Rates and Regulatory Affairs
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August 31, 2009 NWN Advice No. OPUC 09-12

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
550 Capitol Street, N.E., Suite 215
P.O. Box 2148
Salem, Oregon 97308-2148

Attn: Filing Center

Re: Annual Purchased Gas Cost and Technical Rate Adjustments

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), files herewith revisions to its Tariff, P.U.C. Or. 24, as listed on the attached Table of Tariff Sheet Revisions. The Tariff sheets are stated to become effective with service on and after November 1, 2009.

Introduction and Summary

The first purpose of this filing is to (a) revise rates for the effects of changes in purchased gas costs; (b) revise rates for the further effect of removing temporary rate adjustments incorporated into rates effective November 1, 2008; and (c) apply new temporary rate adjustments for inclusion in rates effective November 1, 2009. The Company revises rates for these purposes annually; its last filing was effective November 1, 2008.

The second purpose of this filing is to make temporary adjustments to base rates for the costs associated with the Company's System Integrity Management Program (SIMP) for Bare Steel, Pipeline Integrity Management Program, and Distribution Integrity Management Program, including the application of the final carry over balance from the Geo-Hazard Program.

The third purpose of this filing is to make permanent adjustments to base rates for (a) the inclusion in rates of a portion of Mist storage capacity previously used for upstream sales capacity, and; (b) price elasticity effects of the rate increase reflected in this filing.

If the effects of the temporary rate increments were permanent, the result of all components of the rate changes would be a decrease in the Company's revenues from its Oregon operations of about $174,149,240 or about 19.85%.

Effect on Customer Bills

The average residential Schedule 2 bill will decrease by 16.9%; the commercial Schedule 3 bill will decrease by 19.8%; the commercial Schedule 31 firm sales service bill will decrease by 24.6% and; the bill for the average Schedule 32 industrial firm sales customer will decrease by 29.2%.

The monthly bill of the average residential customer served under Schedule 2 using 55 therms per month will decrease by $13.93. The monthly decrease for the average commercial Schedule 3 customer using 230 therms is $60.30.

See Exhibit B of this filing for materials in support of the application of all adjustments to the applicable rate schedules.

In a separate filing, the Company has requested Commission approval to increase the portion of the Schedule 301 public purposes charge that funds the programs managed by the Energy Trust of Oregon. If approved, the combined effect of both of these filings would be a net bill decrease to residential customers of about 14.5%, and a net bill decrease to commercial customers of about 17.5%

Additional details about this combined filing are described below.

I. UM 1286 PGA Filing Guidelines

Exhibit A of this filing contains the data associated with the PGA Filing Guidelines Sections II, III, and IV, including a complete index of the location of the required information, as prescribed by OPUC Order Nos. 09-263 / 09-248 in Docket UM 1286.

The PGA Filing Guidelines, Section V has been submitted under separate cover. Some of the information contained in this submission is confidential. The Company has filed a motion for a protective order in this proceeding and will provide the confidential data upon issuance of the protective order.

II. Purchased Gas Cost Adjustment (PGA)

This portion of the filing will pass through (1) changes in the cost of gas purchased by the Company from its natural gas suppliers, including the costs of purchasing financial derivative products to limit customers' exposure to gas cost volatility, and (2) changes in the cost of pipeline and storage capacity under contract with the Company's pipeline transporters.

This filing applies the method for calculating the proposed Annual Sales Weighted Average Cost of Gas ("WACOG") that is set forth in a joint party stipulation approved by the Commission in OPUC Order No. 08-504, Docket UM 1286, and as further prescribed by the PGA Filing Guidelines, Section III (1)(d) of OPUC Order Nos. 09-263 / 09-248 in Docket UM 1286. In addition, this filing revises the Winter Sales WACOG option that is available to the Company's Rate Schedule 31 and 32 sales service customers.

This filing also applies the methods for treatment of storage inventory gas and Annual Sales WACOG calculations agreed to between the Staff and the Company in August, 2001, as described in more detail in the Company's PGA filing dated August 14, 2001, NWN Advice No. OPUC 01-18.

The total effect of the PGA portion of this filing is to decrease the Company's annual revenues by about $174,149,240. The effect of the change in gas costs is a decrease of $171,542,293, which results in a proposed Annual Sales WACOG of $0.59044 per therm, and a proposed Winter Sales WACOG of $0.57227.

The effect of the change in demand charges is a decrease in total demand charges of about $1,163,549. However, the volumes used to derive the demand charge in this filing are lower than the volumes in the previous PGA filing, which results in a proposed firm service pipeline capacity charge of $0.12502 per therm, or $1.87 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01486 per therm, all of which are higher than the respective charges currently in effect.

If there are changes in the Company's gas supply costs or costs associated with pipeline services and charges from the levels used to develop the purchased gas adjustments included in this filing, then the Company will reflect such changes to Oregon gas customers in a manner approved by the Commission.

III. Temporary Rate Adjustments

This portion of the filing makes a number of periodic temporary technical adjustments to rates in order to amortize credit or debit balances in its revenue and gas cost balancing accounts and certain other approved Federal Energy Regulatory Commission (FERC) deferred accounts, Accounts 186 and 191, respectively. The rate increments associated with the amortization of the applicable deferral accounts have been calculated in accordance with the PGA Filing Guidelines, Section III(1)(a) as prescribed by OPUC Order Nos. 09-263 / 09-248 in Docket UM 1286.

This portion of the filing is in compliance with ORS 757.259 (2003), which authorizes deferred utility expenses or revenues to be allowed (amortized) in rates to the extent authorized by the Commission in a proceeding to change rates. All of the deferrals included in this filing occurred with appropriate application by Commission authorization, as rate orders or under approved tariffs.

This filing does not a require a review of earnings due to the elimination of the fall earnings review pursuant to OPUC Order No. 08-504 in Docket UM 1286. For the purpose of recovering "other" deferred balances as outlined in ORS 757.259, the required earnings review covering the period(s) during which the deferrals in this filing occurred was performed with Staff's adoption of the 2009 Spring Earnings Review. Page 17 of Exhibit B shows the total proposed average change being applied to billing rates a decrease of $24.5 million, which is below the current three percent limit of $27.7 million.

The net effect of this portion of the filing is to decrease the Company's annual revenues by $1,826,589. The effect of removing the temporary adjustments placed into rates November 1, 2008 is an increase of $10,194,193. The effect of applying the new temporary rate adjustments is a decrease of $12,020,782.

IV. Base Rate Adjustments

The effect of this portion of the filing is to decrease the Company's annual revenues by $780,358.

This portion of the filing makes a number of temporary and permanent adjustments to customer rates as follows:

System Integrity Management Programs. This filing applies temporary adjustments to permanent rates that relate to Part A: Bare Steel, Part B: Transmission Integrity management (TIMP); and Part C: Distribution Integrity Management (DIMP) pursuant to a Stipulation adopted by the Commission in Docket UM 1406, as described in Schedule 177.

Geohazard. This filing applies temporary adjustments to permanent rates that relate to the carry over balance associated with the Geohazard program, which was implemented pursuant to a Stipulation and Agreement adopted by the Commission in Docket UM 1030 and which is now terminated.

Price Elasticity. This filing applies the permanent effects of the price elasticity adjustment pursuant to a Stipulation and Agreement adopted by the Commission in Docket UG 143 and described in Schedule 163.

Mist Recall. This adjustment represents the permanent rate effects of the recall of 100,000 therms per day of Mist reservoir capacity and 50,000 therms per day of compression capacity from upstream market activities for use by the Company's core customers. This adjustment has been applied to rate schedules in the same manner as all Mist expansion projects, as described in Schedule 176.

The Company requests that the tariff sheets filed herewith be permitted to become effective with service on and after November 1, 2009.

Copies of this letter and the filing made herewith are available in the Company's main office in Oregon and on its website at www.nwnatural.com.

Please address correspondence on this matter to me at efiling@nwnatural.com, with copies to the following:

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Sincerely,

NW NATURAL

/s/ Onita R. King

Onita R. King
Regulatory Affairs

Attachments: Tariffs
Exhibits A and B

TABLE OF TARIFF SHEET REVISIONS
PROPOSED TO BECOME EFFECTIVE NOVEMBER 1, 2009

PROPOSED REVISION	CANCELS REVISION	SCHEDULE TITLE
Thirteenth Revision of Sheet v	Twelfth Revision of Sheet v	Tariff Index
Ninth Revision of Sheet 1-1	Eighth Revision of Sheet 1-1	Schedule 1 “General Sales Service”
Ninth Revision of Sheet 2-1	Eighth Revision of Sheet 2-1	Schedule 2 “Residential Sales Service”
Eighth Revision of Sheet 3-3	Seventh Revision of Sheet 3-3	Schedule 3 “Basic Firm Sales Service – Non-Residential”
Eighth Revision of Sheet 19-1	Seventh Revision of Sheet 19-1	Schedule 19 “Gas Light Service”
Fifth Revision of Sheet 31-9	Fourth Revision of Sheet 31-9	Schedule 31 “Non-Residential Sales and Transportation Service”
Sixth Revision of Sheet 31-10	Fifth Revision of Sheet 31-10	Schedule 31 “Non-Residential Sales and Transportation Service”
Fifth Revision of Sheet 32-9	Fourth Revision of Sheet 32-9	Schedule 32 “Large Volume Non-Residential Sales and Transportation Service”
Fifth Revision of Sheet 32-10	Sixth Revision of Sheet 32-10	Schedule 32 “Large Volume Non-Residential Sales and Transportation Service”
Sixth Revision of Sheet 33-6	Fifth Revision of Sheet 33-6	Schedule 33 “High-Volume Non-Residential Firm and Interruptible Transportation Service”
Tenth Revision of Sheet 100-1	Ninth Revision of Sheet 100-1	Schedule 100 “Summary of Adjustments”
Original Sheet 100-1.1	N/A	Schedule 100 “Summary of Adjustments (continued)”
Fifth Revision of Sheet 100-2	Fourth Revision of Sheet 100-2	Schedule 100 “Summary of Adjustments (continued)”
First Revision of Sheet 100-3	Original Sheet 100-3	Schedule 100 “Summary of Adjustments (continued)”
Ninth Revision of Sheet 162-1	Eighth Revision of Sheet 162-1	Schedule 162 “Temporary (Technical) Adjustments to Rates”
Eighth Revision of Sheet 162-2	Seventh Revision of Sheet 162-2	Schedule 162 “Temporary (Technical) Adjustments to Rates”
Tenth Revision of Sheet 163-1	Ninth Revision of Sheet 163-1	Schedule 163 “Special Adjustment to Rates Price Elasticity”

PROPOSED REVISION	CANCELS REVISION	SCHEDULE TITLE
Eighth Revision of Sheet 164-1	Seventh Revision of Sheet 164-1	Schedule 164 "Purchased Gas Cost Adjustment to Rates"
First Revision of Sheet 166-1	Original Sheet 166-1	Schedule 166 "Adjustments to Rates (UM 1335)"
First Revision of Sheet 166-2	Original Sheet 166-2	Schedule 166 "Adjustments to Rates (UM 1335)"
Third Revision of Sheet 169-1	Second Revision of Sheet 169-1	Schedule 169 "Special Adjustment to Rates for Storage Inventories"
Original Sheet 170-1	N/A	Schedule 170 "Special Adjustment to Rates for Pension Expense"
Original Sheet 172-1	N/A	Schedule 172 "Special Adjustment to Rates for Intervenor Funding"
Third Revision of Sheet 177-1	Second Revision of Sheet 177-1	Schedule 177 "System Integrity Program Rate Adjustment"
Ninth Revision of Sheet 177-2	Eighth Revision of Sheet 177-2 and Original Sheet 177-2.1	Schedule 177 "System Integrity Program Rate Adjustment (continued)"
Seventh Revision of Sheet 177-3	Sixth Revision of Sheet 177-3, Original Sheet 177-3.1, Fifth Revision of Sheet 177-4 and Original Sheet 177-4.1	Schedule 177 "System Integrity Program Rate Adjustment (continued)"
Original Sheet 187-1	N/A	Schedule 187 "Special Rate Adjustment for Mist Capacity Recall"
Tenth Revision of Sheet 190-1	Ninth Revision of Sheet 190-1	Schedule 190 "Partial Decoupling Mechanism"
Ninth Revision of Sheet 190-2	Eighth Revision of Sheet 190-2	Schedule 190 "Partial Decoupling Mechanism"
Seventh Revision of Sheet 195-4	Sixth Revision of Sheet 195-4	Schedule 195 "Weather Adjusted Rate Mechanism (WARM Program)"
Sixth Revision of Sheet 195-5	Fifth Revision of Sheet 195-5	Schedule 195 "Weather Adjusted Rate Mechanism (WARM Program)"
Original Sheet 305-1	N/A	Schedule 305 "Special Adjustment to Rates for Smart Energy Program Costs"
Sixth Revision of Sheet P-2	Fifth Revision of Sheet P-2	Schedule P "Purchased Gas Cost Adjustments"
Seventh Revision of Sheet P-3	Sixth Revision of Sheet P-3	Schedule P "Purchased Gas Cost Adjustments"
Ninth Revision of Sheet P-5	Eighth Revision of Sheet P-5	Schedule P "Purchased Gas Cost Adjustments"

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(continued)

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Schedule 160:	Revision of Charges for Coos County Customers	160-1	
Schedule 161:	Automatic Adjustment for Utility Income Tax	161-1	
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Schedule 163:	Special Adjustment to Rates – Price Elasticity	163-1	
Schedule 164:	Purchased Gas Cost Adjustments to Rates	164-1	
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Schedule 167:	General Adjustments to Rates	167-1	
Schedule 169:	Special Adjustment to Rates for Storage Inventories	169-1	
Schedule 170:	Special Adjustment to Rates for Pension Expense	170-1	(N)
Schedule 172:	Special Adjustment to Rates for Intervenor Funding	172-1	(N)
Schedule 176:	Adjustments to Rates for Costs Relating to Mist Storage Expansion Project	176-1...176-2	
Schedule 177:	System Integrity Program Rate Adjustment	177-1…177-3	(C)
Schedule 185:	Special Annual Interstate Storage and Transportation Credit	185-1	
Schedule 186:	Special Annual Core Storage and Pipeline Capacity Optimization Credit	186-1	(N)
Schedule 187:	Special Rate Adjustment for Mist Capacity Recall	187-1	(N)
Schedule 188:	Industrial Demand Side Management (DSM) program Cost Recovery	188-1	
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Issued August 31, 2009 Effective with service on
NWN Advice No. OPUC 09-12 and after November 1, 2009

RATE SCHEDULE 1
GENERAL SALES SERVICE

AVAILABLE:
To all Residential and Commercial Customer classes in all territory served by the Company under the Tariff of which this Rate Schedule is a part, except that service under this Rate Schedule is not available for Standby Service to Commercial Customers. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this (C)
Schedule, is subject to the provisions of **SCHEDULE X**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment including but not limited to one or any multiple or combination of the following:

(a) Non-ducted space heating equipment, including but not limited to fireplace inserts, free standing gas stoves, and room heaters;
(b) Standby space heating equipment used in residential applications, including but not limited to Natural Gas back-up to electric heat pumps,
(c) Water heating equipment used to serve single-family residential swimming pools, spas, and hot tubs;
(c) Other equipment including, but not limited to, log lighter, gas log, gas barbecue, tiki torch, Bunsen burner, Domestic cooking equipment, hobby kilns, refrigeration or Domestic clothes drying;
(d) Equipment installed for use in detached garages, shops, or outbuildings.

(T)

MONTHLY RATE: Effective: November 1, 2009

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**.

	Base Rate	Base Rate Adjustment	Pipeline Capacity	Commodity	Temporary Adjustment	Total Billing
Customer Charge:	$5.00	---	---	---	---	**$5.00**
Delivery Charge (per therm):						
Residential	$0.47719	$0.01943	$0.12502	$0.59044	$(0.00486)	**$1.20722** (R)
Commercial	$0.46066	$0.01431	$0.12502	$0.59044	$(0.03538)	**$1.15505** (R)

Minimum Monthly Bill: Customer Charge plus charges under **SCHEDULE C** and **SCHEDULE 15** (if applicable).

(continue to Sheet 1-2)

Issued August 31, 2009
NWN Advice No. OPUC 09-12

Effective with service on
and after November 1, 2009

RATE SCHEDULE 2
RESIDENTIAL SALES SERVICE

AVAILABLE:
To Residential Customers in all territory served by the Company under the Tariff of which this Rate Schedule is a part. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, is subject to the provisions of **SCHEDULE X**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment used in Residential dwellings that provide complete family living facilities in which the occupant normally cooks, eats, sleeps, and carries on the household operations incident to Domestic life, for at least one of the following purposes:

(a) Operation of ducted forced air Natural Gas space heating equipment that is the primary source for space heating requirements, and/or;
(b) Operation of fully automatic water heating equipment for primary water heating requirements.

Service under this Rate Schedule includes the use of gas for equipment installed in addition to (a) or (b).

MONTHLY RATE: Effective: November 1, 2009 (T)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See Schedule 100 for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160.**

	Base Rate	Base Rate Adjustment	Pipeline Capacity	Commodity	Temporary Adjustment	Total Billing
Customer Charge:	$6.00	---	---	---	---	**$6.00**
Volumetric Charge (per therm):	$0.41526	$0.01437	$0.12502	$0.59044	$(0.00462)	**$1.14047**

(R)

Minimum Monthly Bill: Customer Charge plus charges under **SCHEDULE C** or **SCHEDULE 15** (if applicable)

(continue to Sheet 2-2)

RATE SCHEDULE 3

BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

(T)

MONTHLY RATE: Effective: November 1, 2009

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**.

FIRM SALES SERVICE CHARGES:						Billing Rates [1]	
Customer Charge (per month):						**$8.00**	
Volumetric Charges (per therm):	Base Rate	Base Rate Adjustment	Pipeline Capacity	Commodity Component [2]	Temporary Adjustment		
Commercial (3 CSF):	$0.33622	$0.01121	$0.12502	$0.59044	$(0.03524)	**$1.02765**	(R)
Industrial (3 ISF):	$0.30693	$0.01004	$0.12502	$0.59044	$(0.03886)	**$0.99357**	(R)
Standby Charge (per therm of MHDV) [3]:						**$10.00**	

[1] **SCHEDULE C** and **SCHEDULE 15** Charges shall apply, if applicable.
[2] The Commodity Component will be either Annual Sales WACOG or Monthly Incremental Cost of Gas.
[3] Applies to Standby Sales Service only.

Minimum Monthly Bill. The Minimum Monthly Bill shall be any **SCHEDULE C** and **SCHEDULE 15** Charges, plus:

(a) ***Firm Sales Service.*** Customer Charge.
(b) ***Firm Sales Standby Service.*** Customer Charge, plus Standby Service Charge.

FROZEN

RATE SCHEDULE 19
GAS LIGHT SERVICE

AVAILABLE:
In all territory served by the Company under the Tariff of which this Rate Schedule is a part for use exclusively in gas lighting devices to which Distribution Facilities were committed or installed prior to August 10, 1973.

SERVICE DESCRIPTION:
Firm unmetered gas service delivered on a continuous basis for use in gas lamps, not exceeding a rated capacity of 2.5 cubic feet per hour per Mantle or Mantle equivalent; and, only to approved installations using gas for mood or atmosphere lighting, for porch, patio or walkway lamps and for roadway or street lighting. Gas lamps installed downstream of the meter will be treated as additional equipment under the Rate Schedule appropriate for the existing service.

BILLING UNIT:
Rates for gas service under this Rate Schedule are expressed in units of the standard Mantle with a maximum rated capacity of 2.5 cubic feet per hour.

(T)

MONTHLY RATE: Effective: November 1, 2009

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

	Base Rate	Base Rate Adjustments	Temporary Adjustments	Billing Rate	
One mantle	$18.39	$0.07	$(0.72)	**$17.74**	(R)
All additional mantles	$17.78	$0.07	$(0.72)	**$17.13**	(R)
Minimum Monthly Bill: Amount based on number of mantles installed					

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

RATE SCHEDULE 31
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR COMMERCIAL CUSTOMER CLASS:

Effective: November 1, 2009 (T)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**. The rates for distributed generation customers are subject to **SCHEDULE 31-CHP**.

FIRM SALES SERVICE CHARGES (31 CSF) [1]:					Billing Rates	
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
Block 1: 1st 2,000 therms	$0.17708	$0.00898	$0.59044	$(0.03514)	**$0.74136**	(R)
Block 2: All additional therms	$0.16142	$0.00853	$0.59044	$(0.03512)	**$0.72527**	(R)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.12502**	(I)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.87**	(I)
INTERRUPTIBLE SALES SERVICE CHARGES (31 CSI) [1]:						
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component: [2]	Total Temporary Adjustments [3]		
Block 1: 1st 2,000 therms	$0.17874	$0.00737	$0.59044	$(0.02958)	**$0.74697**	(R)
Block 2: All additional therms	$0.16293	$0.00706	$0.59044	$(0.02957)	**$0.73086**	(R)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.01486**	(I)
FIRM TRANSPORTATION SERVICE CHARGES (31 CTF):						
Customer Charge (per month):					**$325.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [4]		
Block 1: 1st 2,000 therms	$0.17771	$0.00820		$0.00237	**$0.18828**	(I)
Block 2: All additional therms	$0.16200	$0.00782		$0.00239	**$0.17221**	(I)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 15.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 162 may not apply.
[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 162 may also apply.

(continue to Sheet 31-10)

RATE SCHEDULE 31
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR INDUSTRIAL CUSTOMER CLASS: **Effective: November 1, 2009** (T)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**. The rates for distributed generation customers are subject to **SCHEDULE 31-CHP**.

FIRM SALES SERVICE CHARGES (31 ISF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
Block 1: 1st 2,000 therms	$0.16358	$0.00513	$0.59044	$(0.03880)	**$0.72035**	(R)
Block 2: All additional therms	$0.14781	$0.00462	$0.59044	$(0.03877)	**$0.70410**	(R)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.12502**	(I)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.87**	(I)
INTERRUPTIBLE SALES SERVICE CHARGES (31 ISI) [1]:						
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
Block 1: 1st 2,000 therms	$0.25433	$0.13054	$0.59044	$(0.03908)	**$0.93623**	(R)
Block 2: All additional therms	$0.22983	$0.11797	$0.59044	$(0.03851)	**$0.89973**	(R)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.01486**	(I)
FIRM TRANSPORTATION SERVICE CHARGES (31 ITF):						
Customer Charge (per month):					**$325.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [4]		
Block 1: 1st 2,000 therms	$0.16317	$0.00446		$(0.00017)	**$0.16746**	(I)
Block 2: All additional therms	$0.14744	$0.00403		$(0.00015)	**$0.15132**	(I)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from **SCHEDULE C** and **SCHEDULE 15**.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in **SCHEDULE 162** may not apply.
[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in **SCHEDULE 162** may also apply.

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES: **Effective: November 1, 2009** (T)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.
The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**. The rates for distributed generation customers are subject to **SCHEDULE 32-CHP**.

FIRM SALES SERVICE CHARGES [1]:						
Customer Charge (per month, all service types):					**$675.00**	
	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]	**Billing Rates**	
32 CSF Volumetric Charges (per therm):						(R)
Block 1: 1st 10,000 therms	$0.09710	$0.00276	$0.59044	$(0.03760)	**$0.65270**	
Block 2: Next 20,000 therms	$0.08252	$0.00235	$0.59044	$(0.03758)	**$0.63773**	
Block 3: Next 20,000 therms	$0.05826	$0.00165	$0.59044	$(0.03755)	**$0.61280**	
Block 4: Next 100,000 therms	$0.03399	$0.00096	$0.59044	$(0.03751)	**$0.58788**	
Block 5: Next 600,000 therms	$0.01943	$0.00055	$0.59044	$(0.03750)	**$0.57292**	
Block 6: All additional therms	$0.00972	$0.00028	$0.59044	$(0.03748)	**$0.56296**	
32 ISF Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.09775	$ 0.00297	$ 0.59044	$(0.03870)	**$0.65246**	
Block 2: Next 20,000 therms	$0.08308	$ 0.00253	$ 0.59044	$(0.03868)	**$0.63737**	
Block 3: Next 20,000 therms	$0.05866	$ 0.00178	$ 0.59044	$(0.03864)	**$0.61224**	
Block 4: Next 100,000 therms	$0.03421	$ 0.00105	$ 0.59044	$(0.03861)	**$0.58709**	
Block 5: Next 600,000 therms	$0.01956	$ 0.00059	$ 0.59044	$(0.03859)	**$0.57200**	
Block 6: All additional therms	$0.00980	$ 0.00030	$ 0.59044	$(0.03857)	**$0.56197**	(R)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
Firm Sales Service Storage Charge (per therm of MDDV per month):					**$0.20415**	
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.12502**	(I)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.87**	(I)
INTERRUPTIBLE SALES SERVICE CHARGES [4]:						
Customer Charge (per month):					**$675.00**	
32 ISI Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.09752	$0.00263	$0.59044	$(0.03320)	**$0.65739**	(R)
Block 2: Next 20,000 therms	$0.08289	$0.00223	$0.59044	$(0.03318)	**$0.64238**	
Block 3: Next 20,000 therms	$0.05852	$0.00158	$0.59044	$(0.03315)	**$0.61739**	
Block 4: Next 100,000 therms	$0.03414	$0.00093	$0.59044	$(0.03312)	**$0.59239**	
Block 5: Next 600,000 therms	$0.01951	$0.00052	$0.59044	$(0.03310)	**$0.57737**	
Block 6: All additional therms	$0.00977	$0.00026	$0.59044	$(0.03309)	**$0.56738**	(R)
Interruptible Pipeline Capacity Charge (per therm):					**$0.01486**	(I)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 15.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 162 may not apply.
[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 162 may also apply.

(continue to Sheet 32-10)

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RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES: Effective: November 1, 2009 (T)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in Schedule 160. The rates for distributed generation customers are subject to **SCHEDULE 32-CHP**.

FIRM TRANSPORTATION SERVICE CHARGES (32 CTF or 32 ITF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$675.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [2]		
Block 1: 1st 10,000 therms	$0.09708	$0.00224		$(0.00007)	**$0.09925**	(I)
Block 2: Next 20,000 therms	$0.08250	$0.00190		$(0.00006)	**$0.08434**	
Block 3: Next 20,000 therms	$0.05825	$0.00134		$(0.00003)	**$0.05956**	
Block 4: Next 100,000 therms	$0.03399	$0.00078		$(0.00001)	**$0.03476**	
Block 5: Next 600,000 therms	$0.01942	$0.00045		$0.00001	**$0.01988**	
Block 6: All additional therms	$0.00973	$0.00023		$0.00002	**$0.00998**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (32 ITI) [3]:						
Customer Charge (per month):					**$675.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Temporary Adjustments [2]		
Block 1: 1st 10,000 therms	$0.09744	$0.00220		$(0.00007)	**$0.09957**	(I)
Block 2: Next 20,000 therms	$0.08282	$0.00187		$(0.00006)	**$0.08463**	
Block 3: Next 20,000 therms	$0.05847	$0.00132		$(0.00003)	**$0.05976**	
Block 4: Next 100,000 therms	$0.03411	$0.00077		$(0.00001)	**$0.03487**	
Block 5: Next 600,000 therms	$0.01950	$0.00044		$0.00001	**$0.01995**	
Block 6: All additional therms	$0.00977	$0.00022		$0.00002	**$0.01001**	(I)

[1] For Firm Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus any other charges that may apply from Schedule C or Schedule 15.
[2] Where applicable, the Account 191 Adjustments shall apply.
[3] For Interruptible Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus any other charges that may apply from Schedule C or Schedule 15.
[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 162 may also apply.

RATE SCHEDULE 33
HIGH VOLUME NON-RESIDENTIAL
FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICE
(continued)

MONTHLY RATE: Effective: November 1, 2009 (T)

The rates shown below may not always reflect actual billing rates. See **Schedule 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**.

FIRM TRANSPORTATION SERVICE CHARGES (33 TF)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:		Base Rate	Base Rate Adjustments	Total Temporary Adjustment [1]	
Per therm, all therms:		$0.00526	$0.00013	$(0.00001)	**$0.00538**
Firm Service Distribution Capacity Charge: Per therm of MDDV per month					**$0.15748**
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus Firm Service Distribution Capacity Charge, plus any other charges that may apply from **SCHEDULE C** and **SCHEDULE 15**.					

(I)

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (33 TI)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:		Base Rate	Base Rate Adjustments	Total Temporary Adjustment [1]	
Per therm, all therms:		$0.00526	$0.00013	$(0.00001)	**$0.00538**
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus any other charges that may apply from **SCHEDULE C** and **SCHEDULE 15**.					

(I)

[1] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in **SCHEDULE 162** shall apply.

SCHEDULE 100
SUMMARY OF ADJUSTMENTS

PURPOSE:

The purpose of this Schedule is to list and summarize the adjustment Schedules applicable to each of the Company's Rate Schedules.

(C)

SCHEDULE	A	160	161	162	163	164	166	167	169	170	172	176	177
1R	ADD	ADD	ADD	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
1C	ADD	ADD	ADD	INC	INC	INC	INC	INC	INC	INC		INC	INC
2	ADD	ADD	ADD	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
3 (CSF)	ADD	ADD	ADD	INC	INC	INC	INC	INC	INC	INC		INC	INC
3 (ISF)	ADD	ADD	ADD	INC		INC	INC	INC	INC	INC	INC	INC	INC
15	ADD						INC	INC		INC			
19	ADD		ADD	ADD		INC	INC	INC	INC				INC
31 (CSF)	ADD	ADD	ADD	INC	INC	INC	INC	INC	INC	INC		INC	INC
31 (CSI)	ADD	ADD	ADD	INC	INC	INC	INC	INC	INC	INC		INC	INC
31 (CTF)	ADD		ADD	INC	INC		INC	INC		INC		INC	INC
31 (ISF)	ADD	ADD	ADD	INC		INC	INC	INC	INC	INC	INC	INC	INC
31 (ISI)	ADD	ADD	ADD	INC		INC	INC	INC	INC	INC	INC	INC	INC
31 (ITF)	ADD		ADD	INC			INC	INC		INC	INC	INC	INC
32 (CSF/ISF)	ADD	ADD	ADD	INC		INC	INC	INC	INC	INC	INC		INC
32 (CSI/ISI)	ADD	ADD	ADD	INC		INC	INC	INC	INC	INC	INC		INC
32 (CTF/ITF)	ADD		ADD	INC			INC	INC		INC	INC		INC
32 (CTI/ITI)	ADD		ADD	INC			INC	INC		INC	INC		INC
33 (CTI/ITI)	ADD		ADD	INC			INC	INC		INC		INC	INC
33 (CTF/ITF)	ADD		ADD	INC			INC	INC		INC		INC	INC
60	ADD							INC		INC			

(D)

(C)

Table Code Key:

ADD This adjustment is added to the billing rates at the time the bill is issued.
INC This adjustment is included in the billing rates shown on the Rate Schedule.

(continue to Sheet 100-1.1)

SCHEDULE 100
SUMMARY OF ADJUSTMENTS
(continued)

PURPOSE: (continued)

(M)(N)

SCHEDULE	185	186	187	188	190	195	199	301	305
1R	ADD	ADD	INC		INC		INC	ADD	INC
1C	ADD	ADD	INC		INC		INC	ADD	INC
2	ADD	ADD	INC		INC	ADD	INC	ADD	INC
3 (CSF)	ADD	ADD	INC		INC	ADD	INC	ADD	INC
3 (ISF)	ADD	ADD		INC			INC		
15									
19							INC		INC
31 (CSF)	ADD	ADD	INC		INC		INC	ADD	INC
31 (CSI)		ADD	INC		INC		INC	ADD	INC
31 (CTF)					INC		INC		
31 (ISF)	ADD	ADD	INC	INC			INC		
31 (ISI)		ADD	INC	INC			INC		
31 (ITF)							INC		
32 (CSF/ISF)	ADD	ADD	INC	INC			INC		
32 (CSI/ISI)		ADD	INC	INC			INC		
32 (CTF/ITF)							INC		
32 (CTI/ITI)							INC		
33 (CTI/ITI)							INC		
33 (CTF/ITF)							INC		
60									

(D)

(M)

Table Code Key:

ADD This adjustment is added to the billing rates at the time the bill is issued.
INC This adjustment is included in the billing rates shown on the Rate Schedule.

(continue to Sheet 100-2)

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SCHEDULE 100
SUMMARY OF ADJUSTMENTS
(continued)

The following is a brief description of the applicable Schedules:

Schedule A "Billing for City and County Exactions."
This adjustment will be reflected directly on Customer bills.

Schedule 160 "Revision of Charges for Coos County Customers."
This adjustment is added to the Delivery Charges for applicable Coos County Customers.

Schedule 161 "Automatic Adjustment for Utility Income Tax"
These are one-time annual lump sum adjustments to bills that do not affect Rate Schedule billing rates.

Schedule 162 "Temporary (Technical) Adjustments to Rates."
These are Temporary Adjustments that are included in the Delivery Charge reflected on Customer bills.

Schedule 163 "Special Adjustment to Rates Price Elasticity"
These are Base Adjustments that are included in the Delivery or Volumetric Charges reflected on Customer bills.

Schedule 164 "Purchased Gas Cost Adjustments to Rates."
These are Pipeline Capacity and Commodity charges

Schedule 166 "Adjustments to Rates (UM 1335)."
These are Base Adjustments associated with a change in depreciation rates that are included in Delivery or Volumetric Charges reflected on Customer bills.

Schedule 167 "General Adjustments to Rates."
These are Base Adjustments that are included in all applicable charges reflected on Customer bills

Schedule 169 "Special Adjustment to Rates for Storage Inventories."
These are Temporary Adjustments that are included in the Delivery or Volumetric Charges reflected on Customer bills.

Schedule 170 "Special Adjustment to Rates for Pension Expense." (N)
These are Temporary Adjustments that are included in the Delivery or Volumetric Charges reflected on (N)
Customer bills. (N)

Schedule 172 "Special Adjustment to Rates for Intervenor Funding." (N)
These are Temporary Adjustments that are included in the Delivery or Volumetric Charges reflected on (N)
Customer bills. (N)

Schedule 176 "Adjustments to Rates for Costs Relating to Mist Storage Expansion."
These are Base Adjustments that are included in the Delivery or Volumetric Charges reflected on Customer bills.

Schedule 177 "System Integrity Program Rate Adjustment." (T)
These are Base Adjustments that are included in the Delivery or Volumetric Charges reflected on Customer bills.

Schedule 185 "Special Annual Interstate Storage and Transportation Credit."
These are one-time annual lump sum adjustments to bills that do not affect Rate Schedule billing rates.

(continue to Sheet 100-3)

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SCHEDULE 100
SUMMARY OF ADJUSTMENTS
(continued)

Schedule 186 "Special Annual Core Pipeline Capacity Optimization Credit."
These are one-time annual lump sum adjustments to bills that do not affect Rate Schedule billing rates.

Schedule 187 "Special Adjustment for Storage Recall." (N)
These are Base Adjustments that are included in the Delivery or Volumetric Charges reflected on (N)
Customer bills. (N)

Schedule 188 "Industrial Demand Side Management (DSM) program Cost Recovery." (N)
These are Temporary Adjustments that are included in the Delivery or Volumetric Charges reflected (N)
on Customer bills. (N)

Schedule 190 "Price Elasticity and Partial Decoupling Mechanism."
These are Base Adjustments that are included in the Delivery or Volumetric Charges reflected on Customer bills.

Schedule 195 "Weather Adjusted Rate Mechanism (WARM)."
These are winter heating season adjustments that are included in the Delivery Charges reflected on Customer bills.

Schedule 199 "Special Rate Adjustment (UM 1148/UP205)."
These are Base Adjustments that are included in the Delivery or Volumetric Charges reflected on Customer bills.

Schedule 301 "Public Purposes Funding Surcharge."
These are monthly adjustments to bills that do not affect Rate Schedule billing rates.

(N)
Schedule 305 "Special Adjustment for Smart Energy Program Costs." (N)
These are Temporary Adjustments that are included in the Delivery or Volumetric Charges reflected (N)
on Customer bills.

SCHEDULE 162
TEMPORARY (TECHNICAL) ADJUSTMENTS TO RATES

PURPOSE:
To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of balances in all of the Company's conventional deferred revenue and gas cost accounts, Accounts 186 and 191, respectively.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1	Schedule 3	Schedule 31	Schedule 33
Schedule 2	Schedule 19	Schedule 32	Schedule 54

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2009 (T)

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Account 191 Commodity Adjustment	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments	Total Temporary Adjustment	
1R		$(0.03237)	$(0.00622)	$0.03373	**$(0.00486)**	(C)
1C		$(0.03237)	$(0.00622)	$0.00321	**$(0.03538)**	
2		$(0.03237)	$(0.00622)	$0.03397	**$(0.00462)**	
3 (CSF)		$(0.03237)	$(0.00622)	$0.00335	**$(0.03524)**	
3 (ISF)		$(0.03237)	$(0.00622)	$(0.00027)	**$(0.03886)**	
19		(0.62)	(0.12)	0.02000	(0.72)	
31 (CSF)	Block 1	$(0.03237)	$(0.00622)	$0.00345	**$(0.03514)**	
	Block 2	$(0.03237)	$(0.00622)	$0.00347	**$(0.03512)**	
31(CTF)	Block 1	N/A	N/A	$0.00237	**$0.00237**	
	Block 2	N/A	N/A	$0.00239	**$0.00239**	
31 (CSI)	Block 1	$(0.03237)	$(0.00074)	$0.00353	**$(0.02958)**	
	Block 2	$(0.03237)	$(0.00074)	$0.00354	**$(0.02957)**	
31 (ISF)	Block 1	$(0.03237)	$(0.00622)	$(0.00021)	**$(0.03880)**	
	Block 2	$(0.03237)	$(0.00622)	$(0.00018)	**$(0.03877)**	
31 (ITF)	Block 1	N/A	N/A	$(0.00017)	**$(0.00017)**	
	Block 2	N/A	N/A	$(0.00015)	**$(0.00015)**	(C)
31 (ISI)	Block 1	$(0.03237)	$(0.00074)	$(0.00597)	**$(0.03908)**	
	Block 2	$(0.03237)	$(0.00074)	$(0.00540)	**$(0.03851)**	

(continue to Sheet 162-2)

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SCHEDULE 162
TEMPORARY (TECHNICAL) ADJUSTMENTS TO RATES
(continued)

APPLICATION TO RATE SCHEDULES (continued): Effective: November 1, 2009 (T)

Schedule	Block	Account 191 Commodity Adjustment	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments	Total Temporary Adjustment
32 (CSF)	Block 1	$(0.03237)	$(0.00622)	$0.00099	$(0.03760)
	Block 2	$(0.03237)	$(0.00622)	$0.00101	$(0.03758)
	Block 3	$(0.03237)	$(0.00622)	$0.00104	$(0.03755)
	Block 4	$(0.03237)	$(0.00622)	$0.00108	$(0.03751)
	Block 5	$(0.03237)	$(0.00622)	$0.00109	$(0.03750)
	Block 6	$(0.03237)	$(0.00622)	$0.00111	$(0.03748)
32 (ISF)	Block 1	$(0.03237)	$(0.00622)	$(0.00011)	$(0.03870)
	Block 2	$(0.03237)	$(0.00622)	$(0.00009)	$(0.03868)
	Block 3	$(0.03237)	$(0.00622)	$(0.00005)	$(0.03864)
	Block 4	$(0.03237)	$(0.00622)	$(0.00002)	$(0.03861)
	Block 5	$(0.03237)	$(0.00622)	$0.00000	$(0.03859)
	Block 6	$(0.03237)	$(0.00622)	$0.00002	$(0.03857)
32 (TF)	Block 1	N/A	N/A	$(0.00007)	$(0.00007)
	Block 2	N/A	N/A	$(0.00006)	$(0.00006)
	Block 3	N/A	N/A	$(0.00003)	$(0.00003)
	Block 4	N/A	N/A	$(0.00001)	$(0.00001)
	Block 5	N/A	N/A	$0.00001	$0.00001
	Block 6	N/A	N/A	$0.00002	$0.00002
32 (SI)	Block 1	$(0.03237)	$(0.00074)	$(0.00009)	$(0.03320)
	Block 2	$(0.03237)	$(0.00074)	$(0.00007)	$(0.03318)
	Block 3	$(0.03237)	$(0.00074)	$(0.00004)	$(0.03315)
	Block 4	$(0.03237)	$(0.00074)	$(0.00001)	$(0.03312)
	Block 5	$(0.03237)	$(0.00074)	$0.00001	$(0.03310)
	Block 6	$(0.03237)	$(0.00074)	$0.00002	$(0.03309)
32 (TI)	Block 1	N/A	N/A	$(0.00007)	$(0.00007)
	Block 2	N/A	N/A	$(0.00006)	$(0.00006)
	Block 3	N/A	N/A	$(0.00003)	$(0.00003)
	Block 4	N/A	N/A	$(0.00001)	$(0.00001)
	Block 5	N/A	N/A	$0.00001	$0.00001
	Block 6	N/A	N/A	$0.00002	$0.00002
33 (TI)		N/A	N/A	$(0.00001)	$(0.00001)
33 (TF)		N/A	N/A	$(0.00001)	$(0.00001)

(C)

(C)

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 163

SPECIAL ADJUSTMENT TO RATES PRICE ELASTICITY

PURPOSE:
To identify permanent adjustments to rates in the schedules listed below in accordance with a Stipulation and Agreement adopted by the Public Utility Commission of Oregon in Docket UG 143.

APPLICABLE:
To Residential and Commercial Customers served on the following schedules of this Tariff:

Residential	**Commercial**
Schedule 1	Schedule 1
Schedule 2	Schedule 3 (CSF)
	Schedule 31 (CSF)
	Schedule 31 (CTF)
	Schedule 31 (CSI)

APPLICATION TO RATE SCHEDULES: **Effective: November 1, 2009** (T)

The Base Adjustments stated in the above-listed rate schedules reflect the following adjustments (increase). NO FURTHER ADJUSTMENT TO RATES IS REQUIRED.

Residential Rate Schedules: **($0.01277)** per therm (C)
Commercial Rate Schedules: **($0.00595)** per therm (C)

GENERAL RULES AND REGULATIONS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

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d.b.a. NW Natural
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Portland, Oregon 97209-3991

SCHEDULE 164
PURCHASED GAS COST ADJUSTMENT TO RATES

PURPOSE:
To (a) identify the Commodity and Pipeline Capacity Components applicable to the Rate Schedules listed below; and (b) to identify any changes to such components due to changes in the cost of Pipeline capacity and the cost of gas purchased from the Company's suppliers that apply the Rate Schedules listed below.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1	Schedule 3	Schedule 31	Schedule 54
Schedule 2	Schedule 19	Schedule 32	

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2009 (T)

Annual Sales WACOG [1]	$0.59044	(I)
Winter Sales WACOG [2]	$0.57227	(I)
Firm Sales Service Pipeline Capacity Component [3]	$0.12502	(R)
Firm Sales Service Pipeline Capacity Component [4]	$1.87	(R)
Interruptible Sales Service Pipeline Capacity Component [5]	$0.01486	(R)

[1] Applies to all Sales Service Rate Schedules (per therm) except where Winter Sales WACOG or Monthly Incremental Cost of Gas applies.
[2[Applies to Sales Customers that request Winter Sales WACOG at the September 15 Annual Service Election.
[3] Applies to Rate Schedules 1, 2, 3, and Schedule 31 and Schedule 32 Firm Sales Service Volumetric Pipeline Capacity option (per therm).
[4] Applies to Schedules 31 and 32 Firm Sales Service Peak Demand Pipeline Capacity option (per therm of MDDV per month).
[5] Applies to Schedule 31 and Schedule 32 Interruptible Sales Service (per therm).

ADJUSTMENTS TO RATE COMPONENTS: Effective: November 1, 2009 (T)

The above listed components shall be adjusted as follows:

Commodity Component	**Firm Pipeline Capacity Component**
$(0.00000)	**$(0.00000)**

GENERAL TERMS:
This schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued August 31, 2009 Effective with service on
NWN Advice No. OPUC 09-12 and after November 1, 2009

SCHEDULE 166
ADJUSTMENTS TO RATES (UM 1335)

PURPOSE:
To identify the effects of the annual revenue requirement decrease associated with the adoption of the depreciation study in Docket UM 1335

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1	Schedule 31
Schedule 2	Schedule 32
Schedule 3	Schedule 33
Schedule 19	Schedule 54

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2009 (T)

The Base Rates in the listed Rate Schedules include the adjustment shown below. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

(C)

Schedule	Block	Total Base Adjustment
1R		**$(0.01874)**
1C		**$(0.01525)**
2		**$(0.01299)**
3 (CSF)		**$(0.00914)**
3 (ISF)		**$(0.00766)**
19		**$(0.84)**
31 (CSF)	Block 1	**$(0.00614)**
	Block 2	**$(0.00560)**
31(CTF)	Block 1	**$(0.00535)**
	Block 2	**$(0.00487)**
31 (CSI)	Block 1	**$(0.00444)**
	Block 2	**$(0.00404)**
31 (ISF)	Block 1	**$(0.00447)**
	Block 2	**$(0.00404)**
31 (ITF)	Block 1	**$(0.00473)**
	Block 2	**$(0.00428)**
31 (ISI)	Block 1	**$0.08405**
	Block 2	**$0.07596**
32(CSF)	Block 1	**$(0.00306)**
	Block 2	**$(0.00260)**
	Block 3	**$(0.00184)**
	Block 4	**$(0.00107)**
	Block 5	**$(0.00061)**
	Block 6	**$(0.00031)**

(C)

(continue to Sheet 166-2)

SCHEDULE 166
ADJUSTMENTS TO RATES (UM 1335)

<u>APPLICATION TO RATE SCHEDULES</u>: (continued) Effective: November 1, 2009 (T)

Schedule	Block	**Total Base Adjustment**
32(ISF)	Block 1	**$(0.00241)**
	Block 2	**$(0.00204)**
	Block 3	**$(0.00144)**
	Block 4	**$(0.00085)**
	Block 5	**$(0.00048)**
	Block 6	**$(0.00024)**
32(CTF) and 32(ITF)	Block 1	**$(0.00299)**
	Block 2	**$(0.00255)**
	Block 3	**$(0.00180)**
	Block 4	**$(0.00104)**
	Block 5	**$(0.00060)**
	Block 6	**$(0.00030)**
32(CSI) and 32(ISI)	Block 1	**$(0.00263)**
	Block 2	**$(0.00223)**
	Block 3	**$(0.00158)**
	Block 4	**$(0.00092)**
	Block 5	**$(0.00053)**
	Block 6	**$(0.00026)**
32(CTI) and 32(ITI)	Block 1	**$(0.00263)**
	Block 2	**$(0.00223)**
	Block 3	**$(0.00158)**
	Block 4	**$(0.00092)**
	Block 5	**$(0.00052)**
	Block 6	**$(0.00026)**
33(CTI) and 33(ITI)		**$(0.00016)**
33(CTF) and 33(ITF)		**$(0.00016)**

(C)

(C)

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

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SCHEDULE 169
SPECIAL ADJUSTMENT TO RATES FOR STORAGE INVENTORIES

PURPOSE:
To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of balances in the Company's storage inventories.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1 Schedule 3 Schedule 31 (T)
Schedule 2 Schedule 19 Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2009 (T)

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

(T)

Schedule	Block	Adjustment		Schedule	Block	Adjustment
1R		$0.00		32 (ISF)	Block 1	$0.00
1C		$0.00			Block 2	$0.00
2		$0.00			Block 3	$0.00
3 (CSF)		$0.00			Block 4	$0.00
					Block 5	$0.00
3 (ISF)		$0.00			Block 6	$0.00
				32(TF)	Block 1	N/A
19		$0.00			Block 2	N/A
31 (CSF)	Block 1	$0.00			Block 3	N/A
	Block 2	$0.00			Block 4	N/A
31(CTF)	Block 1	N/A			Block 5	N/A
	Block 2	N/A			Block 6	N/A
31 (CSI)	Block 1	$0.00		32(SI)	Block 1	$0.00
	Block 2	$0.00			Block 2	$0.00
31 (ISF)	Block 1	$0.00			Block 3	$0.00
	Block 2	$0.00			Block 4	$0.00
31 (ITF)	Block 1	N/A			Block 5	$0.00
	Block 2	N/A			Block 6	$0.00
31 (ISI)	Block 1	$0.00		32(TI)	Block 1	N/A
	Block 2	$0.00			Block 2	N/A
32 (CSF)	Block 1	$0.00			Block 3	N/A
	Block 2	$0.00			Block 4	N/A
	Block 3	$0.00			Block 5	N/A
	Block 4	$0.00			Block 6	N/A
	Block 5	$0.00		33(TI)		N/A
	Block 6	$0.00		33(TF)		N/A

(C)
(C)
(D)

Issued August 31, 2009 Effective with service on
NWN Advice No. OPUC 09-12 and after November 1, 2009

SCHEDULE 170
SPECIAL ADJUSTMENT TO RATES FOR PENSION EXPENSE

PURPOSE:
To identify adjustments to rates in the Rate Schedules listed below for the amortization of deferred balances related to the Company's pension expense. The rate adjustments under this Schedule are made pursuant to the Stipulation and Agreement in Docket UM 152 adopted by Commission Order No. 03-507.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1 Schedule 3 Schedule 31 (T)
Schedule 2 Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2009 (T)

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment		Schedule	Block	Adjustment
1R		$(0.00073)		32 (ISF)	Block 1	$(0.00014)
1C		$(0.00049)			Block 2	$(0.00012)
2		$(0.00049)			Block 3	$(0.00008)
3 (CSF)		$(0.00035)			Block 4	$(0.00005)
					Block 5	$(0.00003)
3 (ISF)		$(0.00030)			Block 6	$(0.00001)
				32 (TF)	Block 1	$(0.00010)
					Block 2	$(0.00009)
31 (CSF)	Block 1	$(0.00025)			Block 3	$(0.00006)
	Block 2	$(0.00023)			Block 4	$(0.00004)
31 (CTF)	Block 1	$(0.00021)			Block 5	$(0.00002)
	Block 2	$(0.00019)			Block 6	$(0.00001)
31 (CSI)	Block 1	$(0.00017)		32 (SI)	Block 1	$(0.00012)
	Block 2	$(0.00016)			Block 2	$(0.00010)
31 (ISF)	Block 1	$(0.00024)			Block 3	$(0.00007)
	Block 2	$(0.00021)			Block 4	$(0.00004)
31 (ITF)	Block 1	$(0.00020)			Block 5	$(0.00002)
	Block 2	$(0.00018)			Block 6	$(0.00001)
31 (ISI)	Block 1	$(0.00600)		32 (TI)	Block 1	$(0.00010)
	Block 2	$(0.00543)			Block 2	$(0.00009)
32 (CSF)	Block 1	$(0.00013)			Block 3	$(0.00006)
	Block 2	$(0.00011)			Block 4	$(0.00004)
	Block 3	$(0.00008)			Block 5	$(0.00002)
	Block 4	$(0.00004)			Block 6	$(0.00001)
	Block 5	$(0.00003)		33 (TI)		$(0.00001)
	Block 6	$(0.00001)		33 (TF)		$(0.00001)

(C)

(C)

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SCHEDULE 172
SPECIAL ADJUSTMENT TO RATES FOR INTERVENOR FUNDING (N)

PURPOSE:
To identify adjustments to rates in the Rate Schedules listed below for the amortization of deferred balances related to Intervenor Funding. The rate adjustments under this Schedule are made pursuant to the Intervenor Funding Agreement in Docket UM 1357 adopted by Commission in Order No. 07-564.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1R	Schedule 31 (all Industrial Classes)
Schedule 2	Schedule 32 (all Industrial Classes)
Schedule 3 ISF	

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2009

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Residential Customer Adjustment:	$0.00023
Industrial Customer Adjustment:	$0.00003

(N)

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SCHEDULE 177
SYSTEM INTEGRITY PROGRAM RATE ADJUSTMENT

(C)

PURPOSE:
To recover the costs associated with the Company's System Integrity Program in accordance with the Stipulation adopted by Commission in Docket UM 1406, OPUC Order 09-067 entered March 1, 2009.

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SYSTEM INTEGRITY PROGRAM ADJUSTMENT RATE
The System Integrity Program Adjustment Rate recovers the costs incurred from the Company's System Integrity Program which consists of the following parts:

Part A – Bare Steel Replacement Program This program was initiated in 2001 with an estimated completion date of schedule of 2021. The costs for this program will be classified as capital expenditures. The Company will allocate 70% of the cumulative investment to Residential and Commercial firm sales and transportation customers taking service under Rate Schedules 1, 2, 3, 31 and 54 on an equal cents per therm basis. The remaining 30% will be allocated on an equal percent of margin basis to all customer classes. The cost recovery for this Part shall be as agreed to in the Safety Program Stipulation, dated April 17, 2002.

Part B –Transmission Integrity Management Program (TIMP) – This program was initiated in 2002 in response to the Pipeline Safety Improvement Act of 2002 and PHMSA Natural Gas Integrity Management Rule. Associated costs will be spread to all customer classes on an equal percent of margin.

Part C - Distribution Integrity Management Program (DIMP) – This program was initiated in 2008 and will focus on damage prevention. Associated costs will be spread to all customer classes on an equal percent of margin.

SPECIAL PROVISIONS

1. Cost recovery under this Schedule shall not exceed $12 million dollars per PGA Year without the express written consent from all parties to the Stipulation adopted by Commission Order No. 09-067.

2. Each April, the Company will present to the parties to UM 1406 an annual forecast of program expenditures. A report of actual program expenses will be filed with the Commission each August.

3. Adjustments under this Schedule will be based on actual and forecasted expense and investment activity through September 30, adjusted to reflect the difference between the previous year's actual versus forecasted costs. (C)

(continue to Sheet 177-2)

SCHEDULE 177
SYSTEM INTEGRITY PROGRAM RATE ADJUSTMENT
(continued)

SPECIAL PROVISIONS (Continued)

4. For the 2009-2010 PGA Year only, effective November 1, 2009, an adjustment reflecting the final carry over balance of the GeoHazard Repair and Risk Mitigation program will be included in customer rates.

TERM:
The System Integrity Program shall remain in effect through December 31, 2021, or until such other time as the Commission may approve.

APPLICATION TO RATE SCHEDULES: **Effective: November 1, 2009** (T)
The Adjustments shown below are included in the Base Adjustments in the listed Rate Schedules:

(C)

Schedule	Block	Part A		Part B	Part C	Geo-Haz Final	Total Adjustment
		70%	30%				
1R		$0.00364	$0.00250	$0.01062	$0.00000	$0.00267	$0.01943
1C		$0.00364	$0.00169	$0.00718	$0.00000	$0.00180	$0.01431
2		$0.00364	$0.00170	$0.00722	$0.00000	$0.00181	$0.01437
3 (CSF)		$0.00364	$0.00120	$0.00509	$0.00000	$0.00128	$0.01121
3 (ISF)		$0.00364	$0.00101	$0.00431	$0.00000	$0.00108	$0.01004
19		$0.07	$0.00	$0.00	$0.00	$0.00	$0.07
31 (CSF)	Block 1	$0.00364	$0.00085	$0.00359	$0.00000	$0.00090	$0.00898
	Block 2	$0.00364	$0.00077	$0.00329	$0.00000	$0.00083	$0.00853
31(CTF)	Block 1	$0.00364	$0.00072	$0.00307	$0.00000	$0.00077	$0.00820
	Block 2	$0.00364	$0.00066	$0.00281	$0.00000	$0.00071	$0.00782
31 (CSI)	Block 1	$0.00364	$0.00059	$0.00251	$0.00000	$0.00063	$0.00737
	Block 2	$0.00364	$0.00054	$0.00230	$0.00000	$0.00058	$0.00706
31 (ISF)	Block 1	$0.00000	$0.00081	$0.00345	$0.00000	$0.00087	$0.00513
	Block 2	$0.00000	$0.00073	$0.00311	$0.00000	$0.00078	$0.00462
31 (IFT)	Block 1	$0.00000	$0.00071	$0.00300	$0.00000	$0.00075	$0.00446
	Block 2	$0.00000	$0.00064	$0.00271	$0.00000	$0.00068	$0.00403
31 (ISI)	Block 1	$0.00000	$0.02065	$0.08785	$0.00000	$0.02204	$0.13054
	Block 2	$0.00000	$0.01866	$0.07939	$0.00000	$0.01992	$0.11797
32 (CSF)	Block 1	$0.00000	$0.00044	$0.00185	$0.00000	$0.00047	$0.00276
	Block 2	$0.00000	$0.00037	$0.00158	$0.00000	$0.00040	$0.00235
	Block 3	$0.00000	$0.00026	$0.00111	$0.00000	$0.00028	$0.00165
	Block 4	$0.00000	$0.00015	$0.00065	$0.00000	$0.00016	$0.00096
	Block 5	$0.00000	$0.00009	$0.00037	$0.00000	$0.00009	$0.00055
	Block 6	$0.00000	$0.00004	$0.00019	$0.00000	$0.00005	$0.00028

(C)

(continue to Sheet 177-3)

SCHEDULE 177
SYSTEM INTEGRITY PROGRAM RATE ADJUSTMENT
(continued)

APPLICATION TO RATE SCHEDULES: **Effective: November 1, 2009**
The Adjustments shown below are included in the Base Adjustments in the listed Rate Schedules:

Schedule	Block	Part A		Part B	Part C	Geo-Haz Final	Total Adjustment
		70%	**30%**				
32 (ISF)	Block 1	$0.00000	$0.00047	$0.00200	$0.00000	$0.00050	$0.00297
	Block 2	$0.00000	$0.00040	$0.00170	$0.00000	$0.00043	$0.00253
	Block 3	$0.00000	$0.00028	$0.00120	$0.00000	$0.00030	$0.00178
	Block 4	$0.00000	$0.00017	$0.00070	$0.00000	$0.00018	$0.00105
	Block 5	$0.00000	$0.00009	$0.00040	$0.00000	$0.00010	$0.00059
	Block 6	$0.00000	$0.00005	$0.00020	$0.00000	$0.00005	$0.00030
32 (TF)	Block 1	$0.00000	$0.00035	$0.00151	$0.00000	$0.00038	$0.00224
	Block 2	$0.00000	$0.00030	$0.00128	$0.00000	$0.00032	$0.00190
	Block 3	$0.00000	$0.00021	$0.00090	$0.00000	$0.00023	$0.00134
	Block 4	$0.00000	$0.00012	$0.00053	$0.00000	$0.00013	$0.00078
	Block 5	$0.00000	$0.00007	$0.00030	$0.00000	$0.00008	$0.00045
	Block 6	$0.00000	$0.00004	$0.00015	$0.00000	$0.00004	$0.00023
32 (SI)	Block 1	$0.00000	$0.00042	$0.00177	$0.00000	$0.00044	$0.00263
	Block 2	$0.00000	$0.00035	$0.00150	$0.00000	$0.00038	$0.00223
	Block 3	$0.00000	$0.00025	$0.00106	$0.00000	$0.00027	$0.00158
	Block 4	$0.00000	$0.00015	$0.00062	$0.00000	$0.00016	$0.00093
	Block 5	$0.00000	$0.00008	$0.00035	$0.00000	$0.00009	$0.00052
	Block 6	$0.00000	$0.00004	$0.00018	$0.00000	$0.00004	$0.00026
32 (TI)	Block 1	$0.00000	$0.00035	$0.00148	$0.00000	$0.00037	$0.00220
	Block 2	$0.00000	$0.00030	$0.00125	$0.00000	$0.00032	$0.00187
	Block 3	$0.00000	$0.00021	$0.00089	$0.00000	$0.00022	$0.00132
	Block 4	$0.00000	$0.00012	$0.00052	$0.00000	$0.00013	$0.00077
	Block 5	$0.00000	$0.00007	$0.00030	$0.00000	$0.00007	$0.00044
	Block 6	$0.00000	$0.00003	$0.00015	$0.00000	$0.00004	$0.00022
33 (all)		$0.00000	$0.00002	$0.00009	$0.00000	$0.00002	$0.00013

SCHEDULE 187
SPECIAL RATE ADJUSTMENT FOR MIST CAPACITY RECALL

(N)

PURPOSE:
The purpose of this schedule is to reflect the rate effects of the Company's recalling of Mist storage capacity for use by the Company's core customers.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1
Schedule 2
Schedule 3
Schedule 31
Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2009
The Total Adjustment amounts shown below are included in the Base Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Mist Recall Base Rate Adjustment [1]
1R		$0.00028
1C		$0.00018
2		$0.00019
3CSF		$0.00013
3ISF		$0.00011
31CSF	Block 1	$0.00009
	Block 2	$0.00009
31ISF	Block 1	$0.00009
	Block 2	$0.00008
31CSI	Block 1	$0.00007
	Block 2	$0.00006
31ISI	Block 1	$0.00230
	Block 2	$0.00208
32CSF	Block 1	$0.00005
	Block 2	$0.00004
	Block 3	$0.00003
	Block 4	$0.00002
	Block 5	$0.00001
	Block 6	$0.00000
32I SF	Block 1	$0.00005
	Block 2	$0.00004
	Block 3	$0.00003
	Block 4	$0.00002
	Block 5	$0.00001
	Block 6	$0.00001
32CSI /32ISI	Block 1	$0.00005
	Block 2	$0.00004
	Block 3	$0.00003
	Block 4	$0.00002
	Block 5	$0.00001
	Block 6	$0.00000

(N)

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SCHEDULE 190

PARTIAL DECOUPLING MECHANISM

PURPOSE:
To (a) describe the partial decoupling mechanism established in accordance with a Stipulation and Agreement adopted by the Oregon Public Utility Commission (OPUC) in Docket UG 143, Order No. 02-634, dated September 12, 2002, and later reauthorized, with modifications, in Docket UG 163, Order No. 05-934, dated August 25, 2005; and (b) identify the adjustment applicable to rates under the Rate Schedules listed below.

TERM:
This Schedule shall automatically terminate on October 31, 2012, or on such other date as the Commission may approve.

APPLICABLE:
To Residential and Commercial Customers served on the following Rate Schedules of this Tariff:

Residential	Commercial
Schedule 1	Schedule 1
Schedule 2	Schedule 3(SF)
	Schedule 31(SF)
	Schedule 31(SI)
	Schedule 31(TF)

ADJUSTMENT TO RATE SCHEDULES: **Effective: November 1, 2009** (T)
The Temporary Adjustments for Residential and Commercial Customers taking service on the above-listed Rate Schedules includes the following adjustment:

Residential Rate Schedules: **$0.03311** per therm (C)
Commercial Rate Schedules: **$0.00258** per therm (C)

PARTIAL DECOUPLING DEFERRAL ACCOUNT:

1. Each month, the company will calculate the difference between weather-normalized usage and the calculated baseline usage for each Residential and Commercial Customer group. The resulting usage differential shall be multiplied by the per therm distribution margin for the applicable customer group.

   The Company shall defer and amortize, with interest, 100% of the distribution margin differential in a sub-account of Account 186. The deferral will be a credit (accruing a refund to customers) if the differential is positive, or a debit (accruing a recovery by the company) if the differential is negative.

(continue to Sheet 190-2)

SCHEDULE 190

PARTIAL DECOUPLING MECHANISM
(continued)

PARTIAL DECOUPLING DEFERRAL ACCOUNT (continued):

2. The baseline usage shall be determined from actual weather normalized usage for the Company's most recent rate case, as adjusted for any price elasticity effects since that rate case.

   The following is an example baseline usage calculation for the Residential Group:

Weather-normalized usage, divided by Residential Customers, equal Normalized use per therm per customer	330,164,716 450,709 733
October 1 price decrease Usage increase due to price elasticity (-10% x -0.172) Estimated usage increase due to price elasticity (weather normalized usage x % of usage increase)	-10% 1.72% 5,678,833
Total New Baseline Usage: (weather normalized usage plus estimated usage increase), divided by customer count, equal Reset baseline usage per therm per customer	 335,843,549 450,709 745

3. Weather-normalized usage is calculated using the approach to weather normalization adopted in the Company's last general rate case, Docket UG 152. The weather data is taken from the stations identified in **RULE 24**.

   Step One. For the heating season months October through May, usage is normalized by taking the difference between normal and actual heating degree days for each district using a base of 59 degrees for Residential and 58 degrees for Commercial.

   Step Two. This step derives the per-therm customer variance by multiplying the heating degree-day difference by the usage coefficient of .1958 for Residential variances, and .7669 for Commercial variances.

   Step Three. The per-therm customer variance is multiplied by the appropriate customer count, by district, with the sum of the district results representing the normalized therm amount.

4. Baseline usage will be adjusted to reflect actual customers billed each month.

5. The per therm distribution margins to be used in the deferral calculation effective November 1, 2009 is $0.44254 per therm for Residential customers and $0.30374 per therm for Commercial customers. (T)(C)

(continue to Sheet 190-3)

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

WARM FORMULA: (continued)

a. The statistical coefficients to be used in the calculation of the WARM Adjustment Factor effective with the WARM Period commencing November 15, 2003 are:

Schedule 2: .1958	Schedule 3: .7669

c. The applicable margins to be used in the calculation of the WARM Adjustment Factor effective with the WARM Period commencing January 1, 2009 are:

Schedule 2: $0.42963	Schedule 3: $0.34743

(C)

Weather data used in the calculation of HDD for each customer shall be from the same weather stations and weather zones that are used in the determination of thermal units as set forth in **RULE 24.**

WARM BILL EFFECTS:

The following table depicts the impact on residential **RATE SCHEDULE 2** and commercial **RATE SCHEDULE 3** customer bills, respectively, at specified variations in HDDs.

	RESIDENTIAL			**COMMERCIAL**	
HDD Variance (+ or -)	Equivalent therms	Total Monthly WARM adjustment (+ or -) *		Equivalent therms	Total Monthly WARM adjustment (+ or -) *
1	.1958	$0.08		.7669	$0.27
5	.9790	$0.42		3.8345	$1.33
10	1.958	$0.84		7.669	$2.66
15	2.937	$1.26		11.5035	$4.00
20	3.916	$1.68		15.338	$5.33
25	4.895	$2.10		19.1725	$6.66
30	5.874	$2.52		23.007	$7.99
35	6.853	$2.94		26.8415	$9.33
40	7.832	$3.36		30.676	$10.66
45	8.811	$3.79		34.5105	$11.99
50	9.790	$4.21		38.345	$13.32

(C)

(C)

To calculate variations beyond or in-between specified levels, multiply the desired HDD variance by the applicable statistical coefficient, and then multiply that sum by the applicable margin.

To obtain the cent per therm effect of the Warm Adjustment, divide the WARM Adjustment by the number of therms used during the billing month.

(continue to Sheet 195-5)

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

WARM BILL EFFECTS: (continued)

Example Bill Calculation:

Here is the how the WARM adjustment is calculated for a residential **RATE SCHEDULE 2** customer where the billing rate is $1.14047 cents per therm, the HDD variance is 50 HDDs colder than normal, and the monthly therm usage is 129 therms: (C)

HDD Differential:	Normal HDDs:	600 HDDs
	Actual HDDs:	650 HDDs
	HDD variance:	600 – 650 = -50 HDDs
Equivalent Therms:	HDD variance:	-50 HDDs
	Statistical coefficient:	.1958
	Equivalent therms:	-50 x .1958 = -9.79 therms
Total Warm Adjustment:	Equivalent therms:	-9.79 therms
	Margin Rate:	$0.42963
	Total WARM Adj.:	-9.79 x $0.42963 = -$4.20608
Total WARM Adjustment converted to cents per therm:	Total WARM Adj.	-$4.44573
	Monthly usage:	129 therms
	Cent/therm Adj.:	-$4.20608 ÷ 129 = -$0.03261
Billing Rate per therm:	Current Rate/therm:	$1.14047
	WARM cent/therm Adj.	-$0.03261
	WARM Billing Rate:	$1.14047 + -$0.03261 = $1.10786
Total WARM Bill:	Customer Charge:	$6.00
	Usage Charge:	$1.10786
	Total	(129 x $1.10786) + $6.00 = $148.91

(C)
(C)

(continue to Sheet 195-6)

SCHEDULE 305
SPECIAL ADJUSTMENT TO RATES FOR SMART ENERGY PROGRAM COSTS (N)

PURPOSE:
To identify adjustments to rates in the Rate Schedules listed below for the amortization of deferred balances related to the Company's Smart Energy Program.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1R	Schedule 3 CSF	Schedule 31 CSI
Schedule 1C	Schedule 19	Schedule 32 CSF
Schedule 2	Schedule 31 CSF	

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2009

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Volumetric Rate Adjustment (per therm):	$0.00112
Schedule 19 Adjustment (per mantle)	$0.02

(N)

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d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

7. Estimated Annual Sales Weighted Average Cost of Gas (Annual Sales WACOG): The estimated Annual Sales WACOG is the default Commodity Component for billing purposes, and is used for purposes of calculating the monthly gas cost deferral costs for entry into the Account 191 sub-accounts calculated by the following formula: (Forecasted Purchases at Adjusted Contract Prices) divided by forecasted sales volumes.
   a. "Forecasted Purchases" means November 1 – October 31 forecasted sales volumes, "weather-normalized", plus a percentage for distribution system LUFG.
   b. "Distribution system embedded LUFG" means the 5-year average of actual distribution system LUFG, not to exceed 2%.
   c. "Adjusted contract prices" means actual and projected contract prices that are adjusted by each associated Canadian pipeline's published (closest to August 1) fuel use and line loss amount provided for by tariff, and by each associated U.S. pipeline's tariffed rate.

   Effective November 1, 2009: (T)
   Estimated Annual Sales WACOG per therm (w/ revenue sensitive): **$0.59044** (R)
   Estimated Annual Sales WACOG per therm (w/o revenue sensitive): **$0.57277** (R)

8. Estimated Winter Sales WACOG: The Company's weighted average Commodity Cost of Gas for the five-month period November through March.
   Effective November 1, 2009: (T)
   Estimated Winter Sales WACOG per therm (w/ revenue sensitive): **$0.57227** (R)
   Estimated Winter Sales WACOG per therm (w/o revenue sensitive): **$0.55515** (R)

9. Estimated Non-Commodity Cost: Estimated annual Non-Commodity gas costs shall be equal to estimated annual Demand Costs, less estimated annual Capacity Release Benefits, plus or minus estimated annual pipeline refunds or surcharges.

10. Estimated Non-Commodity Cost per Therm – Firm Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Firm Sales Service divided by November 1 – October 31 forecasted Firm Sales Service volumes.
   Effective November 1, 2009: (T)
   Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive): **$0.12502** (I)
   Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive: **$0.12128** (I)

(continue to Sheet P-3)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

11. Estimated Non-Commodity Cost per Therm – Interruptible Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Interruptible Sales Service divided by November 1 – October 31 forecasted Interruptible Sales Service volumes.
    Effective November 1, 2009: (T)
    Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):
    $0.01486 (I)
    Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):
    $0.01442 (I)

12. Estimated Non-Commodity Cost per Therm – MDDV Based Sales: The portion of the Estimated annual Non-Commodity Cost applicable to MDDV Based Sales Service.
    Effective November 1, 2009: (T)
    Estimated Non-Commodity Cost per therm - MDDV Based Sales (w/revenue sensitive):
    $1.87 (I)
    Estimated Non-Commodity Cost per therm- MDDV Based Sales (w/o revenue sensitive):
    $1.81 (I)

13. Actual Monthly Firm Sales Service Volumes: The total actual monthly billed Firm Sales Service therms, excluding MDDV based volumes, adjusted for estimated unbilled Firm Sales Service therms.

14. Actual Monthly Interruptible Sales Service Volumes: The total actual monthly billed Interruptible Sales Service therms, adjusted for estimated unbilled Interruptible Sales Service therms.

15. Actual Monthly MDDV Based Firm Sales Service Volumes: The total actual monthly billed Firm Sales Service Volumes for Rate Schedule 31 and Rate Schedule 32 customers billed under the Firm Pipeline Capacity Charge - Peak Demand option, adjusted for estimated unbilled MDDV Firm Sales Service Volumes.

16. Embedded Commodity Cost: The Estimated Annual Sales WACOG, updated for October 31 storage inventory prices, multiplied by the Total of the Actual Monthly Firm and Interruptible Sales Service Volumes.

17. Embedded Non-Commodity Cost per Therm – Firm Sales Service: The Estimated Non-Commodity Cost per Therm - Firm Sales Service multiplied by the Actual Monthly Firm Sales Service Volumes.

18. Embedded Non-Commodity Cost per Therm – Interruptible Sales Service: The Estimated Non-Commodity Cost per Therm – Interruptible Sales Service multiplied by the Actual Monthly Interruptible Sales Service Volumes.

(continue to Sheet P-4)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

CALCULATION OF MONTHLY GAS COSTS FOR DEFERRAL PURPOSES (continued):

2. A debit or credit entry shall be made equal to 100% of any monthly difference between Embedded Non-Commodity Costs and Monthly Seasonalized Fixed Charges. The monthly Seasonalized Fixed Charges for the period November 1, 2009 through November 30, 2010 are: (T)

November 2009	$8,395,499	(C)
December 2009	$11,788,859	
January 2010	$11,530,612	
February	$9,466,937	
March	$8,126,382	
April	$5,834,847	
May	$3,925,687	
June	$2,626,200	
July	$2,092,431	
August	$2,085,682	
September	$2,392,301	
October	$5,191,674	
November	<u>$8,508,815</u>	
ANNUAL TOTAL	$73,570,427	(C)

3. A debit or credit entry shall be made equal to 90% of the difference between the Actual Commodity Cost and the Embedded Commodity Cost. A debit or credit entry will also be made equal to 100% of the difference between storage withdrawals priced at the actual book inventory rate as of October 31 prior to the PGA year and storage withdrawals priced at the inventory rate used in the PGA filing. (C)

4. Monthly differentials shall be deemed to be positive if actual costs exceed embedded costs and to be negative if actual costs fall below embedded costs.

5. The cost differential entries shall be debited to the sub-accounts of Account 191 if positive, and credited to the sub-accounts of Account 191 if negative.

6. Interest – Beginning November 1, 2007, the Company shall compute interest on existing deferred balances on a monthly basis using the interest rate(s) approved by the Commission.

(continue to Sheet P-6)

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

Exhibit: A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW Natural

SUPPORTING MATERIALS

TO

PGA FILING GUIDELINES

DOCKET UM 1286

OPUC ORDER NOS. 09-263 / 09-248

Purchased Gas Cost and Technical Adjustments to Rates

NWN Advice No. OPUC 09-12

August 31, 2009

NWN Advice No. OPUC 09-12
INDEX

Guideline Reference	Data Requirement	Location	Link
III	Assumptions		
1	General Rate Development		
a)	Deferrals and amortizations: LDCs should use forecasted therms to develop rate increments associated with deferrals and amortizations	See Workpapers of Natasha Siores (submitted separately)	
b)	Calculation and application of revenue sensitive costs: When revenue sensitive costs are updated, the LDC should send in work papers to support revision. The LDCs should first determine the entire revenue requirement associated with the annual PGA and then apply the revenue sensitive calculation to the total. Allocation of revenue requirement totals into rate increments should be made after that point. Alternatively, the revenue requirement could be allocated to customer classes and then the total for each customer class could be grossed up. The rate increment would be calculated from the grossed up total.	Exhibit B, pages 3 and 4	
c)	Deferral accounts: The revenue totals in the PGA Summary Sheet should tie directly to deferral account totals. Utility will provide 2 columns consisting of pre- and post-grossed up totals	See Workpapers of Natasha Siores (submitted separately)	
d)	Annual Sales WACOG: The forward price curve used by the utility in its PGA filing for its Annual Sales WACOG should be based on the formula described in Order 08-504, at page 16-17.	See Work papers of Natasha Siores (submitted separately)	
2	PGA Amortizations unrelated to gas distribution: With its Spring Earnings filing, the company should provide Staff with a notice of “intent to request amortization effective November 1” for any deferral it intends to amortize in the PGA that requires a separate earnings test.	See NWN Spring Earnings filing dated May 1, 2009	
	The notice should include a completed (hard copy and electronic) Deferral Summary Worksheet. The LDC would be expected to submit an updated summary sheet and other necessary information when filing for amortization.	See Workpapers of Natasha Siores (submitted separately)	

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Guideline Reference	Data Requirement	Location	Link
3	Calculation of 3% Test. The calculation for the 3% Test should conform to ORS 757.259(6), (i.e. total proposed amortization times the LDC's gross revenues from the preceding year should not exceed 3%). Gross revenues is defined as all Oregon revenues including Other Revenues that are booked above the line. (First column of the ROO from the preceding year.) Preceding year is defined as preceding calendar year as submitted in the ROO provided for the spring earnings review.) The 3% consists of the total of all amortizations. If the total exceeds 3%, it will be dealt with on a case by case basis as provided by related statutes and regulation. See ORS 757.259(7).	Exhibit B, Page 17	
4	Deferral Application	See separately filed: (1) Application for Reauthorization, Docket UM 1027 dated August 14, 2009; and (2) Application for Reauthorization of purchased gas costs dated August 31, 2009 (not yet docketed)	
IV	General Information and Forecasting		
1	General Information		
a)	Definitions of all major terms and acronyms in the data and information provided.	Exhibit A	Definitions!A1
b)	Any significant new regulatory requirements identified by the utility that in the utility's judgment directly impacts the Oregon portfolio design, implementation, or assessment.	Exhibit A	IV.1.b!A1
c)	All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing is based should be based on a methodology and data sources that are consistent with the most recently acknowledged IRP or IRP update for the utility. If the methodology and/or data sources are not consistent each difference should be identified, explained, and documented as part of the PGA filing workpapers.	Exhibit A	
2	Workpapers		
a)	PGA Summary Sheet	Exhibit A, IV.2.a	IV.2.a!A1
b)	Gas Supply Portfolio and Related Transportation		
1	General Information	Exhibit A, IV.2.b 1-7	IV.2.b.1-7'!A1
2	Overview of portfolio planning process	Exhibit A, IV.2.b 1-7	IV.2.b.1-7'!A1
3	LDC sales system demand forecasting	Exhibit A, IV.2.b 1-7	IV.2.b.1-7'!A1
4	Natural gas price forecasts	Exhibit A, IV.2.b 1-7	IV.2.b.1-7'!A1
5	Physical resources for the portfolio	Exhibit A; IV.2.b 1-7 See also Appendix 'A', V.1	IV.2.b.1-7'!A1

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Guideline Reference	Data Requirement	Location	Link
6	Financial resources for the portfolio (derivatives and other financial arrangements)	Exhibit A; IV.2.b 1-1 See also Appendix 'A', V.2	IV.2.b.1-7'!A1
7	Storage resources	Exhibit A, IV.2.b 1-7 See also Appendix 'A', V.7	IV.2.b.1-7'!A1
8	Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation	Exhibit A, IV.2.b 8	IV.2.b.8!A1
9	Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms	Exhibit A, IV.2.b 9	IV.2.b.9!A1
10	Overview of portfolio documentation provided	See Exhibit A, IV.1 - 7	IV.2.b.1-7'!A1
V.	Data and Analysis (in the entirety)	Appendix 'A'	

NW Natural
PGA Filing Guidelines
OPUC Order Nos. 09-263 – 09-248, Docket UM 1286

Section IV. 1 General Information
a) Definitions and Acronyms

Base Load gas (contract)	Purchase agreements in which NW Natural has to take a set amount of gas each day from a supplier for the term of the agreement. Usually involves paying for any gas not taken unless excused by reason of Force Majeure.
Base Rate	The portion of rates that does not change outside of a general rate case, except as allowed through a Commission approved base rate adjustment.
Base Rate Adjustment	A permanent adjustment to rates approved by the Commission outside of a general rate case process.
Collar	Financial hedges that set ceiling and floor values on the price of gas purchases.
Commodity Component	The Tariff term used to refer to the cost of gas component of a customer's billing rate, and which will equal either (a) the Annual Sales WACOG, (b) the Winter Sales WACOG, or (c) the Monthly Incremental Cost of Gas.
Demand [Charge]	The term used to refer to Pipeline Capacity related costs.
Derivative products	Financial transactions related to gas supply, including but not limited to hedges, swaps, puts, calls, options and collars that are exercised to provide price stability/control or supply reliability for sales service customers.
EIA	U.S. Energy Information Administration
FERC	Federal Energy Regulatory Commission
Financial swaps	Transactions that involve an exchange of cash flows with a counterparty.
Financially hedged	Purchases that have associated financial swaps such that the price of the gas is fixed for a pre-determined period of time.
IRP	Integrated Resource Plan
MDDV	Maximum Daily Delivery Volume
NWP	Northwest Pipeline
Off-system storage	Storage facilities located outside NW Natural's service territory.
On-system storage	Storage facilities located inside NW Natural's service territory.
PGA	Purchased Gas Adjustment
Peak day	The day in which volumes distributed or sold by NW Natural are at a maximum. May be theoretical (the "design day") or actual.

Pipeline Capacity	The quantity (volume) of natural gas available on the interstate pipeline for the transportation of gas supplies to the Company's distribution system. Pipeline Capacity related costs are often referred to as "Demand".
Recallable gas supply/capacity	Refers to arrangements that allow NW Natural to use the upstream pipeline capacity and gas supplies held by third parties.
Revenue Sensitive	The amount by which rates are adjusted to reflect the effects of revenue related costs, such as uncollectible expense, regulatory fees, and city license and franchise fees
Swing gas (contract)	Purchase agreements in which NW Natural has the right, but not the obligation, to take gas from a supplier on any given day.
Technical Rate Adjustments	Also referred to as Temporary Rate Adjustments.
Therm	A unit of heating value equivalent to 100,000 Btus. The amount of heat energy in approximately 100 cubic feet of Natural Gas.
Total Commodity Cost	The combined costs for all purchased gas supplies, excluding transportation costs.
Total Gas Cost	The combined costs of all purchased gas supplies and associated transportation costs.
Transportation Cost	The combined costs for all pipeline related demand, capacity or reservation charges
Transportation Resources	The various upstream pipeline capacity agreements held by the company.
Upstream pipeline	Those pipelines that collect natural gas from the areas where it is produced in the British Columbia, Alberta and the U.S. Rocky Mountain supply regions and transport that gas to NW Natural's service territory.
Upstream pipeline capacity	Refers to the rights that NW Natural has obtained to transport gas on upstream pipelines.
WACOG	The Company's weighted average commodity cost of gas (excluding transportation cost), also referred to as Annual Sales WACOG.
Winter Sales WACOG	The Company's winter period weighted average commodity cost of gas (excluding transportation cost).

NW Natural
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IV General Information and Forecasting

1 General Information

b) Any significant new regulatory requirements identified by the utility that in the utility's judgment directly impacts the Oregon portfolio design, implementation, or assessment.

While there are efforts in Congress to impose new regulatory requirements on over-the-counter (OTC) derivative transactions such as those utilized by the company, nothing new has been implemented yet. Accordingly, there has been no impact on the company's portfolio design, implementation or assessment. We continue to monitor the progress of the proposed legislation and are working through the AGA in this regard.

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IV General Information and Forecasting

1 General Information

c) All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing is based should be based on a methodology and data sources that are consistent with the most recently acknowledged IRP or IRP update for the utility. If the methodology and/or data sources are not consistent each difference should be identified, explained, and documented as part of the PGA filing workpapers.

In accordance with the PGA Filing Guidelines at Section IV(1)(c), the Company acknowledges that all forecasts of demand, weather, etc. upon which the gas supply portfolio for this PGA filing is based on the methodology and data sources that are consistent with the Company's most recently acknowledged IRP.

NW Natural
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IV. General Information and Forecasting

2 Workpapers
a. PGA Summary Sheet

	Amount	Location in Company Filing (cite)
1) Change in Annual Revenues		
(Per OAR 860-022-0017(3)(a))		
A) Dollars *(To .1 million)*	($174,100,000)	Exhibit B, Page 3
B) Percent *(To .1 percent)*	-19.85%	"
2) Annual Revenues Calculation *(Whole Dollars)*		
A) PGA Cost Change *(Commodity & Transportation)*	(171,542,293)	Exhibit B, Page 3
B) Remove Last Year's Temporary Increment Total	(10,194,193)	"
C) Add New Temporary Increment	(12,020,782)	"
D) Other Additions or Subtractions (*Break out & List each below -- Attach additional sheet if necessary*)		
1) Net Safety Programs	791,000	Exhibit B, Page 3
2) Storage Recall	95,825	"
3) Remove Coos Bay	145,783	"
4) Elasticity	(5,888,966)	"
5) UM 1335	4,076,000	"
6)	-	
E) Total Proposed Change	(174,149,240)	"
3) Residential Bill Effects Summary		
A) Residential Schedule 2 Rate Impacts		
1) Current Billing Rate per Therm	$1.39384	Exhibit B, Page 2
2) Proposed Billing Rate per Therm	$1.14047	"
3) Rate Change Per Therm	($0.25337)	
4) Percent Change per Therm *(to .1%)*	-18.2%	
B) Average Residential Bill Impact (forecasted weather-normalized annual)		
1) Average Residential Monthly Use	55	Exhibit B, Page 2
2) Customer Charge	$6.00	"
3) Current Average Monthly Bill	$82.66	"
4) Proposed Average Monthly Bill	$68.73	"
5) Change in Average Monthly Bill	($13.93)	"
6) Percent change in Average Monthly Bill *(to .1%)*	-16.9%	"
C) Average January Residential Bill Impact		
1) Average January Residential Use *(forecasted weather-normalized)*	108	N/A
2) Customer Charge	$6.00	N/A
3) Current Average January Bill	$156.53	N/A
4) Proposed Average January Bill	$129.17	N/A
5) Change in Average January Bill	($27.36)	N/A
6) Percent change in Average January Bill (*to .1%*)	-17.5%	N/A
4) Breakdown of Costs		
A) Embedded in Rates		
1) Total Commodity Cost	0	

a) Total Demand Cost (assoc. w/ supply)	0	
b) Total Peaking Cost (assoc. w/ supply)	0	
c) Total Reservation Cost (assoc. w/ supply)	0	
d) Total Volumetric Cost (assoc. w/ supply)	$560,273,612	N/A
e) Total Storage Cost (assoc. w/ supply)	0	
f) Other	$2,213,269	N/A
2) Total Transportation Cost *(Pipeline related)*	0	
a) Total Upstream Canadian Toll	0	
i.Total Demand, Capacity, or Reservation Cost	33,892,586	N/A
ii. Total Volumetric Cost	0	
b) Total Domestic Cost	0	
i. Total Demand, Capacity, or Reservation Cost	48,748,373	N/A
ii. Total Volumetric Cost	0	
3) Total Storage Costs	$84,692,441	N/A
4) Capacity Release Credits	0	
5) Total Gas Costs	$729,820,281	N/A
B) Projected For New Rates		
1) Total Commodity Cost	0	
a) Total Demand Cost (assoc. w/ supply)	0	
b) Total Peaking Cost (assoc. w/ supply)	0	
c) Total Reservation Cost (assoc. w/ supply)	0	
d) Total Vaporization Cost (assoc. w/ supply)	0	
e) Total Volumetric Cost (assoc. w/ supply)	$342,947,047	Exhibit B, Page 5
f) Total Storage Cost (assoc. w/ supply)	0	
g) Other (A&G Benchmark Savings)	$1,998,052	Exhibit B, Page 5
2) Total Transportation Cost *(Pipeline related)*	0	
a) Total Upstream Canadian Toll	0	
i.Total Demand, Capacity, or Reservation Cost	32,881,145	Exhibit B, Page 6
ii. Total Volumetric Cost	0	
b) Total Domestic Cost	0	
i. Total Demand, Capacity, or Reservation Cost	48,673,480	Exhibit B, Page 6
ii. Total Volumetric Cost	0	
3) Total Storage Costs	$68,469,227	Exhibit B, Page 5
4) Capacity Release Credits	0	
5) Total Gas Costs	$494,968,951	Exhibit B, Page 5

5) WACOG *(Weighted Average Cost of Gas)*		
A) Embedded in Rates		
1) WACOG *(Commodity Only)*	0	
a. With revenue sensitive	$0.85126	N/A
b. Without revenue sensitive	$0.82668	N/A
2) WACOG (Non-Commodity)	$0.00000	
a. With revenue sensitive	$0.12115	N/A
b. Without revenue sensitive	$0.11765	N/A
B) Proposed for New Rates		
1) WACOG *(Commodity Only)*	$0.00000	
a. With revenue sensitive	$0.59044	Exhibit B, Page 5 and Page 8

b. Without revenue sensitive	$0.57277	"
2) WACOG (Non-Commodity)	$0.00000	
a. With revenue sensitive	$0.12502	Exhibit B, Page 7
b. Without revenue sensitive	$0.12128	"
6) Therms Sold	721,775,799	Exhibit B, Page 5

7) Purchasing / Hedging Strategies *Prepare 1-2 page summary of gas cost situation to include resources, purchasing strategy, hedging, and pipeline issues. Within the summary include:*		
A) Resources embedded in current rates and an explanation of proposed resources.		
1) Firm Pipeline Capacity		
a) Year-round supply contracts	N/A	Exhibit A, IV.2.b 1-7
b) Winter-only contracts	N/A	"
c) Reliance on Spot Gas/Other Short Term Contracts	N/A	"
d) Other - e.g. Supply area storage	N/A	"
2) Market Area Storage		
a) Underground-owned	N/A	"
b) Underground- contracted	N/A	"
c) LNG-owned	N/A	"
d) LNG-contracted	N/A	"
3) Other Resources		
a) Recallable Supply	N/A	"
b) City gate Deliveries	N/A	"
c) Owned-Production	N/A	"
d) Propane/Air	N/A	"

NW Natural
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IV	General Information and Forecasting
2	Workpapers
b)	Gas Supply Portfolio and Related Transportation
1	General Information
2	Overview of portfolio planning process
3	LDC sales system demand forecasting
4	Natural gas price forecasts
5	Physical resources for the portfolio
6	Financial resources for the portfolio (derivatives and other financial arrangements)
7	Storage resources

1. General Information.
2. Overview of portfolio planning process.

NWN's goal is to assemble resources sufficient to meet expected firm customer requirements under "design" year conditions at the lowest reasonable cost.[1]

To ensure adequate reliability, NWN contracts for firm upstream pipeline capacity, firm off-system storage service and firm recallable gas supply/capacity arrangements with certain on-system customers, in addition to its development of on-system underground and LNG storage.[2]

Upstream pipeline capacity has been contracted with the following objectives in mind: (1) Diversify capacity sources so that disruptions in any one supply region, such as from a pipeline rupture, well freeze-offs, etc., have a minimal impact on NWN; (2) Obtain upstream capacity along the path from NWN's service territory to points generally recognized for their liquidity, such as AECO, to maximize trading opportunities and minimize price volatility; and (3) Find ways to minimize the cost of upstream capacity such as through optimization activities or committing to capacity only on a winter season basis if possible.

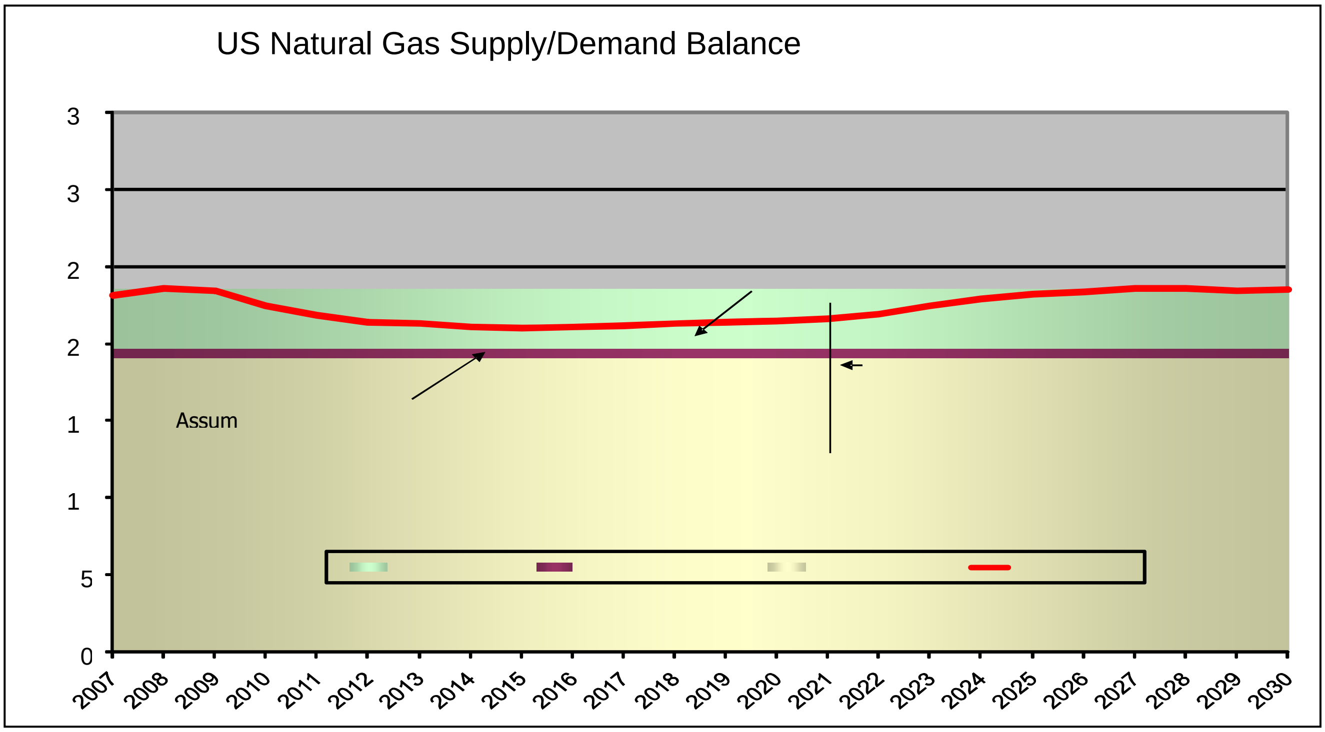
Upstream gas supply contracts have been negotiated with the following objectives in mind: (1) Use a diverse group of reliable suppliers as established by their asset positions, past performance and other factors; (2) Try to match our year-round customer requirements to baseload (take-or-pay) annual or multi-year supply contracts to obtain the most favorable pricing; (3) Use winter only (Nov-Mar) term contracts to match our rise in requirements during the heating season; (4) Leave very little to be purchased on the spot market during the winter due to the likely correlation of high requirements with high spot prices; (5) Use a variety of multi-year contract durations to avoid having to re-contract all supplies every year; (6) Use index-related pricing formulas in term contracts to enable easy evaluation of competitive offers and avoid the need for further price negotiation over the term of the contract; (7) Structure the portfolio to provide some opportunity to take advantage when spot prices are favorable; and (8) Avoid over-contracting gas on a take-or-pay basis, which could result in excess gas supplies that must be sold at a loss if

[1] "Design" year is based on the 85% probability of the coldest heating season in the last 20 years. The design year is augmented by the coldest historical coincident system-weighted average day observed during the last 20 years. This coincident system-weighted coldest average day occurred on February 3, 1989. In addition, the days prior to and following the peak day are also included in the design year to model a consecutive three-day cold snap. For the non-heating season (April through October), daily heating degree day values are assumed equal to the 20-year average.

[2] Customer requirements increase dramatically during the heating season, so past and present storage developed in or adjacent to NWN's

3. LDC sales system demand forecasting.

Customer growth has not equated to load growth in recent years. Conservation and price elasticity among existing residential and commercial customers have offset customer gains. Due in part to its 5-day curtailment of interruptible sales customers in December 2008, many industrial sales customers have elected to switch to transportation service for the coming year, further suppressing sales demand. While interruptible customers do not affect peak day planning and requirements, their annual sales volumes are accounted for in the company's purchasing plans. As a result, the company's annual sales outlook has declined from prior years on a weather-adjusted basis. This mirrors national trends as shown below.

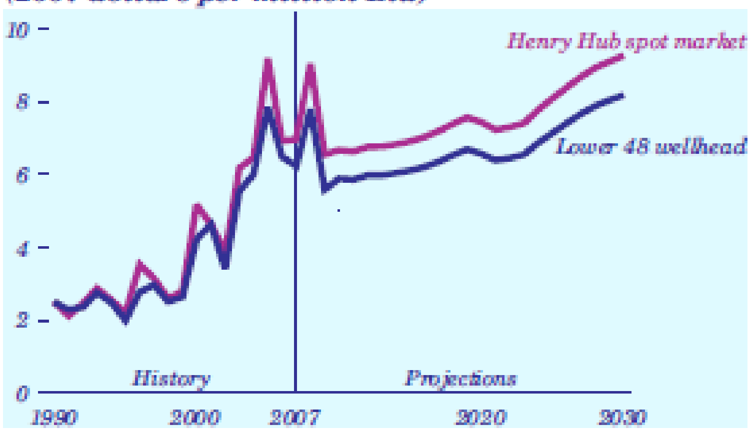


The company's methodology for forecasting annual sales and firm peak day requirements follow the methodology established in its last IRP.

4. Natural gas price forecasts.

NWN relies on forecasts prepared by the U.S. Energy Information Administration (EIA), the Wood Mackenzie consulting firm as well as NYMEX futures prices to help formulate its gas purchase and hedging strategies. Various other price forecasts and analyses also come to NWN by way of trade publications, consultant visits, oil/gas company presentations and other governmental sources. These provide opportunities to test assumptions and explore alternate viewpoints. As an example, below is the latest long-range natural gas forecast as published earlier this year in EIA's Annual Energy Outlook (AEO).

Figure 64. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030 (2007 dollars per million Btu)



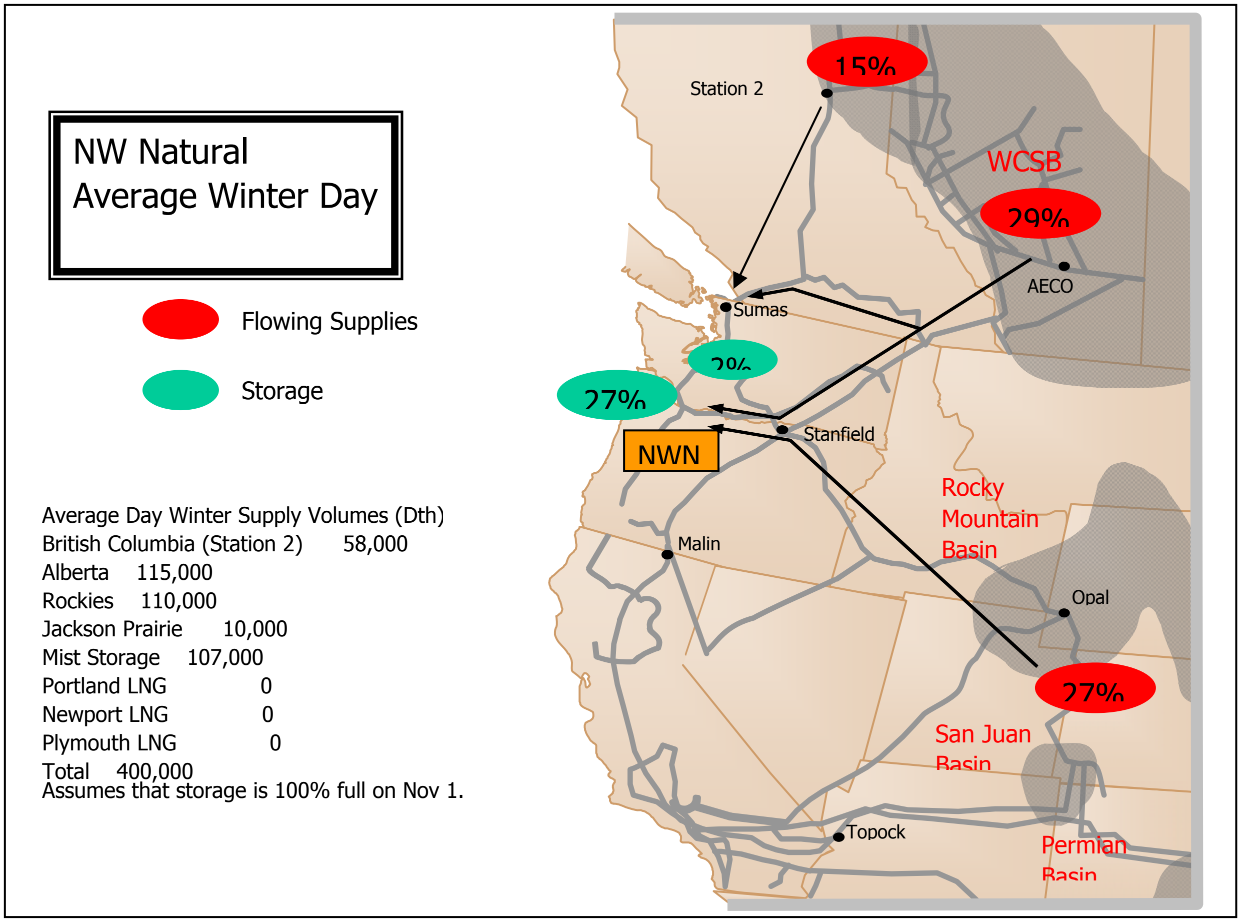
In this case the recent sharp drop in natural gas prices, amid forecasts for rising prices, then leads NWN to formulate hedging strategies around locking in prices on a longer term basis (2 to 3 years out or even longer) for a portion of its expected purchase volumes.

5. Physical resources for the portfolio.

As mentioned above, NWN's physical portfolio on any given day includes gas supplies purchased and transported over the upstream pipeline grid as well as supplies either placed into or withdrawn from five different gas storage facilities. The company also has arrangements with two large on-system customers that allow it to call on their gas supplies on short notice for use by the company ("recall arrangements"). Finally, a very small portion of the company's gas supply (less than 1%) is native gas produced from the Mist Field. This is the company's only gas supply that does not require transportation at one time or another over the interstate pipeline system.

Two changes have occurred in the company's physical supply resources over the past year. First, the company had acquired 5,200 Dth/day of Northwest Pipeline (NWP) capacity from an industrial customer in 1995 under a long-term release. The customer had the option to terminate that release on one year's notice, which was given in July 2008. Hence, that NWP capacity is not available to NWN for any part of the forthcoming PGA period. Second, the company elected last year to recall 10,000 Dth/day of Mist storage capacity effective May 1, 2009. Accordingly, this year's peak day portfolio is slightly larger than last year, while year-round capacity is slightly less.

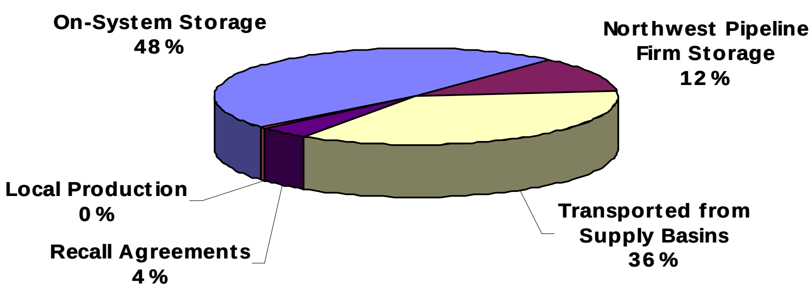
A summary of the company's physical resources is provided in Tables 1 through 5.
Using its mix of transportation and storage resources, the company achieves the following profile on a typical winter day.



Should its “design” peak day occur, all physical resources would be used in the following proportions.

Peak Day Firm Supply

effective November 1, 2009



Total = 9.03 Million Therms

Regarding physical supply purchasing, NWN has contracted with suppliers for approximately 850,000 therms per day of firm deliveries on a daily basis over the upcoming November 2009 through October 2010 period. This reflects the relatively stable daily component of NWN's demand, including some portion of storage injection requirements in the summer months. This figure has been reduced somewhat from prior periods to allow more purchase flexibility during the summer months. It also reflects the lack of load growth associated with new customer additions and the migration of certain interruptible industrial customers from sales to transportation service. This also meshes well with the slight reduction in year-round NWP capacity available to the company that is mentioned above.

For the Nov09-Mar10 heating season, NWN will have contracts for an additional 1.1 million therms/day of supply under baseload and peaking (swing) agreements. This reflects the higher consumption of customers during those months and is about the same volume as contracted for the prior two winter periods. Buying under term supply contracts lessens the need to rely extensively on the spot market during periods of high demand when competition with mid-continent markets for Rockies and Alberta supplies may be intense. Most of the winter contracted volume (750,000 therms/day) is purchased on a take-or-pay basis. The remaining 350,000 therms/day are made available to NWN on a daily basis in exchange either for payment of a fixed "reservation" charge or for equivalent value in the form of put options during the summer months. These swing contracts have no minimum daily, monthly or seasonal purchase requirement, but they provide additional daily supply flexibility, which is especially valuable since winter weather can fluctuate rapidly between mild and cool temperatures, resulting in rapidly changing customer requirements.

This means between 1.2 and 1.6 million therms/day of upstream capacity could be available during the heating season for spot (one month and shorter duration) purchases as and when needed. Accordingly, on days when all upstream capacity is in use, purchases will be split among three roughly equal categories – year-round contracts, winter term contracts and spot purchases.

6. Financial resources for the portfolio (derivatives instruments and other financial arrangements).

NWN "swaps" monthly index prices for fixed prices and other price structures through the use of financial instruments in order to increase price stability across the year. Volumes in storage provide another form of hedging. Overall, NWN's target this year is to hedge the prices of approximately 75% of its expected annual purchase volumes for the upcoming 12-month period commencing in November, the traditional start month for its supply contracts. As storage currently accounts for about 15% of annual purchase quantities, this leaves approximately 60% to be financially hedged. Actual financial hedging targets are set by an executive level oversight committee within the company (the Gas Acquisition Strategy & Policies Committee or GASP) and could change from time-to-time in reaction to market conditions or other factors as the year progresses.

In addition to financial swaps, the company's derivative policies allow the use of financial options (puts and calls) to limit exposure to gas price fluctuations. For example, these instruments can be used in combination in order to "collar" the price of gas for specific purchases.

The company's Gas Supply department performs the actual derivative transactions, while separate individuals, reporting to different executives, oversee the risk management of the hedging program such as approving counterparties and determining credit limits.

7. Storage resources.

NWN relies on five storage facilities to balance its supply portfolio and meet customer requirements. Mist, Portland LNG (also known as Gasco) and Newport LNG are owned and operated by the company. NWN contracts with Northwest Pipeline for service at Jackson Prairie and the Plymouth LNG plant. Storage provides the following benefits to customers:

a) Avoids the need to subscribe to year-round interstate pipeline capacity to meet winter season loads.

b) Allows more gas purchasing during the non-heating season, when prices are typically lower, instead of heating season periods when prices typically peak.

c) Provides diversity of supply and gas movement to and through NWN's service territory, improving overall reliability.

d) Helps balance daily demand with supplies, reducing the potential of imbalance penalties with upstream pipelines.

e) Provides flexibility to take advantage of daily, monthly and seasonal variations in gas pricing, either directly by NWN or through its optimization arrangements.

Additional benefits attributable to Mist have been created through the development of an interstate storage service starting back in 2001. For example, rather than large "lumpy" resource additions requiring years of preparation, the "pre-build" of interstate storage service provides the ability to time and size incremental Mist capacity to a degree not achievable through typical resource development.

More information on the company's storage resources is provided in Table 3 and the workpapers.

Table 1

NW Natural
Firm Off-System Gas Supply Contracts
for the 2009/2010 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Quantity (Dth/day)	Contract Termination Date
British Columbia (Station 2):				
BP Canada	Nov-Oct	5,000		10/31/2012
Coral Energy Canada	Nov-Oct	10,000		10/31/2010
Husky Energy Marketing	Nov-Oct	5,000		10/31/2010
Alta Energy Marketing	Nov-Oct	5,000		10/31/2010
Nexen	Nov-Oct	10,000		10/31/2010
Suncor	Nov-Oct	10,000		10/31/2010
Shell	Nov-Oct	5,000		10/31/2010
Alberta:				
Sempra Energy Trading	Nov-Oct	10,000		10/31/2014
Suncor	Nov-Mar	5,000		3/31/2010
Husky Energy Marketing	Nov-Mar	5,000		3/31/2010
Sequent	Nov-Mar		5,000	3/31/2010
Sequent	Apr-Oct		5,000	10/31/2010
pending	Nov-Mar	*30,000*		3/31/2010
Rockies:				
BP Energy	Nov-Oct	10,000		10/31/2011
Western Gas Resources	Nov-Oct	5,000		10/31/2010
Iberdrola	Nov-Oct	10,000		10/31/2010
BP Energy	Nov-Mar	10,000		3/31/2010
Anadarko	Nov-Mar	5,000		3/31/2010
Enserco Energy	Nov-Mar	5,000		3/31/2010
ONEOK Energy Services	Nov-Mar		10,000	3/31/2010
Kansas Energy	Nov-Mar		5,000	3/31/2010
Kansas Energy	Nov-Mar		5,000	3/31/2010
Shell Energy	Nov-Mar		10,000	3/31/2010
Kansas Energy	Apr-Oct		5,000	10/31/2010
Shell Energy	Apr-Oct		10,000	10/31/2010
pending	Nov-Mar	*15,000*		3/31/2010
Total Off-System Firm Contract Supply		160,000	55,000	

Notes:
1. Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW Natural's system are slightly less due to upstream pipeline fuel consumption.
2. Nov-Mar "Swing" contracts represent physical call options at NWN's discretion, while the Apr-Oct "Swing" contracts represent physical put options at the supplier's discretion.

Table 2

NW Natural
Firm Transportation Capacity
for the 2009/2010 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion	214,889	9/30/2013
1993 Expansion	35,155	9/30/2044
1995 Expansion	102,000	11/30/2011
Occidental (formerly Duke) Cap. Acq.	5,000	10/31/2012
Total NWP Capacity	357,044	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2010
Net NWP Capacity	327,044	
TransCanada's GTN System:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2011
Total GTN Capacity	106,165	
TransCanada's BC System:		
1993 Expansion	47,727	10/31/2010
1995 Rationalization	57,417	10/31/2010
Engage Capacity Acquisition	3,708	Upon 1-year notice
2004 Capacity Acquisition	48,669	10/31/2016
Total TCPL-BC Capacity	157,521	
TransCanada's Alberta System:		
1993 Expansion	48,135	10/31/2011
1995 Rationalization	57,909	10/31/2011
Engage Capacity Acquisition	3,739	Upon 1-year notice
2004 Capacity Acquisition	49,138	10/31/2016
Total TCPL-ALberta Capacity	158,921	
WEI T-South Capacity	57,822	10/31/2014
Southern Crossing Pipeline	47,709	10/31/2020

Notes:
1. All of the above agreements continue year-to-year after termination at NW Natural's sole option except for PGE which requires a mutual agreement to continue.
2. The WEI and Southern Crossing contracts are denominated in volumetric units. Accordingly, the above energy units are an approximation.
3. The numbers shown for the 1993 Expansion contracts on GTN and TCPL-BC are for the winter season (Oct-Mar) only. Both contracts decline during the summer season (Apr-Sep) to approximately 30,000 Dth/day.

Table 3

NW Natural
Firm Storage Resources
for the 2009/2010 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	Upon 1-year notice
TF-2 (redelivery service)	32,624	839,046	Upon 1-year notice
TF-2 (redelivery service)	13,406	281,242	Upon 1-year notice
Plymouth LNG:			
LS-1	60,100	478,900	Upon 1-year notice
TF-2 (redelivery service)	60,100	478,900	Upon 1-year notice
Total Firm Off-system Storage:			
Withdrawal/Vaporization	106,130	1,599,188	
TF-2 Redelivery	106,130	1,599,188	
Firm On-System Storage Plants:			
Mist (reserved for core)	250,000	9,420,270	n/a
Portland LNG Plant	120,000	600,000	n/a
Newport LNG Plant	60,000	1,000,000	n/a
Total On-System Storage	430,000	11,020,270	
Total Firm Storage Resource	536,130	12,619,458	

Notes:

1. All of the above agreements continue year-to-year after termination at NW Natural's sole option.
2. The second Jackson Prairie TF-2 service, for 13,406 Dth/day, is a subordinated firm service. However, on cold weather days, when flows are maximized on NWP's system, service on this agreement should be highly reliable.
3. On-system storage peak deliverability based on design criteria.
4. Mist numbers shown are the portions reserved for service to utility core customers per the company's Integrated Resource Plan. Additional capacity and deliverability has been contracted under varying terms to off-system customers. The number is approximate as it depends on the heat content of the stored gas, which in turn is dependent on the blended heat content of upstream pipeline gas together with Mist production gas.

Table 4

NW Natural
Other Resources: Recall Agreements, Citygate Deliveries and Mist Production
for the 2009/2010 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	11/1/2010
Weyerhaeuser 1	3,000	40	upon 1 year notice
Weyerhaeuser 2	5,000	40	upon 1 year notice
Total Recall Resource	38,000		
Citygate Deliveries:			
none			
Mist Production:			
Enerfin Resources	≈1,800	n/a	12/31/2010

Notes:

1. There are a variety of terms and conditions surrounding the recall rights under each of the above agreements. All of the recall arrangements include delivery to NW Natural's system.
2. Mist production is currently flowing at roughly the figure shown above. Flows vary as new wells are added and older wells deplete. NW Natural's obligation to take gas from existing wells continues for the life of those wells.

Table 5

NW Natural
Firm Resource Summary
for the 2009/2010 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	327,044
Off-System Storage (Jackson Prairie and Plymouth)	106,130
On-System Storage (Mist, Portland LNG and Newport LNG)	430,000
Recallable Capacity and Supply Agreements	38,000
Citygate Deliveries	-
Nominal Mist Production Gas	1,800
Total Firm Resource	902,974

NW Natural
PGA Filing Guidelines

OPUC Order Nos. 09-263 – 09-248, Docket UM 1286

IV	General Information and Forecasting
2	Workpapers
b)	Gas Supply Portfolio and Related Transportation
8	Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation

NW Natural includes *realized* demand response savings in forecasted annual and peak demand by updating use per customer coefficients prior to the annual PGA filing. The updated use per customer coefficient reflects demand measures actually taken in the previous year. Because our ability to accurately forecast annual demand savings is relatively uncertain, we do not include projected demand measures in our forecasted annual and peak demand.

	2009/2010
Forecast Annual Demand (therms)	721,775,790
Forecast Peak Demand (therms)	3,971,602
Forecast DSM Annual (therms)	2,102,781
Forecast DSM Peak (therms)	11,571
Forecast Annual Demand with Forecast DSM	719,673,010
Forecast Peak Demand with Forecast DSM	3,960,031

NW Natural
PGA Filing Guidelines
OPUC Order Nos. 09-263 – 09-248, Docket UM 1286

IV General Information and Forecasting
2 Workpapers
b) Gas Supply Portfolio and Related Transportation
9 Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms

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Our forecasted annual and peak demand is not impacted by gas supply incentive mechanisms.

NW Natural

Exhibit B
Supporting Materials

NWN Advice No. OPUC 09-12

Combined Effects:

Commodity and Non-Commodity Costs:

Temporary and Permanent Adjustments Effects:

NW Natural
Rates & Regulatory Affairs
2009-2010 PGA Filing - Oregon
Calculation of Proposed Rates - SUMMARY

Row	Schedule	Block	1/1/2009 Billing Rates	Net change WACOG	Net change Demand [1]	Proposed Rates PGA Only [1]	Net change Permanent Increments	Net change Temporary Increments	Elasticity Adjustment	Pre-1981 Reg Assets Adjustment	Storage Recall Adjustment	**Proposed 11/1/2009 Rates [1]**
5						D=A+B+C						
6	Schedule	Block	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**
7	1R		1.45725	(0.26082)	0.00387	1.20030	0.00192	0.00609	(0.01277)	0.01140	0.00028	1.20722
8	1C		1.41578	(0.26082)	0.00387	1.15883	0.00091	(0.00662)	(0.00595)	0.00770	0.00018	1.15505
9	2R		1.39384	(0.26082)	0.00387	1.13689	0.00199	0.00642	(0.01277)	0.00775	0.00019	1.14047
10	3C Firm Sales		1.28982	(0.26082)	0.00387	1.03287	0.00154	(0.00640)	(0.00595)	0.00546	0.00013	1.02765
11	Intentionally blank											
12	3I Firm Sales		1.26989	(0.26082)	0.00387	1.01294	0.00144	(0.02555)	0.00000	0.00463	0.00011	0.99357
13	Intentionally blank											
14	19	1st mantle	23.33	(4.98)	0.08	18.43	0.01	(0.46)	(0.24)	0.00	0.00	17.74
15	19	add'l mtls	22.72	(4.98)	0.08	17.82	0.01	(0.46)	(0.24)	0.00	0.00	17.13
16	31C Firm Sales	Block 1	1.00914	(0.26082)		0.74832	0.00128	(0.00624)	(0.00595)	0.00386	0.00009	0.74136
17		Block 2	0.99340	(0.26082)		0.73258	0.00124	(0.00622)	(0.00595)	0.00353	0.00009	0.72527
18	31C Firm Trans	Block 1	0.17195	0.00000		0.17195	0.00125	0.01774	(0.00595)	0.00329	0.00000	0.18828
19		Block 2	0.15616	0.00000		0.15616	0.00121	0.01777	(0.00595)	0.00302	0.00000	0.17221
20	31C Interr Sales	Block 1	1.03105	(0.26082)		0.77023	0.00112	(0.02120)	(0.00595)	0.00270	0.00007	0.74697
21		Block 2	1.01520	(0.26082)		0.75438	0.00110	(0.02120)	(0.00595)	0.00247	0.00006	0.73086
22	31I Firm Sales	Block 1	1.00149	(0.26082)		0.74067	0.00133	(0.02544)	0.00000	0.00370	0.00009	0.72035
23		Block 2	0.98572	(0.26082)		0.72490	0.00118	(0.02540)	0.00000	0.00334	0.00008	0.70410
24	31I Firm Trans	Block 1	0.16378	0.00000		0.16378	0.00081	(0.00035)	0.00000	0.00322	0.00000	0.16746
25		Block 2	0.14800	0.00000		0.14800	0.00072	(0.00031)	0.00000	0.00291	0.00000	0.15132
26	31I Interr Sales	Block 1	1.02147	(0.26082)		0.76065	0.12519	(0.04626)	0.00000	0.09435	0.00230	0.93623
27		Block 2	1.00578	(0.26082)		0.74496	0.11313	(0.04570)	0.00000	0.08526	0.00208	0.89973
28	32C Firm Sales	Block 1	0.93532	(0.26082)		0.67450	0.00027	(0.02411)	0.00000	0.00199	0.00005	0.65270
29		Block 2	0.92067	(0.26082)		0.65985	0.00024	(0.02409)	0.00000	0.00169	0.00004	0.63773
30		Block 3	0.89628	(0.26082)		0.63546	0.00016	(0.02404)	0.00000	0.00119	0.00003	0.61280
31		Block 4	0.87188	(0.26082)		0.61106	0.00009	(0.02399)	0.00000	0.00070	0.00002	0.58788
32		Block 5	0.85724	(0.26082)		0.59642	0.00006	(0.02397)	0.00000	0.00040	0.00001	0.57292
33		Block 6	0.84750	(0.26082)		0.58668	0.00003	(0.02395)	0.00000	0.00020	0.00000	0.56296
34	32I Firm Sales	Block 1	0.93598	(0.26082)		0.67516	0.00039	(0.02529)	0.00000	0.00215	0.00005	0.65246
35		Block 2	0.92125	(0.26082)		0.66043	0.00034	(0.02527)	0.00000	0.00183	0.00004	0.63737
36		Block 3	0.89672	(0.26082)		0.63590	0.00023	(0.02521)	0.00000	0.00129	0.00003	0.61224
37		Block 4	0.87216	(0.26082)		0.61134	0.00016	(0.02518)	0.00000	0.00075	0.00002	0.58709
38		Block 5	0.85747	(0.26082)		0.59665	0.00006	(0.02515)	0.00000	0.00043	0.00001	0.57200
39		Block 6	0.84765	(0.26082)		0.58683	0.00004	(0.02513)	0.00000	0.00022	0.00001	0.56197
40	32 Firm Trans	Block 1	0.09763	0.00000		0.09763	0.00021	(0.00021)	0.00000	0.00162	0.00000	0.09925
41		Block 2	0.08299	0.00000		0.08299	0.00018	(0.00020)	0.00000	0.00137	0.00000	0.08434
42		Block 3	0.05861	0.00000		0.05861	0.00013	(0.00015)	0.00000	0.00097	0.00000	0.05956
43		Block 4	0.03423	0.00000		0.03423	0.00008	(0.00012)	0.00000	0.00057	0.00000	0.03476
44		Block 5	0.01961	0.00000		0.01961	0.00004	(0.00009)	0.00000	0.00032	0.00000	0.01988
45		Block 6	0.00986	0.00000		0.00986	0.00003	(0.00007)	0.00000	0.00016	0.00000	0.00998
46	32 Interr Sales	Block 1	0.95612	(0.26082)		0.69530	0.00048	(0.04034)	0.00000	0.00190	0.00005	0.65739
47		Block 2	0.94146	(0.26082)		0.68064	0.00041	(0.04033)	0.00000	0.00162	0.00004	0.64238
48		Block 3	0.91701	(0.26082)		0.65619	0.00030	(0.04027)	0.00000	0.00114	0.00003	0.61739
49		Block 4	0.89258	(0.26082)		0.63176	0.00018	(0.04024)	0.00000	0.00067	0.00002	0.59239
50		Block 5	0.87792	(0.26082)		0.61710	0.00009	(0.04021)	0.00000	0.00038	0.00001	0.57737
51		Block 6	0.86815	(0.26082)		0.60733	0.00005	(0.04019)	0.00000	0.00019	0.00000	0.56738
52	32 Interr Trans	Block 1	0.09789	0.00000		0.09789	0.00030	(0.00020)	0.00000	0.00158	0.00000	0.09957
53		Block 2	0.08324	0.00000		0.08324	0.00024	(0.00020)	0.00000	0.00135	0.00000	0.08463
54		Block 3	0.05879	0.00000		0.05879	0.00017	(0.00015)	0.00000	0.00095	0.00000	0.05976
55		Block 4	0.03434	0.00000		0.03434	0.00010	(0.00012)	0.00000	0.00055	0.00000	0.03487
56		Block 5	0.01966	0.00000		0.01966	0.00006	(0.00009)	0.00000	0.00032	0.00000	0.01995
57		Block 6	0.00989	0.00000		0.00989	0.00003	(0.00007)	0.00000	0.00016	0.00000	0.01001
58	Intentionally blank											
59	33		0.00529	0.00000	0.00000	0.00529	0.00001	(0.00001)	0.00000	0.00009	0.00000	0.00538
61	**Sources:**											
62	Direct Inputs		Jan 09 filing									
64	Rates in detail			Col F - Col B	Column G+H-C-D		Col C - Col B	Col E - Col D	Column O	Column P	Column Q	

66 [1] For convenience of presentation, demand charges for Rate Schedules 31 and 32 are omitted

NW Natural
Rates & Regulatory Affairs
2009-2010 PGA Filing - Oregon
PGA Effects on Average Bill by Rate Schedule

Calculation of Effect on Customer Average Bill by Rate Schedule [1]

Row	Schedule	Block	Oregon PGA Normalized Volumes page, Column D	Therms in Block	Normal Therms Monthly Average use	Minimum Monthly Charge	1/1/2009 Billing Rates	1/1/2009 Current Average Bill	Proposed 11/1/2009 PGA Only Rates	Proposed 11/1/2009 PGA Only Average Bill	Proposed 11/1/2009 **PGA Only % Bill Change**	Proposed 11/1/2009 Temp & Base Rates	Proposed 11/1/2009 Temp & Base Average Bill	Proposed 11/1/2009 **Temp & Base % Bill Change**	Proposed 11/1/2009 Total **Rates**	Proposed 11/1/2009 Total Average Bill	Proposed 11/1/2009 **Total % Bill Change**
5								F=D+(C * E)		H=D+(C * G)	I =(H - F)/F		K=D+(C * J)	L =(K - F)/F		K=D+(C * M)	O =(N - F)/F
6	Schedule	Block	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
7	1R		726,368	N/A	17.0	5.00	1.45725	29.77	1.20030	25.41	-14.6%	1.46417	29.89	0.4%	1.20722	25.52	-14.3%
8	1C		167,659	N/A	77.0	5.00	1.41578	114.02	1.15883	94.23	-17.4%	1.41200	113.72	-0.3%	1.15505	93.94	-17.6%
9	2R		355,349,088	N/A	55.0	6.00	1.39384	82.66	1.13689	68.53	-17.1%	1.39742	82.86	0.2%	1.14047	68.73	-16.9%
10	3C Firm Sales		152,067,450	N/A	230.0	8.00	1.28982	304.66	1.03287	245.56	-19.4%	1.28460	303.46	-0.4%	1.02765	244.36	-19.8%
11	Intentionally blank																
12	3I Firm Sales		2,174,044	N/A	656.0	8.00	1.26989	841.05	1.01294	672.49	-20.0%	1.25052	828.34	-1.5%	0.99357	659.78	-21.6%
13	Intentionally blank																
14	19	1st mantle	18,760	N/A	98.0	22.04	23.33	23.33	18.43	18.43	-21.0%	22.64	22.64	-3.0%	17.74	17.74	-24.0%
15	19	add'l mtls	0	N/A	0.0	21.43	22.72	22.72	17.82	17.82	-21.6%	22.03	22.03	-3.0%	17.13	17.13	-24.6%
16	31C Firm Sales	Block 1	24,057,306	2,000	4,162.0	325.00	1.00914	2,343.28	0.74832	1,821.64		1.00218	2,329.36		0.74136	1,807.72	
17		Block 2	36,368,804	all additional			0.99340	2,147.73	0.73258	1,583.84		0.98609	2,131.93		0.72527	1,568.03	
18		**Total**						**4,491.01**		**3,405.48**	-24.2%		**4,461.29**	-0.7%		**3,375.75**	-24.8%
19	31C Firm Trans	Block 1	0	2,000	0.0	325.00	0.17195	325.00	0.17195	325.00		0.18828	325.00		0.18828	325.00	
20		Block 2	0	all additional			0.15616		0.15616			0.17221			0.17221		
21		**Total**						**325.00**		**325.00**	0.0%		**325.00**	0.0%		**325.00**	0.0%
22	31C Interr Sales	Block 1	223,579	2,000	0.0	325.00	1.03105	325.00	0.77023	325.00		1.00779	325.00		0.74697	325.00	
23		Block 2	812,974	all additional			1.01520		0.75438			0.99168			0.73086		
24		**Total**						**325.00**		**325.00**	0.0%		**325.00**	0.0%		**325.00**	0.0%
25	31I Firm Sales	Block 1	3,013,400	2,000	3,699.0	325.00	1.00149	2,327.98	0.74067	1,806.34		0.98117	2,287.34		0.72035	1,765.70	
26		Block 2	8,129,370	all additional			0.98572	1,674.74	0.72490	1,231.61		0.96492	1,639.40		0.70410	1,196.27	
27		**Total**						**4,002.72**		**3,037.95**	-24.1%		**3,926.74**	-1.9%		**2,961.97**	-26.0%
28	31I Firm Trans	Block 1	46,557	2,000	5,736.0	325.00	0.16378	652.56	0.16378	652.56		0.16746	659.92		0.16746	659.92	
29		Block 2	159,947	all additional			0.14800	552.93	0.14800	552.93		0.15132	565.33		0.15132	565.33	
30		**Total**						**1,205.49**		**1,205.49**	0.0%		**1,225.25**	1.6%		**1,225.25**	1.6%
31	31I Interr Sales	Block 1	6,751	2,000	53.0	325.00	1.02147	379.14	0.76065	365.31		1.19705	388.44		0.93623	374.62	
32		Block 2	5,979	all additional			1.00578		0.74496			1.16055			0.89973		
33		**Total**						**379.14**		**365.31**	-3.6%		**388.44**	2.5%		**374.62**	-1.2%
27	32C Firm Sales	Block 1	4,257,903	10,000	18,849.0	675.00	0.93532	10,028.20	0.67450	7,420.00		0.91352	9,810.20		0.65270	7,202.00	
28		Block 2	4,488,591	20,000			0.92067	8,147.01	0.65985	5,839.01		0.89855	7,951.27		0.63773	5,643.27	
29		Block 3	1,469,604	20,000			0.89628		0.63546			0.87362			0.61280		
30		Block 4	188,695	100,000			0.87188		0.61106			0.84870			0.58788		
31		Block 5	0	600,000			0.85724		0.59642			0.83374			0.57292		
32		Block 6	0	all additional			0.84750		0.58668			0.82378			0.56296		
33		**Total**						**18,175.21**		**13,259.01**	-27.0%		**17,761.47**	-2.3%		**12,845.27**	-29.3%
34	32I Firm Sales	Block 1	2,502,255	10,000	16,204.0	675.00	0.93598	10,034.80	0.67516	7,426.60		0.91328	9,807.80		0.65246	7,199.60	
35		Block 2	3,460,532	20,000			0.92125	5,715.44	0.66043	4,097.31		0.89819	5,572.37		0.63737	3,954.24	
36		Block 3	1,304,655	20,000			0.89672		0.63590			0.87306			0.61224		
37		Block 4	899,465	100,000			0.87216		0.61134			0.84791			0.58709		
38		Block 5	1	600,000			0.85747		0.59665			0.83282			0.57200		
39		Block 6	0	all additional			0.84765		0.58683			0.82279			0.56197		
40		**Total**						**15,750.24**		**11,523.91**	-26.8%		**15,380.17**	-2.3%		**11,153.84**	-29.2%
41	32 Firm Trans	Block 1	5,662,307	10,000	92,499.0	675.00	0.09763	1,651.30	0.09763	1,651.30		0.09925	1,667.50		0.09925	1,667.50	
42		Block 2	8,929,949	20,000			0.08299	1,659.80	0.08299	1,659.80		0.08434	1,686.80		0.08434	1,686.80	
43		Block 3	5,934,416	20,000			0.05861	1,172.20	0.05861	1,172.20		0.05956	1,191.20		0.05956	1,191.20	
44		Block 4	17,922,013	100,000			0.03423	1,454.74	0.03423	1,454.74		0.03476	1,477.27		0.03476	1,477.27	
45		Block 5	17,050,698	600,000			0.01961		0.01961			0.01988			0.01988		
46		Block 6	0	all additional			0.00986		0.00986			0.00998			0.00998		
47		**Total**						**5,938.04**		**5,938.04**	0.0%		**6,022.77**	1.4%		**6,022.77**	1.4%
48	32 Interr Sales	Block 1	10,429,376	10,000	29,740.0	675.00	0.95612	10,236.20	0.69530	7,628.00		0.91821	9,857.10		0.65739	7,248.90	
49		Block 2	13,880,474	20,000			0.94146	18,829.20	0.68064	13,612.80		0.90320	17,829.17		0.64238	12,680.58	
50		Block 3	7,538,869	20,000			0.91701	(238.42)	0.65619	(170.61)		0.87821			0.61739		
51		Block 4	12,407,037	100,000			0.89258		0.63176			0.85321			0.59239		
52		Block 5	4,994,306	600,000			0.87792		0.61710			0.83819			0.57737		
53		Block 6	0	all additional			0.86815		0.60733			0.82820			0.56738		
54		**Total**						**28,826.98**		**21,070.19**	-26.9%		**27,686.27**	-3.9%		**19,929.48**	-30.8%
55	32 Interr Trans	Block 1	6,243,567	10,000	201,583.0	675.00	0.09789	1,653.90	0.09789	1,653.90		0.09957	1,670.70		0.09957	1,670.70	
56		Block 2	10,718,721	20,000			0.08324	1,664.80	0.08324	1,664.80		0.08463	1,692.60		0.08463	1,692.60	
57		Block 3	7,690,383	20,000			0.05879	1,175.80	0.05879	1,175.80		0.05976	1,195.20		0.05976	1,195.20	
58		Block 4	22,705,048	100,000			0.03434	3,434.00	0.03434	3,434.00		0.03487	3,487.00		0.03487	3,487.00	
59		Block 5	48,168,825	600,000			0.01966	1,014.12	0.01966	1,014.12		0.01995	1,029.08		0.01995	1,029.08	
60		Block 6	76,222,375	all additional			0.00989		0.00989			0.01001			0.01001		
61		**Total**						**8,942.62**		**8,942.62**	0.0%		**9,074.58**	1.5%		**9,074.58**	1.5%
62	Intentionally blank																
63	33		0	N/A	0.0	38,000.00	0.00529	38,000.00	0.00529	38,000.00	0.0%	0.00538	38,000.00	0.0%	0.00538	38,000.00	0.0%
64																	
65	**Totals**		878,398,101														
66			0														
67																	
68	**Sources:**																
69	Direct Inputs			per Tariff		per Tariff											
70																	
71	Rates in summary						Column A		Column D			Cols A+E+F+G+H+I			Column J		
72																	

73 [1] For convenience of presentation, the cent per therm demand charge is used, rather than the available MDDV demand option for Rate Schedules 31 and 32

NW Natural
Rates & Regulatory Affairs
2009-2010 PGA Filing - Oregon
PGA Effects on Revenue

Line		Excluding Revenue Sensitve Amount	Including Revenue Sensitve Amount	Reference
2	**Purchased Gas Cost Adjustment (PGA)**			
4	Gas Cost Change	($165,281,012)	($170,378,744)	NWN 2009-10 PGA gas cost file August filing.xls
6	Capacity Cost Change	(1,128,736)	(1,163,549)	NWN 2009-10 PGA gas cost file August filing.xls
8	**Total PGA Change**	(166,409,748)	(171,542,293)	
10	**Temporary Rate Adjustments**			
12	Proposed Temporary Increments	(11,661,120)	(12,020,782)	NWN 2009-10 Oregon PGA rate development Refiling
14	Removal of Current Temporary Increments	(9,899,887)	(10,194,193)	2008-2009 PGA filing + January Rate Change File
16	**Total Net Temporary Rate Adjustment**	(1,761,233)	(1,826,589)	
18	**Base Rate Adjustments**			
20	Proposed Safety Program Costs	7,496,000	7,727,000	NWN/B Page __ of __
22	Removal of Current Safety Program Costs	(6,728,000)	(6,936,000)	2008-2009 PGA filing
24	Coos Bay Adjustment	0	0	Coos Bay increment is complete
26	Removal of Current Coos Bay Adjustment	141,421	145,783	2008-2009 PGA filing
28	Storage Recall for Core	92,958	95,825	Storage Recall workpaper
30	Pre-1981 Assets	3,954,000	4,076,000	Order 08-578
32	Price Elasticity Adjustment	(5,712,768)	(5,888,966)	NWN 2009-10 Oregon PGA rate development file
34	**Total Net Base Rate Adjustment**	(756,389)	(780,358)	
37	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**($168,927,370)**	**($174,149,240)**	
41	2008 Oregon Earnings Test Normalized Total Revenues	$877,514,000	$877,514,000	
43	Affect of this filing, as a percentage change (line 31÷ line 35)	-19.25%	-19.85%	

NW Natural
Rates and Regulatory Affairs
2009-2010 PGA Filing - OREGON
Basis for Revenue Related Costs

		Twelve Months		
1		Ended 06/30/09		
2				
3	Total Billed Gas Sales Revenues	890,192,604		
4	Total Oregon Revenues	922,390,509		
5				
6	Regulatory Commission Fees [1]	2,305,976	0.250%	Statutory rate
7	City License and Franchise Fees	21,439,393	2.324%	Line 7 ÷ Line 4
8	Net Uncollectible Expense	3,852,973	0.418%	Line 8 ÷ Line 4
9				
10	Total	27,598,342	**2.992%**	Sum lines 8-9
11				
12				
13	**Note:**			
14	[1] Dollar figure is set at statutory level of 0.25% times Total Oregon Revenues (line 4)			
15				
16				
17				

NW Natural
2009-2010 PGA - SYSTEM: August Filing
Summary of Total Commodity Cost

SYSTEM COSTS

1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)		
2			November	December	January	February	March	April	May	June	July	August	September	October	TOTAL		
3			1	2	3	4	5	6	7	8	9	10	11	12			
4	**COSTS**																
5	Commodity Cost from Supply		$39,386,600	$50,149,157	$39,661,174	$32,766,878	$36,582,328	$31,547,457	$22,273,762	$16,404,782	$13,832,066	$13,982,188	$15,854,423	$30,506,233	$342,947,047		
6	tab commodity cost from supply, column ao, lines 93-105																
7	Volumetric Pipeline Chgs		$255,999	$309,273	$238,113	$201,558	$209,683	$183,529	$125,772	$86,876	$71,096	$71,273	$80,756	$164,124	$1,998,052		
8	tab commodity cost from vol pipe, column e, line 78-90																
9	Commodity Cost from Storage		$2,351,553	$12,290,333	$24,309,040	$19,001,957	$9,373,717	$235,012	$152,353	$147,438	$152,353	$152,353	$147,438	$155,680	$68,469,227		
10	tab Commodity Cost from Storage, column h, line 61-73																
11	Total Commodity Cost		$41,994,152	$62,748,763	$64,208,327	$51,970,393	$46,165,728	$31,965,998	$22,551,887	$16,639,096	$14,055,515	$14,205,814	$16,082,617	$30,826,037	$413,414,326		
12																	
13	**VOLUMES**																
14	Pipeline Commodity at Receipt Points		79,765,754	95,109,495	71,668,333	58,933,104	66,185,005	59,019,847	40,709,432	28,257,611	23,139,496	23,196,926	26,285,812	53,021,328	625,292,143		
15	Pipeline Fuel Use		2,104,703	2,480,847	1,948,847	1,583,675	1,778,128	1,511,962	1,068,230	755,440	670,278	671,320	719,278	1,378,423	16,671,131		
16	Pipeline Gas Arriving at City Gate		77,661,051	92,628,648	69,719,486	57,349,429	64,406,877	57,507,885	39,641,202	27,502,171	22,469,218	22,525,606	25,566,534	51,642,905	608,621,012		
17	Storage Gas Deliveries		4,699,391	19,644,010	40,596,042	32,991,221	15,582,522	443,955	217,000	210,000	217,000	217,000	210,000	225,889	115,254,030		
18	Total Gas At Citygate (Storage and Pipeline)		82,360,442	112,272,658	110,315,528	90,340,650	79,989,399	57,951,840	39,858,202	27,712,171	22,686,218	22,742,606	25,776,534	51,868,794	723,875,042		
19																	
20	Unaccounted for Gas		267,866	319,492	240,474	197,811	222,149	198,352	136,729	94,862	77,504	77,696	88,182	178,126	2,099,243	0.290%	0.000%
21																	
22	Load Served		82,092,576	111,953,166	110,075,054	90,142,839	79,767,250	57,753,488	39,721,473	27,617,309	22,608,714	22,664,910	25,688,352	51,690,668	721,775,799		
23															0		
24	**Annual Sales WACOG**		$0.51155	$0.56049	$0.58331	$0.57653	$0.57876	$0.55349	$0.56775	$0.60249	$0.62169	$0.62678	$0.62607	$0.59636	$0.57277		
25																	
OR	**OREGON Sales WACOG with Revenue Sensitive**		$0.52733	$0.57778	$0.60130	$0.59431	$0.59661	$0.57056	$0.58526	$0.62107	$0.64086	$0.64611	$0.64538	$0.61475	$0.59044		
WA	**WASHINGTON Sales WACOG with Revenue Sensitive**		$0.53558	$0.58682	$0.61071	$0.60361	$0.60595	$0.57949	$0.59442	$0.63079	$0.65090	$0.65622	$0.65548	$0.62438	$0.59968		

NW Natural
2009-2010 PGA - SYSTEM: August Filing
Summary of Total Demand Charges

SYSTEM COSTS

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		November	December	January	February	March	April	May	June	July	August	September	October	TOTAL
		30	31	31	28	31	30	31	30	31	31	30	31	365
Transport charges by transporter:														
Northwest Pipeline		$3,982,129	$4,114,865	$4,114,865	$3,716,653	$4,114,865	$3,982,129	$4,114,865	$3,982,129	$4,114,865	$4,114,865	$3,982,129	$4,114,865	$48,449,224
GTN		517,197	534,438	534,438	482,717	534,438	435,253	449,762	435,253	449,762	449,762	435,253	534,438	5,792,711
TCPL BC		239,195	239,195	239,195	239,195	239,195	214,070	214,070	214,070	214,070	214,070	214,070	239,195	2,719,590
NOVA		745,767	745,767	745,767	745,767	745,767	745,767	745,767	745,767	745,767	745,767	745,767	745,767	8,949,204
Terasen (Southern Crossing)		576,541	595,760	595,760	538,105	595,760	576,541	595,760	576,541	595,760	595,760	576,541	595,760	7,014,589
Spectra (Westcoast)		699,229	702,090	702,090	693,505	702,090	699,229	702,090	699,229	702,090	702,090	699,229	702,090	8,405,051
KB Pipeline		18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	224,256
Total System Demand		$6,778,746	$6,950,803	$6,950,803	$6,434,630	$6,950,803	$6,671,677	$6,841,002	$6,671,677	$6,841,002	$6,841,002	$6,671,677	$6,950,803	$81,554,625

NW Natural

2009-2010 PGA - OREGON: August Filing

Derivation of Oregon per therm Non-Commodity Charges

Oregon Derivation of Demand Increments

Line				
1			Without	WITH
2			Revenue Sensitive	Revenue Sensitive
3	(a)	(b)	(c)	(d)
4	System Demand		$81,554,625	
5	Oregon Allocation Factor 1/		90.21%	
6	Oregon Demand		$73,570,427	
7				
8	Oregon Firm Sales Forecasted Normal Volumes		600,643,949	
9	Oregon Interruptible Sales Forecasted Normal Volumes		50,299,345	
10				
11				
12	Proposed Firm Demand Per Therm 2/		$0.12128	$0.12502
13	Proposed Interruptible Demand 2/		$0.01442	$0.01486
14	Proposed MDDV Demand Charge		$1.81	$1.87
15				
16	Current Firm Demand Per Therm		$0.11765	$0.12115
17	Current Interruptible Demand		$0.01399	$0.01441
18	Current MDDV Demand Charge		$1.76	$1.81
19				
20	Percent Change in Firm Demand		3.09%	
21				
22				
23	1/Allocation Factor: Actual 12 months ended 06/30/09 firm sales volumes:			
24		Washington	Oregon	System
25	Residential	45,029,237	362,678,428	407,707,665
26	Commercial	20,837,936	232,002,769	252,840,705
27	Industrial	2,963,408	39,543,978	42,507,386
28	Total	68,830,581	634,225,175	703,055,756
29		9.79%	90.21%	100.00%
30				
31	2/Calculation of Proposed Demand Rates:			
32				
33	Demand change factor		1.031	
34				
35	Firm Demand (line 8 * line 35)		$0.12128	$72,845,038
36	Interruptible Demand (line 9 * line 36)		$0.01442	$725,389
37				$73,570,427
38				$0

NW Natural
2009-2010 PGA - SYSTEM: August Filing
Calculation of Winter WACOG

1	Forecast price for AECO gas:			
2				
3		AECO/NIT		
4				
5	November	$0.41677		
6	December	$0.48498		
7	January	$0.51505		
8	February	$0.51838		
9	March	$0.51234		
10	April	$0.49122		
11	May	$0.49592		
12	June	$0.50579		
13	July	$0.51755		
14	August	$0.52657		
15	September	$0.53247		
16	October	$0.54339		
17				
18				
19	Average price, November-March		$0.48950	average lines 5-9
20				
21	Annual average price, November-October		$0.50504	average lines 5-16
22				
23	Ratio of winter to annual		0.96923	line 19 ÷ line 21
24				
25			Without Rev	WITH Rev
26			Sensitive	Sensitive
OR	Oregon Annual WACOG		$0.57277	$0.59044
OR	Oregon Winter WACOG		$0.55515	$0.57227
			line 23 * 0.57277	
WA	Washington Annual WACOG		$0.57277	$0.59968
WA	Washington Winter WACOG		$0.55515	$0.58123
			line 23 * 0.57277	

NW Natural
2009-2010 PGA - OREGON
Derivation of Oregon Seasonalized Fixed Charges

		Normalized Residential Volumes	Normalized Commercial Volumes	Firm Industrial Volumes	Interruptible Industrial Volumes	Total		Firm Demand Increment Eff. 11/01/09	Interr. Demand Increment Eff. 11/01/09		Seasonalized Fixed Charges
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
November	2009										$8,395,499
December	2009	60,257,634	34,187,004	2,241,113	4,365,649	101,051,400		$0.12502	$0.01486		$11,788,859
January	2010	58,776,677	33,395,753	2,322,859	4,879,644	99,374,933		$0.12502	$0.01486		$11,530,612
February	2010	47,826,909	27,521,856	2,258,932	3,799,622	81,407,319		$0.12502	$0.01486		$9,466,937
March	2010	40,269,247	24,039,410	1,992,124	5,931,645	72,232,426		$0.12502	$0.01486		$8,126,382
April	2010	27,920,025	17,690,288	1,943,223	4,690,428	52,243,964		$0.12502	$0.01486		$5,834,847
May	2010	17,668,739	12,604,553	1,626,778	3,946,234	35,846,304		$0.12502	$0.01486		$3,925,687
June	2010	10,815,310	8,974,715	1,443,027	3,543,614	24,776,666		$0.12502	$0.01486		$2,626,200
July	2010	7,961,557	7,577,884	1,313,885	3,363,111	20,216,437		$0.12502	$0.01486		$2,092,431
August	2010	7,880,156	7,536,292	1,367,799	3,476,159	20,260,406		$0.12502	$0.01486		$2,085,682
September	2010	9,511,021	8,289,484	1,492,550	3,639,444	22,932,499		$0.12502	$0.01486		$2,392,301
October	2010	24,562,011	16,106,435	1,641,342	4,189,708	46,499,496		$0.12502	$0.01486		$5,191,674
November	2010	42,644,930	25,142,338	1,840,091	4,474,086	74,101,445		$0.12502	$0.01486		$8,508,815
		356,094,216	223,066,012	21,483,723	50,299,344	650,943,295					$73,570,427
		ok	ok	ok	ok						

STATEMENT OF RATES
Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1
(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate Minimum	Base Tariff Rate Maximum	ACA(2)	Currently Effective Tariff Rate(3) Minimum	Currently Effective Tariff Rate(3) Maximum
Rate Schedule TF-1 (4)(5)					
Reservation					
(Large Customer)					
System-Wide	.00000	.37984	-	.00000	.37984
15 Year Evergreen Exp.	.00000	.38101	-	.00000	.38101
25 Year Evergreen Exp.	.00000	.36445	-	.00000	.36445
Volumetric					
(Large Customer)					
System-Wide	.00756	.03000	.00190	.00946	.03190
15 Year Evergreen Exp.	.00369	.00369	.00190	.00559	.00559
25 Year Evergreen Exp.	.00369	.00369	.00190	.00559	.00559
(Small Customer) (6)	.00756	.67209	.00190	.00946	.67399
Scheduled Overrun	.00756	.40984	.00190	.00946	.41174
Rate Schedule TF-2 (4)(5)					
Reservation	.00000	.37984	-	.00000	.37984
Volumetric	.00756	.03000	-	.00756	.03000
Scheduled Daily Overrun	.00756	.40984	-	.00756	.40984
Annual Overrun	.00756	.40984	-	.00756	.40984
Rate Schedule TI-1					
Volumetric (7)	.00756	.40984	.00190	.00946	.41174
Scheduled Overrun	.00756	.40984	.00190	.00946	.41174
Rate Schedule TFL-1 (4)(5)					
Reservation	-	-	-	-	-
Volumetric	-	-	-	-	-
Scheduled Overrun	-	-	-	-	-
Rate Schedule TIL-1					
Volumetric	-	-	-	-	-
Scheduled Overrun	-	-	-	-	-

TF0307 0030003P128Third Revised Sheet No. 7
TF04 Second Revised Sheet No. 7
TF05Laren M. Gertsch, Director
TF06112008 010109

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedules SGS-2F and SGS-2I

(Dollars per Dth)

Rate Schedule and Type of Rate	Currently Effective Tariff Rate (1) Minimum	Maximum
Rate Schedule SGS-2F (2) (3) (4) (5)		
Demand Charge		
Pre-Expansion Shipper	0.00000	0.01551
Expansion Shipper	0.00000	0.08476
Capacity Demand Charge		
Pre-Expansion Shipper	0.00000	0.00056
Expansion Shipper - 2009 Phase	0.00000	0.00243
Volumetric Bid Rates		
Withdrawal Charge		
Pre-Expansion Shipper	0.00000	0.01551
Expansion Shipper	0.00000	0.08476
Storage Charge		
Pre-Expansion Shipper	0.00000	0.00056
Expansion Shipper - 2009 Phase	0.00000	0.00243
Rate Schedule SGS-2I		
Volumetric	0.00000	0.00113

Footnotes

(1) Shippers receiving service under these rate schedules are required to furnish fuel reimbursement in-kind at the rates specified on Sheet No. 14.

TF038 0010003P158First Revised Sheet No. 8
TF04 Original Sheet No. 8
TF05Laren M. Gertsch, Director
TF06103108 010109
TF071861272

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedule LS-1

(Dollars per Dth)

Type of Rate	Currently Effective Tariff Rate (1)
Demand Charge (2)	0.03062
Capacity Charge (2)	0.00391
Liquefaction	0.64110
Vaporization	0.04184

Footnotes

(1) Shippers receiving service under this rate schedule are required to furnish fuel reimbursement in-kind at the rate specified on Sheet No. 14.

(2) Rates are daily rates computed on the basis of 365 days per year, except that rates for leap years are computed on the basis of 366 days.

NW Natural
Rates & Regulatory Affairs
2009-2010 PGA Filing - Oregon
Elasticity Adjustment

Line	Schedule	Block	Elasticity Volumes	Monthly Service Charge	Customers	Current 1/1/2009 Billing Rate	Proposed 11/1/2009 Billing Rate Before Elasticity	Current 1/1/2009 Revenue	Proposed 11/1/2009 Revenue	WACOG	Demand	Proposed 11/1/2009 Temporaries	Proposed 11/1/2009 Margin Rate	Proposed 11/1/2009 Margin
								F=(D*A)+(B*C*12)	G=(E*A)+(B*C*12)				K = E - H - I - J	L = K * A
1	Schedule	Block	A	B	C	D	E	F	G	H	I	J	K	L
2	1R		740,147.1	$5.00	3,624	$1.45725	$1.21999	$1,296,019	$1,120,412	$0.59044	$0.12502	($0.00486)	$0.50939	$377,024
3	1C		166,238.8	$5.00	182	$1.41578	$1.16100	$246,278	$203,923	$0.59044	$0.12502	($0.03538)	$0.48092	$79,948
4	2R		362,090,600.4	$6.00	533,687	$1.39384	$1.15324	$543,121,826	$456,002,828	$0.59044	$0.12502	($0.00462)	$0.44240	$160,188,882
5	3C Firm Sales		149,399,860.1	$8.00	55,204	$1.28982	$1.03360	$197,998,512	$159,719,279	$0.59044	$0.12502	($0.03524)	$0.35338	$52,794,923
6	Intentionally blank													
7	3I Firm Sales													
8	Intentionally blank													
9	19	1st mantle												
10	19	add'l mtls												
11	31C Firm Sales	Block 1	23,853,607.3	$325.00	1,210	$1.00914	$0.87233	$28,790,629	$25,527,217	$0.59044	$0.12502	($0.03514)	$0.19201	$4,580,131
12		Block 2	36,060,860.8			$0.99340	$0.85624	$35,822,859	$30,876,751	$0.59044	$0.12502	($0.03512)	$0.17590	$6,343,105
13	31C Firm Trans	Block 1	0.0	$325.00	0	$0.17195	$0.19423	$0	$0	$0.00000	$0.00000	$0.00237	$0.19186	$0
14		Block 2	0.0			$0.15616	$0.17816	$0	$0	$0.00000	$0.00000	$0.00239	$0.17577	$0
15	31C Interr Sales	Block 1	313,225.2	$325.00	0	$1.03105	$0.76778	$322,951	$240,488	$0.59044	$0.01486	($0.02958)	$0.19206	$60,158
16		Block 2	1,066,773.3			$1.01520	$0.75167	$1,082,988	$801,861	$0.59044	$0.01486	($0.02957)	$0.17594	$187,688
17			573,691,313		593,907			$808,682,062	$674,492,759					$224,611,858
18														

Line	Calculation of Class Prices and Margins:	Volumes (A)	Customers (C)	01/01/09 Class Price	11/01/09 Class Price	01/01/09 Class Revenues	11/01/09 Class Revenues	Class Margin Rate	Class Margin
20				Column F ÷ A	Column G ÷ A			Column L ÷ A	
21	**Residential (Line 2 + Line 4)**	362,830,748	537,311	**$1.50047**	**$1.25988**	544,417,845	457,123,240	**$0.44254**	160,565,905
22	**Commercial (Line 17 - Line 21)**	210,860,566	56,596	**$1.25327**	**$1.03087**	264,264,217	217,369,519	**$0.30374**	64,045,953
23		573,691,313	593,907			808,682,062	674,492,759		224,611,858
24									

25 **Sources for lines 1-17:**

Line	Source	A	B	C	D	E	F	G	H	I	J	K	L
26	Direct Inputs		Per Tariff										
27													
28	Rates in Detail page				Column A	Column N			Column F	Columns G + H	Column N		
29	Volumes page	Column G		Column H									
30	PGA Effects page		Column D										
31													

32 **ELASTICITY CALCULATION:**

Line		Residential Current	Residential Proposed	Commercial Current	Commercial Proposed
34	Elasticity volumes		362,830,748		210,860,566
35					
36	Class prices (Columns D & E, lines 21, 22)	$1.50047	$1.25988	$1.25327	$1.03087
37					
38	Change in class prices		($0.24059)		($0.22240)
39					
40	Percentage change in class prices		-16.0%		-17.7%
41					
42	Volume change due to elasticity (Residential @ 0.172, Commercial @ 0.11)		-2.8%		-1.9%
43					
44	Volume change due to elasticity in therms (line 42 x line 34)		(10,159,261)		(4,006,351)
45					
46	Margin rate per therm (Columns K & L, lines 21, 22)		$0.44254		$0.30374
47					
48	**Margin Shortfall (line 44 x Line 46)**		**($4,495,879)**		**($1,216,889)**
49					
50	**Rate Change Due to Elasticity Effects (line 48 ÷ line 34)**		**($0.01239)**		**($0.00577)**
51					
52	**Rate Change Due to Elasticity Effects with revenue sensitive added**		**($0.01277)**		**($0.00595)**

ıral
Regulatory Affairs
10 PGA Filing - Oregon
y of PERMANENT Increments

Schedule	Block	REMOVE Current Bare Steel	REMOVE Current Geo Hazard	REMOVE Current IMP	REMOVE Current Coos Bay	Permanents: Removed Subtotal	ADD Proposed SIP: Bare Steel 70%	ADD Proposed SIP: Bare Steel 30%	ADD Proposed Geo-Haz Final	ADD Proposed SIP: DIMP	ADD Proposed SIP: TIMP	Proposed Subtotal	Net Effect of Permanent Items
		A	B	C	D	E	F	G	H	I	J	K	L
1R		0.00516	0.00276	0.01001	(0.00042)	0.01751	0.00364	0.00250	0.00267	0.00000	0.01062	0.01943	0.00192
1C		0.00455	0.00198	0.00716	(0.00029)	0.01340	0.00364	0.00169	0.00180	0.00000	0.00718	0.01431	0.00091
2R		0.00440	0.00178	0.00647	(0.00027)	0.01238	0.00364	0.00170	0.00181	0.00000	0.00722	0.01437	0.00199
3C Firm Sales		0.00400	0.00126	0.00460	(0.00019)	0.00967	0.00364	0.00120	0.00128	0.00000	0.00509	0.01121	0.00154
Intentionally blank													
3I Firm Sales		0.00384	0.00106	0.00386	(0.00016)	0.00860	0.00364	0.00101	0.00108	0.00000	0.00431	0.01004	0.00144
Intentionally blank													
19	1st mantle	0.06	0.00	0.00	0.00	0.06	0.07	0.00	0.00	0.00	0.00	0.07	0.01
19	add'l mtls	0.06	0.00	0.00	0.00	0.06	0.07	0.00	0.00	0.00	0.00	0.07	0.01
31C Firm Sales	Block 1	0.00371	0.00089	0.00323	(0.00013)	0.00770	0.00364	0.00085	0.00090	0.00000	0.00359	0.00898	0.00128
	Block 2	0.00365	0.00081	0.00295	(0.00012)	0.00729	0.00364	0.00077	0.00083	0.00000	0.00329	0.00853	0.00124
31C Firm Trans	Block 1	0.00360	0.00075	0.00271	(0.00011)	0.00695	0.00364	0.00072	0.00077	0.00000	0.00307	0.00820	0.00125
	Block 2	0.00355	0.00068	0.00248	(0.00010)	0.00661	0.00364	0.00066	0.00071	0.00000	0.00281	0.00782	0.00121
31C Interr Sales	Block 1	0.00350	0.00061	0.00223	(0.00009)	0.00625	0.00364	0.00059	0.00063	0.00000	0.00251	0.00737	0.00112
	Block 2	0.00345	0.00056	0.00203	(0.00008)	0.00596	0.00364	0.00054	0.00058	0.00000	0.00230	0.00706	0.00110
31I Firm Sales	Block 1	0.00056	0.00072	0.00263	(0.00011)	0.00380	0.00000	0.00081	0.00087	0.00000	0.00345	0.00513	0.00133
	Block 2	0.00051	0.00065	0.00238	(0.00010)	0.00344	0.00000	0.00073	0.00078	0.00000	0.00311	0.00462	0.00118
31I Firm Trans	Block 1	0.00054	0.00069	0.00252	(0.00010)	0.00365	0.00000	0.00071	0.00075	0.00000	0.00300	0.00446	0.00081
	Block 2	0.00049	0.00063	0.00228	(0.00009)	0.00331	0.00000	0.00064	0.00068	0.00000	0.00271	0.00403	0.00072
31I Interr Sales	Block 1	0.00079	0.00102	0.00370	(0.00016)	0.00535	0.00000	0.02065	0.02204	0.00000	0.08785	0.13054	0.12519
	Block 2	0.00071	0.00092	0.00335	(0.00014)	0.00484	0.00000	0.01866	0.01992	0.00000	0.07939	0.11797	0.11313
32C Firm Sales	Block 1	0.00037	0.00047	0.00172	(0.00007)	0.00249	0.00000	0.00044	0.00047	0.00000	0.00185	0.00276	0.00027
	Block 2	0.00031	0.00040	0.00146	(0.00006)	0.00211	0.00000	0.00037	0.00040	0.00000	0.00158	0.00235	0.00024
	Block 3	0.00022	0.00028	0.00103	(0.00004)	0.00149	0.00000	0.00026	0.00028	0.00000	0.00111	0.00165	0.00016
	Block 4	0.00013	0.00017	0.00060	(0.00003)	0.00087	0.00000	0.00015	0.00016	0.00000	0.00065	0.00096	0.00009
	Block 5	0.00007	0.00009	0.00034	(0.00001)	0.00049	0.00000	0.00009	0.00009	0.00000	0.00037	0.00055	0.00006
	Block 6	0.00004	0.00005	0.00017	(0.00001)	0.00025	0.00000	0.00004	0.00005	0.00000	0.00019	0.00028	0.00003
32I Firm Sales	Block 1	0.00038	0.00049	0.00178	(0.00007)	0.00258	0.00000	0.00047	0.00050	0.00000	0.00200	0.00297	0.00039
	Block 2	0.00032	0.00042	0.00151	(0.00006)	0.00219	0.00000	0.00040	0.00043	0.00000	0.00170	0.00253	0.00034
	Block 3	0.00023	0.00029	0.00107	(0.00004)	0.00155	0.00000	0.00028	0.00030	0.00000	0.00120	0.00178	0.00023
	Block 4	0.00013	0.00017	0.00062	(0.00003)	0.00089	0.00000	0.00017	0.00018	0.00000	0.00070	0.00105	0.00016
	Block 5	0.00008	0.00010	0.00036	(0.00001)	0.00053	0.00000	0.00009	0.00010	0.00000	0.00040	0.00059	0.00006
	Block 6	0.00004	0.00005	0.00018	(0.00001)	0.00026	0.00000	0.00005	0.00005	0.00000	0.00020	0.00030	0.00004
32 Firm Trans	Block 1	0.00030	0.00039	0.00140	(0.00006)	0.00203	0.00000	0.00035	0.00038	0.00000	0.00151	0.00224	0.00021
	Block 2	0.00025	0.00033	0.00119	(0.00005)	0.00172	0.00000	0.00030	0.00032	0.00000	0.00128	0.00190	0.00018
	Block 3	0.00018	0.00023	0.00084	(0.00004)	0.00121	0.00000	0.00021	0.00023	0.00000	0.00090	0.00134	0.00013
	Block 4	0.00010	0.00013	0.00049	(0.00002)	0.00070	0.00000	0.00012	0.00013	0.00000	0.00053	0.00078	0.00008
	Block 5	0.00006	0.00008	0.00028	(0.00001)	0.00041	0.00000	0.00007	0.00008	0.00000	0.00030	0.00045	0.00004
	Block 6	0.00003	0.00004	0.00014	(0.00001)	0.00020	0.00000	0.00004	0.00004	0.00000	0.00015	0.00023	0.00003
32 Interr Sales	Block 1	0.00032	0.00041	0.00148	(0.00006)	0.00215	0.00000	0.00042	0.00044	0.00000	0.00177	0.00263	0.00048
	Block 2	0.00027	0.00035	0.00125	(0.00005)	0.00182	0.00000	0.00035	0.00038	0.00000	0.00150	0.00223	0.00041
	Block 3	0.00019	0.00024	0.00089	(0.00004)	0.00128	0.00000	0.00025	0.00027	0.00000	0.00106	0.00158	0.00030
	Block 4	0.00011	0.00014	0.00052	(0.00002)	0.00075	0.00000	0.00015	0.00016	0.00000	0.00062	0.00093	0.00018
	Block 5	0.00006	0.00008	0.00030	(0.00001)	0.00043	0.00000	0.00008	0.00009	0.00000	0.00035	0.00052	0.00009
	Block 6	0.00003	0.00004	0.00015	(0.00001)	0.00021	0.00000	0.00004	0.00004	0.00000	0.00018	0.00026	0.00005
32 Interr Trans	Block 1	0.00028	0.00036	0.00132	(0.00006)	0.00190	0.00000	0.00035	0.00037	0.00000	0.00148	0.00220	0.00030
	Block 2	0.00024	0.00031	0.00113	(0.00005)	0.00163	0.00000	0.00030	0.00032	0.00000	0.00125	0.00187	0.00024
	Block 3	0.00017	0.00022	0.00079	(0.00003)	0.00115	0.00000	0.00021	0.00022	0.00000	0.00089	0.00132	0.00017
	Block 4	0.00010	0.00013	0.00046	(0.00002)	0.00067	0.00000	0.00012	0.00013	0.00000	0.00052	0.00077	0.00010
	Block 5	0.00006	0.00007	0.00026	(0.00001)	0.00038	0.00000	0.00007	0.00007	0.00000	0.00030	0.00044	0.00006
	Block 6	0.00003	0.00004	0.00013	(0.00001)	0.00019	0.00000	0.00003	0.00004	0.00000	0.00015	0.00022	0.00003
Intentionally blank													
33		0.00002	0.00002	0.00008	0.00000	0.00012	0.00000	0.00002	0.00002	0.00000	0.00009	0.00013	0.00001

Sources:

		A	B	C	D	E	F	G	H	I	J	K	L
Direct Inputs		08-09 PGA	08-09 PGA	08-09 PGA	08-09 PGA								
Equal ¢ per therm							Column AB						
Equal % of margin								Column O	Column R	Column U	Column X		

NW Natural
Rates & Regulatory Affairs
2009-2010 PGA Filing - Oregon
Summary of TEMPORARY Increments

		Current Temporaries	ADD WACOG Deferral	ADD Demand Deferral FIRM	ADD Demand Deferral INTERR	ADD Residential Decoupling	ADD Commercial Decoupling	ADD Smart Energy	ADD Intervenor Funding - CUB	ADD Pension Expense Credit	ADD Intervenor Funding - NWIGU	Total Proposed Temps	Net Effect of Temps
Schedule	Block	A	B	C	D	E	F	G	H	I	J	K	L
1R		(0.01095)	(0.03237)	(0.00622)	0.00000	0.03311	0.00000	0.00112	0.00023	(0.00073)	0.00000	(0.00486)	0.00609
1C		(0.02876)	(0.03237)	(0.00622)	0.00000	0.00000	0.00258	0.00112	0.00000	(0.00049)	0.00000	(0.03538)	(0.00662)
2R		(0.01104)	(0.03237)	(0.00622)	0.00000	0.03311	0.00000	0.00112	0.00023	(0.00049)	0.00000	(0.00462)	0.00642
3C Sales Firm		(0.02884)	(0.03237)	(0.00622)	0.00000	0.00000	0.00258	0.00112	0.00000	(0.00035)	0.00000	(0.03524)	(0.00640)
Intentionally blank													
3I Sales Firm		(0.01331)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00030)	0.00003	(0.03886)	(0.02555)
Intentionally blank													
19	1st mantle	(0.26)	(0.62)	(0.12)	0.00	0.00	0.00	0.02	0.00	0.00	0.00	(0.72)	(0.46)
19	add'l mtls	(0.26)	(0.62)	(0.12)	0.00	0.00	0.00	0.02	0.00	0.00	0.00	(0.72)	(0.46)
31C Sales Firm	Block 1	(0.02890)	(0.03237)	(0.00622)	0.00000	0.00000	0.00258	0.00112	0.00000	(0.00025)	0.00000	(0.03514)	(0.00624)
	Block 2	(0.02890)	(0.03237)	(0.00622)	0.00000	0.00000	0.00258	0.00112	0.00000	(0.00023)	0.00000	(0.03512)	(0.00622)
31C Trans Firm	Block 1	(0.01537)	0.00000	0.00000	0.00000	0.00000	0.00258	0.00000	0.00000	(0.00021)	0.00000	0.00237	0.01774
	Block 2	(0.01538)	0.00000	0.00000	0.00000	0.00000	0.00258	0.00000	0.00000	(0.00019)	0.00000	0.00239	0.01777
31C Sales Interr	Block 1	(0.00838)	(0.03237)	0.00000	(0.00074)	0.00000	0.00258	0.00112	0.00000	(0.00017)	0.00000	(0.02958)	(0.02120)
	Block 2	(0.00837)	(0.03237)	0.00000	(0.00074)	0.00000	0.00258	0.00112	0.00000	(0.00016)	0.00000	(0.02957)	(0.02120)
31I Sales Firm	Block 1	(0.01336)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00024)	0.00003	(0.03880)	(0.02544)
	Block 2	(0.01337)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00021)	0.00003	(0.03877)	(0.02540)
31I Trans Firm	Block 1	0.00018	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00020)	0.00003	(0.00017)	(0.00035)
	Block 2	0.00016	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00018)	0.00003	(0.00015)	(0.00031)
31I Sales Interr	Block 1	0.00718	(0.03237)	0.00000	(0.00074)	0.00000	0.00000	0.00000	0.00000	(0.00600)	0.00003	(0.03908)	(0.04626)
	Block 2	0.00719	(0.03237)	0.00000	(0.00074)	0.00000	0.00000	0.00000	0.00000	(0.00543)	0.00003	(0.03851)	(0.04570)
32C Sales Firm	Block 1	(0.01349)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00112	0.00000	(0.00013)	0.00000	(0.03760)	(0.02411)
	Block 2	(0.01349)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00112	0.00000	(0.00011)	0.00000	(0.03758)	(0.02409)
	Block 3	(0.01351)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00112	0.00000	(0.00008)	0.00000	(0.03755)	(0.02404)
	Block 4	(0.01352)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00112	0.00000	(0.00004)	0.00000	(0.03751)	(0.02399)
	Block 5	(0.01353)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00112	0.00000	(0.00003)	0.00000	(0.03750)	(0.02397)
	Block 6	(0.01353)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00112	0.00000	(0.00001)	0.00000	(0.03748)	(0.02395)
32I Sales Firm	Block 1	(0.01341)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00014)	0.00003	(0.03870)	(0.02529)
	Block 2	(0.01341)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00012)	0.00003	(0.03868)	(0.02527)
	Block 3	(0.01343)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00008)	0.00003	(0.03864)	(0.02521)
	Block 4	(0.01343)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00005)	0.00003	(0.03861)	(0.02518)
	Block 5	(0.01344)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00003)	0.00003	(0.03859)	(0.02515)
	Block 6	(0.01344)	(0.03237)	(0.00622)	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00003	(0.03857)	(0.02513)
32 Trans Firm	Block 1	0.00014	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00010)	0.00003	(0.00007)	(0.00021)
	Block 2	0.00014	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00009)	0.00003	(0.00006)	(0.00020)
	Block 3	0.00012	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00006)	0.00003	(0.00003)	(0.00015)
	Block 4	0.00011	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00004)	0.00003	(0.00001)	(0.00012)
	Block 5	0.00010	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00002)	0.00003	0.00001	(0.00009)
	Block 6	0.00009	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00003	0.00002	(0.00007)
32 Sales Interr	Block 1	0.00714	(0.03237)	0.00000	(0.00074)	0.00000	0.00000	0.00000	0.00000	(0.00012)	0.00003	(0.03320)	(0.04034)
	Block 2	0.00715	(0.03237)	0.00000	(0.00074)	0.00000	0.00000	0.00000	0.00000	(0.00010)	0.00003	(0.03318)	(0.04033)
	Block 3	0.00712	(0.03237)	0.00000	(0.00074)	0.00000	0.00000	0.00000	0.00000	(0.00007)	0.00003	(0.03315)	(0.04027)
	Block 4	0.00712	(0.03237)	0.00000	(0.00074)	0.00000	0.00000	0.00000	0.00000	(0.00004)	0.00003	(0.03312)	(0.04024)
	Block 5	0.00711	(0.03237)	0.00000	(0.00074)	0.00000	0.00000	0.00000	0.00000	(0.00002)	0.00003	(0.03310)	(0.04021)
	Block 6	0.00710	(0.03237)	0.00000	(0.00074)	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00003	(0.03309)	(0.04019)
32 Trans Interr	Block 1	0.00013	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00010)	0.00003	(0.00007)	(0.00020)
	Block 2	0.00014	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00009)	0.00003	(0.00006)	(0.00020)
	Block 3	0.00012	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00006)	0.00003	(0.00003)	(0.00015)
	Block 4	0.00011	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00004)	0.00003	(0.00001)	(0.00012)
	Block 5	0.00010	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00002)	0.00003	0.00001	(0.00009)
	Block 6	0.00009	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00003	0.00002	(0.00007)
Intentionally blank										0.00000			
33		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00000	(0.00001)	(0.00001)

Sources:

Direct Inputs	Jan 09 filing										
Equal ¢ per therm		Column D	Column G	Column J	Column M	Column P	Column S	Column V		Column Y	
Equal % of margin									Column L		

NW Natural
Bare Steel, Geohazard and Integrity Management Programs
Cost of Service Summary - PGA 2009-10
Thousands of Dollars

		Investment	Tracker Year Cost of Service
Bare Steel Program			
1	Activity Ended September 30, 2002	$2,665	$319
2	Activity Ended September 30, 2003	3,510	415
3	Activity Ended September 30, 2004	3,094	377
4	Activity Ended September 30, 2005	6,000	755
5	Activity Ended September 30, 2006	(695)	(89)
6	Activity Ended September 30, 2007	430	57
7	Activity Ended September 30, 2008	3,850	529
8	Activity Ended September 30, 2009	4,002	616
9	Total Bare Steel Program	$22,857	$2,978
Geohazard Program			
10	Activity Ended September 30, 2002	$1,714	$205
11	Activity Ended September 30, 2003	555	66
12	Activity Ended September 30, 2004	139	17
13	Activity Ended September 30, 2005	206	26
14	Activity Ended September 30, 2006	2,863	367
15	Activity Ended September 30, 2007	254	34
16	Activity Ended September 30, 2008 (Oct 07-Dec 07 ONLY)	1,441	198
17	Final true-up of final program activity (through Dec 07 only)	272	42
18	Total Geohazard Program	$7,443	$954
Integrity Management Program (as of October 2008, "TIMP")			
19	Activity Ended September 30, 2005	$3,476	$437
20	Activity Ended September 30, 2006	8,978	1,152
21	Activity Ended September 30, 2007	2,604	346
22	Activity Ended September 30, 2008	9,680	1,331
23	Activity Ended September 30, 2009	3,446	530
24	Total Integrity Management Program	$28,184	$3,796
Distribution Integrity Management Program ("DIMP")			
25	Activity Ended September 30, 2009	$0	
	Total Integrity Management Program	$0	$0
GRAND TOTAL ALL PROGRAMS		**$58,483**	**$7,729**

Reflects Actuals through June 30, 2009

NW Natural
Rates and Regulatory Affairs
2009-2010 PGA Filing - Oregon
Estimated Revenue Effects for the 12 Months Beginning November 1, 2009

Line No.	Item	Total Increment Amounts	Limit For Increment Amounts
1	Commodity and Demand Deferrals	($24,839,016)	
2	Temporary Increments	388,343	
3	Total	($24,450,673)	
4	2008 Oregon Utility Revenues		$923,914,000
5	@ 3% threshold		3.0%
6	Threshold for Annual Effect of Proposed Change in Amortization		$27,717,420

ORS 757.259 (6)

OPUC ORDER No. 09-263 / 09-248
DOCKET UM 1286
SECTION V. DATA AND ANALYSIS

Guideline Reference	Data Requirement	Location/Link	Status
	Definitions	Definitions!A1	
V.1	**Physical Gas Supply**	V.1.a pg 1'!A1	HIGHLY CONFIDENTIAL
		V.1.a pg 2'!A1	HIGHLY CONFIDENTIAL
		V.1.a pg3'!A1	HIGHLY CONFIDENTIAL
a)	For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following:		
1	Pricing for the resource, including the commodity price and, if relevant, reservation charges.		
2	For new transactions and contracts with pricing provisions entered into since the last PGA: competitive bidding process for the resource. This should include number of bidders, bid prices, utility decision criteria in selecting a "winning" bid, and any special pricing or delivery provisions negotiated as part of the bidding process.		
3	Brief explanation of each contract's role within the portfolio.		
b)	For purchases of physical natural gas supply resource from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:	V.1.b!A1	
1	An explanation of the utility's spot purchasing guidelines, the data/information generally reviewed and analyzed in making spot purchases, and the general process through which such purchases are completed by the utility.	V.1.b!A1	
2	Any contract provisions that materially deviate from the standard NAESB contract.	V.1.b!A1	
V.2	**Hedging**		
	The utility should clearly identify by type, contract, counterparty, and pricing point both the total cost and the cost per volume unit of each financial hedge included in its portfolio.	V.2!A1	HIGHLY CONFIDENTIAL
V.3	**Load Forecasting**		
a)	Customer count and revenue by month and class.	V.3.a!A1	
b)	Historical (five years) and forecasted (one year ahead) sales system physical peak demand.	V.3.b!A1	
c)	Historical (five years), and forecasted (one year ahead) sales system physical annual demand.	V.3.c!A1	
d)	Historical (five years), and forecasted (one year ahead) sales system physical demand for each of following,		
1	Annual for each customer class	V.3.d.1!A1	
2	Annual and monthly baseload.	V.3.d.2!A1	
3	Annual and monthly non-baseload.	V.3.d.3!A1	
4	Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update.	V.3.d.4!A1	

OPUC ORDER No. 09-263 / 09-248
DOCKET UM 1286
SECTION V. DATA AND ANALYSIS

Guideline Reference	Data Requirement	Location/Link	Status
V.4	**Market Information** General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply, prices, and liquidity at those points.	V.4!A1	
V.5	**Data Interpretation** If not included in the PGA filing please explain the major aspects of the LDC's analysis and interpretation of the data and information described in (1) and (2) above, the most important conclusions resulting from that analysis and interpretation, and the application of these conclusions in the development of the current PGA portfolio.	V.5!A1	
V.6	**Credit Worthiness Standards** A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.	V.6!A1	
	Attachment 1 to V.6	V.6 attachment'!A1	CONFIDENTIAL/HIGHLY CONFIDENTIAL
V.7	**Storage** Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.		
a)	Type of storage (e.g., depleted field, salt dome).	V.7.a-c'!A1	
b)	Location of each storage facility.	V.7.a-c'!A1	
c)	Total level of storage in terms of deliverability and capacity held during the gas year.	V.7.a-c'!A1	
d)	Historical (five years) gas supply delivered to storage, both annual total and by month.	V.7.d-e'!A1	
e)	Historical (five years) gas supply withdrawn from storage, both annual total and by month.	V.7.d-e'!A1	
f)	An explanation of the methodology utilized by the LDC to price storage injections and withdrawals, as well as the total and average (per unit) cost of storage gas.	V.7.f!A1	
g)	Copies of all contracts or other agreements and tariffs that control the LDC's use of the storage facilities included in the current portfolio.	V.7.g!A1	
h)	For LDCs that own and operate storage:	V.7.h!A1	CONFIDENTIAL
a.	The date and results of the last engineering study for that storage.		

OPUC ORDER No. 09-263 / 09-248
DOCKET UM 1286
SECTION V. DATA AND ANALYSIS

Guideline Reference	Data Requirement	Location/Link	Status
b.	A description of any significant changes in physical or operational parameters of the storage facility (including LNG) since the current engineering study was completed.		

NW Natural
PGA Filing Guidelines

Definitions

AECO	The industry acronym used for Alberta sourced natural gas supply. It originally comes from Alberta Energy Company which was incorporated in 1973 by the Alberta government (fully divested in 1993).
Baseload gas (contract)	Purchase agreements in which NW Natural has to take a set amount of gas each day from a supplier for the term of the agreement. Usually involves paying for any gas not taken unless excused by reason of Force Majeure.
Btu	British thermal unit. 100,000 Btus is equivalent to one therm.
CGPR	Canadian Gas Price Reporter. This is the industry publication in Canada that is put out by Canadian Enerdata Ltd and is the exclusive source of Canadian natural gas storage and price forecasts and publishes first of month Canadian indices used in baseload purchase pricing
Dth	Dekatherm. A unit of measure equal to 10 therms or one million Btu.
FOM	First of Month
Fuel-in-Kind (KIG)	The published fuel rate calculated based on the amount of fuel used on each pipeline to run the compressors and other equipment to move gas across their pipes. Fuel is taken in kind from all receipt shippers by reducing each shippers daily volumes in accordance to the pipelines estimated fuel requirements.
GMR-NWP Rockies	Inside FERC's Gas Market Report, a publication put out by Platts (a McGraw-Hill subsidiary) that is the source used for price forecasts and indices that used to set US baseload and some daily purchase prices.
Swing gas (contract)	Purchase agreements in which NW Natural has the right, but not the obligation, to take gas from a supplier on any given day.

NW Natural
PGA Filing Guidelines
2009-2010 Oregon PGA

HIGHLY CONFIDENTIAL **REDACTED**

Index!A1

V.1 **Physical Gas Supply**

a) For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following:

1 Pricing for the resource, including the commodity price and, if relevant, reservation charges.

2 For new transactions and contracts with pricing provisions entered into since the last PGA: competitive bidding process for the resource. This should include number of bidders, bid prices, utility decision criteria in selecting a "winning" bid, and any special pricing or delivery provisions negotiated as part of the bidding process.

3 Brief explanation of each contract's role within the portfolio.

All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies
Approved Counterparties all have executed NAESB contracts with NW Natural

Rocky Mountain Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Swing Volume/Day in Dth's	Swing Reservation Fee cents/Dth/day	Contractual Conditions	Default Receipt Pt. Purchase Location
BP Energy Company	11/1/2008	10/31/2011	[redacted]	IFGMR-NWP Rockies FOM	10,000		[redacted]		Opal / Shute Creek
Western Gas Resources	11/1/2007	10/31/2010	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Green River Gathering
Iberdrola Renewables, Inc. (1)	11/1/2009	10/31/2010	[redacted]	IFGMR-NWP Rockies FOM	10,000		[redacted]		NWP Wyoming Pool
Anadarko Energy Services Company (2)	11/1/2009	3/31/2010	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		NWP Rocky Mt. Pool
Enserco Energy Inc.(3)	11/1/2009	3/31/2010	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		NWP Rocky Mt. Pool
BP Energy Company (4)	11/1/2009	3/31/2010	[redacted]	IFGMR-NWP Rockies FOM	10,000		[redacted]		Opal
Oneok Energy Services Company, L.P. (5)	11/1/2009	3/31/2010	[redacted]	IFGMR-NWP Rockies FOM		10,000	[redacted]	NWN Winter Call	Shute Creek
Kansas Energy, L.P. (6)	11/1/2009	3/31/2010	[redacted]	IFGMR-NWP Rockies FOM		5,000	[redacted]	NWN Winter Call	Opal
Kansas Energy, L.P. (7)	11/1/2009	3/31/2010	[redacted]	IFGMR-NWP Rockies FOM		5,000	[redacted]	NWN Winter Call	Opal
Shell Energy North America (US), L.P. (8)	11/1/2009	3/31/2010	[redacted]	IFGMR-NWP Rockies FOM		10,000	[redacted]	NWN Winter Call	NWP Wyoming P / Opal
Kansas Energy, L.P. (7)	4/1/2010	10/31/2010	[redacted]	IFGMR-NWP Rockies FOM		5,000	[redacted]	Kansas Put Option	Opal
Shell Energy North America (US), L.P. (8)	4/1/2010	10/31/2010	[redacted]	IFGMR-NWP Rockies FOM		10,000	[redacted]	Shell Put Option	NWP Wyoming P / Opal

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
Iberdrola Renewables, Inc. (1)	6	[redacted]	Price, Non-Winning bidder had existing term deal in place for 09-10 season
Anadarko Energy Services Company (2)	6	[redacted]	Price
Enserco Energy Inc.(3)	6	[redacted]	Price
BP Energy Company (4)	6	[redacted]	Price
Oneok Energy Services Company, L.P. (5)	5	[redacted]	Price
Kansas Energy, L.P. (6)	3	[redacted]	Price, Non-Winning bidders had existing term deals in place for 09-10 season
Kansas Energy, L.P. (7)	7	[redacted]	[redacted]
Shell Energy North America (US), L.P. (8)	7		Price, Non-Winning bidders had existing term deal in place for 09-10 season

NW Natural
PGA Filing Guidelines
2009-2010 Oregon PGA

HIGHLY CONFIDENTIAL **REDACTED**

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V.1	**Physical Gas Supply**
a)	For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following:
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3	Brief explanation of each contract's role within the portfolio.

All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies
Approved Counterparties all have executed NAESB contracts with NW Natural

Station 2 Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's
Coral Energy Canada	11/1/2005	10/31/2010	[redacted]	CGPR AECO FOM (7A) $US/Dth	10,000
AltaGas Energy, L.P.	11/1/2008	10/31/2010		CGPR AECO FOM (7A) $US/Dth	5,000
Nexen Marketing Canada	11/1/2008	10/31/2010		CGPR AECO FOM (7A) $US/Dth	10,000
Husky Energy Marketing Inc. (1)	11/1/2009	10/31/2010		CGPR AECO FOM (7A) $US/Dth	5,000
Suncor Energy Marketing Inc. (2)	11/1/2009	10/31/2010		CGPR AECO FOM (7A) $US/Dth	10,000
Shell Energy North America (Canada) Inc. (3)	11/1/2009	10/31/2010		CGPR AECO FOM (7A) $US/Dth	5,000
BP Canada Energy Marketing Corp (4)	11/1/2009	10/31/2012		CGPR AECO FOM (7A) $US/Dth	5,000

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
Husky Energy Marketing Inc. (1)	5	[redacted]	Price
Suncor Energy Marketing Inc. (2)	4		Price
Shell Energy North America (Canada) Inc. (3)	4		Price
BP Canada Energy Marketing Corp (4)	6		Price, Non-Winning bidder had existing term deal in place for 09-10 season

NW Natural **HIGHLY CONFIDENTIAL** **REDACTED**
PGA Filing Guidelines
2009-2010 Oregon PGA

Index!A1

V.1	**Physical Gas Supply**
a)	For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following:
1	Pricing for the resource, including the commodity price and, if relevant, reservation charges.
2	For new transactions and contracts with pricing provisions entered into since the last PGA: competitive bidding process for the resource. This should include number of bidders, bid prices,
3	Brief explanation of each contract's role within the portfolio.

All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies
Approved Counterparties all have executed NAESB contracts with NW Natural

Aeco-NIT Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Swing Volume/Day in Dth's	Swing Reservation Fee cents/Dth/day	Contractual Conditions
Sempra Energy Trading	11/1/2004	10/31/2014	[redacted]	CGPR AECO FOM (7A) $US/Dth	10,000		[redacted]	
Husky Energy Marketing Inc. (1)	11/1/2009	3/31/2010		CGPR AECO FOM (7A) $US/Dth	5,000			
Suncor Energy Marketing Inc. (2)	11/1/2009	3/31/2010		CGPR AECO FOM (7A) $US/Dth	5,000			
Sequent Energy Canada Corp (4)	11/1/2009	3/31/2010		CGPR AECO FOM (7A) $US/Dth		5,000		NWN Winter Call
Sequent Energy Canada Corp (4)	4/1/2010	10/31/2010		CGPR AECO FOM (7A) $US/Dth		5,000		Sequent Put Option

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
Husky Energy Marketing Inc. (1)	7	[redacted]	Price
Suncor Energy Marketing Inc. (2)	7		Price
Sequent Energy Canada Corp (4)	5		
Sequent Energy Canada Corp (4)			

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V.1 b) Physical Gas Supply
For purchases of physical natural gas supply resource from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:

1 An explanation of the utility's spot purchasing guidelines, the data/information generally reviewed and analyzed in making spot purchases, and the general process through which such purchases are completed by the utility.

The purchasing of baseload and spot supplies for the 2009-2010 PGA follows the Gas Acquisition Plan updated by the Gas Acquisition Strategic Planning team and approved by the Gas Acquisition Strategy and Policies Committee.

2009-2010 purchasing targets diversity of supply regionally and by approved counterparties listed in the Gas Supply Risk Management Policies. The advantage of regional diversity is the opportunity to manage purchases to capture the lowest cost while maintaining a diversity of suppliers and avoiding over reliance on any one liquid trading point or one approved counterparty.

Diversity of contracts in the portfolio is determined by the forecasted usage of NW Natural customers.
a. One year and greater baseload (take or pay) contract volumes are meant to meet low end requirements by NW Natural firm and interruptible sale customers during the PGA year while capturing the most favorable pricing. Contract volumes are set to avoid having excess supply that might result in loss of revenues sales.
b. November – March winter contract volumes are aligned to meet the forecasted seasonal increase during the heating season and are divided between baseload and winter call option contracts. This helps minimize the exposure to purchasing large volumes of high priced spot gas during cold weather events.
c. April – October summer put option contracts are tied to a winter call option contract to capture a discounted FOM index price and avoid payment of a reservation fee. The volume of the put option contracts is kept to a minimum to avoid over supply when added to term volumes.

d. Spot purchases are used to fill in requirement on a monthly or daily basis throughout the PGA year. One month spot purchases are negotiated to capture the best FOM index pricing, either Inside FERC or Canadian Gas Price Reporter. Daily spot purchasing utilizes either a daily index (in the case of Rocky Mountain or Sumas supply and published in Inside FERC's Gas Daily publication) or a fixed price in US dollars as negotiated using the electronic trading platform Intercontinental Exchange (ICE) for Rocky Mountain, Sumas, Station 2 and Alberta (Aeco/NIT) supplies. NW Natural does not trade electronically but uses the active Bid/Offer pricing at the above liquid points on ICE to negotiate daily spot deals. In the new PGA filing there are no active spot purchases in the NW Natural portfolio.

2 Any contract provisions that materially deviate from the standard NAESB contract.

None.

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V.2 Hedging

The utility should clearly identify by type, contract, counterparty, and pricing point both the total cost and the cos per volume unit of each financial hedge included in its portfolio.

For Physical Flows November 2009 through October 2010

Date	Ref. #	Counterparty	Supply	Ref. Pt.	Term	2009-10 Days	Daily Volumes	Nov9-Mar1(Daily Vols	Nov9-Oct10 Daily Vols	Other	2009-10 Volumes	Price	Total Price
28-Mar-08	2008-01	[redacted]		Rockies	Nov09-Oct10	365	5,000		5,000		1,825,000	[redacted]	
28-May-08	2008-08	[redacted]		Rockies	Nov09-Oct10	365	5,000		5,000		1,825,000	[redacted]	
3-Oct-08	2008-76	[redacted]		AECO / Sumas	Nov09-Oct10	365	5,000		5,000		1,825,000	[redacted]	
3-Oct-08	2008-78	[redacted]		AECO / Sumas	Nov09-Oct10	365	5,000		5,000		1,825,000	[redacted]	
18-Nov-08	2008-80	[redacted]		AECO / Sumas	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
18-Nov-08	2008-81	[redacted]		Sumas	Nov09-Oct10	365	5,000		5,000		1,825,000	[redacted]	
20-Nov-08	2008-82	[redacted]		Sumas	Nov09-Oct10	365	5,000		5,000		1,825,000	[redacted]	
9-Dec-08	2008-83	[redacted]		AECO / Sumas	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
12-Dec-08	2008-84	[redacted]		AECO / Sumas	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
17-Dec-08	2008-85	[redacted]		Rockies	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
18-Dec-08	2008-86	[redacted]		Rockies	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
13-Jan-09	2009-01	[redacted]		AECO / Sumas	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
14-Jan-09	2009-02	[redacted]		Rockies	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
20-Jan-09	2009-03	[redacted]		Sumas	Apr 10	30	10,000			10,000	300,000	[redacted]	
22-Jan-09	2009-04	[redacted]		Sumas	Oct 10	31	10,000			10,000	310,000	[redacted]	
23-Jan-09	2009-05	[redacted]		Sumas	Apr 10	30	10,000			10,000	300,000	[redacted]	
29-Jan-09	2009-06	[redacted]		Rockies	Nov09-Apr10	181	5,000			5,000	905,000	[redacted]	
10-Feb-09	2009-07	[redacted]		Sumas	Oct 10	31	5,000			5,000	155,000	[redacted]	
10-Feb-09	2009-08	[redacted]		Sumas	Nov09-Apr10	181	5,000			5,000	905,000	[redacted]	
12-Feb-09	2009-09	[redacted]		Sumas	Oct 10	31	5,000			5,000	155,000	[redacted]	
18-Feb-09	2009-10	[redacted]		Sumas	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
20-Feb-09	2009-11	[redacted]		Sumas	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
25-Feb-09	2009-12	[redacted]		Sumas	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
10-Mar-09	2009-13	[redacted]		Rockies	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
18-Mar-09	2009-14	[redacted]		Sumas	Nov09-Mar10	151	2,500	2,500			377,500	[redacted]	
18-Mar-09	2009-15	[redacted]		Sumas	May 10	31	5,000			5,000	155,000	[redacted]	
18-Mar-09	2009-16	[redacted]		Sumas	Nov09-Mar10	151	2,500	2,500			377,500	[redacted]	
31-Mar-09	2009-17	[redacted]		Rockies	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
15-Apr-09	2009-18	[redacted]		Sumas	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
24-Apr-09	2009-19	[redacted]		Sumas	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
29-Apr-09	2009-20	[redacted]		Sumas	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
29-Apr-09	2009-21	[redacted]		Sumas	May10	31	5,000			5,000	155,000	[redacted]	
29-Apr-09	2009-22	[redacted]		Sumas	May 10	31	5,000			5,000	155,000	[redacted]	
29-Apr-09	2009-23	[redacted]		AECO	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
15-May-09	2009-24	[redacted]		Sumas	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
22-May-09	2009-25	[redacted]		AECO / Sumas	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
29-May-09	2009-26	[redacted]		AECO	Nov09-Oct12	365	2,500		2,500		912,500	[redacted]	

For Physical Flows November 2009 through October 2010

Date	Ref. #	Counterparty	Supply	Ref. Pt.	Term	2009-10 Days	Daily Volumes	Nov9-Mar10 Daily Vols	Nov9-Oct10 Daily Vols	Other	2009-10 Volumes	Price	Total Price
29-May-09	2009-27	[redacted]		Rockies	Nov09-Mar10	151	5,000	5,000			755,000	[redacted]	
16-Jun-09	2009-28			AECO	Nov09-Oct12	365	2,500		2,500		912,500		
19-Jun-09	2009-29			Sumas	May10	31	5,000			5,000	155,000		
19-Jun-09	2009-30			Sumas	May10	31	5,000			5,000	155,000		
26-Jun-09	2009-31			Rockies	Nov09-Mar10	151	5,000	5,000			755,000		
30-Jun-09	2009-32			Sumas	Nov10-Oct12	0	2,500		2,500		0		
30-Jun-09	2009-33			Rockies	Nov09-Mar10	151	5,000	5,000			755,000		
30-Jun-09	2009-34			Sumas	Apr 10	30	5,000			5,000	150,000		
30-Jun-09	2009-35			Sumas	Oct 10	31	10,000			10,000	310,000		
13-Jul-09	2009-36			Rockies	Nov 09	30	5,000			5,000	150,000		
14-Jul-09	2009-37			Rockies	Dec 09	31	5,000			5,000	155,000		
15-Jul-09	2009-38			Rockies	Dec 09	31	5,000			5,000	155,000		
15-Jul-09	2009-39			Rockies	Nov 09	30	5,000			5,000	150,000		
15-Jul-09	2009-40			Rockies	Nov 09	30	5,000			5,000	150,000		
15-Jul-09	2009-41			Sumas	Nov10-Oct12	0	2,500		2,500		0		
15-Jul-09	2009-42			Rockies	Dec 09	31	5,000			5,000	155,000		
Grand Total							270,000	110,000	40,000	120,000	34,565,000		
												Check:	$0

Date	Ref. #	Counterparty	Supply	Ref. Pt.	Term	2009-10 Days	Daily Volumes	Nov9-Mar10 Daily Vols	Nov9-Oct10 Daily Vols	Other	Volumes	Price	Total Price
28-Mar-08	2008-01	[redacted]		Rockies	Nov09-Oct10	365	4,872		4,872		1,778,444	[redacted]	
28-May-08	2008-08			Rockies	Nov09-Oct10	365	4,872		4,872		1,778,444		
3-Oct-08	2008-76			AECO / Sumas	Nov09-Oct10	365	4,872		4,872		1,778,444		
3-Oct-08	2008-78			AECO / Sumas	Nov09-Oct10	365	4,872		4,872		1,778,444		
18-Nov-08	2008-80			AECO / Sumas	Nov09-Mar10	151	4,872		0		735,740		
18-Nov-08	2008-81			Sumas	Nov09-Oct10	365	4,872		4,872		1,778,444		
20-Nov-08	2008-82			Sumas	Nov09-Oct10	365	4,872		4,872		1,778,444		
9-Dec-08	2008-83			AECO / Sumas	Nov09-Mar10	151	4,872		0		735,740		
12-Dec-08	2008-84			AECO / Sumas	Nov09-Mar10	151	4,872		0		735,740		
17-Dec-08	2008-85			Rockies	Nov09-Mar10	151	4,872		0		735,740		
18-Dec-08	2008-86			Rockies	Nov09-Mar10	151	4,872		0		735,740		
13-Jan-09	2009-01			AECO / Sumas	Nov09-Mar10	151	4,872		0		735,740		
14-Jan-09	2009-02			Rockies	Nov09-Mar10	151	4,872		0		735,740		
20-Jan-09	2009-03			Sumas	Apr 10	30	9,745		0		292,347		
22-Jan-09	2009-04			Sumas	Oct 10	31	9,745		0		302,092		
23-Jan-09	2009-05			Sumas	Apr 10	30	9,745		0		292,347		

For Physical Flows November 2009 through October 2010

Date	Ref. #	Counterparty	Supply	Ref. Pt.	Term	2009-10 Days	Daily Volumes	Nov9-Mar1(Daily Vols	Nov9-Oct10 Daily Vols	Other	2009-10 Volumes	Price	Total Price
29-Jan-09	2009-06	[redacted]		Rockies	Nov09-Apr10	181	4,872		0		881,913	[redacted]	
10-Feb-09	2009-07	[redacted]		Sumas	Oct 10	31	4,872		0		151,046	[redacted]	
10-Feb-09	2009-08	[redacted]		Sumas	Nov09-Apr10	181	4,872		0		881,913	[redacted]	
12-Feb-09	2009-09	[redacted]		Sumas	Oct 10	31	4,872		0		151,046	[redacted]	
18-Feb-09	2009-10	[redacted]		Sumas	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
20-Feb-09	2009-11	[redacted]		Sumas	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
25-Feb-09	2009-12	[redacted]		Sumas	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
10-Mar-09	2009-13	[redacted]		Rockies	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
18-Mar-09	2009-14	[redacted]		Sumas	Nov09-Mar10	151	2,436	2,436			367,870	[redacted]	
18-Mar-09	2009-15	[redacted]		Sumas	May 10	31	4,872	0			151,046	[redacted]	
18-Mar-09	2009-16	[redacted]		Sumas	Nov09-Mar10	151	2,436	2,436			367,870	[redacted]	
31-Mar-09	2009-17	[redacted]		Rockies	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
15-Apr-09	2009-18	[redacted]		Sumas	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
24-Apr-09	2009-19	[redacted]		Sumas	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
29-Apr-09	2009-20	[redacted]		Sumas	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
29-Apr-09	2009-21	[redacted]		Sumas	May10	31	4,872	0			151,046	[redacted]	
29-Apr-09	2009-22	[redacted]		Sumas	May 10	31	4,872	0			151,046	[redacted]	
29-Apr-09	2009-23	[redacted]		AECO	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
15-May-09	2009-24	[redacted]		Sumas	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
22-May-09	2009-25	[redacted]		AECO / Sumas	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
29-May-09	2009-26	[redacted]		AECO	Nov09-Oct12	365	2,436	0			889,222	[redacted]	
29-May-09	2009-27	[redacted]		Rockies	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
16-Jun-09	2009-28	[redacted]		AECO	Nov09-Oct12	365	2,436	0			889,222	[redacted]	
19-Jun-09	2009-29	[redacted]		Sumas	May10	31	4,872	0			151,046	[redacted]	
19-Jun-09	2009-30	[redacted]		Sumas	May10	31	4,872	0			151,046	[redacted]	
26-Jun-09	2009-31	[redacted]		Rockies	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
30-Jun-09	2009-32	[redacted]		Sumas	Nov10-Oct12	0	2,436	0			0	[redacted]	
30-Jun-09	2009-33	[redacted]		Rockies	Nov09-Mar10	151	4,872	4,872			735,740	[redacted]	
30-Jun-09	2009-34	[redacted]		Sumas	Apr 10	30	4,872	0			146,174	[redacted]	
30-Jun-09	2009-35	[redacted]		Sumas	Oct 10	31	9,745	0			302,092	[redacted]	
13-Jul-09	2009-36	[redacted]		Rockies	Nov 09	30	4,872	0			146,174	[redacted]	
14-Jul-09	2009-37	[redacted]		Rockies	Dec 09	31	4,872	0			151,046	[redacted]	
15-Jul-09	2009-38	[redacted]		Rockies	Dec 09	31	4,872	0			151,046	[redacted]	
15-Jul-09	2009-39	[redacted]		Rockies	Nov 09	30	4,872	0			146,174	[redacted]	
15-Jul-09	2009-40	[redacted]		Rockies	Nov 09	30	4,872	0			146,174	[redacted]	
15-Jul-09	2009-41	[redacted]		Sumas	Nov10-Oct12	0	2,436	0			0	[redacted]	
15-Jul-09	2009-42	[redacted]		Rockies	Dec 09	31	4,872	0			151,046	[redacted]	
0-Jan-00	0-Jan-00	[redacted]		0	0	0	0	0			0	[redacted]	
0-Jan-00	0-Jan-00	[redacted]		0	0	0	0	0			0	[redacted]	
0-Jan-00	0-Jan-00	[redacted]		0	0	0	0	0			0	[redacted]	
0-Jan-00	0-Jan-00	[redacted]		0	0	0	0	0			0	[redacted]	
0-Jan-00	0-Jan-00	[redacted]		0	0	0	0	0			0	[redacted]	
Grand Total							263,112	73,087	29,235	0	33,683,247	[redacted]	
									Est. Net of Fuel		97.449%	Check:	$0

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V.3.a Customer count and revenue by month and class

	Customer Cnt Aug-08	Revenue Aug-08	Customer Cnt Sep-08	Revenue Sep-08	Customer Cnt Oct-08	Revenue Oct-08
Total	**655,281**	$ 33,495,182.62	**654,965**	$ 35,323,124.34	**656,536**	$ 45,539,084.25
Oregon	588,517	30,353,985.28	588,271	32,053,490.42	589,596	41,310,889.22
Washington	66,764	3,141,197.34	66,694	3,269,633.92	66,940	4,228,195.03
Total Residential	592,702	14,497,999.45	592,419	15,431,086.54	593,939	22,043,558.33
Total Commercial	61,639	10,120,954.19	61,605	10,558,512.05	61,659	13,417,940.93
Total Industrial	627	2,860,805.19	631	3,227,749.86	628	3,358,499.94
Total Interruptible	179	4,860,091.85	178	4,938,548.63	178	5,515,251.59
Total Transportation - Commercial Firm	2	4,039.89	2	4,074	-	4,699.94
Total Transportation - Industrial Firm	64	508,896.56	63	504,351	64	519,781.43
Total Transportation - Interruptible	68	642,395.49	67	658,802	68	679,352.09

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V.3.a Customer count and revenue by month and class

	Customer Cnt Nov-08	Revenue Nov-08	Customer Cnt Dec-08	Revenue Dec-08	Customer Cnt Jan-09	Revenue Jan-09
Total	**659,629**	$ 73,484,819.80	**662,341**	$ 130,417,558.48	**664,603**	$ 175,692,929.00
Oregon	592,401	66,459,981.53	594,937	117,834,094.87	596,883	157,889,846.11
Washington	67,228	7,024,838.27	67,404	12,583,463.61	67,720	17,803,082.89
Total Residential	596,918	40,159,574.08	599,285	78,630,396.90	601,114	107,514,158.17
Total Commercial	61,772	21,391,630.97	62,115	39,061,202.27	62,520	53,798,379.65
Total Industrial	621	3,982,452.36	624	5,042,198.35	632	5,292,545.93
Total Interruptible	183	6,770,529.36	181	6,470,594.70	191	7,902,634.69
Total Transportation - Commercial Firm	-	6,988.91	-	8,127.27	-	12,978.64
Total Transportation - Industrial Firm	63	538,364.31	65	571,073.58	66	514,467.39
Total Transportation - Interruptible	69	635,279.81	68	633,965.41	76	657,764.53

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V.3.a Customer count and revenue by month and class

	Customer Cnt Feb-09	Revenue Feb-09	Customer Cnt Mar-09	Revenue Mar-09	Customer Cnt Apr-09	Revenue Apr-09
Total	**665,240**	$ 152,164,951.23	**665,387**	$ 135,632,676.08	**664,965**	$ 104,955,689.28
Oregon	597,487	136,339,170.04	597,525	121,402,665.93	597,091	94,274,698.44
Washington	67,753	15,825,781.19	67,862	14,230,010.15	67,874	10,680,990.84
Total Residential	601,760	92,654,241.94	601,917	80,944,062.39	601,614	61,806,138.36
Total Commercial	62,551	46,764,951.27	62,538	41,580,207.54	62,423	32,203,809.68
Total Industrial	611	4,840,132.50	616	4,816,171.64	612	3,863,006.20
Total Interruptible	184	6,864,399.09	180	7,171,522.01	169	5,958,864.75
Total Transportation - Commercial Firm	-	2,301.23	-	7,831.86	-	7,551.73
Total Transportation - Industrial Firm	62	410,161.93	63	477,699.55	67	467,823.35
Total Transportation - Interruptible	68	628,763.27	70	635,181.09	77	648,495.21

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V.3.a Customer count and revenue by month and class

	Customer Cnt May-09	Revenue May-09	Customer Cnt Jun-09	Revenue Jun-09	Customer Cnt Jul-09	Revenue Jul-09
Total	**663,834**	$ 69,399,410.05	**662,475**	$ 8,538,636.72	**660,716**	$ 37,181,986.04
Oregon	596,053	62,426,774.92	594,832	8,303,048.22	593,183	33,316,811.66
Washington	67,781	6,972,635.13	67,643	235,588.50	67,533	3,865,174.38
Total Residential	600,706	38,717,712.22	599,614	2,418,107.58	598,299	17,111,222.57
Total Commercial	62,199	20,935,788.64	61,935	1,635,891.42	61,496	11,555,639.98
Total Industrial	608	3,333,293.38	608	1,195,726.17	601	2,815,372.81
Total Interruptible	171	5,331,958.47	171	1,989,675.28	171	4,587,753.66
Total Transportation - Commercial Firm	-	7,301.16	-	7,601.12	-	8,377.27
Total Transportation - Industrial Firm	68	438,503.90	67	535,688.22	67	449,329.12
Total Transportation - Interruptible	79	634,852.28	77	755,946.93	79	654,290.63

NW Natural

UM1286 PGA Filing Guidelines
2009-2010 Oregon PGA

V.3.b Historical (five years) and forecasted (one year ahead) sales system physical peak demand *

	2009/2010 Forecasted [1]	2008 [2]	2007 [2]	2006 [2]
System peak demand (therms)	9,174,643	8,363,000	7,344,000	7,401,000

* 3 years provided per OPUC Order No. 09-263 / 09-248

[1] Normalized peak as used for purposes of the Annual PGA Filing
[2] Source: NWN Annual Report - Total Peak Delivery

NW Natural

UM1286 PGA Filing Guidelines
2009-2010 Oregon PGA

V.3.c Historical (five years) and forecasted (one year ahead) sales system physical annual demand*

Gas Year *	Forecasted 2009/2010	2008/2009	2007/2008	2006/2007
Annual Demand (therms)	721,775,790	790,275,583	840,622,740	787,223,062

* 3 years provided per OPUC Order No. 09-263 / 09-248

NW Natural

UM1286 PGA Filing Guidelines
2009-2010 Oregon PGA

V.3.d. Historical (five years), and forecasted (one year ahead) sales system physical demand for each of the following:*

1. Annual for each customer class

Gas Year *	**Forecasted 2009/2010**	**2008/2009 [1]**	**2007/2008**	**2006/2007**
Residential (therms)	400,287,324	418,142,545	435,212,254	395,702,901
Commercial (therms)	244,323,824	257,315,400	267,646,613	248,760,365
Industrial Firm (therms)	22,977,295	40,062,127	47,873,776	53,828,063
Industrial Interruptible (therms)	54,187,347	74,755,511	89,687,581	88,835,801

* 3 years provided per OPUC Order No. 09-263 / 09-248

NW Natural

UM1286 PGA Filing Guidelines
2009-2010 Oregon PGA

V.3.d. Historical (five years), and forecasted (one year ahead) sales system physical demand for each of the following:*

2. Annual and monthly baseload

Gas Year *	Forecasted 2009/2010	2008/2009	2007/2008	2006/2007
November	21,769,560	24,413,595	25,070,006	26,190,648
December	22,495,212	25,837,505	25,827,339	26,743,482
January	22,495,212	24,340,768	25,673,977	26,116,496
February	20,318,256	23,164,969	24,358,834	25,455,856
March	22,495,212	24,005,049	25,171,242	25,226,067
April	21,769,560	23,443,584	24,947,798	24,684,614
May	22,495,212	23,943,287	24,495,722	24,762,960
June	21,769,560	23,353,778	25,098,765	25,393,815
July	22,495,212	23,763,006	25,062,882	25,303,961
August	22,495,212	23,945,595	24,974,191	25,381,941
September	21,769,560	24,008,379	25,266,815	25,298,427
October	22,495,212	24,569,322	24,441,090	24,878,078
Annual	264,862,981	288,788,839	300,388,661	305,436,346

* 3 years provided per OPUC Order No. 09-263 / 09-248

NW Natural

UM1286 PGA Filing Guidelines
2009-2010 Oregon PGA

V.3.d. Historical (five years), and forecasted (one year ahead) sales system physical demand for each of the following:*

3. Annual and monthly non-baseload

Gas Year *	Forecasted 2009/2010	2008/2009 [1]	2007/2008	2006/2007
November	60,323,016	32,468,766	43,762,463	38,998,713
December	89,457,953	67,826,619	79,693,312	77,658,460
January	87,579,842	106,444,034	101,915,519	103,367,842
February	69,824,583	90,981,847	99,041,078	93,338,223
March	57,272,037	78,992,113	68,842,326	62,999,517
April	35,983,926	55,041,994	67,165,395	41,287,841
May	17,226,260	26,592,019	38,226,764	27,259,608
June	5,847,746	8,258,527	17,272,557	10,263,521
July	113,502	2,178,558	5,532,941	3,248,045
August	169,697	541,667	1,811,539	1,654,431
September	3,918,792	3,540,249	3,328,953	3,096,795
October	29,195,455	28,620,354	13,438,716	18,517,788
Annual	456,912,810	501,486,744	540,031,563	481,690,784

* 3 years provided per OPUC Order No. 09-263 / 09-248

NW Natural

UM1286 PGA Filing Guidelines
2009-2010 Oregon PGA

V.3.d. Historical (five years), and forecasted (one year ahead) sales system physical demand for each of the following: *

4. Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update

* 3 years provided per OPUC Order No. 09-263 / 09-248

Forecasted 2009/2010	**Albany**	**Astoria**	**The Dalles (OR)**	**Eugene**	**Newport/LC**	**Portland**	**Salem**	**Vancouver**
November	4,740,251	1,161,654	885,967	5,587,356	840,129	49,787,339	11,098,750	7,991,130
December	6,411,398	1,543,690	1,216,605	7,392,563	1,070,921	68,476,806	14,939,417	10,901,765
January	6,201,630	1,523,801	1,205,919	7,167,101	1,067,315	67,772,606	14,436,560	10,700,121
February	5,069,121	1,315,734	971,101	5,906,064	921,279	55,262,778	11,961,242	8,735,520
March	4,629,808	1,272,174	809,512	5,397,897	947,216	48,276,985	10,898,834	7,534,822
April	3,463,366	1,004,378	562,599	4,088,754	788,098	34,225,792	8,110,975	5,509,523
May	2,427,527	752,735	391,435	3,050,582	634,566	22,963,086	5,626,373	3,875,168
June	1,705,932	559,614	296,445	2,255,275	503,894	15,517,768	3,937,737	2,840,641
July	1,328,705	452,638	262,864	1,881,408	442,489	12,628,096	3,220,236	2,392,277
August	1,342,069	445,028	266,553	1,906,674	438,905	12,602,019	3,259,157	2,404,504
September	1,530,434	507,619	303,098	2,088,379	479,676	14,329,700	3,693,594	2,755,853
October	3,011,674	831,546	569,779	3,731,876	661,371	30,446,174	7,247,076	5,191,172
Annual	41,861,916	11,370,610	7,741,878	50,453,931	8,795,859	432,289,148	98,429,952	70,832,496

2008/2009	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver
November	3,624,754	842,463	640,959	4,421,504	677,435	32,913,429	8,348,655	5,413,165
December	5,556,185	1,378,466	976,214	6,322,720	980,942	56,571,715	12,925,515	8,952,368
January	7,223,977	1,825,939	1,484,627	7,980,532	1,299,523	80,856,761	17,451,986	12,661,456
February	6,522,841	1,556,524	1,251,678	7,558,121	1,142,165	69,875,673	15,135,892	11,103,923
March	6,071,184	1,535,991	1,143,546	6,702,613	1,081,079	62,235,214	14,255,558	9,971,978
April	4,645,149	1,288,499	862,128	5,374,562	1,024,022	47,093,604	10,846,813	7,350,803
May	3,021,243	874,917	562,286	3,971,888	704,416	29,445,167	7,272,580	4,682,811
June	1,929,893	628,927	374,076	2,717,956	581,767	17,872,542	4,573,498	2,933,646
July	1,607,519	518,550	344,447	2,323,798	611,160	14,098,105	4,026,192	2,411,793
August	1,509,636	443,470	299,569	2,145,717	437,364	13,533,991	3,606,041	2,511,474
September	1,704,767	505,248	337,579	2,338,298	477,063	15,280,715	4,052,888	2,852,069
October	3,184,687	824,404	604,113	3,973,896	654,516	31,137,298	7,579,062	5,231,700
Annual	46,601,835	12,223,398	8,881,222	55,831,605	9,671,453	470,914,213	110,074,680	76,077,186

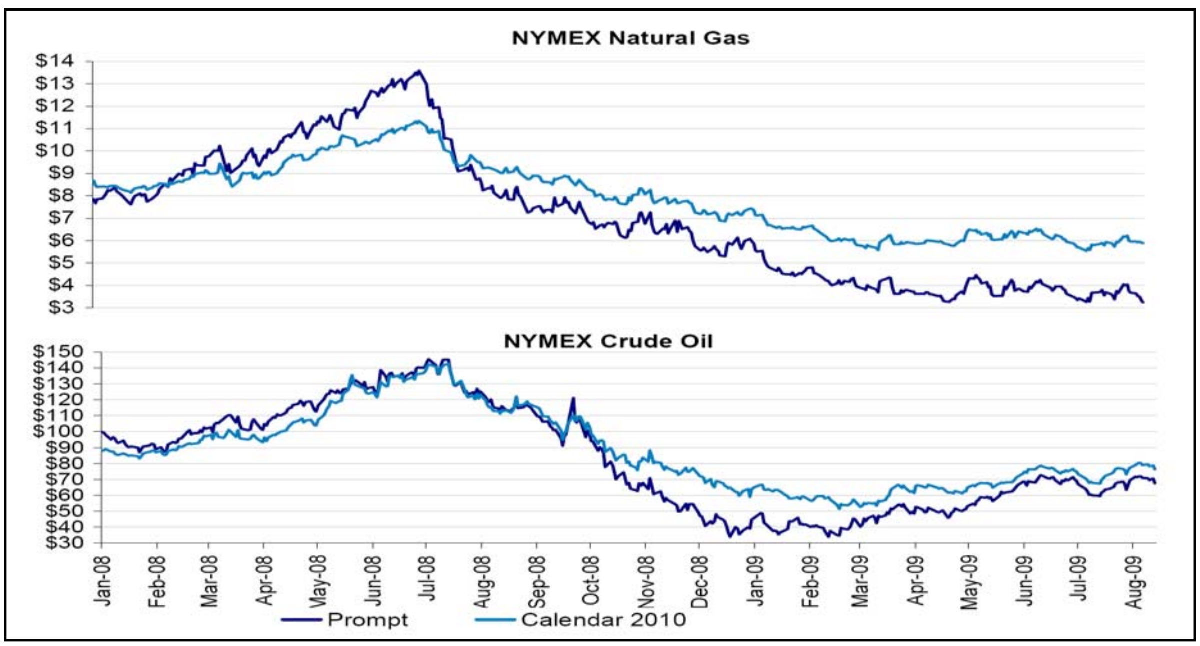
2007/2008	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver
November	4,182,195	1,020,306	714,633	5,328,764	794,380	40,443,798	9,916,379	6,432,017
December	6,111,505	1,434,454	1,148,124	7,266,264	1,132,170	64,040,525	14,279,473	10,108,139
January	7,525,889	1,818,000	1,362,710	8,906,960	1,334,030	76,765,888	17,669,672	12,206,347
February	7,275,281	1,727,923	1,310,289	8,767,209	1,280,677	74,546,238	16,944,082	11,548,213
March	5,806,592	1,423,964	982,372	7,207,188	1,022,585	55,796,872	13,321,732	8,452,263
April	5,536,384	1,496,823	898,205	7,094,652	1,095,624	54,452,628	12,940,164	8,598,713
May	3,831,143	996,118	616,226	5,055,033	779,567	36,821,140	8,801,220	5,822,039
June	2,623,616	779,248	414,955	3,645,849	614,661	24,355,810	5,994,332	3,942,849
July	1,975,877	592,231	347,030	2,691,864	548,150	16,945,575	4,496,352	2,998,745
August	1,788,317	539,314	327,890	2,597,000	580,394	14,184,574	4,226,755	2,541,487
September	1,879,260	491,798	338,625	2,655,135	496,788	15,144,990	4,923,500	2,665,670
October	2,495,259	683,858	430,146	3,293,375	610,483	20,928,007	5,890,615	3,548,062
Annual	51,031,318	13,004,037	8,891,205	64,509,293	10,289,509	494,426,045	119,404,276	78,864,544

2006/2007	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver
November	4,034,228	933,260	652,611	4,892,941	762,841	38,509,913	9,234,927	6,168,643
December	6,135,144	1,419,027	1,139,427	6,858,605	1,068,942	63,676,035	14,232,857	9,871,907
January	7,407,237	1,704,833	1,506,828	8,557,052	1,255,834	79,077,437	17,536,028	12,439,091
February	6,782,072	1,624,244	1,299,240	8,697,719	1,145,151	71,981,839	16,101,922	11,161,895
March	5,270,516	1,331,447	1,019,044	6,573,081	951,132	52,537,651	12,242,601	8,300,115
April	4,030,552	1,069,544	671,423	5,196,638	902,369	38,661,593	9,485,498	5,954,841
May	3,282,925	904,218	503,315	4,340,822	711,752	30,095,182	7,622,525	4,561,830
June	2,324,876	658,575	402,560	3,266,164	631,874	20,099,683	5,107,270	3,166,337
July	1,862,146	535,992	353,273	2,666,890	524,643	15,625,445	4,356,279	2,627,340
August	1,809,024	468,414	250,531	2,581,508	454,717	14,788,546	4,150,622	2,533,010
September	1,882,860	472,501	413,488	2,592,907	459,875	15,130,819	4,723,060	2,719,714
October	2,738,939	669,244	471,650	3,732,974	590,570	24,661,298	6,485,520	4,045,675
Annual	47,560,519	11,791,299	8,683,390	59,957,301	9,459,700	464,845,441	111,279,109	73,550,398

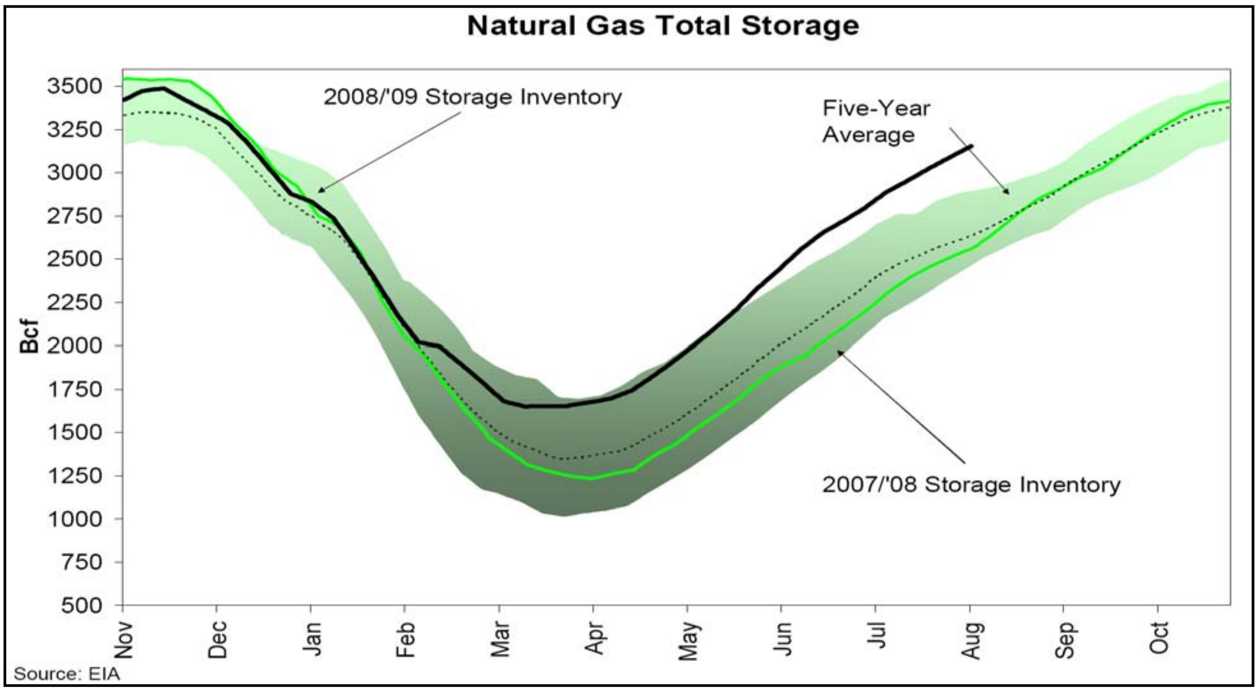
Northwest Natural Gas Company
PGA Filing
2009-2010 Oregon PGA

V.4 Market Information:
General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply, prices, and liquidity at those points.

Over the past 12 months, we have seen an unprecedented amount of oil price volatility. Crude oil (WTI) monthly spot prices went as high as $133/barrel in June 2008, then tumbled to $41/barrel in December. More recent oil prices have ranged between $60 and $75/barrel. Natural gas prices tended to track the swings in oil prices, though the correlation has been very weak at times. The natural gas (Henry Hub) spot price averaged $9.13/Mcf in 2008, though like oil, this average does not tell the story of the wild swings that gas prices experienced through 2008 and into 2009. A graphical depiction of the course of natural gas and oil prices since the beginning of 2008 is shown below.

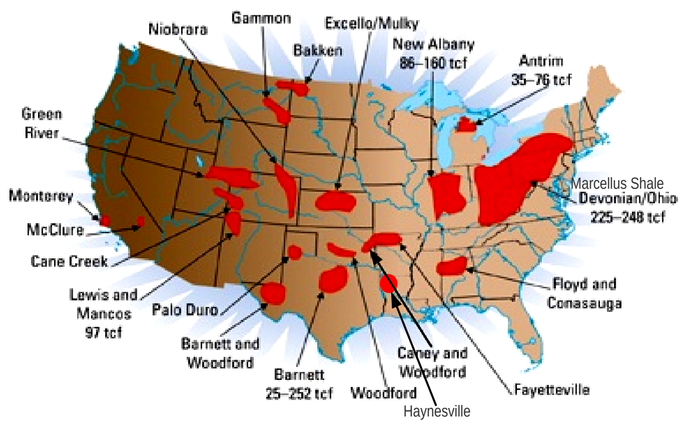


Natural gas storage levels slid below the EIA 5-year average for the first part of 2008 and then turned upward around August and stayed above the average through the end of 2008. Starting in April 2009, weekly storage levels have consistently been close to, if not at, all-time record highs for the amount of gas in storage across the country. In part this is because production growth from shale reserves has offset some if not all of the Gulf Coast production decline that resulted from hurricane damage in the latter part of 2008. It also reflects lower demand due to the "Great Recession" gripping the country, which also led to a very high level of gas remaining in storage at the end of the past heating season. Weekly storage levels through early August 2009 are depicted in the following chart.



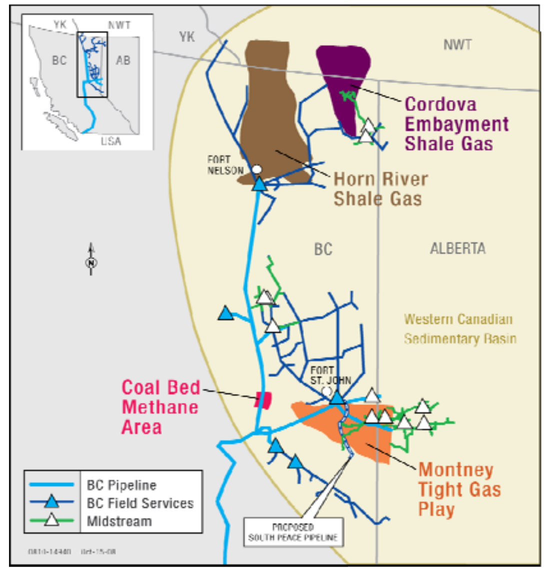
A topic of frequent discussion over the past year has been the resurgence of domestic natural gas production. Once thought to have peaked and be inexorably in decline, domestic gas production has increased and led some to say that the U.S. will be "awash" with gas supplies in the future. These predictions center on the rapid emergence of non-conventional gas production from tight sands and especially shale gas deposits. While much more expensive than conventional gas production, last year's regime of higher prices spurred development of this resource, bringing more gas on line than previously thought technically and/or economically feasible. Shale gas can be found throughout the U.S. and Canada as shown below.

US Shale Gas Supply Areas

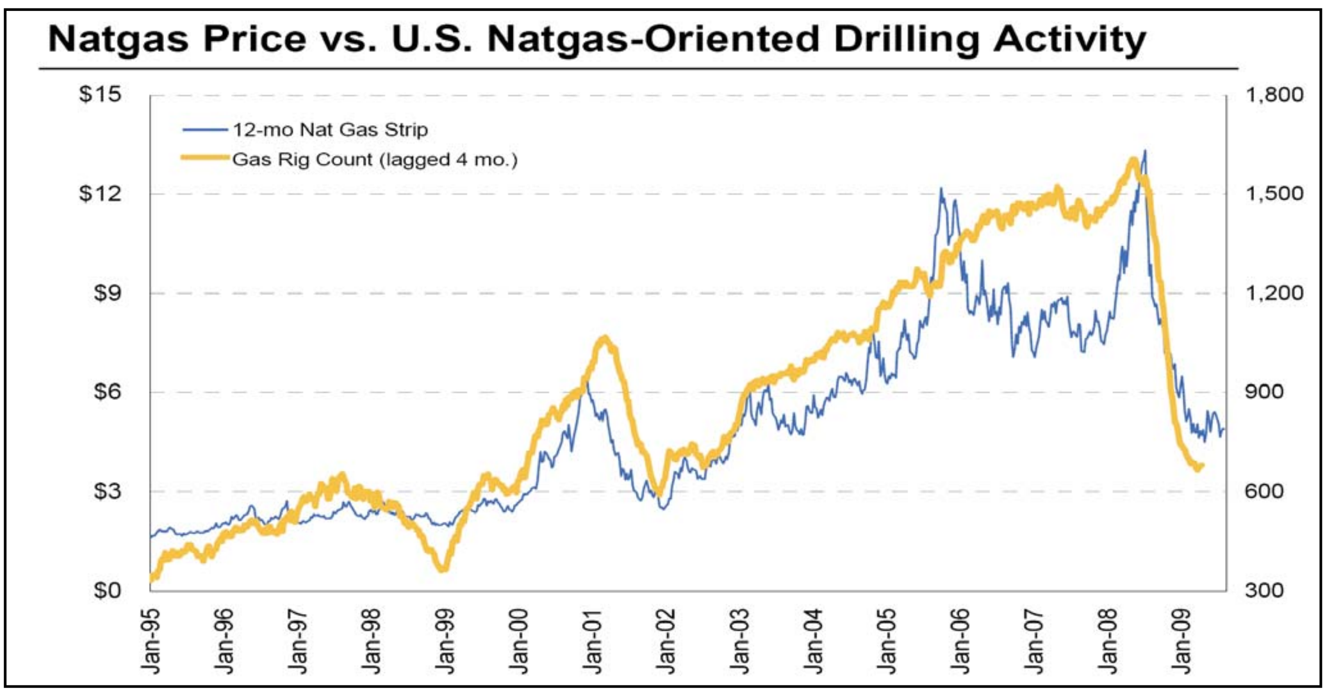


Gas shale deposits appear in basins from the east to the west coast across the United States. Although recovery percentages are low, total volumes are high. (Map from enmag.com, courtesy of Schlumberger)

BC Shale/Tight Gas Supply Areas



However, the sharp drop in natural gas prices has also taken a toll on drilling activity, as shown in the next graph.



As with the rest of the industry, NW Natural is monitoring these trends with great interest. While the potential for higher gas production rates seemed undeniable less than a year ago, the higher cost of these new ventures do not seem to be supported by the current market, which has halted the downward movement in prices that consumers have been enjoying in recent months. Or as stated in last year's testimony "…if market prices do begin to move downward, there are offsetting forces that could force a rapid rebound, including the cessation of development activities as well as a drop in LNG imports due to unfavorable pricing." Certainly supply development activities are being curtailed, but the timing and magnitude of the expected rebound in prices depends primarily on the eventual economic recovery.

Northwest Natural Gas Company
PGA Filing
2009-2010 Oregon PGA

V.5 Data Interpretation

If not included in the PGA filing please explain the major aspects of the LDC's analysis and interpretation of the data and information described in (1) and (2) above, the most important conclusions resulting from that analysis and interpretation, and the application of these conclusions in the development of the current PGA portfolio.

See Exhibit A of NW Natural's PGA Filing, OPUC Advice No. 09-12.

Northwest Natural Gas Company
PGA Filing Guidelines
2009-2010 Oregon PGA

V.6 Credit Worthiness Standards

A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.

IV. Credit Risk Management

The following steps are taken by the Front, Mid and Back Offices to provide credit risk management:

	Procedure	Responsible Office
1	Analyzes the counterparty's profile to determine credit risk tolerances.	Mid Office
2	Sets counterparty credit limits in accordance with company policy (see Exhibit "E" of the Gas Supply Risk Management Policies).	Mid Office
3	Monitors credit exposure and coordinates with the Front Office to mitigate risk.	Mid Office
4	If the credit exposure amount exceeds the counterparty credit limit, verifies the limit violation.	Mid Office
5	Notifies Front Office Executive of limit violations in physical transactions, and Mid Office Executive of limit violations in financial transactions.	Mid Office
6	Determines any appropriate action in response to physical transaction violations.	Front Office Executive
7	Communicates instructions for dealing with physical transaction violations to Front Office and submits copies of the instructions to the Mid Office.	Front Office Executive
8	Determines any appropriate action in response to financial transaction violations.	Mid Office Executive
9	Communicates instructions for dealing with financial transaction violations to Front Office and submits copies of the instructions to the Mid Office.	Mid Office Executive
10	Calculates and analyzes various credit risk metrics to better understand the current and potential risks in the portfolio.	Mid Office
11	Calculates and records appropriate credit reserves on a monthly basis.	Mid Office
12	Reviews credit limits at least twice a year, and additionally as needed, to assess whether changes should be made.	Mid Office
13	Monitors news articles, bankruptcy filings, legal actions, etc. on a daily basis for all established counterparties.	Front Office Mid Office Back Office

Source: NW Natural General Procedure G-72; Physical and financial Commodity Transaction Procedures
Effective March 28, 2005; Last updated January 5, 2008

Northwest Natural Gas Company
PGA Filing Guidelines
2009-2010 Oregon PGA

V.6 Credit Worthiness Standards

A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.

See Appendix 'A', Attachment 1 to V.6 - CONFIDENTIAL

APPENDIX A

ATTACHMENT 1 to V.6

CONFIDENTIAL

NW Natural

SUPPORTING MATERIALS

TO

PGA FILING GUIDELINES

DOCKET UM 1286

OPUC ORDER NOS. 09-263 / 09-248

Purchased Gas Cost and Technical Adjustments to Rates

NWN Advice No. OPUC 09-12

August 31, 2009

APPENDIX 'A'
Attachment 1 to V.6 - REDACTED
HIGHLY CONFIDENTIAL
CONFIDENTIAL

NW NATURAL

Gas Supply Risk Management Policies

Index No. 110

January, 2007

Derivatives Policy: Updated September 2006

Physical Gas Commodity Transactions Policy: Updated January 2007

Northwest Natural Gas Company
PGA Filing Guidelines
2009-2010 Oregon PGA

V.7 Storage

a) Type of storage (e.g., depleted field, salt dome).
b) Location of each storage facility.
c) Total level of storage in terms of deliverability and capacity held during the gas year.

NW Natural storage withdrawals in the Purchased Gas Adjustment (PGA) filing for 2009-2010 are produced by stochastic modeling. As noted in the Integrated Resource Plan (IRP), the Company's Gas Supply Department utilizes the program SENDOUT® to perform its dispatch modeling. Based on expected conditions, this modeling provides guidance to the department in how it anticipates dispatching from various pipeline supplies and storage facilities. The objective is to ensure reliable service during the heating season on an aggregate system-wide basis and, at the same time, achieve the maximum economic benefit from seasonal price differences and varying gas delivery terms. With the assistance of SENDOUT®, resource portfolios are developed with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. The system is operated as an integrated whole and costs are apportioned accordingly.

NW Natural's heavy reliance on storage gas requires examination of the Company's ability to meet peaking loads. SENDOUT® models an ideal operation profile for each storage facility to meet core customer demand based on historical heating season patterns.

Operational capabilities of each storage facility are factored into the analysis. Storage resources modeled for the 2009-2010 PGA included the following:

Firm Storage Resources as of November 2009

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	Upon 1-Year Notice
TF-2 (redelivery service)	32,624	839,046	Upon 1-Year Notice
TF-2 (redelivery service)	13,406	281,242	Upon 1-Year Notice
Plymouth LNG:			
LS-1	60,100	478,900	Upon 1-Year Notice
TF-2 (redelivery service)	60,100	478,900	Upon 1-Year Notice
Total Firm Off-system Storage:			
Withdrawal/Vaporization	106,130	1,599,188	
TF-2 Redelivery	106,130	1,599,188	
Firm On-System Storage Plants:			
Mist (reserved for core)	250,000	9,420,270	n/a
Portland LNG Plant	120,000	600,000	n/a
Newport LNG Plant	60,000	1,000,000	n/a
Total On-System Storage	430,000	11,020,270	
Total Firm Storage Resource	536,130	12,619,458	

Based on Mist core and interstate capacity allocations, Sendout recommended the following monthly core activity from that storage facility during 2009-2010 to meet the stated objectives in the IRP:

2009-2010	2009 Mist Storage Allocation		
Dth	**Core**	**Interstate**	**Total**
Working Gas	9,420,270	6,522,580	15,942,850
Withdrawal (Dth/day)	250,000	269,200	519,200

2009-2010	Mist PGA
Month	Withdrawal
November	469,939
December	1,964,401
January	4,059,604
February	3,299,122
March	1,558,252
April	44,396
May	-
June	-
July	-
August	-
September	-
October	-

Northwest Natural Gas Company
PGA Filing Guidelines
2009-2010 Oregon PGA

V.7.d Historical (five years) gas supply delivered to storage, both annual total and by month.

V.7.e Historical (five years) gas supply withdrawn from storage, both annual total and by month.

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary (Gasco, Newport, Jackson Prairie, Plymouth, Mist)
ACCOUNT NO. (164.21, 164.23, 164.22, 164.16, 164.12)

	BEGINNING BALANCE			ISSUES (Withdrawals)		LIQUEFIED	INJECTIONS (Deliveries)		ENDING BALANCE		
MONTH	THERMS	AMOUNT	RATE	THERMS	AMOUNT	THERMS	AMOUNT	RATE	THERMS	AMOUNT	RATE
Dec-04								-	122,270,766	$ 54,383,996.84	0.44478
Jan-05	122,270,766	$ 54,383,996.84	0.44478	41,203,077	$ 18,472,351.85	6,377,879	$ 2,797,036.71	0.43855	87,445,568	$ 38,708,681.70	0.44266
FEB	87,445,568	$ 38,708,681.70	0.44266	27,877,221	$ 12,308,754.89	1,117,160	$ 606,899.05	0.54325	60,685,507	$ 27,006,825.86	0.44503
MAR	60,685,507	$ 27,006,825.86	0.44503	13,402,702	$ 5,968,337.92	4,822,400	$ 2,781,280.71	0.57674	52,105,205	$ 23,819,768.65	0.45715
APR	52,105,205	$ 23,819,768.65	0.45715	24,411,118	$ 10,879,747.56	2,640,702	$ 1,807,310.58	0.68441	30,334,789	$ 14,747,331.67	0.48615
MAY	30,334,789	$ 14,747,331.67	0.48615	5,650,680	$ 2,695,555.44	12,296,816	$ 7,703,968.49	0.62650	36,980,925	$ 19,755,744.72	0.53421
JUN	36,980,925	$ 19,755,744.72	0.53421	3,863,370	$ 2,183,211.31	19,670,654	$ 12,192,118.81	0.61981	52,788,209	$ 29,764,652.22	0.56385
JUL	52,788,209	$ 29,764,652.22	0.56385	1,224,010	$ 724,858.72	38,439,609	$ 23,367,872.93	0.60791	90,003,808	$ 52,407,666.43	0.58228
AUG	90,003,808	$ 52,407,666.43	0.58228	482,112	$ 281,435.79	21,523,928	$ 14,766,749.57	0.68606	111,045,624	$ 66,892,980.21	0.60239
SEP	111,045,624	$ 66,892,980.21	0.60239	208,406	$ 118,393.47	20,997,893	$ 20,226,464.42	0.96326	131,835,111	$ 87,001,051.16	0.65992
OCT	131,835,111	$ 87,001,051.16	0.65992	4,373,083	$ 2,830,619.23	15,320,883	$ 17,255,139.72	1.12625	142,782,911	$ 101,425,571.65	0.71035
NOV	142,782,911	$ 101,425,571.65	0.71035	12,187,672	$ 8,652,795.12	6,795,869	$ 6,489,344.74	0.95490	137,391,108	$ 99,262,121.27	0.72248
DEC	137,391,108	$ 99,262,121.27	0.72248	41,587,528	$ 30,478,415.34	6,447,660	$ 8,189,402.06	1.27014	102,251,240	$ 76,973,107.99	0.75278
	TOTAL 2005 ACTIVITY			176,470,979	95,594,476.64	156,451,453	118,183,587.79				
Jan 06	102,251,240	$ 76,973,107.99	0.75278	18,958,017	$ 14,644,496.32	1,712,020	$ 1,537,405.03	0.89801	85,005,243	$ 63,866,016.70	0.75132
Feb	85,005,243	$ 63,866,016.70	0.75132	25,301,163	$ 19,685,349.69	1,260,790	$ 912,186.10	0.72350	60,964,870	$ 45,092,853.11	0.73965
Mar	60,964,870	$ 45,092,853.11	0.73965	16,380,123	$ 12,714,357.74	5,744,820	$ 3,500,585.93	0.60935	50,329,567	$ 35,879,081.30	0.71288
Apr	50,329,567	$ 35,879,081.30	0.71288	8,029,038	$ 5,805,872.06	3,712,467	$ 2,413,036.77	0.64998	46,012,996	$ 32,486,246.01	0.70602
May	46,012,996	$ 32,486,246.01	0.70602	2,127,418	$ 1,433,491.41	31,242,513	$ 18,049,315.16	0.57772	75,128,091	$ 49,102,069.76	0.65358
Jun	75,128,091	$ 49,102,069.76	0.65358	1,536,935	$ 990,817.43	30,380,924	$ 17,478,793.68	0.57532	103,972,080	$ 65,590,046.01	0.63084
Jul	103,972,080	$ 65,590,046.01	0.63084	1,228,413	$ 780,336.37	19,668,264	$ 12,257,997.01	0.62324	122,411,931	$ 77,067,706.65	0.62958
Aug	122,411,931	$ 77,067,706.65	0.62958	336,093	$ 210,229.38	12,172,288	$ 7,881,693.44	0.64751	134,248,126	$ 84,739,170.71	0.63121
Sep	134,248,126	$ 84,739,170.71	0.63121	412,841	$ 248,185.88	14,724,165	$ 8,382,441.08	0.56930	148,559,450	$ 92,873,425.91	0.62516
Oct	148,559,450	$ 92,873,425.91	0.62516	8,524,419	$ 5,535,541.34	-	$ -	-	140,035,031	$ 87,337,884.57	0.62369
Nov	140,035,031	$ 87,337,884.57	0.62369	17,928,294	$ 11,288,271.47	5,991,010	$ 3,707,869.38	0.61891	128,097,747	$ 79,757,482.48	0.62263
Dec	128,097,747	$ 79,757,482.48	0.62263	24,118,160	$ 14,846,060.55	6,030,810	$ 3,664,130.91	0.60757	110,010,397	$ 68,575,552.84	0.62336
	TOTAL 2006 ACTIVITY			124,880,914	88,183,009.64	132,640,071	79,785,454.49				

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V.7.d Historical (five years) gas supply delivered to storage, both annual total and by month.

V.7.e Historical (five years) gas supply withdrawn from storage, both annual total and by month.

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary (Gasco, Newport, Jackson Prairie, Plymouth, Mist)
ACCOUNT NO. (164.21, 164.23, 164.22, 164.16, 164.12)

	BEGINNING BALANCE			ISSUES (Withdrawals)		LIQUEFIED	INJECTIONS (Deliveries)		ENDING BALANCE		
MONTH	THERMS	AMOUNT	RATE	THERMS	AMOUNT	THERMS	AMOUNT	RATE	THERMS	AMOUNT	RATE
Jan-07	110,010,397	$ 68,575,552.84	0.62336	32,747,989	$ 20,502,938.66	2,947,690	$ 1,721,085.84	0.58388	80,210,098	$ 49,793,700.02	0.62079
FEB	80,210,098	$ 49,793,700.02	0.62079	21,665,609	$ 13,340,971.41	1,868,810	$ 1,276,550.79	0.68308	60,413,299	$ 37,729,279.40	0.62452
MAR	60,413,299	$ 37,729,279.40	0.62452	5,716,652	$ 3,635,769.46	12,732,030	$ 7,734,741.02	0.60750	67,428,677	$ 41,828,250.96	0.62033
APR	67,428,677	$ 41,828,250.96	0.62033	17,999,410	$ 11,024,026.68	6,693,218	$ 3,500,379.10	0.52297	56,122,485	$ 34,304,603.38	0.61125
MAY	56,122,485	$ 34,304,603.38	0.61125	7,676,136	$ 4,607,187.63	27,758,648	$ 14,102,546.19	0.50804	76,204,997	$ 43,799,961.94	0.57476
JUN	76,204,997	$ 43,799,961.94	0.57476	2,290,199	$ 1,267,185.11	22,587,207	$ 10,082,107.84	0.44636	96,502,005	$ 52,614,884.67	0.54522
JUL	96,502,005	$ 52,614,884.67	0.54522	938,890	$ 518,930.35	27,986,126	$ 14,749,934.89	0.52704	123,549,241	$ 66,845,889.21	0.54105
AUG	123,549,241	$ 66,845,889.21	0.54105	934,511	$ 518,496.94	22,279,127	$ 11,416,040.83	0.51241	144,893,857	$ 77,743,433.10	0.53655
SEP	144,893,857	$ 77,743,433.10	0.53655	1,018,869	$ 561,305.39	11,414,527	$ 2,424,935.55	0.21244	155,289,515	$ 79,607,063.26	0.51264
OCT	155,289,515	$ 79,607,063.26	0.51264	14,791,065	$ 7,301,584.37	2,198,039	$ 724,296.55	0.32952	142,696,489	$ 73,029,775.44	0.51178
NOV	142,696,489	$ 73,029,775.44	0.51178	3,305,990	$ 1,423,564.17	4,497,822	$ 2,768,087.19	0.61543	143,888,321	$ 74,374,298.46	0.51689
DEC	143,888,321	$ 74,374,298.46	0.51689	14,553,312	$ 7,322,402.53	5,864,210	$ 4,026,896.20	0.68669	135,199,219	$ 71,078,792.13	0.52573
	TOTAL 2007 ACTIVITY			123,638,632	72,024,362.70	148,827,454	74,527,601.99				
Jan 08	135,199,219	$ 71,078,792.13	0.52573	42,682,544	$ 22,727,144.60	3,402,230	$ 2,562,147.29	0.75308	95,918,905	$ 50,913,794.82	0.53080
Feb	95,918,905	$ 50,913,794.82	0.53080	29,833,245	$ 15,663,187.27	3,037,860	$ 2,358,605.97	0.77640	69,123,520	$ 37,609,213.52	0.54409
Mar	69,123,520	$ 37,609,213.52	0.54409	29,308,951	$ 16,697,534.41	783,760	$ 651,398.76	0.83112	40,598,329	$ 21,563,077.87	0.53113
Apr	40,598,329	$ 21,563,077.87	0.53113	14,741,559	$ 9,004,018.90	5,468,770	$ 5,261,381.50	0.96208	31,325,540	$ 17,820,440.47	0.56888
May	31,325,540	$ 17,820,440.47	0.56888	1,394,242	$ 1,259,289.68	7,377,193	$ 7,072,723.41	0.95873	37,308,491	$ 23,633,874.20	0.63347
Jun	37,308,491	$ 23,633,874.20	0.63347	2,575,879	$ 2,082,625.25	17,920,700	$ 16,021,216.64	0.89401	52,653,312	$ 37,572,465.59	0.71358
Jul	52,653,312	$ 37,572,465.59	0.71358	2,389,833	$ 2,600,403.22	29,495,668	$ 27,744,517.14	0.94063	79,759,147	$ 62,716,579.51	0.78632
Aug	79,759,147	$ 62,716,579.51	0.78632	867,160	$ 729,520.01	26,131,565	$ 18,238,203.36	0.69794	105,023,552	$ 80,225,262.86	0.76388
Sep	105,023,552	$ 80,225,262.86	0.76388	143,600	$ 102,744.03	28,405,529	$ 14,134,411.09	0.49759	133,285,481	$ 94,256,929.92	0.70718
Oct	133,285,481	$ 94,256,929.92	0.70718	4,536,969	$ 3,453,264.43	26,631,384	$ 13,808,487.81	0.51850	155,379,896	$ 104,612,153.30	0.67327
Nov	155,379,896	$ 104,612,153.30	0.67327	6,716,700	$ 4,480,626.85	7,646,172	$ 6,526,427.47	0.85355	156,309,368	$ 106,657,953.92	0.68235
Dec	156,309,368	$ 106,657,953.92	0.68235	34,572,504	$ 24,087,225.38	5,896,960	$ 3,563,069.48	0.60422	127,633,824	$ 86,133,798.02	0.67485
	TOTAL 2008 ACTIVITY			169,763,186	102,887,584.03	162,197,791	117,901,140.31				
Jan 09	127,633,824	$ 86,133,798.02	0.67485	21,470,123	$ 14,421,841.03	1,969,140	$ 915,206.80	0.46477	108,132,841	$ 72,627,163.79	0.67165
Feb	108,132,841	$ 72,627,163.79	0.67165	8,052,347	$ 5,259,751.99	3,917,370	$ 1,541,494.90	0.39350	103,997,864	$ 68,908,906.70	0.66260

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V.7.d Historical (five years) gas supply delivered to storage, both annual total and by month.

V.7.e Historical (five years) gas supply withdrawn from storage, both annual total and by month.

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary (Gasco, Newport, Jackson Prairie, Plymouth, Mist)
ACCOUNT NO. (164.21, 164.23, 164.22, 164.16, 164.12)

	BEGINNING BALANCE			ISSUES (Withdrawals)		LIQUEFIED	INJECTIONS (Deliveries)		ENDING BALANCE		
MONTH	THERMS	AMOUNT	RATE	THERMS	AMOUNT	THERMS	AMOUNT	RATE	THERMS	AMOUNT	RATE
Mar	103,997,864	$ 68,908,906.70	0.66260	7,169,301	$ 3,809,030.51	15,685,782	$ 5,335,886.23	0.34017	112,514,345	$ 70,435,762.42	0.62602
Apr	112,514,345	$ 70,435,762.42	0.62602	12,549,307	$ 6,792,634.68	6,003,002	$ 1,863,485.18	0.31043	105,968,040	$ 65,506,612.92	0.61817
May	105,968,040	$ 65,506,612.92	0.61817	6,257,410	$ 3,304,746.27	5,698,237	$ 2,601,331.17	0.45652	105,408,867	$ 64,803,197.82	0.61478
Jun	105,408,867	$ 64,803,197.82	0.61478	1,920,050	$ 700,166.12	10,701,397	$ 5,542,374.50	0.51791	114,190,214	$ 69,645,406.20	0.60991
Jul	114,190,214	$ 69,645,406.20	0.60991	902,489	$ 333,164.85	14,375,074	$ 7,356,483.97	0.51175	127,662,799	$ 76,668,725.32	0.60056
TOTAL 2009 ACTIVITY				58,321,027	34,621,335.45	58,350,002	25,156,262.75				

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V.7.f An explanation of the methdology utilized by the LDC to price storage injections and withdrawals, as well as the total and average (per unit) cost of storage gas.

The price of gas placed into storage, classed as working inventory, will be the average cost of gas defined as the average commodity cost of gas delivered to the city gate (utilizing discretionary sources first: i.e., spot gas first, then swing, and base load term supplies last) unless the site is outside the company service territory. This price would represent commodity cost, transmission cost, and fuel-in-kind (FIK) at either the NNG city gas (internal storage) or at the external storage site. This price will include all pipeline demand charges and supplier reservation charges.

This pricing policy will apply to all storage locations owned or under contract to the NNG, with exception as noted.

When the contract for a storage site includes a provision for the price of the gas placed into storage, the price shall be the price as defined by the agreement

Direct associated costs, such as liquefaction fees (LS-1), FIK (SGS) and actual material costs incurred (Newport) can be added to the base cost when determined significant.

Withdrawals at each facility (Mist, Gasco, etc.) are priced at the average inventory price as established at the beginning of each month. The beginning of the month cost at each facility is adjusted for any withdrawals and any injections (priced as per tab #29) to create the end of the month cost, which then becomes the beginning of the month cost for the next month.

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V.7.g Copies of all contracts or other agreements and tariffs that control the LDC's use of the storage facilities included in the current portfolio.

See Appendix 'A', Attachment 1 and Attachment 2 to V.7.g

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V.7.h For LDCs that own and operate storage:

a. The date and results of the last engineering study for that storage.

b. A description of any significant changes in physical or operational parameters of the storage facility (including LNG) since the current engineering study was completed.

From: Roth, Clayton
Sent: Friday, August 14, 2009 9:16 AM
To: Siebert, William; *Gas Controllers; Tilgner, Doug
Cc: Friedman, Randy; Stinson, Charlie; Brosy, Maria; Thomas, Todd; Geertz, Allen; Lee, Amy; Cole, Cindy; Mott, Michael; McAnally, Robert; Timmerman, Rick; Henderson, Denny; Redding, Mike; Wilkeson, Randy; Phelps, Wayne; Jaworski, William; Schmidt, R. Phil; Bekins, Todd; Pearce, Curtis; Dady, Robin; Daniel, Rick

Subject: Mist Storage Status

This is a reminder to all recipients of this storage data that the information you are receiving is sensitive, Company confidential data. It is not to be shared with those outside the distribution list without consulting the sender and in no case should it be shared outside the Company. NW Natural storage customers and others can access weekly storage information on the NW Natural internet web site and customers can access their own account information using a personalized password. FERC has recently been focusing on storage information as a source of market volatility and is emphasizing, in part through enforcement action, that it takes very seriously any discriminatory sharing of this information. Please keep this in mind.

[redacted]

Please contact me if you have any questions.

Clayton

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