Rates and Regulatory Affairs
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August 29, 2008 NWN Advice No. OPUC 08-5

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, 2008.

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, 2007; and (c) apply new temporary rate adjustments for inclusion in rates effective November 1, 2008. The Company revises rates for these purposes annually; its last filing was effective November 1, 2007.

The second purpose of this filing is to make temporary adjustments to base rates for (a) the costs associated with the Company's safety programs for Bare Steel and Geohazard Risk mitigation and for the Pipeline Integrity Management Program; and (b) NW Natural's share of the construction contribution for the Coos County distribution system, pursuant to OPUC Order No. 04-702.

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 increase in the Company's revenues from its Oregon operations of about $235,683,305 or about 25.8%.

The average residential Schedule 2 bill will increase by 25.4%; the commercial Schedule 3 bill will increase by 28.0%; the commercial Schedule 31 bill will increase by 35.5%, and; the bill for the average Schedule 32 industrial firm sales customer will increase by 40.2%.

The monthly bill of the average residential customer served under Schedule 2 using 56 therms per month will increase by $18.97. The monthly increase for the average commercial Schedule 3 customer using 226 therms is $73.25.

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

Additional details about this combined filing are described below.

I. 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.

See Exhibit A of this filing for a summary of the Company's gas purchasing strategy.

This filing applies the methods for calculating the proposed Weighted Average Cost of Gas ("WACOG") that are set forth in a joint party stipulation filed with the Commission on May 2, 2008 in Docket UM 1286. In addition, this filing revises the Winter Sales WACOG option that is available to 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 increase the Company's annual revenues by about $206,927,841. The effect of the change in gas costs is $207,398,276, which results in a proposed Annual Sales WACOG of

$1.00043 per therm, and a proposed Winter Sales WACOG of $1.08654. The effect of the change in demand charge calculation is a decrease in total demand charges of about $470,435, which results in a proposed firm service pipeline capacity charge of $0.12083 per therm, or $1.80 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.014385 per therm.

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.

II. 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.

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 require a review of earnings because the Company has adopted a 33% sharing option for purchased gas and related costs. 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 2006 Earnings Review. Page 17 of Exhibit B shows the total proposed average change being applied to billing rates a decrease of $17.6 million, which is below the current three percent limit of $30.5 million.

The net effect of this portion of the filing is to increase the Company's annual revenues by $17,859,163. The effect of removing the temporary adjustments placed into rates November 1, 2007 is an increase of $35,425,211. The effect of applying the new temporary rate adjustments is a decrease of $17,566,048.

III. Base Rate Adjustments

The effect of this portion of the filing is to increase the Company's annual revenues by $10,896,301.

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

Bare Steel/Geohazard. This filing applies temporary adjustments to permanent rates that relate to the Bare Steel/Geohazard programs, pursuant to a Stipulation and Agreement adopted by the Commission, as described in Schedule 177.

Integrity Management Program. This filing applies temporary adjustments to permanent rates that relate to the Integrity Management Program, pursuant to OPUC Order 04-390.

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.

Coos County. This filing applies the permanent effects of the revenue requirement associated with the construction of the Coos County distribution system pursuant to OPUC Order No. 03-236.

Mist Recall. This adjustment represents the permanent rate effects of the recall of 100,000 therms per day of Mist 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, 2008.

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/ Inara K. Scott

Inara K. Scott, Manager
Regulatory Affairs

Attachments: Tariffs
Exhibits A and B

TABLE OF TARIFF SHEET REVISIONS
PROPOSED TO BECOME EFFECTIVE NOVEMBER 1, 2007

PROPOSED REVISION	CANCELS REVISION	SCHEDULE TITLE
Seventh Revision of Sheet 1-1	Sixth Revision of Sheet 1-1	Schedule 1 “General Sales Service”
Seventh Revision of Sheet 2-1	Sixth Revision of Sheet 2-1	Schedule 2 “Residential Sales Service”
Fifth Revision of Sheet 3-3	Fourth Revision of Sheet 3-3	Schedule 3 “Basic Firm Sales Service – Non-Residential”
Sixth Revision of Sheet 19-1	Fifth Revision of Sheet 19-1	Schedule 19 “Gas Light Service”
Third Revision of Sheet 31-9	Second Revision of Sheet 31-9	Schedule 31 “Non-Residential Sales and Transportation Service”
Fourth Revision of Sheet 31-10	Third Revision of Sheet 31-10	Schedule 31 “Non-Residential Sales and Transportation Service”
Third Revision of Sheet 32-9	Second Revision of Sheet 32-9	Schedule 32 “Large Volume Non-Residential Sales and Transportation Service”
Fifth Revision of Sheet 32-10	Fourth Revision of Sheet 32-10	Schedule 32 “Large Volume Non-Residential Sales and Transportation Service”
Fourth Revision of Sheet 33-6	Third Revision of Sheet 33-9	Schedule 33 “High-Volume Non-Residential Firm and Interruptible Transportation Service”
Seventh Revision of Sheet 54-1	Sixth Revision of Sheet 54-1	Schedule 54 “Emergency Sales Service”
Seventh Revision of Sheet 162-1	Sixth Revision of Sheet 162-1	Schedule 162 “Temporary (Technical) Adjustments to Rates”
Sixth Revision of Sheet 162-2	Fifth Revision of Sheet 162-2	Schedule 162 “Temporary (Technical) Adjustments to Rates”
Eighth Revision of Sheet 163-1	Seventh Revision of Sheet 163-1	Schedule 163 “Special Adjustment to Rates Price Elasticity”
Seventh Revision of Sheet 164-1	Sixth Revision of Sheet 164-1	Schedule 164 “Purchased Gas Cost Adjustment to Rates”

PROPOSED REVISION	CANCELS REVISION	SCHEDULE TITLE
Second Revision of Sheet 169-1	First Revision of Sheet 169-1	Schedule 169 “Special Adjustment to Rates for Storage Inventories”
Eighth Revision of Sheet 177-2	Seventh Revision of Sheet 177-2	Schedule 177 “Adjustments to Rates for Safety Programs”
Original Sheet 177-2.1	N/A	Schedule 177 “Adjustments to Rates for Safety Programs”
Sixth Revision of Sheet 177-3	Fifth Revision of Sheet 177-3	Schedule 177 “Adjustments to Rates for Safety Programs”
Original Sheet 177-3.1	N/A	Schedule 177 “Adjustments to Rates for Safety Programs”
Fifth Revision of Sheet 177-4	Fourth Revision of Sheet 177-4	Schedule 177 “Adjustments to Rates for Safety Programs”
Original Sheet 177-4.1	N/A	Schedule 177 “Adjustments to Rates for Safety Programs”
Ninth Revision of Sheet 190-1	Eighth Revision of Sheet 190-1	Schedule 190 “Partial Decoupling Mechanism”
Seventh Revision of Sheet 190-2	Sixth Revision of Sheet 190-2	Schedule 190 “Partial Decoupling Mechanism”
Sixth Revision of Sheet 195-3	Fifth Revision of Sheet 195-3	Schedule 195 “Weather Adjusted Rate Mechanism (WARM Program)”
Fifth Revision of Sheet 195-4	Fourth Revision of Sheet 195-4	Schedule 195 “Weather Adjusted Rate Mechanism (WARM Program)”
Fourth Revision of Sheet 195-5	Third Revision of Sheet 195-5	Schedule 195 “Weather Adjusted Rate Mechanism (WARM Program)”
Fifth Revision of Sheet P-2	Fourth Revision of Sheet P-2	Schedule P “Purchased Gas Cost Adjustments”
Sixth Revision of Sheet P-3	Fifth Revision of Sheet P-3	Schedule P “Purchased Gas Cost Adjustments”
Eighth Revision of Sheet P-5	Seventh Revision of Sheet P-5	Schedule P “Purchased Gas Cost Adjustments”

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 Schedule, is subject to the provisions of **SCHEDULE X**. (C)

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.

MONTHLY RATE: Effective: November 1, 2008 (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:	$5.00	---	---	---	---	**$5.00**	
Delivery Charge (per therm):							
Residential	$0.51752	$0.01697	$0.12083	$1.00043	$(0.01989)	**$1.63586**	(I)
Commercial	$0.48636	$0.01301	$0.12083	$1.00043	$(0.04086)	**$1.57977**	(I)

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

(continue to Sheet 1-2)

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, 2008 (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):	$0.44994	$0.01204	$0.12083	$1.00043	$(0.02001)	**$1.56323**

(I)

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

(continue to Sheet 2-2)

Issued August 29, 2008
NWN Advice No. OPUC 08-5

Effective with service on
and after November 1, 2008

RATE SCHEDULE 3

BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

(T)

MONTHLY RATE: Effective: November 1, 2008

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):	$0.35587	$0.00942	$0.12083	$1.00043	$(0.04094)	**$1.44561**	(C)(I)
Industrial (3 ISF):	$0.31448	$0.00840	$0.12083	$1.00043	$(0.02442)	**$1.41972**	(C)(I)
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, 2008

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	$27.40	$0.06	$(0.48)	**$26.98**
All additional mantles	$26.79	$0.06	$(0.48)	**$26.37**
Minimum Monthly Bill: Amount based on number of mantles installed				

(I)
(I)

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, 2008 (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	$0.19377	$0.00753	$1.00043	$(0.04099)	**$1.16074**	(I)
Block 2: All additional therms	$0.17757	$0.00713	$1.00043	$(0.04100)	**$1.14413**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.12083**	(R)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.80**	(R)
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	$0.19375	$0.00613	$1.00043	$(0.02082)	**$1.17949**	(I)
Block 2: All additional therms	$0.17755	$0.00585	$1.00043	$(0.02083)	**$1.16300**	(I)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.01438**	(R)
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	$0.19376	$0.00681		$(0.01637)	**$0.18420**	(I)
Block 2: All additional therms	$0.17756	$0.00647		$(0.01638)	**$0.16765**	(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, 2008 (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	$0.16796	$0.00364	$1.00043	$(0.02446)	**$1.14757**	(I)
Block 2: All additional therms	$0.15177	$0.00328	$1.00043	$(0.02447)	**$1.13101**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.12083**	(R)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.80**	(R)
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	$0.16798	$0.00509	$1.00043	$(0.00422)	**$1.16928**	(I)
Block 2: All additional therms	$0.15179	$0.00459	$1.00043	$(0.00424)	**$1.15257**	(I)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.01438**	(R)
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	$0.16795	$0.00352		$0.00017	**$0.17164**	(I)
Block 2: All additional therms	$0.15177	$0.00319		$0.00017	**$0.15513**	(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, 2008 (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):						
Block 1: 1st 10,000 therms	$0.10011	$0.00239	$1.00043	$(0.02458)	**$1.07835**	(I)
Block 2: Next 20,000 therms	$0.08508	$0.00203	$1.00043	$(0.02459)	**$1.06295**	
Block 3: Next 20,000 therms	$0.06007	$0.00144	$1.00043	$(0.02461)	**$1.03733**	
Block 4: Next 100,000 therms	$0.03504	$0.00084	$1.00043	$(0.02462)	**$1.01169**	
Block 5: Next 600,000 therms	$0.02003	$0.00048	$1.00043	$(0.02463)	**$0.99631**	
Block 6: All additional therms	$0.01003	$0.00024	$1.00043	$(0.02464)	**$0.98606**	
32 ISF Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.10011	$0.00246	$1.00043	$(0.02449)	**$1.07851**	
Block 2: Next 20,000 therms	$0.08508	$0.00209	$1.00043	$(0.02450)	**$1.06310**	
Block 3: Next 20,000 therms	$0.06007	$0.00148	$1.00043	$(0.02452)	**$1.03746**	
Block 4: Next 100,000 therms	$0.03504	$0.00085	$1.00043	$(0.02453)	**$1.01179**	
Block 5: Next 600,000 therms	$0.02003	$0.00050	$1.00043	$(0.02454)	**$0.99642**	
Block 6: All additional therms	$0.01003	$0.00025	$1.00043	$(0.02455)	**$0.98616**	(I)
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):					**$0.12083**	(R)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.80**	(R)
INTERRUPTIBLE SALES SERVICE CHARGES [4]:						
Customer Charge (per month):					**$675.00**	
32 ISI Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.10010	$0.00204	$1.00043	$(0.00430)	**$1.09827**	(I)
Block 2: Next 20,000 therms	$0.08508	$0.00174	$1.00043	$(0.00430)	**$1.08295**	
Block 3: Next 20,000 therms	$0.06007	$0.00122	$1.00043	$(0.00432)	**$1.05740**	
Block 4: Next 100,000 therms	$0.03504	$0.00072	$1.00043	$(0.00433)	**$1.03186**	
Block 5: Next 600,000 therms	$0.02003	$0.00041	$1.00043	$(0.00434)	**$1.01653**	
Block 6: All additional therms	$0.01003	$0.00020	$1.00043	$(0.00435)	**$1.00631**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.01438**	(R)

[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)

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

MONTHLY RATES: Effective: November 1, 2008 (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	$0.10010	$0.00194		$0.00014	**$0.10218**	(I)
Block 2: Next 20,000 therms	$0.08508	$0.00166		$0.00013	**$0.08687**	
Block 3: Next 20,000 therms	$0.06007	$0.00116		$0.00012	**$0.06135**	
Block 4: Next 100,000 therms	$0.03504	$0.00067		$0.00011	**$0.03582**	
Block 5: Next 600,000 therms	$0.02003	$0.00039		$0.00010	**$0.02052**	
Block 6: All additional therms	$0.01003	$0.00019		$0.00009	**$0.01031**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.01438**	
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	$0.10010	$0.00183		$0.00014	**$0.10207**	(I)
Block 2: Next 20,000 therms	$0.08507	$0.00156		$0.00012	**$0.08675**	
Block 3: Next 20,000 therms	$0.06007	$0.00111		$0.00012	**$0.06130**	
Block 4: Next 100,000 therms	$0.03504	$0.00065		$0.00011	**$0.03580**	
Block 5: Next 600,000 therms	$0.02003	$0.00037		$0.00010	**$0.02050**	(I)
Block 6: All additional therms	$0.01003	$0.00019		$0.00009	**$0.01031**	

[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, 2008 (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:		$0.00542	$0.00012	$0.00000	**$0.00554**	(I)
Firm Service Distribution Capacity Charge: Per therm of MDDV per month					**$0.15748**	
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus Firm Service Distribution Capacity Charge , plus any other charges that may apply from **SCHEDULE C** and **SCHEDULE 15**.						

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (33 TI)						
					Billing Rates	
Customer Charge:					**$38,000.00**	
Transportation Charge:					**$250.00**	
Volumetric Charge:		Base Rate	Base Rate Adjustments	Total Temporary Adjustment [1]		
Per therm, all therms:		$0.00542	$0.00012	$0.00000	**$0.00554**	(I)
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus any other charges that may apply from **SCHEDULE C** and **SCHEDULE 15**.						

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

RATE SCHEDULE 54
EMERGENCY SALES SERVICE

AVAILABLE:
To Non-Residential Customers, in all territory served by the Company under the Tariff of which this Rate Schedule is a part, on a best efforts basis at times and in amounts determined in Company's sole judgment.

SERVICE DESCRIPTION:
Service under this Rate Schedule is for emergency purposes only. Customer must make a showing acceptable to Company that Customer's operations could not continue or that severe damage to Customer's facilities or the occupants of Customer's facilities would occur in the absence of service by Company under this schedule. Customer shall be obligated to exercise every reasonable effort to obtain and utilize an alternate supply of fuel to minimize the period that emergency service is required.

Gas supplied under this Rate Schedule will be limited to the maximum volume limits imposed on Customer by Company on an hourly or daily basis, or both, and/or as a total over the estimated period of Customer's emergency. These limits may be established by Company in verbal or written instructions given to any authorized representative of Customer. Gas taken under this Rate Schedule will not be applied to the minimum monthly bill requirements under Customer's primary Rate Schedule.

Any gas taken in excess of that permitted shall be unauthorized, subject to charges set forth in **SCHEDULE C**. (T)

MONTHLY RATE: Effective: November 1, 2008

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	Temporary Adjustment	Billing Rate
Usage Charge, per therm, all therms	$1.54570	$(0.02443)	**$1.52127**

(I)

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.

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, 2008 (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		$(0.00085)	$(0.02290)	$0.00477	**$(0.01898)**	(C)
1C		$(0.00085)	$(0.02290)	$(0.01620)	**$(0.03995)**	
2		$(0.00085)	$(0.02290)	$0.00465	**$(0.01910)**	
3 (CSF)		$(0.00085)	$(0.02290)	$(0.01628)	**$(0.04003)**	
3 (ISF)		$(0.00085)	$(0.02290)	$0.00024	**$(0.02351)**	
19		$(0.02)	$(0.44)	$0.00	**$(0.46)**	
31 (CSF)	Block 1	$(0.00085)	$(0.02290)	$(0.01633)	**$(0.04008)**	
	Block 2	$(0.00085)	$(0.02290)	$(0.01634)	**$(0.04009)**	
31(CTF)	Block 1	N/A	N/A	$(0.01637)	**$(0.01637)**	
	Block 2	N/A	N/A	$(0.01638)	**$(0.01638)**	
31 (CSI)	Block 1	$(0.00085)	$(0.00268)	$(0.01638)	**$(0.01991)**	
	Block 2	$(0.00085)	$(0.00268)	$(0.01639)	**$(0.01992)**	
31 (ISF)	Block 1	$(0.00085)	$(0.02290)	$0.00020	**$(0.02355)**	
	Block 2	$(0.00085)	$(0.02290)	$0.00019	**$(0.02356)**	
31 (ITF)	Block 1	N/A	N/A	$0.00017	**$0.00017**	
	Block 2	N/A	N/A	$0.00017	**$0.00017**	
31 (ISI)	Block 1	$(0.00085)	$(0.00268)	$0.00022	**$(0.00331)**	
	Block 2	$(0.00085)	$(0.00268)	$0.00020	**$(0.00333)**	(C)

(continue to Sheet 162-2)

Issued August 29, 2008 Effective with service on
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SCHEDULE 162
TEMPORARY (TECHNICAL) ADJUSTMENTS TO RATES
(continued)

APPLICATION TO RATE SCHEDULES (continued): Effective: November 1, 2008 (T)

Schedule	Block	Account 191 Commodity Adjustment	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments	Total Temporary Adjustment	
32(CSF)	Block 1	$(0.00085)	$(0.02290)	$0.00008	**$(0.02367)**	(C)
	Block 2	$(0.00085)	$(0.02290)	$0.00007	**$(0.02368)**	
	Block 3	$(0.00085)	$(0.02290)	$0.00005	**$(0.02370)**	
	Block 4	$(0.00085)	$(0.02290)	$0.00004	**$(0.02371)**	
	Block 5	$(0.00085)	$(0.02290)	$0.00003	**$(0.02372)**	
	Block 6	$(0.00085)	$(0.02290)	$0.00002	**$(0.02373)**	
32(ISF)	Block 1	$(0.00085)	$(0.02290)	$0.00017	**$(0.02358)**	
	Block 2	$(0.00085)	$(0.02290)	$0.00016	**$(0.02359)**	
	Block 3	$(0.00085)	$(0.02290)	$0.00014	**$(0.02361)**	
	Block 4	$(0.00085)	$(0.02290)	$0.00013	**$(0.02362)**	
	Block 5	$(0.00085)	$(0.02290)	$0.00012	**$(0.02363)**	
	Block 6	$(0.00085)	$(0.02290)	$0.00011	**$(0.02364)**	
32(SI)	Block 1	$(0.00085)	$(0.00268)	$0.00014	**$(0.00339)**	
	Block 2	$(0.00085)	$(0.00268)	$0.00014	**$(0.00339)**	
	Block 3	$(0.00085)	$(0.00268)	$0.00012	**$(0.00341)**	
	Block 4	$(0.00085)	$(0.00268)	$0.00011	**$(0.00342)**	
	Block 5	$(0.00085)	$(0.00268)	$0.00010	**$(0.00343)**	
	Block 6	$(0.00085)	$(0.00268)	$0.00009	**$(0.00344)**	
32(TI)	Block 1	N/A	N/A	$0.00014	**$0.00014**	
	Block 2	N/A	N/A	$0.00012	**$0.00012**	
	Block 3	N/A	N/A	$0.00012	**$0.00012**	
	Block 4	N/A	N/A	$0.00011	**$0.00011**	
	Block 5	N/A	N/A	$0.00010	**$0.00010**	
	Block 6	N/A	N/A	$0.00009	**$0.00009**	
33(TI)		N/A	N/A	$0.00000	**$0.00000**	
33(TF)		N/A	N/A	$0.00000	**$0.00000**	(C)
54		$(0.00085)	$(0.02290)	$0.00023	**$(0.02352)**	

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, 2008** (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: $0.01872 per therm (C)
Commercial Rate Schedules: $0.01094 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.

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, 2008 (T)

Annual Sales WACOG [1]	$1.00043	(I)
Winter Sales WACOG [2]	$1.08654	(I)
Firm Sales Service Pipeline Capacity Component [3]	$0.12083	(R)
Firm Sales Service Pipeline Capacity Component [4]	$1.80	(R)
Interruptible Sales Service Pipeline Capacity Component [5]	$0.01438	(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, 2008 (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 29, 2008 Effective with service on
NWN Advice No. OPUC 08-5 and after November 1, 2008

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	Schedule 54
Schedule 2	Schedule 19	Schedule 32	

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2008 (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.

(C)

Schedule	Block	Account 191 Commodity Adjustment		Schedule	Block	Account 191 Commodity Adjustment
1R		$(0.00091)		32(CSF/ISF)	Block 1	$(0.00091)
1C		$(0.00091)			Block 2	$(0.00091)
2		$(0.00091)			Block 3	$(0.00091)
3 (CSF)		$(0.00091)			Block 4	$(0.00091)
					Block 5	$(0.00091)
3 (ISF)		$(0.00091)			Block 6	$(0.00091)
				32(TF)	Block 1	N/A
19		$(0.02)			Block 2	N/A
31 (CSF)	Block 1	$(0.00091)			Block 3	N/A
	Block 2	$(0.00091)			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	$(0.00091)		32(SI)	Block 1	$(0.00091)
	Block 2	$(0.00091)			Block 2	$(0.00091)
31 (ISF)	Block 1	$(0.00091)			Block 3	$(0.00091)
	Block 2	$(0.00091)			Block 4	$(0.00091)
31 (ITF)	Block 1	N/A			Block 5	$(0.00091)
	Block 2	N/A			Block 6	$(0.00091)
31 (ISI)	Block 1	$(0.00091)		32(TI)	Block 1	N/A
	Block 2	$(0.00091)			Block 2	N/A
					Block 3	N/A
					Block 4	N/A
					Block 5	N/A
					Block 6	N/A
				33(TI)		N/A
				33(TF)		N/A
				54		$(0.00091)

(C)

SCHEDULE 177
ADJUSTMENTS TO RATES FOR SAFETY PROGRAM
(continued)

BARE STEEL REPLACEMENT PROGRAM (continued)

APPLICATION TO RATE SCHEDULES: **Effective: November 1, 2008** (T)
The Adjustments shown below are included in the Base Adjustments in the listed Rate Schedules:

Schedule	Block	70%	30%	Total Adjustment
1R		$0.00302	$0.00214	$0.00516
1C		$0.00302	$0.00153	$0.00455
2		$0.00302	$0.00138	$0.00440
3 (CSF)		$0.00302	$0.00098	$0.00328
3 (ISF)		$0.00302	$0.00082	$0.00384
19		$0.06	$0.00	$0.06
31 (CSF)	Block 1	$0.00302	$0.00069	$0.00371
	Block 2	$0.00302	$0.00063	$0.00365
31(CTF)	Block 1	$0.00302	$0.00058	$0.00360
	Block 2	$0.00302	$0.00053	$0.00355
31 (CSI)	Block 1	$0.00302	$0.00048	$0.00350
	Block 2	$0.00302	$0.00043	$0.00345
31 (ISF)	Block 1	$0.00000	$0.00056	$0.00056
	Block 2	$0.00000	$0.00050	$0.00050
31 (IFT)	Block 1	$0.00000	$0.00054	$0.00054
	Block 2	$0.00000	$0.00049	$0.00049
31 (ISI)	Block 1	$0.00000	$0.00078	$0.00078
	Block 2	$0.00000	$0.00070	$0.00070
32 (CSF)	Block 1	$0.00000	$0.00037	$0.00037
	Block 2	$0.00000	$0.00031	$0.00031
	Block 3	$0.00000	$0.00022	$0.00022
	Block 4	$0.00000	$0.00013	$0.00013
	Block 5	$0.00000	$0.00007	$0.00007
	Block 6	$0.00000	$0.00004	$0.00004
32 (ISF)	Block 1	$0.00000	$0.00038	$0.00038
	Block 2	$0.00000	$0.00032	$0.00032
	Block 3	$0.00000	$0.00023	$0.00023
	Block 4	$0.00000	$0.00013	$0.00013
	Block 5	$0.00000	$0.00008	$0.00008
	Block 6	$0.00000	$0.00004	$0.00004
32 (TF)	Block 1	$0.00000	$0.00030	$0.00030
	Block 2	$0.00000	$0.00025	$0.00025
	Block 3	$0.00000	$0.00018	$0.00018
	Block 4	$0.00000	$0.00010	$0.00010
	Block 5	$0.00000	$0.00006	$0.00006
	Block 6	$0.00000	$0.00003	$0.00003

(C)

(C)

(continue to Sheet 177-2.1)

Issued August 29, 2008 Effective with service on
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SCHEDULE 177
ADJUSTMENTS TO RATES FOR SAFETY PROGRAM
(continued)

BARE STEEL REPLACEMENT PROGRAM (continued)

Schedule	**Block**	**70%**	**30%**	**Total Adjustment**
32 (SI)	Block 1	$0.00000	$0.00031	$0.00031
	Block 2	$0.00000	$0.00027	$0.00027
	Block 3	$0.00000	$0.00019	$0.00019
	Block 4	$0.00000	$0.00011	$0.00011
	Block 5	$0.00000	$0.00006	$0.00006
	Block 6	$0.00000	$0.00003	$0.00003
32 (TI)	Block 1	$0.00000	$0.00028	$0.00028
	Block 2	$0.00000	$0.00024	$0.00024
	Block 3	$0.00000	$0.00017	$0.00017
	Block 4	$0.00000	$0.00010	$0.00010
	Block 5	$0.00000	$0.00006	$0.00006
	Block 6	$0.00000	$0.00003	$0.00003
33 (all)		$0.00000	$0.00002	$0.00002
54		$0.00302	$0.00130	$0.00432

(C)

(C)

(continue to Sheet 177-3)

Issued August 29, 2008
NWN Advice No. OPUC 08-5

Effective with service on
and after November 1, 2008

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

SCHEDULE 177
ADJUSTMENTS TO RATES FOR SAFETY PROGRAM
(continued)

GEOHAZARD REPAIR AND RISK MITIGATION:
Each year, rates in the Rate Schedules listed below will be adjusted to recover the costs of geohazard repair and risk mitigation during the most recent 12-month period November 1 through October 31. Adjustments to rates shall be made coincident with the Company's annual Purchased Gas Adjustment (PGA) filing, or at such other time as the Commission may authorize.

TERM:
The Geohazard Repair and Risk Mitigation Program shall be in effect through December 31, 2007 or until such other time as the Commission may approve. (C)

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2008
The Adjustments shown below are included in the Base Rate Adjustments in the above-listed Rate Schedules. (T)

Schedule	Block	Total Adjustment
1R		$0.00275
1C		$0.00197
2		$0.00178
3 (CSF)		$0.00126
3 (ISF)		$0.00106
19		$0.00
31 (CSF)	Block 1	$0.00089
	Block 2	$0.00081
31 (CTF)	Block 1	$0.00075
	Block 2	$0.00068
31 (CSI)	Block 1	$0.00061
	Block 2	$0.00056
31 (ISF)	Block 1	$0.00072
	Block 2	$0.00065
31 (ITF)	Block 1	$0.00069
	Block 2	$0.00063
31 (ISI)	Block 1	$0.00100
	Block 2	$0.00091
32 (CSF)	Block 1	$0.00047
	Block 2	$0.00040
	Block 3	$0.00028
	Block 4	$0.00017
	Block 5	$0.00009
	Block 6	$0.00005

(C)
(C)

(continue to Sheet 177-3.1)

Issued August 29, 2008 Effective with service on
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SCHEDULE 177
ADJUSTMENTS TO RATES FOR SAFETY PROGRAM
(continued)

Schedule	Block	Total Adjustment
32 (ISF)	Block 1	$0.00048
	Block 2	$0.00041
	Block 3	$0.00029
	Block 4	$0.00017
	Block 5	$0.00010
	Block 6	$0.00005
32 (TF)	Block 1	$0.00038
	Block 2	$0.00033
	Block 3	$0.00023
	Block 4	$0.00013
	Block 5	$0.00008
	Block 6	$0.00004
32 (SI)	Block 1	$0.00040
	Block 2	$0.00034
	Block 3	$0.00024
	Block 4	$0.00014
	Block 5	$0.00008
	Block 6	$0.00004
32 (TI)	Block 1	$0.00036
	Block 2	$0.00031
	Block 3	$0.00022
	Block 4	$0.00013
	Block 5	$0.00007
	Block 6	$0.00004
33 (all)		$0.00002
54		$0.00167

(C)

(C)

(continue to Sheet 177-4)

Issued August 29, 2008
NWN Advice No. OPUC 08-5

Effective with service on
and after November 1, 2008

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

SCHEDULE 177
ADJUSTMENTS TO RATES FOR SAFETY PROGRAM
(continued)

INTEGRITY MANAGEMENT PROGRAM (IMP):
Each year, the costs of the Integrity Management Program during the most recent 12-month period November 1 through October 31, will be allocated to the Rate Schedules listed below on an equal percentage of margin basis, and within a Rate Schedule, spread on a declining block basis. Adjustments to rates shall be made coincident with the Company's annual Purchased Gas Adjustment (PGA) filing, or at such other time as the Commission may authorize.

TERM:
The IMP adjustments shall be in effect through September 30, 2008 or until such other time as the Commission may approve.

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2008 (T)
The Adjustments shown below are included in the Base Rate Adjustments in the above-listed Rate Schedules.

Schedule	Block	Total Adjustment
1R		$0.00948
1C		$0.00678
2		$0.00613
3 (CSF)		$0.00435
3 (ISF)		$0.00366
19		$0.00
31 (CSF)	Block 1	$0.00306
	Block 2	$0.00279
31 (CTF)	Block 1	$0.00257
	Block 2	$0.00234
31 (CSI)	Block 1	$0.00211
	Block 2	$0.00192
31 (ISF)	Block 1	$0.00247
	Block 2	$0.00223
31 (ITF)	Block 1	$0.00239
	Block 2	$0.00216
31 (ISI)	Block 1	$0.00346
	Block 2	$0.00312
32 (CSF)	Block 1	$0.00162
	Block 2	$0.00138
	Block 3	$0.00098
	Block 4	$0.00057
	Block 5	$0.00033
	Block 6	$0.00016

(C)
(T)
(T)
(C)

(continue to Sheet 177-4.1)

SCHEDULE 177
ADJUSTMENTS TO RATES FOR SAFETY PROGRAM
(continued)

INTEGRITY MANAGEMENT PROGRAM (IMP): (continued)

Schedule	Block	Total Adjustment
32 (ISF)	Block 1	$0.00167
	Block 2	$0.00142
	Block 3	$0.00100
	Block 4	$0.00058
	Block 5	$0.00033
	Block 6	$0.00017
32 (TF)	Block 1	$0.00132
	Block 2	$0.00113
	Block 3	$0.00079
	Block 4	$0.00046
	Block 5	$0.00026
	Block 6	$0.00013
32 (SI)	Block 1	$0.00139
	Block 2	$0.00118
	Block 3	$0.00083
	Block 4	$0.00049
	Block 5	$0.00028
	Block 6	$0.00014
32 (TI)	Block 1	$0.00125
	Block 2	$0.00106
	Block 3	$0.00075
	Block 4	$0.00044
	Block 5	$0.00025
	Block 6	$0.00013
33 (all)		$0.00008
54		$0.00576

(C)

(C)

Issued August 29, 2008 Effective with service on
NWN Advice No. OPUC 08-5 and after November 1, 2008

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

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)

(D)

ADJUSTMENT TO RATE SCHEDULES: **Effective: November 1, 2008**
The Temporary Adjustments for Residential and Commercial Customers taking service on the above-listed Rate Schedules includes the following adjustment: (T)

Residential Rate Schedules: **$ 0.00427** per therm
Commercial Rate Schedules: **$(0.01646)** per therm (C)
(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, 2008 is $0.44341 per therm for Residential customers and $0.30331 per therm for Commercial customers. (T)(C)

(continue to Sheet 190-3)

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

SPECIAL CONDITIONS: (continued)

10. Upon request, the Company will provide Customer with historical billing information under both the opt-in and opt-out option for any month during the WARM Period.

11. The WARM Program is subject to other terms and conditions as set forth in the Partial Stipulation and in the Second Stipulation on record in Docket UG 152.

WARM FORMULA:

1. The Formula is: WARM Adjustment = $\sum_{1}^{T}(HDD_{n,t} - HDD_{a,t}) * B * Mrgn$

   Where:

   T = the days covered by the meter read dates for an individual customer's bill
   HDDn = the 25 year average of heating degree-days for each day (1976-2000) determined using a 25-year average temperature published by the National Oceanic and Atmospheric Administration (NOAA).
   HDDa = the actual heating degree-days for each day based on the individual customer's actual beginning and ending meter read dates
   B = the statistical coefficient relating heating degree-days to therm use determined in the most recent general rate case, or other Commission authorized proceeding.
   Mrgn = the relevant Rate Schedule margin defined as the current Billing Rate less the current Commodity Rate, Pipeline Capacity Charge, and any Temporary Adjustments.

2. For purposes of calculating the WARM Adjustment, the following shall apply:

   a. A Heating Degree Day (HDD) is defined as the extent by which the daily mean temperature falls below a specified set point on a specified day. The HDD calculation uses a set point temperature of 59 degrees Fahrenheit for the **RATE SCHEDULE 2** calculation, and 58 degrees Fahrenheit for the **RATE SCHEDULE 3** calculation;

   b. 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 December 1, 2008 are: (T)

Schedule 2: $0.46198	Schedule 3: $0.36529

(R)

(continue to Sheet 195-4)

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

WARM FORMULA: (continued)

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	$0.09		.7669	$ 0.28	(C)
5	.9790	$0.45		3.8345	$ 1.40	
10	1.958	$0.90		7.669	$ 2.80	
15	2.937	$1.36		11.5035	$ 4.20	
20	3.916	$1.81		15.338	$ 5.60	
25	4.895	$2.26		19.1725	$ 7.00	
30	5.874	$2.71		23.007	$ 8.40	
35	6.853	$3.17		26.8415	$ 9.80	
40	7.832	$3.62		30.676	$11.21	
45	8.811	$4.07		34.5105	$12.61	
50	9.790	$4.52		38.345	$14.01	(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 base billing rate is $1.22449 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:	$0.46198	
	Total WARM Adj.:	-9.79 x $0.46198 = -$4.52278	(R)
Total WARM Adjustment converted to cents per therm:	Total WARM Adj.	-$4.52278	(R)
	Monthly usage:	129 therms	
	Cent/therm Adj.:	-$4.52278 ÷ 129 = -$0.03506	(R)
Billing Rate per therm:	Current Rate/therm:	$1.56323	(R)
	WARM cent/therm Adj.	-$0.03506	(R)
	WARM Billing Rate:	$1.56323 + -$0.03506 = $1.52817	(R)
Total WARM Bill:	Customer Charge:	$6.00	
	Usage Charge:	$1.52817	(R)
	Total	(129 x $1.52817) + $6.00 = $203.13	(R)

(continue to Sheet 195-6)

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 used for purposes of calculating the monthly gas cost deferral costs for entry into the Account 191 sub-accounts calculated by the following formula: (Normalized Purchases at Adjusted Contract Prices) divided by (last year's (i.e., July 1 – June 30) actual sales volumes, weather-normalized).
   a. "Normalized Purchases" means last year's (July 1 – June 30) actual sales volumes, "weather-normalized", plus a percentage for distribution system LUFG.
   b. "Weather-normalized" means normalizing assumptions and methods set at the utility's last rate case.
   c. "Distribution system embedded LUFG" means the 5-year average of actual distribution system LUFG, not to exceed 2%.
   d. "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, 2008: (T)
   Estimated Annual Sales WACOG per therm (w/ revenue sensitive): **$1.00043** (I)
   Estimated Annual Sales WACOG per therm (w/o revenue sensitive): **$0.97155** (I)

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, 2008: (T)
   Estimated Winter Sales WACOG per therm (w/ revenue sensitive): **$1.08654** (I)
   Estimated Winter Sales WACOG per therm (w/o revenue sensitive): **$1.05517** (I)

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 last year's (i.e., July 1 – June 30) actual Firm Sales Service volumes, weather normalized.
   Effective November 1, 2008: (T)
   Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive): **$0.12083** (R)
   Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive: **$0.11734** (R)

(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 last year's (i.e., July 1 – June 30) actual Interruptible Sales Service volumes.
    Effective November 1, 2008: (T)
    Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):
    $0.01438 (R)
    Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive): (R)
    $0.01396

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, 2008: (T)
    Estimated Non-Commodity Cost per therm - MDDV Based Sales (w/revenue sensitive):
    $1.80 (R)
    Estimated Non-Commodity Cost per therm- MDDV Based Sales (w/o revenue sensitive): (R)
    $1.75

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)

<u>CALCULATION OF MONTHLY GAS COSTS FOR DEFERRAL PURPOSES (continued)</u>:

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, 2008 through November 30, 2009 are: (T)

November 2008	$8,469,845	(R)
December 2008	$11,639,785	(R)
January 2009	$11,456,425	(R)
February	$9,539,265	(R)
March	$8,306,343	(R)
April	$6,032,131	(R)
May	$4,111,401	(R)
June	$2,783,618	(I)
July	$2,327,295	(R)
August	$2,352,433	(R)
September	$2,634,257	(I)
October	$5,142,612	(I)
November	<u>$8,373,598</u>	(R)
ANNUAL TOTAL	$74,699,163	(R)

3. A debit or credit entry shall be made equal to 67% 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.

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)

Exhibit: A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG ___

NW Natural

SUPPORTING MATERIALS

Purchased Gas Cost and Technical Adjustments to Rates

NWN Advice No. OPUC 08-5

August 29, 2008

Exhibit A
Supporting Materials

NWN Advice No. OPUC 08-5

Gas Purchasing Strategy, Contract Summaries and Gas Cost Forecast:

NW Natural

SUMMARY OF NW NATURAL'S GAS PURCHASING STRATEGY

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 requirements fail to materialize such as during a warm winter.

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[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 service territory has offered a significant cost advantage because it avoids the need to subscribe to upstream pipeline capacity that would be under-utilized much of the year. Future storage developments will depend of course on the cost to develop new reservoirs and associated infrastructure.

NWN has contracted with suppliers for approximately 1.2 million therms per day of firm deliveries on a daily basis over the upcoming November 2008 through October 2009 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 is nearly the same as that contracted for the Nov06-Oct07 and Nov07-Oct08 periods, reflecting relatively flat demand. In essence, the load associated with new customer additions has been offset by overall declining use per customer.

In addition, during the heating season Nov08-Mar09, NWN has contracted for another 1.0 million therms/day of supply under baseload and peaking (swing) agreements, reflecting the higher consumption of customers during those months. This is about the same as the volumes contracted for the Nov07-Mar08 period, which was significantly higher than the prior Nov06-Mar07 period. The increase in winter contract volumes since 2006/07 takes into account pipeline projects in the Rockies, most notably phase 2 of Rockies Express, which increased the outlets for Rockies gas. Buying more under term contracts lessens the need to rely extensively on spot market during periods of high demand when competition with mid-continent markets may be intense. Most of the winter contracted volume (600,000 therms/day) is purchased on a take-or-pay basis. The remaining 400,000 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 1.1 and 1.5 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.

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. This target is set by an executive level oversight committee within the company and could change from time-to-time in reaction to market conditions or other factors as the year progresses.

For example, a topic of frequent discussion of late has been the resurgence of domestic natural gas production. Once thought to have peaked and be inexorably in decline, domestic gas production has increased roughly 7% over the previous year and led some to say that the U.S. will be "awash" with gas supplies in the near future. These predictions center on the rapid emergence of non-conventional gas production from tight sands and shale gas. While much more expensive than conventional gas production, the recent regime of higher prices has spurred development of this resource, which in turn has fostered technological innovations that have and will continue to bring more resources on line than previously thought technically and/or economically feasible.

As with the rest of the industry, NW Natural is monitoring these developments with great interest. While the potential for higher gas production rates seems undeniable, the higher cost of these new ventures may not lead to a downward movement of gas prices. Or stated differently, 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. For these reasons, the company is trying not to over-react to the potential for a world awash with gas, but will adjust its gas buying patterns and hedging targets if and when appropriate.

Table 1

NW Natural
Firm Off-System Gas Supply Contracts
for the 2008/2009 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		10/31/2009
Coral Energy Canada	Nov-Oct	10,000		10/31/2010
Husky Energy Marketing	Nov-Oct	5,000		10/31/2009
Husky Energy Marketing	Nov-Oct	5,000		10/31/2009
Alta Energy Marketing	Nov-Oct	5,000		10/31/2010
Nexen	Nov-Oct	10,000		10/31/2009
Nexen	Nov-Oct	10,000		10/31/2010
TD Commodities	Nov-Oct	5,000		10/31/2009
Alberta:				
BP Canada	Nov-Oct	10,000		10/31/2009
BP Canada	Nov-Oct	10,000		10/31/2009
Suncor	Nov-Mar	10,000		3/31/2009
Husky Energy Marketing	Nov-Mar	10,000		3/31/2009
Sequent	Nov-Mar	10,000		3/31/2009
Sempra Energy Trading	Nov-Oct	10,000		10/31/2014
Sequent	Nov-Mar		10,000	3/31/2009
Rockies:				
Sempra Energy Trading	Nov-Oct	5,000		10/31/2009
BP Energy	Nov-Oct	10,000		10/31/2011
BP Energy	Nov-Mar		10,000	3/31/2009
Coral Energy Resources	Nov-Mar		10,000	3/31/2009
BP Energy	Nov-Mar	5,000		3/31/2009
ONEOK Energy Services	Nov-Mar		10,000	3/31/2009
Iberdrola	Nov-Oct	10,000		10/31/2009
Sempra Energy Trading	Nov-Mar	10,000		3/31/2009
Sempra Energy Trading	Nov-Mar	5,000		3/31/2009
Questar	Nov-Mar	5,000		3/31/2009
Western Gas Resources	Nov-Mar	10,000		3/31/2009
Western Gas Resources	Nov-Oct	5,000		10/31/2010
Total Off-System Firm Contract Supply		180,000	40,000	

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.

Table 2

NW Natural
Firm Transportation Capacity
for the 2008/2009 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion	216,044	9/30/2013
1993 Expansion	34,000	9/30/2008
1995 Expansion	102,000	11/30/2011
Duke Capacity Acquisition	5,000	3/31/2008
Weyerhauser Capacity Acquisition	5,200	6/30/2008
Total NWP Capacity	362,244	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2010
Net NWP Capacity	332,244	
TransCanada's GTN System:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2005
Total GTN Capacity	106,165	
TransCanada's BC System:		
1993 Expansion	47,000	10/31/2008
1995 Rationalization	56,500	10/31/2005
Engage Capacity Acquisition	3,814	10/31/2008
2004 Capacity Acquisition	48,200	10/31/2016
Total TCPL-BC Capacity	155,514	
TransCanada's Alberta System:		
1993 Expansion	47,595	10/31/2008
1995 Rationalization	57,000	10/31/2001
Engage Capacity Acquisition	3,861	10/31/2008
2004 Capacity Acquisition	48,910	10/31/2016
Total TCPL-ALberta Capacity	157,366	
WEI T-South Capacity	60,000	10/31/2014
Southern Crossing Pipeline	47,200	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 and Weyerhaeuser, which require mutual agreement to continue. *The Weyerhauser Capacity Acquisition will end on June 30, 2009, per notice from Weyerhaeuser.*
2. The TCPL-Alberta, 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 2008/2009 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	10/31/2004
TF-2 (redelivery service)	32,624	839,046	10/31/2004
TF-2 (redelivery service)	13,406	281,242	3/31/2008
Plymouth LNG:			
LS-1	60,100	478,900	10/31/2004
TF-2 (redelivery service)	60,100	478,900	10/31/2004
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)	240,000	9,197,000	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	420,000	10,797,000	
Total Firm Storage Resource	526,130	12,396,188	

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 2008/2009 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	≈1,200	n/a	4/1/2005

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. An extension of the current contract is currently being negotiated to allow the addition of new wells.

Table 5

NW Natural
Firm Resource Summary
for the 2008/2009 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	332,244
Off-System Storage (Jackson Prairie and Plymouth)	106,130
On-System Storage (Mist, Portland LNG and Newport LNG)	420,000
Recallable Capacity and Supply Agreements	38,000
Citygate Deliveries	-
Nominal Mist Production Gas	1,200
Total Firm Resource	897,574

Exhibit: B

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW Natural

SUPPORTING MATERIALS

TO

COMBINED EFFECTS,
COMMODITY AND NON-COMMODITY COSTS, AND
TEMPORARY AND PERMANENT ADJUSTMENTS EFFECTS

Purchased Gas Cost and Technical Adjustments to Rates

NWN Advice No. OPUC 08-5

August 29, 2008

Exhibit B
Supporting Materials

NWN Advice No. OPUC 08-5

Combined Effects:

Commodity and Non-Commodity Costs:

Temporary and Permanent Adjustments Effects:

August 29, 2008

NW Natural
Rates & Regulatory Affairs
2008-2009 PGA Filing - Oregon
Calculation of Proposed Rates - SUMMARY

Schedule	Block	11/1/2007 Billing Rates A	Net change WACOG B	Net change Demand [1] C	Proposed Rates PGA Only [1] D=A+B+C D	Net change Permanent Increments E	Net change Temporary Increments F	Elasticity Adjustment G	Storage Recall Adjustment H	**Proposed 11/1/2007 Rates [1]** **I=D+E+F+G+H** **I**
1R		1.29228	0.29238	(0.00051)	1.58415	0.00747	0.02531	0.01872	0.00021	1.63586
1C		1.25248	0.29238	(0.00051)	1.54435	0.00388	0.02045	0.01094	0.00015	1.57977
2R		1.22449	0.29238	(0.00051)	1.51636	0.00348	0.02453	0.01872	0.00014	1.56323
3C Firm Sales		1.12149	0.29238	(0.00051)	1.41336	0.00212	0.01909	0.01094	0.00010	1.44561
Intentionally blank										
3I Firm Sales		1.09951	0.29238	(0.00051)	1.39138	0.00156	0.02670	0.00000	0.00008	1.41972
Intentionally blank										
19	1st mantle	20.60	5.59	(0.01)	26.18	0.01	0.43	0.36	0.00	26.98
19	add'l mtls	19.99	5.59	(0.01)	25.57	0.01	0.43	0.36	0.00	26.37
31C Firm Sales	Block 1	0.83739	0.29238		1.12977	0.00250	0.01746	0.01094	0.00007	1.16074
	Block 2	0.82114	0.29238		1.11352	0.00233	0.01728	0.01094	0.00006	1.14413
31C Firm Trans	Block 1	0.17742	0.00000		0.17742	0.00178	(0.00600)	0.01094	0.00006	0.18420
	Block 2	0.16117	0.00000		0.16117	0.00167	(0.00618)	0.01094	0.00005	0.16765
31C Interr Sales	Block 1	0.83945	0.29238		1.13183	0.00110	0.03557	0.01094	0.00005	1.17949
	Block 2	0.82320	0.29238		1.11558	0.00105	0.03539	0.01094	0.00004	1.16300
31I Firm Sales	Block 1	0.82863	0.29238		1.12101	0.00130	0.02520	0.00000	0.00006	1.14757
	Block 2	0.81238	0.29238		1.10476	0.00117	0.02503	0.00000	0.00005	1.13101
31I Firm Trans	Block 1	0.16866	0.00000		0.16866	0.00118	0.00175	0.00000	0.00005	0.17164
	Block 2	0.15241	0.00000		0.15241	0.00108	0.00159	0.00000	0.00005	0.15513
31I Interr Sales	Block 1	0.83069	0.29238		1.12307	0.00275	0.04338	0.00000	0.00008	1.16928
	Block 2	0.81444	0.29238		1.10682	0.00248	0.04320	0.00000	0.00007	1.15257
32C Firm Sales	Block 1	0.76046	0.29238		1.05284	0.00100	0.02447	0.00000	0.00004	1.07835
	Block 2	0.74536	0.29238		1.03774	0.00085	0.02433	0.00000	0.00003	1.06295
	Block 3	0.72028	0.29238		1.01266	0.00060	0.02405	0.00000	0.00002	1.03733
	Block 4	0.69516	0.29238		0.98754	0.00035	0.02379	0.00000	0.00001	1.01169
	Block 5	0.68008	0.29238		0.97246	0.00020	0.02364	0.00000	0.00001	0.99631
	Block 6	0.67004	0.29238		0.96242	0.00011	0.02353	0.00000	0.00000	0.98606
32I Firm Sales	Block 1	0.76052	0.29238		1.05290	0.00107	0.02450	0.00000	0.00004	1.07851
	Block 2	0.74542	0.29238		1.03780	0.00091	0.02436	0.00000	0.00003	1.06310
	Block 3	0.72034	0.29238		1.01272	0.00064	0.02408	0.00000	0.00002	1.03746
	Block 4	0.69522	0.29238		0.98760	0.00036	0.02382	0.00000	0.00001	1.01179
	Block 5	0.68014	0.29238		0.97252	0.00022	0.02367	0.00000	0.00001	0.99642
	Block 6	0.67010	0.29238		0.96248	0.00012	0.02356	0.00000	0.00000	0.98616
32 Firm Trans	Block 1	0.10055	0.00000		0.10055	0.00055	0.00105	0.00000	0.00003	0.10218
	Block 2	0.08545	0.00000		0.08545	0.00048	0.00091	0.00000	0.00003	0.08687
	Block 3	0.06037	0.00000		0.06037	0.00032	0.00064	0.00000	0.00002	0.06135
	Block 4	0.03525	0.00000		0.03525	0.00018	0.00038	0.00000	0.00001	0.03582
	Block 5	0.02017	0.00000		0.02017	0.00011	0.00023	0.00000	0.00001	0.02052
	Block 6	0.01013	0.00000		0.01013	0.00006	0.00012	0.00000	0.00000	0.01031
32 Interr Sales	Block 1	0.76258	0.29238		1.05496	0.00065	0.04263	0.00000	0.00003	1.09827
	Block 2	0.74748	0.29238		1.03986	0.00056	0.04250	0.00000	0.00003	1.08295
	Block 3	0.72240	0.29238		1.01478	0.00038	0.04222	0.00000	0.00002	1.05740
	Block 4	0.69728	0.29238		0.98966	0.00023	0.04196	0.00000	0.00001	1.03186
	Block 5	0.68220	0.29238		0.97458	0.00013	0.04181	0.00000	0.00001	1.01653
	Block 6	0.67216	0.29238		0.96454	0.00007	0.04170	0.00000	0.00000	1.00631
32 Interr Trans	Block 1	0.10055	0.00000		0.10055	0.00044	0.00105	0.00000	0.00003	0.10207
	Block 2	0.08545	0.00000		0.08545	0.00038	0.00090	0.00000	0.00002	0.08675
	Block 3	0.06037	0.00000		0.06037	0.00027	0.00064	0.00000	0.00002	0.06130
	Block 4	0.03525	0.00000		0.03525	0.00016	0.00038	0.00000	0.00001	0.03580
	Block 5	0.02017	0.00000		0.02017	0.00009	0.00023	0.00000	0.00001	0.02050
	Block 6	0.01013	0.00000		0.01013	0.00006	0.00012	0.00000	0.00000	0.01031
54		1.19829	0.29238	(0.00051)	1.49016	0.00327	0.02771	0.00000	0.00013	1.52127
33		0.00545	0.00000	0.00000	0.00545	0.00004	0.00005	0.00000	0.00000	0.00554

Sources:

Direct Inputs	07-08 PGA								
Rates in detail		Col F - Col B	Column G+H-C-D		Col K - Col J	Col M - Col L	Column O	Column P	

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

NW Natural
Rates & Regulatory Affairs
2008-2009 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	11/1/2007 Billing Rates	11/1/2007 Current Average Bill	Proposed 11/1/2008 PGA Only Rates	Proposed 11/1/2008 PGA Only Average Bill	Proposed 11/1/2008 **PGA Only % Bill Change**	Proposed 11/1/2008 Temp & Base Rates	Proposed 11/1/2008 Temp & Base Average Bill	Proposed 11/1/2008 **Temp & Base % Bill Change**	Proposed 11/1/2008 Total **Rates**	Proposed 11/1/2008 Total Average Bill	Proposed 11/1/2008 **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			A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
7	1R		744,486	N/A	15.0	5.00	1.29228	24.38	1.58415	28.76	18.0%	1.34378	25.16	3.2%	1.63586	29.54	21.2%
8	1C		95,064	N/A	42.0	5.00	1.25248	57.60	1.54435	69.86	21.3%	1.28775	59.09	2.6%	1.57977	71.35	23.9%
9	2R		358,131,828	N/A	56.0	6.00	1.22449	74.57	1.51636	90.92	21.9%	1.27122	77.19	3.5%	1.56323	93.54	25.4%
10	3C Firm Sales		149,890,944	N/A	226.0	8.00	1.12149	261.46	1.41336	327.42	25.2%	1.15364	268.72	2.8%	1.44561	334.71	28.0%
11	Intentionally blank																
12	3I Firm Sales		4,902,436	N/A	1,800.0	8.00	1.09951	1,987.12	1.39138	2,512.48	26.4%	1.12777	2,037.99	2.6%	1.41972	2,563.50	29.0%
13	Intentionally blank																
14	19	1st mantle	22,996	N/A	87.0	22.04	20.60	20.60	26.18	26.18	27.1%	21.40	21.40	3.9%	26.98	26.98	31.0%
15	19	add'l mtls	0	N/A	0.0	21.43	19.99	19.99	25.57	25.57	27.9%	20.79	20.79	4.0%	26.37	26.37	31.9%
16	31C Firm Sales	Block 1	23,178,859	2,000	4,060.0	325.00	0.83739	1,999.78	1.12977	2,584.54		0.86829	2,061.58		1.16074	2,646.48	
17		Block 2	37,919,144	all additional			0.82114	1,691.55	1.11352	2,293.85		0.85169	1,754.48		1.14413	2,356.91	
18		**Total**						**3,691.33**		**4,878.39**	32.2%		**3,816.06**	3.4%		**5,003.39**	35.5%
19	31C Firm Trans	Block 1	0	2,000	0.0	325.00	0.17742	325.00	0.17742	325.00		0.18414	325.00		0.18420	325.00	
20		Block 2	0	all additional			0.16117		0.16117			0.16760			0.16765		
21		**Total**						**325.00**		**325.00**	0.0%		**325.00**	0.0%		**325.00**	0.0%
22	31C Interr Sales	Block 1	189,935	2,000	0.0	325.00	0.83945	325.00	1.13183	325.00		0.88706	325.00		1.17949	325.00	
23		Block 2	985,987	all additional			0.82320		1.11558			0.87058			1.16300		
24		**Total**						**325.00**		**325.00**	0.0%		**325.00**	0.0%		**325.00**	0.0%
25	31I Firm Sales	Block 1	5,793,021	2,000	7,001.0	325.00	0.82863	1,982.26	1.12101	2,567.02		0.85513	2,035.26		1.14757	2,620.14	
26		Block 2	17,814,335	all additional			0.81238	4,062.71	1.10476	5,524.90		0.83858	4,193.74		1.13101	5,656.18	
27		**Total**						**6,044.97**		**8,091.92**	33.9%		**6,229.00**	3.0%		**8,276.32**	36.9%
28	31I Firm Trans	Block 1	46,633	2,000	8,361.0	325.00	0.16866	662.32	0.16866	662.32		0.17159	668.18		0.17164	668.28	
29		Block 2	254,367	all additional			0.15241	969.48	0.15241	969.48		0.15508	986.46		0.15513	986.78	
30		**Total**						**1,631.80**		**1,631.80**	0.0%		**1,654.64**	1.4%		**1,655.06**	1.4%
31	31I Interr Sales	Block 1	116,648	2,000	2,557.0	325.00	0.83069	1,986.38	1.12307	2,571.14		0.87682	2,078.64		1.16928	2,663.56	
32		Block 2	466,320	all additional			0.81444	453.64	1.10682	616.50		0.86012	479.09		1.15257	641.98	
33		**Total**						**2,440.02**		**3,187.64**	30.6%		**2,557.73**	4.8%		**3,305.54**	35.5%
27	32C Firm Sales	Block 1	3,906,434	10,000	18,197.0	675.00	0.76046	8,279.60	1.05284	11,203.40		0.78593	8,534.30		1.07835	11,458.50	
28		Block 2	4,606,330	20,000			0.74536	6,109.72	1.03774	8,506.35		0.77054	6,316.12		1.06295	8,713.00	
29		Block 3	1,430,110	20,000			0.72028		1.01266			0.74493			1.03733		
30		Block 4	320,442	100,000			0.69516		0.98754			0.71930			1.01169		
31		Block 5	0	600,000			0.68008		0.97246			0.70392			0.99631		
32		Block 6	0	all additional			0.67004		0.96242			0.69368			0.98606		
33		**Total**						**14,389.32**		**19,709.75**	37.0%		**14,850.42**	3.2%		**20,171.50**	40.2%
34	32I Firm Sales	Block 1	4,904,828	10,000	18,515.0	675.00	0.76052	8,280.20	1.05290	11,204.00		0.78609	8,535.90		1.07851	11,460.10	
35		Block 2	7,247,986	20,000			0.74542	6,347.25	1.03780	8,836.87		0.77069	6,562.43		1.06310	9,052.30	
36		Block 3	2,912,606	20,000			0.72034		1.01272			0.74506			1.03746		
37		Block 4	2,667,092	100,000			0.69522		0.98760			0.71940			1.01179		
38		Block 5	41,641	600,000			0.68014		0.97252			0.70403			0.99642		
39		Block 6	0	all additional			0.67010		0.96248			0.69378			0.98616		
40		**Total**						**14,627.45**		**20,040.87**	37.0%		**15,098.33**	3.2%		**20,512.40**	40.2%
41	32 Firm Trans	Block 1	5,177,678	10,000	83,518.0	675.00	0.10055	1,680.50	0.10055	1,680.50		0.10215	1,696.50		0.10218	1,696.80	
42		Block 2	8,581,392	20,000			0.08545	1,709.00	0.08545	1,709.00		0.08684	1,736.80		0.08687	1,737.40	
43		Block 3	5,901,959	20,000			0.06037	1,207.40	0.06037	1,207.40		0.06133	1,226.60		0.06135	1,227.00	
44		Block 4	14,327,461	100,000			0.03525	1,181.51	0.03525	1,181.51		0.03581	1,200.28		0.03582	1,200.61	
45		Block 5	15,119,834	600,000			0.02017		0.02017			0.02051			0.02052		
46		Block 6	0	all additional			0.01013		0.01013			0.01031			0.01031		
47		**Total**						**5,778.41**		**5,778.41**	0.0%		**5,860.18**	1.4%		**5,861.81**	1.4%
48	32 Interr Sales	Block 1	16,095,200	10,000	47,221.0	675.00	0.76258	8,300.80	1.05496	11,224.60		0.80586	8,733.60		1.09827	11,657.70	
49		Block 2	23,224,715	20,000			0.74748	14,949.60	1.03986	20,797.20		0.79054	15,810.80		1.08295	21,659.00	
50		Block 3	12,986,104	20,000			0.72240	12,440.45	1.01478	17,475.53		0.76500	13,174.07		1.05740	18,209.49	
51		Block 4	21,582,692	100,000			0.69728		0.98966			0.73947			1.03186		
52		Block 5	8,842,003	600,000			0.68220		0.97458			0.72414			1.01653		
53		Block 6	0	all additional			0.67216		0.96454			0.71393			1.00631		
54		**Total**						**35,690.85**		**49,497.33**	38.7%		**37,718.47**	5.7%		**51,526.19**	44.4%
55	32 Interr Trans	Block 1	5,909,902	10,000	265,587.0	675.00	0.10055	1,680.50	0.10055	1,680.50		0.10204	1,695.40		0.10207	1,695.70	
56		Block 2	10,353,293	20,000			0.08545	1,709.00	0.08545	1,709.00		0.08673	1,734.60		0.08675	1,735.00	
57		Block 3	7,535,404	20,000			0.06037	1,207.40	0.06037	1,207.40		0.06128	1,225.60		0.06130	1,226.00	
58		Block 4	23,202,985	100,000			0.03525	3,525.00	0.03525	3,525.00		0.03579	3,579.00		0.03580	3,580.00	
59		Block 5	50,222,809	600,000			0.02017	2,331.39	0.02017	2,331.39		0.02049	2,368.38		0.02050	2,369.53	
60		Block 6	87,623,948	all additional			0.01013		0.01013			0.01031			0.01031		
61		**Total**						**10,453.29**		**10,453.29**	0.0%		**10,602.98**	1.4%		**10,606.23**	1.5%
62	54		0	N/A	0.0	N/A	1.19829	N/A	1.49016	N/A	N/A	1.22927	N/A	N/A	1.52127	N/A	N/A
63	33		0	N/A	0.0	38,000.00	0.00545	38,000.00	0.00545	38,000.00	0.0%	0.00554	38,000.00	0.0%	0.00554	38,000.00	0.0%
64																	
65	**Totals**		945,277,850														
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 | Column I
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
2008-2009 PGA Filing - Oregon
PGA Effects on Revenue

Line		Amount	Reference
1		**Amount**	**Reference**
2	**Purchased Gas Cost Adjustment (PGA)**		
3			
4	Gas Cost Change	$207,398,276	NWN 2008-09 PGA gas cost file.xls
5			
6	Capacity Cost Change	(470,435)	NWN 2008-09 PGA gas cost file.xls
7			
8	**Total PGA Change**	206,927,841	
9			
10	**Temporary Rate Adjustments**		
11			
12	Proposed Temporary Increments	(17,566,048)	NWN 2008-09 Oregon PGA rate development file
13			
14	Removal of Current Temporary Increments	(35,425,211)	2007-2008 PGA filing
15			
16	**Total Net Temporary Rate Adjustment**	17,859,163	
17			
18	**Base Rate Adjustments**		
19			
20	Proposed Safety Program Costs	6,755,000	NWN/B Page __ of __
21			
22	Removal of Current Safety Program Costs	(4,826,000)	2007-2008 PGA filing
23			
24	Coos Bay Adjustment	(145,783)	Coos Bay workpaper
25			
26	Removal of Current Coos Bay Adjustment	134,214	2007-2008 PGA filing
27			
28	Storage Recall for Core	73,835	Storage Recall workpaper
29			
30	Price Elasticity Adjustment	8,905,035	NWN 2008-09 Oregon PGA rate development file
31			
32	**Total Net Base Rate Adjustment**	10,896,301	
33			
34			
35	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**$235,683,305**	
36			
37			
38			
39	2007 Oregon Earnings Test Normalized Total Revenues	$912,014,804	
40			
41	Affect of this filing, as a percentage change (line 31÷ line 35)	25.84%	

NW Natural
Rates and Regulatory Affairs
2008-2009 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months Ended 06/30/07		
1				
2				
3	Total Billed Gas Sales Revenues	886,722,565		
4	Total Oregon Revenues	915,023,554		
5				
6	Regulatory Commission Fees [1]	2,287,559	0.250%	Statutory rate
7	City License and Franchise Fees	21,287,643	2.326%	Line 7 ÷ Line 4
8	Net Uncollectible Expense	2,847,234	0.311%	Line 8 ÷ Line 4
9				
10	Total	26,422,436	**2.887%**	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
2008-2009 PGA - SYSTEM
Summary of Total Commodity Cost

SYSTEM COSTS

Line	(a)	(b)	(c) November	(d) December	(e) January	(f) February	(g) March	(h) April	(i) May	(j) June	(k) July	(l) August	(m) September	(n) October	(o) TOTAL
3			1	2	3	4	5	6	7	8	9	10	11	12	
4	**COSTS**														
5	Commodity Cost from Supply		$86,815,550	$92,900,887	$92,658,469	$59,631,310	$77,190,325	$55,101,993	$39,293,223	$29,948,260	$27,324,383	$28,030,302	$29,654,754	$46,168,698	$664,718,154
6	tab commodity cost from supply, column ao, lines 93-105														
7	Volumetric Pipeline Chgs		$277,334	$299,151	$297,882	$203,829	$251,630	$196,052	$141,721	$102,075	$87,697	$90,001	$98,758	$177,788	$2,223,918
8	tab commodity cost from vol pipe, column e, line 78-90														
9	Commodity Cost from Storage		$157,014	$24,942,975	$25,086,065	$33,126,687	$10,408,299	$3,133,355	$162,248	$157,014	$162,248	$162,248	$157,014	$162,248	$97,817,415
10	tab Commodity Cost from Storage, column h, line 61-73														
11	Total Commodity Cost		$87,249,898	$118,143,013	$118,042,416	$92,961,826	$87,850,254	$58,431,400	$39,597,192	$30,207,349	$27,574,328	$28,282,551	$29,910,526	$46,508,734	$764,759,487
12															
13	**VOLUMES**														
14	Pipeline Commodity at Receipt Points		88,614,305	89,848,973	88,370,118	58,149,007	76,298,511	62,517,492	45,630,805	32,885,245	28,235,669	28,980,472	31,813,258	57,201,021	688,544,876
15	Pipeline Fuel Use		2,395,653	2,436,278	2,402,530	1,661,321	2,127,056	1,688,464	1,311,837	1,018,766	939,351	954,021	997,454	1,575,869	19,508,600
16	Pipeline Gas Arriving at City Gate		86,218,652	87,412,695	85,967,588	56,487,686	74,171,455	60,829,028	44,318,968	31,866,479	27,296,318	28,026,451	30,815,804	55,625,152	669,036,276
17	Storage Gas Deliveries		210,000	30,622,313	31,515,278	40,829,195	12,659,062	3,887,061	217,000	210,000	217,000	217,000	210,000	217,000	121,010,909
18	Total Gas At Citygate (Storage and Pipeline)		86,428,652	118,035,008	117,482,866	97,316,881	86,830,517	64,716,089	44,535,968	32,076,479	27,513,318	28,243,451	31,025,804	55,842,152	790,047,185
19															
20	Unaccounted for Gas		372,569	377,731	371,486	244,095	320,512	262,856	191,514	137,700	117,954	121,109	133,163	240,368	2,891,058
21															
22	Load Served		86,056,083	117,657,277	117,111,380	97,072,786	86,510,005	64,453,233	44,344,454	31,938,779	27,395,364	28,122,342	30,892,641	55,601,784	787,156,127
23															0
24	**Annual Sales WACOG**		$1.01387	$1.00413	$1.00795	$0.95765	$1.01549	$0.90657	$0.89295	$0.94579	$1.00653	$1.00570	$0.96821	$0.83646	$0.97155
25															
OR	**OREGON Sales WACOG with Revenue Sensitive**		$1.04401	$1.03398	$1.03791	$0.98612	$1.04568	$0.93352	$0.91950	$0.97391	$1.03645	$1.03560	$0.99699	$0.86133	$1.00043
WA	**WASHINGTON Sales WACOG with Revenue Sensitive**		$1.06042	$1.05024	$1.05423	$1.00162	$1.06212	$0.94820	$0.93395	$0.98922	$1.05275	$1.05188	$1.01267	$0.87487	$1.01616

NW Natural
2008-2009 PGA - SYSTEM
Summary of Total Demand Charges

SYSTEM COSTS

(a)	(b)	(c) November	(d) December	(e) January	(f) February	(g) March	(h) April	(i) May	(j) June	(k) July	(l) August	(m) September	(n) October	(o) TOTAL
		30	31	31	28	31	30	31	30	31	31	30	31	365
Transport charges by transporter:														
Northwest Pipeline		$3,958,817	$4,151,843	$4,151,843	$3,750,052	$4,151,843	$4,017,914	$4,151,843	$3,958,817	$4,090,776	$4,090,776	$3,958,817	$4,090,776	$48,524,117
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		281,944	281,944	281,944	281,944	281,944	252,329	252,329	252,329	252,329	252,329	252,329	281,944	3,205,641
NOVA		735,942	735,942	735,942	735,942	735,942	735,942	735,942	735,942	735,942	735,942	735,942	735,942	8,831,301
Terasen (Southern Crossing)		608,078	628,347	628,347	567,539	628,347	608,078	628,347	608,078	628,347	628,347	608,078	628,347	7,398,280
Spectra (Westcoast)		721,065	723,440	723,440	716,314	723,440	721,065	723,440	721,065	723,440	723,440	721,065	723,440	8,664,654
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		$6,841,731	$7,074,642	$7,074,642	$6,553,196	$7,074,642	$6,789,269	$6,960,351	$6,730,172	$6,899,284	$6,899,284	$6,730,172	$7,013,575	$82,640,959

Detail in file "NOVA ANG Monthly Summary for Tracker 2008-9 Updated.xls"

NW Natural
2008-2009 PGA - OREGON
Derivation of Oregon per therm Non-Commodity Charges

Oregon Derivation of Demand Increments

1			Without	WITH
2			Revenue Sensitive	Revenue Sensitive
3	(a)	(b)	(c)	(d)
4	System Demand		$82,640,959	
5	Oregon Allocation Factor 1/		90.39%	
6	Oregon Demand		$74,699,163	
7				
8	Oregon Firm Sales Forecasted Normal Volumes		626,530,581	
9	Oregon Interruptible Sales Forecasted Normal Volumes		84,489,604	
10				
11				
12	Proposed Firm Demand Per Therm 2/		$0.11734	$0.12083
13	Proposed Interruptible Demand 2/		$0.01396	$0.01438
14	Proposed MDDV Demand Charge		$1.75	$1.80
15				
16	Current Firm Demand Per Therm		$0.11795	$0.12134
17	Current Interruptible Demand		$0.01403	$0.01443
18	Current MDDV Demand Charge		$1.76	$1.81
19				
20	Percent Change in Firm Demand		-0.52%	
21				
22				
23	1/Allocation Factor: Actual 12 months ended 06/30/08 firm sales volumes:			
24		Washington	Oregon	System
25	Residential	47,249,317	388,438,971	435,688,288
26	Commercial	21,874,999	245,897,868	267,772,867
27	Industrial	3,298,736	46,638,060	49,936,796
28	Total	72,423,052	680,974,899	753,397,951
29		9.61%	90.39%	100.00%
30				
31	2/Calculation of Proposed Demand Rates:			
32				
33	Demand change factor		0.995	
34				
35	Firm Demand (line 8 * line 35)		$0.11734	$73,519,860
36	Interruptible Demand (line 9 * line 36)		$0.01396	$1,179,303
37				$74,699,163
38				$0

NW Natural
2008-2009 PGA - SYSTEM
Calculation of Winter WACOG

1	Forecast price for AECO gas:			
2				
3		AECO/NIT		
4				
5	November	$1.10105		
6	December	$1.13638		
7	January	$1.15653		
8	February	$1.15202		
9	March	$1.12740		
10	April	$0.97924		
11	May	$0.96364		
12	June	$0.97090		
13	July	$0.97988		
14	August	$0.98603		
15	September	$0.98840		
16	October	$0.99562		
17				
18				
19	Average price, November-March		$1.13468	average lines 5-9
20				
21	Annual average price, November-October		$1.04476	average lines 5-16
22				
23	Ratio of winter to annual		1.08607	line 19 ÷ line 21
24				
25			Without Rev	WITH Rev
26			Sensitive	Sensitive
OR	Oregon Annual WACOG		$0.97155	$1.00043
OR	Oregon Winter WACOG		$1.05517	$1.08654
			line 23 * 0.97155	
WA	Washington Annual WACOG		$0.97155	$1.01616
WA	Washington Winter WACOG		$1.05517	$1.10362
			line 23 * 0.97155	

NW Natural
2008-2009 PGA - OREGON: October REFILING
Derivation of Oregon Seasonalized Fixed Charges

(a)	(b)	Normalized Residential Volumes (c)	Normalized Commercial Volumes (d)	Firm Industrial Volumes (e)	Interruptible Industrial Volumes (f)	Total (g)	(h)	Firm Demand Increment Eff. 11/01/08 (i)	Interr. Demand Increment Eff. 11/01/08 (j)	(k)	Seasonalized Fixed Charges (l)
November	2008										$8,469,845
December	2008	60,499,149	33,808,790	4,168,383	7,387,324	105,863,646		$0.11715	$0.01394		$11,639,785
January	2009	58,764,400	33,076,320	4,903,915	8,787,042	105,531,676		$0.11715	$0.01394		$11,456,425
February	2009	48,649,855	27,629,918	4,316,964	6,966,121	87,562,858		$0.11715	$0.01394		$9,539,265
March	2009	41,196,806	24,267,417	4,414,926	8,592,820	78,471,969		$0.11715	$0.01394		$8,306,343
April	2009	28,436,688	17,778,209	4,327,488	7,957,891	58,500,276		$0.11715	$0.01394		$6,032,131
May	2009	18,338,802	12,960,900	3,097,094	5,861,451	40,258,247		$0.11715	$0.01394		$4,111,401
June	2009	10,966,576	9,142,144	2,964,827	5,773,270	28,846,818		$0.11715	$0.01394		$2,783,618
July	2009	8,284,904	7,920,835	2,999,813	5,545,470	24,751,022		$0.11715	$0.01394		$2,327,295
August	2009	8,169,944	7,817,740	3,380,855	5,978,990	25,347,529		$0.11715	$0.01394		$2,352,433
September	2009	9,663,231	8,455,476	3,640,937	6,100,843	27,860,487		$0.11715	$0.01394		$2,634,257
October	2009	23,660,105	15,248,641	4,122,620	7,270,651	50,302,017		$0.11715	$0.01394		$5,142,612
November	2009	42,268,850	24,416,858	3,946,123	7,091,809	77,723,640		$0.11715	$0.01394		$8,373,598
		358,899,309	222,523,247	46,283,945	83,313,682	711,020,184					$74,699,163
		ok	ok	ok	ok						

TF0305 0000003P158Original Sheet No. 5
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108

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	.37883	-	.00000	.37883
15 Year Evergreen Exp.	.00000	.37995	-	.00000	.37995
25 Year Evergreen Exp.	.00000	.36344	-	.00000	.36344
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	.37883	-	.00000	.37883
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)					
Parachute Lateral (9)					
Reservation	.00000	.07357	-	.00000	.07357
Volumetric	.00000	.00000	.00190	.00190	.00190
Scheduled Overrun	.00000	.07377	.00190	.00190	.07567
Rate Schedule TIL-1					
Parachute Lateral (9)					
Volumetric	.00000	.07377	.00190	.00190	.07567
Scheduled Overrun	.00000	.07377	.00190	.00190	.07567

TF0307 000003P128Original Sheet No. 7
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108

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)		
Demand Charge		
Pre-Expansion Shipper	0.00000	0.01547
Interim Best-Efforts Withdrawal Charge		
Expansion Shipper	0.00000	0.01547
Capacity Demand Charge		
Pre-Expansion Shipper	0.00000	0.00056
Expansion Shipper - 2008 Phase	0.00000	0.00264
Volumetric Bid Rates		
Withdrawal Charge		
Pre-Expansion Shipper	0.00000	0.01547
Storage Charge		
Pre-Expansion Shipper	0.00000	0.00056
Expansion Shipper - 2008 Phase	0.00000	0.00264
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.

TF0308 0000003P126Original Sheet No. 8
TF04
TF05Laren M. Gertsch, Director
TF06121907033007RP06-416-000 013108
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)	0.03054
Capacity Charge (2)	0.00390
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
2008-2009 PGA Filing - Oregon
Elasticity Adjustment

Line			Elasticity Volumes	Monthly Service Charge	Customers	Current 07-08 Billing Rate	Proposed 08-09 Billing Rate Before Elasticity	Current 07-08 Revenue	Proposed 08-09 Revenue	Proposed 08-09 WACOG	Proposed 08-09 Demand	Proposed 08-09 Temporaries	Proposed 08-09 Margin Rate	Proposed 08-09 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		757,605.3	$5.00	4,171	$1.29228	$1.61714	$1,229,298	$1,475,414	$1.00043	$0.12083	($0.01989)	$0.51577	$390,750
3	1C		95,587.6	$5.00	190	$1.25248	$1.56883	$131,122	$161,361	$1.00043	$0.12083	($0.04086)	$0.48843	$46,688
4	2R		364,444,440.3	$6.00	528,391	$1.22449	$1.54451	$484,302,725	$600,932,234	$1.00043	$0.12083	($0.02001)	$0.44326	$161,543,643
5	3C Firm Sales		150,787,006.3	$8.00	55,166	$1.12149	$1.43467	$174,402,056	$221,625,530	$1.00043	$0.12083	($0.04094)	$0.35435	$53,431,376
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	23,306,525.5	$325.00	1,254	$0.83739	$1.27063	$24,407,251	$34,504,570	$1.00043	$0.12083	($0.04099)	$0.19036	$4,436,630
12		Block 2	38,127,998.1			$0.82114	$1.25402	$31,308,424	$47,813,272	$1.00043	$0.12083	($0.04100)	$0.17376	$6,625,121
13	31C Firm Trans	Block 1	0.0	$325.00	0	$0.17742	$0.17326	$0	$0	$0.00000	$0.00000	($0.01637)	$0.18963	$0
14		Block 2	0.0			$0.16117	$0.15671	$0	$0	$0.00000	$0.00000	($0.01638)	$0.17309	$0
15	31C Interr Sales	Block 1	190,980.7	$325.00	0	$0.83945	$1.18293	$160,319	$225,917	$1.00043	$0.01438	($0.02082)	$0.18894	$36,084
16		Block 2	920,938.6			$0.82320	$1.16644	$758,117	$1,074,220	$1.00043	$0.01438	($0.02083)	$0.17246	$158,825
17			578,631,082		589,172			$716,699,312	$907,812,518					$226,669,116
18														
19	**Calculation of Class Prices and Margins:**					07-08 Class Price	08-09 Class Price	07-08 Class Revenues	08-09 Class Revenues				Class Margin Rate	Class Margin
20						Column F ÷ A	Column G ÷ A						Column L ÷ A	
21	**Residential (Line 2 + Line 4)**		365,202,046		532,562	**$1.32949**	**$1.64952**	485,532,023	602,407,648				**$0.44341**	161,934,393
22	**Commercial (Line 17 - Line 21)**		213,429,037		56,610	**$1.08311**	**$1.43094**	231,167,289	305,404,870				**$0.30331**	64,734,724
23			578,631,082		589,172			716,699,312	907,812,518					226,669,116
24														
25	**Sources for lines 1-17:**													
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
33					
34	Elasticity volumes		365,202,046		213,429,037
35					
36	Class prices (Columns D & E, lines 21, 22)	$1.32949	$1.64952	$1.08311	$1.43094
37					
38	Change in class prices		$0.32003		$0.34783
39					
40	Percentage change in class prices		24.1%		32.1%
41					
42	Volume change due to elasticity (Residential @ 0.172, Commercial @ 0.11)		4.1%		3.5%
43					
44	Volume change due to elasticity in therms (line 42 x line 34)		14,973,284		7,470,016
45					
46	Margin rate per therm (Columns K & L, lines 21, 22)		$0.44341		$0.30331
47					
48	**Margin Shortfall (line 44 x Line 46)**		**$6,639,304**		**$2,265,731**
49					
50	**Rate Change Due to Elasticity Effects (line 48 ÷ line 34)**		**$0.01818**		**$0.01062**
51					
52	**Rate Change Due to Elasticity Effects with revenue sensitive added**		**$0.01872**		**$0.01094**

NW Natural
Rates & Regulatory Affairs
2008-2009 PGA Filing - Oregon
Summary of PERMANENT Increments

Schedule	Block	REMOVE Current Bare Steel A	REMOVE Current Geo Hazard B	REMOVE Current IMP C	REMOVE Current Coos Bay D	Current Subtotal E=A+B+C+D E	ADD Proposed Bare Steel 70% F	ADD Proposed Bare Steel 30% G	ADD Proposed Geo Hazard H	ADD Proposed IMP I	ADD Proposed Coos Bay J	Proposed Subtotal K=sum F thru J K	Net Effect of Permanent Items L= K - E L
1R		0.00367	0.00164	0.00448	(0.00029)	0.00950	0.00302	0.00214	0.00275	0.00948	(0.00042)	0.01697	0.00747
1C		0.00361	0.00155	0.00424	(0.00027)	0.00913	0.00302	0.00153	0.00197	0.00678	(0.00029)	0.01301	0.00388
2R		0.00351	0.00142	0.00388	(0.00025)	0.00856	0.00302	0.00138	0.00178	0.00613	(0.00027)	0.01204	0.00348
3C Firm Sales		0.00328	0.00113	0.00309	(0.00020)	0.00730	0.00302	0.00098	0.00126	0.00435	(0.00019)	0.00942	0.00212
Intentionally blank													
3I Firm Sales		0.00320	0.00102	0.00280	(0.00018)	0.00684	0.00302	0.00082	0.00106	0.00366	(0.00016)	0.00840	0.00156
Intentionally blank													
19	1st mantle	0.05	0.00	0.00	0.00	0.05	0.06	0.00	0.00	0.00	0.00	0.06	0.01
19	add'l mtls	0.05	0.00	0.00	0.00	0.05	0.06	0.00	0.00	0.00	0.00	0.06	0.01
31C Firm Sales	Block 1	0.00288	0.00060	0.00166	(0.00011)	0.00503	0.00302	0.00069	0.00089	0.00306	(0.00013)	0.00753	0.00250
	Block 2	0.00284	0.00055	0.00151	(0.00010)	0.00480	0.00302	0.00063	0.00081	0.00279	(0.00012)	0.00713	0.00233
31C Firm Trans	Block 1	0.00288	0.00060	0.00166	(0.00011)	0.00503	0.00302	0.00058	0.00075	0.00257	(0.00011)	0.00681	0.00178
	Block 2	0.00284	0.00055	0.00151	(0.00010)	0.00480	0.00302	0.00053	0.00068	0.00234	(0.00010)	0.00647	0.00167
31C Interr Sales	Block 1	0.00288	0.00060	0.00166	(0.00011)	0.00503	0.00302	0.00048	0.00061	0.00211	(0.00009)	0.00613	0.00110
	Block 2	0.00284	0.00055	0.00151	(0.00010)	0.00480	0.00302	0.00043	0.00056	0.00192	(0.00008)	0.00585	0.00105
31I Firm Sales	Block 1	0.00041	0.00054	0.00148	(0.00009)	0.00234	0.00000	0.00056	0.00072	0.00247	(0.00011)	0.00364	0.00130
	Block 2	0.00037	0.00049	0.00134	(0.00009)	0.00211	0.00000	0.00050	0.00065	0.00223	(0.00010)	0.00328	0.00117
31I Firm Trans	Block 1	0.00041	0.00054	0.00148	(0.00009)	0.00234	0.00000	0.00054	0.00069	0.00239	(0.00010)	0.00352	0.00118
	Block 2	0.00037	0.00049	0.00134	(0.00009)	0.00211	0.00000	0.00049	0.00063	0.00216	(0.00009)	0.00319	0.00108
31I Interr Sales	Block 1	0.00041	0.00054	0.00148	(0.00009)	0.00234	0.00000	0.00078	0.00100	0.00346	(0.00015)	0.00509	0.00275
	Block 2	0.00037	0.00049	0.00134	(0.00009)	0.00211	0.00000	0.00070	0.00091	0.00312	(0.00014)	0.00459	0.00248
32C Firm Sales	Block 1	0.00025	0.00032	0.00088	(0.00006)	0.00139	0.00000	0.00037	0.00047	0.00162	(0.00007)	0.00239	0.00100
	Block 2	0.00021	0.00027	0.00075	(0.00005)	0.00118	0.00000	0.00031	0.00040	0.00138	(0.00006)	0.00203	0.00085
	Block 3	0.00015	0.00019	0.00053	(0.00003)	0.00084	0.00000	0.00022	0.00028	0.00098	(0.00004)	0.00144	0.00060
	Block 4	0.00009	0.00011	0.00031	(0.00002)	0.00049	0.00000	0.00013	0.00017	0.00057	(0.00003)	0.00084	0.00035
	Block 5	0.00005	0.00006	0.00018	(0.00001)	0.00028	0.00000	0.00007	0.00009	0.00033	(0.00001)	0.00048	0.00020
	Block 6	0.00002	0.00003	0.00009	(0.00001)	0.00013	0.00000	0.00004	0.00005	0.00016	(0.00001)	0.00024	0.00011
32I Firm Sales	Block 1	0.00025	0.00032	0.00088	(0.00006)	0.00139	0.00000	0.00038	0.00048	0.00167	(0.00007)	0.00246	0.00107
	Block 2	0.00021	0.00027	0.00075	(0.00005)	0.00118	0.00000	0.00032	0.00041	0.00142	(0.00006)	0.00209	0.00091
	Block 3	0.00015	0.00019	0.00053	(0.00003)	0.00084	0.00000	0.00023	0.00029	0.00100	(0.00004)	0.00148	0.00064
	Block 4	0.00009	0.00011	0.00031	(0.00002)	0.00049	0.00000	0.00013	0.00017	0.00058	(0.00003)	0.00085	0.00036
	Block 5	0.00005	0.00006	0.00018	(0.00001)	0.00028	0.00000	0.00008	0.00010	0.00033	(0.00001)	0.00050	0.00022
	Block 6	0.00002	0.00003	0.00009	(0.00001)	0.00013	0.00000	0.00004	0.00005	0.00017	(0.00001)	0.00025	0.00012
32 Firm Trans	Block 1	0.00025	0.00032	0.00088	(0.00006)	0.00139	0.00000	0.00030	0.00038	0.00132	(0.00006)	0.00194	0.00055
	Block 2	0.00021	0.00027	0.00075	(0.00005)	0.00118	0.00000	0.00025	0.00033	0.00113	(0.00005)	0.00166	0.00048
	Block 3	0.00015	0.00019	0.00053	(0.00003)	0.00084	0.00000	0.00018	0.00023	0.00079	(0.00004)	0.00116	0.00032
	Block 4	0.00009	0.00011	0.00031	(0.00002)	0.00049	0.00000	0.00010	0.00013	0.00046	(0.00002)	0.00067	0.00018
	Block 5	0.00005	0.00006	0.00018	(0.00001)	0.00028	0.00000	0.00006	0.00008	0.00026	(0.00001)	0.00039	0.00011
	Block 6	0.00002	0.00003	0.00009	(0.00001)	0.00013	0.00000	0.00003	0.00004	0.00013	(0.00001)	0.00019	0.00006
32 Interr Sales	Block 1	0.00025	0.00032	0.00088	(0.00006)	0.00139	0.00000	0.00031	0.00040	0.00139	(0.00006)	0.00204	0.00065
	Block 2	0.00021	0.00027	0.00075	(0.00005)	0.00118	0.00000	0.00027	0.00034	0.00118	(0.00005)	0.00174	0.00056
	Block 3	0.00015	0.00019	0.00053	(0.00003)	0.00084	0.00000	0.00019	0.00024	0.00083	(0.00004)	0.00122	0.00038
	Block 4	0.00009	0.00011	0.00031	(0.00002)	0.00049	0.00000	0.00011	0.00014	0.00049	(0.00002)	0.00072	0.00023
	Block 5	0.00005	0.00006	0.00018	(0.00001)	0.00028	0.00000	0.00006	0.00008	0.00028	(0.00001)	0.00041	0.00013
	Block 6	0.00002	0.00003	0.00009	(0.00001)	0.00013	0.00000	0.00003	0.00004	0.00014	(0.00001)	0.00020	0.00007
32 Interr Trans	Block 1	0.00025	0.00032	0.00088	(0.00006)	0.00139	0.00000	0.00028	0.00036	0.00125	(0.00006)	0.00183	0.00044
	Block 2	0.00021	0.00027	0.00075	(0.00005)	0.00118	0.00000	0.00024	0.00031	0.00106	(0.00005)	0.00156	0.00038
	Block 3	0.00015	0.00019	0.00053	(0.00003)	0.00084	0.00000	0.00017	0.00022	0.00075	(0.00003)	0.00111	0.00027
	Block 4	0.00009	0.00011	0.00031	(0.00002)	0.00049	0.00000	0.00010	0.00013	0.00044	(0.00002)	0.00065	0.00016
	Block 5	0.00005	0.00006	0.00018	(0.00001)	0.00028	0.00000	0.00006	0.00007	0.00025	(0.00001)	0.00037	0.00009
	Block 6	0.00002	0.00003	0.00009	(0.00001)	0.00013	0.00000	0.00003	0.00004	0.00013	(0.00001)	0.00019	0.00006
54		0.00345	0.00134	0.00367	(0.00023)	0.00823	0.00302	0.00130	0.00167	0.00576	(0.00025)	0.01150	0.00327
33		0.00001	0.00002	0.00005	0.00000	0.00008	0.00000	0.00002	0.00002	0.00008	0.00000	0.00012	0.00004

Sources:

Direct Inputs	07-08 PGA	07-08 PGA	07-08 PGA	07-08 PGA							
Equal ¢ per therm					Column AE						
Equal % of margin							Column R	Column U	Column X	Column AA	

NW Natural
Rates & Regulatory Affairs
2008-2009 PGA Filing - Oregon
Summary of TEMPORARY Increments

		REMOVE	ADD	ADD	ADD	ADD	ADD	ADD	ADD	ADD	ADD	ADD	ADD		
		Current Temporaries	WACOG Deferral	Demand Deferral FIRM	Demand Deferral INTERR	Residential Decoupling	Commercial Decoupling	DSM & Weatherization	Intervenor Funding - CUB	Storage Inventory Adjustment	Intervenor Funding - NWIGU	IMP Refund	Oregon Tax Kicker	Total Current Temps	Net Effect of Temps
														M=sum B thru L	N = M - A
Schedule	Block	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1R		(0.04520)	(0.00085)	(0.02290)	0.00000	0.00427	0.00000	0.00002	0.00014	(0.00091)	0.00000	0.00013	0.00021	(0.01989)	0.02531
1C		(0.06131)	(0.00085)	(0.02290)	0.00000	0.00000	(0.01646)	0.00002	0.00000	(0.00091)	0.00000	0.00009	0.00015	(0.04086)	0.02045
2R		(0.04454)	(0.00085)	(0.02290)	0.00000	0.00427	0.00000	0.00002	0.00014	(0.00091)	0.00000	0.00008	0.00014	(0.02001)	0.02453
3C Sales Firm		(0.06003)	(0.00085)	(0.02290)	0.00000	0.00000	(0.01646)	0.00002	0.00000	(0.00091)	0.00000	0.00006	0.00010	(0.04094)	0.01909
Intentionally blank															
3I Sales Firm		(0.05112)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00009	0.00005	0.00008	(0.02442)	0.02670
Intentionally blank															
19	1st mantle	(0.91)	(0.02)	(0.44)	0.00	0.00	0.00	0.00	0.00	(0.02)	0.00	0.00	0.00	(0.48)	0.43
19	add'l mtls	(0.91)	(0.02)	(0.44)	0.00	0.00	0.00	0.00	0.00	(0.02)	0.00	0.00	0.00	(0.48)	0.43
31C Sales Firm	Block 1	(0.05845)	(0.00085)	(0.02290)	0.00000	0.00000	(0.01646)	0.00002	0.00000	(0.00091)	0.00000	0.00004	0.00007	(0.04099)	0.01746
	Block 2	(0.05828)	(0.00085)	(0.02290)	0.00000	0.00000	(0.01646)	0.00002	0.00000	(0.00091)	0.00000	0.00004	0.00006	(0.04100)	0.01728
31C Trans Firm	Block 1	(0.01037)	0.00000	0.00000	0.00000	0.00000	(0.01646)	0.00000	0.00000	0.00000	0.00000	0.00003	0.00006	(0.01637)	(0.00600)
	Block 2	(0.01020)	0.00000	0.00000	0.00000	0.00000	(0.01646)	0.00000	0.00000	0.00000	0.00000	0.00003	0.00005	(0.01638)	(0.00618)
31C Sales Interr	Block 1	(0.05639)	(0.00085)	0.00000	(0.00268)	0.00000	(0.01646)	0.00000	0.00000	(0.00091)	0.00000	0.00003	0.00005	(0.02082)	0.03557
	Block 2	(0.05622)	(0.00085)	0.00000	(0.00268)	0.00000	(0.01646)	0.00000	0.00000	(0.00091)	0.00000	0.00003	0.00004	(0.02083)	0.03539
31I Sales Firm	Block 1	(0.04966)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00009	0.00003	0.00006	(0.02446)	0.02520
	Block 2	(0.04950)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00009	0.00003	0.00005	(0.02447)	0.02503
31I Trans Firm	Block 1	(0.00158)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00003	0.00005	0.00017	0.00175
	Block 2	(0.00142)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00003	0.00005	0.00017	0.00159
31I Sales Interr	Block 1	(0.04760)	(0.00085)	0.00000	(0.00268)	0.00000	0.00000	0.00000	0.00000	(0.00091)	0.00009	0.00005	0.00008	(0.00422)	0.04338
	Block 2	(0.04744)	(0.00085)	0.00000	(0.00268)	0.00000	0.00000	0.00000	0.00000	(0.00091)	0.00009	0.00004	0.00007	(0.00424)	0.04320
32C Sales Firm	Block 1	(0.04905)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00000	0.00002	0.00004	(0.02458)	0.02447
	Block 2	(0.04892)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00000	0.00002	0.00003	(0.02459)	0.02433
	Block 3	(0.04866)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00000	0.00001	0.00002	(0.02461)	0.02405
	Block 4	(0.04841)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00000	0.00001	0.00001	(0.02462)	0.02379
	Block 5	(0.04827)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00000	0.00000	0.00001	(0.02463)	0.02364
	Block 6	(0.04817)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00000	0.00000	0.00000	(0.02464)	0.02353
32I Sales Firm	Block 1	(0.04899)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00009	0.00002	0.00004	(0.02449)	0.02450
	Block 2	(0.04886)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00009	0.00002	0.00003	(0.02450)	0.02436
	Block 3	(0.04860)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00009	0.00001	0.00002	(0.02452)	0.02408
	Block 4	(0.04835)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00009	0.00001	0.00001	(0.02453)	0.02382
	Block 5	(0.04821)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00009	0.00000	0.00001	(0.02454)	0.02367
	Block 6	(0.04811)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00009	0.00000	0.00000	(0.02455)	0.02356
32 Trans Firm	Block 1	(0.00091)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00002	0.00003	0.00014	0.00105
	Block 2	(0.00078)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00001	0.00003	0.00013	0.00091
	Block 3	(0.00052)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00001	0.00002	0.00012	0.00064
	Block 4	(0.00027)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00001	0.00001	0.00011	0.00038
	Block 5	(0.00013)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00000	0.00001	0.00010	0.00023
	Block 6	(0.00003)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00000	0.00000	0.00009	0.00012
32 Sales Interr	Block 1	(0.04693)	(0.00085)	0.00000	(0.00268)	0.00000	0.00000	0.00000	0.00000	(0.00091)	0.00009	0.00002	0.00003	(0.00430)	0.04263
	Block 2	(0.04680)	(0.00085)	0.00000	(0.00268)	0.00000	0.00000	0.00000	0.00000	(0.00091)	0.00009	0.00002	0.00003	(0.00430)	0.04250
	Block 3	(0.04654)	(0.00085)	0.00000	(0.00268)	0.00000	0.00000	0.00000	0.00000	(0.00091)	0.00009	0.00001	0.00002	(0.00432)	0.04222
	Block 4	(0.04629)	(0.00085)	0.00000	(0.00268)	0.00000	0.00000	0.00000	0.00000	(0.00091)	0.00009	0.00001	0.00001	(0.00433)	0.04196
	Block 5	(0.04615)	(0.00085)	0.00000	(0.00268)	0.00000	0.00000	0.00000	0.00000	(0.00091)	0.00009	0.00000	0.00001	(0.00434)	0.04181
	Block 6	(0.04605)	(0.00085)	0.00000	(0.00268)	0.00000	0.00000	0.00000	0.00000	(0.00091)	0.00009	0.00000	0.00000	(0.00435)	0.04170
32 Trans Interr	Block 1	(0.00091)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00002	0.00003	0.00014	0.00105
	Block 2	(0.00078)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00001	0.00002	0.00012	0.00090
	Block 3	(0.00052)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00001	0.00002	0.00012	0.00064
	Block 4	(0.00027)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00001	0.00001	0.00011	0.00038
	Block 5	(0.00013)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00000	0.00001	0.00010	0.00023
	Block 6	(0.00003)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00000	0.00000	0.00009	0.00012
54		(0.05214)	(0.00085)	(0.02290)	0.00000	0.00000	0.00000	0.00002	0.00000	(0.00091)	0.00000	0.00008	0.00013	(0.02443)	0.02771
33		(0.00005)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00005

Sources:

Direct Inputs	07-08 PGA										
Equal ¢ per therm		Column D	Column G	Column J	Column M	Column P	Column S	Column V	Column Y	Column AB	
Equal % of margin										Column L	Column O

NW Natural
Bare Steel, Geohazard and Integrity Management Programs
Cost of Service Summary - PGA 2008-09
Thousands of Dollars

		Investment	Tracker Year Cost of Service
Bare Steel Program			
1	Activity Ended September 30, 2002	$2,665	$330
2	Activity Ended September 30, 2003	3,510	428
3	Activity Ended September 30, 2004	3,094	389
4	Activity Ended September 30, 2005	6,000	779
5	Activity Ended September 30, 2006	(695)	(92)
6	Activity Ended September 30, 2007	430	59
7	Activity Ended September 30, 2008	3,861	594
8	Total Bare Steel Program	$18,865	$2,486
Geohazard Program			
9	Activity Ended September 30, 2002	$1,714	$212
10	Activity Ended September 30, 2003	555	68
11	Activity Ended September 30, 2004	139	17
12	Activity Ended September 30, 2005	206	27
13	Activity Ended September 30, 2006	2,863	380
14	Activity Ended September 30, 2007	254	35
15	Activity Ended September 30, 2008	1,441	222
16	Total Geohazard Program	$7,171	$961
Integrity Management Program			
17	Activity Ended September 30, 2005	$3,476	$451
18	Activity Ended September 30, 2006	8,978	1,192
19	Activity Ended September 30, 2007	2,604	358
20	Activity Ended September 30, 2008	8,491	1,306
21	Total Integrity Management Program	$23,549	$3,308
GRAND TOTAL ALL PROGRAMS		**$49,585**	**$6,754**

Reflects Actuals through June 30, 2008

NW Natural
Rates and Regulatory Affairs
2008-2009 PGA Filing - Oregon
Estimated Revenue Effects for the 12 Months Beginning November 1, 2008

Line No.	Item	Total Increment Amounts	Limit For Increment Amounts
1	Commodity and Demand Deferrals	($15,173,296)	
2	Temporary Increments	(2,392,752)	
3	Total	($17,566,048)	
4	2007 Utility Revenues		$1,015,970,324
5	@ 3% threshold		3.0%
6	Threshold for Annual Effect of Proposed Change in Amortization		$30,479,110

ORS 757.259 (6)