE RESULTS OF DR. HADAWAY'S RISK PREMIUM MODELS?

A. I acknowledge some confusion on my part regarding exactly what those results are. Dr. Hadaway's testimony has a 9.75 percent estimated ROE

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[38] Exhibit NWN/2102 Hadaway/2.

[39] See footnote 4 at Exhibit NWN/2100 Hadaway/6 (emphasis added).

[40] See; e.g., Exhibit Staff/1200 Muldoon/13 through Muldoon/14.

based on “the most recent three months average single-A rates,”[41] whereas the copy I have of his Exhibit NWN/2104 Hadaway/2 lists “indicated equity return” as 9.44 percent based on “current interest rates.”[42] This latter value is essentially the same as his 9.43 percent estimate based on “projected interest rates” in Exhibit NWN/2104 Hadaway/1.

Even though it appears that the results of Hadaway’s risk premium models support my recommended ROE value of 9.4 percent, I recommend the Commission give very little if any weight to the results of Dr. Hadaway’s risk premium models, as his results are clearly based on authorized ROEs in other jurisdictions in that the “explained variable” in his regression model are authorized ROEs,[43] which I presume are primarily in jurisdictions other than Oregon. This is an example of the “circular reasoning” on which the Commission has previously commented.[44]

Q. WHAT DO YOU RECOMMEND TO THE COMMISSION REGARDING THE RESULTS OF DR. HADAWAY’S DISCOUNTED CASH FLOW MODELS?

A. I recommend the Commission disregard Dr. Hadaway’s apparent 20 to 60 basis point “outboard” adjustment (i.e., the upward adjustment resulting in the Company’s 10.2 percent proposed ROE), for the reasons discussed above, and review the direct results of his multistage DCF model, which has an

41 See Exhibit NWN/2100 Hadaway/20 lines 19 – 22. See also Exhibit NWN/2100 Hadaway/2 lines 15 – 16.

42 I checked the Company’s rate case ftp site for a corrected version of this exhibit on July 18, 2012. The version available on that date had the 9.43 percent and 9.44 percent results listed above.

43 See Exhibit NWN/2100 Hadaway/3.

44 See; e.g., pages 33 – 34 in Order No. 01-777 in Docket No. UE115.

average estimated ROE of 9.8 percent and a median estimated ROE of 9.9 percent.

I recommend the Commission give little weight to these results from Dr. Hadaway's multistage DCF model in light of the 5.7 percent estimated long-term growth rate in nominal GDP producing these results and the 3.0 percent annual rate of inflation in the GDP Price Inflator embedded in the 5.7 percent rate. I am unaware of any credible long-term forecast of nominal GDP equaling or exceeding the 5.7 percent Dr. Hadaway uses in two of his three DCF models as his long-term sustainable growth rate for gas utilities' dividends.

ISSUE 3, DECOUPLING

Q. WHAT IS THE CORE ISSUE YOU HAVE WITH THE COMPANY'S EXISTING "USE PER CUSTOMER" DECOUPLING MECHANISM?

A. My analysis shows that the current mechanism, whether considered with or without the changes proposed by the Company, and under both historical and likely future conditions, results in the Company collecting more revenue for new customers than the increase in its fixed costs. I estimate this to be an additive and incremental $374 thousand per year in over-compensation. This results in over-compensation exceeding $5.6 million over the course of five years; i.e., $374 thousand the first year, $748 thousand the second year, etc.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION GIVEN THIS PROJECTED RESULT?

A. Should the Commission decide to adopt the Company's recommended decoupling mechanism, I urge the Commission take this finding into account in setting the Company's ROE.

Q. DOES THE MECHANISM YOU RECOMMEND ND THE COMPANY'S MECHANISM PRODUCE THE SAME RESULTS IF THE NUMBER OF CUSTOMERS DOES NOT CHANGE?

A. Yes. If there is no change in the number of customers, the existing decoupling mechanism, with or without changes proposed by the Company, and the decoupling mechanism with the changes I recommended in my opening testimony produce the same result, given generally expected declines in use per customer over time. Therefore, it is very important to understand the impact of new customers on the Company's costs and the differences with respect to new customers between the existing mechanism, with or without implementation of changes proposed by the Company, and the mechanism with implementation of my recommended changes.

Q. WHERE DO YOU PRESENT YOUR ANALYSIS OF THE COMPANY'S DECOUPLING MECHANISM?

A. I present this analysis in Appendix 1, which includes a quotation from NW Natural Chief Executive Officer Gregg Kantor clearly showing the Company is incented to acquire new customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix 1

Additional Discussion of NW Natural's Decoupling Mechanism

Q. HOW DOES THE EXISTING MECHANISM WORK WITH RESPECT TO NEW CUSTOMERS?

A. The current mechanism multiplies the benchmark use per customer by the actual number of customers to arrive at a benchmark total use in therms. This value is compared with actual total use, with the variance (which is in total therms), multiplied by the allowed margin rate per therm to derive the monthly dollar amount to be deferred.

Q. WHAT IS ANOTHER WAY OF SAYING THIS?

A. The current mechanism increases the total therm benchmark, established as one outcome of this proceeding, by the average use per customer, also established as an outcome in this proceeding, for each new customer going forward. I note that the existing mechanism also works this way "in reverse," with a reduction in the number of customers, but as the most likely future for the Company with respect to those rate schedules impacted by the decoupling mechanism is one of customer and volume growth, I discuss the existing mechanism in this light.

Q. WHAT BENCHMARK DID YOU RECOMMEND IN YOUR OPENING TESTIMONY?

A. The benchmark I recommended was total use (in therms), which can be derived by multiplying the benchmark use per customer by the benchmark number of customers.[45] Both Staff and the Company intend that all three of these values are established as outcomes of this proceeding for each month of the test year; i.e., benchmark total use, the benchmark number of customers, and the resulting benchmark use per customer.

Note that, if the actual number of customers in any period going forward is the same as the benchmark number of customers, the current mechanism's benchmark of use per customer, when multiplied by the actual number of customers, is exactly the same benchmark total use in therms I recommend. Given that both the Company and Staff anticipate growth in the number of customers over time, the difference between the existing mechanism and the existing mechanism incorporating my recommended changes is in the treatment of new customers.

Again, Ms. Siores' contends that implementing the changes I recommended "…would prevent the Company from recovering its full fixed costs <u>for</u> <u>new</u> <u>customers</u>."[46]

Q. WHAT DOES MS. SIORES MEAN BY "FULL FIXED COSTS FOR NEW CUSTOMERS?"

A. I propose we take this one part at a time. By "new customers" I believe she means, for the decoupled rate schedules, the Company's establishment of service at a location where service may or may not have been previously provided. In other words, a "new customer" may come from "conversion" of an

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[45] Note that, alternatively, the existing mechanism's benchmark use per customer can be derived by dividing the benchmark total use by the benchmark number of customers.

[46] Exhibit NWN/1900 Siores/1 lines 17 – 19. Emphasis added.

existing location or from a newly constructed potential service location. My understanding is that an existing location not receiving service may or may not have an existing service connection and meter.

Q. WHAT DOES MS. SIORES MEAN BY "FULL FIXED COSTS?"

A. She means "the full LRIC,"[47] which she asserts is "the appropriate measure of the incremental fixed cost associated with an additional customer."[48] More specifically, she means "the full LRIC" on per existing customer bases for residential customers and for those commercial customers in rate schedules subject to decoupling.[49]

Ms. Siores means the following: if total LRIC is $X and the number of existing customers is Y, "the full LRIC" is $X/Y, and the incremental fixed cost associated with a new customer is $X/Y. Her assertion therefore tacitly includes the conclusion that the long-run incremental costs per new customer equal the long-run incremental cost per existing customer. I discussed this concept, of imputing the average LRIC per existing customer to each new customer, in my opening testimony.[50]

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47 Exhibit NWN/1900 Siores/9 lines 1 – 2.

48 Exhibit NWN/1900 Siores/4 at lines 16 – 18.

49 To be more precise, I believe Ms. Siores means "the full LRIC" as reconciled with the authorized revenue requirement. Should she mean otherwise, any decline in authorized revenue requirement from that reflecting the $43.7 million requested increase results in the Company not fully covering its fixed costs as an outcome of this proceeding if forecasted sales are realized. Obviously Staff would take considerable issue with this alternative meaning.

50 See; e.g., Exhibit Staff/1300 Storm/32 and 33.

Q. WHAT DOES THIS ASSERTION BY THE COMPANY IMPLY IN TERMS OF CHANGES IN THE SCALE OF NW NATURAL'S LOCAL GAS DISTRIBUTION UTILITY OPERATIONS?

A. It means there are absolutely no economies of scale with respect to customers; each additional customer costs $X/Y. This seems an extreme position for the Company to take, especially given that the Company's testimony points to economies of scale in terms of volumes.[51]

Q. PLEASE HELP US UNDERSTAND THE TWO POSITIONS.

A. Consider a hypothetical situation in which there are no changes in volumes over time and no changes in the number of customers over time; i.e., use per customer does not change. These assumed results imply that there are no changes in revenues generated from volumetric rates over time and that fixed costs are fully covered in each time period.

Now consider a second hypothetical situation, in which the number of customers increases by one percent annually and use per customer declines by one percent. Volume has not changed, and therefore revenue generated from volumetric rates has not changed.[52] The Company's position is that fixed costs have increased by one percent due to the one percent increase in customers and my position is that fixed costs, while they may have increased, have increased by something less than one percent as a result of the one

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51 See; e.g., Exhibit NWN/2500 Feingold/4 lines9 through Feingold/8 line 2. See also Exhibit NWN/1100 Feingold/7 lines 13: "Finally, utility costs exhibit significant economies of scale."

52 While I presume "has not changed" is sufficiently accurate for my purposes here, I note that 99 percent of the initial use per customer times 101 percent of the initial number of customers is 99.99 percent, not 100 percent.

percent increase in customers. The Company's position reflects my statement that "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" and my clarifying statement that "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 [with volumes and the number of customers established as outcomes for the test year in a general rate case], then adding a new customer increases fixed costs by $X/Y."[53]

Q. CAN YOU PROVIDE US WITH A SIMPLE EXAMPLE DEMONSTRATING THE FLAW IN THE COMPANY'S REASONING ON THIS POINT?

A. Yes. Please see Table 2 at Exhibit Staff/1300 Storm/28, which includes that Northwest Natural's fixed costs for the functions of storage and transmission do not vary with the number of customers. I believe it is self-evident that fixed costs associated with the storage and transmission functions vary based on volumes,[54] not customers. As noted in my opening testimony, the only way this is not the case is if new customers are, on average, "peakier" on a design day basis than are existing customers on average.[55, 56] I also note Mr. Feingold's statement that "[t]his trend in declining use per customer

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[53] See Exhibit Staff/1300 Storm/32 lines 14 – 22, including footnote 50. Emphasis present in the original.

[54] In this specific context, I mean "volumes" to be design day requirements.

[55] See footnote 44 at Exhibit Staff/1300 Storm/29.

[56] I note that there is nothing in the record in this proceeding indicating that the average new customer in a decoupled rate schedule is more or less "peakier" than the average existing customer in that rate schedule.

creates additional design day capacity within the utility's existing gas system to serve new loads."[57] Mr. Feingold mentions my table and related discussion in his reply testimony,[58] but does not attempt negation of my statement as being applicable to storage or transmission fixed costs; i.e., the Company witness sponsoring testimony on the Company's long-run incremental cost study neither confirms nor denies that the fixed costs associated with storage and distribution do not vary with the number of customers and do vary with volumes.

If fixed costs associated with storage and distribution do not vary with the number of customers and do vary with volumes, the Company's reasoning immediately breaks down. If these fixed costs do not vary entirely (100 percent) with the number of customers, then an increase in the number of customers does not serve to increase these costs; it is only if *volumes* increase that these fixed costs increase. I refer to my second hypothetical situation, in which customers increase one percent and volumes do not change. The Company has it ("full fixed costs,"[59] etc.) that all fixed costs have increased by one percent, exactly matching the percentage increase in the number of customers. I contend that storage and transmission costs have not increased, as volumes, including design day requirements, have not changed.

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57 See Exhibit NWN/1100 Feingold/11 lines 16 – 17. I choose to interpret his "creates additional" as meaning "frees-up existing."

58 See Exhibit NWN/2500 Feingold/20 lines 1 – 6.

59 See; e.g., Exhibit NWN/1900 Siores/5 lines 4 – 7.

This is precisely the Company's claim, that "full fixed costs"—presumably including in "full" those fixed costs associated with storage and transmission[60]—increase, and increase proportionately, with an increase in the number of customers. The storage and transmission functions account for 18.3 percent[61] of the Company's total long-run incremental cost of $310 million and approximately the same percent[62] of the total long-run incremental cost the Company attributes to the decoupled rate schedules.[63]

Q. HOW DID THE COMPANY DEVELOP THE LONG-RUN INCREMENTAL COSTS OF STORAGE AND TRANSMISSION?

A. The Company developed storage long-run incremental costs (LRIC) on the bases of plant investment and projected O&M costs. Transmission LRIC were developed on the basis of design day requirements by customer class using forecasted transmission investment of the Corvallis Loop and the Mid-Willamette Valley Feeder projects.[64]

Q. HOW DOES THE COMPANY ALLOCATE STORAGE COSTS TO RATE SCHEDULES (RATE SPREAD)?

A. Generally on the basis of design day requirements.[65]

[60] Fixed costs for these two functions are most certainly in the Company's LRIC study. See; e.g., lines 12 - 18 of Exhibit NWN/1101 Feingold/1.

[61] This is ($46,697,054+$8,265,500+$1,677,913)/$310,156,482) = 0.183, or 18.3 percent.

[62] I calculate this as 18.2 percent (the sum of $45,525,511+$8,049,565+$1,509,700 divided by $303,292,460).

[63] See Exhibit NWN/1101 Feingold/5 (the page identified as "Page 4 of 13").

[64] See Exhibit NWN/1101 Feingold/1.

[65] See; e.g., Exhibit NWN/2500 Feingold/15 lines 15 – 16: "…the Company's LRIC Study classifies the LRIC costs of transmission and storage as demand-related."

Q. HOW DOES THE COMPANY ALLOCATE TRANSMISSION COSTS TO RATE SCHEDULES?

A. Generally on the basis of design day requirements.

Q. WHAT IS THE MEANING OF THE 18 PERCENT OF INCREMENTAL COSTS FOR DECOUPLED RATE SCHEDULES YOU CALCULATE AS BEING ATTRIBUTABLE TO THE FUNCTIONS OF STORAGE AND TRANSMISSION?

A. The most important meaning is that less than 100 percent of NW Natural's "full LRIC" varies with the number of customers. This is contrary to the Company's categorically-stated claim[66] and oft-repeated accompanying claim that allowing the Company anything less than 100 percent of LRIC per *existing* customer for each *new* customer ("$X costs/Y customers," both established as outcomes in a general rate case proceeding), "results in less than full recovery of its fixed costs.[67, 68, 69, 70, 71, 72, 73, 74, 75, 76, 77]

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66 See Exhibit NWN/1900 Siores/4 lines 15 - 18, which includes that "…LRIC is caused by customers and not volumes…"

67 See Exhibit NWN/1800 Anderson/7 lines 19 – 21 ("…fully recover its fixed costs").

68 See Exhibit NWN/1900 Siores/1 lines 17 – 19.

69 See Exhibit NWN/1900 Siores/3 lines 6 – 7.

70 See Exhibit NWN/1900 Siores/4 lines 16 – 18 ("…LRIC is caused by customers and not volumes; therefore the full LRIC is the appropriate measure of the incremental cost associated with an additional customer").

71 See Exhibit NWN/1900 Siores/6 lines 9 – 11 ("This is because the New Service Rate is too low to reflect the fixed costs associated with adding the new customer").

72 See Exhibit NWN/1900 Siores/9 lines 1 – 2 ("Customers would pay less because Staff's proposal intends for the Company to recover less than full LRIC") and lines 11 – 12 ("Staff's proposal allows for recovery of less than full fixed costs").

73 See Exhibit NWN/1900 Siores/10 lines 20 – 21 ("Therefore, the only real change effected by Staff's proposal is to ensure the Company recovers less than its fixed cost associated with serving customers").

Returning to my second hypothetical example, in which use per customer declines by one percent, the number of customers increases by one percent, and volumes are unchanged: the long-run incremental costs associated with storage and transmission, accounting for 18 percent of NW Natural's long-run incremental costs for the decoupled rate schedules, in reality and as developed in the Company's LRIC study *remain unchanged*. I point out that this conclusion is not one I derive, but stems directly from the LRIC study, in which the long-run incremental cost of both storage and transmission result from design day requirements.[78]

The Company's position regarding this situation is very different; having that the long-run incremental costs associated with storage and distribution *increase by the one percent increase in the number of customers*. I offer that the Company appears to be "having it both ways" in that, for decoupling, "LRIC is caused by customers" whereas the Company's LRIC study clearly has it that the long-run incremental costs for storage and transmission are

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[74] See Exhibit NWN/1900 Siores/14 lines 2 – 4 ("…the proposed mechanism goes a step farther by ensuring that the Company will recover less than its fixed costs whenever a new customer is added, regardless of total customer usage. Staff's proposed mechanism amounts to a fundamental shift in the existing mechanism in that the Company will not recover its fixed costs regardless of customer usage").

[75] See Exhibit NWN/1900 Siores/14 lines 22 – 23 ("…Staff's proposal ensures that fixed costs associated with serving customers will not be recovered…").

[76] See Exhibit NWN/1900 Siores/15 lines 3 – 5 ("Staff's proposal has the added detriment of ensuring that the Company will not have the opportunity to recover the fixed costs associated with serving customers"). Ms. Siores repeats this claim in her reply testimony no less than nine times in her introduction and summary plus the less than 13 full pages she devotes to discussing decoupling.

[77] See Exhibit NWN/2500 Feingold/20 lines 13 – 16 ("[Staff's recommended changes to the Company's decoupling mechanism] provides the Company with no reasonable opportunity to earn its allowed rate of return").

[78] See the electronic worksheet supporting Exhibit NWN/1101 Feingold/1 and related.

caused by design day requirements. As pointed out in my opening testimony,[79] these are not the same thing.

Q. HOW DOES THE EXISTING MECHANISM ADDRESS THE DYNAMICS OF FIXED COSTS ASSOCIATED WITH STORAGE AND DISTRIBUTION DUE TO CHANGES IN THE NUMBER OF CUSTOMERS, IN USE PER CUSTOMER, AND IN TOTAL VOLUMES?

A. The existing mechanism, with or without the changes proposed by the Company, does not use a comparative metric or benchmark of total volumes (or, equivalently, total revenue generated through volumetric rates). With respect to the decoupled rate schedules, if the number of customers increases by Z percent, the result is a charge to customers unless total volume increases by the same Z percent; i.e., unless there has been no decline in use per customer.

Q. PLEASE PROVIDE AN EXAMPLE OF THIS USING REAL-WORLD VALUES.

A. Using values for rate schedule 2R, the primary residential schedule, the Company's LRIC study provides an LRIC for storage plus transmission of $37 million.[80] My opening testimony included that the base case in the Company's 2011 IRP assumed a 1.2 percent annual rate of growth in the number of residential customers and a one percent annual rate of decline in

[79] See Exhibit Staff/1300 Storm/30 lines 1 – 5.

[80] See Exhibit NWN/1101 Feingold/1. The sum of $30,875,387 + $5,373,856 + $912,625 is, rounded, $37 million.

use per residential customer.[81] This implies total use increases at a 0.19 percent annual rate,[82] which in turn implies revenues generated through volumetric rates increase at a 0.19 percent annual rate.

As applicable to the fixed costs of storage and transmission, the 0.19 percent increase in volumes directly implies a 0.19 percent increase in design day requirements,[83] which in turn implies a 0.19 percent increase in the long-run incremental costs of storage and transmission based on the Company's LRIC study. This amounts to $70 thousand on an annual basis.[84] Under the current mechanism, revenues generated through volumetric base rates collect an additional 0.19 percent, which covers the increase in fixed costs, and the decoupling mechanism charges ratepayers an additional 1.01 percent of the revenue generated through volumetric rates, since total use did not increase by the 1.2 percent increase in the number of customers. This 1.01 percent amounts to $374 thousand dollars annually.[85] There is, for these two functional areas of storage and transmission, a total of $444 thousand collected to cover costs that increase by $70 thousand, or an excess of $374 thousand collected from residential ratepayers in the first year following this proceeding's test year based on the Company's values. Using the Company's "base case" growth rates from the 2011 IRP, *the Company*

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[81] Exhibit Staff/1300 Storm/50.

[82] This is 1.012 X 0.99, or 1.0019, or 1.9 percent.

[83] Please see the discussion above on this point.

[84] This is $37 million X 0.0019.

[85] This is $37 million X .0101.

collects over six times[86] *the increase in cost for these two functions*, based on Company-provided information*.*

Q. PLEASE DISCUSS THE REMAINING 82 PERCENT OF THE COMPANY'S LONG-RUN INCREMENTAL COSTS FOR THE DECOUPLED RATE SCHEDULES.

A. The Company's LRIC study decomposes long-run incremental costs into the functional areas of storage, transmission, and distribution. Within the distribution function, the Company decomposes the long-run costs of distribution mains into costs based on design day requirements (volume-related) and costs based on numbers of customers. The Company identifies all other costs in the distribution function as being "customer-related," and identifies these as costs associated with services, meters and regulators, and accounting.[87]

Q. ACCORDING TO THE COMPANY, WHAT ARE THE LONG-RUN INCREMENTAL COSTS OF DISTRIBUTION MAINS BASED ON DESIGN DAY REQUIREMENTS?

A. These total $3 million for the decoupled rate schedules. The Company has determined the customer-related long-run incremental distribution costs to be $245 million for the decoupled rate schedules, with the total long-run

[86] This is, in thousands, ($70 + $374)/$70, or 6.3 times.

[87] See Exhibits Staff/1300 Storm/28 and NWN/1101 Feingold/9.

incremental distribution costs for the decoupled rate schedules totaling $248 million.[88]

Q. PLEASE IDENTIFY THOSE RATE SCHEDULES ACCOUNTING FOR THE MAJORITY OF THE LONG-RUN INCREMENTAL DISTRIBUTION COSTS OF THE DECOUPLED RATE SCHEDULES THE COMPANY CONSIDERS TO BE CUSTOMER-RELATED.

A. Using information in Exhibit NWN/1101 Feingold/1 and therefore incorporating the results of the Company's costing methodologies, I obtain the following: the total customer-related incremental distribution costs for the decoupled schedules are $245 million, with residential schedule 2R accounting for $204 million (83 percent) and commercial schedule 3C accounting for $38 million (16 percent). Results of the Company's LRIC study include that these two rate schedules represent 99 percent of the long-run incremental distribution costs determined by the Company to be customer-related. Based on the Company's inter-rate schedule cost allocations, the total of all other decoupled rate schedules represents one percent of the customer-related long-run incremental distribution costs for the decoupled rate schedules. I note that Staff has significant issues with the Company's costing methodology as it pertains to distribution mains, as does the Citizens' Utility Board of Oregon (CUB).[89, 90]

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[88] I derived these values from information in Exhibit NWN/1101 Feingold/1.

[89] See Exhibits Staff/1400, Staff/1500, Staff/2400 and Staff/2500.

[90] See Exhibit CUB/100 Jenks – Feighner/3 line 7 through Jenks – Feighner/10 line 8.

Q. WHAT IS THE COMPOSITION OF THE $204 MILLION CUSTOMER-RELATED LONG-RUN INCREMENTAL DISTRIBUTION COSTS FOR SCHEDULE 2R?

A. Based on the Company's LRIC study, Schedule 2R customer-related costs for distribution mains represent 29 percent of the schedule's total customer-related long-run incremental distribution costs, services are 43 percent of the total, meters and regulators are 16 percent, and accounting costs are 12 percent.[91]

Q. WHAT IS THE COMPOSITION OF THE $38 MILLION CUSTOMER-RELATED LONG-RUN INCREMENTAL DISTRIBUTION COSTS FOR SCHEDULE 3C?

A. Schedule 3C customer-related costs for distribution mains represent 17 percent of the total, services are 59 percent, meters and regulators are 17 percent, and accounting costs are 8 percent.[92]

Q. IF I UNDERSTAND THIS CORRECTLY, CUSTOMER-RELATED LONG-RUN INCREMENTAL COSTS OF DISTRIBUTION MAINS FOR RATE SCHEDULE 2R ARE 29 PERCENT OF $204 MILLION, OR APPROXIMATELY $59 MILLION, AND FOR RATE SCHEDULE 3C ARE 17 PERCENT OF $38 MILLION, OR APPROXIMATELY $6 MILLION, AND THE $65 MILLION SUM OF THESE TWO DOLLAR VALUES REPRESENTS APPROXIMATELY 21 PERCENT OF THE TOTAL LRIC OF

[91] Displayed at this level of precision, these values do not total 100 percent due to rounding.

[92] Displayed at this level of precision, these values do not total 100 percent due to rounding.

THE DECOUPLED RATE SCHEDULES AND ABOUT THE SAME PERCENT OF THE COMPANY'S TOTAL LONG-RUN INCREMENTAL COSTS OF $310 MILLION?

Q. Yes; that is correct based on my calculations using values in Exhibit NWN/1101.

Q. PLEASE WALK US THROUGH THE RESULTS OF THE COMPANY'S LONG-RUN INCREMENTAL COST STUDY, BEGINNING WITH THE TOTAL OF $310 MILLION IN EXHIBIT NWN/1101 FEINGOLD/1 AND BASED ON INFORMATION IN EXHIBIT NWN/1101.

A. Of the $310 million total, the Company attributes $303 million (98 percent) to the decoupled rate schedules. Of the $303 million attributed to the decoupled rate schedules, $55 million (18 percent) is in the functional areas of storage and transmission, which I discussed above, and $248 million (82 percent) is in the distribution function.

Of the $248 million in long-run incremental distribution costs, the Company considers about $3 million of the long-run incremental costs of distribution mains to result from design day requirements, with the remaining $245 million considered by the Company to be customer-related.

Of the $245 million of long-run incremental distribution costs for the decoupled rate schedules the Company considers to be customer-related, the Company allocates about $204 million (83 percent) to rate schedule 2R and $38 million (15 percent) to rate schedule 3C. Again, and as resulting from the Company's costing methodology, these two rate schedules represent all but

$3 million of the total customer-related long-run incremental distribution costs for the decoupled rate schedules; i.e., as the Company's LRIC study has it, the vast majority (99 percent!) of long-run distribution costs the Company considers to be customer-related are attributed to these two rate schedules.

Q. SO THE LONG-RUN INCREMENTAL COSTS OF DISTRIBUTION MAINS FOR THE DECOUPLED RATE SCHEDULES CONSIDERED BY THE COMPANY TO BE CUSTOMER-RELATED TOTAL APPROXIMATELY $65 MILLION?

A. Yes, except that some portion of the $3 million remaining customer-related costs are attributable to distribution mains as well, so this value is somewhat higher; i.e., $66 million.[93]

Q. PUTTING THIS TOGETHER THEN, THE COMPANY TAKES ISSUE WITH THE TREATMENT OF ABOUT $66 MILLION IN LONG-RUN INCREMENTAL COSTS (FOR DISTRIBUTION MAINS) WITH THE DECOUPLING MECHANISM FOLLOWING IMPLEMENTATION OF YOUR RECOMMENDATIONS AND, TO THIS POINT, YOU TAKE ISSUE WITH THE TREATMENT OF ABOUT $55 MILLION[94] IN LONG-RUN INCREMENTAL COSTS (FOR STORAGE AND TRANSMISSION) WITH

[93] The percent of customer-related distribution costs attributed to distribution mains, based information in Exhibit NWN/1101 Feingold/9, are: 1R 33 percent; 1C 29 percent; 31C Firm Sales 17 percent; 31C Firm Transportation 4 percent; and 31C Interruptible Sales 4 percent. As the highest value for these schedules is 33 percent, the customer-related distribution costs for distribution mains for decoupled rate schedules other 2R and 3C can be no more than 0.33 X $4 million, or $1.3 million.

[94] This is the 18 percent of $303 million previously discussed.

THE CURRENT DECOUPLING MECHANISM (WITH OR WITHOUT IMPLEMENTATION OF THE COMPANY'S PROPOSED CHANGES)?

A. Yes; to the extent of my discussion at this point, that is accurate. However, I repeat that both my Staff colleagues and CUB have issues with the Company's costing methodologies related to distribution mains, with Staff's recommended methodology for allocating customer-related ("non-demand-related"[95]) likely to result in more distribution main costs being allocated to rate schedules *not* decoupled. In other words, the $66 million above will decline with implementation of Staff's recommended changes to the Company's costing methodology, and perhaps materially so.

Q. WHAT DID MR. FEINGOLD, NW NATURAL'S WITNESS REGARDING THE COMPANY'S LRIC STUDY, SAY IN RESPONSE TO YOUR TESTIMONY ON DECOUPLING?

A. I first note that Mr. Feingold's testimony is regarding my discussion of distribution mains, and not storage, transmission, or any cost determined by the Company to be customer-related other than distribution mains. In other words, Mr. Feingold's issues with my recommendations regarding the Company's decoupling mechanism appear to be limited to the treatment of the costs of distribution mains under the mechanism with the changes I recommend.

I think it is important to examine what Mr. Feingold said, so I repeat two portions of his testimony below:

[95] See Exhibit Staff/2400 Ordonez/12.

> **"Q. Will you please comment on the NARUC quote related to revenue decoupling mechanisms presented in Mr. Storm's testimony?**
>
> A. The NARUC quote highlighted by Mr. Storm explains that decoupling on a per customer basis increases a gas utility's earnings where customer growth occurs with little or no investment in distribution mains. It is true that the infill of mains (i.e., where no new main is installed) is generally more profitable for a gas utility, with or without a revenue decoupling mechanism, so long as the added customer produces revenue in excess of the incremental costs of adding the customer in the short-run. Mr. Storm demonstrates that NW Natural has grown faster than the overall population of Oregon. This is an important point because it is obvious that this growth requires new investment in mains to connect these customers to the Company's gas system. However, it cannot all be accomplished through the infill of mains. As a result, the average installed footage of mains for new customers reflects a mix of infill <u>and</u> main extensions, as does the Company's total revenue requirement that must be recovered through rates. The Company's LRIC study quantifies the cost impact per customer of a combination of main extensions and mains infill and already results in a lower LRIC per customer related to distribution mains."[96]

In the context of discussing CUB's testimony on distribution mains and costs thereof, Mr. Feingold says:

> "The only positive marginal cost in the long-run relates to adding new distribution main to serve new customers. As a

96 Exhibit NWN/2500 Feingold/20 line 17 through Feingold/21 line 13. Emphasis in the original.

> result, the Company's LRIC Study correctly estimates the marginal cost and is theoretically consistent. It is important to note that sunk costs (i.e., the historical costs of the Company's existing distribution main are sunk) have no impact on marginal costs"[97]

Q. WHAT CAN YOU TELL US ABOUT MR. FEINGOLD'S STATEMENT THAT "THE AVERAGE INSTALLED FOOTAGE OF MAINS FOR NEW CUSTOMERS REFLECTS A MIX OF INFILL AND MAIN EXTENSIONS..."?

A. Worksheet "Average Main per Service" in the electronic spreadsheet provided by the Company and supporting Exhibit NWN/1101 calculates the "Average Main Addition Length" per "# of Meters (w/o idle and addset)". This worksheet adds, over the period 2004 through 2010, the "Installed Footages" of "MX Residential" and "System Expansion," arriving at a total installed footage of 5,990,199 [feet]. The worksheet also adds "Conversion Service" and "New Residential Service" values over the same period, arriving a total "number of meters without idle and addset" of 77,816. The worksheet calculates the "Average Main Addition Length" by dividing the first value by the second value, with an average value over this timeframe of 77 [feet].

Q. WHAT ARE "# of Meters (w/o idle and addset)"?

A. Per the Company's provided documentation, "[i]dle and add sets are new customers that currently have meter and service connections."[98] From this, I deduce that "# of Meters (w/o idle and addset)" are counts of new customers

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97 Exhibit NWN/2500 Feingold/23 lines 9 – 13.

98 See Exhibit NWN/1101 Feingold/7 lines 8 and 15.

having newly installed meters and service connections;[99] i.e., they are not new customers in service locations where there is an existing meter and service connection.

Q. SO THE COMPANY'S CALCULATION OF ADDITIONAL FEET OF DISTRIBUTION MAIN PER NEW CUSTOMER DOES NOT INCLUDE NEW CUSTOMERS THAT ALREADY HAVE A METER AND SERVICE CONNECTION?

A. It apparently does not.

Q. WHAT DOES THIS MEAN IN TERMS OF MR. FEINGOLD'S STATEMENT THAT "THE AVERAGE INSTALLED FOOTAGE OF MAINS FOR NEW CUSTOMERS REFLECTS A MIX OF INFILL AND MAIN EXTENSIONS..."?

A. I believe the only thing it can mean, taking the Company's documentation and Mr. Feingold's statement as represented and at face value, is that Mr. Feingold's "new customer" definition as it relates to "infill" does not include new customers in service locations for which there is already a meter and service connection.[100] He must, therefore, be referring to "infill" new customers who do not have an existing meter and service connection ("new customer meter set without idle and add sets").

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON THIS POINT.

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[99] I assume that "w/o" means "without."

[100] This assumes that "meters with idle and add sets" associated with main extension is either an oxymoron or a circumstance having a very infrequent occurrence; i.e., I presume the Company does not with any frequency need to extend a distribution main to reach a customer with an existing meter and service connection.

A. Mr. Feingold's statement, that "the average installed footage of mains for new customers reflects a mix of infill and main extensions," is *entirely inapplicable* to new customers in service locations where a meter and service connection already exist, as such customers do not require any distribution main construction. Instead, his "infill" new customers, as he must intend the meaning of the term, require new meters and new service connections. Combining this with Mr. Feingold's testimony replicated above that "[t]he only positive marginal cost in the long-run relates to adding new distribution main to serve new customers," <u>there are no long-run incremental costs of distribution mains to serve new customers at service locations where a meter and service connection already exist</u>. I note that Mr. Feingold's testimony includes that "infill of mains…" means "…no new main is installed,"[101] whether for new customers with or without "idle and add set."

Q. PLEASE TELL US WHY THIS IS IMPORTANT.

A. Recall that my recommendations include the concept of a New Service Rate, to be multiplied by the cumulative count of new meters/new service locations.[102] I recommend this approach so as to not include in the number of customers (or number of new customers) metric those new customers in service locations that: a) already have a meter; b) already have a service connection; and, following the Company's statements and reasoning implied

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[101] Exhibit NWN/2500 Feingold/21 lines 1 – 2.

[102] See Exhibit Staff/1300 Storm/41 line 6 through Storm/46 line 20 and Exhibit NWN/1900 Siores/3 lines 15 - 22.

therein, c) have no long-run incremental costs associated with distribution mains.

As discussed above, the Company can include as a new customer one who has an existing meter and service connection.

Q. PLEASE EXPLAIN WHAT CUSTOMER-RELATED DISTRIBUTION COSTS ARE INCURRED BY THE COMPANY, ON A LONG-RUN INCREMENTAL COST BASIS, TO PROVIDE SERVICE TO NEW CUSTOMERS IN SERVICE LOCATIONS WHERE A METER AND SERVICE CONNECTION ALREADY EXIST.

A. Recall that NW Natural defines customer-related costs to include those related to distribution mains, services, meters and regulators, and accounting. Adding the new customers we are now discussing, with an existing meter and service connection, result in a long-run incremental customer-related cost to the Company on a monthly basis of $3.90 for customers in rate schedule 2R and $4.18 for customers in rate schedule 3C.[103] This is because there are no long-run incremental customer-related costs of distribution mains, services, or meters and regulators.

I want to reinforce two things related to this: these two rate schedules represent 99 percent of the long-run incremental distribution cost that is customer-related, based on the Company's costing methodology and long-run

[103] This are the values of the annual long-run incremental cost per customer for Accounting divided by 12 for schedules 2R ($46.76) and 3C ($50.20).

incremental cost study. Additionally, the current monthly customer charge for each rate schedule exceeds these costs, at $6.00 for 2R and $8.00 for 3C.

Q. PLEASE TELL US WHAT THIS MEANS IN TERMS OF THE COMPANY'S ASSERTION THAT THE APPROPRIATE LEVEL OF REVENUE FOR THE COMPANY TO RECEIVE FOR EACH NEW CUSTOMER IS THE "FULL LRIC" PER EXISTING CUSTOMER?

A. It means that new customers in rate schedules 2R and 3C can be added, and included in the count of total customers for purposes of calculating the monthly decoupling deferral under the existing mechanism (with or without the Company's proposed changes), that have long-run incremental customer-related distribution costs that are, on a monthly basis, less than the customer charge. I stress that, as discussed above, these customers are NOT "averaged-in" the Company's customer-related long-run incremental costs of distribution mains, so compensating the Company for the addition of such customers at the "full LRIC" rate results in increased revenue flowing to the Company that exceeds its increase in cost as defined by the "full LRIC."

Q. HOW MANY NEW CUSTOMERS LIKE THIS ARE THERE?

A. I do not know.

Q. PLEASE DISCUSS THE CONCEPT OF MAIN INFILL.

A. I propose we consider a simple model of residential distribution. Assume that my street has 100 single family dwellings, 50 of which are existing NW Natural customers in rate schedule 2R. Further assume that the remaining 50 do not have existing meters or service connections ("without idle and addset").

For the purposes of developing the Company's LRIC study, it does not matter if the Company acquired any portion of the 50 existing customers from main infill or as new construction. Recall that the main addition length calculation is total footage divided by the sum of "# of Meters (w/o idle and addset)" for each of the Company's "Conversion Service" and "New Residential Service." Therefore, the number of customers on my street counted for purposes of the Company's LRIC study is 50. Please also assume my street is exactly representative of the Company's residential customers as per the LRIC study; i.e., the "average main addition length" on my street is (was) 77 feet.

Consider that my street represents exactly one-half of the Company's residential customers. The other one-half ("Other Street") is today just like my street.

Over time, people on my street convert to being NW Natural customers; i.e., the Company adds my neighbors as main infill new customers at, say 10 customers per year. The other street adds customers at the same rate, but it is entirely through main extension to reach newly constructed residences, as new development increases the length of the other street.

Table 1 depicts this situation, with the number of 2R customers growing by 20 per year, and by 10 in each of the two neighborhoods. Consider for our purposes here that the Company's assertion that it is the "full LRIC" that is the appropriate level at which the Company should be compensated for additional fixed costs associated with customer growth. This requires that the average main per service remain at 77 feet in each year.

Table 5

Residential Customer Growth and Distribution Main per Customer

Year	Customers	NWN LRIC Feet per Customer	NWN LRIC Distribution Main Feet	Actual Main Feet	Actual Feet per Customer
My Street					
1	50	77	3,850	3,850	77
2	60	77	4,620	3,850	64
3	70	77	5,390	3,850	55
4	80	77	6,160	3,850	48
5	90	77	6,930	3,850	43
6	100	77	7,700	3,850	39
Other Street					
1	50	77	3,850	3,850	77
2	60	77	4,620	5,390	90
3	70	77	5,390	6,930	99
4	80	77	6,160	8,470	106
5	90	77	6,930	10,010	111
6	100	77	7,700	11,550	116
Total NW Natural					
1	100	77	7,700	7,700	77
2	120	77	9,240	9,240	77
3	140	77	10,780	10,780	77
4	160	77	12,320	12,320	77
5	180	77	13,860	13,860	77
6	200	77	15,400	15,400	77

Q. WHAT INFORMATION IS IMPORTANT TO TAKE FROM TABLE 1?

A. Please note the values in the “Actual Feet per Customer” column. As assumed, my neighborhood is becoming more dense with respect to NW

Natural's distribution mains and, also as assumed, the total Company is staying the same (which the Company's $X/Y reasoning associated with the cost of new customers requires), at 77 feet per customer.

The important point is that, for the Company's reasoning to hold with respect to the long-run incremental customer-related distribution main costs associated with adding new customers, the Other Street must become *less dense* over time, with the average feet per distribution main increasing from 77 feet to 116 feet over the five year period.

While this is clearly impossible on a state-wide basis with respect to, say, single-family housing, as no (inhabitable) land is being added to the state, it *could* be true for a natural gas local distribution utility. I believe this is unlikely given the strong conservation ethic of Oregon's citizens and implementation of land use laws that serve as examples for the nation of forward-looking planning.

Q. IS IT POSSIBLE THAT NW NATURAL IS EXPANDING ITS DISTRIBUTION FOOTPRINT IN MATERIAL WAYS AND THAT THIS WILL BE THE OUTCOME?

A I acknowledge it is possible. However, I ask two questions in turn: is it likely? In addition, if it is likely: are revenues collected through a decoupling mechanism the best way to pay for such expansion? I point to Table 3 in my opening testimony, which indicates the Company has almost 170 thousand single-family homes either on an existing main or within 150 feet of an existing main.[104] I examine the "distribution main density" issue later in this testimony, from a different perspective and using the Company's historical data.

Below are NW Natural Chief Executive Officer Gregg Kantor's words from the transcript of the Company's May 4, 2011 earnings call regarding some facets of main extension and customer growth as they relate to the (then) upcoming general rate case filing. Mr. Kantor was responding to an analyst's question regarding the rate case.

> "…we are going to be looking at the rules that currently govern our ability to extend our mains to customers. We believe there are opportunities to get our pipes to sort of suburban communities around our service territory, on the fringes of our service territory. And it will take some policies to get that done in a way that's economic for the company and economic for our customers, so basically having the system help pay for some of those larger main extensions.
>
> So we actually have that and some other marketing policies that we're going to talk to the Commission about, which we think will help us add additional customers… ****
>
> …there is a formula that allows for the extension to converging customers. And what the Commission is trying to avoid is the whole system subsidizing a few customers. And so we can't extend mains for long distances that exceed this revenue to cost of installation mechanism, and we think that needs to be looked at. And then there are a number of communities that sit on the sort of fringes of our service territory, one would be Estacada, another Dayton, that

[104] See Exhibit Staff/1300 Storm/38. The material cited is on page 18 of an investor presentation by the Company made May 18, 2010 at the American Gas Association Financial Form.

> are fairly large communities, have grown in large ways over the last 10 to 15 years. They do not have gas. You're talking about fairly short extensions of pipe, relatively speaking eight miles or so to the Estacada and it has just never penciled out.
>
> In Coos Bay, when we added the Coos Bay service territory, we were allowed to have the system partially pay for the expansion of our mains down in Coos Bay. And we think that's a model that we ought to use in other parts of our service territory. So in addition to being able to get to more customers by allowing somewhat longer main extensions within our service territory, we'd like to see some policies that would allow us to get to brand new communities and help us on the growth side."

I leave it to the reader to assess whether and the extent to which the Company is incented to acquire new customers.[105]

Q. MR. FEINGOLD "ANALYZED THE RELATIONSHIP OVER TIME BETWEEN THE NUMBER OF CUSTOMERS SERVED AND THE INSTALLED FOOTAGE OF MAINS" FOR NW NATURAL'S GAS DISTRIBUTION SYSTEM."[106] DO YOU OFFER US ANY THOUGHTS REGARDING HIS WORK IN THIS AREA?

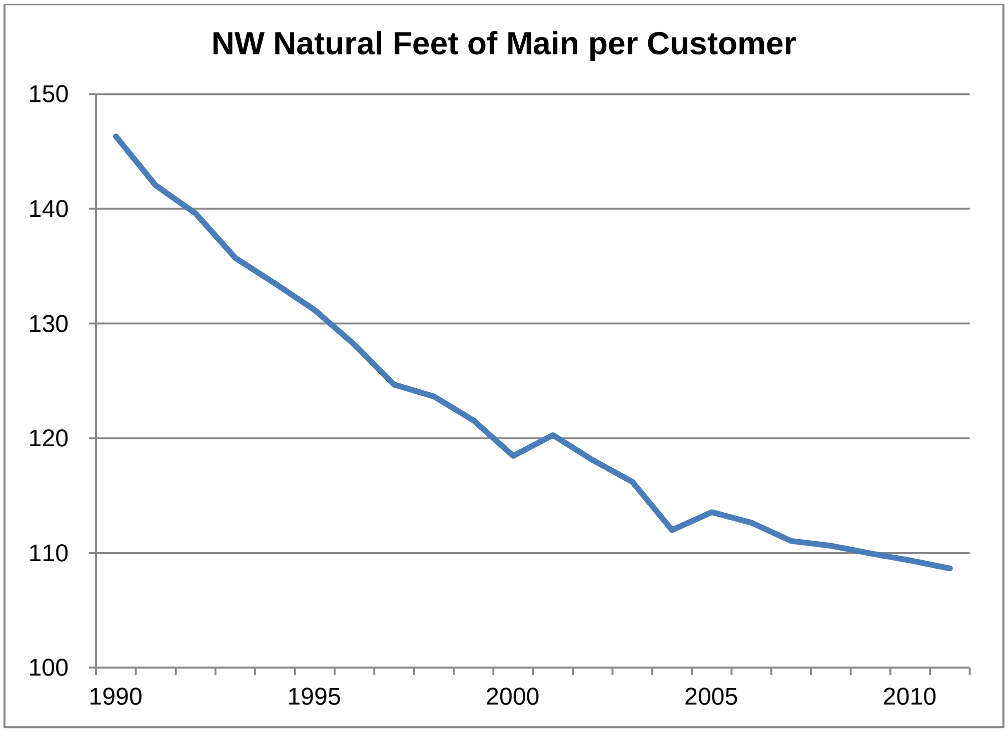
A. I also "analyzed the relationship over time between the number of customers served and the installed footage of mains" for NW Natural, using the same data used by Mr. Feingold. I conclude that the data used by Mr. Feingold answer the earlier question regarding customer growth and distribution main

[105] See Exhibits Staff/1300 Storm/30 line 9 through Storm/39 line 4 and NWN/1900 Siores/7 lines 10 – 19.

[106] See Exhibit NWN/2500 Feingold/18 – Feingold/19 and Exhibits NWN/2503 Feingold/1 through Feingold/4.

density: NW Natural's distribution system is becoming more "customer dense" in terms of distribution mains, as depicted in Figure 5.[107] If this was not the case on an historical basis—if 77 feet of main per customer today always equals 77 feet of main per customer for some tomorrow—the line in the chart would be flat.

Figure 5



Q. WHAT ARE ADDITIONAL RESULTS OF YOUR ANALYSIS OF THE DATA USED BY MR. FEINGOLD?

[107] The information in Chart 1 is derived from data in the electronic worksheet supporting Exhibit NWN/2503.

A. No less than 39 percent of Northwest Natural's customer growth has come through main infill and no more than 61 percent through main expansion over the period 1991 through 2011.

Q. HOW DO YOU SUPPORT THOSE RESULTS?

A. The intensity in 1990 was 146.3 feet of main per customer.[108] As NW Natural extended its mains, if customer growth came only from main extension growth that value would remain very similar, if not identical, to that for the prior year; i.e., the mileage increase each year (times 5,280 feet per mile) divided by the average feet of main per customer for the prior year equals customer growth due to mileage expansion for that year. All other customer growth in that year came from main infill. The results over this 21 year period are that 218 thousand (61 percent) of the increase in customers came from main extension and 141 thousand (39 percent) came from main infill.

I note that the above line of reasoning assumes that density on the extension is equal to the system average of the prior year. As Figure 1 shows density *increasing over time* (feet of distribution main per customer *decreasing*), I find it difficult to believe that the Company could be extending mains into areas that are more customer dense in the year of expansion than the system as a whole (other than in a rare year). Such a situation implies "main outfill" for the existing mains. Intuitively, the opposite seems more likely: declining marginal productivity vis-à-vis customer acquisition in terms of mile

[108] From Exhibit NWN/2503 Feingold/1 and for 1990, this is 8,867 miles X 5,280 feet per mile divided by 319,962 customers.

of distribution main extension. See also the discussion above regarding "my street" and the "other street."

Quantitatively, as represented in Figure 5, there are only two years in which feet of distribution main per customer increased: 2002, which can be explained by a decrease in the number of customers, and 2006; i.e., in most years the density declines. To the extent that the main extension mileage is *less* customer dense in the year of extension than the system average, the number and proportion due to main infill I represent above are understated.

Q. IS THERE ANOTHER WAY TO LOOK AT THIS DATA?

A. One other way is to consider the system development from 1990 through 2011 as having occurred in one period. Unlike the preceding approach, which allowed for main infill on main extensions made in prior years, this approach assumes that all main extension and customer growth occurred in one period: "today," in 2011, versus "yesterday," in 1990.

This approach has 185 thousand of the increase in customers coming from main extension (51 percent) and 175 thousand from main infill (49 percent) over the 21 year period. Thus, reasonable bounds provide that 51 to 61 percent of the customer growth came from main extension and 39 to 49 percent came from main infill.

While I am sympathetic with Mr. Feingold's statement that "…it cannot all be accomplished through the infill of mains,"[109] no less than an estimated

[109] See Exhibit NWN/2500 Feingold/20 lines 7 - 8.

39 percent was accomplished exactly this way over the 1991 through 2011 period.

Q. DO NEW CUSTOMERS HAVE HIGHER OR LOWER USAGE THAN EXISTING CUSTOMERS?

A. To my knowledge, the only evidence in this proceeding regarding this topic is my response to the Company's Data Request 40, pages 3 and 4 of which I include as Exhibit Staff/2201. The Company's modified IRP filed September 1, 2011, cited in my response, includes that, in the context of discussing declining use per customer:

> "A number of factors are at work in the demand forecast which drives this decline. <u>New conversion customer additions tend to have lower use profiles than existing customers</u>. In addition, NW Natural expects significant energy savings to come from programs administered to both new construction and existing customers by the Energy Trust of Oregon. Public purpose funds are collected from Oregon ratepayers to fund these programs. Also, as the existing housing stock ages, water heaters, furnaces and windows are replaced with newer, more efficient versions, furthering the decline in use. Finally, customers may respond to natural gas price increases by actively making improvements to the housing shell, or even changing behavior, such as turning down the thermostat. The price factor *rp* in the load model (Eq. 2.3) conveys the demand response to price changes."[110]

Q. ANYTHING ELSE REGARDING THE DATA USED BY MR. FEINGOLD?

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110 See page 2.12 of the modified IRP filed September 1, 2011 in Docket No. LC 51. Emphasis added.

A. Yes. While the "source" of customer growth, based on the first approach above, in the first 10 years of the 1991 through 2011 period is similar to the composition as the entire 21 year period (57 percent from main expansion and 43 percent from main infill), the average portion coming from main expansion for the years 2009 through 2011 is radically different, at 29 percent, while the portion coming from main infill is 71 percent.

Q. WHAT DOES THIS MEAN FOR MS. SIORES' ASSERTION THAT "THE MAINS COST IN THE LRIC ALREADY ACCOUNTS FOR THE FACT THAT ADDED CUSTOMERS MAY OR MAY NOT HAVE ADDITIONAL COST ASSOCIATED WITH THEM?"

A. I offer a couple of thoughts on this. The Company derived the 77 feet of distribution main per new customer[111] using values over the period 2004 through 2010 (inclusive). If we use only values for the last three years of this period, the 77 feet, which by the Company's $X/Y imputation of LRIC costs to future new customers *must always be 77 feet*, becomes 30 feet of distribution main per new customer. This confirms my result above using Mr. Feingold's data: main infill <u>has</u> <u>grown</u> in importance in terms of NW Natural's acquisition of new customers. Another way of saying this is that, while infill has been an important (39 percent or greater) part of the Company's customer growth over the period 1991 through 2011, *its importance has increased in recent years*.

Regarding Ms. Siores' assertion, if main infill is becoming a larger component of customer growth over time, *which it has*, the use of the a static

[111] As defined by the Company. See the preceding discussion related to this.

value ("77 feet") as the representation of an average including the "no additional cost" main infill new customers and the "with additional cost" main extension new customers becomes suspect as best when applied to future years for purposes of calculating decoupling adjustments under the existing mechanism, with or without implementation of those changes recommended by the Company. More precisely, it will overstate the actual cost, and the degree of overstatement will increase with any increase in the proportion of new customers from main infill versus main expansion from that for the period used to calculate the average of 77 feet.

Q. PLEASE PROVIDE AN EXAMPLE OF THIS AS IT PERTAINS TO THE EXISTING DECOUPLING MECHANISM.

A. Using values from the Company's LRIC study, the average cost per foot of distribution main is $1.43 annually[112] and the average distribution main per customer is 77 feet. Using 100 new customers, if 60 (60 percent) were acquired through main expansion; they had an average of 128.3 feet each.[113] In other words, 60 new customers cost ($1.43 X 128.3 =) $183 each and 40 new customers cost nothing. This is the average of $110 per new customer and this is why Ms. Siores provides the following:

> "[t]he mains cost included in the LRIC represent an average of main footage that includes conversion and new construction services.

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[112] See Exhibits NWN/1101 Feingold/7 and Feingold/9: $110 per customer per year divided by 77 feet of distribution main per customer equals a cost of $1.43 per foot of distribution main per customer per year.

[113] This is so the $1.43 X 60 + $0.00 X 40 = $110 X 100; i.e., so the average is the $110 per customer.

Thus, the mains cost in the LRIC already accounts for the fact that added customers may or may not have additional mains cost associated with them."

If, in the period between the test years of general rate cases, the actual composition is not 60/40, but 50/50, and the average new customer from main extension averages the same 128.3 feet of distribution main,[114] the Company still collects "the full LRIC" *per new customer* totaling (100 X $110 =) $11,000. The Company's actual cost, at the same $183 per new customer acquired through main extension, is actually now (50 X $183 =) $9,150. In other words, the Company has collected compensation from ratepayers exceeding costs at a rate of $18.50 per new customer per year.[115]

Q. HOW MUCH MIGHT THIS BE ON AN ANNUAL BASIS?

A. The Company estimates 538,601 rate schedule 2R customers for the test year.[116] At a growth rate of 1.2 percent annually, this equates to 6,463 new schedule 2R customers in the year following the test year. This means the Company will collect ($18.50 X 6,463 =) $120 thousand in excess of its increased cost for the first year following the test year of this rate case, under these assumptions on customer growth and declines in use per customer. With compounding, this amount increases by somewhat more than $120

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114 See my testimony above with respect to Oregon's land use laws and *decreasing* housing density.

115 This is ($11,000 - $9,150) / 100.

116 See Exhibit NWN/2500 Feingold//1.

thousand per year under these assumptions; i.e., for the fifth year following the test year, the excess collection could exceed $600 thousand. This equates to a cumulative $1.8 million over five years.

I also note that this example depicts a change from a mix of 60/40 main extension versus main infill to a mix of 50/50; i.e., not to the level of the 2008 through 2010 average of 29%/71% main extension versus main infill.

Q. MIGHT NOT THE VALUE FOR THESE LATTER YEARS REFLECT THE DECLINE IN RESIDENTIAL NEW CONSTRUCTION?

A. Perhaps. At the same time, I am not aware of any credible predictions that Oregon's housing market will come roaring back in the near future, thereby creating a large demand for the extension of the Company's distribution mains to reach newly constructed residential housing.

Q. WHAT ARE YOUR SUMMARY THOUGHTS REGARDING THE CUSTOMER-RELATED LONG-RUN INCREMENTAL COSTS OF DISTRIBUTION MAINS AND YOUR REASONS FOR NOT INCLUDING THEM IN YOUR NEW SERVICE RATE?

A. In the order I discussed them above, my reasons for not including these costs are:

- Staff and CUB have issues with the Company's LRIC study as it pertains to distribution mains. The distribution mains cost for decoupled rate schedules are likely to decrease with implementation of Staff's recommendation.
- There may be a mismatch between what is counted as a new customer for calculation of the decoupling deferral ("all customers") versus what is

counted in the LRIC study, which apparently does not include those new customers with an existing meter and service connection ("idle and add sets").

- The dynamics of customer growth by main infill versus main extension use a parameter ("77 feet") that Figure 1 shows to have a systemic declining trend for at least the last 21 years. Overstatement of this parameter with respect to its actual future value results in compensation from ratepayers to the Company in excess of the increase in fixed costs.

For these additional reasons, I believe using "the full LRIC" as to compensate NW Natural for increased costs associated with customer growth over time results in over-recovery of the Company's increase in fixed costs.

Q. MS. SIORES HAS AN EXHIBIT[117] SHOWING HOW THE CURRENT MECHANISM AND THE MECHANISM WITH YOUR PROPOSED CHANGES WORK. WHAT COMMENTS DO YOU HAVE ON HER EXHIBIT AND HER DESCRIPTION[118] THEREOF?

A. Her conclusion begs the question. If you believe "an appropriately-operating decoupling mechanism" should provide the same result as a "use per customer" decoupling mechanism, then any mechanism that does not must be one that is not " appropriately operating."

I also note that her description implicitly has the $X/Y for existing customer applied to a new customer "full LRIC" reasoning. As I clearly

[117] See Exhibit NWN/1901.

[118] See NWN/1900 Siores/5 line 8 through Siores/6 line 11.

demonstrate in my discussion of storage and transmission costs, this reasoning is flawed.

Q. WHAT IS THE "SIMPLEST AND PUREST" DECOUPLING MECHANISM?

A. I believe it is one with but one metric and where the simple question to be answered on a periodic basis is: was total use above or below the benchmark? If above the benchmark, the result is a credit to customers. If below the benchmark, the result is a charge to customers. This most definitely removes the throughput incentive, which presumably is and I believe should be the *sine qua non* for any decoupling mechanism. Such a mechanism does not attempt to serve as a quasi-alternative form of regulation (AFOR), with dynamics that result in "puts and takes" in an attempt to account for changes in fixed costs beyond the test year of a general rate case.

Q. MS. SIORES REPEATS THE OBJECTIVES YOU LISTED IN YOUR OPENING TESTIMONY FOR THE DECOUPLING MECHANISM RESULTING FROM YOUR RECOMMENDED CHANGES.[119] HAVE YOU ANY THOUGHTS ON HER OBSERVATIONS?

A. I do. First, it would be an improvement if the existing mechanism actually worked the way she describes in her response to Staff objective 1. She obviously omitted an important qualification to her statement by not including "on a per customer basis."

In a similar vein, I note that, from my perspective, it would be an improvement if it operated in the fashion she describes at Exhibit NWN/1900

119 See Exhibit NWN/1900 Siores/8 line 16 through Siores/10 line 17.

Siores/7 lines 7 – 8: "[i]f actual weather normalized volumes exceed baseline volumes, customers receive a credit for the excess volumes." This is my "simplest and purest" decoupling mechanism above and the decoupling mechanism that would result from implementation of my recommendations (aside from results due to the New Service Rate calculation).

Unfortunately, this statement is only true *if the percentage increase in customers is no more than the percentage increase in actual weather normalized volumes*. Otherwise, use per customer, at any level of increase in total volume, has declined, and the result is a charge to customers.

Regarding her responses to Staff objectives 2 and 4: Ms. Siores correctly identifies that my recommendations result in a mechanism that does not cover "full LRIC" with customer growth. This rebuttal testimony explains why such recovery, as based on results of the Company's LRIC study, is inappropriate and results in excessive compensation to the Company.

Regarding her comments with respect to Staff objective 5, my recommendations result in a mechanism that is much simpler that the existing mechanism with the "outboard" price elasticity adjustment. It is at the same level of complexity as the existing mechanism without the price elasticity adjustment. Remember that, for the three benchmark values I discuss earlier in this testimony, we can calculate any one value from the other two, and all three benchmark values are to be results from the current proceeding. I recommend using use per customer times the number of customers. The existing mechanism, without the price elasticity adjustment and as recommended by Ms. Siores, uses total usage divided by the number of customers.

Included in Ms. Siores' discussion of Staff objective 7 is a statement on which we differ. If I understand her correctly and as presumed by me to mean customers today, tomorrow, and in the future year of your choice ("…all new customers…"), I do not believe it is the appropriate role of a decoupling mechanism to "…help[s] ensure that fixed costs associated with any customer are recovered, regardless of their usage." I believe a review of rate base additions and other costs in the context of a general rate case proceeding should have a lot to do with coverage of fixed costs that differ from the level of those established as a result of a prior general rate case proceeding. Decoupling should not be considered, as it seems clear NW Natural does, a rate mechanism whereby increases in fixed costs ("rate base") associated with customer growth are automatically covered (or more than covered) on a year-after-year basis.

Q. ARE THERE ANY REASONABLE POSITIONS BETWEEN THE COMPANY'S AND YOURS WITH RESPECT TO NW NATURAL'S DECOUPLING MECHANISM?

A. I believe so. One such intermediate position might be to use as benchmarks total use for storage and distribution costs and use per customer for all other functions. I would consider such a mechanism to be demonstrably better than the existing mechanism under the conditions of declining use per customer and increasing numbers of customers.

Another approach, and perhaps combined with the first, is for the Commission to direct Parties to a) resolve differences regarding the Company's LRIC study, if possible; b) determine a consensus approach for establishing a dynamic (or periodically updated) parameter of feet of distribution main per customer, as it pertains to new customers; and c) establish methods for determining counts of relevant new customers. If these tasks are achieved, the LRIC associated with distribution mains on a forward new customer basis can be incorporated into the New Service Rate.

Q. IS CONTINUANCE OF THE EXISTING DECOUPLING MECHANISM, WITH OR WITHOUT THE COMPANY'S PROPOSED CHANGES, IMPORTANT TO NW NATURAL?

A. Yes. My testimony provides illumination as to why this is the case.

CASE: UG 221
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2201

Exhibits in Support
Of Rebuttal Testimony

July 20, 2012

UG 221 Northwest Natural

Three-stage Discounted Dividend Model with Terminal Valuation based on a Growing Perpetuity
Stage 3 Annual Growth Rate of 4.51 Percent

	Unadjusted ROE (IRR) (A)	Average Recent Share Price (B)	Dividend Yield @ Average Recent Share Price[1] (C)	2013-17 Average Annual Dividend Growth Rate[2] (D)	2018-22 Average Annual Dividend Growth Rate[2] (E)	2023-52 Annual Dividend Growth Rate[2] (F)	Terminal Value as % of Total Valuation (G)	2012 Common Equity % of Capital Structure (H)	Test Year Common Equity % of Capital Structure (I)	Value Line Beta[3] (J)	Unlevered Beta[4] (Business Risk) (K)	Beta Relevered to Test Year Capital Structure[4] (L)	ROE Capital Structure Adjustment[4] (M)	ROE Adjusted for Divergent Capital Structures (O)
Staff's Peer Utilities														
1 Laclede Group	8.4%	$38.92	4.3%	2.2%	3.6%	4.51%	21.8%	64.0%	50.0%	0.55	0.45	0.62	0.6%	9.1%
2 Northwest Natural Gas	8.1%	$45.75	4.0%	2.1%	3.8%	4.51%	24.8%	55.0%	50.0%	0.60	0.45	0.63	0.3%	8.4%
3 Piedmont Natural Gas	8.3%	$30.54	4.0%	3.2%	3.9%	4.51%	23.4%	57.0%	50.0%	0.70	0.53	0.76	0.5%	8.8%
4 Questar	8.7%	$19.71	3.5%	5.5%	8.3%	4.51%	20.5%	52.5%	50.0%	NMF	0.47	0.64	0.1%	8.9%
5 WGL Holdings	8.2%	$39.99	4.0%	2.4%	3.5%	4.51%	23.7%	67.5%	50.0%	0.65	0.55	0.76	0.9%	9.1%
Group Average	8.4%		3.9%	3.1%	4.6%	4.51%	22.9%	59.2%	50.0%	0.63	0.49	0.68	0.5%	8.8%
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Northwest Natural's Peer Utilities														
1 Alliant Energy	8.9%	$44.03	4.2%	5.1%	4.7%	4.51%	18.6%	50.5%	50.0%	0.75	0.53	0.75	0.0%	9.0%
2 Avista	9.3%	$25.91	4.6%	4.7%	4.6%	4.51%	16.2%	49.0%	50.0%	0.70	0.50	0.69	-0.1%	9.3%
3 Black Hills	8.7%	$33.04	4.5%	2.0%	3.6%	4.51%	20.1%	53.0%	50.0%	0.85	0.60	0.88	0.3%	8.9%
4 CMS Energy	9.3%	$22.87	4.3%	5.6%	4.9%	4.51%	16.7%	33.5%	50.0%	0.75	0.44	0.60	-1.2%	8.0%
5 Consolidated Edison	7.9%	$59.50	4.1%	0.8%	3.0%	4.51%	26.4%	53.5%	50.0%	0.60	0.46	0.62	0.2%	8.1%
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7 Integrys	8.8%	$54.00	5.0%	0.8%	3.1%	4.51%	19.1%	60.5%	50.0%	0.90	0.70	1.01	0.9%	9.6%
8 NiSource	7.6%	$24.84	3.9%	0.4%	2.2%	4.51%	30.2%	48.0%	50.0%	0.85	0.59	0.83	-0.2%	7.4%
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13 Sempra Energy	8.3%	$63.42	3.8%	5.0%	4.2%	4.51%	23.9%	49.0%	50.0%	0.80	0.55	0.79	-0.1%	8.2%
14 Southwest Gas	8.0%	$42.49	2.9%	8.2%	5.6%	4.51%	26.8%	54.0%	50.0%	0.75	0.55	0.78	0.3%	8.3%
15 Wisconsin Energy	9.2%	$36.62	3.5%	10.3%	6.5%	4.51%	17.5%	46.5%	50.0%	0.65	0.46	0.63	-0.2%	9.0%
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Group Average	8.6%		4.2%	3.9%	4.1%	4.51%	21.2%	50.3%	50.0%	0.73	0.52	0.74	0.0%	8.6%
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Notes

1. Based on dividends over next 4 quarters.
2. Based on calendar year dividends.
3. Value Line reports Questar's beta as "NMF" (not meaningful). Questar's unlevered beta is average of remaining members of peer group.
4. Calculations of the unlevered beta, the relevered beta, and the ROE capital structure adjustment use Hamada's equation.

Displayed values have not been rounded.

Staff/2201
Storm/1

UG 221 Northwest Natural

Three-stage Discounted Dividend Model with Terminal Valuation based on P/E Ratio
Stage 3 Annual Growth Rate of 4.51 Percent

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Notes

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2. Based on calendar year values for dividends and Earnings per Share (EPS).
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UG 221 Northwest Natural

Three-stage Discounted Dividend Model with Terminal Valuation based on a Growing Perpetuity
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Staff/2201
Storm/3

UG 221 Northwest Natural

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2 Northwest Natural Gas	8.6%	$45.75	4.0%	2.1%	7.9%	4.0%	8.8%	4.83%	27.9%	55.0%	50.0%	0.60	0.45	0.63	0.3%	8.9%
3 Piedmont Natural Gas	8.4%	$30.54	4.0%	3.2%	4.2%	4.1%	4.6%	4.83%	22.8%	57.0%	50.0%	0.70	0.53	0.76	0.5%	8.9%
4 Questar	9.3%	$19.71	3.5%	5.5%	9.6%	8.4%	10.9%	4.83%	24.4%	52.5%	50.0%	NMF	0.47	0.64	0.1%	9.4%
5 WGL Holdings	8.4%	$39.99	4.0%	2.4%	2.9%	3.7%	3.3%	4.83%	23.0%	67.5%	50.0%	0.65	0.55	0.76	0.9%	9.3%
											50.0%					
Group Average	8.7%		3.9%	3.1%	5.7%	4.8%	6.4%	4.83%	23.9%	59.2%	50.0%	0.63	0.49	0.68	0.5%	9.1%
Group Median	8.6%		4.0%	2.4%	4.2%	4.0%	4.6%	4.83%	23.0%	57.0%	50.0%	0.63	0.47	0.64	0.5%	9.2%
Northwest Natural's Peer Utilities																
1 Alliant Energy	9.2%	$44.03	4.2%	5.1%	5.6%	4.9%	6.3%	4.83%	19.3%	50.5%	50.0%	0.75	0.53	0.75	0.0%	9.2%
2 Avista	9.6%	$25.91	4.6%	4.7%	5.7%	4.8%	6.4%	4.83%	17.0%	49.0%	50.0%	0.70	0.50	0.69	-0.1%	9.5%
3 Black Hills	8.9%	$33.04	4.5%	2.0%	5.4%	3.8%	6.0%	4.83%	20.7%	53.0%	50.0%	0.85	0.60	0.88	0.3%	9.2%
4 CMS Energy	9.4%	$22.87	4.3%	5.6%	4.4%	5.1%	4.9%	4.83%	16.5%	33.5%	50.0%	0.75	0.44	0.60	-1.2%	8.2%
5 Consolidated Edison	8.1%	$59.50	4.1%	0.8%	3.5%	3.2%	3.9%	4.83%	26.1%	53.5%	50.0%	0.60	0.46	0.62	0.2%	8.3%
6 DTE Energy	9.0%	$56.12	4.4%	3.4%	5.4%	4.1%	6.1%	4.83%	21.3%	51.0%	50.0%	0.75	0.54	0.76	0.1%	9.0%
7 Integrys	9.1%	$54.00	5.0%	0.8%	7.8%	3.3%	8.4%	4.83%	20.6%	60.5%	50.0%	0.90	0.70	1.01	0.9%	10.0%
8 NiSource	8.0%	$24.84	3.9%	0.4%	6.4%	2.4%	7.3%	4.83%	32.5%	48.0%	50.0%	0.85	0.59	0.83	-0.2%	7.9%
9 Northwest Natural Gas	8.6%	$45.75	4.0%	2.1%	7.9%	4.0%	8.8%	4.83%	27.9%	55.0%	50.0%	0.60	0.45	0.63	0.3%	8.9%
10 Piedmont Natural Gas	8.4%	$30.54	4.0%	3.2%	4.2%	4.1%	4.6%	4.83%	22.8%	57.0%	50.0%	0.70	0.53	0.76	0.5%	8.9%
11 Pepco Holdings	10.1%	$19.02	5.8%	1.7%	8.1%	3.4%	9.2%	4.83%	16.7%	51.0%	50.0%	0.75	0.55	0.76	0.1%	10.2%
12 SCANA	8.6%	$46.24	4.3%	2.2%	4.6%	3.6%	5.1%	4.83%	22.4%	46.0%	50.0%	0.70	0.48	0.67	-0.3%	8.3%
13 Sempra Energy	8.8%	$63.42	3.8%	5.0%	8.5%	4.4%	9.7%	4.83%	27.8%	49.0%	50.0%	0.80	0.55	0.79	-0.1%	8.8%
14 Southwest Gas	8.6%	$42.49	2.9%	8.2%	8.6%	5.8%	9.7%	4.83%	30.2%	54.0%	50.0%	0.75	0.55	0.78	0.3%	8.8%
15 Wisconsin Energy	9.4%	$36.62	3.5%	10.3%	5.0%	6.7%	5.6%	4.83%	17.3%	46.5%	50.0%	0.65	0.46	0.63	-0.2%	9.2%
16 Xcel Energy	9.4%	$27.20	4.0%	6.2%	6.5%	5.6%	7.3%	4.83%	19.5%	46.5%	50.0%	0.65	0.46	0.62	-0.2%	9.1%
Group Average	9.0%		4.2%	3.9%	6.1%	4.3%	6.8%	4.83%	22.4%	50.3%	50.0%	0.73	0.52	0.74	0.0%	9.0%
Group Median	8.9%		4.1%	3.3%	5.6%	4.1%	6.3%	4.83%	21.0%	50.8%	50.0%	0.75	0.53	0.76	0.1%	9.0%

Notes

1. Based on dividends over next 4 quarters.
2. Based on calendar year values for dividends and Earnings per Share (EPS).
3. Value Line reports Questar's beta as "NMF" (not meaningful). Questar's unlevered beta is average of remaining members of peer group.
4. Calculations of the unlevered beta, the relevered beta, and the ROE capital structure adjustment use Hamada's equation.

Displayed values have not been rounded.

Staff/2201
Storm/4

UG 221 Northwest Natural

Three-stage Discounted Dividend Model with Terminal Valuation based on a Growing Perpetuity
Stage 3 Annual Growth Rate of 5.14 Percent

	Unadjusted ROE (IRR) (A)	Average Recent Share Price (B)	Dividend Yield @ Average Recent Share Price[1] (C)	2013-17 Average Annual Dividend Growth Rate[2] (D)	2018-22 Average Annual Dividend Growth Rate[2] (E)	2023-52 Annual Dividend Growth Rate[2] (F)	Terminal Value as % of Total Valuation (G)	2012 Common Equity % of Capital Structure (H)	Test Year Common Equity % of Capital Structure (I)	Value Line Beta[3] (J)	Unlevered Beta[4] (Business Risk) (K)	Beta Relevered to Test Year Capital Structure[4] (L)	ROE Capital Structure Adjustment[4] (M)	ROE Adjusted for Divergent Capital Structures (O)
Staff's Peer Utilities														
1 Laclede Group	8.9%	$38.92	4.3%	2.2%	4.0%	5.14%	22.9%	64.0%	50.0%	0.55	0.45	0.62	0.6%	9.6%
2 Northwest Natural Gas	8.6%	$45.75	4.0%	2.1%	4.1%	5.14%	26.0%	55.0%	50.0%	0.60	0.45	0.63	0.3%	8.9%
3 Piedmont Natural Gas	8.8%	$30.54	4.0%	3.2%	4.2%	5.14%	24.6%	57.0%	50.0%	0.70	0.53	0.76	0.5%	9.3%
4 Questar	9.2%	$19.71	3.5%	5.5%	8.6%	5.14%	21.6%	52.5%	50.0%	NMF	0.47	0.64	0.1%	9.4%
5 WGL Holdings	8.8%	$39.99	4.0%	2.4%	3.9%	5.14%	24.9%	67.5%	50.0%	0.65	0.55	0.76	0.9%	9.7%
Group Average	8.9%		3.9%	3.1%	5.0%	5.14%	24.0%	59.2%	50.0%	0.63	0.49	0.68	0.5%	9.3%
Group Median	8.8%		4.0%	2.4%	4.1%	5.14%	24.6%	57.0%	50.0%	0.63	0.47	0.64	0.5%	9.4%
Northwest Natural's Peer Utilities														
1 Alliant Energy	9.4%	$44.03	4.2%	5.1%	5.1%	5.14%	19.6%	50.5%	50.0%	0.75	0.53	0.75	0.0%	9.5%
2 Avista	9.8%	$25.91	4.6%	4.7%	4.9%	5.14%	17.1%	49.0%	50.0%	0.70	0.50	0.69	-0.1%	9.7%
3 Black Hills	9.2%	$33.04	4.5%	2.0%	3.9%	5.14%	21.2%	53.0%	50.0%	0.85	0.60	0.88	0.3%	9.4%
4 CMS Energy	9.7%	$22.87	4.3%	5.6%	5.3%	5.14%	17.7%	33.5%	50.0%	0.75	0.44	0.60	-1.2%	8.5%
5 Consolidated Edison	8.4%	$59.50	4.1%	0.8%	3.4%	5.14%	27.6%	53.5%	50.0%	0.60	0.46	0.62	0.2%	8.6%
6 DTE Energy	9.2%	$56.12	4.4%	3.4%	4.2%	5.14%	21.5%	51.0%	50.0%	0.75	0.54	0.76	0.1%	9.3%
7 Integrys	9.3%	$54.00	5.0%	0.8%	3.5%	5.14%	20.1%	60.5%	50.0%	0.90	0.70	1.01	0.9%	10.1%
8 NiSource	8.1%	$24.84	3.9%	0.4%	2.5%	5.14%	31.4%	48.0%	50.0%	0.85	0.59	0.83	-0.2%	7.9%
9 Northwest Natural Gas	8.6%	$45.75	4.0%	2.1%	4.1%	5.14%	26.0%	55.0%	50.0%	0.60	0.45	0.63	0.3%	8.9%
10 Piedmont Natural Gas	8.8%	$30.54	4.0%	3.2%	4.2%	5.14%	24.6%	57.0%	50.0%	0.70	0.53	0.76	0.5%	9.3%
11 Pepco Holdings	10.1%	$19.02	5.8%	1.7%	3.5%	5.14%	14.8%	51.0%	50.0%	0.75	0.55	0.76	0.1%	10.2%
12 SCANA	8.9%	$46.24	4.3%	2.2%	3.8%	5.14%	23.4%	46.0%	50.0%	0.70	0.48	0.67	-0.3%	8.6%
13 Sempra Energy	8.8%	$63.42	3.8%	5.0%	4.5%	5.14%	25.1%	49.0%	50.0%	0.80	0.55	0.79	-0.1%	8.7%
14 Southwest Gas	8.5%	$42.49	2.9%	8.2%	6.0%	5.14%	28.0%	54.0%	50.0%	0.75	0.55	0.78	0.3%	8.8%
15 Wisconsin Energy	9.7%	$36.62	3.5%	10.3%	6.9%	5.14%	18.5%	46.5%	50.0%	0.65	0.46	0.63	-0.2%	9.5%
16 Xcel Energy	9.5%	$27.20	4.0%	6.2%	5.7%	5.14%	19.5%	46.5%	50.0%	0.65	0.46	0.62	-0.2%	9.3%
Group Average	9.1%		4.2%	3.9%	4.5%	5.14%	22.2%	50.3%	50.0%	0.73	0.52	0.74	0.0%	9.1%
Group Median	9.2%		4.1%	3.3%	4.2%	5.14%	21.3%	50.8%	50.0%	0.75	0.53	0.76	0.1%	9.3%

Notes

1. Based on dividends over next 4 quarters.
2. Based on calendar year dividends.
3. Value Line reports Questar's beta as "NMF" (not meaningful). Questar's unlevered beta is average of remaining members of peer group.
4. Calculations of the unlevered beta, the relevered beta, and the ROE capital structure adjustment use Hamada's equation.

Displayed values have not been rounded.

Staff/2201
Storm/5

UG 221 Northwest Natural

Three-stage Discounted Dividend Model with Terminal Valuation based on P/E Ratio
Stage 3 Annual Growth Rate of 5.14 Percent

	Unadjusted ROE (IRR) (A)	Average Recent Share Price (B)	Dividend Yield @ Average Recent Share Price[1] (C)	2013-17 Average Annual Dividend Growth Rate[2] (D)	2013-17 Average Annual EPS Growth Rate[2] (E)	2018-22 Average Annual Dividend Growth Rate[2] (F)	2018-22 Average Annual EPS Growth Rate[2] (G)	2023-52 Annual Dividend & EPS Growth Rates (H)	Terminal Value as % of Total Valuation (I)	2012 Common Equity % of Capital Structure (J)	Test Year Common Equity % of Capital Structure (K)	Value Line Beta[3] (L)	Unlevered Beta[4] (Business Risk) (M)	Beta Relevered to Test Year Capital Structure[4] (N)	ROE Capital Structure Adjustment[4] (O)	ROE Adjusted for Divergent Capital Structures (P)
Staff's Peer Utilities																
1 Laclede Group	8.9%	$38.92	4.3%	2.2%	4.0%	4.0%	4.5%	5.14%	22.0%	64.0%	50.0%	0.55	0.45	0.62	0.6%	9.5%
2 Northwest Natural Gas	8.8%	$45.75	4.0%	2.1%	7.9%	4.1%	8.9%	5.14%	28.3%	55.0%	50.0%	0.60	0.45	0.63	0.3%	9.1%
3 Piedmont Natural Gas	8.7%	$30.54	4.0%	3.2%	4.2%	4.2%	4.6%	5.14%	23.2%	57.0%	50.0%	0.70	0.53	0.76	0.5%	9.1%
4 Questar	9.5%	$19.71	3.5%	5.5%	9.6%	8.6%	10.9%	5.14%	24.8%	52.5%	50.0%	NMF	0.47	0.64	0.1%	9.7%
5 WGL Holdings	8.6%	$39.99	4.0%	2.4%	2.9%	3.9%	3.3%	5.14%	23.3%	67.5%	50.0%	0.65	0.55	0.76	0.9%	9.5%
											50.0%					
Group Average	8.9%		3.9%	3.1%	5.7%	5.0%	6.4%	5.14%	24.3%	59.2%	50.0%	0.63	0.49	0.68	0.5%	9.4%
Group Median	8.8%		4.0%	2.4%	4.2%	4.1%	4.6%	5.14%	23.3%	57.0%	50.0%	0.63	0.47	0.64	0.5%	9.5%
Northwest Natural's Peer Utilities																
1 Alliant Energy	9.4%	$44.03	4.2%	5.1%	5.6%	5.1%	6.3%	5.14%	19.6%	50.5%	50.0%	0.75	0.53	0.75	0.0%	9.5%
2 Avista	9.8%	$25.91	4.6%	4.7%	5.7%	4.9%	6.4%	5.14%	17.3%	49.0%	50.0%	0.70	0.50	0.69	-0.1%	9.8%
3 Black Hills	9.1%	$33.04	4.5%	2.0%	5.4%	3.9%	6.0%	5.14%	21.1%	53.0%	50.0%	0.85	0.60	0.88	0.3%	9.4%
4 CMS Energy	9.7%	$22.87	4.3%	5.6%	4.4%	5.3%	4.9%	5.14%	16.8%	33.5%	50.0%	0.75	0.44	0.60	-1.2%	8.4%
5 Consolidated Edison	8.3%	$59.50	4.1%	0.8%	3.5%	3.4%	3.9%	5.14%	26.4%	53.5%	50.0%	0.60	0.46	0.62	0.2%	8.5%
6 DTE Energy	9.2%	$56.12	4.4%	3.4%	5.4%	4.2%	6.1%	5.14%	21.6%	51.0%	50.0%	0.75	0.54	0.76	0.1%	9.3%
7 Integrys	9.3%	$54.00	5.0%	0.8%	7.8%	3.5%	8.4%	5.14%	20.9%	60.5%	50.0%	0.90	0.70	1.01	0.9%	10.2%
8 NiSource	8.3%	$24.84	3.9%	0.4%	6.4%	2.5%	7.3%	5.14%	32.9%	48.0%	50.0%	0.85	0.59	0.83	-0.2%	8.1%
9 Northwest Natural Gas	8.8%	$45.75	4.0%	2.1%	7.9%	4.1%	8.9%	5.14%	28.3%	55.0%	50.0%	0.60	0.45	0.63	0.3%	9.1%
10 Piedmont Natural Gas	8.7%	$30.54	4.0%	3.2%	4.2%	4.2%	4.6%	5.14%	23.2%	57.0%	50.0%	0.70	0.53	0.76	0.5%	9.1%
11 Pepco Holdings	10.3%	$19.02	5.8%	1.7%	8.1%	3.5%	9.2%	5.14%	17.1%	51.0%	50.0%	0.75	0.55	0.76	0.1%	10.4%
12 SCANA	8.8%	$46.24	4.3%	2.2%	4.6%	3.8%	5.1%	5.14%	22.7%	46.0%	50.0%	0.70	0.48	0.67	-0.3%	8.6%
13 Sempra Energy	9.1%	$63.42	3.8%	5.0%	8.5%	4.5%	9.7%	5.14%	28.2%	49.0%	50.0%	0.80	0.55	0.79	-0.1%	9.0%
14 Southwest Gas	8.8%	$42.49	2.9%	8.2%	8.6%	6.0%	9.8%	5.14%	30.6%	54.0%	50.0%	0.75	0.55	0.78	0.3%	9.1%
15 Wisconsin Energy	9.6%	$36.62	3.5%	10.3%	5.0%	6.9%	5.6%	5.14%	17.6%	46.5%	50.0%	0.65	0.46	0.63	-0.2%	9.4%
16 Xcel Energy	9.6%	$27.20	4.0%	6.2%	6.5%	5.7%	7.3%	5.14%	19.9%	46.5%	50.0%	0.65	0.46	0.62	-0.2%	9.4%
Group Average	9.2%		4.2%	3.9%	6.1%	4.5%	6.8%	5.14%	22.8%	50.3%	50.0%	0.73	0.52	0.74	0.0%	9.2%
Group Median	9.2%		4.1%	3.3%	5.6%	4.2%	6.3%	5.14%	21.3%	50.8%	50.0%	0.75	0.53	0.76	0.1%	9.2%

Notes

1. Based on dividends over next 4 quarters.
2. Based on calendar year values for dividends and Earnings per Share (EPS).
3. Value Line reports Questar's beta as "NMF" (not meaningful). Questar's unlevered beta is average of remaining members of peer group.
4. Calculations of the unlevered beta, the relevered beta, and the ROE capital structure adjustment use Hamada's equation.

Displayed values have not been rounded.

UG 221 Northwest Natural

Three-stage Discounted Dividend Model with Terminal Valuation based on a Growing Perpetuity
Stage 3 Annual Growth Rate is Dr. Hadaway's 5.7 Percent

	Unadjusted ROE (IRR) (A)	Average Recent Share Price (B)	Dividend Yield @ Average Recent Share Price[1] (C)	2013-17 Average Annual Dividend Growth Rate[2] (D)	2018-22 Average Annual Dividend Growth Rate[2] (E)	2023-52 Annual Dividend Growth Rate[2] (F)	Terminal Value as % of Total Valuation (G)	2012 Common Equity % of Capital Structure (H)	Test Year Common Equity % of Capital Structure (I)	Value Line Beta[3] (J)	Unlevered Beta[4] (Business Risk) (K)	Beta Relevered to Test Year Capital Structure[4] (L)	ROE Capital Structure Adjustment[4] (M)	ROE Adjusted for Divergent Capital Structures (O)
Staff's Peer Utilities														
1 Laclede Group	9.4%	$38.92	4.3%	2.2%	4.3%	5.70%	23.9%	64.0%	50.0%	0.55	0.45	0.62	0.6%	10.0%
2 Northwest Natural Gas	9.0%	$45.75	4.0%	2.1%	4.3%	5.70%	27.1%	55.0%	50.0%	0.60	0.45	0.63	0.3%	9.3%
3 Piedmont Natural Gas	9.3%	$30.54	4.0%	3.2%	4.5%	5.70%	25.6%	57.0%	50.0%	0.70	0.53	0.76	0.5%	9.7%
4 Questar	9.7%	$19.71	3.5%	5.5%	8.9%	5.70%	22.7%	52.5%	50.0%	NMF	0.47	0.64	0.1%	9.8%
5 WGL Holdings	9.2%	$39.99	4.0%	2.4%	4.2%	5.70%	25.9%	67.5%	50.0%	0.65	0.55	0.76	0.9%	10.1%
Group Average	9.3%		3.9%	3.1%	5.3%	5.70%	25.0%	59.2%	50.0%	0.63	0.49	0.68	0.5%	9.8%
Group Median	9.3%		4.0%	2.4%	4.3%	5.70%	25.6%	57.0%	50.0%	0.63	0.47	0.64	0.5%	9.8%
Northwest Natural's Peer Utilities														
1 Alliant Energy	9.9%	$44.03	4.2%	5.1%	5.4%	5.70%	20.5%	50.5%	50.0%	0.75	0.53	0.75	0.0%	9.9%
2 Avista	10.2%	$25.91	4.6%	4.7%	5.3%	5.70%	18.0%	49.0%	50.0%	0.70	0.50	0.69	-0.1%	10.2%
3 Black Hills	9.6%	$33.04	4.5%	2.0%	4.3%	5.70%	22.1%	53.0%	50.0%	0.85	0.60	0.88	0.3%	9.9%
4 CMS Energy	10.2%	$22.87	4.3%	5.6%	5.6%	5.70%	18.5%	33.5%	50.0%	0.75	0.44	0.60	-1.2%	8.9%
5 Consolidated Edison	8.9%	$59.50	4.1%	0.8%	3.7%	5.70%	28.6%	53.5%	50.0%	0.60	0.46	0.62	0.2%	9.1%
6 DTE Energy	9.6%	$56.12	4.4%	3.4%	4.5%	5.70%	22.5%	51.0%	50.0%	0.75	0.54	0.76	0.1%	9.7%
7 Integrys	9.7%	$54.00	5.0%	0.8%	3.8%	5.70%	21.0%	60.5%	50.0%	0.90	0.70	1.01	0.9%	10.6%
8 NiSource	8.6%	$24.84	3.9%	0.4%	2.8%	5.70%	32.6%	48.0%	50.0%	0.85	0.59	0.83	-0.2%	8.4%
9 Northwest Natural Gas	9.0%	$45.75	4.0%	2.1%	4.3%	5.70%	27.1%	55.0%	50.0%	0.60	0.45	0.63	0.3%	9.3%
10 Piedmont Natural Gas	9.3%	$30.54	4.0%	3.2%	4.5%	5.70%	25.6%	57.0%	50.0%	0.70	0.53	0.76	0.5%	9.7%
11 Pepco Holdings	10.5%	$19.02	5.8%	1.7%	3.9%	5.70%	15.6%	51.0%	50.0%	0.75	0.55	0.76	0.1%	10.6%
12 SCANA	9.4%	$46.24	4.3%	2.2%	4.1%	5.70%	24.4%	46.0%	50.0%	0.70	0.48	0.67	-0.3%	9.1%
13 Sempra Energy	9.2%	$63.42	3.8%	5.0%	4.8%	5.70%	26.1%	49.0%	50.0%	0.80	0.55	0.79	-0.1%	9.1%
14 Southwest Gas	9.0%	$42.49	2.9%	8.2%	6.3%	5.70%	29.1%	54.0%	50.0%	0.75	0.55	0.78	0.3%	9.3%
15 Wisconsin Energy	10.1%	$36.62	3.5%	10.3%	7.2%	5.70%	19.3%	46.5%	50.0%	0.65	0.46	0.63	-0.2%	9.9%
16 Xcel Energy	10.0%	$27.20	4.0%	6.2%	6.0%	5.70%	20.5%	46.5%	50.0%	0.65	0.46	0.62	-0.2%	9.8%
Group Average	9.6%		4.2%	3.9%	4.8%	5.70%	23.2%	50.3%	50.0%	0.73	0.52	0.74	0.0%	9.6%
Group Median	9.6%		4.1%	3.3%	4.5%	5.70%	22.3%	50.8%	50.0%	0.75	0.53	0.76	0.1%	9.7%

Notes

1. Based on dividends over next 4 quarters.
2. Based on calendar year dividends.
3. Value Line reports Questar's beta as "NMF" (not meaningful). Questar's unlevered beta is average of remaining members of peer group.
4. Calculations of the unlevered beta, the relevered beta, and the ROE capital structure adjustment use Hamada's equation.

Displayed values have not been rounded.

Staff/2201
Storm/7

UG 221 Northwest Natural

Three-stage Discounted Dividend Model with Terminal Valuation based on P/E Ratio
Stage 3 Annual Growth Rate is Dr. Hadaway's 5.7 Percent

	Unadjusted ROE (IRR) (A)	Average Recent Share Price (B)	Dividend Yield @ Average Recent Share Price[1] (C)	2013-17 Average Annual Dividend Growth Rate[2] (D)	2013-17 Average Annual EPS Growth Rate[2] (E)	2018-22 Average Annual Dividend Growth Rate[2] (F)	2018-22 Average Annual EPS Growth Rate[2] (G)	2023-52 Annual Dividend & EPS Growth Rates (H)	Terminal Value as % of Total Valuation (I)	2012 Common Equity % of Capital Structure (J)	Test Year Common Equity % of Capital Structure (K)	Value Line Beta[3] (L)	Unlevered Beta[4] (Business Risk) (M)	Beta Relevered to Test Year Capital Structure[4] (N)	ROE Capital Structure Adjustment[4] (O)	ROE Adjusted for Divergent Capital Structures (P)
Staff's Peer Utilities																
1 Laclede Group	9.3%	$38.92	4.3%	2.2%	4.0%	4.3%	4.5%	5.70%	22.6%	64.0%	50.0%	0.55	0.45	0.62	0.6%	9.9%
2 Northwest Natural Gas	9.2%	$45.75	4.0%	2.1%	7.9%	4.3%	8.9%	5.70%	29.0%	55.0%	50.0%	0.60	0.45	0.63	0.3%	9.5%
3 Piedmont Natural Gas	9.1%	$30.54	4.0%	3.2%	4.2%	4.5%	4.6%	5.70%	23.8%	57.0%	50.0%	0.70	0.53	0.76	0.5%	9.5%
4 Questar	9.9%	$19.71	3.5%	5.5%	9.6%	8.9%	10.9%	5.70%	25.5%	52.5%	50.0%	NMF	0.47	0.64	0.1%	10.1%
5 WGL Holdings	9.0%	$39.99	4.0%	2.4%	2.9%	4.2%	3.4%	5.70%	23.9%	67.5%	50.0%	0.65	0.55	0.76	0.9%	9.9%
											50.0%					
Group Average	9.3%		3.9%	3.1%	5.7%	5.3%	6.4%	5.70%	25.0%	59.2%	50.0%	0.63	0.49	0.68	0.5%	9.8%
Group Median	9.2%		4.0%	2.4%	4.2%	4.3%	4.6%	5.70%	23.9%	57.0%	50.0%	0.63	0.47	0.64	0.5%	9.9%
Northwest Natural's Peer Utilities																
1 Alliant Energy	9.8%	$44.03	4.2%	5.1%	5.6%	5.4%	6.3%	5.70%	20.2%	50.5%	50.0%	0.75	0.53	0.75	0.0%	9.9%
2 Avista	10.2%	$25.91	4.6%	4.7%	5.7%	5.3%	6.4%	5.70%	17.9%	49.0%	50.0%	0.70	0.50	0.69	-0.1%	10.2%
3 Black Hills	9.6%	$33.04	4.5%	2.0%	5.4%	4.3%	6.0%	5.70%	21.7%	53.0%	50.0%	0.85	0.60	0.88	0.3%	9.8%
4 CMS Energy	10.1%	$22.87	4.3%	5.6%	4.4%	5.6%	4.9%	5.70%	17.3%	33.5%	50.0%	0.75	0.44	0.60	-1.2%	8.8%
5 Consolidated Edison	8.7%	$59.50	4.1%	0.8%	3.5%	3.7%	3.9%	5.70%	27.1%	53.5%	50.0%	0.60	0.46	0.62	0.2%	8.9%
6 DTE Energy	9.6%	$56.12	4.4%	3.4%	5.4%	4.5%	6.1%	5.70%	22.3%	51.0%	50.0%	0.75	0.54	0.76	0.1%	9.7%
7 Integrys	9.7%	$54.00	5.0%	0.8%	7.8%	3.8%	8.4%	5.70%	21.5%	60.5%	50.0%	0.90	0.70	1.01	0.9%	10.6%
8 NiSource	8.7%	$24.84	3.9%	0.4%	6.4%	2.8%	7.3%	5.70%	33.6%	48.0%	50.0%	0.85	0.59	0.83	-0.2%	8.5%
9 Northwest Natural Gas	9.2%	$45.75	4.0%	2.1%	7.9%	4.3%	8.9%	5.70%	29.0%	55.0%	50.0%	0.60	0.45	0.63	0.3%	9.5%
10 Piedmont Natural Gas	9.1%	$30.54	4.0%	3.2%	4.2%	4.5%	4.6%	5.70%	23.8%	57.0%	50.0%	0.70	0.53	0.76	0.5%	9.5%
11 Pepco Holdings	10.7%	$19.02	5.8%	1.7%	8.1%	3.9%	9.2%	5.70%	17.6%	51.0%	50.0%	0.75	0.55	0.76	0.1%	10.8%
12 SCANA	9.3%	$46.24	4.3%	2.2%	4.6%	4.1%	5.2%	5.70%	23.3%	46.0%	50.0%	0.70	0.48	0.67	-0.3%	9.0%
13 Sempra Energy	9.5%	$63.42	3.8%	5.0%	8.5%	4.8%	9.7%	5.70%	28.9%	49.0%	50.0%	0.80	0.55	0.79	-0.1%	9.4%
14 Southwest Gas	9.2%	$42.49	2.9%	8.2%	8.6%	6.3%	9.8%	5.70%	31.2%	54.0%	50.0%	0.75	0.55	0.78	0.3%	9.5%
15 Wisconsin Energy	10.0%	$36.62	3.5%	10.3%	5.0%	7.2%	5.6%	5.70%	18.2%	46.5%	50.0%	0.65	0.46	0.63	-0.2%	9.8%
16 Xcel Energy	10.0%	$27.20	4.0%	6.2%	6.5%	6.0%	7.3%	5.70%	20.5%	46.5%	50.0%	0.65	0.46	0.62	-0.2%	9.8%
Group Average	9.6%		4.2%	3.9%	6.1%	4.8%	6.9%	5.70%	23.4%	50.3%	50.0%	0.73	0.52	0.74	0.0%	9.6%
Group Median	9.6%		4.1%	3.3%	5.6%	4.5%	6.3%	5.70%	22.0%	50.8%	50.0%	0.75	0.53	0.76	0.1%	9.6%

Notes

1. Based on dividends over next 4 quarters.
2. Based on calendar year values for dividends and Earnings per Share (EPS).
3. Value Line reports Questar's beta as "NMF" (not meaningful). Questar's unlevered beta is average of remaining members of peer group.
4. Calculations of the unlevered beta, the relevered beta, and the ROE capital structure adjustment use Hamada's equation.

Displayed values have not been rounded.

CASE: UG 221
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2202

Exhibits in Support Of Rebuttal Testimony

July 20, 2012

Request:

40. Reference Staff/1300, pg. 23: Please explain the basis for the assumption that new residential customers use less than existing residential customers (lines 1-8).

Response:

40. Staff's testimony at the location cited does not make the assumption stated in the request above.

The passage cited lists two changes over time which, if true, are believed by Staff to explain NW Natural's declining use per average residential customer. The first of the two changes, "lower average use per customer for all Residential customers" IS true (see Table 2 at Exhibit NWN/1200 Siores/7). The cited passage includes that lower use per customer for new Residential customers, as compared with existing, "...seems unlikely to, by itself, account for the large decline [in usage per Residential customer] between these two periods." In other words, even if the second listed change is true, it alone would not explain the extent of the observed phenomenon.

I note that page 39 of Exhibit NWN/201 in Docket No. UG 163 states that "[t]he residential results indicate that new connections tend to have lower consumption rates than [do] existing customers. These results should be interpreted with some caution, as factors such as changes in building materials, building codes, and appliance efficiency levels could contribute to the observed differences between existing and new connections customers."

I also note that page 2.12 of the modified IRP filed in Docket No. LC 51 on September 1, 2011, in the context of discussing declining use per customer, includes that (with emphasis added):

> "A number of factors are at work in the demand forecast which drives this decline. <u>New conversion customer additions tend to have lower use profiles than existing customers</u>. In addition, NW Natural expects significant energy savings to come from programs administered to both new construction and existing customers by the Energy Trust of Oregon. Public purpose funds are collected from Oregon ratepayers to fund these programs. Also, as the existing housing stock ages, water heaters, furnaces and windows are replaced with newer, more efficient versions, furthering the decline in use. Finally, customers may respond to natural gas price increases by actively making improvements to the housing shell, or even changing behavior, such

as turning down the thermostat. The price factor *rp* in the load model (Eq. 2.3) conveys the demand response to price changes."

CASE: UG 221
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2300

Rebuttal Testimony

July 20, 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. ARE YOU THE SAME MATT MULDOON WHO FILED OPENING TESTIMONY IN THIS PROCEEDING ON BEHALF OF COMMISSION STAFF?

A. Yes, as Exhibits Staff/1200-1204.

Q. WHAT IS THE PURPOSE OF YOUR REPLY TESTIMONY?

A. My testimony responds to Northwest Natural Gas Company's (NWN or Company) reply testimony of Stephen P. Feltz. His testimony is found in Exhibits 2000-2008 as pertains to the Cost of Long-Term Debt (Cost of LT Debt).

Q. DID YOU PREPARE AN EXHIBIT FOR THIS TESTIMONY?

A. Yes. I have prepared Exhibit Staff /1301 consisting of one page.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as shown below:

SUMMARY

Q. HAVE YOU PREPARED A SUMMARY TABLE THAT SUMMARIZES STAFF'S RECOMMENDED COST OF LT DEBT?[1]

A. Yes. Table 1 below summarizes the Company-proposed and Staff's recommended cost of LT Debt for NWN:

Table 1

Cost of LT Debt			
Company Initial Proposal	**June 21, 2012 Company Proposal**	**Staff Recommendation**	**Adjustment to Filing Value**
6.265 %	**6.070 %**	**6.022 %***	**(0.243%)**
*Subject to update of 2012 bond issuances with actual coupon rates and costs. Staff requests that the record be kept open for this limited purpose.			

Q. HOW MANY ISSUES DO YOU ADDRESS REGARDING THE COMPANY'S CALCULATION OF ITS COST OF LT DEBT?

A. My rebuttal testimony addresses three issues:

Q. WHAT IS THE FIRST ISSUE YOU ADDRESS?

A. Staff agrees with NWN that it is reasonable to not re-price the portion of LT-Debt that matures within one year of the end of the test year.[2]

[1] Pursuant to Docket No. 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."

[2] Testimony found in NWN/2000 Feltz/3 starting at line 14 articulates the Company's concerns.

Q. IS THIS TREATMENT OF LT DEBT MATURING IN 2014 CONSISTENT WITH COMMISSION ORDER NO. 01-787 AT 14?

A. Yes. Staff does not contest the Company's pricing of LT debt maturing in 2014.

Q. HAS STAFF PREPARED A SPREADSHEET DEPICTING OUTSTANDING AND ANTICIPATED BOND ISSUES?

A. Yes; please see Exhibit Staff/2301 Muldoon/1.

Q. ARE THERE REMAINING DIFFERENCES BETWEEN THE COMPANY AND STAFF REGARDING THIS ISSUE?

A. No.

Q. WHAT IS THE SECOND ISSUE YOU ADDRESS?

A. Staff agrees with NWN that utilizing the Company's revised, pro forma coupon rates and issuance costs and replacing these with actual values to the extent possible given rate case schedule constraints, is reasonable. Doing so will likely capture historic low issuance costs for the Company's planned 30-year bonds. The Company is also likely to achieve a historic low 10-year coupon rate, but may incur some additional cost for delayed execution through private placement. Please note that the Company only expresses certainty that actual values for the imminent 30-year issuance will be able to be timely incorporated into this rate case.

Q. AS YOU NOTE ABOVE, THE COMPANY PROPOSES TO USE PLACEHOLDER VALUES FOR ITS PROPOSED 2012 $50 MILLION ISSUANCE OF 30-YEAR FIRST MORTGAGE BONDS, AND UPDATE

RATES AND COSTS, INCLUDING THE COMPOSITE COST OF LT DEBT, WITH ACTUAL VALUES AS THESE ARE AVAILABLE.[3] IS THIS A REASONABLE APPROACH?

A. Yes; I utilize this approach in Exhibit Staff/2301 Muldoon/1.

Q. IS THIS SAME APPROACH REASONABLE FOR NW NATURAL'S PLANNED $25 MILLION ISSUANCE OF 10-YEAR LT DEBT IN FALL 2012?

A. Yes. Staff recommends the Commission substitute and consider the actual coupon rate for the Company's planned 10-year bond issuance if an investment bank pricing summary has been presented to the Company prior to when the Commission makes its decision. However, if actual values are not available, Staff recommends the Commission rely on the estimated coupon rate shown on line 25 of NWN/2001 Feltz/1. Staff requests that the record be kept open for this limited purpose.

Q. WHAT IS THE THIRD ISSUE YOU ADDRESS?

A. Staff recommends the Commission disallow $2,248,000 of a financial hedge loss. The Company has not presented evidence that this loss was prudently addressed on an *ex ante* basis by Company planning, analysis or contract provisions. It is unreasonable for ratepayers to absorb the entirety of a large loss associated with a high impact risk that the Company could have analyzed and mitigated at the time of hedge execution.

Q. WHAT IS THE BASIS OF THE $2,248,000 VALUE?

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[3] As Mr. Feltz states in NWN/2000 Feltz/2 on lines 19 and 20, "it will be straightforward to both confirm the final costs and include them in the final revenue requirement determination."

A. NWN identifies in its analysis presented in this case that $4,496,000 million is associated with the distribution of potential losses of the hedge that had less than 2.5 percent chance of occurring. The $2,248,000 amount is half this $4,496,000 reflecting equal sharing between ratepayers and the Company for this portion of the hedge loss.

Q. HOW DOES STAFF'S RECOMMENDED TREATMENT COMPARE WITH TREATMENT OF POWER COSTS?

A. For power costs the Company bears operational risk within a dead band of likeliest outcomes, while the Company and ratepayers share less frequent distribution tail outcomes. For financial hedging, a similar conceptual framework could be used provided that the Company prudently analyzes and constrains adverse tail distribution outcomes. Staff recommends that the Commission consider an equal sharing by the Company and ratepayers of costs associated with less frequent adverse distribution tail financial hedge outcomes that have less than 2.5 percent chance of occurring. I would note that in this financial hedging issue, Staff is not recommending the Company bear the costs of the "dead band," that is the $5,504,000 loss, but rather focus on the "tails" of the distribution as NWN has constructed its analysis.

Q. HOW DOES A LOSS ON A FINANCIAL HEDGE IMPACT COST OF LT DEBT IN THIS CASE?

A. The Company has assigned the loss to the issuance costs of a subsequent bond series shown on line 9 of the spreadsheet in Staff/2301 Muldoon/1. The

Commission's decision on how much of this hedge loss was prudently incurred may change the calculation of appropriate cost of LT Debt.

Q. MR. FELTZ'S REPLY TESTIMONY IN EXHIBIT NWN/200 CREATES AN IMPRESSION THAT: 1) THE COMPANY MET THE STANDARD OF CARE EXPECTED IN EXECUTING FINANCIAL INTEREST RATE HEDGES AS AUTHORIZED BY COMMISSION ORDER NO. 07-032; 2) ADDITIONAL OR DIFFERENT ANALYSIS AND PLANNING BY THE COMPANY OR BY THE COMPANY'S DIRECTLY RETAINED EXTERNAL EXPERTS COULD NOT HAVE IMPACTED WHAT THE COMPANY KNEW OR COULD HAVE KNOWN AT THE TIME OF HEDGE EXECUTION, WHICH WAS OCTOBER, 2007 (2007); AND, 3) THE HEDGE LOSS WAS DUE TO HISTORICALLY ABERRANT MARKET CONDITIONS AND WAS THEREFORE UNAVOIDABLE ONCE THE HEDGE WAS ENTERED INTO. GIVEN WHAT THE COMPANY KNEW AT THE TIME. BY THIS REASONING THE HEDGE LOSS SHOULD BE BORN ENTIRELY BY RATEPAYERS. DO YOU AGREE WITH THESE POINTS?[4]

A. No.

Q. DOES THE COMPANY ENGAGE IN FINANCIAL HEDGE ACTIVITY WITH ANY FREQUENCY?

[4] Staff specifically disagrees with the Company's assertion that it "would have to been able to predict the financial crisis…" as stated in Exhibit NWN/2000 Feltz/9. In fact, the Company only had to identify what correlations it assumed would hold true and limit its maximum loss to reflect those parameters.

A. No. This was the first financial interest rate hedge that the Company entered into. Unlike the investment banks that offer such hedges, the Company does not have a portfolio of offsetting financial hedging transactions.

Q. HOW IS THE REASONABLENESS OF THE COMPANY'S ACTIONS BASED ON WHAT IT KNEW OR COULD HAVE KNOWN AT THE TIME RELEVANT?

A. Historically, the Commission has tended to consider prudence based in light of existing circumstances, what the regulated utility knew or could have known at time(s) of decision and whether reasonable care could have prevented an adverse outcome.[5]

Q. IS IT THE COMPANY'S RESPONSIBILITY TO CONSIDER THE COST OF VOLATILITY MANAGED RELATIVE TO COSTS AND RISKS INCURRED BY ENTERING INTO AN INTEREST RATE SWAP CONTRACT, INCLUDING SUCH ADDITIONAL COSTS TO MODIFY STANDARD CONTRACTUAL LANGUAGE IN ORDER TO MEET THE COMPANY'S SPECIFIC NEEDS.

A. Yes.

Q. CAN YOU EXPLAIN THIS REASONING?

A. Yes. Presumably the Company would not want to incur more risk or spend more on hedging than is commensurate with management of the range of underlying volatility described by Mr. Feltz in NWN/2000 Feltz 7. Similarly, it would be unreasonable to assume that high-impact low-frequency (HILF)

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5 Examples of this include Order No. 99-033 at 36-37, Order No. 02-459 at 5, and Order No. 11-435 at 4.

outcomes that could financially damage the Company or harm ratepayers associated with incremental hedging risk need not be constrained.

Q. NW NATURAL HAS ASKED FOR AN EXAMPLE OF A FINANCIAL HEDGING AND ARBITRAGE SITUATION IN WHICH A UTILITY LIKE NW NATURAL LOOKS EXTERNALLY FOR REINFORCEMENT OF ITS ANALYTICAL RESOURCES. CAN YOU PROVIDE SUCH AN EXAMPLE?

A. Yes. Keith White, the Company's Vice President of Business Development and Energy Supply, and the Chief Strategic Officer, indicates several material points within his testimony provided in Exhibit NWN/2700 which can provide such an example.

Q. WHAT IS THE FIRST OF THESE MATERIAL POINTS?

A. When confronted with complex gas storage optimization activities requiring more expertise and resources than normal utility gas purchasing practices, the Company acquired these skill sets through collaboration with external third parties. This afforded NW Natural its own access to a sophisticated trading floor operation and other expertise, which were unavailable in-house.[6]

Q. WHAT IS THE SECOND MATERIAL POINT?

A. In conjunction with third party Altos Management Partners, Inc. (Altos), the Company went beyond analysis centered on a 95 percent confidence interval to perform scenario analysis regarding gas storage optimization and arbitrage, examining how assets would perform under a wide range of possible

[6] This Testimony is provided in NWN/2700 White/5 on lines 19 through 24 with supporting decision tree analysis in NWN/2701 White/14 and a discussion of uncertainty analysis is in NWN/2701 White/21.

scenarios. Altos used decision trees and other tools to examine outcomes and “develop recommended actions for optimizing Company performance.

Q. ARE YOU SAYING THAT, DEPENDING ON THE FREQUENCY WITH WHICH THE COMPANY ANALYZES COMPLEX FINANCIAL OPPORTUNITIES, THE SIZE OF THE RISK OR OPPORTUNITY AND THE SKILL SETS AVAILABLE IN-HOUSE, UTILITIES LIKE NW NATURAL SHOULD CONTRACT FOR SUPPLEMENTAL EXTERNAL CAPABILITIES?

A. Yes.

Q. DOES THE USE OF SCENARIOS AND DECISION TREES IN THE EXAMPLE ABOVE SUGGEST THAT THERE IS MORE THAN ONE WAY TO CONSIDER AND ANALYZE RISK?

A. Yes. In addition to analysis of the probability of most likely events, there is analysis of high-impact, low-frequency (HILF) events?

Q. SO, IF THE OUTCOME OF AN ACTIVITY COULD BANKRUPT THE COMPANY, BUT A PRIORI EVIDENCE IS THAT THIS OUTCOME HAPPENED ONCE IN EVERY HUNDRED TIMES THE COMPANY ENTERED INTO THAT ACTIVITY (ONE PERCENT PROBABILITY), EXAMINING WHAT PROTECTIONS ARE IN PLACE TO MITIGATE THE RESULTS OF THAT OUTCOME WOULD BE PRUDENT?

A. Yes, such examination would be consistent with advice the Company received regarding prospective financial hedging activity, in multiple forms, from multiple investment banks. The banks clarified that investment banks are sophisticated parties regularly engaged in financial swaps and hedging activities, that the bank are acting only on the bank's behalf, and that if the counterparty to a hedge does not have sufficient financial, legal, and other resources in-house, it would be prudent for the counterparty to procure such resources from independent third parties.

Q. THAT SEEMS FAIRLY STRAIGHTFORWARD. CAN YOU CREATE A VISUAL REPRESENTATION OF THIS THINKING?

A. Yes, I have created Figure 1 for this discussion. The horizontal axis considers the likelihood of an occurrence, while the vertical axis represents the occurrence's importance or impact. Where the Company now emphasizes the upper right quadrant of possible outcomes depicted below, NW Natural appears to indicate that, prior to entering into the hedge; it did not consider either its own probabilistic assessment or HILF events beyond truncation by a 95 percent confidence interval.

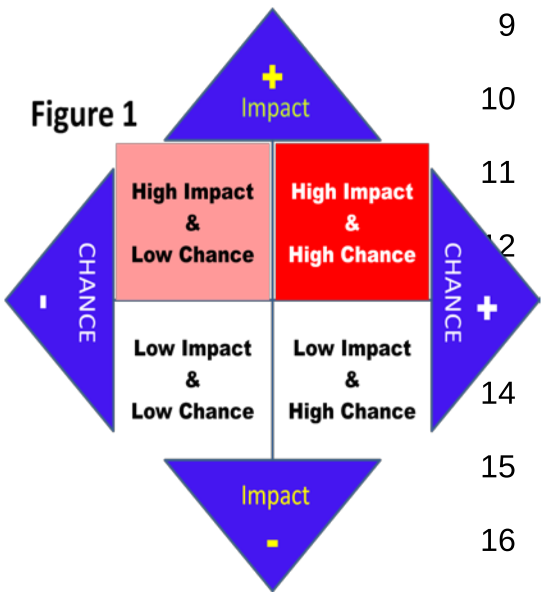

Figure 1

Q. SO USING FIGURE 1 AS A GUIDE, A MONTE CARLO, "BOOTSTRAP," OR OTHER PROBABILISTIC APPROACHS OR STOCHASTIC SIMULATION METHODS ADDRESS THE UPPER RIGHT QUADRANT, BUT POORLY ADDRESS THE UPPER LEFT QUADRANT RISKS?

A. That is correct. The tools best suited to address the upper right quadrant typically discard outcomes of concern that lie outside of a 95 percent confidence interval. Presuming a normal distribution and using Monte Carlo methods, focusing on outcomes within two standard deviations of the expected outcome restricts examination to about 95 percent of all potential outcomes. In the Monte Carlo assessment outcomes are ignored that could bankrupt the Company, but that occur with less frequency.

Q. CAN SCENARIO ANALYSIS, DECISION TREES AND SIMILAR TECHNIQUES SUPPLEMENT STOCHASTIC ANALYSIS AND ADDRESS THE QUESTION "WHAT SEVERE OUTCOMES MUST BE CONSTRAINED FOR THE HEDGE TO BE A MORE COST BENEFICIAL CHOICE THAN ALTERNATIVES SUCH AS A DELAYED START (FORWARD START) IN PRIVATE PLACEMENT AT A SMALL ADDITIONAL COST RELATIVE TO ISSUANCE AT CURRENT MARKET RATES?"

A. Yes. Scenario analysis of HILF events answers questions such as which counterparty gains and loses money in a hedge or arbitrage effort in outcomes beyond those most likely. Again, this is important when there is not a volume of hedge activity to at least partially balance out outlier outcomes; i.e., a portfolio of hedges.

Q. PRIOR TO EXECUTING THE HEDGE, COULD THE COMPANY HAVE PERFORMED THIS TYPE OF ANALYSIS ON ITS OWN OR IN CONJUNCTION WITH THIRD PARTY ANALYTICAL SUPPORT?

A. Yes. This information was or could have been available to NW Natural at the time of hedge execution in 2007.

Q. DID THE COMPANY PERFORM THIS TYPE OF ROBUST ANALYSIS ON ITS OWN OR IN CONJUNCTION WITH THIRD PARTY ASSISTANCE?

A. Responses to multiple data requests indicate the Company relied heavily on historical correlations as communicated by prospective counter parties and bank sales force projections. It appears that the Company did not recognize a need for and did not perform its own robust analysis prior to entering into the hedge.

Q. WOULD IT BE FAIR TO SAY THAT ANY PROVISION THE COMPANY WANTED TO INCLUDE IN ITS FINANCIAL INTEREST RATE SWAP HEDGE, INFORMED BY STOCHASTIC, SCENARIO, DECISION TREE, AND OTHER ANALYSIS HAD TO BE NEGOTIATED BY THE COMPANY?

A. Yes, as a sophisticated counterparty, it was necessary for NW Natural to negotiate a contract with termination clauses and other provisions that allowed the Company to meet NW Natural's own standard of care.

Q. WHERE THERE ANY PRESSURES PRESENT IN 2007 SUFFICIENT TO CAUSE THE COMPANY TO NOT PERFORM ANY PARTICULAR ANALYSIS OR TO ACCEPT ANY PARTICULAR CONTRACT LANGUAGE IN ANY MANNER?

A. I have identified none other than the usual pressures present to accept a standardized position without modification from sophisticated and seasoned investment banks selling, bidding and negotiating the hedge contract. The investment banks provided representative analysis which did not emphasize Company risk, but carried ample warning of this fact.

Q. WAS IT UP TO THE INVESTMENT BANK COUNTERPARTY TO PERFORM FINANCIAL DUE DILIGENCE ON BEHALF OF THE COMPANY AND THOSE DEPENDENT ON THE COMPANY?

A. No. The bank may benefit from obfuscating risks to increase transaction volume.

Q. AT THE TIME OF ENTERING INTO THE HEDGE CONTRACT, WAS THE COMPANY POSSIBLY DISTRACTED BY THE FINANCIAL CRISIS, REDUCING THE COMPANY'S ABILITY TO EXERCISE DUE DILLIGENCE?

A. No. Hedge execution was in 2007, well before the financial crisis beginning in September of 2008. The Company could have performed analyses that would have informed it as to the best steps to take to limit unacceptable losses within the framework of managing bond issuance coupon rate variability.

Q. THE COMPANY SUGGESTS THAT REGULATED UTILITIES MAY NOT USE FINANCIAL HEDGING TOOLS IN THE FUTURE IF THE COMPANY IS NOT FULLY IMMUNIZED FROM THE RESULTS OF HEDGING, REGARDLESS OF THE SIZE OF LOSS INCURRED. DOES STAFF AGREE?

A. No; Staff does not agree. Use of the authorized hedging tools serves to increase the standard of appropriate level of fiduciary responsibility. For the regulated utility, the appropriate standard of care (given few offsetting other financial hedges) can be greater than for a bank counterparty. It is the responsibility of the Company to make informed decisions prior to entering into hedging activities. Informed by this analysis, the Company then would negotiate hedge contract provisions reflecting the costs of underlying volatility. Staff rejects the supposition that ratepayers stand ready to absorb all losses of whatever magnitude, in turn releasing the Company from both a high standard of fiduciary care and a need to negotiate for hedge provisions that eliminate unacceptable risk introduced by a hedge. In 2007, the Company could have negotiated to limit hedge risk or selected an unadorned delayed start in private placement to deliver timing and low-cost certainty. The Company appears to be proceeding in precisely this manner with respect to near-term issuances; e.g., Mr. Feltz's statement that "[t]he Company plans to issue in the private debt market, which will allow for a delayed take-down of the debt proceeds later this year *at very little additional cost for the delay*."[7]

Q. WITHOUT MEASURED CONSEQUENCE, MIGHT THE COMPANY PRESUME THAT RATEPAYERS WILL FULLY INDEMNIFY THE COMPANY AGAINST LARGE ADVERSE OUTCOMES THAT ARE EX ANTE PREVENTABLE?

A. It may be best policy to not create incentives to ignore extreme risks. Systematic and independent analysis of extreme risk can clarify whether it is cost effective to preclude adverse outcomes, and also when the hedge constitutes a risk to avoid.

7 See Exhibit NWN/2000 Feltz/5 lines 1 – 3; emphasis added.

Q. DOES STAFF HAVE ANY RECOMMENDATION FOR THE COMMISSION REGARDING TREATMENT OF THE HEDGE OTHER THAN THE DISSALLOWANCE OF THE $2,248,000 EQUAL TO HALF THE LOSS THAT EXCEEDED 97.5 PERCENT OF POSSIBLE HEDGE OUTCOMES[8]?

A. Not specifically. The Commission may prefer a different sharing of costs or may wish to disallow the entirety of the hedge loss in favor of the forward yield for September, 2008 (target bond issuance) as of October, 2007 (hedge execution). Staff's recommendation is disallowance of half the excess hedge loss of $4,496,000 that the Company, did not analyze and did not mitigate. Were it informed by its own analysis considering outcomes beyond the 95% most likely outcomes, the Company had several low-cost alternatives in 2007 including one or more of: 1) Negotiate a provision to automatically terminate the hedge at maximum acceptable loss; 2) Cap final losses at 95 percent confidence interval outcomes, and 3) Select a delayed start in private placement at low additional cost and no incremental risk.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[8] Mr. Feltz calculates in NWN/2005 Feltz/1 that with a 95% confidence interval, the maximum potential hedge loss is $5.6 Million.

CASE: UG 221
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2301

Exhibits in Support
Of Rebuttal Testimony

July 20, 2012

OPUC Staff Modified – Northwest Natural Gas
Embedded Cost of Long-Term Debt Capital
Pro-Forma Period Ended: October 31, 2013

Rebuttal Testimony

Columns not shown are subject to protective order.

After Removing a Portion of Hedge Loss

ln. #	Coupon Rate	Description of Issue (a)	Date Issued (b)	Maturity Date (c)	Years to Maturity	Outstanding (d)	Offered (e)	Premium/Discount Amount (f)	Premium/Discount Per $ 100 Principal Amount (g)	Underwriter's Commission Amount (h)	Underwriter's Commission Per $ 100 Principal Amount (i)	Expense of Issue Amount (j)	Expense of Issue Per $ 100 Principal Amount (k)	Net Proceeds Amount (l)	Net Proceeds Per $100 Principal Amount (m)	Original Term to Maturity Yrs. (n)	All-In Cost of Money (o) / DR 415	Annual Cost of Outstanding Debt (p)
		Medium-Term Notes First Mortgage Bonds:																
1	8.260%	**8.260% Series**	09/94	**09/14**	1.7	10,000,000	10,000,000	0	0.00	40,000	0.400	863,369 ❷	8.63	9,096,631	90.966	20	9.260%	926,014
2	3.950%	**3.95 % Series**	07/09	**07/14**	1.5	50,000,000	50,000,000	0	0.00	250,500	0.501	191,076 ❷	0.38	49,558,424	99.117	5	4.147%	2,073,327
3	4.700%	4.700% Series	06/05	06/15	2.5	40,000,000	40,000,000	0	0.00	250,000	0.625	91,898	0.23	39,658,102	99.145	10	4.809%	1,923,451
4	5.150%	5.150% Series	12/06	12/16	4.0	25,000,000	25,000,000	0	0.00	156,250	0.625	121,426	0.49	24,722,324	98.889	10	5.294%	1,323,622
5	7.000%	7.000% Series	08/97	08/17	4.6	40,000,000	40,000,000	0	0.00	300,000	0.750	75,600	0.19	39,624,400	99.061	20	7.089%	2,835,419
6	6.600%	6.600% Series	03/98	03/18	5.2	22,000,000	22,000,000	0	0.00	165,000	0.750	1,179,884	5.36	20,655,116	93.887	20	7.181%	1,579,726
7	8.310%	8.310% Series	09/94	09/19	6.7	10,000,000	10,000,000	0	0.00	40,000	0.400	1,071,757	10.72	8,888,243	88.882	25	9.479%	947,931
8	7.630%	7.630% Series	12/99	12/19	6.9	20,000,000	20,000,000	0	0.00	150,000	0.750	45,421	0.23	19,804,579	99.023	20	7.727%	1,545,347
9	5.370%	**5.370% Series**	03/09	02/20	7.1	75,000,000	75,000,000	0	0.00	468,750	0.625	8,146,058 ❺	10.86	66,385,192	88.514	11	6.889%	5,166,913
10	9.050%	9.050% Series	08/91	08/21	8.6	10,000,000	10,000,000	0	0.00	75,000	0.750	40,333	0.40	9,884,667	98.847	30	9.163%	916,340
11	3.176%	3.176% Series	09/11	09/21	8.7	50,000,000	50,000,000	0	0.00	312,500	0.625	292,655	0.59	49,394,845	98.790	10	3.319%	1,659,546
12	5.620%	5.620% Series	11/03	11/23	10.9	40,000,000	40,000,000	0	0.00	372,588	0.931	2,952,850	7.38	36,674,562	91.686	20	6.360%	2,544,175
13	7.720%	7.720% Series	09/00	09/25	12.7	20,000,000	20,000,000	0	0.00	150,000	0.750	1,136,261	5.68	18,713,739	93.569	25	8.336%	1,667,197
14	6.520%	6.520% Series	12/95	12/25	12.9	10,000,000	10,000,000	0	0.00	62,500	0.625	27,646	0.28	9,909,854	99.099	30	6.589%	658,931
15	7.050%	7.050% Series	10/96	10/26	13.8	20,000,000	20,000,000	0	0.00	125,000	0.625	50,940	0.25	19,824,060	99.120	30	7.121%	1,424,279
16	7.000%	7.000% Series	05/97	05/27	14.4	20,000,000	20,000,000	0	0.00	125,000	0.625	28,906	0.14	19,846,094	99.230	30	7.062%	1,412,411
17	6.650%	6.650% Series	11/97	11/27	14.9	**19,700,000**	**20,000,000**	0	0.00	125,000	0.625	37,800	0.19	19,837,200	99.186	30	6.713%	1,322,538
18	6.650%	6.650% Series	06/98	06/28	15.4	10,000,000	10,000,000	0	0.00	75,000	0.750	23,300	0.23	9,901,700	99.017	30	6.727%	672,666
19	7.740%	7.740% Series	08/00	08/30	17.7	20,000,000	20,000,000	0	0.00	150,000	0.750	1,354,914	6.77	18,495,086	92.475	30	8.433%	1,686,529
20	7.850%	7.850% Series	09/00	09/30	17.7	10,000,000	10,000,000	0	0.00	75,000	0.750	678,107	6.78	9,246,893	92.469	30	8.551%	855,067
21	5.820%	5.820% Series	09/02	09/32	19.7	30,000,000	30,000,000	0	0.00	225,000	0.750	165,382	0.55	29,609,618	98.699	30	5.913%	1,773,949
22	5.660%	5.660% Series	02/03	02/33	20.2	40,000,000	40,000,000	0	0.00	300,000	0.750	56,663	0.14	39,643,337	99.108	30	5.723%	2,289,013
23	5.250%	5.250% Series	06/05	06/35	22.5	10,000,000	10,000,000	0	0.00	75,000	0.750	22,974	0.23	9,902,026	99.020	30	5.316%	531,569
24	**4.200%**	**4.200% Series**	07/12	07/42	29.5	50,000,000	50,000,000	0	0.00	325,000	0.650	200,000 ❶	0.40	49,475,000	98.950	30	4.262%	2,131,173
25	**3.330%**	**3.330% Series**	11/12	11/22	9.8	25,000,000	25,000,000	0	0.00	156,250	0.625	250,000 ❶	1.00	24,593,750	98.375	10	3.524%	881,056
	***Line 24 and 25 Coupon Rates Subject to Update**					**$676,700,000**	**$677,000,000**	**0**		**$4,549,338**		**$19,105,220**		**$653,345,442**			**6.022%**	**$40,748,189**

Changes to NWN Cost of Debt: $40,748,189 $676,700,000 Equals = 6.022% ❹ Impact 0.243% Cost LTD 12 BPS ROR

* Staff Recommended Cost of LT Debt

❶ Company issuance amounts, coupon rate and issuance costs are accepted subject to update with actual values as these are available.
❷ Staff recognizes the Company's recommendation for a policy change and does not reprice LT-Debt maturing within one year past the end of the test year.
❸ This table matches NWN/2001 Feltz/1 with the exception of hidden confidential columns, minor rounding differences and treatment of a hedge loss.
❹ Impact of Staff Adjustments is calculated form original NWN filed 6.265% Cost of LT Debt and based on a presumed 50 / 50 common equity to long-term debt capital structure.
❺ NWN/2005 Feltz/1 indicates that the Company financial hedge risk management addressed only a maximum risk of a loss of $5.6 million.
Staff has modified the interest rate hedge loss amount on line 9 to exclude 1/2 excessive hedge loss, not mitigated by Company planning or contract provisions.
Excluding 1/2 of loss not shown to be prudently anticipated, managed and avoided: Of $ 10,096,000 **22.266%** or $ 2,248,000 is removed from cost of issuance.

CASE: UG 221
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2400

Rebuttal Testimony

July 20, 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 a Senior Financial Economist in the Economic Research and Financial Analysis Division. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. ARE YOU THE SAME JORGE ORDONEZ WHO TESTIFIED IN STAFF'S OPENING TESTIMONY IN THIS PROCEEDING?

A. Yes. Staff's opening testimony included my exhibits, Exhibit Staff/1400 through Exhibit Staff/1407.[1]

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to Northwest Natural Gas Company's (NW Natural or Company) reply testimony[2] pertaining to its Long-Run Incremental Cost (LRIC) Study,[3] which is the basis for allocating the Company's proposed revenue requirement among customer rate schedules. I focus on the following issues raised by the Company:

1. Staff's allocation of revenue requirement on the basis of functionalized revenue requirement;[4]
2. Staff's costing treatment of distribution mains;[5] and
3. Staff's costing treatment of interruptible customers.[6]

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1 See http://edocs.puc.state.or.us/efdocs/HTB/ug221htb165020.pdf.
2 See http://edocs.puc.state.or.us/efdocs/HTB/ug221htb154542.pdf.
3 See Exhibit NWN/2500 through Exhibit NWN/2503.
4 See Exhibit NWN/2500, Feingold/3, line 18 through Feingold/4, line 2.
5 See Exhibit NWN/2500, Feingold/4, line 9 through Feingold/10, line 11.

In thoroughly reviewing the Company's LRIC study, Staff referred to the Company's initial filing, related reply testimony, and the Company's responses to approximately 76 data requests.

Q. HAVE YOU PREPARED EXHIBITS ASSOCIATED WITH YOUR REPLY TESTIMONY?

A. I have prepared Exhibit Staff/2401, consisting of four pages (Staff Rebuttal Testimony LRIC and Rate Spread), and Exhibit Staff/2402, consisting of 20 pages (NW Natural's response to Staff Data Request 502).

SUMMARY RECOMMENDATION

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS IN THIS REBUTTAL TESTIMONY?

A. Regarding NW Natural's LRIC study, as recommended in my opening testimony,[7] I continue to recommend that the Commission find the Company's LRIC study to be reasonable with the exception of the LRIC of distribution mains,[8] for which I recommend that the Commission require NW Natural to complete and provide a study relating the existing length of distribution mains as a function of customer rate schedules (Distribution Mains Study).

I recommend in this rebuttal testimony that, if the Commission requires NW Natural to provide a Distribution Mains Study, such a study should also include,

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6 See Exhibit NWN/2500, Feingold/10, line 12 through Feingold/14, line 21.
7 See Exhibit Staff/1400, Ordonez/2, lines 13-17.
8 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.

to the extent possible, quantitative values identifying the "numerous factors that impact the relationship between the frontage of length of distribution mains and the length of setback for services for different customers across the Company's rate [schedules]."[9]

With respect to the Company's proposed rate spread, based on an overall rate decrease of approximately negative 1.40 percent[10] (approximately negative $4.05 million)[11] as proposed in Staff's opening testimony,[12, 13, 14] I propose the rate spread represented in column D1 of Table 1 (following).

Column D of Table 1 provides a rate spread based on a hypothetical overall rate increase of approximately positive 15.20 percent[15, 16] (approximately positive $43.68 million),[17] which is the increase requested in the Company's initial filing.

The information in columns D and D1 of Table 1 is intended to provide the Commission with additional information regarding rate spread and recognizes

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9 See Exhibit NWN/2500, Feingold/9, lines 17-20.
10 See Exhibit Staff/2401, Ordonez/1, line 54, column A.
11 See the functionalized revenue requirement in NW Natural's response to Staff Data Request 502 attached to this testimony in Exhibit Staff/2402 Ordonez/10.
12 See Staff's errata filing Exhibit Staff/102, Goodwin/1-3 at http://edocs.puc.state.or.us/efdocs/HTB/ug221htb153620.pdf.
13 The actual rate decrease recommended in Staff's opening testimony (i.e., Staff's errata filing Exhibit Staff/102, Goodwin/1-3) was approximately -$9.49 million; however, in NW Natural's supplemental response to Staff Data Request 502, the Company made adjustments to Staff's recommendations arriving at the approximately -$4.05 million decrease.
14 See NW Natural's initial and supplemental responses to Staff Data Request 502 attached to this testimony in Exhibit Staff/2402 Ordonez/1-20 (specifically Ordonez/19-20).
15 See Exhibit NWN/1102, Feingold/1, line 10, column A.
16 15.20 percent is the quotient obtained by dividing the Company-requested increase in rates of $43.68 million by the revenues collected under current rates of $287.40 million.
17 See page 11, line 4 of NW Natural's Executive Summary of the Company's Application for a General Rate Revision at http://edocs.puc.state.or.us/efdocs/UAA/ug221uaa142959.pdf.

that calculating marginal costs, which are the basis of Staff's proposed rate spread, is as much an art as a science, as noted by the Commission in Order No. 98-374 (Docket No. UM 827).

Table 1

Schedule	COST OF SERVICE: Embedded Costs (EC) versus Current Revenue (CR) $\left(=\frac{EC-CR}{CR}\right)$			RATE SPREAD: Increase (+)/Decrease (-) from Current Rates (%)		
	NW Natural's Initial Filing[18]	**Staff's Opening Testimony**[19]	**Staff's Rebuttal Testimony**[20]	**NW Natural**[21, 22] **Initial Filing**	**Staff's Opening Testimony**[23]	**Staff's Rebuttal Testimony**[24]
Revenue Requirement Increase (+)/Decrease (-)	**+$43 million**	**+$43 million**	**-$4 million**[25]	**+$43 million**	**+$43 million**	**-$4 million**[26]
	(A)	**(B)**	**(B1)**	**(C)**	**(D)**	**(D1)**
1R	145.9%	134.1%	100.7%	19.0%	N/A[27]	
1C	30.3%	24.6%	7.0%	14.9%	20.9%	-1.4%
2R	36.0%	31.4%	12.7%	17.7%	20.9%	0.2%
3C Firm Sales	-1.6%	9.5%	-7.3%	15.2%	6.8%	-2.8%
3I Firm Sales	-21.6%	-0.3%	-10.6%	15.2%	3.0%	-2.8%
31C Firm Sales	-44.6%	-45.5%	-53.4%	7.6%	0.0%	-7.0%
31C Firm Transmission	-74.8%	-68.4%	-69.7%	0.0%	0.0%	-7.0%
31C Interruptible Sales	-88.6%	-83.7%	-86.5%	0.0%	0.0%	-7.0%
31I Firm Sales	-59.6%	-50.7%	-56.9%	0.0%	0.0%	-7.0%
31I Firm Transmission	-76.2%	-71.0%	-71.2%	0.0%	0.0%	-7.0%
31I Interruptible Sales	-58.8%	-42.3%	-49.4%	0.0%	0.0%	-7.0%
32C Firm Sales	-37.3%	-40.8%	-49.3%	0.0%	0.0%	-7.0%
32I Firm Sales	-79.1%	-75.1%	-78.6%	0.0%	0.0%	-7.0%
32 Firm Transmission	-82.3%	-78.5%	-77.1%	0.0%	0.0%	-7.0%
32C Interruptible Sales	-84.1%	-74.1%	-78.8%	0.0%	0.0%	-7.0%
32I Interruptible Sales	-82.2%	-71.6%	-76.1%	0.0%	0.0%	-7.0%
32 Interruptible Transmission	-77.0%	-58.5%	-66.2%	0.0%	0.0%	-7.0%
Overall	**15.2%**	**15.2%**	**-1.4%**	**15.2%**	**15.2%**	**-1.4%**

18 See Exhibit Staff/1402 Ordonez/1-2, line 45.
19 See Exhibit Staff/1402 Ordonez/1-2, line 54.
20 See Exhibit Staff/2401 Ordonez/1-2, line 54.
21 See Exhibit NWN/1102 Feingold/1-2, line 13.
22 Also see Exhibit Staff/1402 Ordonez/1-2, line 62.
23 See Exhibit Staff/1402 Ordonez/1-2, line 66.
24 See Exhibit Staff/2401 Ordonez/1-2, line 66.
25 See the functionalized revenue requirement in NW Natural's response to Staff Data Request 502 in Exhibit Staff/2402 Ordonez/10.
26 See the functionalized revenue requirement in NW Natural's response to Staff Data Request 502 in Exhibit Staff/2402 Ordonez/10.
27 In Exhibit Staff/1500, Dr. George Compton is proposing to terminate the 1R schedule, and include all of its customers with Schedule 2R.

The concepts of "cost-causation" and "benefit received" are the foundational principles of my recommendations. Staff's reliance on the "benefit-received" principle complements Staff's reliance on the "cost-causation" principle, as corroborated in the Company's footnote 10 in Exhibit NWN/2500 Feingold/9, which notes that the U.S. Court of Appeals for the District of Columbia has defined the "cost-causation" principle as follows:

> "[I]t has been traditionally required that all approved rates <u>reflect to some degree</u> [emphasis added] the costs actually caused by the customer who must pay them."[28]

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

1. Topic 1: Staff's allocation of revenue requirement on the basis of functionalized revenue requirement;
2. Topic 2: Costing treatment of distribution mains; and
3. Topic 3: Costing treatment of interruptible customers.

[28] The Company's footnote 10 cites K N Energy, Inc. v. FERC, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (K N Energy).

TOPIC 1: STAFF'S ALLOCATION OF REVENUE REQUIREMENT ON THE BASIS OF FUNCTIONALIZED REVENUE REQUIREMENT

Q. PLEASE EXPLAIN THE COMPANY'S POSITION REGARDING STAFF'S USE OF FUNCTIONALIZED REVENUES TO ALLOCATE COSTS AMONG CUSTOMER SCHEDULES.

A. The Company takes issue with three aspects of Staff's opening testimony.[29, 30] One issue is Staff's approach of allocating the Company's revenue requirement on the basis of the functionalized revenue requirement.[31]

Q. WHY DOES THE COMPANY DISAGREE WITH STAFF'S APPROACH?

A. The Company did not specify why it disagrees with Staff regarding this approach, but it mentioned that "the changes proposed by Staff are not based upon sound costing principles and are not reflective of the Company's actual operating and system design practices."[32]

Q. WHAT OBSERVATION DO YOU OFFER REGARDING THAT STATEMENT?

A. The Company did not provide any sound costing principle supporting its proposed alternative to Staff's approach of using the functionalized revenue requirement to allocate costs among customer schedules.

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29 The three issues are 1) Staff's allocation of revenue requirement on the basis of functionalized revenue requirement; 2) costing treatment of distribution mains; and 3) costing treatment of interruptible customers.

30 See Exhibit NWN/2500, Feingold/3, line 10 through Feingold/4, line 2.

31 See Exhibit NWN/2500, Feingold/3, line 18 through Feingold/4, line 2.

32 See Exhibit NWN/2500, Feingold/4, lines 5-7.

Q. WHY DOES STAFF USE FUNCTIONALIZED REVENUES TO ALLOCATE REVENUE REQUIREMENT AMONG CUSTOMER SCHEDULES?

A. As stated in my opening testimony,[33] Staff's approach was motivated by the fact that Oregon-regulated electric Investor Owned Utilities are required by law to functionalize their revenue requirement pursuant to ORS 757.642 and OAR 860-038-0200.

Staff's approach implements the "cost-causation" approach by segregating costs into categories before allocating them to customer rate schedules, reflecting cost-causation of each customer schedule at functional levels, as opposed to at an aggregate level.

Finally, as stated in my opening testimony,[34] 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. In other words, costs by function may vary between customer schedules on an incremental basis versus an embedded basis, and not accounting for this distorts rate spread results.

[33] See Exhibit Staff/1400, Ordonez/21, lines 1-3.
[34] See Exhibit Staff/1400, Ordonez/20, lines 15-18.

TOPIC 2: COSTING TREATMENT OF DISTRIBUTION MAINS

Q. PLEASE DESCRIBE THE COMPANY'S COSTING TREATMENT OF DISTRIBUTION MAINS IN THE COMPANY'S INITIAL FILING.

A. As I discussed in my opening testimony,[35] NW Natural's proposed LRIC of distribution mains of approximately $70 million comprises approximately $4 million[36, 37, 38] of demand-related costs and $66 million[39, 40, 41] of non-demand-related[42] costs. In other words, six percent of the incremental costs of distribution mains are demand-related and 94 percent are not demand-related.

Q. HOW DID STAFF BREAK DOWN THE COMPANY'S EMBEDDED COSTS OF MAINS OF APPROXIMATELY $113 MILLION[43, 44, 45] INTO DEMAND-RELATED AND NON-DEMAND-RELATED COSTS?

A. As discussed in my opening testimony,[46] Staff used the same proportions of mains costs used in the Company's LRIC study to disaggregate the embedded costs of mains of approximately $113 million into approximately $6 million[47, 48]

[35] See Exhibit Staff/1400 Ordonez/26, lines 3-9.
[36] The exact value is $3,897,495.
[37] See Exhibit Staff/1402 Ordonez/3, line 20g, column A.
[38] Also see Exhibit Staff/2401 Ordonez/3, line 20g, column A.
[39] The exact value is $66,441,772.
[40] See Exhibit Staff/1402 Ordonez/3, line 20c, column A.
[41] Also see Exhibit Staff/2401 Ordonez/3, line 20c, column A.
[42] Staff's term "non-demand-related" costs, refers to what the Company refers to as "customer-related-costs".
[43] The exact value is $113,387,169.
[44] See Exhibit Staff/1402 Ordonez/1, line 19, column A; and Exhibit Staff/2401 Ordonez/1, line 19.
[45] Also see Staff/1407 Ordonez/5, line 327, column (G); and NW Natural's response to Staff Data Request 306, workbook file "OPUC DR 306 Attachment-1," line 327 (MS Excel row 339), column "Mains."
[46] See Exhibit Staff/1400 Ordonez/25, lines 16-18.
[47] The exact value is $6,282,778.
[48] See Exhibit Staff/1402 Ordonez/1, line 18, column A.

(approximately six percent) of demand-related costs and $107 million[49, 50] (approximately 94 percent) of non-demand-related[51] costs.

Q. HOW DID STAFF ALLOCATE THE $6 MILLION OF DEMAND-RELATED COSTS AMONG CUSTOMER SCHEDULES?

A. Staff allocated the $6 million of demand-related costs on the basis of demand information[52] (i.e., "Design Day Sales, Excluding Residential"[53, 54] customers).

Q. WHAT WAS THE COMPANY'S RESPONSE TO THIS APPROACH?

A. The Company represented that, by using design-day-sales demand information, Staff had "excluded the design day loads of the firm transportation service rate [schedules]"[55] in allocating demand-related costs among customer schedules.

Q. DO YOU AGREE WITH THAT STATEMENT?

A. The Company's observation is reasonable. Staff has incorporated the Company's feedback in Staff's rebuttal testimony LRIC by allocating demand-related costs among customer rate schedules still on the basis of demand, but changing the allocation metric to "Firm Design Day Throughput, Excluding Residential"[56] customers. By doing this, Staff includes the design day loads of the firm transportation service rate classes in allocating demand-related costs among customer schedules.

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49 The exact number is $107,104,392.
50 See Exhibit Staff/1402, Ordonez/1, line 17, column A.
51 Staff's term "non-demand-related" costs, refers to what the Company refers to as "customer-related-costs".
52 See Exhibit Staff/1400, Ordonez/26, lines 1-2.
53 See Exhibit Staff/1402, Ordonez/3, line 6c.
54 See Exhibit Staff/2401, Ordonez/3, line 6c.
55 See Exhibit NWN/2500, Feingold/8, line 21.
56 See Exhibit Staff/2401, Ordonez/3, line 5c.

Q. DOES THAT CHANGE PRODUCE MATERIAL CHANGES IN YOUR LONG-RUN INCREMENTAL COST RESULTS?

A. The change is negligible, as shown in Table 2:

Table 2

COST OF SERVICE		
Schedule	**Embedded Costs (EC) versus Current Revenue (CR)** $\left(= \frac{EC-CR}{CR}\right)$	
	Staff Opening Testimony	
	As Filed Allocation Basis: Design Day Sales, Excluding Residential[57]	Allocation Basis: Firm Design Day Throughput, Excluding Residential[58]
	(A)	**(B)**
1R	134.1%	134.1%
1C	24.6%	24.4%
2R	31.4%	31.4%
3C Firm Sales	9.5%	9.2%
3I Firm Sales	-0.3%	-0.4%
31C Firm Sales	-45.5%	-45.9%
31C Firm Transportation	-68.4%	-63.4%
31C Interruptible Sales	-83.7%	-83.7%
31I Firm Sales	-50.7%	-50.9%
31I Firm Transportation	-71.0%	-66.5%
31I Interruptible Sales	-42.3%	-42.3%
32C Firm Sales	-40.8%	-41.4%
32I Firm Sales	-75.1%	-75.2%
32 Firm Transportation	-78.5%	-72.1%
32C Interruptible Sales	-74.1%	-74.1%
32I Interruptible Sales	-71.6%	-71.6%
32 Interruptible Transportation	-58.5%	-58.5%
Overall	**15.2%**	**15.2%**

[57] See Exhibit Staff/1402 Ordonez/1-2, line 54.
[58] See workpaper workbook “Workpaper difference in allocation of demand-related mains costs,” worksheet “Final Summary,” column B1.

Q. HOW DID STAFF ALLOCATE THE $107 MILLION OF NON-DEMAND-RELATED COSTS OF MAINS AMONG CUSTOMER SCHEDULES?

A. As stated in Staff's opening testimony, Staff allocated the $107 million among customer schedules by using the same proportions used for allocating the LRIC of Services[59, 60, 61] "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)."[62]

Q. WHY DID STAFF NOT USE THE COMPANY'S APPROACH?

A. As stated in my opening testimony, the Company erroneously assumes that every customer rate schedule has a main length of 77 feet and a cost per foot of $14.56.[63]

Assigning a residential customer the same cost of main as an industrial customer clearly violates the "cost-causation" principle.

Q. HOW DID THE COMPANY RESPOND TO THIS IN ITS REPLY TESTIMONY?

A. The Company stated that "Staff offers no evidence that his assumption [that the frontage of length of distribution mains is proportional to the length of setback from the distribution mains for different classes] is correct."[64]

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59 See Exhibit Staff/1400 Ordonez/25, line 18 through Ordonez/26, line 1.
60 See Exhibit Staff/1402 Ordonez/3, line 20l.
61 Also see Staff/2401 Ordonez/3, line 20l.
62 See Exhibit Staff/1400 Ordonez/26, lines 15-18.
63 See Exhibit Staff/1400 Ordonez/14, line 9 through Ordonez/15, line 16.
64 See Exhibit NWN/2500, Feingold/9, lines 13-14.

The Company's rebuttal testimony included that "even in residential developments with identical size lots, homes have different setbacks just based on the topography of the lot and the types of facilities being constructed. In [Mr. Feingold's] opinion, [Staff's] method is much too crude an attempt to capture cost causation because there are numerous factors that impact the relationship between the frontage of length of distribution mains and the length of setback for services for different customers across the Company's rate classes."[65]

Q. WHAT ARE YOUR THOUGHTS REGARDING THIS ASSERTION?

A. While I do not think my approach is the "best" method, I do not agree with the Company's assertion that my approach is "too crude an attempt to capture cost causation." I believe my approach is a "better" approach for reflecting cost causation than the Company's approach of assuming that the average residential customer has the same length of mains and the same cost of mains as the average industrial customer.[66]

That is why, in the Summary Recommendation section of my opening testimony, I recommended that the Commission require NW Natural to complete and provide a study relating the existing length of distribution mains as a function of customer rate schedules (Distribution Mains Study)[67] and, consistent with the Company's reply testimony, to the extent possible, provide quantitative values associated with each of the "numerous factors that impact the relationship between the frontage of length of distribution mains and the

[65] See Exhibit NWN/2500, Feingold/9, lines 14-20.
[66] See Exhibit Staff/1400,Ordonez/14, line 9 through Ordonez/15, line 16.
[67] See Exhibit Staff/1400 Ordonez/2, lines 15-17.

length of setback for services for different customers across the Company's rate [schedules]."[68] Absent such a requirement, I recommend the Commission require that the Company provide an estimate of the average length of main per customer for each customer schedule within 90 days of the effective date of the relevant Order in this proceeding.

[68] See Exhibit NWN/2500, Feingold/9, lines 17-20.

TOPIC 3: COSTING TREATMENT OF INTERRUPTIBLE CUSTOMERS

Q. PLEASE EXPLAIN THE COMPANY'S CRITICISM OF STAFF'S APPROACH OF ALLOCATING 25 PERCENT OF TRANSMISSION COSTS TO ALL CUSTOMER SCHEDULES.

A. The Company disagrees with Staff's approach, which approach is based on these two reasons:

1. Interruptible customers experienced curtailment approximately 0.40 percent of the time in the five-year period from 2007 through 2011.[69] In other words, interruptible customers had service 99.60 percent of the time during that period.
2. "System reinforcements include consideration of interruptions of interruptible customers."[70]

Q. WHAT DID THE COMPANY SAY REGARDING THE FIRST REASON?

A. NW Natural asserted that "the Company's relatively low level of curtailment [emphasis added] of these [interruptible service] customers over the last five years is simply a function of the relatively low level of firm demands of the other customers actually served by NW Natural over that time period (due to warmer than planned for peak day weather and other factors)…" [71]

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[69] See Exhibit Staff/1400, Ordonez/24, lines 9-11.
[70] See Exhibit Staff/1400, Ordonez/24, lines 12-14.
[71] See Exhibit NWN/2500, Feingold/13, line 19 through Feingold/14, line 1.

Q. WHAT IS STAFF'S RESPONSE TO THAT STATEMENT?

A. Staff takes no issue with the Company's understanding regarding highly infrequent service interruption for its customers on interruptible service. The "benefit-received" principle is Staff's <u>main reason</u> (or most important reason) for proposing that all customers, including interruptible customers, share a small portion of transmission costs. Interruptible customers benefited from NW Natural's transmission system 99.60 percent of the time during the five-year period from 2007 through 2011, experiencing curtailment only 0.40 percent of the time. Interruptible customers clearly benefit and some sharing of transmission costs by all customers (i.e., both non-interruptible and interruptible customers) is not unreasonable.

Q. WHAT DID THE COMPANY SAY REGARDING THE SECOND FACT LISTED ABOVE?

A. Staff's <u>marginal reason</u> (or least important reason) is based on Exhibit NWN/600 Yoshihara/3, lines 4-20, where the Company represented that "for the past several years, interruptible customers in this area have experienced partial curtailment as temperatures in the area drop below 42 degrees Fahrenheit, with full curtailment generally occurring as temperatures drop below 32 degrees Fahrenheit. For these reasons, the Company determined that it needed to increase capacity to this service area by the fourth quarter of 2012…"[72, 73]

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[72] See Exhibit Staff/1400, Ordonez/11, lines 13-18.
[73] Exhibit NWN/600, Yoshihara/3, lines 13-18.

Q. WHAT WAS THE COMPANY'S RESPONSE TO THIS SECOND REASON?

A. As highlighted in Exhibit NWN/2500 Feingold/13, the Company stated "that Mr. Yoshihara's statement was not intended to mean that the reduction of curtailments for interruptible customers in the area where the Corvallis Loop Project will be installed was the purpose of this project. Rather, the Company experiencing curtailments of its interruptible customers in that area over the past several years was an <u>operational outcome</u> [emphasis added] which indicates that insufficient firm capacity currently exists on NW Natural's gas pipeline system to accommodate all of its firm demand requirements."[74] The Company also asserts that "Staff has misinterpreted the Company's operational situation."[75]

Q. WHAT IS STAFF'S RESPONSE TO THOSE STATEMENTS?

A. In Staff Data Request 274, Staff proactively asked the Company to explain the Company's apparent inconsistency in saying, on the one hand, that "system reinforcements include consideration of interruptions of interruptible customers"[76, 77] in addition to firm customers and, on the other hand, that "…NW Natural does not install firm pipeline capacity to serve its interruptible customers."[78] Staff believes that the Company's response, based on operational outcomes, is inconsistent with the Company's assertion that system reinforcements include considerations of interruptions of interruptible customers. This is based on

[74] See Exhibit NWN/2500, Feingold/13, line 5-11.
[75] See Exhibit NWN/2500, Feingold/13, line 12.
[76] See Exhibit Staff/1400, Ordonez/24, lines 12-14.
[77] Based on the Company's Exhibit NWN/600 Yoshihara/3, lines 4-20.
[78] See NW Natural's supplemental response to Staff Data Request 274, page 2, second paragraph.

Staff's reasonable interpretation (not "misinterpretation") of the Company's statement that "[f]or these reasons the Company determined that it needed to increase capacity to this service area by the fourth quarter of 2012." [79]

Q. WHAT ADDITIONAL THOUGHTS DO YOU HAVE REGARDING THE TWO FACTS SUPPORTING STAFF'S APPROACH OF ALLOCATING A SMALL PORTION OF TRANSMISSION COSTS TO ALL CUSTOMERS (I.E., TO BOTH NON-INTERRUPTIBLE AND INTERRUPTIBLE CUSTOMERS)?

A. I recommend that the Commission not lose perspective regarding the two reasons [one main reason (or most important reason) and one marginal reason (or least important reason)] that I presented in support of my allocation basis. Although Staff does not consider the marginal reason (system reinforcements include consideration of interruptions of interruptible customers), my main reason (interruptible customers benefited from NW Natural's transmission system 99.60 percent of the time during the five-year period from 2007 through 2011) is sufficiently robust to support my proposal, because it is based on the "benefit-received" principle.

Q. DOES THE BENEFIT-RECEIVED PRINCIPLE CONFLICT WITH THE COST-CAUSATION PRINCIPLE THE COMPANY CLAIMS TO BE USING?

A. Absolutely not. As the Company stated in footnote 10 of Exhibit NWN/2500 Feingold/9, the U.S. Court of Appeals for the District of Columbia Circuit has defined the cost-causation principle as follows:

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[79] See Exhibit Staff/1400, Ordonez/11, lines 13-18.

"[I]t has been traditionally required that all approved rates reflect to some degree [emphasis added] the costs actually caused by the customer who must pay them."[80]

The cost-causation principle is not an absolute principle in approving rates.

Q. DO YOU HAVE ANY FURTHER THOUGHTS?

A. Yes. Customers do not have a right to interruptible service. The availability of an interruptible rate should be based on consideration of the utility's costs avoided by reason of the availability of the interruptible rights as well giving consideration to the level of rate discount as compared to the expected utility costs avoided. Given that interruptible customers have been interrupted very infrequently, perhaps the rate discount should take a different form. Staff understands that one reason for the lack of interruptions has been the weather conditions experienced over the last several years. Nevertheless, the fact is that customers have rarely been interrupted and the Company expands service availability including some consideration for interruptible customers.

Q. WHAT ALTERNATIVE RATE DISCOUNT FORM DO YOU PROPOSE?

A. Similar to some electric tariffs, the tariff may make more sense to have interruptible rates at standard tariffs, with a payment to the customer made in the event the customer is actually interrupted or is willing to be interrupted on a limited basis.[81] The referenced utility programs base their customer incentive

[80] See K N Energy, Inc. v. FERC, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (K N Energy).
[81] See Portland General Electric Company's Schedule 77: Firm Load Reduction Pilot Program, and Idaho Power Company's Schedule 23: Irrigation Peak Rewards Program (Optional).

payments upon the utility's avoided capacity costs made possible by the interruptions. There may be other options as well to achieve the needed reductions in deliveries on a sound avoided cost basis.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UG 221
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2401

Exhibits in Support
Of Rebuttal Testimony

(LRIC and Rate Spread)

July 20, 2012

Staff/2401
Ordonez/1

UG 221 NW Natural - Staff Rebuttal Testimony - Rate Spread including LRIC Study
Based on NW Natural's Respose to Staff Data Request 225 (Updated LRIC)

STAFF'S ESTIMATIONS

Line	Description	Allocation Criterion		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		$	27,647,936	27,379	4,314	18,280,398	6,324,525	49,982	2,317,684	0	0
5	Capacity (energy or commodity) [Allocated based on Company's LRIC of Capacity Storage]	Same as Company		$	4,738,551	4,531	899	3,080,792	1,146,012	13,244	382,522	0	0
6	**Total Embedded Storage Costs**			$	**32,386,488**	31,911	5,214	21,361,190	7,470,537	63,227	2,700,205	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%	$	3,174,012	3,101	489	2,070,580	716,365	5,661	262,519	653	0
11	25% (versus Company's 0%) [Allocated based throughput]	Staff proposed	25%	$	1,058,004	797	123	395,116	169,950	4,725	68,438	263	1,551
12	**Total Embedded Transmission Costs**		100%	$	**4,232,016**	3,899	612	2,465,696	886,315	10,386	330,957	915	1,551
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%	$	90,178,856	388,340	18,334	68,928,681	17,452,250	170,451	1,091,255	8,870	15,936
18	Demand-Related (6%) [Allocation % Firm Design Day (Excluding Residential)]	Staff proposed	6%	$	5,289,920	0	2,349	0	3,443,975	27,218	1,262,078	3,137	0
19	Total Distribution - Mains		100%	$	**95,468,776**	388,340	20,684	68,928,681	20,896,225	197,669	2,353,333	12,007	15,936
20	Distribution Services												
21	Distribution - Services [Allocation based on the Company's LRIC of Distribution Services]	Same as Company		$	**53,177,531**	229,000	10,812	40,646,524	10,291,410	100,513	643,501	5,230	9,397
22	Distribution Meters & Regulators												
23	Distribution - Meters & Regulators [Allocation based on the Company's LRIC of Meters & Regulators]	Same as Company		$	**31,439,104**	151,868	11,499	25,213,974	5,039,385	104,425	567,352	3,440	6,613
24	Distribution Accounting												
25	Distribution - Accounting (Allocation based on the Company's "LRIC of Accounting)	Same as Company		$	**41,514,660**	246,726	11,892	35,300,369	3,986,560	676,846	84,289	422	844
26	**Total Embedded Distribution Costs**			$	**221,600,071**	1,015,935	54,887	170,089,549	40,213,580	1,079,452	3,648,475	21,099	32,791
27	**%**				**100.00%**	0.46%	0.02%	76.76%	18.15%	0.49%	1.65%	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%	$	9,047,431	38,961	1,839	6,915,451	1,750,943	17,101	109,483	890	1,599
31	44% [based on the allocation of the Company's Embedded Distribution costs <u>except</u> Distribution Accounting	Staff proposed	44%	$	11,057,971	47,233	2,640	8,276,600	2,224,485	24,722	218,855	1,270	1,962
32	20% (remaining) [based on the allocation of the Company's Embedded costs <u>except</u> Prod-Dist Other]	Staff proposed	20%	$	5,026,350	20,473	1,182	3,774,678	945,447	22,445	130,022	429	668
33	**Total Embedded Production - Distribution Other Costs**		100%	$	**25,131,752**	106,667	5,661	18,966,729	4,920,875	64,268	458,361	2,588	4,229
34	**%**				**100.00%**	0.42%	0.02%	75.47%	19.58%	0.26%	1.82%	0.01%	0.02%
35													
36	**TOTAL EMBEDDED COSTS**			**$**	**283,350,327**	**1,158,411**	**66,373**	**212,883,163**	**53,491,307**	**1,217,333**	**7,137,998**	**24,603**	**38,570**
37	**%**			**%**	**100.00%**	**0.41%**	**0.02%**	**75.13%**	**18.88%**	**0.43%**	**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 in its initial filing 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			$	287,404,942	577,125	62,009	188,891,594	57,697,369	1,362,237	15,322,004	81,269	285,292
52	Staff's Opening Testimony revenue requirement allocated based on Staff's cost of service			$	283,350,327	1,158,411	66,373	212,883,163	53,491,307	1,217,333	7,137,998	24,603	38,570
53	$ Increase/decrease from current revenue			$	(4,054,615)	581,287	4,364	23,991,570	(4,206,062)	(144,904)	(8,184,006)	(56,666)	(246,721)
54	% Increase/decrease from current revenue			%	-1.4%	100.7%	7.0%	12.7%	-7.3%	-10.6%	-53.4%	-69.7%	-86.5%
55													
56													
57													
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			%	-1.4%	0.2%	-1.4%	0.2%	-2.8%	-2.8%	-7.0%	-7.0%	-7.0%
67	$ Increase/decrease from current revenue			$	(4,054,615)	965	(868)	315,979	(1,615,526)	(38,143)	(1,072,540)	(5,689)	(19,970)

UG 2

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		$	142,790	0	0	433,752	67,111	0	0	0	0
5	Capacity (energy or commodity) [Allocated based on Company's LRIC of Capacity Storage]	Same as Company		$	43,648	0	0	54,693	12,209	0	0	0	0
6	**Total Embedded Storage Costs**			$	186,439	0	0	488,445	79,320	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%	$	16,174	1,317	0	49,130	7,601	40,422	0	0	0
11	25% (versus Company's 0%) [Allocated based throughput]	Staff proposed	25%	$	19,323	935	349	12,944	13,330	66,955	23,745	37,849	241,610
12	**Total Embedded Transmission Costs**		100%	$	35,497	2,252	349	62,074	20,932	107,378	23,745	37,849	241,610
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%	$	298,800	10,624	9,296	105,715	89,758	213,597	170,877	216,883	989,188
18	Demand-Related (6%) [Allocation % Firm Design Day (Excluding Residential)]	Staff proposed	6%	$	77,755	6,333	0	236,197	36,545	194,334	0	0	0
19	Total Distribution - Mains		100%	$	376,555	16,957	9,296	341,912	126,303	407,930	170,877	216,883	989,188
20	Distribution Services												
21	Distribution - Services [Allocation based on the Company's LRIC of Distribution Services]	Same as Company		$	176,199	6,265	5,482	62,339	52,930	125,956	100,765	127,894	583,314
22	Distribution Meters & Regulators												
23	Distribution - Meters & Regulators [Allocation based on the Company's LRIC of Meters & Regulators]	Same as Company		$	125,277	4,454	3,934	29,485	25,034	36,577	28,929	37,343	49,512
24	Distribution Accounting												
25	Distribution - Accounting (Allocation based on the Company's "LRIC of Accounting)	Same as Company		$	534,352	18,999	16,624	3,730	106,870	154,368	3,659	156,743	211,366
26	**Total Embedded Distribution Costs**			$	1,212,384	46,675	35,336	437,466	311,137	724,831	304,230	538,863	1,833,380
27	**%**				0.55%	0.02%	0.02%	0.20%	0.14%	0.33%	0.14%	0.24%	0.83%
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%	$	29,978	1,066	933	10,606	9,005	21,430	17,144	21,759	99,243
31	44% [based on the allocation of the Company's Embedded Distribution costs except Distribution Accounting	Staff proposed	44%	$	41,634	1,699	1,149	26,633	12,543	35,029	18,456	23,464	99,598
32	20% (remaining) [based on the allocation of the Company's Embedded costs except Prod-Dist Other]	Staff proposed	20%	$	27,920	952	695	19,232	8,008	16,199	6,384	11,226	40,391
33	**Total Embedded Production - Distribution Other Costs**		100%	$	99,532	3,718	2,776	56,471	29,556	72,658	41,984	56,449	239,232
34	**%**				0.40%	0.01%	0.01%	0.22%	0.12%	0.29%	0.17%	0.22%	0.95%
35													
36	**TOTAL EMBEDDED COSTS**			**$**	**1,533,851**	**52,645**	**38,461**	**1,044,456**	**440,945**	**904,867**	**369,959**	**633,161**	**2,314,222**
37	**%**			**%**	**0.54%**	**0.02%**	**0.01%**	**0.37%**	**0.16%**	**0.32%**	**0.13%**	**0.22%**	**0.82%**
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 in its initial filing 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			$	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	Staff's Opening Testimony revenue requirement allocated based on Staff's cost of service			$	1,533,851	52,645	38,461	1,044,456	440,945	904,867	369,959	633,161	2,314,222
53	$ Increase/decrease from current revenue			$	(2,027,733)	(129,915)	(37,509)	(1,016,104)	(1,615,464)	(3,040,885)	(1,379,062)	(2,014,210)	(4,532,595)
54	% Increase/decrease from current revenue			%	-56.9%	-71.2%	-49.4%	-49.3%	-78.6%	-77.1%	-78.8%	-76.1%	-66.2%
55													
56													
57													
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			%	-7.0%	-7.0%	-7.0%	-7.0%	-7.0%	-7.0%	-7.0%	-7.0%	-7.0%
67	$ Increase/decrease from current revenue			$	(249,311)	(12,779)	(5,318)	(144,239)	(143,949)	(276,203)	(122,431)	(185,316)	(479,277)

UG 221 NW Natural - Staff Rebuttal Testimony - Rate Spread including LRIC Study
Based on NW Natural's Respose to Staff Data Request 225 (Updated LRIC)

COMPANY'S ESTIMATIONS

Line	Item		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%
5b	Firm Design Day (Excluding Residential)		Dth/day	294,665		131		191,840	1,516	70,302	175	0
5c	% Firm Design Day (Excluding Residential)		%	100.00%	0.00%	0.04%	0.00%	65.10%	0.51%	23.86%	0.06%	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												
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												
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	94%	$	**$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

≈ 94% [≈ $66.4 million/(66.4 million + $3.8 million)]

≈ 6% [≈ $3.8 million/(66.4 million + $3.8 million)]

UG 2

NW Natural - Rate Spread including LRIC Study

Based on NW Natural's Respose to Staff Data Request 225 (Updated LRIC)

COMPANY'S ESTIMATIONS

Line	Description		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%
5b	Firm Design Day (Excluding Residential)		Dth/day	4,331	353	0	13,157	2,036	10,825	0	0	0
5c	% Firm Design Day (Excluding Residential)		%	1.47%	0.12%	0.00%	4.47%	0.69%	3.67%	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												
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												
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	94%	$	$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

≈ 94% [≈ $66.4 million/(66.4 million + $3.8 million)]

≈ 6% [≈ $3.8 million/(66.4 million + $3.8 million)]

CASE: UG 221
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2402

Exhibits in Support
Of Rebuttal Testimony

(NW Natural's Response to
Staff Data Request No. 502)

July 20, 2012

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 502**:**
Regarding Exhibit Staff/1400 Ordonez/4, "Summary Recommendation" section, lines 6-8, where Staff stated the intention to work with NW Natural to obtain the Company's functionalized revenue requirement reflecting Staff adjustments, please provide:
a) In electronic spreadsheet format with cell references and formulae intact, the Company's functionalized revenue requirement (embedded costs), reflecting OPUC Staff Opening Testimony's adjustments as represented in Exhibit Staff/102, Goodwin/1-3, Staff Errata Filing, where OPUC Staff recommended a $9.485 million reduction from the revenue requirement resulting from base rates in the Company's initial filing in this proceeding.
Please include workpapers, in electronic spreadsheet format with cell references and formulae intact. 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.

1 See http://edocs.puc.state.or.us/efdocs/HTB/ug221htb153620.pdf.
2 See Exhibit Staff/102, Goodwin/3.

Response: 6/26/2012

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).

NW Natural staff provided Mr. Feingold with an approximation of Staff's Opening Testimony adjustments based on the Exhibit Staff/102, Goodwin/1-3 Staff Errata filing in the interest of being responsive to this request. However, it should be noted that at the time of this data response, all of the adjustments in Staff's filing are open items that have not been agreed to or resolved by any of the Parties in this case.

DR 502 Attachment-1.pdf is a file which functionalizes NW Natural's revenue requirement with Staff's adjustments based on data compiled by NW Natural staff. DR

502 Attachment-2.xls is a file which includes the electronic spreadsheet format with cell references and formulae intact. This file also includes all workpapers in electronic spreadsheet format with cell references and formulae intact. The 1101-Feingold Workpaper-1 was modified in DR 502 Attachments 1 and 2 to include a Transmission function and three Customer Accounts categories based on the functional categories previously specified in OPUC Staff Data Request 306.

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)

NW NATURAL
Long-Run Incremental Cost Study – Response to OPUC Staff Data Request 502

Account Description	Account Code	Account Balance	Prod-Trans DistOther	Stor	Mains	Service	Meters	Cust Acct
I. GAS PLANT IN SERVICE								
A. INTANGIBLE PLANT								
Organization	301	852	44	107	372	243	72	16
Franchise and Consents	302	83,496	4,292	10,461	36,415	23,769	7,031	1,528
Miscellaneous Intangible Plant	303	94,013,486	4,832,195	11,779,038	41,002,195	26,763,030	7,916,272	1,720,755
Subtotal - INTANGIBLE PLANT	301-303	94,097,834	4,836,531	11,789,606	41,038,981	26,787,042	7,923,375	1,722,299
B. PRODUCTION PLANT								
Other Land & Land Rights-Land	304, 305, 325	93,061	93,061					
Gas Well Structures	318, 326	388,447	388,447					
Field Compressor Station Structures	327	0	0					
Field M&R Station Structures	328	0	0					
Other Structures	329	0	0					
Producing Gas Wells-Well Equipment	331	0	0					
Field Lines	332	0	0					
Field Compressor Station Equipment	333	0	0					
Field M&R Station Equip-Company	311, 334	8,242	8,242					
Drilling & Cleaning Equipment	319, 335	185,448	185,448					
Other Equipment-Other	337	0	0					
Subtotal - PRODUCTION PLANT	325-337	675,198	675,198	0	0	0	0	0
C. NATURAL GAS STORAGE PLANT & PROD PLANT								
Land and Land Rights	350, 360	870,224		870,224				
Structures and Improvements	351, 361	13,831,591		13,831,591				
Wells-Well Equipment	352, 362	39,340,908		39,340,908				
Lines	353, 363	24,738,958		24,738,958				
Compressor Station Equipment - Other	354	25,203,830		25,203,830				
M&R Equipment-Meters & Gauges	355, 356	5,964,468		5,964,468				
Other Equipment	357	141,807,053		141,807,053				
Subtotal - STORAGE PLANT	350-363	251,757,033	0	251,757,033	0	0	0	0
D. TRANSMISSION PLANT								
Land & Land Rights	365	6,544,949	6,544,949					
Structures & Improvements	366	1,041,984	1,041,984					
Mains	367	31,319,351	31,319,351					
M&R Station Equipment	369	3,661,168	3,661,168					
Other Equipment	371	0	0					
Subtotal - TRANSMISSION PLANT	365-371	42,567,452	42,567,452		0	0	0	0
E. DISTRIBUTION PLANT								
Land and Land Rights	374	1,888,356	1,888,356					
Structures and Improvements	375	49,372	49,372					
Mains	376	883,204,384			883,204,384			
Compressor Station Equipment	377	818,380	818,380					

NW NATURAL

Long-Run Incremental Cost Study – Response to OPUC Staff Data Request 502

	Account Description	Account Code	Account Balance	Prod-Trans DistOther	Stor	Mains	Service	Meters	Cust Acct
10									
62	M & R Station Equipment	378, 379	25,814,245	25,814,245					
63	Services	380	577,248,944				577,248,944		
64	Meters	381	94,218,327					94,218,327	
65	Meter Install Residential	382	63,080,383					63,080,383	
66	Meter Install Commercial	383	538,750					538,750	
67	House Regulator Install.	384	0	0					
68	Industrial M & R Station Equipment	385	0	0					
69	Other Property on Customers Premise	386	0	0					
70	Other Equipment	387	281,415	281,415					
71	Subtotal - DISTRIBUTION PLANT	374-387	1,647,142,556	28,851,768	0	883,204,384	577,248,944	157,837,461	0
72	**TOTAL GAS PLANT**								
73									
74						60.47%	39.53%		
75	**F. GENERAL PLANT**								
76									
77	Land and Land Rights	389	3,230,763	938,299	170,180	401,574	240,893	430,722	1,049,095
78	Structures and Improvements	390	33,508,503	9,731,757	1,765,061	4,165,008	2,498,467	4,467,314	10,880,896
79	Office Furniture and Equipment	391	25,909,006	7,524,662	1,364,757	3,220,413	1,931,832	3,454,158	8,413,184
80	Transportation Equipment	392	23,791,851	6,909,784	1,253,236	2,957,257	1,773,972	3,171,902	7,725,701
81	Stores Equipment	393	107,585	31,245	5,667	13,372	8,022	14,343	34,935
82	Tools, Shop and Garage Equipment	394	13,822,166	4,014,323	728,083	1,718,055	1,030,611	1,842,755	4,488,340
83	Laboratory Equipment	395	61,532	17,871	3,241	7,648	4,588	8,203	19,981
84	Power Operated Equipment	396	6,734,945	1,956,006	354,763	837,134	502,172	897,895	2,186,974
85	Communication Equipment	397	8,674,816	2,519,396	456,946	1,078,254	646,813	1,156,516	2,816,890
86	Miscellaneous Equipment	398	169,201	49,141	8,913	21,031	12,616	22,558	54,943
87	Other Tangible Plant	399	0	0	0	0	0	0	0
88	Subtotal - GENERAL PLANT	389-399	116,010,369	33,692,484	6,110,848	14,419,748	8,649,985	15,466,366	37,670,939
89									
90	**TOTAL PLANT IN SERVICE**		2,152,250,443	110,623,433	269,657,487	938,663,114	612,685,971	181,227,201	39,393,237
91									
92	G. Utility Plant	105	0						
93									
94	**TOTAL UTILITY PLANT - Minus Intangibles**		2,058,152,609	105,786,902	257,867,881	897,624,132	585,898,929	173,303,826	37,670,939
95				5.14%	12.53%	43.61%	28.47%	8.42%	1.83%
96	**II. DEPRECIATION RESERVE**								
97									
98	Intangible Plant	301-303	60,994,540	3,135,056	7,642,063	26,601,609	17,363,453	5,135,959	1,116,400
99	Production Plant	332-337	691,037	691,037	0				
100	Local Storage Plant	350-357	96,211,239		96,211,239				
101	Transmission	365-371	14,541,662	14,541,662	0				
102	Distribution Land Structures & Improvements	374-375	936,378	936,378	0				
103	Distribution Mains	376	391,860,551			391,860,551			
104	Compressor Station Equipment	377	560,469	560,469	0				
105	Distribution M&R General	378,379	9,447,019	9,447,019	0				
106	Distribution Services	380	314,424,072				314,424,072		
107	Distribution - Meters	381	26,614,033					26,614,033	
108	Distribution - Meters Installations	382	15,503,636					15,503,636	
109	Industrial M & R Station Equipment - Other	385	0	0	0				
110	Other Property on Customers Premises	383,386	64,019	64,019	0				
111	Other Equipment	387	281,415	281,415	0				
112	General Plant	392-399	58,732,364	17,057,434	3,093,728	7,300,260	4,379,213	7,830,129	19,071,599

NW NATURAL
Long-Run Incremental Cost Study – Response to OPUC Staff Data Request 502

	Account Description	Account Code	Account Balance	Prod-Trans DistOther	Stor	Mains	Service	Meters	Cust Acct
113	Total-DEP. RESERVE (PLANT IN SERV)		990,862,436	46,714,490	106,947,031	425,762,420	336,166,737	55,083,758	20,187,999
114									
115	Retirement Obligation								
116									
117	**TOTAL - DEPRECIATION RESERVE**		**990,862,436**	**46,714,490**	**106,947,031**	**425,762,420**	**336,166,737**	**55,083,758**	**20,187,999**
118									
119	III. OTHER RATE BASE ITEMS								
120	Gas Storage Underground - NonCurrent	117	13,156,228		13,156,228				
121	Gas Stored Underground - Current	164	(466,362)		(466,362)				
122	Materials and Supplies	154	7,422,433	381,505	929,964	3,237,153	2,112,961	624,995	135,855
123	Working Capital		0						
124	Pension		0	0	0	0	0	0	0
125	Deferred Income Taxes	283	(319,816,163)	(16,438,218)	(40,070,069)	(139,481,739)	(91,042,786)	(26,929,667)	(5,853,684)
126	Other		(838,817)	(43,114)	(105,096)	(365,834)	(238,788)	(70,631)	(15,353)
127	Total - OTHER RATE BASE ITEMS		(300,542,681)	(16,099,827)	(26,555,335)	(136,610,420)	(89,168,613)	(26,375,303)	(5,733,182)
128									
129	**IV. TOTAL RATE BASE (Excl. Working Capital)**		860,845,327	47,809,116	136,155,121	376,290,273	187,350,620	99,768,140	13,472,056
130			860,845,203						
131	Gas Purchases Cash Working Capital	131							
132									
133	**V. TOTAL RATE BASE**		860,845,327	47,809,116	136,155,121	376,290,273	187,350,620	99,768,140	13,472,056
134				5.55%	15.82%	43.71%	21.76%	11.59%	1.56%
135	**I. OPERATION & MAINTENANCE EXPENSE**								
136									
137	**A. PRODUCTION EXPENSES**								
138									
139	1. Manufactured Gas Production								
140									
141	Production Maps	751	0	0					
142	Gas Wells Expense	752	0	0					
143	Field Lines Expense	753	0	0					
144	Field Compressor Station Expense	755	0	0					
145	Other Expense	759	0	0					
146	Rents	760	0	0					
147	Subtotal - Operation Accounts	751-760	**0**	0					
148	Maint Supervision & Engineering	762	0	0					
149	Field Lines	764	0	0					
150	Field Meas/Reg	766	0	0					
151	Subtotal - Maintenance Accounts	762-766	**0**	0					
152									
153	Subtotal - Manufactured Gas Production	751-766	**0**	0					
154									
155	2. Other Gas Supply Expenses								
156									
157	Nat Gas Field Lines	801	0	0					
158	Nat Gas Transmission Lines	803	0	0					
159	Natural Gas City Gate	804	0	0					
160	Purchase Gas Cost Adjustment	805	0	0					
161	Exchange Gas	806	0	0					
162	Well Expense - Purchase Gas	807	0	0					
163	Gas Delivery/Withdraw from Storage	808	0	0					

NW NATURAL

Long-Run Incremental Cost Study – Response to OPUC Staff Data Request 502

	Account Description	Account Code	Account Balance	Prod-Trans DistOther	Stor	Mains	Service	Meters	Cust Acct
164	Gas used Compressor Station	810	0	0					
165	Gas Used Other Utility	812	0	0					
166	Subtotal - Other Gas Production	801-812	0						
167	**Subtotal - PRODUCTION EXPENSES**	751-812	**0**	0					
168									
169	**B. NATURAL GAS STORAGE, TERMINALING & PROCESSING EXPENSES**								
170									
171	Wells Expense	816	253,553		253,553				
172	Lines Expenses	817	0		0				
173	Compressor Station Expenses	818	544,458		544,458				
174	Compressor Station Fuel	819, 845	(67,759)		(67,759)				
175	Meas/Reg Station Expenses	820	1,073,699		1,073,699				
176	Purification Expenses	821	27,531		27,531				
177	Gas Losses	823	0		0				
178	Other Expenses	824, 840, 844	1,660,207		1,660,207				
179	Storage Well Royalties	825	0		0				
180	**Subtotal - Operations Accounts**	816-825	**3,491,689**		3,491,689				
181	Maint. of Structures & Improvements	831	0		0				
182	Maint. of Reservoirs and Wells	832	116,015		116,015				
183	Maint. of Lines	833	0		0				
184	Maint. of Compressor Station Equipment	834	0		0				
185	Maint. of Meas/Reg Statoin Equipment	835	0		0				
186	Maint. Other	847	478,829		478,829				
187	Subtotal - Maint. Accounts	831-835	**594,844**	0	594,844				
188									
189	**Subtotal - NATURAL GAS STORAGE**	816-835	**4,086,533.06**	0.00	4,086,533.06				
190									
191	**C. TRANSMISSION EXPENSES**								
192									
193	Supvervision/Engineering	850	0	0					
194	Compressor Station Labor & Expenses	853	0	0					
195	Mains Expense	856	430,127	430,127					
196	Meas/Reg Station Expenses	857	0	0					
197	Transmission/Compressor Ga	858	0	0					
198	Other Expenses	859	0	0					
199	Rents	860	0	0					
200	**Subtotal - Operation Accounts**	856-860	**430,127**	430,127					
201	Maint. of Mains	863	83,693	83,693					
202	Maint. Of Compressor Station	864	0	0					
203	Maint. Of Meas/Reg Station Equipment	865	0	0					
204	**Subtotal - Maintenance Accounts**	863-865	**83,693**	83,693					
205									
206	**Subtotal - TRANSMISSION EXPENSES**	850-865	**513,820**	513,820					
207									
208	**D. DISTRIBUTION EXPENSES**								
209									
210	Operation Supervision & Engineering	870	2,150,754	1,051,847		452,744	268,817	377,346	
211	Distribution Load Dispatching	871	0	0					
212	Mains and Services Expenses	874	7,366,862			4,455,086	2,911,776		
213	Meas. & Reg. Station Expenses	875, 877	351,229	351,229					
214	Meter & House Regulator Expenses	878	3,694,526					3,694,526	

NW NATURAL
Long-Run Incremental Cost Study – Response to OPUC Staff Data Request 502

	Account Description	Account Code	Account Balance	Prod-Trans DistOther	Stor	Mains	Service	Meters	Cust Acct
215	Customer Installations Expenses	879	12,695,405	12,695,405					
216	Other Expenses	880	1,152,036	1,152,036					
217	Rents	881	163,270	163,270					
218	Maint. Supervision and Engineering	885	7,907,132	3,867,058		1,664,489	988,293	1,387,292	
219	Maint. of Structures & Improvements	886	0	0					
220	Maint. of Mains	887	2,094,421			2,094,421			
221	Maint. of Compressor Station Equip.	888	0	0					
222	Maint. of Meas. & Reg. Station Expenses-General	889, 891	834,139	834,139					
223	Maint. of Meas. & Reg. Station Expenses-Indust.	890	0	0					
224	Maint. of Services	892	977,002				977,002		
225	Maint. of Meters & House Regulators	893	1,764,252					1,764,252	
226	Maint. of Other Equipment	894	20,194	20,194					
227									
228	**Subtotal - DISTRIBUTION EXPENSES**	870-894	**41,171,222**	20,135,178	0	8,666,740	5,145,888	7,223,416	0
229									
230	**Total - OPERATION & MAINTENANCE EXPENSES**		**45,771,575.41**	20,648,998.02	4,086,533.06	8,666,740.04	5,145,888.07	7,223,416.22	0.00
231	Allocator of Supervision		31,113,336	15,216,273	0	6,549,507	3,888,778	5,458,778	0
232									
233	**II. CUSTOMER ACCOUNTS EXPENSES**								
234									
235	Supervision	901	1,199,076						1,199,076
236	Meter Reading Expenses	902	534,875						534,875
237	Customer Records & Collection Expense	903	14,521,848						14,521,848
238	Uncollectible Accounts	904	**2,231,394**						2,231,394
239									
240	Total - CUSTOMER ACCOUNTS EXPENSES	901-904	18,487,193	0		0	0	0	18,487,193
241									
242	**III. CUSTOMER SERVICE & INFORMATIONAL EXPENSES**								
243									
244	Supervision	907	212,406						212,406
245	Customer Assistance Expenses	908	2,982,237						2,982,237
246	Misc. Customer Serv. & Inform. Expen.	909, 910	1,132,918						1,132,918
247									
248	Subtotal - CUSTOMER SERVICE	907-910	4,327,561	0		0	0	0	4,327,561
249									
250	**IV. SALES EXPENSES (C-8)**								
251									
252	Supervision	911	242,298						242,298
253	Demonstrating & Selling Expenses	912	1,848,272						1,848,272
254	Advertising	913	712,233						712,233
255	Miscellaneous Sales Expenses	916	107						107
256	Subtotal - O&M Accounts	911-916	2,802,909						2,802,909
257									
258	Total - SALES EXPENSES	911-916	2,802,909	0		0	0	0	2,802,909
259									
260	Total - CUSTOMER ACCOUNTS, SERVICES & SALE	901-916	**25,617,663**	0		0	0	0	25,617,663
261									
262	**V. ADMINISTRATIVE & GENERAL EXPENSES**								
263									
264	A. Labor-Related:								
265									

NW NATURAL
Long-Run Incremental Cost Study – Response to OPUC Staff Data Request 502

Line	Account Description	Account Code	Account Balance	Prod-Trans DistOther	Stor	Mains	Service	Meters	Cust Acct
266	Administrative & General Salaries	920	0	0	0	0	0	0	0
267	Office Supplies & Expenses	921	30,972,898	8,995,350	1,631,498	3,849,840	2,309,407	4,129,270	10,057,533
268	Admin. Expenses Transferred-Credit	922	(12,679,264)	(3,682,394)	(667,880)	(1,575,995)	(945,393)	(1,690,385)	(4,117,216)
269	Outside Services Employed	923	0	0	0	0	0	0	0
270	Employee Pensions and Benefits	926	1,375,359	399,441	72,447	170,953	102,550	183,361	446,607
272	Subtotal - O&M Accounts	920-932	19,668,992	5,712,396	1,036,064	2,444,798	1,466,563	2,622,247	6,386,924
274	B. Plant-Related:								
276	Property Insurance	924	1,856,883	95,442	232,651	809,844	528,603	156,356	33,987
277	Injuries and Damages	925	881,635	45,315	110,461	384,509	250,977	74,237	16,137
278	Maintenance of General Plant	935	3,580,857	184,052	448,649	1,561,723	1,019,371	301,521	65,541
280	Subtotal - O&M Accounts 924-925, 932		6,319,376	324,809	791,761	2,756,076	1,798,951	532,114	115,665
282	C. Other-Related:								
284	Franchise Requirements	927	0	0	0				0
285	Regulatory Commission Expenses	928	234,667	13,033	37,116	102,577	51,072	27,197	3,672
286	Duplicate Charges - Credit	929	0	0	0				0
287	Misc. Gen'l Expenses	930	3,266,006	948,535	172,037	405,955	243,521	435,420	1,060,539
288	Rents	931	3,623,559	186,247	453,999	1,580,346	1,031,527	305,117	66,323
290	Total - ADMINISTRATIVE & GENERAL EXPENSES	920-931	**33,112,600**	7,185,020	2,490,977	7,289,752	4,591,633	3,922,094	7,633,124
292	**TOTAL - OPERATING EXPENSES (Excl. Depr.,**		**104,501,839**	27,834,018	6,577,510	15,956,492	9,737,521	11,145,511	33,250,787
293	**Taxes, and Gas Supply Expense)**								
295	**VI. DEPRECIATION EXPENSE**								
296	Intangible Plant	403.1	3,291,170	169,163	412,354	1,435,381	936,905	277,128	60,239
297	Production Plant	403.2	0						
298	Natural Gas Storage Plant	403.3	6,071,183		6,071,183				
299	Transmission	403.4	1,266,677	1,266,677					
300	Distribution Mains	403.5	24,389,315			24,389,315			
301	Distribution Services	403.6	15,185,332				15,185,332		
302	Distr- Meters & House Regulators	403.7	4,289,347					4,289,347	
303	Distribution- All Other	403.8	758,986	758,986					
304	General Plant	403.9	4,755,863	1,381,229	250,515	591,140	354,607	634,046	1,544,326
305	Total - DEPRECIATION EXPENSE	403,404	60,007,873	3,576,054	6,734,052	26,415,836	16,476,844	5,200,521	1,604,565
307	**VII. TAXES OTHER THAN INCOME TAXES**		60,007,873	3,576,054	6,734,052	26,415,836	16,476,844	5,200,521	1,604,565
309	A. General Taxes								
311	Payroll Taxes	408.15	5,117,689	1,486,312	269,574	636,114	381,586	682,284	1,661,818
312	Plant Related Taxes	408.17	14,486,503	804,543	2,291,250	6,332,299	3,152,779	1,678,921	226,711
313	Gas Related	408.18	(11,609,000)	(11,609,000)					
314	Subtotal - Real Estate & Other	408.17,408.18	2,877,503	(10,804,457)	2,291,250	6,332,299	3,152,779	1,678,921	226,711
315	Subtotal - General Taxes		7,995,192	(9,318,145)	2,560,824	6,968,413	3,534,365	2,361,205	1,888,529

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Account Description	Account Code	Account Balance	Prod-Trans DistOther	Stor	Mains	Service	Meters	Cust Acct
TOTAL EXPENSES (excl. Gross Receipts Taxes & Gas Purchases)	408.1	172,504,903	22,091,927	15,872,386	49,340,741	29,748,730	18,707,237	36,743,881
B. Revenue Taxes: (GRT)								
Franchise Tax	408.11	22,548,062	1,252,261	3,566,302	9,856,145	4,907,262	2,613,220	352,873
Regulatory Tax	408.12	0						
Subtotal - Revenue Taxes (GRT)		22,548,062	1,252,261	3,566,302	9,856,145	4,907,262	2,613,220	352,873
C. INCOME TAXES								
Fed & State Income Taxes Based on Net Income	409.1	29,997,239	3,108,632	3,428,636	10,106,922	5,629,706	3,328,340	4,395,002
Normalized Depreciation	409.1Dep							
Real Estate Taxes	409.1RE							
Fed & State Inc Taxes Based on Deferred Plant	409.1Plant							
Other	409.4							
Subtotal - Income Taxes		29,997,239	3,108,632	3,428,636	10,106,922	5,629,706	3,328,340	4,395,002
TOTAL TAXES (Excl. General Taxes)		52,545,301	4,360,893	6,994,938	19,963,067	10,536,968	5,941,560	4,747,874
TOTAL EXPENSES		**225,050,204**	**26,452,821**	**22,867,324**	**69,303,808**	**40,285,698**	**24,648,797**	**41,491,756**
V. OPERATING REVENUES								
Sale of Gas	480-485	682,881,427						
Transportation		12,870,563						
Miscellaneous Revenues		4,983,159						
Gas Costs		(410,818,525)						
Total Operating Revenues		289,916,624						
NET INCOME		64,866,420						
SUMMARY								
Rate Base		860,845,327	47,809,116	136,155,121	376,290,273	187,350,620	99,768,140	13,472,056
Return on Rate Base with Tax Effect Return of	7.56%	65,097,124	3,615,325	10,296,050	28,455,070	14,167,454	7,544,467	1,018,757
Expenses		104,501,839	27,834,018	6,577,510	15,956,492	9,737,521	11,145,511	33,250,787
Depreciation		60,007,873	3,576,054	6,734,052	26,415,836	16,476,844	5,200,521	1,604,565
Other Taxes		30,543,253	(8,065,884)	6,127,126	16,824,558	8,441,627	4,974,425	2,241,402
Total PreTax Revenue Requirement		260,150,088	26,959,514	29,734,738	87,651,956	48,823,446	28,864,924	38,115,511
Income Taxes		29,997,239	3,108,632	3,428,636	10,106,922	5,629,706	3,328,340	4,395,002
Total Revenue Requirement		290,147,327	30,068,146	33,163,374	97,758,878	54,453,152	32,193,264	42,510,512
			10%	11%	34%	19%	11%	15%
Adjustments/Recon (Allocated using Total Rev Req)								

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Account Description	Account Code	Account Balance	Prod-Trans DistOther	Stor	Mains	Service	Meters	Cust Acct
Special Contract revenue (rates not part of this GRC)		1,814,000	187,986	207,337	611,188	340,441	201,272	265,776
Miscellaneous revenue (rates not part of this GRC)		4,983,000	516,391	569,549	1,678,914	935,180	552,888	730,077
Total Revenue Requirement for LRIC		283,350,327	29,363,769	32,386,488	95,468,776	53,177,531	31,439,104	41,514,660

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Account Description	Account Code	Account Balance	Labor Percentage	Labor Trans-Dist Other	Labor Stor	Labor Mains	Labor Services	Labor Meters	Labor Cust Acct
I. GAS PLANT IN SERVICE									
A. INTANGIBLE PLANT									
Organization	301	852							
Franchise and Consents	302	83,496							
Miscellaneous Intangible Plant	303	94,013,486							
Subtotal - INTANGIBLE PLANT	301-303	94,097,834							
B. PRODUCTION PLANT									
Other Land & Land Rights-Land	304, 305, 325	93,061							
Gas Well Structures	318, 326	388,447							
Field Compressor Station Structures	327	0							
Field M&R Station Structures	328	0							
Other Structures	329	0							
Producing Gas Wells-Well Equipment	331	0							
Field Lines	332	0							
Field Compressor Station Equipment	333	0							
Field M&R Station Equip-Company	311, 334	8,242							
Drilling & Cleaning Equipment	319, 335	185,448							
Other Equipment-Other	337	0							
Subtotal - PRODUCTION PLANT	325-337	675,198							
C. NATURAL GAS STORAGE PLANT & PROD PLANT									
Land and Land Rights	350, 360	870,224							
Structures and Improvements	351, 361	13,831,591							
Wells-Well Equipment	352, 362	39,340,908							
Lines	353, 363	24,738,958							
Compressor Station Equipment - Other	354	25,203,830							
M&R Equipment-Meters & Gauges	355, 356	5,964,468							
Other Equipment	357	141,807,053							
Subtotal - STORAGE PLANT	350-363	251,757,033							
D. TRANSMISSION PLANT									
Land & Land Rights	365	6,544,949							
Structures & Improvements	366	1,041,984							
Mains	367	31,319,351							
M&R Station Equipment	369	3,661,168							
Other Equipment	371	0							
Subtotal - TRANSMISSION PLANT	365-371	42,567,452							
E. DISTRIBUTION PLANT									
Land and Land Rights	374	1,888,356							
Structures and Improvements	375	49,372							
Mains	376	883,204,384							
Compressor Station Equipment	377	818,380							

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	Account Description	Account Code	Account Balance	Labor Percentage	Labor rans-Dist Other	Labor Stor	Labor Mains	Labor Services	Labor Meters	Labor Cust Acct
62	M & R Station Equipment	378, 379	25,814,245							
63	Services	380	577,248,944							
64	Meters	381	94,218,327							
65	Meter Install Residential	382	63,080,383							
66	Meter Install Commercial	383	538,750							
67	House Regulator Install.	384	0							
68	Industrial M & R Station Equipment	385	0							
69	Other Property on Customers Premise	386	0							
70	Other Equipment	387	281,415							
71	Subtotal - DISTRIBUTION PLANT	374-387	1,647,142,556							
72	**TOTAL GAS PLANT**									
73										
74										
75	**F. GENERAL PLANT**									
76										
77	Land and Land Rights	389	3,230,763							
78	Structures and Improvements	390	33,508,503							
79	Office Furniture and Equipment	391	25,909,006							
80	Transportation Equipment	392	23,791,851							
81	Stores Equipment	393	107,585							
82	Tools, Shop and Garage Equipment	394	13,822,166							
83	Laboratory Equipment	395	61,532							
84	Power Operated Equipment	396	6,734,945							
85	Communication Equipment	397	8,674,816							
86	Miscellaneous Equipment	398	169,201							
87	Other Tangible Plant	399	0							
88	Subtotal - GENERAL PLANT	389-399	116,010,369							
89										
90	**TOTAL PLANT IN SERVICE**		2,152,250,443							
91										
92	G. Utility Plant	105	0							
93										
94	**TOTAL UTILITY PLANT - Minus Intangibles**		2,058,152,609							
95										
96	**II. DEPRECIATION RESERVE**									
97										
98	Intangible Plant	301-303	60,994,540							
99	Production Plant	332-337	691,037							
100	Local Storage Plant	350-357	96,211,239							
101	Transmission	365-371	14,541,662							
102	Distribution Land Structures & Improvements	374-375	936,378							
103	Distribution Mains	376	391,860,551							
104	Compressor Station Equipment	377	560,469							
105	Distribution M&R General	378,379	9,447,019							
106	Distribution Services	380	314,424,072							
107	Distribution - Meters	381	26,614,033							
108	Distribution - Meters Installations	382	15,503,636							
109	Industrial M & R Station Equipment - Other	385	0							
110	Other Property on Customers Premises	383,386	64,019							
111	Other Equipment	387	281,415							
112	General Plant	392-399	58,732,364							

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Row	Account Description	Account Code	Account Balance	Labor Percentage	Labor rans-Dist Other	Labor Stor	Labor Mains	Labor Services	Labor Meters	Labor Cust Acct
113	Total-DEP. RESERVE (PLANT IN SERV)		990,862,436							
114										
115	Retirement Obligation									
116										
117	**TOTAL - DEPRECIATION RESERVE**		**990,862,436**							
118										
119	III. OTHER RATE BASE ITEMS									
120	Gas Storage Underground - NonCurrent	117	13,156,228							
121	Gas Stored Underground - Current	164	(466,362)							
122	Materials and Supplies	154	7,422,433							
123	Working Capital		0							
124	Pension		0							
125	Deferred Income Taxes	283	(319,816,163)							
126	Other		(838,817)							
127	Total - OTHER RATE BASE ITEMS		(300,542,681)							
128										
129	**IV. TOTAL RATE BASE (Excl. Working Capital)**		860,845,327							
130			860,845,203							
131	Gas Purchases Cash Working Capital	131								
132										
133	**V. TOTAL RATE BASE**		860,845,327							
134										
135	**I. OPERATION & MAINTENANCE EXPENSE**									
136										
137	**A. PRODUCTION EXPENSES**									
138										
139	1. Manufactured Gas Production									
140										
141	Production Maps	751	0							
142	Gas Wells Expense	752	0							
143	Field Lines Expense	753	0							
144	Field Compressor Station Expense	755	0							
145	Other Expense	759	0							
146	Rents	760	0							
147	Subtotal - Operation Accounts	751-760	**0**							
148	Maint Supervision & Engineering	762	0							
149	Field Lines	764	0							
150	Field Meas/Reg	766	0							
151	Subtotal - Maintenance Accounts	762-766	**0**							
152										
153	Subtotal - Manufactured Gas Production	751-766	**0**							
154										
155	2. Other Gas Supply Expenses									
156										
157	Nat Gas Field Lines	801	0							
158	Nat Gas Transmission Lines	803	0							
159	Natural Gas City Gate	804	0							
160	Purchase Gas Cost Adjustment	805	0							
161	Exchange Gas	806	0							
162	Well Expense - Purchase Gas	807	0							
163	Gas Delivery/Withdraw from Storage	808	0							

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Row	Account Description	Account Code	Account Balance	Labor Percentage	Labor rans-Dist Other	Labor Stor	Labor Mains	Labor Services	Labor Meters	Labor Cust Acct
164	Gas used Compressor Station	810	0							
165	Gas Used Other Utility	812	0							
166	Subtotal - Other Gas Production	801-812	0							
167	**Subtotal - PRODUCTION EXPENSES**	751-812	**0**							
168										
169	**B. NATURAL GAS STORAGE, TERMINALING & PROCESSING EXPENSES**									
170										
171	Wells Expense	816	253,553	4%	0	11,017	0	0	0	0
172	Lines Expenses	817	0	0%	0	0	0	0	0	0
173	Compressor Station Expenses	818	544,458	10%	0	52,299	0	0	0	0
174	Compressor Station Fuel	819, 845	(67,759)	0%	0	0	0	0	0	0
175	Meas/Reg Station Expenses	820	1,073,699	71%	0	760,404	0	0	0	0
176	Purification Expenses	821	27,531	21%	0	5,818	0	0	0	0
177	Gas Losses	823	0	0%	0	0	0	0	0	0
178	Other Expenses	824, 840, 844	1,660,207	73%	0	1,212,144	0	0	0	0
179	Storage Well Royalties	825	0	0%	0	0	0	0	0	0
180	**Subtotal - Operations Accounts**	816-825	**3,491,689**		**0**	**2,041,683**	**0**	**0**	**0**	**0**
181	Maint. of Structures & Improvements	831	0	0%	0	0	0	0	0	0
182	Maint. of Reservoirs and Wells	832	116,015	48%	0	55,654	0	0	0	0
183	Maint. of Lines	833	0	0%	0	0	0	0	0	0
184	Maint. of Compressor Station Equipment	834	0	0%	0	0	0	0	0	0
185	Maint. of Meas/Reg Statoin Equipment	835	0	0%	0	0	0	0	0	0
186	Maint. Other	847	478,829	60%	0	285,553	0	0	0	0
187	Subtotal - Maint. Accounts	831-835	**594,844**		0	341,207	0	0	0	0
188										
189	**Subtotal - NATURAL GAS STORAGE**	816-835	**4,086,533.06**		0.00	2,382,889.16	0.00	0.00	0.00	0.00
190										
191	**C. TRANSMISSION EXPENSES**									
192										
193	Supvervision/Engineering	850	0	0%	0	0	0	0	0	0
194	Compressor Station Labor & Expenses	853	0	0%	0	0	0	0	0	0
195	Mains Expense	856	430,127	65%	281,577	0	0	0	0	0
196	Meas/Reg Station Expenses	857	0	0%	0	0	0	0	0	0
197	Transmission/Compressor Ga	858	0	0%	0	0	0	0	0	0
198	Other Expenses	859	0	0%	0	0	0	0	0	0
199	Rents	860	0	0%	0	0	0	0	0	0
200	**Subtotal - Operation Accounts**	856-860	**430,127**	0	**281,577**	**0**	**0**	**0**	**0**	**0**
201	Maint. of Mains	863	83,693	42%	35,325	0	0	0	0	0
202	Maint. Of Compressor Station	864	0	0%	0	0	0	0	0	0
203	Maint. Of Meas/Reg Station Equipment	865	0	0%	0	0	0	0	0	0
204	**Subtotal - Maintenance Accounts**	863-865	**83,693**		0	0	0	0	0	0
205					0	0	0	0	0	0
206	**Subtotal - TRANSMISSION EXPENSES**	850-865	**513,820**		281,577	0	0	0	0	0
207										
208	**D. DISTRIBUTION EXPENSES**									
209										
210	Operation Supervision & Engineering	870	2,150,754	85%	891,716	0	383,820	227,893	319,900	0
211	Distribution Load Dispatching	871	0	0%	0	0	0	0	0	0
212	Mains and Services Expenses	874	7,366,862	62%	0	0	2,765,317	1,807,369	0	0
213	Meas. & Reg. Station Expenses	875, 877	351,229	55%	192,849	0	0	0	0	0
214	Meter & House Regulator Expenses	878	3,694,526	90%	0	0	0	0	3,326,349	0

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#	Account Description	Account Code	Account Balance	Labor Percentage	Labor rans-Dist Other	Labor Stor	Labor Mains	Labor Services	Labor Meters	Labor Cust Acct
215	Customer Installations Expenses	879	12,695,405	60%	7,661,438	0	0	0	0	0
216	Other Expenses	880	1,152,036	95%	1,096,743	0	0	0	0	0
217	Rents	881	163,270	0%	0	0	0	0	0	0
218	Maint. Supervision and Engineering	885	7,907,132	60%	2,325,041	0	1,000,762	594,204	834,099	0
219	Maint. of Structures & Improvements	886	0	0%	0	0	0	0	0	0
220	Maint. of Mains	887	2,094,421	70%	0	0	1,472,997	0	0	0
221	Maint. of Compressor Station Equip.	888	0	0%	0	0	0	0	0	0
222	Maint. of Meas. & Reg. Station Expenses-General	889, 891	834,139	81%	674,273	0	0	0	0	0
223	Maint. of Meas. & Reg. Station Expenses-Indust.	890	0	0%	0	0	0	0	0	0
224	Maint. of Services	892	977,002	76%	0	0	0	743,545	0	0
225	Maint. of Meters & House Regulators	893	1,764,252	88%	0	0	0	0	1,550,670	0
226	Maint. of Other Equipment	894	20,194	72%	14,549	0	0	0	0	0
228	**Subtotal - DISTRIBUTION EXPENSES**	870-894	**41,171,222**		12,856,609	0	5,622,896	3,373,011	6,031,018	0
230	**Total - OPERATION & MAINTENANCE EXPENSES**		**45,771,575.41**		###########	2,382,889.16	5,622,895.88	3,373,010.81	6,031,018.24	0.00
231	Allocator of Supervision		31,113,336							
233	**II. CUSTOMER ACCOUNTS EXPENSES**									
235	Supervision	901	1,199,076	98%	0	0	0	0	0	1,174,880
236	Meter Reading Expenses	902	534,875	87%	0	0	0	0	0	467,698
237	Customer Records & Collection Expense	903	14,521,848	68%	0	0	0	0	0	9,894,446
238	Uncollectible Accounts	904	**2,231,394**	0	0	0	0	0	0	0
240	Total - CUSTOMER ACCOUNTS EXPENSES	901-904	18,487,193		0	0	0	0	0	11,537,024
242	**III. CUSTOMER SERVICE & INFORMATIONAL EXPENSES**									
244	Supervision	907	212,406	100%	0	0	0	0	0	212,406
245	Customer Assistance Expenses	908	2,982,237	89%	0	0	0	0	0	2,667,901
246	Misc. Customer Serv. & Inform. Expen.	909, 910	1,132,918	24%	0	0	0	0	0	272,231
248	Subtotal - CUSTOMER SERVICE	907-910	4,327,561		0	0	0	0	0	3,152,537
250	**IV. SALES EXPENSES (C-8)**									
252	Supervision	911	242,298	98%	0	0	0	0	0	238,524
253	Demonstrating & Selling Expenses	912	1,848,272	68%	0	0	0	0	0	1,260,049
254	Advertising	913	712,233	0%	0	0	0	0	0	0
255	Miscellaneous Sales Expenses	916	107	0%	0	0	0	0	0	0
256	Subtotal - O&M Accounts	911-916	2,802,909							
258	Total - SALES EXPENSES	911-916	2,802,909		0	0	0	0	0	0
260	Total - CUSTOMER ACCOUNTS, SERVICES & SALE	901-916	**25,617,663**		13,138,186	2,382,889	5,622,896	3,373,011	6,031,018	14,689,561
261					29.04%	5.27%	12.43%	7.46%	13.33%	32.47%
262	**V. ADMINISTRATIVE & GENERAL EXPENSES**									
264	A. Labor-Related:									

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Line	Account Description	Account Code	Account Balance	Labor Percentage	Labor rans-Dist Other	Labor Stor	Labor Mains	Labor Services	Labor Meters	Labor Cust Acct
266	Administrative & General Salaries	920	0							
267	Office Supplies & Expenses	921	30,972,898							
268	Admin. Expenses Transferred-Credit	922	(12,679,264)							
269	Outside Services Employed	923	0							
270	Employee Pensions and Benefits	926	1,375,359							
271										
272	Subtotal - O&M Accounts	920-932	19,668,992							
273										
274	B. Plant-Related:									
275										
276	Property Insurance	924	1,856,883							
277	Injuries and Damages	925	881,635							
278	Maintenance of General Plant	935	3,580,857							
279										
280	Subtotal - O&M Accounts 924-925, 932		6,319,376							
281										
282	C. Other-Related:									
283										
284	Franchise Requirements	927	0							
285	Regulatory Commission Expenses	928	234,667							
286	Duplicate Charges - Credit	929	0							
287	Misc. Gen'l Expenses	930	3,266,006							
288	Rents	931	3,623,559							
289										
290	Total - ADMINISTRATIVE & GENERAL EXPENSES	920-931	**33,112,600**							
291										
292	**TOTAL - OPERATING EXPENSES (Excl. Depr.,**		**104,501,839**							
293	**Taxes, and Gas Supply Expense)**									
294										
295	**VI. DEPRECIATION EXPENSE**									
296	Intangible Plant	403.1	3,291,170							
297	Production Plant	403.2	0							
298	Natural Gas Storage Plant	403.3	6,071,183							
299	Transmission	403.4	1,266,677							
300	Distribution Mains	403.5	24,389,315							
301	Distribution Services	403.6	15,185,332							
302	Distr- Meters & House Regulators	403.7	4,289,347							
303	Distribution- All Other	403.8	758,986							
304	General Plant	403.9	4,755,863							
305	Total - DEPRECIATION EXPENSE	403,404	60,007,873							
306										
307	**VII. TAXES OTHER THAN INCOME TAXES**		60,007,873							
308										
309	A. General Taxes									
310										
311	Payroll Taxes	408.15	5,117,689							
312	Plant Related Taxes	408.17	14,486,503							
313	Gas Related	408.18	(11,609,000)							
314	Subtotal - Real Estate & Other	408.17,408.18	2,877,503							
315	Subtotal - General Taxes		7,995,192							
316										

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Account Description	Account Code	Account Balance	Labor Percentage	Labor rans-Dist Other	Labor Stor	Labor Mains	Labor Services	Labor Meters	Labor Cust Acct
TOTAL EXPENSES (excl. Gross Receipts Taxes & Gas Purchases)	408.1	172,504,903							
B. Revenue Taxes: (GRT)									
Franchise Tax	408.11	22,548,062							
Regulatory Tax	408.12	0							
Subtotal - Revenue Taxes (GRT)		22,548,062							
C. INCOME TAXES									
Fed & State Income Taxes Based on Net Income	409.1	29,997,239							
Normalized Depreciation	409.1Dep								
Real Estate Taxes	409.1RE								
Fed & State Inc Taxes Based on Deferred Plant	409.1Plant								
Other	409.4								
Subtotal - Income Taxes		29,997,239							
TOTAL TAXES (Excl. General Taxes)		52,545,301							
TOTAL EXPENSES		**225,050,204**							
V. OPERATING REVENUES									
Sale of Gas	480-485	682,881,427							
Transportation		12,870,563							
Miscellaneous Revenues		4,983,159							
Gas Costs		(410,818,525)							
Total Operating Revenues		289,916,624							
NET INCOME		64,866,420							
SUMMARY									
Rate Base		860,845,327							
Return on Rate Base with Tax Effect Return of	7.56%	65,097,124							
Expenses		104,501,839							
Depreciation		60,007,873							
Other Taxes		30,543,253							
Total PreTax Revenue Requirement		260,150,088							
Income Taxes		29,997,239							
Total Revenue Requirement		290,147,327							

Adjustments/Recon (Allocated using Total Rev Req)

NW NATURAL
Long-Run Incremental Cost Study – Response to OPUC Staff Data Request 502

Account Description	Account Code	Account Balance	Labor Percentage	Labor rans-Dist Other	Labor Stor	Labor Mains	Labor Services	Labor Meters	Labor Cust Acct
Special Contract revenue (rates not part of this GRC)		1,814,000							
Miscellaneous revenue (rates not part of this GRC)		4,983,000							
Total Revenue Requirement for LRIC		283,350,327							

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 502**:**
Regarding Exhibit Staff/1400 Ordonez/4, "Summary Recommendation" section, lines 6-8, where Staff stated the intention to work with NW Natural to obtain the Company's functionalized revenue requirement reflecting Staff adjustments, please provide:
a) In electronic spreadsheet format with cell references and formulae intact, the Company's functionalized revenue requirement (embedded costs), reflecting OPUC Staff Opening Testimony's adjustments as represented in Exhibit Staff/102, Goodwin/1-3, Staff Errata Filing, where OPUC Staff recommended a $9.485 million reduction from the revenue requirement resulting from base rates in the Company's initial filing in this proceeding.
Please include workpapers, in electronic spreadsheet format with cell references and formulae intact. 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.

1 See http://edocs.puc.state.or.us/efdocs/HTB/ug221htb153620.pdf.
2 See Exhibit Staff/102, Goodwin/3.

Response: SUPPLEMENTAL RESPONSE 6/29/2012

After the Company provided its response to this data request on 6/26/2012, Staff raised a follow-up question regarding the revenue requirement of $283 million included in the response. Staff indicated they had expected the revenue requirement would be about $278 million ($287.4 million as the Company originally filed in the case less $9.5 million revenue decrease proposed by Staff in their Errata Reply Testimony = $277.9 million).

Staff's proposal as reflected in their Errata Reply Testimony included an adjustment of revenues (adjustment S-24) that resulted in a $5.2 million net increase to the Company's test year revenues at current rates (a $9.4 million increase in sales revenues less a $4.2 million increase in cost of gas expense = $5.2 million net increase to test year revenues). Because this adjustment has the effect of increasing test year revenues at current rates, the total revenue requirement is increased also.

Thus, the $283 million revenue requirement included in the DR 502 response can be reconciled to Staff's expectation of $278 million as follows:

	Revenue requirement rounded to nearest $million
	Derivation of Company's DR 502 response:
$287	Revenue requirement in Company's original filing
+ $5	Staff adjustment S-24 net increase to test year revenue
- $9	Staff's total recommended rate decrease
$283	Resulting revenue requirement in DR 502 response
	Reconciliation to Staff:
$278	Revenue requirement expected by Staff
+ $5	Staff adjustment S-24 net increase to test year revenue
$283	Resulting revenue requirement in DR 502 response

CASE: UG 221
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2500

Rebuttal Testimony
Residential Rate Design

July 20, 2012

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

A. My name is George R. Compton. I am employed by the Public Utility Commission of Oregon (OPUC) as a Senior Economist in the Economic Research and Financial Analysis Division. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. ARE YOU THE SAME GEORGE COMPTON WHO TESTIFIED IN STAFF'S OPENING TESTIMONY IN THIS PROCEEDING?

A. Yes. In Staff's opening testimony I filed Staff Exhibit/1500 through Staff Exhibit/1504.

Q. WHAT IS THE PURPOSE AND ORGANIZATIONAL STRUCTURE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the portion of Northwest Natural Gas Company's ("NW Natural" or "Company") reply testimony filed by Russell A. Feingold that pertained primarily to residential rate design.

I specifically address the following contentions made by Mr. Feingold:

1. "[R]elying on volumetric rates [as proposed by Staff] to recover the Company's fixed distribution costs is unduly discriminatory...;"[1]
2. It is wrong for Staff to "argue that density should be a factor to be considered in rate design;"[2]
3. Staff's residential rate design proposal is not in conformance with the economics and cost-causation principles of utility ratemaking;[3] and

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[1] See Exhibit NWN/2500: Feingold/2, line 22 through Feingold/3, line 1; Feingold/33, line 15 through Feingold/35, line 13; and Feingold/38, line 15 through Feingold/43, line 19.

[2] See Exhibit NWN/2500: Feingold/35, line 14 through Feingold/38, line 14.

4. "[T]here is no justification for a winter summer commodity [price] differential…."[4]

SUMMARY

Q. WHAT ARE YOUR SUMMARY POINTS IN THIS REBUTTAL TESTIMONY?

A. They are as follows:

- While relying on volumetric rates as opposed to a large customer charge to recover the Company's fixed distribution costs may unfairly[5] charge *different* amounts to customers that have the *same* costs, *not* relying at all on volumetric rates is likely to unfairly charge the *same* amount to customers with *different* costs. Given the inevitability of unfairness of one form or another, it is Staff's position—taking social equity[6] into consideration as well as long-held customer expectations (which of themselves define a form of fairness) and long-term energy conservation/environmental objectives—that recovering something over half of embedded distribution costs through volumetric rates is superior to collecting *all* of those costs through a flat customer charge.[7]

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3 *See* Exhibit NWN/2500: Feingold/43, line 20 through Feingold/51, line 8; and Feingold/53, line 1 through Feingold/57, line 12.

4 *See* Exhibit NWN/2500: Feingold/79, line 9.

5 I believe "unfair" better characterizes an unwanted outcome in this context than does "unduly discriminatory."

6 When direct cost-causation is indeterminate, it is Staff's social equity position that benefits-received should be considered, where benefits are most readily quantified by volumetric levels of consumption or demand.

7 *See* Staff/1503, Compton/1 for a quantification of the distribution costs properly included in the customer charge.

- While Mr. Feingold brings out some interesting observations regarding cost-causal factors for gas mains, including the mains' vintage and why the cost per foot in dense urban areas can exceed such costs in suburban areas, his testimony does not persuade this reader that mains costs fairly attributable to lower-use customers residing in multi-unit housing are always just as great as mains costs fairly attributable to larger-use customers in unattached dwellings on average-sized lots.
- While there is virtually universal acknowledgment that utility rates should reflect "cost-causation," there is far from universal understanding as to what that term means. The best that economic theory has to offer is that marginal costs are "really" what matter and that prices should reflect such. But unless a customer is at the end of a line (thereby requiring a main extension), the marginal cost of mains to serve that customer is zero.[8] With distribution mains used in common by all the upstream customers, there is no cost-causation link that would definitively connect a specific positive amount of cost responsibility to any particular customer. But obviously a zero price for mains will fail the number-one ratemaking objective—utility cost recovery. So what to do? The stock answer, Ramsey Pricing,[9] satisfies those who a) want to encourage additional consumption by existing customers; or b) aren't

[8] The main would be there whether or not the customer chose to connect to it. Upstream customers in a given length of main who choose *not* to connect to the main are every bit as "responsible" for the main's cost being what it is as are the customers who do choose to connect to the main. This general point was the subject of Footnote No. 14 of Exhibit Staff/1500, Compton/16.

[9] Whereby the supra-marginal-cost price is applied to the least demand-elastic "service" so that a marginal-cost price can be applied to ostensibly the most demand-elastic service, i.e., fuel consumption by existing customers.

terribly worried about the inefficiency of lower-use customers dropping off the system or not entering it to begin with; and/or c) see nothing inequitable with small residential customers paying just as much as would large customers to support a gas mains infrastructure used by those customers in common. Staff won't be found, comfortably, in any of those places.

- Contrary to assertions made by Mr. Feingold, simple, straightforward cost-causation and marginal-cost considerations would hold that storage, transmission, and pipeline capacity costs should be recovered through some form of winter-specific surcharge.

<u>TOPIC 1: THE POTENTIAL FOR UNFAIRLY CHARGING *DIFFERENT* AMOUNTS TO CUSTOMERS THAT HAVE THE *SAME* COSTS CAN BE PREFERRED TO THE POTENTIAL FOR UNFAIRLY CHARGING THE *SAME* AMOUNT TO CUSTOMERS WITH *DIFFERENT* COSTS</u>

Q. TWICE IN HIS TESTIMONY[10] MR. FEINGOLD CREATES STRAWMAN EXAMPLES WHEREBY CUSTOMERS WITH WHAT ARE EFFECTIVELY IDENTICAL DELIVERY COSTS (DUE IN ONE INSTANCE TO THEIR BEING LOCATED ACROSS THE STREET FROM EACH OTHER), BUT WITH DIFFERENT LEVELS OF GAS CONSUMPTION, WOULD PAY DIFFERENT AMOUNTS OF MAINS INFRASTRUCTURE SUPPORT IF MAINS COST RECOVERY WAS THROUGH A VOLUMETRIC CHARGE RATHER THAN THROUGH A UNIFORM LUMP-SUM FIXED (I.E., CUSTOMER) CHARGE.

10 *See* Exhibit NWN/2500: Feingold/33, line 15 through Feingold/35, line 3; and Feingold/38, line 15 through Feingold/40, line 9.

HE CONCLUDES[11] "THAT RELYING ON VOLUMETRIC RATES TO RECOVER THE COMPANY'S FIXED DISTRIBUTION COSTS IS UNDULY DISCRIMINATORY BECAUSE IT CHARGES DIFFERENT RATES TO RESIDENTIAL CUSTOMERS THAT HAVE THE SAME COSTS." DO YOU AGREE WITH THAT CONCLUSION?

A. Yes I do, although I would substitute the term, "unfair," for "unduly discriminatory."[12] But having said that, I can quickly come up with strawmen examples where the obvious conclusion is that fairness can best be achieved by having customers pay *unequal* amounts because their per-customer cost impositions are indeed not equal.

Q. PLEASE PROVIDE SUCH A STRAWMAN.

A. Refer to Mr. Feingold's apartment building case where the building on one side of the street was modernized so as to be more energy efficient than the otherwise identical building across the street.[13] Alter the strawman condition by assuming that rather than modernizing the one building, it was re-configured *within* so as to double the number of rental units. A flat-rate, customer charge for recovery of mains' costs would be unfair in this case because the customers of the re-configured building would now be contributing twice as much towards mains cost recovery as would the customers of the other

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[11] *See* Exhibit NWN/2500: Feingold/2, line 22 through Feingold/3, line 2.

[12] Difficulties in achieving agreement on the demarcation between "due-" and "undue-" discrimination are anticipated.

[13] *See* Exhibit NWN/2500: Feingold/38, line 15 through Feingold/40, line 9. Mr. Feingold's point was that unless the distribution costs were recovered through a fixed monthly customer charge the customers in the unmodernized building would have to pay more towards distribution cost than would the customers in the building on the other side of the street even though the distribution cost to serve each building was the same.

building even though each building, by Mr. Feingold's stipulation,[14] caused the same amount of mains costs to be incurred. The obvious way to avoid that unfairness would be through the volumetric charge for mains cost recovery rather than the uniform customer charge. With identical energy efficiency technology assumed in both buildings,[15] it can be assumed that each building continued to consume about the same amount of gas as the other—ergo the volumetric charge would recover about the same amount of mains costs for both buildings.

Q. SINCE YOU HAVE ALREADY AGREED WITH MR. FEINGOLD'S "UNFAIRNESS" CONCLUSION IN THE STRAWMAN THAT HE CONSTRUCTED, IT WOULD APPEAR THAT, DEPENDING UPON THE CIRCUMSTANCES, UNFAIRNESS CAN BE PRODUCED *BOTH* BY A CUSTOMER CHARGE RECOVERY OF MAINS COSTS[16] *AND* BY A VOLUMETRIC CHARGE RECOVERY. SO WHERE DOES ONE TURN?

A. One must take other considerations into account.

Q. WHAT CONSIDERATIONS DO YOU HAVE IN MIND?

A. A consideration commonplace among Oregonians is the objective of encouraging conservation in the consumption of natural gas for long-term environmental reasons. Another consideration is maintaining consistency with

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[14] "The costs to serve the two buildings are identical except for the service investment…" *See* Exhibit NWN/2500: Feingold/39, lines 8-9.

[15] Recall that no modernization took place.

[16] The focus here is on mains costs because they constitute by far the largest single cost element of a gas distribution utility's *own* costs (i.e., cost not recoverable through pass-through treatment), and because other major cost components are commonly acknowledged as properly recovered either through the customer charge (e.g., meters and service lines) or through some volumetric charge (e.g., transmission and storage).

the expectation—long-held due to the historically low Northwest Natural customer charge[17]—that bills should track consumption in a much stronger way than would be the case with a customer charge that approached $30/month as per the Company's petition. Both these considerations argue for increasing the volumetric charge above the simple fuel cost level so as to be able to recover at least some of the cost of mains via an enlarged volumetric charge. Limiting the amount of the customer charge also addresses the potential economic efficiency loss due to smaller-use customers dropping off the system so as to avoid the unacceptably high average price for their gas service that would be the consequence of the fully phased-in straight fixed/variable customer charge requested by Northwest Natural.

Finally, there is Staff's equity consideration. Recall that while Mr. Feingold, uncontestably, avers that each apartment building in our joint example incurs the same costs of mains, he does not suggest that he would ever be able to say what, precisely, those costs are. As an economist, all that Mr. Feingold would be able to say was that the *marginal* cost of mains to serve *any one* of the two buildings is precisely zero. That is because the cost of mains would be the same whether or not the building was connected to the main.[18] All Mr. Feingold can do is what anyone else might do—i.e., make the simple mathematical calculation of the *average* cost of serving the entire class of

[17] The current residential (Schedule 2R) monthly customer charge is $6.

[18] I make the same assumption Mr. Feingold makes when he refers to the cost of mains that serve residential neighborhoods—i.e., that the standard, minimum-sized main has a large enough diameter to serve all but the largest of residential loads that are likely to be connected to it. (*See* Exhibit NWN/1100: Feingold/14, lines 8-14.) Also, the cost of actually connecting to the main is properly categorized as part of the cost of the service line between the main and the customer's meter.

residential customers by dividing the total residential cost allocation by the total number of residential customers. The reason it is impossible to specify the cost of mains to a particular customer is that any particular main in a public utility network will be shared by any number of customers, rendering it entirely arbitrary to specify what a particular customer's own share of those costs might be. So given the *impossibility of a cost-causation determination* of a customer's share of main costs, it is Staff's position that the cause of equity is served by assigning costs on the basis of *benefits received.*[19] One simple way to quantify benefits received in a natural gas context is by using volumes delivered. Accordingly, as with the other three considerations discussed earlier in my answer to this question, the resolution of Staff's equity objective would be for the cost of mains to be recovered through a volumetric charge.

[19] Staff has consistently taken this position since the PacifiCorp general rate case Docket No. UE 210. (*See* from that docket: Exhibit Staff/1100, Compton/28, lines 6-12.)

TOPIC 2: CUSTOMER DENSITY IS A FACTOR REASONABLY CONSIDERED IN RESIDENTIAL RATE DESIGN

Q. WHILE GREATER CUSTOMER DENSITY CAN ALLOW MORE CUSTOMERS TO BE SERVED BY A GIVEN LENGTH OF MAIN,[20] MR. FEINGOLD POINTS TO A NUMBER OF REASONS WHY MAINS COSTS CAN BE HIGHER IN HIGH-DENSITY NEIGHBORHOODS.[21] WHILE NOT CONTESTING STAFF'S EARLIER POINT THAT CUSTOMERS IN MULTI-UNIT HOUSING TEND TO USE LESS GAS THAN DO OTHER RESIDENTIAL CUSTOMERS, HE CONCLUDES THAT SINCE MULTI-UNIT HOUSING IS ASSOCIATED WITH HIGHER-DENSITY NEIGHBORHOODS, AND ASSOCIATED WITH HIGHER-DENSITY NEIGHBORHOODS ARE GREATER MAINS COSTS, THE HIGHER-DENSITY CUSTOMERS SHOULD STILL PAY THE LARGE, STRAIGHT FIXED/VARIABLE CUSTOMER CHARGE RATHER THAN HAVING MAIN COST RECOVERY VIA A VOLUMETRIC CHARGE. HOW WOULD YOU RESPOND?

A. I would first refer back to my prior strawman example of two equally-sized apartment buildings with equal amounts of gas consumption and which are located across the street from each other—with the only difference being that

[20] Recall from Staff's Cost-of-Service testimony that a principal cost driver in inter-class cost allocations is the greater lengths of mains required to serve commercial and industrial customers as compared to serving residential customers. (*See* Exhibit Staff/1400, Ordonez/12, line 7 through Ordonez/16, line 9.) The same principle is regarded as applying to intra-class cost responsibility. Greater density allows for fewer feet of distribution main per customer, which should translate to smaller monthly charges for the affected customers.

[21] *See* Exhibit NWN/2500: Feingold/35, line 18 through Feingold/36, line 8; and Feingold/37, line 1 through Feingold/38, line 2.

one building has twice as many rental units, resulting in an average per-unit consumption that is half that of the other building. Assuming equal service investments to each building, the costs to serve the two buildings are identical apart from the extra meters on the re-configured building that are required to accommodate the doubling of the number of customers therein. With identical mains costs to serve the two buildings, and remaining within Mr. Feingold's paradigm of attaching cost responsibility to each building's occupants in the aggregate, it is readily seen as unfair if the customers in the higher-occupancy building were required to contribute twice as much as customers in the other building toward mains cost recovery—as would be the case with Northwest Natural's high fixed/variable customer charge, and as would not be the case with Staff's volumetric charge.

Q. OKAY, I CAN SEE HOW WITHIN A GIVEN NEIGHBORHOOD IT WOULD BE MORE FAIR TO ALLOW THE LOW-USE CUSTOMERS ASSOCIATED WITH MULTI-UNIT HOUSING TO PAY LESS TOWARDS MAINS COST RECOVERY THAN WOULD THE HIGHER-USE CUSTOMERS RESIDING IN LARGER, INDIVIDUAL HOUSING UNITS. BUT WOULDN'T MR. FEINGOLD'S POINT THAT HIGHER DENSITY TRANSLATES TO HIGHER COSTS IMPLY THAT *ALL* OF THE CUSTOMERS IN YOUR DESCRIBED APARTMENT-BUILDING-OCCUPYING NEIGHBORHOOD SHOULD, ON AVERAGE AT LEAST, BE PAYING SOMETHING MORE TOWARDS

MAINS COST RECOVERY THAN WOULD BE THE CASE WITH YOUR VOLUMETRIC CHARGE? PLEASE RESPOND.

A. To grasp what is involved here we must first turn to the nature of the data that Mr. Feingold relies upon to reach his conclusion.[22] He stated that "actual cost data of its *recent* [emphasis added] main extensions and distribution system expansions" yielded, respectively, approximately $48 per foot and $15 per foot. The larger figure is attributable to such factors as "hard surface cuts, paving or working with other utilites' assets," etc. that are associated with main extensions, which the "Company defines…as typically associated with residential *conversions in established neighborhoods* [emphasis added]…." But the inference of the more-than-triple cost of mains being applied to higher density dwelling units is only valid if the bulk of higher-density dwelling units are found in higher-density neighborhoods (i.e., which are more likely to contain commercial as well as residential buildings) rather than scattered across average-cost/average-density neighborhoods, or *if* the bulk of higher-density dwelling units were indeed found in higher-density neighborhoods and that the defacto installation was of the higher-cost, main extension variety rather than part of a lower-cost system expansion. And even if the cost of mains is higher in areas with greater residential densities, could not the greater consumption and volumetric revenues associated with the larger edifices compensate for those greater costs?

[22] *See* Exhibit NWN/2500: Feingold/37.

These are all empirical questions which Mr. Feingold makes no attempt to answer.[23] In the absence of countervailing evidence, I stand by my position that lower-use customers who are often associated with smaller, multi-unit housing are entitled to pay a smaller amount towards the recovery of mains costs than would be the case with the large straight fixed/variable customer charge proposed by the Company and defended by Mr. Feingold.

TOPIC 3: DISTRIBUTION FIXED COST RECOVERY, ECONOMIC PRINCIPLES, AND REGULATORY CANT

Q. FOOTNOTE NUMBER TEN OF EXHIBIT NWN/2500, FEINGOLD/9, CITES, APPROVINGLY, THE FOLLOWING:

> **The U.S. Court of Appeals for the District Of Columbia Circuit (D.C. Circuit) has defined the cost-causation principle as follows: "[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them [emphasis added]." (See *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (*K N Energy*).)**

YOU HAVE REPEATEDLY MADE THE POINT THAT WHEREAS METERS, METER-READING, BILLING, AND SERVICE LINE COSTS ARE "ACTUALLY CAUSED BY THE CUSTOMER WHO [ACCORDINGLY] MUST PAY THEM," THE SAME IS NOT TRUE OF GAS DISTRIBUTION MAINS. YOUR REASONING HAS BEEN THAT MAINS ARE SHARED AMONG A HOST OF UPSTREAM AND DOWNSTREAM CUSTOMERS, RENDERING IT

[23] That is understandable. These are obviously very difficult questions, about which satisfactory data undoubtedly does not currently exist.

IMPOSSIBLE TO SAY PRECISELY HOW MUCH OF ANY PARTICULAR MAIN'S COST IS "ACTUALLY CAUSED" BY A PARTICULAR CUSTOMER. FROM THAT CITATION AND YOUR SHARED-COST REASONING CAN WE CONCLUDE THAT "COST-CAUSATION," THUS DEFINED, DOES NOT APPLY TO GAS DISTRIBUTION MAINS?

A. Yes we can. When Mr. Feingold refers to "cost causation" in the context of residential rate design, all he is referring to is the per-customer *average* of main costs that have been allocated to the residential class as a whole. Since the cost of mains would be unaffected by whether or not a particular customer received service from a particular main, mains' costs are not "actually caused" by any particular customer.

Q. EXHIBIT NWN/2500, FEINGOLD/46, DISPLAYS THE FOLLOWING CITATION FROM THE ESTIMABLE ALFRED KAHN:

> **It is short-run marginal cost to which price should at any time—hence always—be equated, because it is short-run marginal [sic] that reflects the social opportunity cost of providing the additional unit that buyers are at any given time trying to decide whether to buy." (*See* <u>The Economics of Regulation</u>, Alfred E. Kahn, the MIT Press, 1995 (Sixth Printing), Vol. I, page 71.)**

EARLIER YOU HAVE SUGGESTED THAT WHEN A *PROSPECTIVE* CUSTOMER IS INITIALLY "TRYING TO DECIDE WHETHER TO BUY" GAS UTILITY SERVICES PER SE, THAT THE MARGINAL COST OF MAINS THAT CONFRONTS HIM IS ZERO. WOULD YOU THEN AGREE THAT THIS CITATION IS ALSO IRRELEVANT WHEN IT COMES TO PRICING MAINS SINCE THE PROSPECTIVE CUSTOMER WILL BE EXPECTED TO PAY SOMETHING ABOVE ZERO FOR HIS USE OF MAINS?

A. I can't say I agree entirely. This passage is generally interpreted as applying to a person who has already become a customer—not when he is deciding whether or not to become a customer. Given that general interpretation, the underlying objective is to attempt to keep the volumetric price, at least on the margin, as close to short-run marginal cost as possible.[24] Economic efficiency is fostered by consumption whose marginal benefit equals or exceeds its marginal cost. Conversely, economic efficiency is diminished by prices that exceed marginal costs—resulting in consumption being foregone despite the fact that the marginal benefits (which equate to the price) would have exceeded the marginal costs.

Q. WHAT IS THE RECEIVED WISDOM REGARDING HOW DISTRIBUTION MAINS COSTS ARE TO BE RECOVERED IN THE EVENT THAT IT WON'T BE RECOVERED THROUGH THE MARGINAL VOLUMETRIC PRICE?

A. This is where Ramsey Pricing comes to bear. With small, mostly punctuation modifications, I accept Mr. Feingolds description as follows: "Under Ramsey Pricing, the marginal variable [i.e., volumetric] rate recovers the [relevant] marginal cost, and the infra-marginal variable charge combined with the customer charge recovers the remainder of the revenue requirement because they are the least elastic elements of the rate structure."[25] The theory is that

[24] While it is not germane to the point of this particular Q&A, it should be made clear that Staff would look to long-run marginal costs rather than the short-run. The long-run consideration comes to bear when a customer is deciding whether or not to purchase some long-lived appliance that will be utilizing a utility's fuel/energy product over many years. Marginal-cost-of-service studies conducted for the OPUC focus on the long-run, specifically twenty years.

[25] The original language is as follows: "Under Ramsey Pricing, the variable rate recovers the marginal cost and the infra-marginal charge, and the customer charge recovers the remainder

raising the customer or infra-marginal volumetric charge won't do damage to economic efficiency due to the expectation that elevating those charges will have very little effect on consumer behavior—i.e., that being a customer and consumption prior to reaching the tail-block price are quite insensitive (i.e., relatively "inelastic") to the customer charge and the infra-marginal variable charge.

Q. BASED ON THE APPLICABLE MINIMUM SYSTEM NOTIONS PRESENTED BY MR. FEINGOLD,[26] DO YOU SHARE HIS POSITION THAT DISTRIBUTION MAINS COSTS IN RESIDENTIAL NEIGHBORHOODS "ARE NOT CAUSED BY DEMAND OR ENERGY"[27]?

A. To some degree, yes.

Q. WOULD YOU THEN ACCEPT MR. FEINGOLD'S INFERENCE THAT MAINS COSTS CONSTITUTE A *CUSTOMER* COST COMPONENT AND SHOULD CONSEQUENTLY BE RECOVERED ENTIRELY THROUGH A *UNIFORM CUSTOMER* CHARGE (I.E., WITH NONE RECOVERED THROUGH RAMSEY'S INFRA-MARGINAL VARIABLE CHARGE)?

A. No. I am aware of the simplistic pattern of the industry to label specific costs as either demand-, energy-, or customer-related. But most assuredly I reject the proposition that just because something is *labeled* as a customer *cost* it must be recovered through a uniform customer *charge*. If that were the case I would

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of the revenue requirement because it is the least elastic element of the rate structure." (*See* Exhibit NWN/2500: Feingold/44, line 12 through line 15.)

[26] *See* Exhibit NWN/1100: Feingold/14, lines 8-14.

[27] *See* Exhibit NWN/2500: Feingold/54, line 10 through line 16.

insist upon applying to gas mains PacifiCorp's minimum-infrastucture label of "commitment costs." And as already argued in this rebuttal testimony, when costs (labeled "customer," "commitment," or whatever) can't be assigned to individual consumers on a strict cost-causation basis, then it is preferable on equity grounds to recover such costs on a benefits-received basis—which will entail some form of volumetric pricing.

Q. I NOTICE THAT NEITHER YOU NOR MR. FEINGOLD RECOMMENDED A DECLINING BLOCK RATE STRUCTURE WHEREBY RAMSEY'S "INFRA-MARGINAL" VARIABLE CHARGE WOULD RECOVER SOME OF THE COST OF THE MAINS. OBVIOUSLY MR. FEINGOLD SEEKS FULL DISTRIBUTION SYSTEM COST RECOVERY THROUGH THE CUSTOMER CHARGE, BUT WHY HAVE YOU NOT RECOMMENDED A DECLINING BLOCK RATE DESIGN FOR RESIDENTIAL CUSTOMERS, WITH THE INFRA-MARGINAL VOLUMETRIC CHARGE USED TO RECOVER MAINS COSTS?

A. Given the large revenue requirement associated with mains, that infra-marginal charge would have to be very large. Except for customers who are small enough to not leave the infra-marginal price block, the outcome would be equivalent to having Northwest Natural's large customer charge.[28] There are reasons for not embracing that outcome.

Q. SUCH AS?

[28] Frankly, that's the Ramsey Pricing advocates' objective.

A. Recovering mains costs (and any other fixed costs not recovered in the customer charge) in the infra-marginal price block(s) allows the utility to minimize its marginal, or tail-block, rate. Minimizing the tail-block rate will encourage “maximum” consumption by existing customers whose consumption is great enough to place them beyond the higher, infra-marginal price. The NW Energy Coalition and others may oppose creating such an incentive, due to environmental and other concerns. Environmentalists bolster their stance on economic theoretic grounds by positing that the current market price paid for gas does not capture environmental/“external” costs. For its part, Staff has expressed concern in this case regarding the acknowledged (i.e., by the Company[29]) risk of having a substantial number of low-use customers dropping off of the system in the presence of a high straight/fixed variable customer charge. While a declining-block rate design would mitigate that concern for the very smallest customers (i.e., who are far from reaching the end of the infra-marginal block), such wouldn’t help the other small customers as much as would the flat rate recommended by Staff. Finally, and depending upon the degree to which small customers’ loads reach the beginning point of the tail block, an individual small customer may pay just as much to support the mains’ cost recovery as would the largest of customers. That arguably unfair outcome is avoided with the use of a flat volumetric rate for mains cost recovery.

Q. FOLLOWING THE DR. KAHN CITATION, MR. FEINGOLD MAKES THE FOLLOWING STATEMENT: “THE PRINCIPLE OF MARGINAL COST

[29] *See* Exhibit NWN/2500: Feingold/69, lines 1-2.

PRICING PROVIDES THE PRESCRIPTION FOR ECONOMICALLY EFFICIENT PRICES." MR. FEINGOLD WOULD ACHIEVE THAT EFFICIENCY BY, IN ESSENCE, MINIMIZING THE VOLUMETRIC CHARGE AND MAXIMIZING THE CUSTOMER CHARGE. BUT WOULD THE COMPANY-ACKNOWLEDGED ENSUING LOSS OF LOW-USE CUSTOMERS DUE TO A VERY HIGH CUSTOMER CHARGE, ALSO CONSTITUTE A LOSS OF ECONOMIC EFFICIENCY?

A. Yes. Low-use customers currently benefit from being able to consume gas or they wouldn't remain on the system. The associated consumer surplus (i.e., where consumer value exceeds price) would be lost if the elevated customer charge caused the low-use customers to leave the system. Failure to gain new customers who would benefit from being on the gas utility system beyond the marginal costs they imposed would result in an additional economic efficiency loss.

There is also the matter of stranded investment in meters and service lines due to low-use-customer abandoning the system. Such constitutes a pure dead-weight loss that would burden remaining customers until the associated rate base was fully depreciated.[30] As Mr. Feingold acknowledges, as long as existing or prospective small customers contributed something beyond their

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[30] The alternative would be a simple, uncompensated write-off, which would consititute a burden to shareholders.

direct marginal costs (i.e., beyond the commodity, meter-reading, and billing costs), then the "system" benefits from having those customers connected.[31]

Q. GIVEN THE TRADE-OFF BETWEEN AN EFFICIENCY LOSS CAUSED BY VOLUMETRIC PRICES EXCEEDING SHORT-RUN MARGINAL COSTS[32] AND A CONSUMER SURPLUS LOSS OWING TO ATTENUATED CUSTOMER ENROLLMENT, WHERE WOULD STAFF BE ALIGNED?

A. Placing the burden to remaining customers into the efficiency losses and gains calculus,[33] leads this Staff person to advocate preserving customer enrollment by not making the "entry price" (i.e., the customer charge) so high as to foreclose the opportunity for small customers to benefit themselves and the rest of the system.

[31] Mr. Feingold says, "Prices are said to be subsidy-free so long as the price exceeds marginal cost….The logic for this concept is that if customers' prices exceed marginal cost, those customers make a contribution to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear." (*See* Exhibit NWN/1100: Feingold/8, lines 15-19.)

[32] Recall that some would dispute that loss under the notion that "true" marginal-cost prices should reflect environmental externalities, rendering those marginal costs well above current market gas commodity costs

[33] That is while disregarding the impossible-to-quantify equity and environmental considerations mentioned earlier.

TOPIC 4: SEASONAL GAS RATES REFLECT CLEAR COST-CAUSATION AND PROMOTE BOTH EFFICIENCY AND EQUITY

Q. IN ARGUING AGAINST STAFF'S PROPOSED WINTER/SUMMER VOLUMETRIC PRICE DIFFERENTIAL FOR THE RECOVERY OF STORAGE AND TRANSMISSION COSTS, MR. FEINGOLD POINTS TO THEIR "USE…ON AN ANNUAL BASIS" AS JUSTIFICATION FOR "RECOVERING ANNUAL COSTS ANNUALLY…."[34] DO YOU FIND HIS LOGIC COMPELLING?

A. No. Of course the Company's transmission system is used year-round, but during the off-season it is operating well under capacity—meaning that its proper marginal-cost-based price in the off-season is zero, to be made up by a positive price in the winter. The same reasoning applies to pipeline capacity costs, which are established entirely by the winter peak demand. And of course the Company "in the summer…uses the storage assets to inject gas into storage," but a key purpose is to obtain cheaper gas beyond what is needed for the summer and make it available for sale in the higher-priced winter season. As Mr. Feingold also acknowledges, storage utilization in winter brings down the peak capacity requirement from the interstate pipeline companies. Given that the primary benefit from storage lies reducing winter costs, it is appropriate for the winter price signal to incorporate storage costs. If the year-round load emulated the off-season load, transmission, storage, and pipeline capacity requirements would be vastly reduced. The system needs for those resources

[34] *See* Exhibit NWN/2500: Feingold/79.

is directly related to winter demand. Prices should reflect that reality; summer usage should not have to subsidize winter usage.

Q. SINCE CUSHION GAS IS USED YEAR-ROUND,[35] WOULD YOU CONCEDE THAT THE CARRYING COSTS OF CUSHION GAS SHOULD BE RECOVERED ON A YEAR-ROUND BASIS?

A. I would. But again, storage facilities where that gas resides are sized to meet winter peak needs. Accordingly the marginal cost of storage *capacity* in the off-season is zero, which in turn should be its off-season price.[36]

Q. ARE YOU CONCERNED THAT BY REDUCING THE OFF-SEASON VOLUMETRIC PRICE, NORTHWEST NATURAL WILL BE INAPPROPRIATELY STIMULATING OFF-SEASON CONSUMPTION?

A. Not at all. First recall that without the large fixed/variable customer charge, the volumetric rates will tend to be higher year-round in any case. More importantly, and as stated in my Opening Testimony, there are economic efficiency and environmental advantages to using natural gas instead of electricity for water-heating, clothes-drying, and other year-round applications.[37]

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[35] *See* Exhibit NWN/2500: Feingold/79, line 7.
[36] I would support collecting storage O&M costs (as opposed to capital costs) on a year-round, volumetric basis.
[37] *See* Exhibit Staff/1500, Compton/28 line 22 through Compton/29 line 4.

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CERTIFICATE OF SERVICE

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(REBUTTAL TESTIMONY)

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 20th day of July, 2012 at Salem, Oregon.

Kay Barnes

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