Rates and Regulatory Affairs
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August 15, 2005 NWN Advice No. OPUC 05-9

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: Purchased Gas Cost and Technical Rate Adjustments

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), files herewith the revisions and additions to its Tariff, P.U.C. Or. 24, included in the Tariffs section of this filing, and stated to become effective with service on and after October 1, 2005.

Introduction and Summary

The first purpose of this filing is to (a) revise rates for the effects of changes in purchased gas costs (see Schedule 164 and Schedule P); (b) revise rates for the further effect of removing temporary rate adjustments incorporated into rates effective October 1, 2004; and (c) apply new temporary rate adjustments for inclusion in rates effective October 1, 2005 (see Schedule 162). The Company revises rates for these purposes annually; its last filing was effective October 1, 2004.

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 geo-hazard risk mitigation and for the pipeline Integrity Management Program (see Schedule 177); and (b) NW Natural's first year 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 costs associated with the South Mist Pipeline Extension Project (see Schedule 176); (b) the revenue requirement associated with the construction of the Coos County distribution system pursuant to OPUC Order No. 04-702; (c) Price Elasticity effects of the rate increase reflected in this filing (see Schedule 163); and (d) the effect of removing the Y2K increment placed into permanent rates in December 1999.

The fourth purpose of this filing is to request a waiver of OAR 860-021-035(2004), to the extent such rule is applicable, for the application of the amortization of the balance in the deferral account for the partial decoupling mechanism (Schedule 190), which includes the effects of a correction for Albany weather data that was also used in the calculation of adjustments to customer bills under the Company's Weather Adjustment Rate Mechanism (WARM) from November 15, 2003 to and including June 30, 2004. The Company issued corrected bills to Albany customers for the effect of the corrected weather data on the WARM calculations with May and June billings.

If the effects of the temporary rate increments were permanent, the result of all components of the rate changes would be an increase in the Company's revenues from its Oregon operations of about $118,148,396, or about 16.7%.

The average residential Schedule 2 bill will increase by 13%; the commercial Schedule 3 bill will increase by 14.1%; the Schedule 31 commercial bill will increase by 16.2%; and the bill for the average Schedule 32 industrial firm sales customer will increase by 18.7%.

The monthly bill of the average residential customer served under Schedule 2 using 59.2 therms per month will increase by $9.28. The monthly increase for the average commercial Schedule 3 customer using 229 therms is $34.15.

See Exhibits 1 and 2 of this filing for materials in support of the application of all adjustments to the applicable rate schedules. The PGA Summary Sheet requested by OPUC Staff is included as Exhibit A to this filing.

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.

This filing applies the methods for calculating the proposed Weighted Average Cost of Gas ("WACOG") that are set forth in Commission Order No. 05-852, entered July 14, 2005, in Docket UG 73.

This filing also applies the methods for treatment of storage inventory gas and 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 effect of the PGA portion of this filing is to increase the Company's annual revenues by about $111,318,000. The proposed WACOG is $0.70927 per therm. The proposed firm service pipeline capacity cost is $0.09466 per therm, and the proposed interruptible service pipeline capacity cost is $0.01126. The net effect of these purchased gas adjustments in this filing is an increase of $0.14091 cents per therm for firm sales rate schedules and an increase of $0.16454 cents per therm for interruptible sales rate schedules.

Also in this portion of the filing, changes were made in the way certain Canadian pipeline demand charges are handled. In prior years, Duke Energy's Westcoast Pipeline demand charges were embedded in the commodity price of gas as received at Sumas. The Company's British Columbia gas suppliers would inform the Company as to what the specific demand component was on a cent per therm basis. The Company would then calculate this cent per therm component represented in total demand dollars, and would add this amount to the total of all pipeline demand charges. The cent per therm figure upon which this calculation was based would then be removed from the per therm commodity charge for all British Columbia ("BC") gas. In recent years, the long-term contracts with these BC suppliers ended, and the Company has begun to directly purchase capacity on the Westcoast Pipeline system. Because of this, the Company is now able to directly calculate T-South demand charges for moving gas from Station 2 to Sumas on the Westcoast system. These charges are not embedded in commodity, but are paid directly by the Company, and have been incorporated into rates in a manner compatible with procedures detailed in the OPUC Order No. 05-852.

The effect of the change in demand charge calculation is a reduction in total demand charges of about $17 million. This reduction results because a significant set of charges that were formerly treated as demand charges are now being treated as commodity costs. These charges, which include gathering fees, gas processing charges, liquids charges and credits, and the cost of moving the processed gas to Station 2 (called T-North on the Westcoast system), are embedded in the commodity rate as delivered to Station 2. Because some of these charges vary with gas quality and location, specifically gathering, processing, and liquids charges, they are difficult to measure in advance. Thus, though the rates charged are tariffed, they would be speculative to predict, and the associated costs which are embedded in the commodity remain embedded.

Materials in support of this portion of the filing are attached at Exhibit 1.

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 Federal Energy Regulatory Commission (FERC) approved deferred accounts (Accounts 186 and 191, respectively). These adjustments are shown in the Supporting Materials as the application of new temporary rate adjustments.

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 for Commission authorization, as rate orders or under approved tariffs.

This filing does not require a review of earnings because the Company has adopted a 1/3 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 2005 Earnings Review. Page 25 of Exhibit 2 shows the total proposed average change being applied to billing rates as an increase of $11.8 million, which is below the current three percent limit of $21 million.

The net effect of this portion of the filing is to increase the Company's annual revenues by $404,000; the effect of removing the temporary adjustments placed into rates October 1, 2004 is $11,428,000; and the effect of applying the new temporary rate adjustments is $11,832,000.

Materials in support of this portion of the filing are attached at Exhibit 2.

III. Base Rate Adjustments

The effect of this portion of the filing is to increase the Company's annual revenues by $6,426,000.

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 Commission 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 as described in Schedule 163.

South Mist Pipeline Expansion (SMPE). This filing applies the permanent effects of the true-up of the cost of service amounts related to investment amounts and deferred tax treatment for the South Mist Expansion Project, pursuant to OPUC Order in Docket UG 152.

IV. Request for Waiver of OAR 860-021-0135(2004).

This filing includes the application of the amortization of the balance in the deferral account for the partial decoupling mechanism set forth in Schedule 190. The balance in this account reflects the effects on all customers of a correction for Albany weather data between November 15, 2003 to and including June 30, 2004. Because this is a deferral account, the correction for the Albany weather data error is automatically captured by adjusting the balance in the deferral account. As such, the effect of the data correction is reflected in the application of the new temporary adjustment proposed to be amortized into rates effective with this filing.

This weather data was also used in the calculation of adjustments to customer bills under the Company's Weather Adjustment Rate Mechanism (WARM). The correction for the effect on bills issued under the WARM program was shown on May and June billings.

In the event that the Commission determines that the correction of the Albany weather data in the Schedule 190 deferral account for the period November 15, 2003 to and including June 30, 2004 constitutes a billing adjustment as set forth in OAR 860-021-0135(2004), the Company respectfully requests a waiver of OAR 860-021-035(2004), and requests that the correction be allowed to occur in the manner described herein.

The Schedule 190 tariff sheets proposed in this filing set forth changes to the tariff sheets the parties in UG 163 agreed upon in a stipulation filed with the Commission on August 5, 2005 (the “Stipulation”). Since all of the parties to the proceeding signed onto the Stipulation or stated they would not contest it, the Company assumes the Commission will approve the Stipulation and issue an order requiring a compliance filing prior to the effective date of this filing. In such event, the Company respectfully requests that the Fifth revision of Sheet 190-1, the Third revision of Sheet 190-2, and the First revision of Sheet 190-3, as filed herewith, be considered said compliance filing. In the event that the Commission order in Docket UG 163 is not issued prior to the effective date of the tariff changes proposed herein, the Company will submit revised Schedule 190 tariff sheets accordingly.

The Company requests that the tariff sheets filed herewith be permitted to become effective with service on and after October 1, 2005.

Copies of this letter and the filing made herewith are available in the Company's main and district offices in Oregon.

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

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Sincerely,

NW NATURAL

/s/ Onita King

Onita R. King, Manager
Tariffs and Regulatory Compliance

Attachments: Tariffs
Exhibit A
Exhibits 1 and 2

TABLE OF TARIFF SHEET REVISIONS
PROPOSED TO BECOME EFFECTIVE OCTOBER 1, 2005

PROPOSED REVISION	CANCELS REVISION	SCHEDULE TITLE
Third Revision of Sheet v	Second Revision of Sheet v	Tariff Index
First Revision of Sheet P-1	Original Sheet P-1	Schedule P "Purchased Gas Cost Adjustments and Weighted Average Cost of Gas"
First Revision of Sheet P-2	Original Sheet P-2	
First Revision of Sheet P-3	Original Sheet P-3	
Fourth Revision of Sheet P-4	Third Revision of Sheet P-4 and Second Revision of Sheet P-5	
Fourth Revision of Sheet 1-1	Third Revision of Sheet 1-1	Schedule 1 "General Sales Service"
Fourth Revision of Sheet 2-1	Third Revision of Sheet 2-1	Schedule 2 "Residential Sales Service"
Fifth Revision of Sheet 3-2	Fourth Revision of Sheet 3-2	Schedule 3 "Basic Firm Sales and Transportation Service Non-Residential"
Third Revision of Sheet 19-1	Second Revision of Sheet 19-1	Schedule 19 "Gas Light Service"
Fifth Revision of Sheet 31-2	Fourth Revision of Sheet 31-2	Schedule 31 "Non-Residential Sales and Transportation Service"
Fourth Revision of Sheet 31-3	Third Revision of Sheet 31-3	
Sixth Revision of Sheet 32-2	Fifth Revision of Sheet 32-2	Schedule 32 "Large Volume Non-Residential Sales and Transportation Service"
Fourth Revision of Sheet 32-3	Third Revision of Sheet 32-3	
Third Revision of Sheet 33-2	Second Revision of Sheet 33-2	Schedule 33 "High-Volume Non-Residential Firm and Interruptible Transportation Service"
Fourth Revision of Sheet 54-1	Third Revision of Sheet 54-1	Schedule 54 "Emergency Sales Service"
Third Revision of Sheet 162-1	Second Revision of Sheet 162-1	Schedule 162 "Temporary (Technical) Adjustments to Rates"
Third Revision of Sheet 162-2	Second Revision of Sheet 162-2	
Fourth Revision of Sheet 163-1	Third Revision of Sheet 163-1	Schedule 163 "Special Adjustment to Rates Price Elasticity"

PROPOSED REVISION	CANCELS REVISION	SCHEDULE TITLE
Third Revision of Sheet 164-1	Second Revision of Sheet 164-1	Schedule 164 "Purchased Gas Cost Adjustment to Rates"
Third Revision of Sheet 176-1	Second Revision of Sheet 176-1	Schedule 176 "Adjustments to Rates for Costs Relating to South Mist Storage Expansion Project"
Fourth Revision of Sheet 177-2	Third Revision of Sheet 177-2	Schedule 177 "Adjustments to Rates for Safety Programs"
Second Revision of Sheet 177-3	First Revision of Sheet 177-3	
First Revision of Sheet 177-4	Original Sheet 177-4	
Fifth Revision of Sheet 190-1	Fourth Revision of Sheet 190-1	Schedule 190 "Partial Decoupling Mechanism"
Third Revision of Sheet 190-2	Second Revision of Sheet 190-2	
First Revision of Sheet 190-3	Original Sheet 190-3	
Third Revision of Sheet 195-3	Second Revision of Sheet 195-3	Schedule 195 "Weather Adjusted Rate Mechanism (WARM Program)"
First Revision of Sheet 195-4	Original Sheet 195-4	
First Revision of Sheet 195-5	Original Sheet 195-5	
First Revision of Sheet 199-1	Original Sheet 199-1	Schedule 199 "Special Rate Adjustment (UM 1148/UP 205)"
First Revision of Sheet 199-2	Original Sheet 199-2	

TARIFF INDEX
(continued)

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

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS (C)

PURPOSE: (C)
The purpose of this Schedule is to:
(a) Define procedures for periodic revisions in rates due to changes in the Company's Purchased Gas Costs;
(b) Define Purchased Gas Costs and related terms, and Weighted Average Cost of Gas (WACOG); and
(c) Define procedures for the deferral of differences experienced between the Company's actual Purchased Gas Costs and Purchased Gas Costs incorporated in the rates and charges specified in the Rate Schedules of this Tariff. (C)

This Schedule is an "automatic adjustment clause" as defined in *ORS 757.210(2003)*, and is subject to review by the Commission at least once every two (2) years. (D)

APPLICABLE:
To the following Rate Schedules of this Tariff: (M)

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

Charges under the applicable Rate Schedules are subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in Purchased Gas Costs. Such adjustments, if any, may be shown in **SCHEDULE 164**, or may be incorporated directly in the applicable Rate Schedules.

FILING AND EFFECTIVE DATE:
On or before August 15 of each calendar year, the Company shall file adjustments to its Purchased Gas Costs to be effective on October 1. At the same time, the Company shall file annual temporary rate adjustments for the amortization of balances in the PGA Account.

The Company may file for changes at times other than stated in the above schedule, if the Company's Weighted Average Cost of Gas (WACOG) changes by ten percent (10%) or more, or for such other reasons and on such terms as the Commission may approve.

GENERAL TERMS:
Service under 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. (M)

(continue to Sheet P-2)

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

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued) (C)

DEFINITIONS (N)

Actual Fixed Charge Collections. Actual fixed charges collected, calculated by multiplying monthly Sales Service volumes by the Embedded Non-Commodity Costs of Gas, and added to Rate Schedules 31, 32 and 33 capacity charges recovered on an MDDV basis, net of revenue sensitive effects.

Adjusted Contract Prices. Contract prices that are adjusted by each associated Canadian pipeline's published (closest to August 1) fuel-in-kind and line loss amount provided for by tariff, and by each associated U.S. pipeline's tariffed rate.

Annual Sales WACOG. Also called "Commodity", is used in the calculation of Sales Service billing rates for the applicable Rate Schedules. (N)

Commodity Cost of Gas. All known and measurable costs, fixed or variable, associated with the Company's acquisition of gas supply from producers and marketers at Adjusted Contract Prices. The commodity cost of gas includes the cost of all gas purchased by the company, any reservation charges paid to various gas suppliers, the variable costs charged by natural gas pipelines to move purchased commodity gas to the Company's gas distribution system, the cost of gas withdrawn from storage facilities, including any variable costs associated with adding, withdrawing and moving storage gas into the Company's distribution system, the appropriate capacity release credits, and the costs associated with the Company's Distribution System Unaccounted for Gas. (M)(C) … (M)(C)

Distribution System Unaccounted for Gas. The Company's 5-year average of actual unaccounted for gas, not to exceed 2%, calculated in accordance with Commission Order No. 05-852. (N)

Embedded Commodity Cost of Gas. The Weighted Average Cost of Gas (WACOG) included in rates for the applicable Rate Schedules.

Embedded Non-Commodity Cost of Gas. The Non-Commodity Costs of Gas included in rates for the applicable Rate Schedules.

Financial Instrument Costs. Costs relating to derivative financial instruments such as commodity swaps or commodity caps purchased as hedging mechanisms to mitigate volatility in the company's gas Purchased Gas Costs. (N)

Non-Commodity Costs of Gas. Non-commodity costs of gas consist of pipeline capacity charges and storage capacity charges. These are fixed charges, also referred to as demand charges, which are paid to secure the right to a given amount of daily and annual capacity on pipelines and non-company owned storage facilities. (M)(C) … (M)(C)

(continue to Sheet P-3)

Issued August 15, 2005 Effective with service on
NWN Advice No. OPUC 05-9 and after October 1, 2005

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued) (C)

DEFINITIONS (continued) (N)

Normalized Purchases. Actual gas sales for the most recent 12-months ended June, Weather Normalized, plus a percentage for Distribution System Unaccounted for Gas.

Pipeline Capacity Charges. The Non-Commodity Costs of Gas divided by Sales Service volumes.

Purchased Gas Costs. The total of the Company's Commodity Cost of Gas, Non-Commodity Costs of Gas, and Financial Instrument Costs.

Seasonalized Fixed Charges. The projected monthly Non-Commodity Costs of Gas recovery, calculated by multiplying the Embedded Non-Commodity Costs of Gas by Oregon normalized sales.

Weather Normalized. Volumes adjusted to reflect normal weather using the normalizing assumptions established with the Company's general rate case. (N)

Weighted Average Cost of Gas (WACOG). The Company's weighted average Commodity Cost of Gas, calculated as [Normalized Purchases @ Adjusted Contract Prices] divided by actual sales, weather normalized]. The monthly purchases WACOG is used for PGA Account calculations. (C)(M) (C)(M)

The monthly purchases and Annual Sales WACOG effective October 1, 2005 are: (T)

	WACOG	Revenue-Sensitive*	Adjusted WACOG	
Annual Sales WACOG (per therm):	**$0.68904**	**$0.02023**	**$0.70927**	(C)

Monthly Purchases WACOG (per therm)			
October **2005**	$0.66041	$0.01939	$0.67980
November	$0.50286	$0.01476	$0.51762
December	$0.74289	$0.02181	$0.76470
January **2006**	$0.73449	$0.02156	$0.75605
February	$0.74132	$0.02176	$0.76308
March	$0.74046	$0.02174	$0.76220
April	$0.74050	$0.02174	$0.76224
May	$0.65826	$0.01932	$0.67758
June	$0.66173	$0.01943	$0.68116
July	$0.66324	$0.01947	$0.68271
August	$0.66620	$0.01956	$0.68576
September	$0.66334	$0.01947	$0.68281

* Revenue-sensitive effects on WACOG at 2.852%. (C)

(continue to Sheet P-4)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS (C)
(continued)

PURCHASED GAS COST ADJUSTMENT BALANCING ACCOUNT
The Company will maintain a Purchased Gas Cost Adjustment Balancing Account (PGA Account) as a sub-account of Account 191. The Company shall impute interest on the deferred balance of the PGA Account on a monthly basis consistent with current deferred accounting procedures as authorized by the Commission. The PGA Account balances shall be amortized over twelve (12) months, or until fully amortized, commencing with the October 1 effective date, or such other time period acceptable to the Company and the Commission. A credit balance at the end of a reporting period indicates a subsequent temporary rate decrease (refund) and a debit balance indicates a subsequent temporary rate increase (surcharge). (C)

Monthly entries into the PGA Account will be made to reflect the differences between the Company's actual Purchased Gas Costs and the Purchased Gas Costs embedded in rates, as follows:

1. A debit or credit entry shall be made equal to (100%) of any monthly difference between actual Non-Commodity Costs of Gas and Embedded Non-Commodity Costs of Gas, net of revenue sensitive effects.
2. A debit or credit entry shall be made equal to 100% of any monthly difference between Actual Fixed Charge Collections and Seasonalized Fixed Charges.

   The monthly Seasonalized Fixed Charges for the period October 1, 2005 through November 30, 2006 are:

October 2005	$4,730,559
November	$8,461,347
December	$9,262,594
January 2006	$9,332,496
February	$7,414,615
March	$6,357,898
April	$4,799,830
May	$3,382,276
June	$2,234,597
July	$1,893,709
August	$1,893,343
September	$2,091,984
October	$3,835,580
November	$6,754,373
ANNUAL TOTAL	$59,253,295

3. A debit or credit entry shall be made equal to 67% of any monthly difference between actual Commodity Cost of Gas and Embedded Commodity Cost of Gas, net of revenue sensitive effects.
4. A credit entry equal to 100% of any payments made to the Company by a financial entity pursuant to the exercise of a commodity cap, if any.
5. A credit entry equal to 80% of any capacity release credits earned through the temporary use of core market capacity. (C)

Issued August 15, 2005 Effective with service on
NWN Advice No. OPUC 05-9 and after October 1, 2005

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, are subject to the provisions of **SCHEDULE X**.

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

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

MONTHLY RATE: Effective: October 1, 2005 (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	$0.49044	$0.01564	$0.09466	$0.70927	$0.02263	**$1.33264**	(I)
Commercial	$0.46813	$0.01300	$0.09466	$0.70927	$0.01820	**$1.30326**	(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, are 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: October 1, 2005 (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):	$0.42250	$0.01564	$0.09466	$0.70927	$0.02242	**$1.26449**	(I)

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

(continue to Sheet 2-2)

RATE SCHEDULE 3
BASIC FIRM SALES AND TRANSPORTATION SERVICE
NON-RESIDENTIAL

MONTHLY RATE: Effective: October 1, 2005 (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.**

SALES SERVICE CHARGES:						**Total Billing [1]**	
Customer Charge (per month):						**$8.00**	
Delivery Charge (per therm):	Base Rate	Base Rate Adjustment	Pipeline Capacity	Commodity	Temporary Adjustment		
Commercial:	$0.33717	$0.01269	$0.09466	$0.70927	$0.01782	**$1.17161**	(I)
Industrial:	$0.31430	$0.00212	$0.09466	$0.70927	$0.00928	**$1.12963**	(I)
Standby Charge (per therm of MHDV) [2]:						**$10.00**	
TRANSPORTATION SERVICE CHARGES:						**Total Billing [1]**	
Customer Charge (per month):						**$8.00**	
Transportation Charge (per month):						**$250.00**	
Delivery Charge (per therm):	Total Base Rate	Base Rate Adjustment			Temporary Adjustment		
Commercial:	$0.43183	$0.01269			$0.02247	**$0.46699**	(I)
Industrial:	$0.40896	$0.00212			$0.01393	**$0.42501**	(I)

[1] **SCHEDULE C** and **SCHEDULE 15** Charges shall apply, if applicable.
[2] 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 Transportation Service.*** Customer Charge, plus Transportation Charge.
(b) ***Firm Sales Service.*** Customer Charge.
(c) ***Firm Sales Standby Service.*** Customer Charge, plus Standby Service Charge

(continue to Sheet 3-3)

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

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 servi ce.

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.

MONTHLY RATE: Effective: October 1, 2005 (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.

	Base Rate	Base Rate Adjustments	Temporary Adjustments	Billing Rate	
One mantle	$20.82	$0.28	$0.42	**$21.52**	(I)
All additional mantles	$20.21	$0.28	$0.42	**$20.91**	(I)
Minimum Monthly Bill: Amount based on number of mantles installed					

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

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

MONTHLY RATES: Effective: October 1, 2005 (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**.

COMMERCIAL FIRM SALES SERVICE CHARGES [1]:					Total Billing Components [2]	
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Rate	Temporary Adjustments		
Block 1: 1st 2,000 therms	$0.17548	$0.01126	$0.70927	$0.01747	**$0.91348**	(I)
Block 2: All additional therms	$0.15928	$0.01116	$0.70927	$0.01741	**$0.89712**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.09466**	(R)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.37**	(R)
COMMERCIAL INTERRUPTIBLE SALES SERVICE CHARGES [1]:						
Customer Charge (per month):						
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Rate	Temporary Adjustments		
Block 1: 1st 2,000 therms	$0.17548	$0.01126	$0.70927	$0.00561	**$0.90162**	(I)
Block 2: All additional therms	$0.15928	$0.01116	$0.70927	$0.00555	**$0.88526**	(I)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.01126**	(R)
COMMERCIAL FIRM TRANSPORTATION SERVICE CHARGES:						
Customer Charge (per month):					**$325.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Temporary Adjustments		
Block 1: 1st 2,000 therms	$0.17548	$0.01126		$0.00898	**$0.19572**	(I)
Block 2: All additional therms	$0.15928	$0.01116		$0.00892	**$0.17936**	(I)

[1] The Total Sales Service Billing Rate is the total of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer.
[2] **SCHEDULE C** and **SCHEDULE 15** Charges shall apply, if applicable.

Minimum Monthly Bill. The Minimum Monthly Bill shall be any **SCHEDULE C** and **SCHEDULE 15** Charges, plus:
(a) ***Firm Transportation Service.*** Customer Charge, plus Transportation Charge.
(b) ***Firm Sales Service – Volumetric Pipeline Capacity Option.*** Customer Charge.
(c) ***Firm Sales Service – Peak Demand option.*** Customer Charge, plus Capacity Charge.
(d) ***Interruptible Sales Service.*** Customer Charge.

(continue to Sheet 31-3)

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

MONTHLY RATES (continued): Effective: October 1, 2005 (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 distributed generation customers are subject to **SCHEDULE 31-CHP**.

INDUSTRIAL FIRM SALES SERVICE CHARGES [1]:					Total Billing Components [2]	
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Rate	Temporary Adjustments		
Block 1: 1st 2,000 therms	$0.16802	$0.00102	$0.70927	$0.00899	**$0.88730**	(I)
Block 2: All additional therms	$0.15183	$0.00092	$0.70927	$0.00893	**$0.87095**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.09466**	(R)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.37**	(R)
INDUSTRIAL INTERRUPTIBLE SALES SERVICE CHARGES [1]:						
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Rate	Temporary Adjustments		
Block 1: 1st 2,000 therms	$0.16802	$0.00102	$0.70927	($0.00287)	**$0.87544**	(I)
Block 2: All additional therms	$0.15183	$0.00092	$0.70927	($0.00293)	**$0.85909**	(I)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.01126**	
INDUSTRIAL FIRM TRANSPORTATION SERVICE CHARGES:						
Customer Charge (per month):					**$325.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Temporary Adjustments		
Block 1: 1st 2,000 therms	$0.16802	$0.00102		$0.00050	**$0.16954**	(I)
Block 2: All additional therms	$0.15183	$0.00092		$0.00044	**$0.15319**	(I)

[1] The Total Sales Service Billing Rate is the total of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer.
[2] **SCHEDULE C** and **SCHEDULE 15** Charges shall apply, if applicable.

Minimum Monthly Bill. The Minimum Monthly Bill shall be any **SCHEDULE C** and **SCHEDULE 15** Charges, plus:
(a) ***Firm Transportation Service.*** Customer Charge, plus Transportation Charge.
(b) ***Firm Sales Service – Volumetric Pipeline Capacity Option.*** Customer Charge.
(c) ***Firm Sales Service – Peak Demand option.*** Customer Charge, plus Capacity Charge.
(d) ***Interruptible Sales Service.*** Customer Charge.

(continue to Sheet 31-4)

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

MONTHLY RATES: Effective: October 1, 2005 (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]:					**Total Billing Components [3]**	
Customer Charge (per month):					**$675.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Rate	Temporary Adjustments		
Block 1: 1st 10,000 therms	$0.09984	($0.00178)	$0.70927	$0.00893	**$0.81626**	(I)
Block 2: Next 20,000 therms	$0.08486	($0.00153)	$0.70927	$0.00886	**$0.80146**	
Block 3: Next 20,000 therms	$0.05991	($0.00108)	$0.70927	$0.00874	**$0.77684**	
Block 4: Next 100,000 therms	$0.03495	($0.00063)	$0.70927	$0.00863	**$0.75222**	
Block 5: Next 600,000 therms	$0.01998	($0.00036)	$0.70927	$0.00856	**$0.73745**	
Block 6: All additional therms	$0.01000	($0.00017)	$0.70927	$0.00852	**$0.72762**	(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):					**$0.09466**	(R)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.37**	(R)
INTERRUPTIBLE SALES SERVICE CHARGES [2]:						
Customer Charge (per month):					**$675.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Rate	Temporary Adjustments		
Block 1: 1st 10,000 therms	$0.09984	($0.00178)	$0.70927	($0.00293)	**$0.80440**	(I)
Block 2: Next 20,000 therms	$0.08486	($0.00153)	$0.70927	($0.00300)	**$0.78960**	
Block 3: Next 20,000 therms	$0.05991	($0.00108)	$0.70927	($0.00312)	**$0.76498**	
Block 4: Next 100,000 therms	$0.03495	($0.00063)	$0.70927	($0.00323)	**$0.74036**	
Block 5: Next 600,000 therms	$0.01998	($0.00036)	$0.70927	($0.00330)	**$0.72559**	
Block 6: All additional therms	$0.01000	($0.00017)	$0.70927	($0.00334)	**$0.71576**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.01126**	(R)

[1] The total Firm Sales Service Billing Rate is the total of the Customer Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus the Storage Capacity Charge, plus the Pipeline Capacity Charge selected by the Customer.
[2] The total Interruptible Sales Service Billing Rate is the total of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge.
[3] **SCHEDULE C** and **SCHEDULE 15** Charges shall apply, if applicable.

(continue to Sheet 32-3)

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

MONTHLY RATES: Effective: October 1, 2005 (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 distributed generation customers are subject to **SCHEDULE 32-CHP**.

FIRM TRANSPORTATION SERVICE CHARGES [1]:					**Total Billing Components [3]**	
Customer Charge (per month):					**$675.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Temporary Adjustments		
Block 1: 1st 10,000 therms	$0.09984	$0.00122		$0.00047	**$0.10153**	(I)
Block 2: Next 20,000 therms	$0.08486	$0.00102		$0.00039	**$0.08627**	
Block 3: Next 20,000 therms	$0.05991	$0.00072		$0.00027	**$0.06090**	
Block 4: Next 100,000 therms	$0.03495	$0.00042		$0.00015	**$0.03552**	
Block 5: Next 600,000 therms	$0.01998	$0.00024		$0.00008	**$0.02030**	
Block 6: All additional therms	$0.01000	$0.00013		$0.00003	**$0.01016**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES [2]:						
Customer Charge (per month):					**$675.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Temporary Adjustments		
Block 1: 1st 10,000 therms	$0.09984	$0.00122		$0.00047	**$0.10153**	(I)
Block 2: Next 20,000 therms	$0.08486	$0.00102		$0.00039	**$0.08627**	
Block 3: Next 20,000 therms	$0.05991	$0.00072		$0.00027	**$0.06090**	
Block 4: Next 100,000 therms	$0.03495	$0.00042		$0.00015	**$0.03552**	
Block 5: Next 600,000 therms	$0.01998	$0.00024		$0.00008	**$0.02030**	
Block 6: All additional therms	$0.01000	$0.00013		$0.00003	**$0.01016**	(I)

[1] The total Firm Transportation Service Billing Rate is the total of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge.

[2] The total Interruptible Transportation Service Billing Rate is the total of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges.

[3] **SCHEDULE C** and **SCHEDULE 15** charges shall apply, if applicable.

(continue to Sheet 32-4)

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

MONTHLY RATE: Effective: October 1, 2005 (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.

		Base Rate	Base Rate Adjustments	Temporary Adjustment	**Billing Rate**	
Customer Charge:					**$38,000.00**	
Transportation Charge:		$250.00			**$250.00**	
Volumetric Charge:	Per therm, all therms	$0.00541	$0.00007	$0.00001	**$0.00549**	(I)
Firm Service Distribution Capacity Charge:	Per therm of MDDV per month				**$0.15748**	
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus Capacity Charge (if applicable), plus **SCHEDULE C** and **SCHEDULE 15** Charges (if applicable).						

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**.

MONTHLY RATE: Effective: October 1, 2005 (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	Temporary Adjustment	Billing Rate	
Usage Charge, per therm, all therms	$1.22166	$0.01802	**$1.23968**	(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: October 1, 2005 (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		($0.00465)	$0.01077	$0.01651	**$0.02263**
1C		($0.00465)	$0.01077	$0.01208	**$0.01820**
2		($0.00465)	$0.01077	$0.01630	**$0.02242**
3 (CFS)		($0.00465)	$0.01077	$0.01170	**$0.01782**
3 (CFT)		N/A	$0.01077	$0.01170	**$0.02247**
3 (IFS)		($0.00465)	$0.01077	$0.00316	**$0.00928**
3 (IFT)		N/A	$0.01077	$0.00328	**$0.01405**
19		($0.09)	$0.21	$0.30	**$0.42**
31 (CFS)	Block 1	($0.00465)	$0.01077	$0.01135	**$0.01747**
	Block 2	($0.00465)	$0.01077	$0.01129	**$0.01741**
31(CFT)	Block 1	N/A	N/A	$0.00898	**$0.00898**
	Block 2	N/A	N/A	$0.00892	**$0.00892**
31 (CIS)	Block 1	($0.00465)	$0.00128	$0.00898	**$0.00561**
	Block 2	($0.00465)	$0.00128	$0.00892	**$0.00555**
31 (IFS)	Block 1	($0.00465)	$0.01077	$0.00287	**$0.00899**
	Block 2	($0.00465)	$0.01077	$0.00281	**$0.00893**
31 (IFT)	Block 1	N/A	N/A	$0.00050	**$0.00050**
	Block 2	N/A	N/A	$0.00044	**$0.00044**
31 (IIS)	Block 1	($0.00465)	$0.00128	$0.00050	**($0.00287)**
	Block 2	($0.00465)	$0.00128	$0.00044	**($0.00293)**

(C)

(C)

(continue to Sheet 162-2)

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

APPLICATION TO RATE SCHEDULES (continued): Effective: October 1, 2005 (T)

Schedule	Block	Account 191 Commodity Adjustment	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments	Total Temporary Adjustment
32(FS)	Block 1	($0.00465)	$0.01077	$0.00281	**$0.00893**
	Block 2	($0.00465)	$0.01077	$0.00274	**$0.00886**
	Block 3	($0.00465)	$0.01077	$0.00262	**$0.00874**
	Block 4	($0.00465)	$0.01077	$0.00251	**$0.00863**
	Block 5	($0.00465)	$0.01077	$0.00244	**$0.00856**
	Block 6	($0.00465)	$0.01077	$0.00240	**$0.00852**
32(FT)	Block 1	N/A	N/A	$0.00047	**$0.00047**
	Block 2	N/A	N/A	$0.00039	**$0.00039**
	Block 3	N/A	N/A	$0.00027	**$0.00027**
	Block 4	N/A	N/A	$0.00015	**$0.00015**
	Block 5	N/A	N/A	$0.00008	**$0.00008**
	Block 6	N/A	N/A	$0.00003	**$0.00003**
32(IS)	Block 1	($0.00465)	$0.00128	$0.00044	**($0.00293)**
	Block 2	($0.00465)	$0.00128	$0.00037	**($0.00300)**
	Block 3	($0.00465)	$0.00128	$0.00025	**($0.00312)**
	Block 4	($0.00465)	$0.00128	$0.00014	**($0.00323)**
	Block 5	($0.00465)	$0.00128	$0.00007	**($0.00330)**
	Block 6	($0.00465)	$0.00128	$0.00003	**($0.00334)**
32(IT)	Block 1	N/A	N/A	$0.00047	**$0.00047**
	Block 2	N/A	N/A	$0.00039	**$0.00039**
	Block 3	N/A	N/A	$0.00027	**$0.00027**
	Block 4	N/A	N/A	$0.00015	**$0.00015**
	Block 5	N/A	N/A	$0.00008	**$0.00008**
	Block 6	N/A	N/A	$0.00003	**$0.00003**
33(IT)		N/A	N/A	$0.00000	**$0.00000**
33(FT)		N/A	N/A	$0.00000	**$0.00000**
54		(0.00465)	$0.01077	$0.01190	**$0.01802**

(C)

(C)

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

Issued August 15, 2005 Effective with service on
NWN Advice No. OPUC 05-9 and after October 1, 2005

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 (CFS)
	Schedule 3 (CFT)
	Schedule 31 (CFS)
	Schedule 31 (CFT)
	Schedule 31 (CIS)

APPLICATION TO RATE SCHEDULES: **Effective: October 1, 2005** (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: $0.00978 per therm (C)
Commercial Rate Schedules: $0.00742 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: October 1, 2005 (T)

Commodity Component [1]	$0.70927	(I)
Firm Sales Service Pipeline Capacity Component [2]	$0.09466	(R)
Gas Light Service Pipeline Capacity Component [3]	$1.81	(I)
Firm Sales Service Pipeline Capacity Component [4]	$1.37	(R)
Interruptible Sales Service Pipeline Capacity Component [5]	$0.01126	(R)

[1] Applies to all Sales Service Rate Schedules (per therm).
[2] Applies to Rate Schedules 1, 2, 3, and Schedule 31 and Schedule 32 Firm Sales Service Volumetric Pipeline Capacity option (per therm).
[3] Applies to Schedule 19.
[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: October 1, 2005 (T)

The above listed components shall be adjusted as follows:

Commodity Component	**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 by: ***NORTHWEST NATURAL GAS COMPANY***
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Portland, Oregon 97209-3991

SCHEDULE 176

ADJUSTMENTS TO RATES FOR COSTS RELATING TO SOUTH MIST PIPELINE EXTENSION PROJECT

PURPOSE:
The rate adjustments under this Schedule represent the rate treatment for the Oregon portion of the incremental cost of service relating to NW Natural's South Mist Pipeline Extension Project ("Mist Project").

The allocation of costs to customers under this Schedule is consistent with OPUC Order No. 03-507, in Docket UG 152.

APPLICATION TO RATE SCHEDULES: Effective: October 1, 2005 (T)

The Base Adjustment in each of the following Rate Schedules includes the following amounts. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Adjustments
1(R)	$0.00030
1(C)	$0.00029
2	$0.00026
3C(FS/FT)	$0.00021
3I(FS/FT)	$0.00019
31C (FS/IS/FT):	
Block 1	$0.00011
Block 2	$0.00010
31I (FS/IS/FT):	
Block 1	$0.00011
Block 2	$0.00010
33 (All)	$0.00000

(C)

(C)

SPECIAL CONDITIONS:

Each Mist project phase shall be considered in service beginning on the date that NW Natural provides attestation by a corporate officer that the project meets the following minimum requirements:

(a) Completion of any operational testing required by the construction contract;
(b) Release of the plant operation to the system dispatcher for full commercial operation, and;
(c) Continuous operation for 24 hours.

(continue to Sheet 176-2)

SCHEDULE 177
ADJUSTMENTS TO RATES FOR SAFETY PROGRAM
(continued)

BARE STEEL REPLACEMENT PROGRAM (continued)

APPLICATION TO RATE SCHEDULES: Effective: October 1, 2005 (T)
The Adjustments shown below are included in the Base Adjustments in the listed Rate Schedules:

Schedule	Block	30%	70%	Total Adjustment
1R		$0.00147	$0.00282	**$0.00429**
1C		$0.00141	$0.00282	**$0.00423**
2		$0.00127	$0.00282	**$0.00409**
3 (CFS)		$0.00102	$0.00282	**$0.00384**
3 (CFT)		$0.00102	$0.00282	**$0.00384**
3 (IFS)		$0.00094	N/A	**$0.00094**
3 (IFT)		$0.00094	N/A	**$0.00094**
19		$0.02	$0.05	**$0.07**
31 (CFS)	Block 1	$0.00053	$0.00282	**$0.00335**
	Block 2	$0.00048	$0.00282	**$0.00330**
31(CFT)	Block 1	$0.00053	$0.00282	**$0.00335**
	Block 2	$0.00048	$0.00282	**$0.00330**
31 (CIS)	Block 1	$0.00053	$0.00282	**$0.00335**
	Block 2	$0.00048	$0.00282	**$0.00330**
31 (IFS)	Block 1	$0.00053	N/A	**$0.00053**
	Block 2	$0.00048	N/A	**$0.00048**
31 (IFT)	Block 1	$0.00053	N/A	**$0.00053**
	Block 2	$0.00048	N/A	**$0.00048**
31 (IIS)	Block 1	$0.00053	N/A	**$0.00053**
	Block 2	$0.00048	N/A	**$0.00048**
32 (all)	Block 1	$0.00030	N/A	**$0.00030**
	Block 2	$0.00025	N/A	**$0.00025**
	Block 3	$0.00018	N/A	**$0.00018**
	Block 4	$0.00010	N/A	**$0.00010**
	Block 5	$0.00006	N/A	**$0.00006**
	Block 6	$0.00003	N/A	**$0.00003**
33 (all)		$0.00000	N/A	**$0.00000**
54		$0.00141	$0.00282	**$0.00423**

(C)

(C)

(continue to Sheet 177-3)

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 October 1 through September 30. 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, 2006 or until such other time as the Commission may approve.

APPLICATION TO RATE SCHEDULES: Effective: October 1, 2005 (T)
The Adjustments shown below are included in the Base Rate Adjustments in the above-listed Rate Schedules.

Schedule	Block	Total Adjustment
1R		$0.00078
1C		$0.00074
2		$0.00067
3 (CFS)		$0.00054
3 (CFT)		$0.00054
3 (IFS)		$0.00050
3 (IFT)		$0.00050
19		$0.01
31 (all)	Block 1	$0.00028
	Block 2	$0.00025
32 (all)	Block 1	$0.00016
	Block 2	$0.00013
	Block 3	$0.00009
	Block 4	$0.00006
	Block 5	$0.00003
	Block 6	$0.00002
33 (all)		$0.00002
54		$0.00074

(C)

(C)

(continue to Sheet 177-4)

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 October 1 through September 30, 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: October 1, 2005 (T)
The Adjustments shown below are included in the Base Rate Adjustments in the above-listed Rate Schedules.

Schedule	Block	Total Adjustment
1R		$0.00116
1C		$0.00111
2		$0.00100
3 (CFS)		$0.00080
3 (CFT)		$0.00080
3 (IFS)		$0.00074
3 (IFT)		$0.00074
19		$0.01
31 (all)	Block 1	$0.00042
	Block 2	$0.00038
32 (all)	Block 1	$0.00024
	Block 2	$0.00020
	Block 3	$0.00014
	Block 4	$0.00008
	Block 5	$0.00005
	Block 6	$0.00002
33 (all)		$0.00000
54		$0.00111

(C)

(C)

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SCHEDULE 190

PARTIAL DECOUPLING MECHANISM

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

TERM:
This Schedule shall automatically terminate on September 30, 2009. (C)

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(FS)
	Schedule 3(FT)
	Schedule 31(FS)
	Schedule 31(IS)
	Schedule 31(FT)

ADJUSTMENT TO RATE SCHEDULES: Effective: October 1, 2005 (T)
The Temporary Adjustments for Residential and Commercial Customers taking service on the above-listed Rate Schedules includes the following adjustment:

Residential Rate Schedules: $0.01265 per therm (C)
Commercial Rate Schedules: $0.00846 per therm (C)

PARTIAL DECOUPLING DEFERRAL ACCOUNT:

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

   The Company shall defer and amortize, with interest, 100% of the distribution margin differential (C)
   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)

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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. (C) (C)

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

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

(T)

3. Weather-normalized usage is calculated using the approach to weather normalization adopted in the Company's last general rate case, Docket UG 152.

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. (N)

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. (N)

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 October 1, 2005 are $0.45093 per therm for Residential customers and $0.30330 per therm for Commercial customers. (T) (C)

(continue to Sheet 190-3)

SCHEDULE 190

PARTIAL DECOUPLING MECHANISM
(continued)

PARTIAL DECOUPLING DEFERRAL ACCOUNT (continued):

6. Coincident with the Company's annual Purchased Gas Cost and Technical Rate Adjustment filing commencing with the filing effective October 1, 2003, and each year thereafter during the term of this Schedule, the Company shall apply an adjustment to Residential and Commercial rates to amortize over the following 12 months, the balance in the balancing account as of June 30.

7. This Schedule is an "automatic adjustment clause" as defined in ORS 757.210, and is subject to review by the Commission at least once every two (2) years. (D)

SPECIAL CONDITIONS:

1. The existence of this Partial Decoupling Mechanism will not affect the Company's service line and main extension policies.

2. Other terms and conditions as specified in the Stipulation and Agreement.

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.

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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 November 15, 2005 are: (T)

Schedule 2: $0.43814	Schedule 3: $0.34986

(C)

(continue to Sheet 195-4)

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

WARM FORMULA: (continued)

c. Weather data used in the calculation of HDD for each customer shall be based on the daily temperatures reported at the following weather stations. In the event that data is not available for any of the listed stations, the company will use a substitute station and associated basis temperature differentials in accordance with Company policy. (C) | (C)

Weather Station	NWN Service District
Astoria (350328)	Astoria
Coos Bay (356073)	Coos Bay
Newport (356032)	Lincoln City
Corvallis (351862)	Albany
Hood River Exp Station (354003)	The Dalles
Portland (356751)	Portland
Eugene (352709)	Eugene
Salem (357500)	Salem

(N)

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	$ 0.27
5	.9790	$0.43		3.8345	$ 1.34
10	1.958	$0.86		7.669	$ 2.68
15	2.937	$1.29		11.5035	$ 4.02
20	3.916	$1.72		15.338	$ 5.37
25	4.895	$2.14		19.1725	$ 6.71
30	5.874	$2.57		23.007	$ 8.05
35	6.853	$3.00		26.8415	$ 9.39
40	7.832	$3.43		30.676	$10.73
45	8.811	$3.86		34.5105	$12.07
50	9.790	$4.29		38.345	$13.42

(C) | (C)

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

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

(continue to Sheet 195-5)

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

WARM BILL EFFECTS: (continued)

Example Bill Calculation:

Here is the how the WARM adjustment is calculated for a residential **RATE SCHEDULE 2** customer where the base billing rate is $1.26449 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	(C)
	Margin Rate:	$0.43814	
	Total WARM Adj.:	-9.79 x $0.43814 = -$4.28939	
Total WARM Adjustment converted to cents per therm:	Total WARM Adj.	-$4.28939	
	Monthly usage:	129 therms	
	Cent/therm Adj.:	-$4.28939 ÷ 129 = -$0.03325	
Billing Rate per therm:	Current Rate/therm:	$1.26449	
	WARM cent/therm Adj.	-$0.03325	
	WARM Billing Rate:	$1.26449 + -$0.03325 = $1.23124	
Total WARM Bill:	Customer Charge:	$6.00	
	Usage Charge:	$1.23124	(C)
	Total	(129 x $1.23124) + $6.00 = $164.83	

(continue to Sheet 195-6)

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SCHEDULE 199
SPECIAL RATE ADJUSTMENT (UM 1148/UP 205)

PURPOSE
The purpose of this schedule is to reflect the effects of rate adjustments made pursuant to OPUC Order No. 04-439 in Docket UM 1148/UP 205.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1	Schedule 3 (all)	Schedule 31 (all)	Schedule 33
Schedule 2	Schedule 19 (all)	Schedule 32 (all)	Schedule 54

APPLICATION TO RATE SCHEDULES: Effective: October 1, 2005 (T)

The Total Adjustment amounts shown below are included in the Base Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

(C)

Schedule	Block	Temporary Adjustment	Base Rate Adjustment
1R		($0.00001)	$0.00000
1C		($0.00001)	$0.00000
2		($0.00001)	$0.00000
3 (CFS)		($0.00001)	$0.00000
3 (CFT)		($0.00001)	$0.00000
3 (IFS)		$0.00000	$0.00000
3 (IFT)		$0.00000	$0.00000
19		$0.00000	$0.00
31 (CFS)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
31(CFT)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
31 (CIS)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
31 (IFS)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
31 (IFT)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
31 (IIS)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000

(C)

(continue to Sheet 199-2)

SCHEDULE 199
SPECIAL RATE ADJUSTMENT (UM 1148/UP205)
(continued)

APPLICATION TO RATE SCHEDULES (continued): Effective: October 1, 2005 (T)

(C)

Schedule	Block	Temporary Adjustment	Base Rate Adjustment
32(FS)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000
32(FT)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000
32(IS)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000
32(IT)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000
33(IT)		$0.00000	$0.00000
33(FT)		$0.00000	$0.00000
54		($0.00001)	$0.00000

(C)

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

NW NATURAL OREGON RATE SUMMARY WORKSHEET

OPUC Docket No. UG ____; NWN Advice No. OPUC 05-9
Exhibit A Supporting Materials; Page 1 of 8

NWN Advice No. OPUC 05- 9

Issue Date: **15-Aug-05** Proposed Effective Date: **October 1, 2005**

	REMOVE: October 1, 2004							**ADD: October 1, 2005**						
Schedule	Billing Rates	Temporary Adjustments	Temporary Base Adjustments	Base Rates	Demand	Commodity	Starting Base Rates	Base Adjustment	Total Base Rates	Demand	Commodity	Temporary Adjustments	**Proposed Billing Rates**	**Proposed Base Rates**
Or 24														
1 Service	5.00			5.00			5.00		5.00				5.00	5.00
Residential Volumetric	$1.17638	$0.01949	$0.00343	$1.15346	$0.12148	$0.54154	$0.49044	$0.01564	$0.50608	$0.09466	$0.70927	$0.02263	$1.33264	$1.31001
Commercial Volumetric	$1.15455	$0.02003	$0.00337	$1.13115	$0.12148	$0.54154	$0.46813	$0.01300	$0.48113	$0.09466	$0.70927	$0.01820	$1.30326	$1.28506
2 Service	6.00			6.00			$6.00		6.00				6.00	6.00
Volumetric	$1.10784	$0.01913	$0.00319	$1.08552	$0.12148	$0.54154	$0.42250	$0.01564	$0.43814	$0.09466	$0.70927	$0.02242	$1.26449	$1.24207
3C Sales Service	8.00			8.00			$8.00		8.00				8.00	8.00
Commercial Volumetric	$1.02239	$0.01931	$0.00289	$1.00019	$0.12148	$0.54154	$0.33717	$0.01269	$0.34986	$0.09466	$0.70927	$0.01782	$1.17161	$1.15379
3C Transportation Service	8.00			8.00			$8.00		8.00				8.00	8.00
Commercial Volumetric	$0.48250	$0.02096	$0.00289	$0.45865			$0.43183	$0.01269	$0.44452			$0.02247	$0.46699	$0.44452
3I Sales Service	8.00			8.00			$8.00		8.00				8.00	8.00
Industrial Volumetric	$0.99346	$0.01498	$0.00116	$0.97732	$0.12148	$0.54154	$0.31430	$0.00212	$0.31642	$0.09466	$0.70927	$0.00928	$1.12963	$1.12035
3I Transportation Service	8.00			8.00			$8.00		8.00				8.00	8.00
Industrial Volumetric	$0.45357	$0.01663	$0.00116	$0.43578			$0.40896	$0.00212	$0.41108			$0.01393	$0.42501	$0.41108
19 One mantle	$18.46	$0.28	$0.06	$18.12	$2.32	$10.34	$20.82	$0.28	$21.10	$1.81	$13.55	$0.42	$21.52	$36.46
Additional mantles	$17.85	$0.28	$0.06	$17.51	$2.32	$10.34	$20.21	$0.28	$20.49	$1.81	$13.55	$0.42	$20.91	$35.85
31C Commercial Firm Sales Service	$325.00			$325.00			$325.00		$325.00				$325.00	$325.00
Pipeline Capacity Charge (per th/MDDV)	1.76												$1.37	$1.37
Pipeline Capacity Charge (per therm)	$0.12148												$0.09466	$0.09466
Commodity Charge	$0.54154												$0.70927	
First 2,000	$0.73774	$0.01844	$0.00228	$0.71702		$0.54154	$0.17548	$0.01126	$0.18674		$0.70927	$0.01747	$0.91348	$0.89601
All additional	$0.72140	$0.01835	$0.00223	$0.70082		$0.54154	$0.15928	$0.01116	$0.17044		$0.70927	$0.01741	$0.89712	$0.87971
31I Industrial Firm Sales Service	$325.00			$325.00			$325.00		$325.00				$325.00	$325.00
Pipeline Capacity Charge (per th/MDDV)	1.76												$1.37	$1.37
Pipeline Capacity Charge (per therm)	$0.12148												$0.09466	$0.09466
Commodity Charge	$0.54154												$0.70927	
First 2,000	$0.72442	$0.01423	$0.00063	$0.70956		$0.54154	$0.16802	$0.00102	$0.16904		$0.70927	$0.00899	$0.88730	$0.87831
All additional	$0.70808	$0.01414	$0.00057	$0.69337		$0.54154	$0.15183	$0.00092	$0.15275		$0.70927	$0.00893	$0.87095	$0.86202
31C Commercial Interruptible Sales Service	$325.00			$325.00			$325.00		$325.00				$325.00	$325.00
Pipeline Capacity Charge (per therm)	$0.01445												$0.01126	$0.01126
Commodity Charge	$0.54154												$0.70927	
First 2,000	$0.72429	$0.00499	$0.00228	$0.71702		$0.54154	$0.17548	$0.01126	$0.18674		$0.70927	$0.00561	$0.90162	$0.89601
All additional	$0.70795	$0.00490	$0.00223	$0.70082		$0.54154	$0.15928	$0.01116	$0.17044		$0.70927	$0.00555	$0.88526	$0.87971
31I Industrial Interruptible Sales Service	$325.00			$325.00			$325.00		$325.00				$325.00	$325.00
Pipeline Capacity Charge (per therm)	$0.01445												$0.01126	$0.01126
Commodity Charge	$0.54154												$0.70927	$0.70927
First 2,000	$0.71097	$0.00078	$0.00063	$0.70956		$0.54154	$0.16802	$0.00102	$0.16904		$0.70927	($0.00287)	$0.87544	$0.87831
All additional	$0.69463	$0.00069	$0.00057	$0.69337		$0.54154	$0.15183	$0.00092	$0.15275		$0.70927	($0.00293)	$0.85909	$0.86202
31C Commercial Firm Transportation Service	$325.00			$325.00			$325.00		$325.00				$325.00	$325.00
First 2,000	$0.18308	$0.00532	$0.00228	$0.17548			$0.17548	$0.01126	$0.18674			$0.00898	$0.19572	$0.18674
All additional	$0.16674	$0.00523	$0.00223	$0.15928			$0.15928	$0.01116	$0.17044			$0.00892	$0.17936	$0.17044
31I Industrial Firm Transportation Service	$325.00			$325.00			$325.00		$325.00				$325.00	$325.00
First 2,000	$0.16976	$0.00111	$0.00063	$0.16802			$0.16802	$0.00102	$0.16904			$0.00050	$0.16954	$0.16904
All additional	$0.15342	$0.00102	$0.00057	$0.15183			$0.15183	$0.00092	$0.15275			$0.00044	$0.15319	$0.15275

	REMOVE: October 1, 2004							ADD: October 1, 2005						
32 Firm Sales Service	$675.00			$675.00			$675.00		$675.00				$675.00	$675.00
Distribution Capacity Charge (per MDDV)	$0.15748												$0.15748	$0.15748
Storage Charge (per MDDV)	$0.20415												$0.20415	$0.20415
Pipeline Capacity Charge (per MDDV)	$1.76												$1.37	$1.37
Pipeline Capacity Charge (volumetric)	$0.12148												$0.09466	$0.09466
First 10,000	$0.65431	$0.01256	$0.00037	$0.64138		$0.54154	$0.09984	($0.00178)	$0.09806		$0.70927	$0.00893	$0.81626	$0.80733
Net 20,000	$0.63938	$0.01268	$0.00030	$0.62640		$0.54154	$0.08486	($0.00153)	$0.08333		$0.70927	$0.00886	$0.80146	$0.79260
Next 20,000	$0.61453	$0.01288	$0.00020	$0.60145		$0.54154	$0.05991	($0.00108)	$0.05883		$0.70927	$0.00874	$0.77684	$0.76810
Next 100,000	$0.58968	$0.01308	$0.00011	$0.57649		$0.54154	$0.03495	($0.00063)	$0.03432		$0.70927	$0.00863	$0.75222	$0.74359
Next 600,000	$0.57476	$0.01320	$0.00004	$0.56152		$0.54154	$0.01998	($0.00036)	$0.01962		$0.70927	$0.00856	$0.73745	$0.72889
All additional	$0.56482	$0.01328	$0.00000	$0.55154		$0.54154	$0.01000	($0.00017)	$0.00983		$0.70927	$0.00852	$0.72762	$0.71910
32 Interruptible Sales Service	$675.00			$675.00			$675.00		$675.00				$675.00	$675.00
Pipeline Capacity Charge (volumetric)	$0.01445												$0.01126	$0.01126
First 10,000	$0.64085	($0.00090)	$0.00037	$0.64138		$0.54154	$0.09984	($0.00178)	$0.09806		$0.70927	($0.00293)	$0.80440	$0.80733
Net 20,000	$0.62592	($0.00078)	$0.00030	$0.62640		$0.54154	$0.08486	($0.00153)	$0.08333		$0.70927	($0.00300)	$0.78960	$0.79260
Next 20,000	$0.60107	($0.00058)	$0.00020	$0.60145		$0.54154	$0.05991	($0.00108)	$0.05883		$0.70927	($0.00312)	$0.76498	$0.76810
Next 100,000	$0.57622	($0.00038)	$0.00011	$0.57649		$0.54154	$0.03495	($0.00063)	$0.03432		$0.70927	($0.00323)	$0.74036	$0.74359
Next 600,000	$0.56130	($0.00026)	$0.00004	$0.56152		$0.54154	$0.01998	($0.00036)	$0.01962		$0.70927	($0.00330)	$0.72559	$0.72889
All additional	$0.55136	($0.00018)	$0.00000	$0.55154		$0.54154	$0.01000	($0.00017)	$0.00983		$0.70927	($0.00334)	$0.71576	$0.71910
32 Firm Transportation Service	$675.00			$675.00			$675.00		$675.00				$675.00	$675.00
Distribution Capacity Charge (per MDDV)	$0.15748												$0.15748	$0.15748
First 10,000	$0.09964	($0.00057)	$0.00037	$0.09984			$0.09984	$0.00122	$0.10106			$0.00047	$0.10153	$0.10106
Net 20,000	$0.08471	($0.00045)	$0.00030	$0.08486			$0.08486	$0.00102	$0.08588			$0.00039	$0.08627	$0.08588
Next 20,000	$0.05986	($0.00025)	$0.00020	$0.05991			$0.05991	$0.00072	$0.06063			$0.00027	$0.06090	$0.06063
Next 100,000	$0.03501	($0.00005)	$0.00011	$0.03495			$0.03495	$0.00042	$0.03537			$0.00015	$0.03552	$0.03537
Next 600,000	$0.02009	$0.00007	$0.00004	$0.01998			$0.01998	$0.00024	$0.02022			$0.00008	$0.02030	$0.02022
All additional	$0.01015	$0.00015	$0.00000	$0.01000			$0.01000	$0.00013	$0.01013			$0.00003	$0.01016	$0.01013
32 Interruptible Transportation Service	$675.00			$675.00			$675.00		$675.00				$675.00	$675.00
First 10,000	$0.09964	($0.00057)	$0.00037	$0.09984			$0.09984	$0.00122	$0.10106			$0.00047	$0.10153	$0.10106
Net 20,000	$0.08471	($0.00045)	$0.00030	$0.08486			$0.08486	$0.00102	$0.08588			$0.00039	$0.08627	$0.08588
Next 20,000	$0.05986	($0.00025)	$0.00020	$0.05991			$0.05991	$0.00072	$0.06063			$0.00027	$0.06090	$0.06063
Next 100,000	$0.03501	($0.00005)	$0.00011	$0.03495			$0.03495	$0.00042	$0.03537			$0.00015	$0.03552	$0.03537
Next 600,000	$0.02009	$0.00007	$0.00004	$0.01998			$0.01998	$0.00024	$0.02022			$0.00008	$0.02030	$0.02022
All additional	$0.01015	$0.00015	$0.00000	$0.01000			$0.01000	$0.00013	$0.01013			$0.00003	$0.01016	$0.01013
33 Firm and Interruptible Transportation Service														
Customer Charge	$38,000.00			$38,000.00			$38,000.00		$38,000.00				$38,000.00	$38,000.00
Distribution Capacity Charge	$0.15748												$0.15748	$0.15748
Volumetric Charge (per therm)	$0.00559	$0.00016	$0.00002	$0.00541			$0.00541	$0.00007	$0.00548			$0.00001	$0.00549	$0.00548
54 Emergency Service														
Volumetric Charge (per therm)	$1.08136	$0.01357	$0.00327	$1.06452	$0.12148	$0.54154	$0.40150	$0.01623	$0.41773	$0.09466	$0.70927	$0.01802	$1.23968	$1.22166

NW Natural

Effects of PGA by Rate Schedule

Schedule	Current Rates	Custs	Therms	SC Revenue	Therm Rev	Total Rev	Proposed Rates	Proposed SC Revenue	Proposed Therm Rev	Proposed Total Rev	Revenue Change	Percent Rev Chang	Average Use/mo	Average Bill	Dollar Increase	Percent Rev Change
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	$5.00	3,369		$202,140				$202,140								
1r	$1.17638	176	776,617	$10,560	$913,596	$1,115,736	$1.33264	$10,560	$1,034,951	$1,237,091	$121,354	10.9%	19.2	$27.60	3.00	10.9%
1c	$1.15455		63,497		$73,310	$83,870	$1.30326		$82,753	$93,313	$9,443	11.3%	30.1	$39.71	4.47	11.3%
2	$6.00	486,843		$35,052,696				$35,052,696								
2r	$1.10784		345,955,930		$383,263,818	$418,316,514	$1.26449		$437,457,814	$472,510,510	$54,193,996	13.0%	59.2	$71.60	9.28	13.0%
3	$8.00	52,862		$5,074,752				$5,074,752								
3c	$1.02239	279	145,167,952	$26,784	$148,418,262	$153,493,014	$1.17161	$26,784	$170,080,224	$175,154,976	$21,661,962	14.1%	228.8	$241.97	34.15	14.1%
3i	$0.99346		4,023,348		$3,997,036	$4,023,820	$1.12963		$4,544,895	$4,571,679	$547,859	13.6%	1,201.7	$1,201.86	163.64	13.6%
19	$18.46	139	34,949	$30,794		$30,794	$21.52000		$35,899	$35,899	$5,105	16.6%	19.1	$18.46	3.06	16.6%
0	$17.85															
31c	$325.00	1,250		$4,875,000				$4,875,000								
0	$0.85922		30,000,000		$25,776,600	$65,667,324	$1.00814		$30,244,200	$76,320,670	$4,467,600	16.2%	4,769.5	$4,377.82	297.84	16.2%
0	$0.84288		41,542,953		$35,015,724		$0.99178		$41,201,470		$6,185,746					
31i	$325.00	322		$1,255,800				$1,255,800								
0	$0.84610		7,728,000		$6,538,661	$26,921,834	$0.98196		$7,588,587	$31,103,333	$1,049,926	15.5%	7,965.8	$6,967.35	271.72	15.5%
0	$0.82976		23,051,694		$19,127,374		$0.96561		$22,258,946		$3,131,573					
32	$675.00	215		$1,741,500				$1,741,500								
0	$0.77579		13,168,175		$10,215,738	$116,617,813	$0.91092		$11,995,154	$126,374,614	$1,779,415	18.7%	62,138.7	$45,200.70	689.70	18.7%
0	$0.76086		21,943,982		$16,696,298		$0.89612		$19,664,441		$2,968,143					
0	$0.73601		15,415,435		$11,345,915		$0.87150		$13,434,552		$2,088,637					
0	$0.71116		35,280,872		$25,090,345		$0.84688		$29,878,665		$4,788,320					
0	$0.69624		39,462,726		$27,475,528		$0.83211		$32,837,329		$5,361,801					
0	$0.68630		35,046,611		$24,052,489		$0.82228		$28,818,128		$4,765,638					
33	$38,000.00															
0	$0.00509															
54	$1.08136															

Northwest Natural	**2005 PGA Filing Summary Sheet**	
Change in Annual Revenues	**Amount**	**Location**
A. Dollars (000)	$118,148	Exhibit 2, Page 1, Summary of PGA Revenue Effects
B. Percent	16.7%	Increase / actual Oregon rev 12 mo. ened 6/30/05
Annual Revenues Calculation		
A. PGA Cost Change (Commodity and Transportation)	$111,318	Exhibit 2, Page 1, Summary of PGA Revenue Effects
B. Remove Last Year's Temporary Increment Total	($11,428)	"
C. Add New Temporary Increment	$11,832	"
D. Elasticity	$4,894	"
1 Bare Steel/Geohazard/Pipeline Integrity	$1,486	"
2 SMPE, Coos Bay (Schedule 176)	$1,314	"
3 Removal of Y2K	($1,268)	"
E. Total Proposed Change	$118,148	"
Residential Bill Effects Summary		
A. Residential Schedule Rate Impact		
1. Current Rate Per Therm	$1.10784	Exhibit A, PGA Effects by Rate Schedule
2. Proposed Rate Per Therm	$1.26449	"
3. Rate Change Per Therm	$0.15665	(Item 2, above, less Item 1, above.
4. Percent Change Per Therm	14.1%	(Item 4, above, divided by Item 1, above)
B. Average Residential Bill Impact		
1. Average Monthly Use	59.22	Exhibit A, PGA Effects by Rate Schedule
2. Customer Charge	$6.00	"
3. Current Average Monthly Bill	$71.60	Calculated from data on this page
4. Proposed Average Monthly Bill	$80.88	Calculated from data on this page
5. Change in Average Monthly Bill	$9.28	Calculated from data on this page
6. Percent Change in Average Monthly Bill	13.0%	Calculated from data on this page
C.. Average January Monthly Bill Impact		
1. January Monthly Use	122.09	Normalized January Sales Figures
2. Customer Charge	6.00	Calculated from data on this page
3. Current January Monthly Bill	$141.25	Calculated from data on this page
4. Proposed January Monthly Bill	$160.38	Calculated from data on this page
5. Change in January Monthly Bill	$19.13	Calculated from data on this page
6. Percent Change in January Monthly Bill	13.5%	Calculated from data on this page

Breakdown of Costs	Whole Dollars	Location in Company Filing
A. Embedded in Rates		
1. Total Commodity Cost	$379,235,790	Flowingdispatch_og2005.xls WACOG tab
Total Reservation Charges Accociated with Gas Contracts	$10,679,475	Flowingdispatch_og2005.xls Flowing Prices tab
Total Vaporization Costs	$14,511	Flowingdispatch_og2005.xls Pipeline Charges tab
2. Pipeline Charges		
Total Upstream Canadian Toll	$34,424,428	OT2005GS.xls GasCost Tab
Total Demand, Capacity or Reservation Cost	$81,828,410	OT2005GS.xls GasCost Tab
Total Volumetric Cost	$2,501,569	Flowingdispatch_og2005.xls WACOG tab
Total Volumetric Cost	$381,737,359	Flowingdispatch_og2005.xls WACOG tab
3. Total Storage Costs	$53,796,976	Flowingdispatch_og2005.xls Summary tab
B. Projected for New Rates		
1. Total Commodity Cost	$564,308,349	Flowingdispatch_og2005.xls WACOG tab
Total Reservation Charges Accociated with Gas Contracts	$6,133,620	Flowingdispatch_og2005.xls Flowing Prices tab
Total Vaporization Costs	$14,511	Flowingdispatch_og2005.xls Pipeline Charges tab
2. Pipeline Charges		
Total Upstream Canadian Toll	$27,878,790	Flowingdispatch_og2005.xls
Total Demand, Capacity or Reservation Cost	$64,699,041	Flowingdispatch_og2005.xls
Total Volumetric Cost	$2,695,758	
Total Volumetric Cost	$567,004,107	Flowingdispatch_og2005.xls
3. Total Storage Costs	$68,701,262	Flowingdispatch_og2005.xls

5. WACOG (Weighted Average Cost of Gas	Amount	Location in Company Filing
A. Embedded in Rates		
1. WACOG (Purchases)	$0.52579	Exhibit 2, Cost of Demand and Commodity Components for Gas Service
2. WACOG (For Sales)	$0.54154	"
		"
B. Proposed for New Rates		"
1. WACOG (Purchases)	$0.68904	"
2. WACOG (For Sales)	$0.70927	"
		"
6. Therms Sold	822,895,435	"

7) Customer Assistance Programs *(Include a brief explanation of each on a separate sheet)*	**Name of Program and Tariff Sheet No.** *(if applicable)*
A) DSM Programs	
1) Energy Efficiency Programs	Schedule 350 "Energy Efficiency Services & Programs - Residential and Commercial;
2) Mandated Energy Audits	Schedule 350 "Energy Efficiency Services & Programs - Residential and Commercial;
3) Any other DSM Program	Schedule 320 "Oregon Low-Income Energy Efficiency Program (OLIEE)"
B) Bill Pay Assistance Programs	
1) Tariffed Programs	Schedule 310 "Oregon Low-Income Gas Assistance Program (OLGA)"
2) Below-the-line Programs	N/A
C) Other Programs	Gas Assistance Program (GAP); a voluntary program funded by customer contributions

8) Purchasing/ Hedging Strategies *Prepare 1-2 page summary of gas cost situation to include resources, purchasing strategy, hedging, and*

A) Resources embedded in current rates and an explanation of proposed resources.

1) Firm Pipeline Capacity	
a) Year-round supply contracts	c) Reliance on Spot Gas/Other Short Term Contracts
b) Winter-only contracts	d) Other - e.g. Supply area storage
2) Market Area Storage	
a) Underground-owned	c) LNG-owned
b) Underground- contracted	d) LNG-contracted
3) Other Resources	
a) Recallable Supply	c) Owned-Production
b) City gate Deliveries	d) Propane/Air

See Staff Summary Page 4 for Summary of Purchasing Strategies

B. Were there any major events that caused a change in your purchasing strategy? If so, what were the events and how did your strategy change in response to them? ANSWER: There were no major events.

C) How are your purchasing/hedging strategies different from those outlined in your last filed IRP or 2-year action plan? ANSWER: Our purchasing and hedging strategies are consistent with those outlined in our last filed IRP and consistent with the draft IRP which is expected to be completed later this year.

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.

NWN currently has contracted with suppliers for approximately 1.3 million therms/day of firm deliveries on a year-round basis, reflecting the relatively stable daily component of NWN's demand including some portion of storage injection requirements in the summer months. In addition, during the heating season (Nov-Mar), NWN currently contracts for approximately another 1.5 million therms/day, reflecting the higher consumption of customers and potentially more intense competition for supplies during those months. About half of this winter contracted volume is purchased on a take-or-pay basis. The remaining contracted volumes are made available to NWN on a daily basis in exchange for payment of a fixed "reservation" charge, but there is no minimum daily, monthly or seasonal purchase requirement. These "swing" supplies 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 0.4 and 1.1 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. Spot purchases account for roughly 10% of annual purchases, but many of those purchases occur during the non-heating season, especially in late spring and early summer when storage injections are heaviest.

NWN "swaps" monthly index prices for fixed prices either directly with the physical supplier or, more typically, through the use of financial instruments, in order to increase price stability across the year. All take-or-pay volumes are fixed in price and NWN also will enter into several "call options" to help limit price exposure on supplies purchased on either a swing or spot basis during the winter months. Overall, NWN tries to hedge the prices of approximately 90% of its expected annual purchase volumes for the upcoming 12-month period commencing in November, the traditional start month for its supply contracts. NWN also engages in 2-year and 3-year price swaps for a portion of its future requirements to help stabilize prices to customers by dampening year-over-year volatility.

Assuming underground storage capacity continues to be added at Mist to meet customer requirements, the need for upstream "swing" supplies should gradually diminish as storage performs the same function. More storage capacity also means more gas will be injected during the summer months, providing better year-round utilization of upstream pipeline capacity.

[1] "Design" year refers to the coldest heating season (currently 1985/86) plus the coldest single day (currently February 3, 1989) experienced over the past 20 years. Expected firm requirements are derived using the degree-days from those design weather conditions along with current firm customer counts and expected gas usage per degree-day per customer.

[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.

NW NATURAL

Cost of Demand and Commodity Component for Gas Service
Cents/Therm
OREGON

	System Cost of Gas Adjustment	**Demand** **($17,129,369)**	**Commodity** **$136,717,830**	**Total** **$119,588,460**	
	(a)		**(b)** **Present** **Demand**	**(c)** **Proposed** **Demand**	**(d)** **Proposed** **Change [1]**
1	***Cents Per Therm Firm Demand Component ----------------------------***		**11.795**	**9.196**	**-2.599**
2	***Firm Demand per Therm with Revenue Sensitive Effects---------------***		**12.148**	**9.466**	**-2.683**
3	***Cents Per Therm Int. Demand Component ---------------------------***		**1.403**	**1.094**	**-0.309**
4	***Int Demand per Therm with Revenue Sensitive Effects---------------***		**1.445**	**1.126**	**-0.319**
	PRESENT AND PROPOSED WACOG	Present Sales Wacog	Proposed Sales Wacog	Change	
5	***A. Without Revenue Sensitive***	**52.579**	**68.904**	**16.325**	
6	***B. With Revenue Sensitive***	**54.154**	**70.927**	**16.773**	
7	***Derivation of Proposed Wacog***				
8	***Total proposed gas costs***	$567,004,107			
9	***Divided by System Actual Sales [3]***	822,895,435	**68.904**		
	CENT PER THERM RATE CHANGE				
10	***Firm Change (Cents/therm)***	**14.090**			
11	***Inter. Change (Cents/therm)***	**16.454**			
	OREGON REVENUE EFFECT (On Normalized Volumes)				
12	***Oregon Firm Demand Effect Equals [2]***	629,883,256		($0.02683)	($16,899,768)
13	***Plus Oregon Commidity Effect***	629,883,256	***times line 7***	$0.16773	$105,650,318
14	***For a Total Firm Effect of---***				$88,750,551
	Oregon Interruptible Demand Effect	121,779,867		($0.00319)	($388,492)
15	***Oregon Interruptible Effect***	121,779,867	***times line 8***	$0.16773	$20,426,137
				Total Commodity Change	$126,076,456
16			***Total Demand change***		($17,288,259)
	Total Oregon Revenue Change------------------------------------				$108,788,196

[1] This change applies to firm throughput net of Schedule 6
[2] The total demand paid by Oregon customer decreases, even though the per therm charge to non-sch 6 firm customers goes up.

[3] System actual sales year ended............			**[6] Oregon Normalized sales year**		
	30-Jun-05	822,895,435	**ended -----**	**30-Jun-05**	751,663,123
[4] Normalized Firm Deliveries----------------------		694,524,806	**Firm Deliveries-------------------**		657,845,173
[5] System Normalized			**Firm Sales--------------------------**		629,883,256
Firm Deliveries---------------------		725,738,061	**Interruptible Sales---------------**		121,779,867
			Normalized Firm Deliveries------------------		657,845,173
			Normalized Firm Sales-----------		629,883,256

[6] Revenue Sensitive Factor: 2.908%

NW NATURAL
Demand and Commodity Calculations

			CURRENT			PROPOSED	CHANGE		
TOTAL DEMAND			$81,828,410			$64,699,041	**($17,129,369)**		
TOTAL PURCHASES WACOG	826,615,203	$0.52054	$430,286,278	826,615,203	$0.68593	567,004,107		**$136,717,830**	
Normalized Throughput for Demand								**$119,588,460**	TOTAL CHANGE

Total proposed Commodity Cost of Gas	$567,004,107
Total Gas Purchases	826,615,203
Proposed Purchases Wacog ($/therm)	**$0.68593**
Purchases Wacog with Revenue Sensitive ($/therm)	**$0.70607**
Total Gas Sales	822,895,435
Proposed Sales Wacog ($/therm)	**$0.68904**
Proposed Sales Wacog with Rev. Sensitive ($/therm)	**$0.70927**
Unaccounted for Volumes	3,719,768
Unaccounted for Percent	0.45%
Calculated purchases	831,207,510

NW Natural Gas

Calculation of Oregon Per Therm Demand Charges

1	System Demand	$64,699,041
2	Oregon Allocation Factor	91.6%
3	Oregon Demand	$59,253,295
4	Oregon Firm Sales	629,883,256
5	Oregon Interruptible Sales	121,779,867
6	Demand Charges Generated by Proposed Rates	59,253,295
7	Current Demand Per Therm without Rev Sens	$0.11795
8	Current Interruptible Demand Without Rev. Sens.	$0.01403
9	Proposed Firm Demand Charge Per Therm-without Rev Sens	$0.09196
10	Peoposed Oregon Int. Demand per Therm without sensitive	$0.01094
11	Proposed Firm Demand Charge Per Therm with Rev Sens	$0.09466
12	Peoposed Oregon Int. Demand per Therm with sensitive	$0.01126
13		
14	Current Firm Demand With Revenue Sensitive	$0.12148
15	Current Int. Demand With Revenue Sensitive	$0.01520
16	Current MDDV Demand Charge	$1.76
17	Percent Change in Demand	-22.1%
18	Proposed MDDV Demand Charge	$1.37

NORTHWEST NATURAL GAS
TOTAL WACOG WITH VOLUMETRIC

	Gas Purchase Volumes	Gas Cost	Volumetric Charges
OCTOBER	53811111.4166541	27081542.7908245	191978.676505362
NOVEMBER	92250222.1012793	67214033.7070059	297735.151471598
DECEMBER	123243374.342106	87889294.672742	376782.708313166
JANUARY	124021817.651841	87373720.1068202	348771.28713122
FEBRUARY	99082975.9761184	68679101.6750787	258678.208967966
MARCH	87535133.7147486	63072771.2199142	286926.097326405
APRIL	68340186.9612458	44863838.7240077	243739.890494796
MAY	50861577.9673986	33644012.9723617	192254.002932037
JUNE	36830219.1560364	24414824.2485238	144233.914423527
JULY	29293302.2948289	19501644.2560245	114586.220308656
AUGUST	29071350.2933236	19271355.0837314	113711.534088774
SEPTEMBER	32273930.8643743	21302209.8626631	126360.106203743
TOTAL	826615202.739956	564308349.319697	2695758

[1] Volumetric costs include the TF-1 c
SGS-1 and LS-1 withdrawal charges;
and transportation costs.

Total Cost of Gas	Wacog
27273521.4673298	0.50684
67511768.8584775	0.73183
88266077.3810551	0.71619
87722491.3939514	0.70731
68937779.8840467	0.69576
63359697.3172406	0.72382
45107578.6145025	0.66004
33836266.9752937	0.66526
24559058.1629473	0.66682
19616230.4763332	0.66965
19385066.6178201	0.66681
21428569.9688668	0.66396
567004107.117865	0.685934767759453

Table 1

NW Natural
Firm Off-System Gas Supply Contracts
for the 2005/2006 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		10/31/2006
BP Canada	Nov-Mar	5,000		3/31/2006
Coral Energy Canada	Nov-Oct	10,000		10/31/2010
Husky Energy Marketing	Nov-Oct	5,000		10/31/2006
Nexen (assigned from Duke)	Nov-Oct	20,000		10/31/2008
PremStar Energy	Nov-Mar	3,000		3/31/2006
Sempra Energy Trading	Nov-Oct	10,000		10/31/2008
Alberta:				
BP Canada	Nov-Oct	10,000		10/31/2009
BP Canada	Nov-Oct	10,000		10/31/2009
Burlington Resources Canada	Nov-Oct	15,000		10/31/2006
Coral Energy Canada	Nov-Oct	10,000		10/31/2008
Husky Energy Marketing	Nov-Oct	10,000		10/31/2006
Nexen (assigned from Duke)	Nov-Oct	10,000		10/31/2006
Nexen (assigned from Duke)	Dec-Feb	15,000		2/28/2006
Nexen (assigned from Duke)	Nov-Mar	5,000		3/31/2006
ONEOK Canada	Nov-Mar	10,000	10,000	3/31/2006
Sempra Energy Trading	Nov-Oct	10,000		10/31/2014
Rockies:				
EnCana	Nov-Mar	10,000	10,000	3/31/2006
National Fuel Marketing	Nov-Mar	20,000	20,000	3/31/2006
ONEOK Energy Services	Nov-Mar	10,000	10,000	3/31/2006
Sempra Energy Trading	Nov-Mar	10,000	10,000	3/31/2006
Wasatch Energy	Nov-Mar	5,000	5,000	3/31/2006
Total Off-System Firm Contract Supply		218,000	65,000	

Notes:
1. Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW Natural's system are slightly less due to upstream pipeline fuel consumption.
2. There is also one Rockies summer-only (Apr-Oct) contract with National Fuel totaling 10,000 Dth/day.

Table 2

NW Natural
Firm Transportation Capacity
for the 2005/2006 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion	216,044	9/30/2013
1993 Expansion	34,000	9/30/2009
1995 Expansion	102,000	11/30/2011
Duke Capacity Acquisition	5,000	3/31/2008
Total NWP Capacity	357,044	
less recallable releases to -		
Portland General Electric	(30,000)	10/31/2010
Georgia Pacific	(7,000)	10/31/2003
Net NWP Capacity	320,044	
TransCanada's GTN System:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2005
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:		
1995 Rationalization	57,000	10/31/2001
Burlington/Summit Cap. Assignments	23,561	10/31/2008
Engage Capacity Acquisition	3,861	10/31/2008
Engage Capacity Assignments	24,121	10/31/2008
2004 Capacity Acquisition	48,910	10/31/2016
Total TCPL-ALberta Capacity	157,453	
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 GP. Those two contracts require mutual agreement to continue. requires mutual agreement to continue.
2. NW Natural also acquired NWP capacity from Weyerhaeuser in 1995 (5,200 Dth/day). This agreement expires on 12/31/2005 and will not be renewed, hence it is not shown above.
3. The TCPL-Alberta, WEI and Southern Crossing contracts are denominated in volumetric units. Accordingly, the above energy units are an approximation.
4. 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 2005/2006 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)	230,000	8,900,000	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	410,000	10,500,000	
Total Firm Storage Resource	516,130	12,099,188	

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.

Table 4

NW Natural
Other Resources: Recall Agreements, Citygate Deliveries and Mist Production
for the 2005/2006 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	11/1/2010
Georgia Pacific - Toledo	7,000	35	upon 1 year notice
Weyerhaeuser 1	3,000	40	upon 1 year notice
Weyerhaeuser 2	5,000	40	upon 1 year notice
Total Recall Resource	45,000		
Citygate Deliveries:			
none			
Mist Production:			
Enerfin Resources	≈1,300	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, but unless/until a new contract is negotiated to replace the now expired contract, no new wells will be added. NW Natural's obligation to take gas from existing wells continues for the life of those wells.

Table 5

NW Natural
Firm Resource Summary
for the 2005/2006 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	320,044
Off-System Storage (Jackson Prairie and Plymouth)	106,130
On-System Storage (Mist, Portland LNG and Newport LNG)	410,000
Recallable Capacity and Supply Agreements	45,000
Citygate Deliveries	-
Nominal Mist Production Gas	1,300
Total Firm Resource	882,474

NW Natural

Summary of PGA Revenue Effects

1	Gas Cost and Demand Changes	$111,317,546
	Permanent Rate Changes	
2	Addition of Proposed Bare Steel	$2,270,000
3	Removal of Current Bare Steel	($1,338,000)
4	Addition of Proposed Geohazard	$360,000
5	Removal of current Geohazard	($341,000)
6	Addition of Proposed Pipeline Integrity	$535,000
7	Removal of Y2K	($1,267,708)
8	Addition of SMPE gate station	$404,359
9	SMPE True Up	($273,732)
10	Addition of Coos Bay Revenue Requirement	$1,297,000
11	Company Coos Bay Contribution	($113,757)
12	Application of Elasticity Adjustment	$4,894,003
13	Total Permanent Adjustments	$6,426,165
	Temporary Increments	
14	Amortization of 191 Account Gas Costs (Demand, Commodity and Coos Bay Demand)	$3,440,578
15	Amortization of 186 for DSM	$1,492,000
16	Amortization of Remaining Balances	$12,955
17	Amortization Of UM1148 Stipulation--Parking	($3,395)
18	Amortization of in place SMPE revenues	$83,205
19	Amortization of Intervenor Funding	$55,012
20	Amortization of Decoupling (Residential and Commercial)	$6,220,353
21	Coos Bay Revenue Deferral	$1,100,857
22	UM1124 West Linn Refund	($51,348)
23	Y2K Refund	($517,859)
24	Total Proposed Temporary Increments	$11,832,359
25	Removal of Current Temporary Increments	($11,427,674)
26	Total Net Temporary Increments	$404,684
27	Total Change	$118,148,396

NW Natural

Estimated Balance in Accounts as of September 30, 2005

Line No.		
	Amortization Over 12-Month Period - Commodity Costs	
1	191.400	Deferral of Gas Commodity Cost Changes
2		Beginning October 2004
3	191.401	Remainder of 10/1/04 Amortization of Cost of
4		Gas Commodity Deferral Accounts
5		Total Amount to be Amortized
6		Estimated Interest During Amortization
7		Estimated Refund of Commodity Deferrals
8	Allocation:	Equal cent per therm basis to all sales schedules
	Amortization Over 12-Month Period - Demand Costs	
9	191.410	Deferral of Gas Demand Cost Differences
10		Beginning October 2004
11	191.411	Remainder of 10/1/04 Amortization of Demand Cost
12	191.417	Deferral of Coos Bay Demand Costs
12	191.450	Deferral of Gas Demand Volumetric Differences
13		Beginning October 2004
14	191.455	Deferral of Interest on Gas Demand Cost vs Collection Differences
15		Total Amount to be Amortized
16		Estimated Interest During Amortization
17		Total Estimated Collection of Demand Deferrals
18		Estimated Collection of Demand Deferrals from Firm
19		Estimated Collection of Demand Deferrals from Interruptible
20	Allocation:	Equal cent per Firm and Interruptible therm basis to all sales schedules

NW Natural

Estimated Balance in Accounts as of September 30, 2005

Line No.		
		Amortization Over 12-Month Period - Decoupling - Residential
1	186.275	Deferral of differences between weather-normalized
2		usage & calculated baseline usage beginning 10/04
3	186.277	Remainder of 10/1/04 Amortization of Decoupling - Residential
4		Total Amount to be Amortized
5		Estimated Interest During Amortization
6		Total Estimated Collection of Residential Decoupling
7	Allocation:	Equal cent per therm basis to Residential schedules 1 and 2
		Amortization Over 12-Month Period - Decoupling - Commercial
8	186.270	Deferral of differences between weather-normalized
9		usage & calculated baseline usage beginning 10/04
10	186.271	Remainder of 10/1/04 Amortization of Decoupling - Commercial
11		Total Amount to be Amortized
12		Estimated Interest During Amortization
13		Total Estimated Collection of Commercial Decoupling
14	Allocation:	Equal cent per therm basis to Commercial schedules 1, 3 and 31

NW Natural

Estimated Balance in Accounts as of September 30, 2005

Line No.		
	Amortization Over 12-Month Period - 186 Accounts DSM and Weatherization	
1	186.599	Deferral of DSM Costs Beginning October 2004
2	186.231	Remainder of 10/1/03 Amortization of DSM Costs
4	186.244	Deferral of Excess Weatherization Costs Beginning 10/04
5		Total Amount to be Amortized
6		Estimated Interest During Amortization
7		Estimated Collection of DSM and Weatherization
8	Allocation:	Equal cent per therm basis to all Firm sales schedules
	Amortization Over 12-Month UM 1124	
9	186.289	Special Contract Refund Deferral
10		Total Amount to be Amortized
11		Estimated Interest During Amortization
12		Total Estimated Refund
13	Allocation:	Equal cent per therm basis to Schedules 1, 2 and 3

NW Natural

Estimated Balance in Accounts as of September 30, 2005

Line No.		
	Amortization Over 12-Month Period - Remaining Cr Gty, Parking, OQ and Vanc Prop	
1	186.246	Remainder of 10/1/04 Amort of NNGFC Credit Guaranty
2	186.274	Remainder of 10/1/04 Amort of Parking, OQ and Vancouver Property
3		Total Amount to be Amortized
4		Estimated Interest During Amortization
5		Total Estimated Collection for Cr Gty, Parking, OQ and Vanc Prop
6	Allocation:	Equal percent of margin basis to all classes and rate schedules, excluding special contracts
	Amortization Over 12-Month Period - Remainder of UM1148 Stipulation	
7	186.254	Remainder of 10/1/04 Amort of Fish/Garden Block Refund
8		Total Amount to be Amortized
9		Estimated Interest During Amortization
10		Total Estimated Refund
11	Allocation:	Equal percent of margin basis to all classes and rate schedules, excluding special contracts
	Amortization Over 12-Month Period - Coos Bay	
12	186.247	Coos Bay Revenue Deferral
13		Total Amount to be Amortized
14		Estimated Interest During Amortization
15		Total Estimated Collection
16	Allocation:	Equal percent of margin basis to all classes and rate schedules, excluding special contracts

NW Natural

Estimated Balance in Accounts as of September 30, 2005

Line No.		
	Amortization Over 12-Month Period - Intervenor Funding	
1	186.276	Intervenor Funding - CUB Fund
2	186.286	Remainder of 10/1/04 Amort Intervenor Funding - CUB Fund
3		Total Amount to be Amortized
4		Estimated Interest During Amortization
5		Total Estimated Collection from residential customers
6	Allocation:	Equal cents per therm basis to all residential customers
7	186.288	Remainder of 10/1/04 Amort Intervenor Funding - Matching Fund
8		Total Amount to be Amortized
9		Estimated Interest During Amortization
10		Total Estimated refund to industrial customers
11	Allocation:	Equal cents per therm basis to all industrial customers

NW Natural

Estimated Balance in Accounts as of September 30, 2005

Line No.		
	Amortization Over 12-Month Period - SMPE	
1	186.258	SMPE Gate Station Revenue Deferral
2	186.243	Remainder of 10/1/04 Amort of SMPE Revenue Deferral
3	186.241	SMPE True Up Revenue Deferral
4		Total Amount to be Amortized
5		Estimated Interest During Amortization
6		Total Estimated Collection
7	Allocation:	Equal percent of margin basis to all classes on rate schedules 1, 2, 3, 19 and 31
	Amortization Over 12-Month Period - Y2K	
8	186.250	Y2K Deferral
9	186.251	Y2K Amortization
10		Total Amount to be Amortized
11		Estimated Interest During Amortization
12		Total Estimated Refund
13	Allocation:	Equal percent of margin basis to all residential, all commercial and industrial sales rate schedules, excluding special contracts

Amount		
($3,884,401)		
639,340		
(3,245,061)		
(153,469)		
($3,398,530)	(3,498,302)	w/Rev Sens
$708,301		
1,013,825		
157,461		
4,995,160		
(438,170)		
6,436,577		
304,406		
$6,740,983	6,938,880	w/Rev Sens
$6,589,438	6,782,886	w/Rev Sens
$151,545	155,994	w/Rev Sens

Amount		
$4,636,065		
(566,171)		
4,069,894		
192,478		
$4,262,372	4,387,504	w/Rev Sens
$1,752,788		
(52,617)		
1,700,171		
80,406		
$1,780,577	1,832,850	w/Rev Sens

Amount		
$1,271,063		
112,876		
0		
1,383,939		
65,451		
$1,449,390	1,491,940	w/Rev Sens
($47,631)		
(47,631)		
(2,253)		
($49,884)	(51,348)	w/Rev Sens

Amount		
$4,514		
7,504		
12,018		
568		
$12,586	12,955	w/Rev Sens
($3,242)		
(3,242)		
(153)		
($3,395)	(3,395)	Rev Sens Emt
$1,051,145		
1,051,145		
49,712		
$1,100,857	1,100,857	Rev Sens Emt

Amount		
$50,000		
8,213		
58,213		
2,753		
$60,966	62,756	w/Rev Sens
($6,813)		
(6,813)		
(322)		
($7,135)	(7,344)	w/Rev Sens

Amount		
$266,179		
(60,163)		
(126,569)		
79,447		
3,758		
$83,205	83,205	Rev Sens Emb
$6,089,149		
(6,583,623)		
(494,474)		
(23,385)		
($517,859)	(517,859)	Rev Sens Emb

NW Natural

Volumes Used in Derivation of Increments
Twelve Months Ended June 30, 2005

Line No.		Normalized 12 Month Ended
	Sales Volumes	
1	**Residential**	346,767,496
2	**Commercial**	216,774,402
3	**Industrial Firm**	66,341,357
4	**Interruptible**	121,779,868
5	**Total Sales Volumes**	751,663,123
	Transportation Volumes	
6	**Commercial Firm**	286,070
7	**Industrial Firm**	27,675,847
8	**Interruptible**	155,529,404
9	**Incentive and Special Contract**	161,247,907
10	**Total Transportation**	344,739,228
11	**Total Oregon Volumes**	1,096,402,351

12 Month Volumes

(a)	**Oregon total sales therms**	751,663,123
(b)	**Oregon firm sales therms**	629,883,255
(c)	**Oregon interruptible sales therms**	121,779,868
(d)	**Oregon residential therms**	346,767,496
(e)	**Oregon commercial therms**	216,774,402
(f)	**Oregon industrial therms**	371,612,546
(g)	**Oregon schedules 1, 2 and 3**	495,987,344
(h)	**Oregon all classes and rate schedules, excluding special contracts**	935,154,444

NW Natural

Derivation of Margin Change Due to Price Elasticity

Line		Residential	Commercial
	(a)	(b)	(c)
1	Normalized Volumes 12 Months Ended June 2004	341,042,043	209,706,795
2	Class Prices on Rates in Effect 10/01/2004	$1.20983	$0.94932
3	Class Prices on Proposed Rates Effective 10/01/2005	$1.35824	$1.15476
4	Cumulative Price Increase 10/01/2004 to 10/01/2005	12.3%	21.6%
5	Percent Volume Change Due to Elasticity Res at -0.172, Comm. At -0.11	2.1%	2.4%
6	Volume Change Due to Elasticity in Therms	7,188,623	4,987,950
7	Margin Rate per Therm	$0.45093	$0.30330
8	Margin Shortfall	$3,241,585	$1,512,841
9	Normalized Oregon Volumes	341,042,043	209,706,795
10	Rate Change Due to Elasticity Effects	$0.00950	$0.00721
11	Rate Change Due to Elasticity Effects With Rev Sens	$0.00978	$0.00742

NW NATURAL

Application of Base Adjustments to Rate Schedules

Proposed Effective: **10/01/05**

Revenue-Sensitive 2.852% $0.97148

		Apply New Base (Revenue-Sensitized) Adjustments to Rates:													
		Temporary Base Adjustments						Permanent Base Adjustments							
Rate Schedule		**Geohazard**	**Bare Steel 30%**	**Bare Steel 70%**	**IMP**	**Coos Bay (NWN $100K)**	**Subtotal Temp. Base Adjs.**	**Elasticity**	**Coos Bay (perm)**	**SMPE**	**UM 1148**	**Mist Recall**	**Remove Y2K**	**Subtotal Perm. Base Adjs.**	**Total**
Schedule 1R		$0.00078	$0.00147	$0.00282	$0.00116	($0.00025)	**$0.00598**	$0.00978	$0.00281	$0.00030	$0.00000	$0.00000	($0.00323)	**$0.00966**	**$0.01564**
Schedule 1C		$0.00074	$0.00141	$0.00282	$0.00111	($0.00024)	**$0.00584**	$0.00742	$0.00268	$0.00029	$0.00000	$0.00000	($0.00323)	**$0.00716**	**$0.01300**
Schedule 2		$0.00067	$0.00127	$0.00282	$0.00100	($0.00021)	**$0.00555**	$0.00978	$0.00242	$0.00026	$0.00000	$0.00000	($0.00237)	**$0.01009**	**$0.01564**
Schedule 3C Sales		$0.00054	$0.00102	$0.00282	$0.00080	($0.00017)	**$0.00501**	$0.00742	$0.00193	$0.00021	$0.00000	$0.00000	($0.00188)	**$0.00768**	**$0.01269**
Schedule 3I Sales		$0.00050	$0.00094		$0.00074	($0.00016)	**$0.00202**		$0.00179	$0.00019	$0.00000	$0.00000	($0.00188)	**$0.00010**	**$0.00212**
Schedule 3C Transp		$0.00054	$0.00102	$0.00282	$0.00080	($0.00017)	**$0.00501**	$0.00742	$0.00193	$0.00021	$0.00000	$0.00000	($0.00188)	**$0.00768**	**$0.01269**
Schedule 3I Transp		$0.00050	$0.00094		$0.00074	($0.00016)	**$0.00202**		$0.00179	$0.00019	$0.00000	$0.00000	($0.00188)	**$0.00010**	**$0.00212**
Schedule 19		$0.01	$0.02	$0.05	$0.01	$0.00000	**$0.09**	$0.19	$0.03		$0.00	$0.00	($0.03)	**$0.19**	**$0.28**
Schedule 31C Firm Sales	Block 1	$0.00028	$0.00053	$0.00282	$0.00042	($0.00009)	**$0.00396**	$0.00742	$0.00101	$0.00011	$0.00000		($0.00124)	**$0.00730**	**$0.01126**
	Block 2	$0.00025	$0.00048	$0.00282	$0.00038	($0.00008)	**$0.00385**	$0.00742	$0.00092	$0.00010	$0.00000		($0.00113)	**$0.00731**	**$0.01116**
Schedule 31C Intp. Sales	Block 1	$0.00028	$0.00053	$0.00282	$0.00042	($0.00009)	**$0.00396**	$0.00742	$0.00101	$0.00011	$0.00000		($0.00124)	**$0.00730**	**$0.01126**
	Block 2	$0.00025	$0.00048	$0.00282	$0.00038	($0.00008)	**$0.00385**	$0.00742	$0.00092	$0.00010	$0.00000		($0.00113)	**$0.00731**	**$0.01116**
Schedule 31C Firm Transp	Block 1	$0.00028	$0.00053	$0.00282	$0.00042	($0.00009)	**$0.00396**	$0.00742	$0.00101	$0.00011	$0.00000		($0.00124)	**$0.00730**	**$0.01126**
	Block 2	$0.00025	$0.00048	$0.00282	$0.00038	($0.00008)	**$0.00385**	$0.00742	$0.00092	$0.00010	$0.00000		($0.00113)	**$0.00731**	**$0.01116**
Schedule 31I Firm Sales	Block 1	$0.00028	$0.00053		$0.00042	($0.00009)	**$0.00114**		$0.00101	$0.00011	$0.00000		($0.00124)	**($0.00012)**	**$0.00102**
	Block 2	$0.00025	$0.00048		$0.00038	($0.00008)	**$0.00103**		$0.00092	$0.00010	$0.00000		($0.00113)	**($0.00011)**	**$0.00092**
Schedule 31I Intp. Sales	Block 1	$0.00028	$0.00053		$0.00042	($0.00009)	**$0.00114**		$0.00101	$0.00011	$0.00000		($0.00124)	**($0.00012)**	**$0.00102**
	Block 2	$0.00025	$0.00048		$0.00038	($0.00008)	**$0.00103**		$0.00092	$0.00010	$0.00000		($0.00113)	**($0.00011)**	**$0.00092**
Schedule 31I Firm Tranp	Block 1	$0.00028	$0.00053		$0.00042	($0.00009)	**$0.00114**		$0.00101	$0.00011	$0.00000		($0.00124)	**($0.00012)**	**$0.00102**
	Block 2	$0.00025	$0.00048		$0.00038	($0.00008)	**$0.00103**		$0.00092	$0.00010	$0.00000		($0.00113)	**($0.00011)**	**$0.00092**
Schedule 32 Firm Sales	Block 1	$0.00016	$0.00030		$0.00024	($0.00005)	**$0.00065**		$0.00057		$0.00000		($0.00300)	**($0.00243)**	**($0.00178)**
	Block 2	$0.00013	$0.00025		$0.00020	($0.00004)	**$0.00054**		$0.00048		$0.00000		($0.00255)	**($0.00207)**	**($0.00153)**
	Block 3	$0.00009	$0.00018		$0.00014	($0.00003)	**$0.00038**		$0.00034		$0.00000		($0.00180)	**($0.00146)**	**($0.00108)**
	Block 4	$0.00006	$0.00010		$0.00008	($0.00002)	**$0.00022**		$0.00020		$0.00000		($0.00105)	**($0.00085)**	**($0.00063)**
	Block 5	$0.00003	$0.00006		$0.00005	($0.00001)	**$0.00013**		$0.00011		$0.00000		($0.00060)	**($0.00049)**	**($0.00036)**
	Block 6	$0.00002	$0.00003		$0.00002	$0.00000	**$0.00007**		$0.00006		$0.00000		($0.00030)	**($0.00024)**	**($0.00017)**
Schedule 32 Intp. Sales	Block 1	$0.00016	$0.00030		$0.00024	($0.00005)	**$0.00065**		$0.00057		$0.00000		($0.00300)	**($0.00243)**	**($0.00178)**
	Block 2	$0.00013	$0.00025		$0.00020	($0.00004)	**$0.00054**		$0.00048		$0.00000		($0.00255)	**($0.00207)**	**($0.00153)**
	Block 3	$0.00009	$0.00018		$0.00014	($0.00003)	**$0.00038**		$0.00034		$0.00000		($0.00180)	**($0.00146)**	**($0.00108)**
	Block 4	$0.00006	$0.00010		$0.00008	($0.00002)	**$0.00022**		$0.00020		$0.00000		($0.00105)	**($0.00085)**	**($0.00063)**
	Block 5	$0.00003	$0.00006		$0.00005	($0.00001)	**$0.00013**		$0.00011		$0.00000		($0.00060)	**($0.00049)**	**($0.00036)**
	Block 6	$0.00002	$0.00003		$0.00002	$0.00000	**$0.00007**		$0.00006		$0.00000		($0.00030)	**($0.00024)**	**($0.00017)**
Schedule 32 Firm Transp	Block 1	$0.00016	$0.00030		$0.00024	($0.00005)	**$0.00065**		$0.00057		$0.00000		$0.00000	**$0.00057**	**$0.00122**
	Block 2	$0.00013	$0.00025		$0.00020	($0.00004)	**$0.00054**		$0.00048		$0.00000		$0.00000	**$0.00048**	**$0.00102**
	Block 3	$0.00009	$0.00018		$0.00014	($0.00003)	**$0.00038**		$0.00034		$0.00000		$0.00000	**$0.00034**	**$0.00072**
	Block 4	$0.00006	$0.00010		$0.00008	($0.00002)	**$0.00022**		$0.00020		$0.00000		$0.00000	**$0.00020**	**$0.00042**
	Block 5	$0.00003	$0.00006		$0.00005	($0.00001)	**$0.00013**		$0.00011		$0.00000		$0.00000	**$0.00011**	**$0.00024**
	Block 6	$0.00002	$0.00003		$0.00002	$0.00000	**$0.00007**		$0.00006		$0.00000		$0.00000	**$0.00006**	**$0.00013**
Schedule 32 Intp. Transp	Block 1	$0.00016	$0.00030		$0.00024	($0.00005)	**$0.00065**		$0.00057		$0.00000		$0.00000	**$0.00057**	**$0.00122**
	Block 2	$0.00013	$0.00025		$0.00020	($0.00004)	**$0.00054**		$0.00048		$0.00000		$0.00000	**$0.00048**	**$0.00102**
	Block 3	$0.00009	$0.00018		$0.00014	($0.00003)	**$0.00038**		$0.00034		$0.00000		$0.00000	**$0.00034**	**$0.00072**
	Block 4	$0.00006	$0.00010		$0.00008	($0.00002)	**$0.00022**		$0.00020		$0.00000		$0.00000	**$0.00020**	**$0.00042**
	Block 5	$0.00003	$0.00006		$0.00005	($0.00001)	**$0.00013**		$0.00011		$0.00000		$0.00000	**$0.00011**	**$0.00024**
	Block 6	$0.00002	$0.00003		$0.00002	$0.00000	**$0.00007**		$0.00006		$0.00000		$0.00000	**$0.00006**	**$0.00013**
Schedule 33 Firm Transp	All therms	$0.00001	$0.00002		$0.00001	$0.00000	**$0.00004**		$0.00003	$0.00000	$0.00000		$0.00000	**$0.00003**	**$0.00007**
Schedule 33 Intp. Transp	All therms	$0.00001	$0.00002		$0.00001	$0.00000	**$0.00004**		$0.00003	$0.00000	$0.00000		$0.00000	**$0.00003**	**$0.00007**
Schedule 54		$0.00074	$0.00141	$0.00282	$0.00111	($0.00024)	**$0.00584**	$0.00742	$0.00268	$0.00029	$0.00000	$0.00000	$0.00000	**$0.01039**	**$0.01623**

NW NATURAL **Summary of Application of Temporary Increments to Rate Schedules**
Proposed Effective: **10/01/05**

Revenue-Sensitive 2.852% $0.97148

Apply New Adjustments to Rates:					
Rate Schedule		**Commodity (Account 191)**	**Capacity (Account 191)**	**Other (Account 186)**	**Total**
Schedule 1R		($0.00465)	$0.01077	$0.01651	$0.02263
Schedule 1C		($0.00465)	$0.01077	$0.01208	$0.01820
Schedule 2		($0.00465)	$0.01077	$0.01630	$0.02242
Schedule 3C Sales		($0.00465)	$0.01077	$0.01170	$0.01782
Schedule 3I Sales		($0.00465)	$0.01077	$0.00316	$0.00928
Schedule 3C Transp			$0.01077	$0.01170	$0.02247
Schedule 3I Transp			$0.01077	$0.00316	$0.01393
Schedule 19		($0.09)	$0.21	$0.30	$0.42
Schedule 31C Firm Sales	Block 1	($0.00465)	$0.01077	$0.01135	$0.01747
	Block 2	($0.00465)	$0.01077	$0.01129	$0.01741
Schedule 31C Intp. Sales	Block 1	($0.00465)	$0.00128	$0.00898	$0.00561
	Block 2	($0.00465)	$0.00128	$0.00892	$0.00555
Schedule 31C Firm Transp	Block 1			$0.00898	$0.00898
	Block 2			$0.00892	$0.00892
Schedule 31I Firm Sales	Block 1	($0.00465)	$0.01077	$0.00287	$0.00899
	Block 2	($0.00465)	$0.01077	$0.00281	$0.00893
Schedule 31I Intp. Sales	Block 1	($0.00465)	$0.00128	$0.00050	($0.00287)
	Block 2	($0.00465)	$0.00128	$0.00044	($0.00293)
Schedule 31I Firm Tranp	Block 1			$0.00050	$0.00050
	Block 2			$0.00044	$0.00044
Schedule 32 Firm Sales	Block 1	($0.00465)	$0.01077	$0.00281	$0.00893
	Block 2	($0.00465)	$0.01077	$0.00274	$0.00886
	Block 3	($0.00465)	$0.01077	$0.00262	$0.00874
	Block 4	($0.00465)	$0.01077	$0.00251	$0.00863
	Block 5	($0.00465)	$0.01077	$0.00244	$0.00856
	Block 6	($0.00465)	$0.01077	$0.00240	$0.00852
Schedule 32 Intp. Sales	Block 1	($0.00465)	$0.00128	$0.00044	($0.00293)
	Block 2	($0.00465)	$0.00128	$0.00037	($0.00300)
	Block 3	($0.00465)	$0.00128	$0.00025	($0.00312)
	Block 4	($0.00465)	$0.00128	$0.00014	($0.00323)
	Block 5	($0.00465)	$0.00128	$0.00007	($0.00330)
	Block 6	($0.00465)	$0.00128	$0.00003	($0.00334)
Schedule 32 Firm Transp	Block 1			$0.00047	$0.00047
	Block 2			$0.00039	$0.00039
	Block 3			$0.00027	$0.00027
	Block 4			$0.00015	$0.00015
	Block 5			$0.00008	$0.00008
	Block 6			$0.00003	$0.00003
Schedule 32 Intp. Transp	Block 1			$0.00047	$0.00047
	Block 2			$0.00039	$0.00039
	Block 3			$0.00027	$0.00027
	Block 4			$0.00015	$0.00015
	Block 5			$0.00008	$0.00008
	Block 6			$0.00003	$0.00003
Schedule 33 Firm Transp				$0.00001	$0.00001
Schedule 33 Intp. Transp				$0.00001	$0.00001
Schedule 54		(0.00465)	$0.01077	$0.01190	$0.01802

NW NATURAL
Detail for Temporary Increments to Rate Schedules 01-Oct-05

191.xxx accounts:	Before Rev.-Sens.	After Rev.-Sens.	Applicable	
Pipeline Capacity	$0.01046	$0.01077	Firm Sales Schedules Volumetric	
Pipeline Capacity	$0.00124	$0.00128	Interruptible Sales Schedules - Volumetric	
Pipeline Capacity	$0.00000	$0.00000	Firm Sales Schedules - MDDV	
Commodity	($0.00452)	($0.00465)	All Sales Schedules, Firm and Interruptible	

186.xxx accounts:	Before Rev.-Sens.	After Rev.-Sens.	Applicable
SMPE - Mist Sch. 176	$0.00019	$0.00019	RS 1R
	$0.00018	$0.00018	RS 1C/RS 54
	$0.00016	$0.00016	RS 2
	$0.00013	$0.00013	RS 3C
	$0.00012	$0.00012	RS 3I
	$0.00007	$0.00007	RS 31C S&T
	$0.00006	$0.00006	RS 31C S&T
	$0.00007	$0.00007	RS 31I S&T
	$0.00006	$0.00006	RS 31I S&T
Other - DSM, OQ & Weather	$0.00230	$0.00237	All Firm Sales Schedules
	$0.00230	$0.00237	RS 19
Decoupling	$0.01229	$0.01265	Residential
	$0.00821	$0.00846	Commercial and RS 54
Intervenor Funding	$0.00017	$0.00018	RS 1C, 1R, 2
	$0.00017	$0.00018	RS 19
	($0.00002)	($0.00002)	RS 3I, 31, 32 and 33 Ind. Only

Other Special:	**Before R-S**	**After R-S**		
Gain on Sale of	$0.00003	$0.00003	RS 1R	
Parking,Vancouver Property	$0.00003	$0.00003	RS 1C	
Sale, Line of Credit, and OQ	$0.00002	$0.00002	RS 2	
	$0.00002	$0.00002	RS 3C	
	$0.00002	$0.00002	RS 3I	
	$0.00001	$0.00001	RS 19	
	$0.00001	$0.00001	RS 31C	Block 1
	$0.00001	$0.00001		Block 2
	$0.00001	$0.00001	RS 31I	Block 1
	$0.00001	$0.00001		Block 2
	$0.00001	$0.00001	RS 32	Block 1
	$0.00000	$0.00000		Block 2
	$0.00000	$0.00000		Block 3
	$0.00000	$0.00000		Block 4
	$0.00000	$0.00000		Block 5
	$0.00000	$0.00000		Block 6
	$0.00000	$0.00000	RS 33 Intp.	
	$0.00003	$0.00003	RS 54	

Other Special:	**Before R-S**	**After R-S**		
UM 1148/UP 205 Fish Block	($0.00001)	($0.00001)	RS 1R	
	($0.00001)	($0.00001)	RS 1C	
	($0.00001)	($0.00001)	RS 2	
	($0.00001)	($0.00001)	RS 3C	
	$0.00000	$0.00000	RS 3I	
	$0.00000	$0.00000	RS 19	
	$0.00000	$0.00000	RS 31C	Block 1
	$0.00000	$0.00000		Block 2
	$0.00000	$0.00000	RS 31I	Block 1
	$0.00000	$0.00000		Block 2
	$0.00000	$0.00000	RS 32	Block 1
	$0.00000	$0.00000		Block 2
	$0.00000	$0.00000		Block 3
	$0.00000	$0.00000		Block 4
	$0.00000	$0.00000		Block 5
	$0.00000	$0.00000		Block 6
	$0.00000	$0.00000	RS 33 F&I	
	($0.00001)	($0.00001)	RS 54	

Coos Bay - 186 account	**Before R-S**	**After R-S**		
	$0.00238		RS 1R	
	$0.00228		RS 1C	
	$0.00205		RS 2	
	$0.00164		RS 3C	
	$0.00152		RS 3I	
	$0.00127		RS 19	
	$0.00086		RS 31C	Block 1
	$0.00078			Block 2
	$0.00086		RS 31I	Block 1
	$0.00078			Block 2
	$0.00048		RS 32	Block 1
	$0.00041			Block 2
	$0.00029			Block 3
	$0.00017			Block 4
	$0.00010			Block 5
	$0.00005			Block 6
	$0.00003		RS 33 F&I	
	$0.00228		RS 54	

Y2K- 186 account	**Before R-S**	**After R-S**		
	($0.00118)		RS 1R	
	($0.00113)		RS 1C	
	($0.00102)		RS 2	
	($0.00081)		RS 3C	
	($0.00075)		RS 3I	
	($0.00063)		RS 19	
	($0.00042)		RS 31C	Block 1
	($0.00039)			Block 2
	($0.00042)		RS 31I	Block 1
	($0.00039)			Block 2
	($0.00003)		RS 32	Block 1
	($0.00002)			Block 2
	($0.00002)			Block 3
	($0.00001)			Block 4
	($0.00001)			Block 5
	$0.00000			Block 6
	$0.00000		RS 33 F&I	
	($0.00113)		RS 54	

UM 1124	**Before R-S**	**After R-S**	
West Linn Special Contract	($0.00010)	($0.00010)	RS 1R
(186 Account)	($0.00010)	($0.00010)	RS 1C
	($0.00010)	($0.00010)	RS 2
	($0.00010)	($0.00010)	RS 3C
	($0.00010)	($0.00010)	RS 3I
	($0.00001)	($0.00001)	RS 19
	($0.00010)	($0.00010)	RS 54

NW Natural
Bare Steel Program

Total Cost of Service		$2,270,000	$1,338,000
Portion to All Customers		$681,000	
	30%		
Increment to all non-incentive customers		$0.00073	
Portion To Res and Comm			
	70%	$1,589,000	
Average Residential and Commercial increment		$0.00282	
Average Total Res and Comm increment		$0.00355	
Normalized Oregon Residential Volumes		346,767,496	
Normalized Oregon Commercial Volumes		216,774,402	
Oregon Res-Comm Normalized Volumes		563,541,898	
Total Non-Incentive Deliveries		935,154,444	

NW Natural
Geo-Hazard Mitigation Program

Total Cost of Service		$360,000
Portion to All Customers		$360,000
	100%	
Increment to all non-incentive customers		$0.00296

Total Non-Incentive Deliveries	121,779,867

NW Natural

SMPE Revenue Requirement
Spread to the Various Schedules on an
Equal Percentage of Margin Basis

Proposed total Increase of **$130,627**
Appliled to Sch 1, 2, 3, 31, 33

Multiplier	Rate Sched	Current Permanent Rates	Current Margins	Custs	Therms	Service Chrg & Min Bill Margi	Volumetric Margin	Total Margin	Proposed Margin Rate With Genera	Proposed Service Chg & Min Bill Margi	Proposed Volumetric Margin	Proposed Total Margin	Margin Increase	Proposed Increase	Proposed Increase	Percent Increase On Margin
0	1	$5.00	$5.00	3369	776,617	$202,140	$384,324	$586,464	$5.00	$202,140	$384,557	$586,697	$232	$0.00030	$0.00030	0.1%
	1R	$1.15689	$0.49487						$0.49517							
1	1C	1.13452	$0.47250	176	62,130	$10,560	$29,357	$39,917	$0.47279	$10,560	$29,374	$39,934	$18	$0.00029	$0.00029	0.1%
0	2	$6.00	$6.00	486,843		$35,052,696		$35,052,696	$6.00	$35,052,696		$35,052,696	$0	$0.00000	$0.00000	0.0%
1	2	1.08871	$0.42669		345,955,930		$147,615,936	$147,615,936	$0.42695		$147,705,227	$147,705,227	$89,291	$0.00026	$0.00026	0.1%
0	3	$8.00	$8.00						$8.00					$0.00000	$0.00000	0.0%
1	3C	$1.00308	$0.34106	52,862	145,167,952	$5,074,752	$49,510,982	$54,585,734	$0.34127	$5,074,752	$49,540,930	$54,615,682	$29,949	$0.00021	$0.00021	0.1%
1	3I	$0.97848	$0.31646	139	4,023,348	$13,345	$1,273,229	$1,286,574	$0.31665	$13,345	$1,273,999	$1,287,344	$770	$0.00019	$0.00019	0.1%
0	31C	$325.00	$325.00	1,250		$4,875,000			$325.00	$4,875,000						
1		$0.17776	$0.17776		30,000,000		$5,332,800	$16,917,402	$0.17787		$5,336,026	$16,924,687	$7,284	$0.00011	$0.00011	0.1%
1		$0.16151	$0.16151		41,542,953		$6,709,602		$0.16161		$6,713,661			$0.00010	$0.00010	0.1%
0	31I	$325.00	$325.00	322		$1,255,800			$325.00	$1,255,800						
1		$0.17776	$0.17776		7,728,000		$1,373,729	$6,352,608	$0.17787		$1,374,560	$6,355,691	$3,083	$0.00011	$0.00011	0.1%
1		$0.16151	$0.16151		23,051,694		$3,723,079		$0.16161		$3,725,331			$0.00010	$0.00010	0.1%
	33		$0.00500											$0.00000	$0.00000	0.1%
					$598,308,625	$46,484,293	$215,953,038	$262,437,331		$46,484,293	$216,083,665	$262,567,958	$130,627			
											$130,627	$130,627				

NW Natural

Spread on Equal
Percent of Margin

Row	Schedule	Therms In Min	10/01/04 Permanent Rates	Commodity and Demand	Permanent Margin	Adjusted Permanent Margin	Customers	Therms
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	1	0.00	$5.00		$5.00	$5.00		
2	1r	1.00	$1.15689	$0.66302	$0.49387	$0.49387	3369	776,617
3	1c	1.00	$1.13452	$0.66302	$0.47150	$0.47150	176	63,497
4	2	0.00	$6.00	$0.00000	$6.00	$6.00	486,843	
5	2r	1.00	$1.08871	$0.66302	$0.42569	$0.42569		345,955,930
6	3	0.00	$8.00	$0.00000	$8.00	$8.00		
7	3c	1.00	$1.00308	$0.66302	$0.34006	$0.34006	52,862	145,167,952
8	3i	1.00	$0.97848	$0.66302	$0.31546	$0.31546	279	4,023,348
9	19	19.10	$18.18	$0.66302	$5.52	$5.52	139	34,949
		19.10	$17.57	$0.66302	$4.91	$4.91		
10	31c		$325.0		$325.00		1,250	
11		0.00	$0.17776	$0.00000	$0.17776	$0.17776		30,000,000
12		0.00	$0.16151	$0.00000	$0.16151	$0.16151		41,542,953
13	31i	0.00	$325.0	$0.00000	$325.00	$325.000	322	
14		0.00	$0.17776	$0.00000	$0.17776	$0.17776		7,728,000
15		0.00	$0.16151	$0.00000	$0.16151	$0.16151		23,051,694
16	32	0.00	$675.00	$0.00000	$675.00	$675.00	305	
17		0.00	$0.10021	$0.00000	$0.10021	$0.10021		25,619,872
18		0.00	$0.08516	$0.00000	$0.08516	$0.08516		42,693,995
19		0.00	$0.06011	$0.00000	$0.06011	$0.06011		29,992,120
20		0.00	$0.03506	$0.00000	$0.03506	$0.03506		68,642,118
21		0.00	$0.02002	$0.00000	$0.02002	$0.02002		76,778,293
22		0.00	$0.01000	$0.00000	$0.01000	$0.01000		68,186,343
23	33	0.00	$38,000.00	$0.00000	$38,000.00	$38,000.00	0	0
24		0.00	$0.00510	$0.00000	$0.00510	$0.00510		0
25	54	1.00	$1.06779	$0.66302	$0.40477	$0.40477		

NW Natural

Spread on Equal Percent of Margin

0.30

Row	Schedule	Bare Steel Computation: Base Margin	Bare Steel Proposed Margin	Bare Steel Margin Change	Bare Steel Margin Change $/ Therm	Geo Hazard Computation: Base Margin	Geo Hazard Proposed Margin	Geo Hazard Margin Change	Geo Hazard Margin Change $/ Therm
	(a)	(i)	(j)	(k)	(l)	(n)	(o)	(p)	(q)
1	1								
2	1r	$383,548	$384,693	$1,145	$0.00147	$383,548	$384,153	$605	$0.00078
3	1c	$29,939	$30,028	$89	$0.00141	$29,939	$29,986	$47	$0.00074
4	2								
5	2r	$147,269,980	$147,709,662	$439,682	$0.00127	$147,269,980	$147,502,411	$232,431	$0.00067
6	3								
7	3c	$49,365,814	$49,513,198	$147,384	$0.00102	$49,365,814	$49,443,726	$77,912	$0.00054
8	3i	$1,269,205	$1,272,995	$3,789	$0.00094	$1,269,205	$1,271,209	$2,003	$0.00050
9	19	$9,202	$9,230	$27	$0.00079	$9,202	$9,217	$15	$0.00042
10	31c								
11		$5,332,800	$5,348,721	$15,921	$0.00053	$5,332,800	$5,341,217	$8,417	$0.00028
12		$6,709,602	$6,729,634	$20,032	$0.00048	$6,709,602	$6,720,192	$10,590	$0.00025
13	31i								
14		$1,373,729	$1,377,831	$4,101	$0.00053	$1,373,729	$1,375,897	$2,168	$0.00028
15		$3,723,079	$3,734,195	$11,115	$0.00048	$3,723,079	$3,728,955	$5,876	$0.00025
16	32	$0	$0						
17		$2,567,367	$2,575,032	$7,665	$0.00030	$2,567,367	$2,571,419	$4,052	$0.00016
18		$3,635,821	$3,646,676	$10,855	$0.00025	$3,635,821	$3,641,559	$5,738	$0.00013
19		$1,802,826	$1,808,209	$5,382	$0.00018	$1,802,826	$1,805,672	$2,845	$0.00009
20		$2,406,593	$2,413,778	$7,185	$0.00010	$2,406,593	$2,410,391	$3,798	$0.00006
21		$1,537,101	$1,541,691	$4,589	$0.00006	$1,537,101	$1,539,527	$2,426	$0.00003
22		$681,863	$683,899	$2,036	$0.00003	$681,863	$682,940	$1,076	$0.00002
23	33	$0	$0	$0	N/A	$0	$0	$0	$0.00000
24		0.00	0.00	$0	0.00000	$0	$0	$0	$0.00002
25	54				0.00127	$0			$0.00067

NW Natural

Spread on Equal Percent of Margin

		Leftover Balances Vancouver Parking Lot Sale and Line of Credit				Coos Bay Revenue Requirement into rates			
Row	Schedule	Base Margin	Proposed Margin	Margin Change	Margin Change $/ Therm	Base Margin	Proposed Margin	Margin Change	Change $/ Therm
	(a)	(s)	(t)	(u)	(v)	(s)			
1	1								
2	1r	$383,548	$383,569	21	$0.00003	$383,548	$385,729	$2,181	$0.00281
3	1c	$29,939	$29,940	2	$0.00003	$29,939	$30,109	$170	$0.00268
4	2								
5	2r	$147,269,980	$147,278,106	8,126	$0.00002	$147,269,980	$148,107,378	$837,398	$0.00242
6	3								
7	3c	$49,365,814	$49,368,538	2,724	$0.00002	$49,365,814	$49,646,515	$280,701	$0.00193
8	3i	$1,269,205	$1,269,276	70	$0.00002	$1,269,205	$1,276,422	$7,217	$0.00179
9	19	$9,202	$9,203	1	$0.00001	$9,202	$9,254	$52	$0.00150
10	31c								
11		$5,332,800	$5,333,094	294	$0.00001	$5,332,800	$5,363,123	$30,323	$0.00101
12		$6,709,602	$6,709,973	370	$0.00001	$6,709,602	$6,747,754	$38,152	$0.00092
13	31i								
14		$1,373,729	$1,373,805	76	$0.00001	$1,373,729	$1,381,540	$7,811	$0.00101
15		$3,723,079	$3,723,285	205	$0.00001	$3,723,079	$3,744,249	$21,170	$0.00092
16	32								
17		$2,567,367	$2,567,509	142	$0.00001	$2,567,367	$2,581,966	$14,598	$0.00057
18		$3,635,821	$3,636,021	201	$0.00000	$3,635,821	$3,656,494	$20,674	$0.00048
19		$1,802,826	$1,802,926	99	$0.00000	$1,802,826	$1,813,077	$10,251	$0.00034
20		$2,406,593	$2,406,725	133	$0.00000	$2,406,593	$2,420,277	$13,684	$0.00020
21		$1,537,101	$1,537,186	85	$0.00000	$1,537,101	$1,545,842	$8,740	$0.00011
22		$681,863	$681,901	38	$0.00000	$681,863	$685,741	$3,877	$0.00006
23	33	$0			N/A	$0			N/A
24		$0			$0.00000	$0			$0.00000
25	54	$0			$0.00003	$0			$0.00268

NW Natural

Spread on Equal
Percent of Margin

Row	Schedule	SMPE Amortization Base Margin	SMPE Amortization Proposed Margin	SMPE Amortization Margin Change	SMPE Amortization Change $/ Therm	Removal of current Y2K for 32 Base Margin	Removal of current Y2K for 32 Proposed Margin	Removal of current Y2K for 32 Margin Change	Removal of current Y2K for 32 Change $/ Therm
	(a)								
1	1								
2	1r	$383,548	$383,696	$148	$0.00019	$0	$0	$0	$0.00000
3	1c	$29,939	$29,950	$12	$0.00018	$0	$0	$0	$0.00000
4	2								
5	2r	$147,269,980	$147,326,850	$56,870	$0.00016	$0	$0	$0	$0.00000
6	3								
7	3c	$49,365,814	$49,384,877	$19,063	$0.00013	$0	$0	$0	$0.00000
8	3i	$1,269,205	$1,269,696	$490	$0.00012	$0	$0	$0	$0.00000
9	19	$9,202	$9,206			$0	$0	$0	$0.00000
10	31c								
11		$5,332,800	$5,334,859	$2,059	$0.00007	$0	$0	$0	$0.00000
12		$6,709,602	$6,712,193	$2,591	$0.00006	$0	$0	$0	$0.00000
13	31i								
14		$1,373,729	$1,374,260	$530	$0.00007	$0	$0	$0	$0.00000
15		$3,723,079	$3,724,517	$1,438	$0.00006	$0	$0	$0	$0.00000
16	32								
17						$291,615	$282,872	($8,743)	($0.00300)
18						$412,976	$400,594	($12,382)	($0.00255)
19						$204,775	$198,635	($6,140)	($0.00180)
20						$273,354	$265,158	($8,196)	($0.00105)
21						$174,592	$169,357	($5,235)	($0.00060)
22						$77,450	$75,128	($2,322)	($0.00030)
23	33								
24									
25	54				$0.00018				

NW Natural

Spread on Equal Percent of Margin

Row	Schedule	Coos Bay Increment Base Margin	Coos Bay Increment Proposed Margin	Coos Bay Increment Margin Change	Coos Bay Increment Change $/ Therm	Removal of current Y2K for 31 Base Margin	Removal of current Y2K for 31 Proposed Margin	Removal of current Y2K for 31 Margin Change	Removal of current Y2K for 31 Change $/ Therm
	(a)								
1	1								
2	1r	$383,548	$385,399	$1,851	$0.00238			$0	$0.00000
3	1c	$29,939	$30,083	$144	$0.00228			$0	$0.00000
4	2								
5	2r	$147,269,980	$147,980,740	$710,760	$0.00205			$0	$0.00000
6	3								
7	3c	$49,365,814	$49,604,065	$238,251	$0.00164			$0	$0.00000
8	3i	$1,269,205	$1,275,331	$6,125	$0.00152			$0	$0.00000
9	19	$9,202	$9,247	$44	$0.00127			$0	$0.00000
10	31c								
11		$5,332,800	$5,358,537	$25,737	$0.00086	$5,332,800	$5,295,462	($37,338)	($0.00124)
12		$6,709,602	$6,741,984	$32,382	$0.00078	$6,709,602	$6,662,625	($46,977)	($0.00113)
13	31i								
14		$1,373,729	$1,380,359	$6,630	$0.00086	$1,373,729	$1,364,111	($9,618)	($0.00124)
15		$3,723,079	$3,741,048	$17,968	$0.00078	$3,723,079	$3,697,012	($26,067)	($0.00113)
16	32								
17		$2,567,367	$2,579,758	$12,391	$0.00048				
18		$3,635,821	$3,653,368	$17,547	$0.00041				
19		$1,802,826	$1,811,527	$8,701	$0.00029				
20		$2,406,593	$2,418,207	$11,615	$0.00017				
21		$1,537,101	$1,544,520	$7,418	$0.00010				
22		$681,863	$685,154	$3,291	$0.00005				
23	33								
24					$0.00002				
25	54				$0.00228				

NW Natural

Spread on Equal
Percent of Margin

		Y2K				Pipeline Integrity			
Row	**Schedule**	**Base Margin**	**Proposed Margin**	**Margin Change**	**Change $/ Therm**	**Base Margin**	**Proposed Margin**	**Margin Change**	**Change $/ Therm**
	(a)								
1	**1**								
2	**1r**	$383,548	$382,632	-$916	($0.00118)	$383,548	$384,447	$900	$0.00116
3	**1c**	$29,939	$29,867	-$71	($0.00113)	$29,939	$30,009	$70	$0.00111
4	**2**								
5	**2r**	$147,269,980	$146,918,369	-$351,611	($0.00102)	$147,269,980	$147,615,398	$345,419	$0.00100
6	**3**								
7	**3c**	$49,365,814	$49,247,951	-$117,862	($0.00081)	$49,365,814	$49,481,600	$115,786	$0.00080
8	**3i**	$1,269,205	$1,266,175	-$3,030	($0.00075)	$1,269,205	$1,272,182	$2,977	$0.00074
9	**19**	$9,202	$9,180	-$22	($0.00063)	$9,202	$9,224	$22	$0.00062
10	**31c**								
11		$5,332,800	$5,320,068	-$12,732	($0.00042)	$5,332,800	$5,345,308	$12,508	$0.00042
12		$6,709,602	$6,693,583	-$16,019	($0.00039)	$6,709,602	$6,725,340	$15,737	$0.00038
13	**31i**								
14		$1,373,729	$1,370,449	-$3,280	($0.00042)	$1,373,729	$1,376,951	$3,222	$0.00042
15		$3,723,079	$3,714,190	-$8,889	($0.00039)	$3,723,079	$3,731,811	$8,732	$0.00038
16	**32**	32 Sales Only							
17		$291,615	$290,919	-$696	($0.00003)	$2,567,367	$2,573,389	$6,022	$0.00024
18		$412,976	$411,990	-$986	($0.00002)	$3,635,821	$3,644,348	$8,528	$0.00020
19		$204,775	$204,286	-$489	($0.00002)	$1,802,826	$1,807,055	$4,228	$0.00014
20		$273,354	$272,701	-$653	($0.00001)	$2,406,593	$2,412,237	$5,645	$0.00008
21		$174,592	$174,175	-$417	($0.00001)	$1,537,101	$1,540,707	$3,605	$0.00005
22		$77,450	$77,265	-$185	$0.00000	$681,863	$683,463	$1,599	$0.00002
23	**33**	$0	$0						
24									$0.00000
25	**54**								$0.00111

NW Natural

Spread on Equal Percent of Margin

		Coos Bay investment Coos Bay Increment				UM1148 Stipulation			
Row	Schedule	Base Margin	Proposed Margin	Margin Change	Change $/ Therm	Base Margin	Proposed Margin	Margin Change	Change $/ Therm
	(a)								
1	1								
2	1r	$383,548	$383,356	($191)	($0.00025)	$383,548	$383,542	($6)	($0.00001)
3	1c	$29,939	$29,924	($15)	($0.00024)	$29,939	$29,938	($0)	($0.00001)
4	2								
5	2r	$147,269,980	$147,196,534	($73,446)	($0.00021)	$147,269,980	$147,267,788	($2,192)	($0.00001)
6	3								
7	3c	$49,365,814	$49,341,194	($24,620)	($0.00017)	$49,365,814	$49,365,079	($735)	($0.00001)
8	3i	$1,269,205	$1,268,573	($633)	($0.00016)	$1,269,205	$1,269,187	($19)	$0.00000
9	19	$9,202	$9,198	($5)	($0.00013)	$9,202	$9,202	($0)	$0.00000
10	31c								
11		$5,332,800	$5,330,140	($2,660)	($0.00009)	$5,332,800	$5,332,721	($79)	$0.00000
12		$6,709,602	$6,706,256	($3,346)	($0.00008)	$6,709,602	$6,709,502	($100)	$0.00000
13	31i								
14		$1,373,729	$1,373,044	($685)	($0.00009)	$1,373,729	$1,373,709	($20)	$0.00000
15		$3,723,079	$3,721,222	($1,857)	($0.00008)	$3,723,079	$3,723,024	($55)	$0.00000
16	32								
17		$2,567,367	$2,566,087	($1,280)	($0.00005)	$2,567,367	$2,567,329	($38)	$0.00000
18		$3,635,821	$3,634,007	($1,813)	($0.00004)	$3,635,821	$3,635,767	($54)	$0.00000
19		$1,802,826	$1,801,927	($899)	($0.00003)	$1,802,826	$1,802,799	($27)	$0.00000
20		$2,406,593	$2,405,392	($1,200)	($0.00002)	$2,406,593	$2,406,557	($36)	$0.00000
21		$1,537,101	$1,536,335	($767)	($0.00001)	$1,537,101	$1,537,079	($23)	$0.00000
22		$681,863	$681,523	($340)	$0.00000	$681,863	$681,853	($10)	$0.00000
23	33								
24					$0.00000				$0.00000
25	54				($0.00024)				($0.00001)

Northwest Natural Gas Company
Basis for Revenue Related Costs
Oregon

		12 months Ended 06/30/04		
1	Total Billed Gas Sales Revenues	706,856,956		
2	Total Oregon Revenues	729,176,083		
	Percent of Revenues			
3	Regulatory Commission Fees [1]	1,822,940	0.250%	statutory
4	City License and Franchise Fees	16,111,143	2.209%	Line 4/Line 2
5	Unbilled Franchise Accrual	113,876	0.016%	Line 5/Line 2
6	Net Uncollectible Expense	2,747,359	0.377%	Line 6/Line 2
7	Total	20,795,318	**2.852%**	sum 3-6

[1] Dollar figures is set at statutory level of 0.25% times Total Oregon Revenues (Line 3)

NW Natural
OPUC Tracking
Estimated Revenue Effects for the 12 Months Beginning October 1, 2005

Line No.	Item	Residential Increment	Commercial Increment	Industrial Increment	Total Increment Amounts	Limit For Increment Amounts
1	Commodity and Demand Deferrals	$2,120,149	$1,325,572	($5,143)	**$3,440,578**	
2	Temporary Increments	5,661,269	2,508,629	221,844	**8,391,782**	
3	Total	$7,781,418	$3,834,241	$216,701	**$11,832,360**	
4	2004 Utility Revenues					**$700,945,482**
5	@ 3% threshold					**3.0%**
6	Threshold for Annual Effect of Proposed Change in Amortization					**$21,028,364**

ORS 757.259 (6)